Renewed Market Rules

for the Ontario Electricity Market

Issue 1.0 - November 11, 2024 Public

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RUL-9	Renewed Market Rules CH 0.3 – Administration, Supervision, Enforcement	1.0
RUL-10	Renewed Market Rules CH 0.3 Appendices – Administration, Supervision, Enforcement	1.0
RUL-11	Renewed Market Rules CH 0.4 – Grid Connection Requirements	1.0
RUL-12	Renewed Market Rules CH 0.4 Appendices – Grid Connection Requirements	1.0
RUL-13	Renewed Market Rules CH 0.5 – Power System Reliability	1.0
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RUL-15	Renewed Market Rules CH 0.6 – Wholesale Metering	1.0
RUL-16	Renewed Market Rules CH 0.6 Appendices – Wholesale Metering	1.0
RUL-17	Renewed Market Rules CH 0.7 – System Operations and Physical Markets	1.0
RUL-18	Renewed Market Rules CH 0.7 Appendices – System Operations and Physical Markets	1.0
RUL-19	Renewed Market Rules CH 0.8 – Physical Bilateral Contracts and Financial Markets	1.0
RUL-20	Renewed Market Rules CH 0.8 Appendices – Physical Bilateral Contracts and Financial Markets	1.0
RUL-21	Renewed Market Rules CH 0.9 – Settlements and Billing	1.0
RUL-22	Renewed Market Rules CH 0.9 Appendices – Settlements and Billing	1.0
RUL-23	Renewed Market Rules CH 0.10 – Transmission Service and Planning	1.0
RUL-24	Renewed Market Rules CH 0.11 – Definitions	1.0

Document Control

Authorities

Prepared by
Market Rules

Reviewed by
Technical Panel
Legal Affairs

Approved by
IESO Board

Table of Contents

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for the Ontario Electricity Market

- Appendices

Issue 1.0 - November 11, 2024

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Table of Contents

RUL-6

Renewed Market Rules

Chapter 0.1

Introduction and Interpretation of the Market Rules

Renewed Market Rules – Chapter 0.1: Introduction and Interpretation of the Market Rules

0.1

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

1. Definitions

1.1 Market Rules

1.1.1 The rules set forth in MR Ch.1 to 11 are called the Market Rules for the Ontario Electricity Market (the "*market rules*") and constitute the *market rules* made under the authority and for the purposes of the *Electricity Act, 1998*.

1.2 Italicized Expressions

1.2.1 Italicized expressions used in the *market rules* have the meanings ascribed thereto in the definitions set forth in MR Ch.11. Words and phrases defined in the *Electricity Act, 1998* have the same meaning when used in the *market rules*.

2. Background and Legislative Authority

2.1 White Paper

2.1.1 In November, 1997, the Government of Ontario issued a White Paper entitled "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario", which set forth the broad framework for electricity sector reform with a view to the establishment of a competitive electricity market in Ontario.

2.2 Market Design Committee

2.2.1 During the course of 1998 and early 1999, the Market Design Committee, a committee created by Order in Council 2156/97 and comprised of representatives of stakeholders and consumers within the electricity industry, in its four quarterly reports made recommendations to the Government of Ontario on the design of the competitive electricity market for Ontario. As part of its responsibilities, the Market Design Committee was tasked with the preparation of initial draft rules governing the Ontario wholesale electricity market for submission to the *Minister*. In late January, 1999, the Market Design Committee submitted a set of draft initial rules to the *Minister*, with such further development of and revisions to the draft initial rules as may be necessary or appropriate being contemplated to be made prior to opening of the competitive markets.

2.3 Legislative Authority

2.3.1 The legislative authority for the *market rules* is contained in the *Electricity Act, 1998*. Specifically, subsection 32(1) of the *Electricity Act, 1998* contemplates that there will be made rules governing the *IESO-controlled grid* and establishing and governing the *IESO-administered markets* related to electricity and *ancillary services*.

3. Market Objective

3.1.1 The objective of the *IESO-administered markets* is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and *ancillary services* in Ontario.

4. Objectives and Status of Market Rules

4.1 Objectives and Status of Market Rules

4.1.1 The objectives of the *market rules* are to govern the *IESO-controlled grid* and to establish and govern efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and *ancillary services* in Ontario.

4.2 Purposes of Market Rules

4.2.1 Accordingly, the *market rules* include provisions:

4.2.1.1 governing the making, *amendment* and *publication* of the *market rules*;

4.2.1.2 governing the conveying of electricity into, through or out of the *IESO-controlled grid* and the provision of *ancillary services*;

4.2.1.3 governing the terms and conditions pursuant to which persons may be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

4.2.1.4 governing the manner in which electricity and *ancillary services* are sold, purchased and *dispatched* in the *IESO-administered markets*;

4.2.1.5 governing standards and procedures to be observed in system *emergencies*;

4.2.1.6 authorizing and governing the giving of directions by the *IESO*;

4.2.1.7 authorizing and governing the making of orders by the *IESO*;

4.2.1.8 providing a mechanism for the resolution of certain disputes arising under the *market rules*;

4.2.1.9 providing mechanisms for monitoring, surveillance and investigation of activities in the *IESO-administered markets* and the conduct of *market participants*; and

4.2.1.10 providing generally for the exercise by the *IESO* of such powers and authority as may be necessary or desirable for the purpose of carrying out its objects in relation to the *IESO-administered markets* and the *IESO-controlled grid*.

4.3 Contractual Force

4.3.1 The *market rules* have the effect of a contract between each *market participant* and the *IESO* by virtue of the execution by the *IESO* and each *market participant* of the *participation agreement* under which each *market participant* and the *IESO* agree to perform and observe the *market rules* so far as they are applicable to each *market participant* and the *IESO* as provided for in the *market rules,* their respective *licences* and *applicable law*.

5. The IESO

5.1 Responsibility for Market Rules

5.1.1 The body corporate responsible for the administration and supervision of the *market rules* is the *IESO*.

5.2 Objects of the IESO

5.2.1 The objects of the *IESO* are specified in subsection 6(1) of the *Electricity Act, 1998*.

5.3 Functions of the IESO

5.3.1 The functions, powers and authority of the *IESO* in relation to the administration and supervision of the *market rules* include:

5.3.1.1 supervising, administering and enforcing the *market rules*;

5.3.1.2 operating the markets related to electricity and *ancillary services* established under the *market rules*;

5.3.1.3 instituting and ensuring through the administration, supervision and enforcement of the *market rules* the effective and efficient implementation of the rules and standards contained in the *market rules*;

5.3.1.4 collecting information and statistics and *publishing* reports and information relating to the performance of the *IESO-administered markets*;

5.3.1.5 administering the ongoing development of, and *amendments* to, the *market rules*;

5.3.1.6 establishing power system *reliability standards* and maintaining power system *reliability*;

5.3.1.7 undertaking its coordination of power system planning responsibilities;

5.3.1.8 authorizing persons to participate in the *IESO-administered markets* and to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

5.3.1.9 undertaking monitoring, surveillance and investigation of activities in the *IESO-administered markets* and the conduct of *market participants*; and

5.3.1.10 liaising with other bodies having regulatory functions with respect to the *IESO-administered markets* and the *IESO-controlled grid*, such as the *Ontario Energy Board* and the federal Competition Bureau,

the whole of which in accordance with the *market rules*, the by-laws and *licence* of the *IESO* and *applicable law*.

5.4 Compliance with Market Rules

5.4.1 The *IESO* is bound to comply with, observe and perform any duties and obligations imposed on the *IESO* by the *market rules*.

6. Market Participants

6.1 Classes of Market Participants

6.1.1 The classes of *market participants* are described in MR Ch.2 s.2.

6.2 Third-Party Rights or Benefits

6.2.1 Unless otherwise expressly stated in the *market rules* or the *Electricity Act, 1998*, a person other than the *IESO* who is not a *market participant* is not entitled to any rights or benefits under the *market rules*.

6.3 Compliance with Market Rules

6.3.1 Subject to the terms of its *licence* and to the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and to any regulations enacted under those *Acts*, each *market participant* is bound to comply with, observe and perform any duties and obligations imposed on the *market participant* by the *market rules.*

6.3.2 Except as otherwise provided in these *market rules* or in any standard, policy, guideline, procedure or other document established by the *IESO* pursuant to these *market rules,* a *market participant* may use such information systems, communication systems, business processes, personnel, service providers or other agents as the *market participant*, in its sole discretion, considers appropriate for the purpose of assisting in the performance of its obligations under these *market rules* and under such standard, policy, guideline, procedure or other document provided that, as between the *IESO* and the *market participant*:

6.3.2.1 the *market participant* shall be bound by and fully responsible for all acts or omissions of its personnel, service providers or other agents; and

6.3.2.2 the *market participant* shall remain solely responsible and liable to the *IESO* for the due performance of such obligations.

7. Interpretation and Rules of Construction

7.1 General

7.1.1 In the *market rules*, unless the context otherwise requires:

7.1.1.1 words importing the singular include the plural and vice versa;

7.1.1.2 words importing a gender include any gender;

7.1.1.3 when italicized, other parts of speech and grammatical forms of a word or phrase defined in the *market rules* have a corresponding meaning;

7.1.1.4 an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, any government agency or body politic or collegiate, and any other entity or body or class of entity or body designated by regulation made pursuant to the *Electricity Act, 1998* as coming within the definition of the word "person";

7.1.1.5 a reference to a thing includes a part of that thing;

7.1.1.6 a reference to a Chapter, section, provision, condition, part or appendix is to a Chapter, section, provision, condition, part or appendix of the *market rules*;

7.1.1.7 a reference in a Chapter of the *market rules* to a section is to a section of that Chapter;

7.1.1.8 Unless the context suggests otherwise, reference to:

a. "MR" means the *market rules*;

b. "Ch." means a chapter of the *market rules;*

c. "App." means an appendix of a chapter of the *market rules*; and

d. "s." means section and "ss." means sections of the *market rules.*

7.1.1.9 a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it and a reference to a statute includes all regulations, proclamations, orders in council, rules and by-laws of a legislative nature issued under that statute;

7.1.1.10 a reference to a document or provision of a document, including the *market rules* or a provision of the *market rules*, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;

7.1.1.11 a reference to a person includes that person's executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation) and permitted assigns;

7.1.1.12 a reference to a body (including, without limitation, an institute, association or authority), whether statutory or not, which ceases to exist or whose functions are transferred to another body is a reference to the body which replaces it or which substantially succeeds to its powers or functions;

7.1.1.13 a reference to sections of the *market rules* separated by the word "to" (i.e., "sections 1.1 to 1.4") shall be a reference to the sections inclusively;

7.1.1.14 a reference to a time:

a. without the qualification "EST" or "EPT" is a reference to eastern time,which is the prevailing eastern standard or eastern daylight time in the Province of Ontario, unless otherwise specified;

b. followed by the qualification "EST" is a reference to eastern standard time in the Province of Ontario;

c. followed by the qualification "EPT" is a reference to eastern time, which is the prevailing eastern standard or eastern daylight time in the Province of Ontario; and

d. without the qualification "am", "a.m.", "pm" or "p.m." is a reference to time based on a 24-hour clock.

7.1.1.15 a reference to a month, calendar month, year or calendar year shall mean the period that commences the first hour of the first *trading day* that starts in such month or year and terminates the last hour of the last *trading day* that commences in such month or year; and

7.1.1.16 "maintaining" *reliability* shall include re-establishing or restoring *reliability* and "maintain" and "maintenance" shall be interpreted accordingly.

7.2 Headings

7.2.1 Headings in the *market rules* are inserted for convenience of reference only and shall not affect the interpretation of the *market rules*, nor shall they be construed as indicating that all of the provisions of the *market rules* relating to any particular topic are to be found in any particular Chapter, sub-Chapter, section, subsection, clause, provision, part or appendix.

7.3 Shall, Must and May

7.3.1 The words "shall" and "must" shall be construed as imperative and the word "may" shall be construed as permissive.

7.4 Explanatory Notes

7.4.1 Any provision in this document which is indicated as being an "explanatory note" or a "rule note" shall be deemed not to form a part of the *market rules.* Such explanatory notes or rule notes are inserted for convenience only and shall not affect the interpretation of the *market rules* nor be binding on the *IESO* or on any *market participant*.

7.5 Computation of Time

7.5.1 In the computation of time under these *market rules*, unless a contrary intention appears, if there is a reference to a number of days between two events, they are counted by excluding the day on which the first event happens and including the day on which the second event happens.

7.5.2 In the computation of time under MR Ch.2, 3, 6 and 10, unless a contrary intention appears, if the time for doing any act or thing expires on a day which is not a *business day*, the act or thing may be done on the next day that is a *business day.*

7.6 IESO Delegates

7.6.1 Delegation by the *IESO* of its powers and duties under these *market rules* shall be governed by the provisions of the *Governance and Structure By-law*.

7.6A Forms, Policies, Guidelines and Other Documents

7.6A.1 Forms, policies, guidelines and other documents, including but not limited to *market manuals* designed, created, developed, established or implemented by the *IESO* or a panel established by the *IESO* shall be interpreted in accordance with the *market rules* and the *Electricity Act, 1998*. Where there is any inconsistency between the *market rules* and a form, policy, guideline or other document, including but not limited to a *market manual*, the *market rules* shall prevail to the extent of the inconsistency.

7.7 Other Documents

7.7.1 Subject to section 7.7.4, and unless the context otherwise requires, where reference is made in the *market rules* to the design, creation, development, establishment or implementation of policies, guidelines and other documents by the *IESO* or a panel established by the *IESO*, such policies, guidelines and other documents shall not come into force until adopted by the *IESO Board, published* and notice thereof provided in accordance with section 7.7.2. The *IESO Board* may enter into such consultations, seek such advice and assistance and request such input from one or more persons as the *IESO Board* determines appropriate prior to adopting such policies, guidelines and other documents provided that the *IESO Board* retains the sole discretion to adopt such policies, guidelines and other documents in such form as the *IESO Board* determines appropriate. For certainty, any reference to "other documents" in section 7.7 shall not include forms or *market manuals*.

7.7.2 The policies, guidelines and other documents referred to in section 7.7.1 once adopted by the *IESO Board*, and forms and *market manuals* once prepared by the *IESO* shall be *published* by the *IESO* and notice thereof shall be provided to all *market participants*. The *IESO* and each *market participant* shall thereafter be bound to comply with the provisions of any such policies, guidelines, other documents and the *market manuals*.

7.7.2A The *IESO* shall establish a procedure which shall include but not be limited to processes for the stakeholdering of *market manuals* when the *market manuals* are created and for any subsequent amendments.

7.7.3 The *IESO Board* or a committee of the *IESO Board* established for that purpose may, from time to time, amend, and the *IESO Board* may from time to time replace or repeal, any policies, guidelines and other documents referred to in section 7.7.1. The procedures set forth in sections 7.7.1 and 7.7.2 shall apply equally to any amendment, replacement or repeal of such policies, guidelines and other documents and any reference in such sections to the *IESO Board* shall, with respect to the amendment of such policies, guidelines and other documents be deemed to include a reference to a committee of the *IESO Board* established for that purpose.

7.7.4 Any policy, guideline and other document required by the *market rules* to be implemented as an *amendment* to the *market rules* shall be implemented in accordance with the procedures set forth in MR Ch.3 s.4. Any policy, guideline and other document referred to in section 7.7.1 or in the *market manuals* which, by virtue of its prohibitive or mandatory character or its importance to the efficient operation of the *IESO-administered markets* or the *reliable* operation of the *IESO-controlled grid*, should have a legislative character shall be implemented by the *IESO* as an *amendment* to the *market rules.*

7.8 Currency

7.8.1 All references in:

7.8.1.1 the *market rules*;

7.8.1.2 any form, policy, guideline or other document referred to in section 7.7.1 or 7.7.3, including but not limited to all *market manuals*;

7.8.1.3 a *settlement statement*; or

7.8.1.4 an *invoice*,

to a monetary amount are expressed in Canadian dollars.

7.8.2 Any payment required to be made by or to the *IESO* or by or to a *market participant* pursuant to any of the documents referred to in sections 7.8.1.1 to 7.8.1.4 shall be made in Canadian dollars.

8. Notice, Notification, Service and Filing

8.1 Provision of Notice

8.1.1 Subject to section 8.3, and unless a contrary intention appears, notice is properly given, notification is properly made and service, filing, issuance and submission is properly effected under the *market rules*:

8.1.1.1 by courier or other form of personal delivery;

8.1.1.2 by prepaid first class mail addressed to the person at the address for service (if any) supplied by the person to the sender or, where the person is a *market participant*, to the address shown for that person in the list of *market participants* maintained by the *IESO* pursuant to MR Ch.2 s.3.1.6 or, where the person is the *IESO*, to the registered office of the *IESO*; or

8.1.1.3 by facsimile or electronic mail to a number or reference which corresponds with the address referred to in section 8.1.1.2.

8.2 Time of Notice

8.2.1 Subject to section 8.3, and unless a contrary intention appears, notice, notification, service, filing, issuance or submission shall be treated as having been duly given, made or effected to a person by the sender:

8.2.1.1 where given, made or effected by mail in accordance with section 8.1.1.2 to an address in the Province of Ontario, on the fourth *business day* after the day on which it is mailed;

8.2.1.2 where given, made or effected by mail in accordance with section 8.1.1.2 to an address in Canada outside the Province of Ontario or to an address in the United States, on the sixth *business day* after the day on which it is mailed;

8.2.1.3 where given, made or effected by mail in accordance with section 8.1.1.2 to an address outside Canada or the United States, on the twentieth *business day* after the day on which it is mailed;

8.2.1.4 where given, made or effected by facsimile in accordance with section 8.1.1.3 and a complete transmission report is issued from the sender's facsimile transmission equipment:

a. where notice, notification, service, filing or submission is of the type in relation to which the addressee is obliged to monitor the receipt by facsimile outside of, as well as during, business hours, on the day and at the time of transmission as indicated on the sender's facsimile transmission report; and

b. in all other cases, on the day and at the time of transmission as indicated on the sender's facsimile transmission report, if a *business day* or, if the transmission is on a day which is not a *business day* or is after 5:00 pm (addressee's time), at 9:00 am on the following *business day*;

8.2.1.5 Where given, made or effected by electronic mail in accordance with section 8.1.1.3:

a. where notice, notification, service, filing or submission is of a type in relation to which the addressee is obliged to monitor receipt by electronic mail outside of, as well as during, business hours, on the day and at the time when the notice or notification is recorded by the sender's electronic communication system as having been first received at the electronic mail destination; and

b. in all other cases, on the day and at the time when the notice, notification or document or other material served, filed or submitted is recorded by the sender's electronic communications system as having been first received at the electronic mail destination, if a *business day*, or if that time is after 5:00 pm (addressee's time) or the day is not a *business day*, at 9:00 am on the following *business day*; or

8.2.1.6 in any other case, when the person actually receives the notice, notification or document or other material served, filed or submitted.

8.3 Notice of Directions and Orders

8.3.1 Unless a contrary intention appears, instructions, directions and orders of the *IESO* may be given or issued to *market participants*:

8.3.1.1 in accordance with sections 8.1 or 8.2; or

8.3.1.2 by voice communication, in which case the instruction, direction or order shall be deemed validly given or issued at the time of communication.

9. Publication

9.1.1 Subject to section 9.1.2, where any document or information is required by the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO* to be *published* by the *IESO* or, in the case of the *market rules*, to be published by the *Minister*, *publication* shall be effected by placing the document or information on the public *IESO* web site. The document or information shall be deemed to be *published* when the document or information has been so placed.

9.1.2 Where the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO* prescribe a mode of publication other than that described in section 9.1.1 in respect of a specified document or information, the *IESO* shall, in addition to complying with section 9.1.1 comply with the publication requirement applicable to such document or information as is so prescribed. In such a case, the document or information shall be deemed to be published on the date on which the prescribed publication requirement has been satisfied.

10. [Intentionally left blank]

10A. General Conduct

10A.1 *Market participants* and the *IESO* shall not directly or indirectly engage or attempt to engage in conduct, alone or with another person, that they know, or ought reasonably to know:

10A.1.1 exploits the *IESO-administered markets*, including by, without limitation, exploiting any gap or defect in the *market rules*;

10A.1.2 circumvents any of the *market rules*;

10A.1.3 manipulates any of the *IESO-administered markets*, including by, without limitation, manipulating the determination of a *settlement amount*;

10A.1.4 undermines through any means the ability of the *IESO* to carry out its powers, duties or functions under the *Electricity Act, 1998* or the *market rules*; or

10A.1.5 interferes with the determination of a *market price* or *dispatch* outcome by competitive market forces.

10A.2 Without limiting the availability of any defences that a *market participant* may have with respect to conduct set out in section 10A.1, a *market participant* will not have violated section 10A.1 where it establishes that its conduct was entirely or predominantly caused by:

10A.2.1 a procurement contract as defined in the *Electricity Act, 1998*, or;

10A.2.2 an order of the *Ontario Energy Board* made in accordance with s.78.1 of the *Ontario Energy Board Act, 1998*.

10A.3 For the purposes of this section 10A, "conduct" includes acts and omissions, but with respect to the *OPA* and *OEFC* only includes acts or omissions in their capacity as *market participants*, and with respect to the *IESO* does not include:

10A.3.1 market design or implementing government policy; and

10A.3.2 the development of the *market rules*, *market manuals* and policies, guidelines, or other documents referenced in section 7.7.

11. Information Disclosure

11.1 Mandatory Disclosure

11.1.1 *Market participants* shall disclose or provide to the *IESO* and/or to other *market participants,* and the *IESO* shall disclose or provide to *market participants*, such information as is required to be disclosed or provided pursuant to the *market rules*. Such information shall be disclosed or provided within the time specified in, and in the form and manner required by, the relevant provisions of the *market rules*. Where no time is specified in relation to the disclosure or provision of specific information, the information shall be disclosed or provided within a reasonable time.

11.2 No Misleading or Deceptive Information

11.2.1 Information disclosed or provided by a *market participant* to the *IESO* and/or to other *market participants* or by the *IESO* to *market participants* pursuant to the *market rules* shall be, to the best of the disclosing person's knowledge, true, correct and complete at the time at which such disclosure or provision is made. Neither the *IESO* nor *market participants* shall knowingly or recklessly disclose or provide information pursuant to the *market rules* that, at the time and in light of the circumstances in which such disclosure or provision is made, is misleading or deceptive or does not state a fact that is required to be stated or that is necessary to make the statement not misleading or deceptive.

11.3 Correction of Incorrect Information

11.3.1 Where a *market participant* or the *IESO* discovers that any information previously disclosed or provided by it to any person pursuant to the *market rules* was, at the time at which it was disclosed or provided, or becomes untrue, incorrect, incomplete, misleading or deceptive, the disclosing person shall immediately rectify the situation and disclose or provide the true, correct, complete, not misleading or not deceptive information to the person to whom the original or currently untrue, incorrect, incomplete, misleading or deceptive information had been disclosed or provided.

11.4 Use of Information by the IESO

11.4.1 Subject to the provisions of MR Ch.3 ss.3 and 5, the *IESO* and any panel established by the *IESO* is entitled to use any data or information obtained in pursuance of the *IESO*'s or the panel's powers, functions or duties under the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO.* The *IESO* may use such information in connection with or to initiate processes provided for in the *market rules* including, but not limited to:

11.4.1.1 a process to *amend* the *market rules* pursuant to MR Ch.3 s.4; or

11.4.1.2 a process to enforce compliance with the *market rules* pursuant to MR Ch.3 s.6.

12. Interpretation Bulletins

12.1.1 [Intentionally left blank]

12.1.2 [Intentionally left blank]

12.1.3 Where the *IESO* receives a request from any person, including a member of a panel established by the *IESO*, a *market participant* or the *IESO Board*, seeking a clarification or posing a question as to the interpretation, application or implementation of a *market rule*, the *IESO* may refer the matter to the *technical panel* and the *technical panel* shall provide such clarification or the answer to such question to the *IESO.*

12.1.4 The *IESO* may, from time to time, either on its own initiative or upon receipt from the *technical panel* of a material clarification of, or answer to, a question concerning the interpretation, application or implementation of a *market rule*, *publish* and give notice of bulletins as to the interpretation, application or implementation of a *market rule*.

12.1.5 A bulletin *published* pursuant to section 12.1.4 shall be binding on the *IESO*, provided that:

12.1.5.1 none of the relevant *market rules* are thereafter *amended*;

12.1.5.2 there is thereafter no amendment to any relevant provisions of the *Electricity Act, 1998;* and

12.1.5.3 the *IESO* has been provided with all relevant facts in respect of which the interpretation or clarification has been requested and all such facts were true at the time the interpretation or clarification was made.

13. Liability and Indemnification

13.1 Liability of IESO

13.1.1 Except as required by section 13.1.2 or as otherwise provided in these *market rules,* the *IESO* shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of a *market participant* whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the *IESO* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual.*

13.1.2 Subject to section 13.1.4, the *IESO* shall indemnify and hold harmless a *market participant* and the *market participant's* directors, officers and employees from any and all claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *market participant* or its directors, officers or employees to the extent that such claims, losses, liabilities, actions, judgements, suits, costs, expenses, disbursements or damages arise out of any willful misconduct by or any act or omission that constitutes gross neglience of the *IESO* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.1.3 For the purposes of section 13.1.2, an act or omission of the *IESO* effected in compliance with these *market rules* or with the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* shall be deemed not to constitute willful misconduct or gross negligence.

13.1.4 Except as otherwise provided in these *market rules* other than in this section 13, in no event shall the *IESO* be liable to indemnify and hold harmless a *market participant* or the *market participant's* directors, officers or employees from or in respect of:

13.1.4.1 any indirect or consequential loss or incidental or special damages including, but not limited to, punitive damages; or

13.1.4.2 any loss of profit, loss of contract, loss of opportunity or loss of goodwill,

and no *market participant* shall assert or attempt to assert against the *IESO* any claim in respect of any of the losses or damages referred to in sections 13.1.4.1 and 13.1.4.2.

13.1.5 Each *market participant* shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims for indemnification that may be made by the *market participant* pursuant to section 13.1.2.

13.2 Liability of Market Participants

13.2.1 Except as required by section 13.2.2 or as otherwise provided in these *market rules,* a *market participant* shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of the *IESO* whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual.*

13.2.2 Subject to section 13.2.4, each *market participant* shall indemnify and hold harmless the *IESO,* the *IESO's* directors, officers and employees and any member of a panel established by the *IESO* from any and all claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO,* its directors, officers or employees or the member of a panel established by the *IESO* to the extent that such claims, losses, liabilities, actions, judgements, suits, costs, expenses, disbursements or damages arise out of any willful misconduct by or any negligent act or omission of the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.2.3 For the purposes of section 13.2.2, an act or omission of a *market participant* effected in compliance with the *market rules* or with the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* shall be deemed not to constitute willful misconduct or a negligent act or omission.

13.2.4 Except as otherwise provided in these *market rules* other than in this section 13, in no event shall a *market participant* be liable to indemnify and hold harmless the *IESO,* the *IESO's* directors, officers or employees or a member of a panel established by the *IESO* from or in respect of:

13.2.4.1 any indirect or consequential loss or incidental or special damages including, but not limited to, punitive damages; or

13.2.4.2 any loss of profit, loss of contract, loss of opportunity or loss of goodwill,

and the *IESO* shall not assert or attempt to assert against a *market participant* any claim in respect of any of the losses or damages referred to in sections 13.2.4.1 and 13.2.4.2.

13.2.5 Nothing in this section 13.2 shall be read as limiting the right of the *IESO* to impose a financial penalty or other sanction including, but not limited to, the issuance of a *suspension order*, a *disconnection order* or a *termination order*, on a *market participant* in accordance with the provisions of these *market rules.*

13.2.6 The *IESO* shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims for indemnification that may be made by the *IESO* pursuant to section 13.2.2 including, but not limited to, seeking recovery under any applicable policies of insurance to which the *IESO* or the *market participant,* as the case may be, is a beneficiary.

13.3 Force Majeure

13.3.1 Subject to section 13.3.14, the *IESO* shall not be liable to any *market participant* for any failure or delay in the performance of any of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*, other than the obligation to make payments of money, to the extent that such failure or delay is due to a *force majeure event*, provided that the *IESO* shall only be excused from performance pursuant to this section 13.3.1:

13.3.1.1 for so long as the *force majeure event* continues and for such reasonable period of time thereafter as may be necessary for the *IESO* to resume performance of the obligation; and

13.3.1.2 where and to the extent that the failure or delay in performance would not have been experienced but for such *force majeure event*.

13.3.2 Subject to section 13.3.14, a *market participant* shall not be liable to the *IESO* for any failure or delay in the performance of any of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*, other than the obligation to make payments of money, to the extent that such failure or delay is due to a *force majeure event,* provided that the *market participant* shall only be excused from performance pursuant to this section 13.3.2:

13.3.2.1 for so long as the *force majeure event* continues and for such reasonable period of time thereafter as may be necessary for the *market participant* to resume performance of the obligation; and

13.3.2.2 where and to the extent that such failure or delay would not have been experienced but for such *force majeure event*.

13.3.3 Neither the *IESO* nor a *market participant* may invoke a *force majeure event* unless it has given notice in accordance with section 13.3.4 or 13.3.5, respectively.

13.3.4 Where the *IESO* invokes a *force majeure event*, it shall give notice to *market participants* and shall *publish* notice of the *force majeure event* as soon as reasonably practicable but in any event within two *business days* of the date on which the *IESO* becomes aware of the occurrence of the *force majeure event*, which notice shall include particulars of:

13.3.4.1 the nature of the *force majeure event*;

13.3.4.2 the effect that such *force majeure event* is having on the *IESO's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document or referred to in section 7.7 or any *market manual*; and

13.3.4.3 the measures that the *IESO* is taking, or proposes to take, to alleviate the impact of the *force majeure event*.

13.3.5 Where a *market participant* invokes a *force majeure event*, it shall give notice to the *IESO* of the *force majeure event* as soon as reasonably practicable but in any event within two *business days* of the date on which the *market participant* becomes aware of the occurrence of the *force majeure event*, which notice shall include particulars of:

13.3.5.1 the nature of the *force majeure event*;

13.3.5.2 the effect that such *force majeure event* is having on the *market participant's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*; and

13.3.5.3 the measures that the *market participant* is taking, or proposes to take, to alleviate the impact of the *force majeure event*.

13.3.6 Subject to section 13.3.7, where the *IESO* or a *market participant* invokes a *force majeure event*, it shall use all reasonable endeavours to mitigate or alleviate the effects of the *force majeure event* on the performance of its obligations under these *market rules*.

13.3.7 The settlement of any strike, lockout, restrictive work practice or other labour disturbance constituting a *force majeure event* shall be within the sole discretion of the *IESO* or the *market participant*, as the case may be, involved in such strike, lockout, restrictive work practice or other labour disturbance and nothing in section 13.3.6 shall require the *IESO* or the *market participant*, as the case may be, to mitigate or alleviate the effects of such strike, lockout, restrictive work practice or other labour disturbance.

13.3.8 Where the *IESO* invokes a *force majeure event,* it shall notify *market participants* and shall as soon as practicable *publish* notice of any material change in the information contained in the notice referred to in section 13.3.4 or in any previous notice given and *published* pursuant to this section 13.3.8.

13.3.9 Where a *market participant* invokes a *force majeure event*, it shall as soon as practicable notify the *IESO* of any material change in the information contained in the notice referred to in section 13.3.5 or in any previous notice given pursuant to this section 13.3.9.

13.3.10 Where the *IESO* invokes a *force majeure event*, it shall give notice to *market participants* and shall *publish* notice of the cessation of the *force majeure event* and of the cessation of the effects of such *force majeure event* on the *IESO*'s performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.3.11 Where a *market participant* invokes a *force majeure event*, it shall give notice to the *IESO* of the cessation of the *force majeure event* and of cessation of the effects of such *force majeure event* on the *market participant's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.3.12 The *IESO* shall *publish* any notice provided to it pursuant to section 13.3.5, 13.3.9 or 13.3.11.

13.3.13 Nothing in this section 13.3 shall be read as limiting the right of the *IESO* to impose on a *market participant* a sanction, other than a financial penalty, including but not limited to the issuance of a *suspension order*, a *disconnection order* or a *termination order*, in accordance with the provisions of these *market rules.*

13.3.14 Nothing in this section 13.3 shall excuse the *IESO* or a *market participant* from performing any of their respective obligations contained in:

13.3.14.1 those provisions of these *market rules* that govern the *IESO* and the *market participant* during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*;

13.3.14.2 those provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* that govern the *IESO* and the *market participant* during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*;

13.3.14.3 the *Ontario electricity emergency plan*;

13.3.14.4 the *market participant's emergency preparedness plan*;

13.3.14.5 the *Ontario power system restoration plan*; or

13.3.14.6 the *market participant's restoration participant attachment*,

during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*.

13.4 Contractual Liability

13.4.1 The liability and indemnification provisions of sections 13.1 and 13.2 and, where applicable, of any other section of these *market rules* other than this section 13, and the *force majeure* provisions of section 13.3 shall apply to any agreement or contract referred to in these *market rules* or in any policy, guideline or other document referred to in section 7.7 or any *market manual* to which the *IESO* and a *market participant* are parties or to the terms of which the *IESO* and a *market participant* are bound and to all acts or omissions of the *IESO* or the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under such agreement, contract, policy, guideline or other document referred to in section 7.7 or any *market manual*. In the event of an inconsistency between such liability, indemnification and *force majeure* provisions and the liability, indemnification and *force majeure* provisions of such agreement, the liability and indemnification provisions of sections 13.1 and 13.2 and, where applicable, of any other section of these *market rules*, and the *force majeure* provisions of section 13.3 shall prevail to the extent of the inconsistency.

14. Exemptions

14.1 Scope of Exemptions

14.1.1 As provided in the *Electricity Act, 1998* an *exemption applicant* may apply to the *IESO* for an *exemption* from the application of any obligation or standard which is or may be imposed upon the *exemption applicant* or in respect of the *exemption applicant's facilities* or equipment pursuant to these *market rules, market manuals* or to any standard, policy or procedure established by the *IESO* pursuant to these *market rules*.

14.1.2 In this section 14, a reference to an *exemption applicant* shall, where the context so requires, be deemed to include a reference to an *exemption applicant* to whom an *exemption* has been granted by the *IESO Board*.

14.2 Application Process

14.2.1 An *exemption applicant* shall apply for an *exemption* in accordance with the practices and procedures established by the *IESO Board.*

14.3 Effect of Exemption and Monitoring

14.3.1 Failure by an *exemption applicant* to comply with any of the terms and conditions of an *exemption* imposed pursuant to an order of the *IESO Board*, including without limitation any amendments to such terms and conditions, shall constitute a breach of the *market rules*.

14.3.2 An *exemption applicant* to whom an *exemption* has been granted shall from time to time provide to the *IESO* such information as the *IESO* may request for the purposes of monitoring:

14.3.2.1 compliance by the *exemption applicant* with any terms and conditions of the *exemption*; and

14.3.2.2 the progress of implementation of the *exemption* plan forming part of the *exemption application*, as such *exemption* plan may be amended from time to time with the concurrence of the *IESO Board.*

14.4 Reconsideration, Removal or Transfer of Exemptions

14.4.1 Procedures for the reconsideration, removal or transfer of *exemptions* are included in the practices and procedures referred to in section 14.2.1.

14.5 Costs

14.5.1 Where the *IESO Board* has established and included in the practices and procedures referred to in section 14.2.1 the manner in which the *IESO* will recover from each *exemption applicant* the costs of processing its *exemption application* and, where a panel of the *IESO Board* so decides as a term or condition of the *exemption*, an *exemption applicant* other than the *IESO* shall submit to the *IESO* such costs, commit to the *IESO* in such form as the *IESO* considers appropriate to pay such costs, or both, in the manner specified in the practices and procedures referred to in section 14.2.1.

14.5.2 Where the removal or reconsideration of an *exemption* granted to a *pre-existing facility or equipment* prior to *market commencement date* was prompted as a result of the activities of one or more *market participants* and the *IESO* determines that such *market participant(s)* will benefit from the removal or reconsideration of the *exemption*, unless the costs to be incurred by the *exemption applicant* to comply with the standard of obligation to which the *exemption* relates or with the amended terms and conditions of the *exemption* as the case may be, are recoverable by means of a process or procedure mandated by the *OEB*, costs shall be recovered from each such *market participant* on a pro-rata basis based upon the *IESO's* assessment of the benefit accruing to each such *market participant* from the removal or reconsideration of the *exemption*. No costs shall be recoverable in respect of the removal or reconsideration of an *exemption* granted after the *market commencement date.*

14.5.3 The costs that may be collected and remitted pursuant to section 14.5.2 shall be calculated by the *IESO* by subtracting from the costs to be incurred by the *exemption applicant* to comply with the standard or obligation to which the *exemption* relates or with the amended terms and conditions of the *exemption*, as the case may be, the value of any benefit determined by the *IESO* as accruing to the *exemption applicant* as a result of its compliance with such standard or obligation or such amended terms and conditions.

14.5.4 Where an *exemption* was granted to a *pre-existing facility or equipment* prior to *market commencement date* but section 14.5.2. is not applicable, the costs will be recovered from one or more of the following classes of *market participants* as determined by the *IESO*:

14.5.4.1 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* withdrawn at all *delivery points,* determined in accordance with MR Ch.9, during such period as may be specified by the *IESO*;

14.5.4.2 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* injected at all *delivery points*, determined in accordance with MR Ch.9, during such period as may be specified by the *IESO*;

14.5.4.3 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* withdrawn at all *intertie metering points*, determined in accordance with MR Ch.9, during such period as may be specified by the *IESO*; and

14.5.4.4 all *market participants* on a pro-rata basis based on their respective allocated quantities of *energy* injected at all *intertie metering points*, determined in accordance with MR Ch.9, during such period as may be specified by the *IESO*.

14.6 Need for Rule Amendment

14.6.1 Where the *IESO* determines that the benefit of an *exemption* should be extended to all *market participants* or persons or to a class of *market participants* or persons the *IESO* may:

14.6.1.1 where the *exemption* was granted prior to the date on which MR Ch.3 s.4 comes into force, recommend to the *IESO Board* that it advise the *Minister* that an *amendment* to the *market rules* be made accordingly; or

14.6.1.2 where the *exemption* was granted after the date on which MR Ch.3 s.4 comes into force, recommend to the *IESO Board* that the *amendment* process set forth in MR Ch.3 s.4 be initiated with a view to *amending* the *market rules* accordingly.

RUL-7

Renewed Market Rules

Chapter 0.2

Participation

Connecting Today.
Powering Tomorrow.

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Market Rules

Reviewed by
Technical Panel
Legal Affairs

Approved by
IESO Board

Table of Contents

Introduction

A.1 Chapter Scope and Operation

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

B.1 Exceptions

B.1.1 Notwithstanding section 5.5.1, for the purposes of facilitating the *market transition*, and for such time as may be required for the *IESO* to accumulate sufficient data to comply with section 5.5.1, the IESO may for the calculation of *actual exposure*, calculate a *market participant's actual exposure* for *physical transactions* using an average of the actual net *settlement amounts* for the three most recent *energy market billing periods*, in which that *market participant* has conducted *physical transactions* for *energy*.

1. Introduction

1.1 Introduction

1.1.1 This Chapter sets forth:

1.1.1.1 the procedures pursuant to which persons may apply to the *IESO* for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

1.1.1.2 the prudential, technical and other requirements which must be met by prospective *market participants* and by *market participants*;

1.1.1.3 the fees payable by prospective *market participants* and by *market participants*; and

1.1.1.4 the terms and conditions upon which a *market participant* may cease to be a *market participant*.

1.2 Participation

1.2.0 A person who has been issued a *licence* by the *OEB* pursuant to Part V of the Ontario Energy Board Act, 1998, is subject to all *market rules* relating to the activities authorized by such *licence* and all other applicable *market rules*.

1.2.1 No person shall participate in the *IESO-administered markets* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that person has been authorized by the *IESO* to do so pursuant to this Chapter, provided however that this section 1.2.1 shall not apply to require any authorization in respect of physical loop flows inadvertently arising as a result of transactions between entities located outside the *IESO control area*.

1.2.2 No person shall be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless the *IESO* is satisfied:

1.2.2.1 on the basis of the certification, tests, and inspections referred to in section 6.2, that the person satisfies the technical requirements referred to in that section applicable to all *market participants*;

1.2.2.2 that the person, if it applies to participate in the *IESO-administered markets*, will satisfy the applicable *prudential support* requirements and any other financial requirements set forth in the *market rules*;

1.2.2.3 that the person has executed a *participation agreement* and filed same with the *IESO*;

1.2.2.4 that the person holds a *licence* permitting the person to engage in one or more of the activities described in section 57 of the *Ontario Energy Board Act, 1998*, unless:

a. the person is exempt by regulation enacted pursuant to the *Ontario Energy Board Act, 1998* from the obligation to hold such a *licence*; or

b. the person is not engaging in an activity for which the person requires a *licence* pursuant to section 57 of the *Ontario Energy Board Act, 1998*; and

1.2.2.5 [Intentionally left blank – section deleted]

1.2.2.6 on the basis of the documentation referred to in section 3.1.2.2, that the person, if it applies for authorization as a *market participant* other than for authorization to participate solely as one or a combination of (i) a *virtual trader*; (ii) a *TR participant*; or (iii) a *capacity auction participant*:

a. is registered for the federal harmonized value-added tax system under Part IX of the *Excise Tax Act* (Canada); or

b. is resident in Canada and is, by virtue of *applicable law*, not liable to pay the federal harmonized value-added tax imposed under Part IX of the *Excise Tax Act* (Canada).

1.2.2.7 that the person has disclosed to the *IESO* all its *market control entities* pursuant to MR Ch.7 s.22.9.2.

1.2.3 A person who has been authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* may participate in the market or trading activities to which the authorization to participate relates.

1.2.4 A person who is authorized prior to a *market transition* by the *IESO* to conduct *physical transactions* under this section 1.2, shall be authorized to participate in the *real-time market* and the *day-ahead market*. For greater certainty, nothing in this provision shall be construed to permit a *market participant* to change its *facility* or *resource* registration, except as otherwise permitted by the *market rules*.

2. Classes of Market Participants

2.1.1 A person may apply for authorization to participate as one or more of the following classes of *market participants* in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid:*

2.1.1.1 *generators*;

2.1.1.2 *distributors*;

2.1.1.3 *wholesale sellers*;

2.1.1.4 *wholesale consumers*;

2.1.1.5 *retailers*;

2.1.1.6 *transmitters*;

2.1.1.7 *capacity market participants*;

2.1.1.8 *capacity auction participants*;

2.1.1.9 *electricity storage participants*;

2.1.1.10 *virtual traders*; and

2.1.1.11 *TR participants*.

3. Authorization

3.1 Application for Authorization

3.1.1 A person who wishes to be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* must file a completed *application for authorization to participate* in accordance with the applicable *market manual*.

3.1.2 The *application for authorization to participate* shall be accompanied by:

3.1.2.1 the non-refundable application fee established from time to time by the *IESO* to defray the costs of processing the *application for authorization to participate*; and

3.1.2.2 unless the *application for authorization to participate* is submitted in respect of an applicant that is applying for authorization to participate in the *IESO-administered markets* solely as one or a combination of (i) a *virtual trader;* (ii) a *TR participant;* or (iii) a *capacity auction participant*, either:

a. the federal harmonized value-added tax system registration number issued to the applicant by the Canada Customs and Revenue Agency; or

b. where the applicant is resident in Canada and is, by virtue of *applicable law*, not liable to pay the federal harmonized value-added tax under Part IX of the *Excise Tax Act* (Canada), such documentation as may be prescribed in the *Excise Tax Act* (Canada) or described in the policies of the Canada Customs and Revenue Agency to support the exemption from such liability to pay.

3.1.3 The *IESO* shall, within ten *business days* of receiving an *application for authorization to participate* or within such longer period of time as may be agreed between the *IESO* and the applicant, advise the applicant of any further information or clarification which is required in support of its application if, in the *IESO's* opinion, the *application for authorization to participate* is:

3.1.3.1 incomplete; or

3.1.3.2 contains information with respect to which the *IESO* requires clarification.

3.1.4 If the further information or clarification which is requested by the *IESO* pursuant to section 3.1.3 is not provided to the *IESO's* satisfaction within fifteen *business days* of the request or within such longer period of time as may be agreed between the *IESO* and the applicant, the applicant will be deemed to have withdrawn the *application for authorization to participate*.

3.1.5 An applicant or *market participant* shall forthwith advise the *IESO* of any circumstances which result or are likely to result in a change in the information provided in the *application for authorization to participate* or in any updates thereto.

3.1.6 The *IESO* shall establish, maintain, update and *publish*:

3.1.6.1 a list of all *market participants* and a list of all *applications for authorization* to *participate* filed with the *IESO*;

3.1.6.2 a list of all *market participants* that will cease to be *market participants* and the time that each listed *market participant* will cease to be a *market participant*;

3.1.6.3 a list of all *market participants* that are the subject of a *suspension order* or a *termination order* and the time at which the rights of each listed *market participant* was suspended or terminated; and

3.1.6.4 a list of all *market participants* that are the subject of an order referred to in MR Ch.3 s.6.5.1, and the time at which such order became effective in respect of each listed *market participant*.

4. Orders Authorizing Participation

4.1 Authorization Orders

4.1.1 The *IESO* shall by order authorize or may by order conditionally authorize an applicant to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on such terms and conditions as the *IESO* considers appropriate, if:

4.1.1.1 for a conditional order, the *IESO* is satisfied that the applicant meets the requirements set out in section 1.2.2.2; or

4.1.1.2 for an order other than a conditional order, the *IESO* is satisfied that the applicant meets the requirements set out in section 1.2.2 applicable to the applicant.

4.1.2 The *IESO* shall issue an order made pursuant to section 4.1.1 in accordance with the following timelines:

4.1.2.1 within twenty *business days* of receipt of the applicant's *application for authorization to participate* or of the further information or clarification requested under section 3.1.3, whichever is the later; or

4.1.2.2 within such longer period of time as may be agreed between the *IESO* and the applicant.

4.1.3 A conditional order issued pursuant to section 4.1.1, shall:

4.1.3.1 stipulate the date by which the applicant must satisfy the conditions; and

4.1.3.2 lapse on the date referred to in section 4.1.3.1 if the applicant has not, prior to that date, received from the *IESO* notification that the applicant has fulfilled all conditions set out in the order. A lapsed order shall be deemed to constitute an order denying the applicant authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* as of the date it lapses.

4.1.4 The *IESO* may, at any time and in its sole discretion, amend a conditional order issued pursuant to section 4.1.1 to include an additional condition, to remove a condition, or to extend the date stipulated pursuant to section 4.1.3.1.

4.1.5 A person to whom a conditional order relates may request, in accordance with the applicable *market manual*, that the *IESO* extend the date stipulated pursuant to section 4.1.3.1 if a condition of the order cannot be met due to circumstances beyond the person's control or influence.

4.1.6 The *IESO* may terminate or suspend a conditional order issued pursuant to section 4.1.1 at any time if the *IESO* determines that:

4.1.6.1 there are material reliability or operational risks in maintaining the order;

4.1.6.2 the person to whom the order relates failed to address or complete a condition of the order; or

4.1.6.3 the person to whom the order relates fails to comply with the applicable *market rules*.

4.1.7 If an order issued pursuant to section 4.1.1 is terminated or suspended or lapses, the person to whom the order relates may submit a request to the *IESO* in accordance with the applicable *market manual* to extend or renew the order.

4.1.8 If the *IESO* is not satisfied that an applicant meets the requirements set out in section 1.2.2, the *IESO* shall, within twenty *business days* of receipt of the *application for authorization to participate* or of the further information or clarification requested under section 3.1.3, whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, by order deny the applicant authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

4.1.9 A conditional order shall be deemed to constitute the order authorizing the applicant to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* as of the date the applicant receives notification from the *IESO* that the applicant has fulfilled all the conditions of the order.

4.1.10 A person to whom a *facility* is transferred in accordance with MR Ch.7 s.2.5, shall be deemed to be a *market participant* as of the commencement of the first *trading day* following completion of the transfer and shall expeditiously pursue and complete the conditions precedent to becoming fully authorized as required by this Chapter.

4.1.11 A person who wishes to dispute an order of the *IESO* made pursuant to section 4.1.1 or 4.1.8 shall follow the dispute resolution procedures set forth in MR Ch.3 s.2.

5. Prudential Requirements

5.1 Purpose and Application

5.1.1 Sections 5, 5B, 5C and 5D set forth the nature and amount of *prudential support* that must be provided by *market participants* as a condition of participation in the *real-time market* or the *day-ahead market*, as the case may be, or of causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid,* and the manner in which *market participants* must provide and maintain such *prudential support* on an on-going basis in order to minimize the impact of payment defaults on *market participants*.

5.1.2 [Intentionally left blank – section deleted]

Application

5.1.3 The rules governing *prudential support* in this Chapter 2 apply to *market participants* in the manner set out below:

Physical Transactions and/or Virtual Transactions

5.1.3.1 Sections 5.1 and 5.2 shall apply to *market participants* authorized to conduct one or any combination of:

a. *physical transactions* in the *day-ahead market;*

b. *physical transactions* in the *real-time market*; or

c. *virtual transactions* in the *day-ahead market,* except for subsection 5.2.6.

Physical Transactions

5.1.3.2 Subject to subsection 5.1.3.4, sections 5.3 to 5.8 shall apply to *market participants* authorized to conduct one or any combination of:

a. *physical transactions* in the *day-ahead market*; or

b. *physical transactions* in the *real-time market.*

Virtual Transactions

5.1.3.3 Subject to subsection 5.1.3.4, section 5C shall apply to *market participants* authorized to conduct *virtual transactions* in the *day-ahead market*.

Physical Transactions and Virtual Transactions

5.1.3.4 Section 5D shall apply to *market participants* authorized to conduct both *physical transactions* and *virtual transactions*. Sections 5 and 5C shall also apply, as appropriate, to *market participants* authorized to conduct both *physical transactions* and *virtual transactions*, except for sections 5.4, 5.6, 5C.2 and 5C.4.

Capacity Auctions

5.1.3.5 *Market participants* participating in the *IESO-administered markets* solely as a *capacity market participant* or *capacity auction participant* with a *capacity obligation* shall be subject only to the *capacity prudential support* requirements in section 5B.

5.2 Market Participant Obligations

5.2.1 Each *market participant* shall initially and continually satisfy the obligations set forth in this section 5.2 with regard to the provision of *prudential support* as a condition of (i) conducting *physical transactions* in the *real-time market* or (ii) conducting *physical transactions* or *virtual transactions* in the *day-ahead market* or (iii) causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid*.

5.2.2 Each *market participant* shall provide to the *IESO* and at all times maintain *prudential support* the value of which is not less than the *market participant's* applicable *prudential support obligations.* For this purpose, the aggregate value of the *prudential support* shall be equal to the value of the undrawn or unclaimed amounts of *prudential support* provided by the *market participant.*

5.2.3 No *market participant* that is required, pursuant to section 5.3.9, section 5C.5.1, or section 5D.5.1, as the case may be, to provide *prudential support* shall participate in the *real-time market* or the *day-ahead market* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that *market participant* satisfies the *prudential support* requirements of section 5, section 5C, section 5D and MR Ch.2 App.2.3.

5.2.4 Each *market participant* shall provide to the *IESO,* on an ongoing basis, such information as the *IESO* may reasonably require for the purpose of determining that *market participant's maximum net exposure* for *physical transactions* and *virtual transactions.*

5.2.5 If *prudential support* previously provided to the *IESO* by a *market participant* pursuant to section 5.7, section 5C.5, or section 5D.5 (the "*existing support*"), is due to expire or terminate and, upon expiry or termination of the *existing support* the total *prudential support* held by the *IESO* in respect of that *market participant* will be less than the *market participant's* applicable *prudential support obligations* then, at least ten *business days* prior to the time at which the *existing support* is due to expire or terminate, the *market participant* must provide to the *IESO* a replacement *prudential support* which will become effective no later than the expiry or termination of the *existing support*, such that the total *prudential support* provided is equal to the *market participant's prudential support obligation*.

5.2.6 Where a *market participant's prudential support obligation* for *physical transactions* has been reduced pursuant to section 5.8 and the relevant credit rating is revised or the relevant payment history has changed, whether under section 5.8 or otherwise, such as to result in an increase in the *market participant's prudential support obligation* then, within five *business days* of any such change, the *market participant* must provide to the *IESO* additional *prudential support* such that the total *prudential support* provided for *physical transactions* is equal to the *market participant's prudential support obligation* for *physical transactions* when calculated on the basis of the revised credit rating or payment history.

5.2.7 Where any part of the *prudential support* provided by a *market participant* otherwise ceases to be current or valid for any reason, the *market participant* must immediately so notify the *IESO* and provide to the *IESO*, within two *business days*, a replacement *prudential support* such that the total *prudential support* provided is at least equal to the *market participant's* applicable *prudential support obligation.*

5.2.7A Notwithstanding any other provision of the *market rules*, the *IESO* may exercise its rights in accordance with MR Ch.3 s.6.3.3.2 and MR Ch.2 App.2.3 over any amount of *prudential support* that has been provided by a *market participant* or a person providing *prudential support* on behalf of that *market participant* irrespective of whether the *prudential support* was provided for the purpose of satisfying a *prudential support obligation* for *physical transactions* or a *prudential support obligation* for *virtual transactions.*

5.2.8 If, as a result of the *IESO* exercising its rights over the *prudential support* provided by a *market participant* in accordance with MR Ch.3 s.6.3.3.2 and MR Ch.2 App.2.3**,** the remaining *prudential support* held by the *IESO* in respect of that *market participant* is less than the *market participant's* applicable *prudential support obligations*, the *market participant* must, within five *business days* of receiving notice of the exercise by the *IESO* of such rights, provide the *IESO* with additional *prudential support* such that the total *prudential support* provided is equal to the *market participant's* applicable *prudential support obligations*.

5.2.9 A *market participant* to which a *margin call* has been issued pursuant to section 5.4.2, 5C.2.2, or 5D.3.2 shall respond to such *margin call* in accordance with section 5.6, 5C.4 or 5D.4, as the case may be.

5.2.10 For the purpose of section 5, a *retailer* shall be deemed to be an *energy trader.*

5.3 Calculation of Participant Trading Limit, Default Protection Amount and Maximum Net Exposure for Physical Transactions

Maximum Net Exposure

5.3.1 The *IESO* shall determine, for each *market participant* intending to conduct *physical transactions*, subject to section 5.6.5, a *maximum net exposure* for *physical transactions* as the sum of the *market participant's trading limit* for *physical transactions*, the *market participant's default protection amount* for *physical transactions* and amounts, if any, for which the *market participant* is liable under MR Ch.7 s.2.5.4.

Self-Assessed Trading Limit

5.3.2 Subject to section 5.3.3, each *market participant* intending to conduct *physical transactions* shall determine and submit to the *IESO*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*, the amount of its *self-assessed trading limit*, even if that *self-assessed trading limit* is zero.

5.3.3 The *self-assessed trading limit* submitted by a *market participant* under section 5.3.2 shall be applicable for the remainder of the current and all future *energy market billing periods* until a revised *self-assessed trading limit* is submitted by that *market participant* to the *IESO* in accordance with the provisions of section 5.3.2. If a *market participant* submits a *self-assessed trading limit* pursuant to section 5.3.2, that *self-assessed trading limit* shall, subject to section 5.3.3A, supersede any previous *self-assessed trading limit*, and the previous *self-assessed trading limit* shall not be applicable to any such future *energy market billing periods*.

5.3.3A A *market participant's* revised *self-assessed trading limit* submitted in accordance with section 5.3.3 shall take effect once the *IESO* confirms receipt of any additional *prudential support*, as would be required based on the *market participant's* revised *self-assessed trading limit* pursuant to the *market rules*.

Minimum Trading Limit

5.3.4 Subject to section 5.6.5, the *IESO* shall establish a *minimum trading limit* for *physical transactions* for each *market participant* intending to conduct *physical transactions* as follows:

5.3.4.1 the *minimum trading limit* for *physical transactions* for a *market participant* that is not an *energy trader*, shall be equal to the *IESO's* estimate of the *market participant's* net *settlement amounts*, excluding estimated *settlement amounts* associated with *virtual transactions* and *transmission rights*, assuming seven days of participation by way of *physical transactions* and assuming all *energy* injected or withdrawn is transacted through *physical transactions*. The *IESO* may use a greater number, up to and including 49 days, of participation in *physical transactions* for the determination of a *market participant's minimum trading limit* for *physical transactions* if that *market participant* that is not an *energy trader* was subject to more than one *margin call* per *energy market billing period* in respect of *physical transactions*, provided that any such *margin call* is not the result of a price spike;

5.3.4.2 the *minimum trading limit* for *physical transactions* for an *energy trader* that has conducted *physical transactions* for *energy* for at least three previous *energy market billing periods* shall be equal to 25% of the *IESO's* estimate of the *market participant's* net *settlement amounts* for the upcoming *energy market billing period* associated with *physical transactions*. In estimating this net *settlement amount*, the *IESO* shall, subject to section 5.3.4.3, use an average of the actual net *settlement amounts* for the three most recent *energy market billing periods* in which that *market participant* has conducted *physical transactions* for *energy*. The *IESO* may use a greater percentage, up to and including 100%, of the estimated *market participant's* net *settlement amounts* for the determination of a *market participant's minimum trading limit* for *physical transactions* if that *market participant* was subject to more than one *margin call* in respect of *physical transactions* per *energy market billing period*, provided that any such *margin call* is not caused by a price spike; and

5.3.4.3 the *minimum trading limit* for *physical transactions* for an *energy trader* who has not conducted *physical transactions* for *energy* for at least three previous *billing periods*, shall be equal to the greater of:

a. 25% of the absolute value of the *market participant's* estimate of its net *settlement amount* for the upcoming *energy market billing period*. Such a *market participant* shall provide to the *IESO*, an estimate of its net *settlement amount* for the upcoming *energy* *market billing period*. The *IESO* may adjust the *market participant's minimum trading limit* at any time if that *market participant's* actual net *settlement amounts* for the current *billing period* are projected to differ significantly from the estimate provided; or

b. $25,000.

Establishing Market Participant Trading Limit

5.3.5 Upon receipt of a *market participant's self-assessed trading limit* under section 5.3.2, the *IESO* shall use the greater of the following two amounts for that *market participant's trading limit* for *physical transactions* for the remainder of the current or upcoming *energy market billing period*:

5.3.5.1 the *market participant's minimum trading limit* for that *energy market billing period* as determined pursuant to section 5.3.4; or

5.3.5.2 the *market participant's self-assessed trading limit* submitted under section 5.3.2.

5.3.6 If a *market participant* does not provide a *self-assessed trading limit* as specified in section 5.3.2, the *IESO* shall use the greater of the following two amounts for that *market participant's trading limit* for *physical transactions* for upcoming *energy market billing period*:

5.3.6.1 the *market participant's minimum trading limit* for that *energy market billing period* as determined pursuant to section 5.3.4; or

5.3.6.2 the *market participant's trading limit* for *physical transactions* in effect for the current *energy market billing period*.

5.3.7 [Intentionally left blank – section deleted]

Establishing Market Participant Default Protection Amount

5.3.8 The *IESO* shall, for each *energy market billing period*, establish a *default protection amount* for *physical transactions* for each *market participant* intending to conduct *physical transactions* as follows:

5.3.8.1 for a *market participant* that is not an *energy trader*, its *default protection amount* shall be equal to the *IESO's* estimate of the *market participant's* net *settlement amounts* for that *energy market billing period*, excluding estimated *settlement amounts* associated with *virtual transactions* and *transmission rights*, assuming 21 days of participation by way of *physical transactions* and assuming all *energy* injected or withdrawn is transacted through *physical transactions*; and

5.3.8.2 for a *market participant* that is an *energy trader*, the *default protection amount* shall be equal to the *minimum trading limit* for that *market participant* for that *energy market billing period* as determined by the *IESO* pursuant to section 5.3.4.2 or section 5.3.4.3, as applicable.

Adjusting Trading Limit and Default Protection Amount for Physical Bilateral Contracts

5.3.8A A *market participant* that is not an *energy trader* with a credit rating of BBB- or higher, subject to any adjustment under section 5.8.2, may request that its *minimum trading limit* and *default protection amount,* in respect of *physical transactions* be calculated by removing the *energy* quantities associated with the *market participant's physical bilateral contracts* registered with the *IESO* provided it submits to the *IESO* the quantity and duration of the applicable *physical bilateral contracts* and it notifies the *IESO* immediately upon a change in the quantity or duration of the *physical bilateral contracts* including the termination of any of the contracts.

5.3.8B If the conditions of 5.3.8A are met, the *IESO* shall determine the *market participant's minimum trading limit* and *default protection amount,* in respect of *physical transactions,* assuming all *energy* injected or withdrawn is transacted through *physical transactions* net of *energy* quantities associated with those *physical bilateral contracts*.

Requirement to Provide Prudential Support

5.3.9 If a *market participant's maximum net exposure* for *physical transactions*, as calculated by the *IESO*, is zero or negative, the *market participant* is not required to provide any form of *prudential support* for *physical transactions* to the *IESO*. If a *market participant's maximum net exposure* for *physical transactions*, as calculated by the *IESO*, is positive, the *market participant* must provide an amount of *prudential support* to the *IESO* equal to its *prudential support obligation* for *physical transactions*.

Price Bases Used for Determining Minimum Trading Limit and Default Protection Amount

5.3.10 The *IESO* shall estimate the net *settlement amounts* for a *market participant* referred to in sections 5.3.4 and 5.3.8 initially based on information provided to the *IESO* by the *market participant* in its *application for authorization to participate* and subsequently using such information as the *IESO* may reasonably require for that purpose and, in each case, on the price bases referred to in 5.3.10A, and the *IESO's estimated market prices* for all other applicable charges for the relevant *energy market billing period*.

5.3.10A When calculating the *minimum trading limit* and the *default protection amount* for *market participants* other than *energy traders* in sections 5.3.4, 5.3.8 and 5.3.8B respectively, the *IESO* shall establish and use as its price basis the price basis established in accordance with the following:

5.3.10A.1 for a *market participant* that is associated with *generation resource, electricity storage resource, dispatchable load,* or *price responsive load,* the price basis will be determined as the value that is the percentile set out in the applicable *market manual* of the following values ranked from lowest to highest:

a. in respect of each *delivery point* and all *settlement hours* over the preceding three-year period, the greater of the *locational marginal price* in the *day-ahead market* and the hourly average *locational marginal price* in the *real-time market*;

5.3.10A.2 for a *market participant* that is associated with a *non-dispatchable load,* the price basis will be determined as the value that is the percentile set out in the applicable *market manual* of the following values ranked from lowest to highest:

a. in respect of each *delivery point* and all *settlement hours* over the preceding three-year period, the greater of the *Ontario zonal price* in the *day-ahead market* and the hourly average *Ontario zonal price* in the *real-time market;*

5.3.10A.3 notwithstanding the foregoing, until the requisite amount of historical data is available, the price basis shall be determined by the *IESO* using the same methodology as described in sections 5.3.10A.1 and 5.3.10A.2 except using shadow prices from the day-ahead commitment process and the *real-time market* as necessary to ensure the requisite amount of data is included in the determination of the price basis; or

5.3.10A.4 notwithstanding the foregoing, if the *OEB* publishes prices, the *IESO* may use such published prices as the price basis.

5.3.10B The *IESO* may from time to time, but no less frequent than annually, review each price basis established in accordance with section 5.3.10A. If during such review the *IESO* determines that reassessing the price basis in accordance with section 5.3.10A would result in an increase or decrease by 15% or more, the *IESO* shall reassess and establish a new price basis in accordance with section 5.3.10A.

Reviewing and Modifying Trading Limits, Default Protection Amount and Maximum Net Exposure

5.3.11 The *IESO* may review the *minimum trading limit* for *physical transactions* where applicable, the *trading limit*, *default protection amount* and *maximum net exposure* for *physical transactions*, of each *market participant* in circumstances that include:

5.3.11.1 prior to the start of each *energy market billing period*;

5.3.11.2 within two *business days* after a *market participant's actual exposure* for *physical transactions* exceeds the *trading limit* for that *market participant*;

5.3.11.3 within two *business days* after it receives notice of any changes to the status of a *market participant* as compared to such status that was in effect when the *market participant's maximum net exposure* for *physical transactions* was last calculated if the *IESO* determines that the change in such status would have a material impact on the *market participant's maximum net exposure*;

5.3.11.4 when the *IESO* has adjusted a *market participant's minimum trading limit* for *physical transactions* pursuant to section 5.3.4.3; and

5.3.11.5 when the *IESO* has adjusted its price basis under section 5.3.10B.

5.3.12 The *IESO* may change the *minimum trading limit, trading limit, default protection amount, maximum net exposure* or the *prudential support obligation* for *physical transactions*, for a *market participant* at any time as a result of a review conducted pursuant to section 5.3.11 and shall promptly notify the *market participant* of any such change. Any change to a *market participant's minimum trading limit, trading limit, default protection amount, maximum net exposure* or *prudential support obligation* in respect of *physical transactions* shall apply with effect from such time, not being earlier than the time of notification of the changed *minimum trading limit, trading limit, default protection amount, maximum net exposure* or *prudential support obligation* to the *market participant*, as the *IESO* may specify in the notice. The *market participant* must supply the *IESO*, within five business days of the effective date of the change, any additional *prudential support* for *physical transactions* that may be required as a result of an increase in the *market participant's prudential support obligation* that results from such change.

5.4 Monitoring of Actual Exposure and Trading Limit for Physical Transactions

5.4.1 If at any time the *actual exposure* for *physical transactions* of a *market participant* that is not also a *virtual trader,* is equal to or exceeds 70% and is less than 100% of the *market participant's trading limit*, the *IESO* shall inform the *market participant* of that fact unless the *market participant* has opted for the *no margin call option* pursuant to section 5.6.4. The *market participant* may, but is not required to, make a cash payment to be applied to reduce its *actual exposure* or take other action to prevent its *actual exposure* from reaching its *trading limit*. No interest shall be paid on any such payment.

5.4.2 If at any time the *actual exposure* for *physical transactions* of a *market participant* that is not also a *virtual trader*, equals or exceeds the *market participant's trading limit* for *physical transactions*, the *IESO* shall issue to the *market participant* a *margin call* unless the *market participant* has opted for the *no margin call option* pursuant to section 5.6.4.

5.5 Calculation of Actual Exposure for Physical Transactions

5.5.1 For the purposes of section 5.4, a *market participant's actual exposure* for *physical transactions* shall be a dollar amount determined by the *IESO* each *business day* shall be equal to and as further described in the applicable *market manual*:

5.5.1.1 the aggregate of:

a. all amounts payable by the *market participant* in respect of *physical transactions* for *billing periods* prior to the current *billing period* which remain unpaid by the *market participant*, whether or not the applicable *market participant payment date* has yet been reached; and

b. the *IESO's* reasonable estimate of the aggregate hourly and non-hourly *settlement amounts* payable by the *market participant* in respect of *physical transactions* which have already occurred in the current *billing period*;

5.5.1.2 less the aggregate of:

a. all amounts payable to the *market participant* in respect of *physical transactions* for *billing periods* prior to the current *billing period* which remain unpaid, whether or not the applicable *IESO payment date* has yet been reached; and

b. the *IESO's* reasonable estimate of the aggregate hourly and non-hourly *settlement amounts* payable to the *market participant* in respect of *physical transactions* which have already occurred in the current *billing period*.

5.6 Margin Call Requirements and the No Margin Call Option for Physical Transactions

5.6.1 A *market participant* that is not also a *virtual trader* must satisfy a *margin call* in respect of *physical transactions* within the time prescribed in section 5.6.2 by paying a portion of the amount payable or which will become payable in respect of the previous or current *energy market billing period*, in accordance with MR Ch.9, in an amount sufficient to reduce the *market participant's actual exposure* to no more than the dollar equivalent of 75% of the *market participant's trading limit*. No interest shall be paid on such payments.

5.6.2 The time within which a *margin call* in respect of *physical transactions* must be satisfied under section 5.6.1 shall be by 4:00 pm on the second *business day* following the date of the *margin call*.

5.6.3 For the purposes of the *market rules*, a payment made pursuant to section 5.6.1 shall be applied first to the amount outstanding for *physical transactions* with respect to the earliest *energy market billing period* under the *market rules* and, if the amount outstanding under the *market rules* in respect of that *billing period* is less than the amount of the payment, then the excess shall be applied to the next earliest *energy market billing period* in respect of which there is an amount outstanding under the *market rules* and so on until there is no excess.

5.6.4 Subject to section 5.6.7, a *market participant* shall not be subject to the *margin call* requirements of sections 5.6.1 and 5.6.2, subject to *IESO* approval, if it elects to use the *no margin call option* using forms and procedures as may be established by the *IESO* in the applicable *market manual*.

5.6.5 The *IESO* shall determine the *maximum net exposure* for *physical transactions* of a *market participant* that is not an *energy trader,* that has selected the *no margin call option* based on 70 days of market activity and assuming all of the *market participant's energy* is injected or withdrawn through *physical transactions.* For an *energy trader* that has selected the *no margin call option*, the *IESO* shall determine *maximum net exposure* for *physical transactions* based on an estimate of 100% of its net *settlement amount* for the upcoming *energy market billing period*. A *market participant* that has elected the *no margin call option* shall not have a *trading limit*.

5.6.6 Other than *small distributors*, any *market participant* that elects to use the *no margin call option* shall not be eligible for reductions in its *prudential support obligations* pursuant to section 5.8.

5.6.7 A *market participant* authorized to conduct *physical transactions* shall not be eligible to use the *no margin call option* if it is also a *virtual trader*.

5.7 Obligation to Provide Prudential Support for Physical Transactions

5.7.1 Each *market participant* must meet its obligation under this section 5 to provide and maintain *prudential support* for *physical transactions* by providing to the *IESO* and maintaining *prudential support*, the value of which is equal to the *market participant's prudential support obligation* for *physical transactions*.

5.7.2 A *market participant's prudential support obligation* for *physical transactions* must be met through the provision to the *IESO* and the maintenance of *prudential support* in one or more of the following forms:

5.7.2.1 a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the *IESO* and provided by:

a. a bank named in a Schedule to the *Bank Act*, S.C. 1991, c.46 with a minimum long-term credit rating of "A" from a major bond rating agency as identified in the list referred to in section 5.8.7; or

b. a credit union licensed by the Financial Services Regulatory Authority of Ontario with a minimum long-term credit rating of "A" from a major bond rating agency as identified in the list referred to in section 5.8.7.

5.7.2.2 a guarantee in a form acceptable to the *IESO* provided by a person, other than an *affiliate* of the *market participant,* having a credit rating from a major bond rating agency identified on the list referred to in section 5.8.7;

5.7.2.3 marketable securities in the form of Canadian Government treasury bills. Such treasury bills shall be valued as cash at their current market value less 2 percent to take into account the potential eroding effects of interest rate increases;

5.7.2.4 subject to section 5.7.4 and 5.7.4A, a guarantee in a form acceptable to the *IESO* provided by a person that is an *affiliate* of the *market participant* and that has a credit rating from a major bond rating agency identified on the list referred to in section 5.8.7; and/or

5.7.2.5 cash deposits made with the *IESO* by or on behalf of the *market participant* provided that that *market participant* meets the following criteria:

a. the *market participant* was already meeting its *prudential support obligation* in whole or in part through a cash deposit on November 4, 2004; and

b. the *market participant's prudential support obligation* was less than or equal to $200,000 on November 4, 2004 and remains less than or equal to $200,000 thereafter.

5.7.2A A *market participant* who has previously provided *prudential support* for *physical transactions* in accordance with subsections 5.7.2.2 or 5.7.2.4, who thereafter intends to become authorized as a *virtual trader* in accordance with subsection 2.1.1.14, shall provide the *IESO* with replacement *prudential support* for *physical transactions*.

5.7.3 For the purposes of sections 5.7.2.1 and 5.7.2.2, the *IESO* shall establish, maintain, update as required and *publish* a list of organizations eligible to provide the *prudential support* referred to in sections 5.7.2.1 and 5.7.2.2 and shall establish, for each such eligible *prudential support* provider, an aggregate limit of the *prudential support* that may be provided by that *prudential support* provider to *market participants.* If aggregate limits are reached for any of these eligible organizations, *market participants* will be required to obtain *prudential support* from other eligible organizations that are still within their respective *prudential support* limits.

5.7.3A Where a *market participant's prudential support obligation* for *physical transactions* is reduced pursuant to section 5.8.1, 5.8.1A, 5B.5.1 or 5B.5.1A, the *IESO* shall not accept a guarantee from an *affiliate* of the *market participant* pursuant to section 5.7.2.4, unless the *market participant* provides a letter from the applicable major bond rating agency identified in the list referred to in section 5.8.7, stating that the two ratings are not directly linked and are stand alone ratings in relation to each other.

5.7.3B The *IESO* shall not accept a guarantee from an *affiliate* of the *market participant* pursuant to section 5.7.2.4 if the *affiliate* is also a *market participant* and has obtained a reduction of its own *prudential support obligation* for *physical transactions* pursuant to section 5.8.1, 5.8.1A, 5B.5.1 or 5B.5.1A.

5.7.4 For *market participants*, other than a *distributor*, subject to sections 5.7.3A and 5.7.3B the *IESO* shall not accept a guarantee from a rated *affiliate* of the *market participant* pursuant to section 5.7.2.4 where the value of the guarantee exceeds the following;

Credit Rating Category of Affiliate using Standard and Poor's Rating Terminology	**Maximum Amount which May be Guaranteed by Affiliate**
AA- and above or equivalent	100% of *maximum net exposure* of all *market participants* guaranteed by *affiliate*

Credit Rating Category of Affiliate using Standard and Poor's Rating Terminology	**Maximum Amount which May be Guaranteed by Affiliate**
A-, A, A+ or equivalent	Greater of 90% of *maximum net exposure* or $37,500,000 of all *market participants* guaranteed by *affiliate*
BBB-, BBB, BBB+ or equivalent	Greater of 65% of *maximum net exposure* or $15,000,000 of all *market participants* guaranteed by *affiliate*
BB-, BB, BB+ or equivalent	Greater of 30% of *maximum net exposure* or $4,500,000 of all *market participants* guaranteed by *affiliate*
Below BB- or equivalent	0

5.7.4A For *distributors*, subject to sections 5.7.3A and 5.7.3B the *IESO* shall not accept a guarantee from a rated *affiliate* of the *market participant* pursuant to section 5.7.2.4 where the value of the guarantee exceeds the following:

Credit Rating Category of Affiliate using Standard and Poor's Rating Terminology	**Maximum Amount which May be Guaranteed by Affiliate**
AA- and above or equivalent	100% of *maximum net exposure* of all *market participants* guaranteed by *affiliate*
A-, A, A+ or equivalent	Greater of 95% of *maximum net exposure* or $45,000,000 of all *market participants* guaranteed by *affiliate*
BBB-, BBB, BBB+ or equivalent	Greater of 80% of *maximum net exposure* or $22,500,000 of all *market participants* guaranteed by *affiliate*
BB-, BB, BB+ or equivalent	Greater of 55% of *maximum net exposure* or $7,500,000 of all *market participants* guaranteed by *affiliate*
Below BB- or equivalent	0

5.7.5 The minimum terms and conditions that shall be included in the *prudential support* for *physical transactions* shall be as follows:

5.7.5.1 *prudential support* provided in accordance with sections 5.7.2.1, 5.7.2.2 and 5.7.2.4 shall be obligations in writing;

5.7.5.2 *prudential support* provided in accordance with sections 5.7.2.3 and 5.7.2.5 shall be obligations reflected in a written instrument in a form acceptable to the *IESO*;

5.7.5.3 *prudential support* provided in accordance with sections 5.7.2.1, 5.7.2.3 and 5.7.2.5 shall constitute valid and binding unsubordinated obligations to pay to the *IESO* amounts in accordance with its terms which relate to the obligations of the relevant *market participant* under the *market rules*; and

5.7.5.4 *prudential support* provided in accordance with sections 5.7.2.1 to 5.7.2.5 shall permit drawings or claims by the *IESO* on demand to a stated certain amount.

5.8 Reductions in Prudential Support Obligations for Physical Transactions

5.8.1 Subject to section 5.8.2, the *prudential support obligation* for *physical transactions* of a rated *market participant*, other than a *distributor*, may be reduced relative to the *market participant's maximum net exposure* for *physical transactions* by an amount equal to the monetary value prescribed, by the table below, to a credit rating from a major bond rating agency identified in the list referred to in section 5.8.7 issued and in effect in respect of the *market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of *maximum net exposure*
A-, A, A+ or equivalent	Greater of 90% of *maximum net exposure* or $37,500,000
BBB-, BBB, BBB+ or equivalent	Greater of 65% of *maximum net exposure* or $15,000,000
BB-, BB, BB+ or equivalent	Greater of 30% of *maximum net exposure* or $4,500,000
Below BB- or equivalent	0

5.8.1A Subject to section 5.8.2, the *prudential support obligation* for *physical transactions* of a rated *distributor* may be reduced relative to the *market participant's maximum net exposure* for *physical transactions* by an amount equal to the monetary value prescribed, by the table below, to a credit rating from a major bond rating agency identified in the list referred to in section 5.8.7 issued and in effect in respect of the *market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of *maximum net exposure*

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
A-, A, A+ or equivalent	Greater of 95% of *maximum net exposure* or $45,000,000
BBB-, BBB, BBB+ or equivalent	Greater of 80% of *maximum net exposure* or $22,500,000
BB-, BB, BB+ or equivalent	Greater of 55% of *maximum net exposure* or $7,500,000
Below BB- or equivalent	0

5.8.2 Any recommendation to move a *market participant* to "credit watch negative" by any of the major bond rating agencies identified in the list referred to in section 5.8.7 shall be deemed to automatically result in a one-notch reduction in terms of the credit rating (for example, from BBB+ to BBB) of that *market participant* for the purpose of determining the *market participant's prudential support obligation*.

5.8.3 Subject to section 5.8.6, the *prudential support obligation* for *physical transactions* of a *market participant* may be reduced relative to the *market participant's maximum net exposure* for *physical transactions*, by an amount equal to the monetary value ascribed, in accordance with section 5.8.4 or 5.8.5, to the *market participant's* historical good payment history in Ontario, which shall be assessed by the *IESO* on the basis of:

5.8.3.1 evidence provided by the *market participant* as to the continuous purchase of electricity by the *market participant* prior to the effective date of the *IESO-administered markets* during which time no call for collateral was issued to that *market participant* to protect the supplier from the risk of a payment default by that *market participant;*

5.8.3.2 verification of the evidence referred to in section 5.8.3.1 by the *IESO*; and

5.8.3.3 the *market participant's* payment history in the *IESO-administered markets* provided that the *market participant's* payment history includes no *event of default*.

5.8.4 The *IESO* shall determine the dollar amount of any allowable reduction in the *prudential support obligation* for *physical transactions* of an unrated *market participant*, other than a *distributor,* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Non-Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 50% of *maximum net exposure* or $12,000,000
≥5 years, <6 years	Lesser of 30% of *maximum net exposure* or $7,500,000
≥4, <5 years	Lesser of 25% of *maximum net exposure* or $6,000,000
≥3, <4 years	Lesser of 20% of *maximum net exposure* or $4,500,000
≥2, <3 years	Lesser of 15% of *maximum net exposure* or $3,000,000
<2 years	0

5.8.5 If the *market participant* is an unrated *distributor*, the *IESO* shall determine the dollar amount of any allowable reduction in the *market participant's prudential support obligation* for *physical transactions* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 80% of *maximum net exposure* or $14,000,000
≥5 years, <6 years	Lesser of 65% of *maximum net exposure* or $9,000,000
≥4, <5 years	Lesser of 45% of *maximum net exposure* or $7,500,000
≥3, <4 years	Lesser of 35% of *maximum net exposure* or $6,000,000
≥2, <3 years	Lesser of 25% of *maximum net exposure* or $4,500,000
<2 years	0

For purposes of this section 5.8.5, the historical payment history of a *distributor* that is the transferee under a transfer by-law made pursuant to subsection 145(1) of the *Electricity Act, 1998* shall be deemed to include the historical payment history of the *distributor* whose licence has been transferred to the transferee under such by-law. For purposes of this section 5.8.5, the historical payment history of a *distributor* that is the successor at law to two or more *distributors*, shall be deemed to include the historical payment history of the predecessor *distributors*.

5.8.6 The following restrictions shall apply to the provision of reductions in a *market participant's prudential support obligation* for *physical transactions* as provided for under sections 5.8.1, 5.8.1A, and 5.8.3:

5.8.6.1 subject to the last paragraph of section 5.8.5, a *market participant* shall not be entitled to a reduction in its *prudential support obligation* pursuant to section 5.8.3 using the payment history of an *affiliate*;

5.8.6.2 a *market participant* that has a credit rating from a major bond rating agency identified in the list referred to in section 5.8.7 shall not be entitled to a reduction in its *prudential support obligation* under section 5.8.3; and

5.8.6.3 an *energy trader* shall not receive a reduction to its *prudential support obligation* for *physical transactions* pursuant to section 5.8.1 until the *energy trader* has conducted *physical transactions* for *energy* in the *IESO-administered markets* for at least three previous *energy market billing periods.*

5.8.7 For the purposes of this chapter, the *IESO* shall establish, maintain, update as required and *publish* a list of major bond rating agencies eligible to provide the credit ratings mentioned throughout.

5.8.8 The *IESO* shall reduce the *prudential support obligation* for *physical transactions* of a *distributor* by an amount equal to 60% of the *distributor's* collection of *prudential support,* in the forms specified in section 5.7.2.1, 5.7.2.2, 5.7.2.3, or 5.7.2.4, from the *distributor's* customers. In order to qualify for this reduction in *prudential support obligation,* the *distributor* shall provide the *IESO* with an affidavit attesting to the amount of *prudential support* of the types specified in this section which the *distributor* has collected from its customers attached to which by way of exhibits shall be copies of bank statements showing any cash deposits and any applicable letters of credit, guarantees, or Government of Canada T-bills held as *prudential support*. The *IESO* shall first deduct the *distributor's* collection of *prudential support* from the *distributor's* customers before applying any other *prudential support obligation* deductions in respect of *physical transactions*.

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5B.Capacity Prudential Requirements

5B.1 Purpose

5B.1.1 This section 5B sets forth the nature and amount of *capacity prudential support* that must be provided by *market participants* that are either *capacity auction participants* or *capacity market participants* as a condition of delivering on a *capacity obligation,* and the manner in which such *market participants* must provide and maintain *capacity prudential support* on an on-going basis, in order to protect the *IESO* and *market participants* from payment defaults.

5B.1.2 The *IESO* shall review the *capacity prudential support* requirements set out in this chapter at least once every three years, as part of the review of the *prudential support* requirements pursuant to section 5.1.2.

5B.2 Market Participant Obligations

5B.2.1 Each *market participant* shall initially and continually satisfy the obligations set forth in this section 5B.2 with regard to the provision of *capacity prudential support* as a condition of delivering on a *capacity obligation*.

5B.2.2 No *market participant* that is required to provide *capacity prudential support* shall participate in the *day-ahead market* or *real-time market* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that *market participant* satisfies the requirements of this section 5B.2.

5B.2.3 Each *market participant* shall provide to the *IESO*, on an ongoing basis, such information as the *IESO* may reasonably require for the purpose of determining that *market participant's capacity prudential support obligation*.

5B.2.4 If *capacity prudential support* previously provided to the *IESO* by a *market participant* is due to expire or terminate, and upon expiry or termination of the existing *capacity prudential support*, the total *capacity prudential support* held by the *IESO* in respect of that *market participant* will be less than the *market participant's capacity prudential support obligation*, then at least ten *business days* prior to the time at which the existing security is due to expire or terminate, the *market participant* must provide to the *IESO* replacement *capacity prudential* *support* which will become effective no later than the expiry or termination of the existing collateral, such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation*.

5B.2.5 Where a *market participant's capacity prudential support obligation* has been reduced pursuant to section 5B.5 and the relevant credit rating is revised or the relevant payment history has changed, such as to result in an increase in the *market participant's capacity prudential support obligation,* then within five *business days,* the *market participant* must provide to the *IESO* additional *capacity prudential support* such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation* when calculated on the basis of the revised credit rating or payment history.

5B.2.6 Where any part of the *capacity prudential support* provided by a *market participant* otherwise ceases to be current or valid for any reason, the *market participant* must immediately so notify the *IESO* and provide to the *IESO*, within two *business days*, replacement *capacity prudential support* such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation.*

5B.2.7 If the *IESO* draws upon part or all of a *market participant's capacity prudential support* in accordance with MR Ch.3 s.6.3.3.2 and the remaining *capacity prudential support* held by the *IESO* in respect of that *market participant* is less than the *market participant's capacity prudential support obligation*, the *market participant* must, within five *business days* of receiving notice from the *IESO*, provide the *IESO* with additional *capacity prudential support* such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation*.

5B.3 Calculation of Capacity Prudential Support Obligations

5B.3.1 The *IESO* shall determine, in accordance with the applicable *market manual*, for each *market participant*, a *capacity prudential support obligation* for each *obligation period*, based on a percentage of the highest monthly availability payment, less any allowable reductions pursuant to section 5B.5.

5B.3.2 The *IESO* shall review the *capacity prudential support obligation* of each *market participant* as follows:

5B.3.2.1 prior to the start of each *obligation period*;

5B.3.2.2 within two *business days* after it receives notice of any changes to the status of a *market participant* as compared to such status that was in effect when the *market participant's capacity prudential support* was last calculated; or

5B.3.2.3 as a result of either a change in or loss of a *market participant's* credit rating or good payment history reduction calculated in accordance with section 5B.5.

5B.3.3 The *IESO* may change the *capacity prudential support obligation* for a *market participant* at any time as a result of a review conducted pursuant to section 5B.3.2, and shall promptly notify the *market participant* of any such change. Any change to a *market participant's capacity prudential support obligation* shall apply with effect from such time, not being earlier than the time of notification of the change to the *market participant*, as the *IESO* may specify in the notice. The *market participant* must supply the *IESO*, within five *business days* of the effective date of the change, any additional *capacity prudential support* that may be required as a result of an increase in the *market participant's capacity prudential support obligation* that results from such change.

5B.4 Obligation to Provide Capacity Prudential Support

5B.4.1 Each *market participant* must provide to the *IESO* and maintain *capacity prudential support*, the value of which is at least equal to the *market participant's capacity prudential support obligation*. The aggregate value of the *capacity prudential support* shall be equal to the value of the undrawn or unclaimed amounts of *capacity prudential support* provided by the *market participant.*

5B.4.2 A *market participant's capacity prudential support obligation* must be met through the provision to the *IESO* and the maintenance of *capacity prudential support* in the following form:

5B.4.2.1 a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the *IESO* and provided by:

a. a bank named in a Schedule to the *Bank Act*, S.C. 1991, c.46 with a minimum long-term credit rating of "A" from an *IESO* acceptable major bond rating agency as identified in the list referred to in section 5B.5.7; or

b. a credit union licensed by the Financial Services Commission of Ontario with a minimum long-term credit rating of "A" from an *IESO* acceptable major bond rating agency as identified in the list referred to in section 5B.5.7.

5B.4.3 The following provisions shall apply to a guarantee or irrevocable letter of credit provided in section 5B.4.2.1:

5B.4.3.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 2007 Revision, ICC Publication No. 600 or The International Standby Practices 1998;

5B.4.3.2 the *IESO* shall be named as beneficiary in each letter of credit, each letter of credit shall be irrevocable, partial draws on any letter of credit shall not be prohibited and the letter of credit or the aggregate amount of all letters of credit shall be in the face amount of at least the amount specified by the *IESO*;

5B.4.3.3 the only conditions on the ability of the *IESO* to draw on the letter of credit shall be the occurrence of an *event of default* by or in respect of the *market participant* and a certificate of an officer of the *IESO* that the *IESO* is entitled to draw on the letter of credit, in accordance with the provisions of the *market rules* in the amount specified in the certificate as at the date of delivery of the certificate;

5B.4.3.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. In either case it is the responsibility of the *market participant* to maintain the requisite amount of *capacity prudential support*. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *market participant* shall arrange for and deliver alternative *capacity prudential support* within the time frame mandated by the *market rules* so as to enable the *market participant* to be in compliance with the *market rules*; and

5B.4.3.5 by including a letter of credit as part of its *capacity prudential support*, the *market participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *market participant*.

5B.4.4 For the purpose of section 5B.4.2.1, the *IESO* shall establish, maintain, and *publish* a list of organizations eligible to provide the *capacity prudential support* referred to in section 5B.4.2.1 and shall establish for each such eligible *capacity prudential support* provider, an aggregate limit of the *capacity prudential support* that may be provided by that *capacity prudential support* provider to *market participants*. If aggregate limits are reached for any of these eligible organizations, *market participants* will be required to obtain *capacity prudential support* from other eligible organizations that are still within their respective *capacity prudential support* limits.

5B.4.5 In the event that the *capacity prudential support* provided by a *market participant* is a greater amount than required by the *market rules*, the *IESO* shall, upon written request by the *market participant*, return to the *market participant* an amount equal to the difference between the value of *capacity prudential support* held by the *IESO* and the *capacity prudential support obligation* of the *market participant* at that time. The *IESO* shall return such amount within five *business days* of the receipt of the request for the return of the amount from the *market participant*. In all circumstances, the *IESO* shall return *capacity prudential support* only after all payments and charges for the final month of a *commitment period* have been settled.

5B.4.6 The minimum terms and conditions that shall be included in the *capacity prudential support* in accordance with section 5B.4.2.1 shall be as follows:

5B.4.6.1 *capacity prudential support* shall be obligations in writing;

5B.4.6.2 *capacity prudential support* shall constitute valid and binding unsubordinated obligations to pay to the *IESO* amounts in accordance with its terms which relate to the obligations of the relevant *market participant* under the *market rules*; and

5B.4.6.3 *capacity prudential support* shall permit drawings or claims by the *IESO* on demand to a stated certain amount, including partial drawings or claims.

5B.4.7 Upon the occurrence of an *event of default*, the *IESO* shall be entitled to exercise its rights and remedies as set out in the *market rules,* or provided for at law or in equity. Without limiting the generality of the foregoing, such rights and remedies shall, in respect of the *capacity prudential support* provided by the *market participant*, include setting-off and applying any and all *capacity prudential support* held against the indebtedness, obligations and liabilities of the *market participant* to the *IESO* in respect of the participation by the *market participant* in the *day-ahead market* or the *real-time market,* including the costs, charges, expenses and fees described in section 5B.4.9.

5B.4.8 Each of the remedies available to the *IESO* under the *market rules* or at law or in equity is intended to be a separate remedy and in no way is a limitation on or substitution for any one or more of the other remedies otherwise available to the *IESO*. The rights and remedies expressly specified in the *market rules* or at law or in equity are cumulative and not exclusive. The *IESO* may in its sole discretion exercise any and all rights, powers, remedies and recourses available under the *market rules* or under any document comprising the *capacity prudential support* provided by the *market participant* or any other remedy available to the *IESO* howsoever arising, and whether at law or in equity, and such rights, powers and remedies and recourses may be exercised concurrently or individually without the necessity of any election.

5B.4.9 The *market participant* agrees to pay to the *IESO* forthwith on demand all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, legal fees on a substantial indemnity basis) of or incurred by or on behalf of the *IESO* in the realization, recovery or enforcement of the *capacity prudential support* provided by the *market participant* and enforcement of the rights and remedies of the *IESO* under the *market rules* or at law or in equity in respect of the participation by the *market participant* in the *day-ahead market* or the *real-time market.*

5B.5 Reductions in Capacity Prudential Support Obligations

5B.5.1 Subject to section 5B.5.2, the *IESO* may reduce the *capacity prudential support obligation* of a rated *market participant*, other than a *distributor*, by an amount equal to the monetary value prescribed by the table below, resulting from a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 issued and in effect in respect of the *capacity market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of the *capacity prudential support obligation* before allowable reductions
A-, A, A+ or equivalent	Greater of 90% of the *capacity prudential support obligation* before allowable reductions or $37,500,000
BBB-, BBB, BBB+ or equivalent	Greater of 65% of the *capacity prudential support obligation* before allowable reductions or $15,000,000
BB-, BB, BB+ or equivalent	Greater of 30% of the *capacity prudential support obligation* before allowable reductions or $4,500,000
Below BB- or equivalent	0

5B.5.1A Subject to section 5B.5.2, the *IESO* may reduce the *capacity prudential support obligation* of a rated *distributor* by an amount equal to the monetary value prescribed by the table below, resulting from a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 issued and in effect in respect of the *capacity market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of the *capacity prudential support obligation* before allowable reductions

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
A-, A, A+ or equivalent	Greater of 95% of the *capacity prudential support obligation* before allowable reductions or $45,000,000
BBB-, BBB, BBB+ or equivalent	Greater of 80% of the *capacity prudential support obligation* before allowable reductions or $22,500,000
BB-, BB, BB+ or equivalent	Greater of 55% of the *capacity prudential support obligation* before allowable reductions or $7,500,000
Below BB- or equivalent	0

5B.5.2 Any recommendation to move a *market participant* to "credit watch negative" by any of the major bond rating agencies identified in the list referred to in section 5B.5.7, shall be deemed to automatically result in a one-notch reduction in terms of the credit rating (for example, from BBB+ to BBB) of that *market participant* for the purpose of determining the *market participant's capacity prudential support obligation*.

5B.5.3 Where a *market participant's capacity prudential support obligation* reflects a reduction by reason of the *market participant's* credit rating from a major bond agency identified in the list referred to in section 5B.5.7, the *market participant* shall advise the *IESO* in writing immediately upon the *market participant* becoming aware of either a change in or loss of the then current credit rating or the decision of the bond rating agency to place the *market participant* on "credit watch status" or equivalent.

5B.5.4 Subject to section 5B.5.6, the *IESO* may reduce the *market participant's capacity prudential support obligation* in accordance with sections 5B.5.5 or 5B.5.5A based on the *market participant's* historical good payment history in the *IESO-administered markets*, provided that the *market participant's* payment history includes no *event of default*.

5B.5.5 The *IESO* shall determine the dollar amount of any allowable reduction in the *capacity prudential support obligation* of an unrated *market participant*, other than a *distributor*, by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Non-Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 50% of the *capacity prudential support obligation* before allowable reductions or $12,000,000
≥5 years, <6 years	Lesser of 30% of the *capacity prudential support obligation* before allowable reductions or $7,500,000
≥4, <5 years	Lesser of 25% of the *capacity prudential support obligation* before allowable reductions or $6,000,000
≥3, <4 years	Lesser of 20% of the *capacity prudential support obligation* before allowable reductions or $4,500,000
≥2, <3 years	Lesser of 15% of the *capacity prudential support obligation* before allowable reductions or $3,000,000
<2 years	0

5B.5.5A The *IESO* shall determine the dollar amount of any allowable reduction in the *capacity prudential support obligation* of an unrated *distributor* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 80% of the *capacity prudential support obligation* before allowable reductions or $14,000,000
≥5 years, <6 years	Lesser of 65% of the *capacity prudential support obligation* before allowable reductions or $9,000,000
≥4, <5 years	Lesser of 45% of the *capacity prudential support obligation* before allowable reductions or $7,500,000
≥3, <4 years	Lesser of 35% of the *capacity prudential support obligation* before allowable reductions or $6,000,000
≥2, <3 years	Lesser of 25% of the *capacity prudential support obligation* before allowable reductions or $4,500,000
<2 years	0

5B.5.6 The following restrictions shall apply to the provision of reductions in a *market participant's capacity prudential support obligation* as provided for under sections 5B.5.1, 5B.5.1A, and 5B.5.4:

5B.5.6.1 a *market participant* shall not be entitled to a reduction in its *capacity prudential support obligation* pursuant to section 5B.5.4 using the payment history of an *affiliate*;

5B.5.6.2 a *market participant* that has a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 shall not be entitled to a reduction in its *capacity prudential support obligation* under section 5B.5.4; and

5B.5.6.3 a *market participant's* reduction for either a credit rating or good payment history reduction shall be reduced by the amount of any reductions already granted to the *market participant* under section 5.8.

5B.5.7 For the purposes of this chapter, the *IESO* shall establish, maintain, and *publish* a list of major bond rating agencies eligible to provide the credit ratings mentioned in this section 5B.

5C.Virtual Transactions

5C.1 Calculation of Participant Trading Limit, Default Protection Amount and Maximum Net Exposure for Virtual Transactions

Maximum Net Exposure

5C.1.1 The *IESO* shall determine, for each *virtual trader*, a *maximum net exposure* for *virtual transactions* as the sum of the *virtual trader's trading limit* for *virtual transactions* and the *virtual trader's default protection amount* for *virtual transactions*.

Maximum Daily Trading Limit

5C.1.2 Each *virtual trader* intending to conduct *virtual transactions* shall determine and submit to the *IESO*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*, the absolute value of its *maximum daily trading limit* (in MWh).

5C.1.3 The *maximum daily trading limit* submitted by a *virtual trader* under section 5C.1.2 shall be applicable for the current and all future *billing periods* until a revised *maximum daily trading limit* is submitted by that *virtual trader* to the *IESO* in accordance with section 5C.1.2. If a *virtual trader* submits a *maximum* *daily trading limit* pursuant to section 5C.1.2, that *maximum daily trading limit* shall, subject to section 5C.1.4, supersede any previous *maximum daily trading limit*, and the previous *maximum daily trading limit* shall not be applicable to any such future *billing periods*.

5C.1.4 A *virtual trader's* revised *maximum daily trading limit* submitted in accordance with section 5C.1.3 shall take effect once the *IESO* confirms receipt of any additional *prudential support*, as would be required based on the *virtual trader's* revised *maximum daily trading limit* pursuant to the *market rules*.

Minimum Trading Limit

5C.1.5 The *IESO* shall establish a *minimum trading limit* for *virtual transactions* for each *virtual trader* equal to the *IESO's* estimate of the *virtual trader's* net *settlement amounts*, assuming two days of participation in the *day-ahead market*. The *IESO* may use a greater number, up to and including seven days of participation in the *day-ahead market* for the determination of a *virtual trader's minimum trading limit* for *virtual transactions*, if that *virtual trader* was subject to more than one *margin call* per *billing period*.

Establishing Trading Limits for Virtual Transactions

5C.1.6 For *virtual transactions*, the *IESO* established *minimum trading limit* determined in accordance with section 5C.1.5 shall be the *trading limit* for *virtual transactions* for that *virtual trader* for the current or upcoming *billing period*.

Establishing Default Protection Amounts for Virtual Transactions

5C.1.7 The *IESO* shall, for each *energy market billing period*, establish a *default protection amount* for *virtual transactions* for each *virtual trader* equal to the *IESO's* estimate of the *virtual trader's* net *settlement amounts*, assuming seven days of participation in the *day-ahead market*.

Requirement to Provide Prudential Support

5C.1.8 If a *virtual trader's maximum net exposure* for *virtual transactions*, as calculated by the *IESO*, is zero or negative, the *virtual trader* is not required to provide any form of *prudential support* for *virtual transactions* to the *IESO*. If a *virtual trader's maximum net exposure* for *virtual transactions*, as calculated by the *IESO*, is positive, the *virtual trader* must provide an amount of *prudential support* to the *IESO* equal to its *prudential support obligation* for *virtual transactions*.

Price Delta Used for Determining Minimum Trading Limit and Default Protection Amount

5C.1.9 For purposes of calculating the *minimum trading limit* for *virtual transactions* and the *default protection amount* for *virtual transactions*, the *IESO* shall determine the price delta (Δ DAP_{VT}, $ARTP_{VT}$) as follows:

5C.1.9.1 The price delta (Δ DAP_{VT}, $ARTP_{VT}$) will be determined as the value that is the percentile set out in the applicable *market manual* of the following values ranked from lowest to highest:

a. In respect of all *virtual transaction zones*, the absolute value of the difference between the *day-ahead market virtual zonal price* and the hourly average *real-time market virtual zonal price* of the same *settlement hours* for all *settlement hours* within the immediately preceding three-year period.

5C.1.9.2 Until three years of historical data is available, the price delta (Δ DAP_{VT}, $ARTP_{VT}$) shall be estimated by the *IESO* based on relevant proxies and deemed to mean the "interim price delta" (Δ $DAP_{VT\mathrm{I}}$, $ARTP_{VT\mathrm{I}}$). The interim price delta may consider, but will not be limited to the following:

a. shadow prices from the day-ahead commitment process and the *real-time market*;

b. price delta information from *day-ahead markets* and *real-time markets* in neighbouring electricity systems; and

c. temporal weightings of the data used to calculate the price deltas (Δ$DAP_{VT,}$ $ARTP_{VT}$).

5C.1.10 The *IESO* shall review the price delta referred to in section 5C.1.9, at least once annually. The *IESO* shall modify the applicable price delta if it has increased or decreased by 15% or more from the price delta used by the *IESO*.

5C.1.11 The *IESO* shall *publish* annually the price delta described in section 5C.1.9, and *publish* any modified price delta information resulting from a review pursuant to section 5C.1.10.

Reviewing and Modifying Trading Limits, Default Protection Amount and Maximum Net Exposure

5C.1.12 The *IESO* may review the *minimum trading limit*, *trading limit*, *default protection amount* and *maximum net exposure*, for *virtual transactions*, of each *virtual trader* in circumstances that include:

5C.1.12.1 prior to the start of each *energy market billing period*;

5C.1.12.2 within two *business days* after a *virtual trader's actual exposure* for *virtual transactions* exceeds the *virtual trader's trading limit* for *virtual transactions*;

5C.1.12.3 within two *business days* after it receives notice of any changes to the status of a *virtual trader* as compared to such status that was in effect when the *virtual trader's maximum net exposure* for *virtual transactions* was last calculated if the *IESO* determines that the change in such status would have a material impact on the *virtual trader's maximum net exposure* for *virtual transactions*;

5C.1.12.4 when the *IESO* has adjusted a *virtual trader's minimum trading limit,* if the *virtual trader* was subject to more than one *margin call* per *energy market billing period*, pursuant to section 5C.1.4;

5C.1.12.5 when the *IESO* has adjusted the price delta under section 5C.1.9; and

5C.1.12.6 when a *virtual trader* submits a revised *maximum daily trading limit* in accordance with section 5C.1.3.

5C.1.13 The *IESO* may change the *minimum trading limit*, *trading limit*, *default protection amount*, *maximum net exposure* or the *prudential support obligation*, for *virtual transactions*, for a *virtual trader* at any time as a result of a review conducted pursuant to section 5C.1.12 and shall promptly notify the *virtual trader* of any such change. Any change to a *virtual trader's minimum trading limit*, *trading limit*, *default protection amount*, *maximum net exposure* or *prudential support obligation* for *virtual transactions* shall apply with effect from such time, not being earlier than the time of notification of the changed *minimum trading limit*, *trading limit*, *default protection amount*, *maximum net exposure* or *prudential support obligation* for *virtual transactions* to the *virtual trader*, as the *IESO* may specify in the notice. The *virtual trader* must supply the *IESO*, within five *business days* of the effective date of the change, any additional *prudential support* for *virtual transactions* that may be required as a result of an increase in the *virtual trader's prudential support obligation* that results from such change.

5C.2 Monitoring of Actual Exposure and Trading Limit for Virtual Transactions

5C.2.1 If at any time the *actual exposure* for *virtual transactions* of a *virtual trader* that is not authorized to conduct *physical transactions*, is equal to or exceeds 70% and is less than 100% of the *virtual trader's trading limit* for *virtual transactions*, the *IESO* shall inform the *virtual trader* of that fact. The *virtual trader* may, but is not required to, make a cash payment to be applied to reduce its *actual exposure* or take other action to prevent its *actual exposure* from reaching its *trading limit*. No interest shall be paid on any such payment.

5C.2.2 If at any time the *actual exposure* for *virtual transactions* of a *virtual trader* that is not authorized to conduct *physical transactions*, equals or exceeds the *virtual trader's trading limit* for *virtual transactions*, the *IESO* shall issue to the *virtual trader* a *margin call* in respect of *virtual transactions*. Upon issuance of a *margin call*, the *IESO* shall reject subsequent *virtual trader bids* and *offers* for *virtual transactions* until the *virtual trader* satisfies the *margin call* in accordance with section 5C.4.1.

5C.3 Calculation of Actual Exposure for Virtual Transactions

5C.3.1 For the purposes of sections 5C.2 and 5D.2.2, a *virtual trader's actual exposure* for *virtual transactions* shall be a dollar amount determined by the *IESO* each *business day*, in accordance with the applicable *market manual*, and shall be equal to:

5C.3.1.1 the aggregate of:

a. all amounts payable by the *virtual trader* in respect of *virtual transactions* for *billing periods* prior to the current *billing period* which remain unpaid by the *virtual trader*, whether or not the *market participant payment date* thereof has yet been reached; and

b. the *IESO's* reasonable estimate of the aggregate hourly and non-hourly *settlement amounts* payable by the *virtual trader* in respect of *virtual transactions* which have already occurred in the current *billing period*;

5C.3.1.2 less the aggregate of:

a. all amounts payable to the *virtual trader* in respect of *virtual transactions* for *billing periods* prior to the current *billing period* which remain unpaid, whether or not the *IESO payment date* thereof has yet been reached; and

b. the *IESO's* reasonable estimate of the aggregate hourly and non-hourly *settlement amounts* payable to the *virtual trader* in respect of *virtual transactions* which have already occurred in the current *billing period*.

5C.3.2 The *IESO* shall *publish* daily, a price delta for the purposes of calculating the daily cumulative *actual exposure* for *virtual transactions*. This price delta will be determined as the value that is the percentile set out in the applicable *market manual* of the following values ranked from lowest to highest:

5C.3.2.1 In respect of each *virtual transaction zone*, the absolute value of the difference between the *day-ahead market virtual zonal price* and the hourly average *real-time market virtual zonal price* of the same *settlement hours* for all *settlement hours* within the following days:

a. the 30 days immediately prior to *trading day* for which the price delta is being *published;*

b. the *trading day* that is exactly 1 year prior to the *trading day* for which the price delta is being *published;*

c. the 30 days immediately prior to and the 30 days immediately following th*e trading day* referred to in subsection b;

d. the *trading day* that is exactly 2 years prior to the *trading day* for which the price delta is being *published;* and

e. the 30 days immediately prior to and the 30 days immediately following the *trading day* referred to in subsection d.

5C.3.3 Notwithstanding section 5C.3.2, until the requisite amount of historical data is available, the price delta shall be determined by the *IESO* using the same methodology as described in section 5C.3.2 except using shadow prices from the day-ahead commitment process and the *real-time market* as necessary to ensure the requisite amount of data is included in the determination of the price delta.

5C.4. Margin Call Requirements for Virtual Transactions

5C.4.1 A *virtual trader* that is not also authorized to conduct *physical transactions* must satisfy a *margin call* in respect of *virtual transactions* within the time prescribed in section 5C.4.2 by paying a portion of the amount payable or which will become payable in respect of the previous or current *energy market billing period*, in accordance with MR Ch.9, in an amount sufficient to reduce the *virtual trader's actual exposure* for *virtual transactions* to no more than the dollar equivalent of 75% of the *virtual trader's trading limit* for *virtual transactions*. No interest shall be paid on such payments.

5C.4.2 The time within which a *margin call* in respect of *virtual transactions* must be satisfied under section 5C.4.1 shall be by 4:00 pm on the second *business day* following the date of the *margin call*.

5C.4.3 For the purposes of the *market rules*, a payment made pursuant to section 5C.4.2 shall be applied first to the amount outstanding for *virtual transactions* with respect to the earliest *billing period* under the *market rules* and, if the amount outstanding under the *market rules* in respect of that *billing period* is less than the amount of the payment, then the excess shall be applied to the next earliest *billing period* for *virtual transactions* in respect of which there is an amount outstanding under the *market rules* and so on until there is no excess.

5C.4.4 Upon receipt of a *margin call* payment in respect of *virtual transactions* in accordance with section 5C.4.1, the *IESO* shall reinstate the *virtual trader's* ability to conduct *virtual transactions*.

5C.5 Obligation to Provide Prudential Support for Virtual Transactions

5C.5.1 Each *virtual trader* must meet its obligation under this section 5C to provide and maintain *prudential support* for *virtual transactions* by providing to the *IESO* and maintaining *prudential support*, the value of which is equal to the *virtual trader's prudential support obligation* for *virtual transactions*.

5C.5.2 A *virtual trader's prudential support obligation* for *virtual transactions* must be met through the provision to the *IESO* and the maintenance of *prudential support* in one or more of the following forms:

5C.5.2.1 a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the *IESO* and provided by:

a. a bank named in a Schedule to the *Bank Act*, S.C. 1991, c.46 with a minimum long-term credit rating of "A" from a major bond rating agency as identified in the list referred to in section 5C.5.3; or

b. a credit union licensed by the Financial Services Regulatory Authority of Ontario with a minimum long-term credit rating of "A" from a major bond rating agency as identified in the list referred to in section 5C.5.3.

5C.5.3 For the purposes of sections 5C.5.2.1, the *IESO* shall establish, maintain, update as required and *publish* a list of organizations eligible to provide the *prudential support* referred to in sections 5C.5.2.1 and shall establish, for each such eligible *prudential support* provider, an aggregate limit of the *prudential support* that may be provided by that *prudential support* provider to *virtual traders.* If aggregate limits are reached for any of these eligible organizations, *virtual traders* will be required to obtain *prudential support* from other eligible organizations that are still within their respective *prudential support* limits.

5C.6 Reductions in Prudential Support Obligations for Virtual Transactions

5C.6.1 Subject to the *IESO's* approval, a *virtual trader* that is a *market creditor* based on its *physical transactions* as a *generator*, that has achieved *market creditor* status in its most recent six *energy market billing periods*, may receive a reduction to its *prudential support obligation* for *virtual transactions* as calculated by the *IESO,* by an amount up to 75% of the average amount that the *IESO* owes to the *virtual trader* during the relevant six *billing periods*.

5D. Prudential Support for Market Participants Authorized to Conduct Both Physical Transactions and Virtual Transactions

5D.1 Purpose and Application

5D.1.1 This section 5D shall apply to a *market participant* that is authorized to conduct both *physical transactions* and *virtual transactions.*

5D.2 Calculation of Consolidated Actual Exposure and Consolidated Trading Limit

5D.2.1 The consolidated *actual exposure* of a *market participant* shall be the sum of the *market participant's actual exposure* for *physical transactions* in accordance with section 5.5 and the *actual exposure* for *virtual transactions* in accordance with section 5C.3.

5D.2.2 The consolidated *trading limit* of a *market participant* shall be the sum of the *market participant's trading limit* for *physical transactions* in accordance with section 5.3 and the *trading limit* for *virtual transactions* in accordance with section 5C.1.5.

5D.3 Monitoring of Consolidated Actual Exposure and Consolidated Trading Limit

5D.3.1 If at any time the consolidated *actual exposure* of a *market participant* is equal to or exceeds 70% and is less than 100% of the *market participant's* consolidated *trading limit*, the *IESO* shall inform the *market participant* of that fact. The *market participant* may, but is not required to, make a cash payment to be applied to reduce its consolidated *actual exposure* or take other action to prevent its consolidated *actual exposure* from reaching its consolidated *trading limit*. No interest shall be paid on any such payment.

5D.3.2 If at any time the consolidated *actual exposure* of a *market participant* equals or exceeds the *market participant's* consolidated *trading limit*, the *IESO* shall issue to the *market participant* a consolidated *margin call.* Upon issuance of a consolidated *margin call*, the *IESO* shall reject subsequent *market participant bids* and *offers* for *virtual transactions* until the *market participant* satisfies the consolidated *margin call* in accordance with section 5D.4.1.

5D.4 Consolidated Margin Call Requirements

5D.4.1 A *market participant* must satisfy a consolidated *margin call* within the time prescribed in section 5D.4.2 by paying a portion of the amount payable or which will become payable in respect of the previous or current *energy market billing period*, in accordance with MR Ch. 9, in an amount sufficient to reduce the *market participant's* consolidated *actual exposure* to no more than the dollar equivalent of 75% of the *market participant's consolidated trading limit*. No interest shall be paid on such payments.

5D.4.2 The time within which a consolidated *margin call* must be satisfied under section 5D.4.1 shall be by 4:00 pm on the second *business day* following the date of the *margin call*.

5D.4.3 For the purposes of the *market rules*, a payment made pursuant to section 5D.4.1 shall be applied first to the amount outstanding with respect to the earliest *billing period* under the *market rules* and, if the amount outstanding under the *market rules* in respect of that *billing period* is less than the amount of the payment, then the excess shall be applied to the next earliest *billing period* in respect of which there is an amount outstanding under the *market rules* and so on until there is no excess.

5D.4.4 Upon receipt of a payment made in response to a consolidated *margin call* in accordance with this section 5D.4.1, the *IESO* shall reinstate the *market participant's* ability to conduct *virtual transactions.*

5D.5 Obligation to Provide Prudential Support for Market Participants Authorized to Conduct Both Physical Transactions and Virtual Transactions

5D.5.1 *Market participants* authorized to conduct both *physical transactions* and *virtual transactions* shall provide and maintain:

5D.5.1.1 *prudential support* for *physical transactions*, the value of which is not less than the *market participant's prudential support obligation* for *physical transactions* as calculated by the *IESO* in accordance with sections 5.3 and 5.8, and in the forms of *prudential support* for *physical transactions* specified in section 5.7; and

5D.5.1.2 *prudential support* for *virtual transactions*, the value of which is not less than the *market participant's prudential support obligation* for *virtual transactions* as calculated by the *IESO* in accordance with sections 5C.1 and 5C.6, and in the forms of *prudential support* for *virtual transactions* specified in section 5C.5.

6. Technical Requirements

6.1 Technical Requirements

6.1.1 Each *market participant, embedded generator, embedded electricity storage participant* and *embedded load consumer* shall, in addition to ensuring that its *facilities* and equipment meet all other applicable technical requirements set forth in these *market rules* ensure that its *facilities*:

6.1.1.1 meet the applicable technical requirements of Appendix 2.2; and

6.1.1.2 are capable of meeting the performance standards referred to in MR Ch.4 ss.7.3.1.4, 7.3A.1.4, 7.4.1.2, 7.5.1.2 or 7.6.1.2, as the case may be.

6.2 Certification, Testing and Inspection for Authorization

6.2.1 Each person referred to in section 6.1.1 that applies for authorization as a *market participant* shall, as a condition of obtaining authorization as a *market participant* pursuant to section 3 or 4.1.1, certify to the *IESO* that its *participant workstation* complies with all applicable technical requirements set forth in MR Ch.2 App.2.2.

6.2.2 Each person referred to in section 6.1.1 that applies for authorization as a *market participant* shall, as a condition of obtaining authorization as a *market participant* pursuant to section 3 or 4.1.1, successfully complete such testing and permit such inspection as the *IESO* may require for the purposes of testing or inspecting whether the person's *participant workstation* meets all applicable technical requirements set forth in MR Ch.2 App.2.2.

6.3 Certification, Testing and Inspection for Registration of Facilities

6.3.1 Each *market participant* shall, as a condition of obtaining the registration of its *facility* and any associated *resource* or for using a *boundary entity resource* pursuant to MR Ch. 7 s. 2.2 or as a condition of obtaining approval to aggregate *resources*:

6.3.1.1 provide the certifications referred to in MR Ch.7 ss.2.2.3.3 and 2.2.3.4 or in MR Ch.7 ss.2.3.2.4 and 2.3.2.5, as the case may be; and

6.3.1.2 successfully complete the testing and permit the inspection referred to in MR Ch.7 ss.2.2.3.5 or 2.3.2.6, as the case may be.

7. Payment Default Procedure

7.1.1 The *events of default* relating to payment and either *prudential support*, *capacity prudential support*, as well as the rights and obligations of the *IESO* and *market participants* upon the occurrence of such *event of default*, are specified in MR Ch.3 s.6.3.

8. Default Levy

8.1 Power to Impose Default Levy

8.1.1 The *IESO* shall be entitled to recover, by means of the imposition of a *default levy* on *non-defaulting market participants,* in accordance with this section 8, the aggregate of any amounts owing to the *IESO* under the *market rules* which have not been paid in full by the *defaulting market participant* and the costs and expenses reasonably incurred by the *IESO* in investigating the default in payment, in realizing on any applicable *prudential support* and in implementing the *default levy*.

8.1.2 The imposition of a *default levy* pursuant to this section 8 shall in no way waive, excuse or relieve a *defaulting market participant* of its obligations under the *market rules* and shall be without prejudice to:

8.1.2.1 such rights or remedies which the *IESO* may otherwise have to recover all amounts owing by the *defaulting market participant*; and

8.1.2.2 the right of the *IESO* to take such other action, including but not limited to the issuance of a *suspension order,* as may be provided for in these *market rules* in respect of the *defaulting market participant's* default in payment.

8.1.3 [Intentionally left blank – section deleted]

8.1.4 The provisions of this section 8 apply only to a default in payment by a *defaulting market participant* in the *real-time market* or the *day-ahead market.*

Default in payment by a *defaulting market participant* in the *TR market* shall be addressed in accordance with the provisions of MR Ch.8 s.3.

8.2 Notice of First Default Levy

8.2.1 Where a *market participant* has failed to either remit or cause to be remitted to the *IESO settlement clearing account* the full amount due by that *market participant* by the close of banking business (of the bank at which the *IESO settlement clearing account* is held) on a *market participant payment date*:

8.2.1.1 [Intentionally left blank]

8.2.1.2 [Intentionally left blank]

8.2.1.3 the *IESO* may take such steps as may be permitted by MR Ch.9 s.6.16.

8.2.2 Where the *IESO* has issued a *suspension order* or *termination order* to a *defaulting market participant*, the *IESO* may:

8.2.2.1 issue a first *notice of default levy* in accordance with section 8.2.3; and

8.2.2.2 take such steps, if it has not already done so, as may be required to realize, in accordance with section 3 of Appendix 2.3, any *prudential support* held in respect of the *defaulting market participant* the right to realization of which is triggered by the default in payment at issue.

8.2.3 A first *notice of default levy* shall be issued to each *non-defaulting market participant* that participated in the *real-time market* or the *day-ahead market* to which the default in payment by the *defaulting market participant* relates during the *billing period* to which such default relates and shall identify:

8.2.3.1 the name of the defaulting *market participant*;

8.2.3.2 [Intentionally left blank];

8.2.3.3 the *defaulting market participant's default amount,* calculated in accordance with section 8.3.1;

8.2.3.4 the amount of the first *default levy* calculated in accordance with section 8.3.2; and

8.2.3.5 [Intentionally left blank];

8.2.3.6 [Intentionally left blank];

8.2.3.7 the *non-defaulting market participant's* share of the first *default levy*, calculated in accordance with section 8.6.1.

8.2.4 The first *notice of default levy* shall be issued at least ten days prior to the date on which the *invoice* imposing the first *default levy* on *non-defaulting market participants* is issued by the *IESO* in accordance with section 8.6.2.

8.3 Calculation of Default Amount and First Default Levy

8.3.1 For the purposes of section 8.2.3.3, the *market participant's default amount* shall be the aggregate of:

8.3.1.1 the net *invoice* amount payable by the *defaulting market participant* for the *billing period* in respect of which payment has not been received within the time specified in section 8.2.2, exclusive of any amounts payable on account of financial penalties or damages; and

8.3.1.2 any *default interest* payable in respect of the amount referred to in section 8.3.1.1 that has accrued since the *market participant payment date* referred to in section 8.2.1 in accordance with MR Ch.9 s.6.16.3.

8.3.2 For the purposes of section 8.2.3.4, the amount of the first *default levy* shall be:

8.3.2.1 the aggregate of:

a. the *defaulting market participant's default amount*, calculated in accordance with section 8.3.1; and

b. any costs and expenses reasonably incurred to the date of issuance of the first *notice of default levy* by the *IESO* in investigating the default in payment to which the *default levy* relates, in realizing on any applicable *prudential support* held in respect of the *defaulting market participant* and in implementing the *default levy*;

8.3.2.2 less the aggregate unclaimed or undrawn dollar amount of all *prudential support* held in respect of the *defaulting market participant* the right to realization of which is triggered by the default in payment at issue.

8.3.3 The first *default levy* shall be apportioned amongst and *invoiced* to *non-defaulting market participants* in accordance with sections 8.6.1 and 8.6.2.

8.4 Notice of Second Default Levy

8.4.1 Unless the amount of the first *default levy* is equal to the *defaulting market participant's default amount* the *IESO* shall, issue a second *notice of default levy* or further successive *default levy* notices in accordance with section 8.4.2.

8.4.2 The second *notice of default levy* or successive residual *default levy* notices shall be issued to each *non-defaulting market participant* on whom the residual *default levy amount period* has been imposed and shall identify:

8.4.2.1 the name of the defaulting *market participant*;

8.4.2.2 [Intentionally left blank];

8.4.2.3 the *defaulting market participant's* residual *default amount,* calculated in accordance with section 8.5.1;

8.4.2.4 the aggregate amount of the first *default levy* or *default levies*;

8.4.2.5 [Intentionally left blank];

8.4.2.6 [Intentionally left blank];

8.4.2.7 the amount of the residual *default levy*, calculated in accordance with section 8.5.2; and

8.4.2.8 the *non-defaulting market participant's* share of the second *default levy*, calculated in accordance with section 8.6.1.

8.4.3 The second *notice of default levy* shall be issued at least ten days prior to the date on which the *invoice* imposing the second *default levy* on *non-defaulting market participants* is issued by the *IESO* in accordance with section 8.6.2.

8.5 Calculation of Residual Default Amount and Second Default Levy

8.5.1 For the purposes of section 8.4.2.3, the *defaulting market participant's* residual *default amount* shall be:

8.5.1.1 the aggregate of:

a. the net *invoice* amount payable by the *defaulting market participant* for the *billing period* in respect of which payment has not been received as of the date of issuance of the second *notice of default levy,* exclusive of any amounts payable on account of financial penalties or damages; and

b. any *default interest* payable in respect of the amount referred to in section 8.5.1.1(a) that has accrued since the date of issuance of the first *notice of default levy* in accordance with MR Ch.9 s.6.16.3;

8.5.1.2 less the aggregate of:

a. the amount of the first *default levy*; and

b. any amount that has been recovered by the *IESO* since the date of issuance of the first *notice of default levy* under any *prudential support* held in respect of the *defaulting market participant.*

8.5.2 For the purposes of section 8.4.2.7, the amount of the second *default levy* shall be the aggregate of:

8.5.2.1 the *defaulting market participant's* residual *default amount*, calculated in accordance with section 8.5.1; and

8.5.2.2 any costs and expenses reasonably incurred by the *IESO* in investigating the default in payment to which the *default levy* relates, in realizing any applicable *prudential support* and in implementing the *default levy* since the date on which the first *default levy* was calculated.

8.5.3 The second *default levy* shall be apportioned and *invoiced* to *non-defaulting market participants* in accordance with sections 8.6.1 and 8.6.2.

8.6 Apportionment and Invoicing of Default Levy

8.6.1 For the purposes of sections 8.2.3.7 and 8.4.2.8, the amount of a *default levy* shall be apportioned amongst all *non-defaulting market participants* to whom a *notice of default levy* has been issued in accordance with sections 8.2.3 or 8.4.2 by allocating to each *non-defaulting market participant* a share of the *default levy* calculated as follows:

8.6.1.1 in the case of a *default levy* imposed in respect of a default in the *real-time market* and the *day-ahead market*, the share allocated to each *non-defaulting market participant* shall be determined on the basis of the following formula:

[*default amount* x (absolute value of the *non-defaulting market participant's* net *invoice* amount, exclusive of any amounts payable on account of financial penalties or damages, in the *real-time market* and the *day-ahead market* for the *billing period* to which the default in payment by the *defaulting market participant* relates)]	divided by	net transaction dollar amount

Where the *net transaction dollar amount* is:

∑ the absolute value, in dollars, of each *market participant's* net *invoice* amount, for the *energy market billing period* to which the default in payment by the *defaulting market participant* relates	Minus	the absolute value, in dollars, of the *defaulting market participant's* net *invoice* amount for such *energy market billing period*;

8.6.2 Subject to section 8.6.3, a *non-defaulting market participant's* share of a *default levy* shall be included in or with the first *invoice* scheduled to be issued to the *non-defaulting market participant* pursuant to MR Ch.9 following the expiry of the time noted in section 8.2.4 or 8.4.3, as the case may be, in respect of each *IESO-administered market* to which the *default levy* relates.

8.6.3 Where, for any reason, no *invoice* is scheduled to be issued to a *non-defaulting market participant* to whom a second *notice of default levy* has been issued under section 8.4.2, the *IESO* shall issue an *invoice* to that *non-defaulting market participant* comprising the amount of that *non-defaulting market participant's* share of the second *default levy.* Any such *non-defaulting market participant* shall pay to the *IESO* the *invoice* amount on the second *business day* following receipt of the *invoice*.

8.7 Allocation of Default Levy

8.7.1 The *IESO* shall allocate amounts received from *non-defaulting market participants* in respect of a *default levy*:

8.7.1.1 first, to repay any short-term funds borrowed by the *IESO* pursuant to MR Ch.9 s.6.16.5 on account of the *defaulting market participant's* default in payment; and

8.7.1.2 [Intentionally left blank]

8.7.1.3 second, to the payment of amounts owed by the *defaulting market participant* to the *IESO* on account of the *IESO administration charge.*

8.7.2 Amounts received from *non-defaulting market participants* in respect of a *default levy* to cover the reasonable costs and expenses referred to in sections 8.3.2.1 and 8.5.2.2 shall be used to offset the *IESO administration charge.*

8.8 Other Recovery of Default Amounts

8.8.1 Notwithstanding the imposition of a *default levy*, the *IESO* shall take all reasonable steps to recover from the *defaulting market participant*, including by means of the realization of any *prudential support* held in respect of a *defaulting market participant* that has not been realized as at the date of calculation of a second *default levy*, all amounts owing to the *IESO* under the *market rules*. The *IESO* may, but shall not be obliged to, follow the dispute resolution process set forth in MR Ch.3 s.2 for the purpose of obtaining such recovery.

8.8.2 Subject to section 8.8.3, any full or partial recovery made by the *IESO* pursuant to section 8.8.1 shall be distributed to each *non-defaulting market participant* that remitted payment to the *IESO* on account of a *default levy* on a prorated basis according to, and in an amount that does not exceed, the amount so remitted by the *non-defaulting market participant.* Where the *non-defaulting market participant* is, at the relevant time, still a *market participant*, any such amount shall appear as a credit on the next *invoice* scheduled to be issued to that *non-defaulting market participant* under MR Ch.9. Where the *non-defaulting market participant* is no longer a *market participant* at the relevant time, any such amount shall be paid to the former *non-defaulting market participant* in such manner as the *IESO* determines appropriate.

8.8.3 In the event that the *IESO* cannot, after taking all reasonable steps to do so, locate a former *non-defaulting market participant* that has remitted payment to the *IESO* on account of a *default levy*, any amount that would otherwise be distributed to such former *non-defaulting market participant* under section 8.8.2 shall:

8.8.3.1 be allocated and distributed to other *non-defaulting market participants* in the manner described in section 8.8.2; or

8.8.3.2 where other *non-defaulting market participants* have already been reimbursed in respect of a *default levy* and are therefore not entitled to payment of any amounts under section 8.8.2, be used to offset the *IESO administration charge.*

8.8.4 Any costs and expenses reasonably incurred by the *IESO* in recovering amounts from a *defaulting market participant* under section 8.8.1 that have not been included in a *default levy* under section 8.3.2.1(b) or 8.5.2.2 shall be included in the *IESO administration charge.*

9. Withdrawal by a Market Participant

9.1.1 Provided that the *market participant* has requested that the *IESO* de-register or transfer any applicable *facilities* pursuant to MR Ch.7 ss.2.4 or 2.5, a *market* *participant* shall notify the *IESO* in writing if it wishes to cease to be a *market participant*. The notice shall specify the date of the *trading day* upon which the *market participant* intends to cease to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*. The *trading day* specified shall not be earlier than the *trading day* on which:

9.1.1.1 the last of the *market participant's* applicable *facilities* is to be de-registered by the *IESO* and, where applicable, *disconnected* from the *IESO-controlled grid*, determined in accordance with MR Ch.7 s.2.4; or

9.1.1.2 the registration of the last of the *market participant's* applicable *facilities* is to be transferred by the *IESO*, determined in accordance with MR Ch.7 s.2.5.

9.1.2 Upon receipt of the notice referred to in section 9.1.1, the *IESO* must *publish* and provide to all *market participants* a further notice stating that:

9.1.2.1 the *IESO* has received a notice under section 9.1.1; and

9.1.2.2 the person who gave the notice has stated that, from the end of the *trading day* specified in the notice, the person intends to cease participating in the *IESO-administered markets* or causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid*.

9.1.3 The *markets participant* shall cease to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* no later than the end of the *trading day* specified in the notice given under section 9.1.1.

9.1.4 A *market participant* which has given a notice under section 9.1.1 shall cease to be a *market participant* on the date:

9.1.4.1 specified in the notice referred to in section 9.1.1;

9.1.4.2 on which the last of the *market participant's* applicable *facilities* is de-registered by the *IESO* and, where applicable, *disconnected* from the *IESO-controlled grid* pursuant to MR Ch.7 s.2.4;

9.1.4.3 on which the registration for the last of the *market participant's* applicable *facilities* has been transferred by the *IESO* pursuant to MR Ch.7 s.2.5;

9.1.4.4 on which all payments due to be paid by it or to it under the *market rules* have been made; or

9.1.4.5 the *market participant* has no further liability under MR Ch.7 s.2.5.4,

whichever is the latest. Any *boundary entity resource* registered to be used by such *market participant* shall no longer be used by that *market participant* as of such date.

9.1.5 A person who ceases to be a *market participant* shall remain subject to and liable for all of its obligations and liabilities as a *market participant* including, but not limited to, a liability under section 8 and an *adjustment period allocation* debit under MR Ch.9 ss.6.8.11.2, 6.9.4.2, or 6.10.4.4(a) resulting from an event that occurred while such person was a *market participant*, which were incurred or arose under the *market rules* prior to or on the *trading day* on which it ceases to be a *market participant* regardless of the date on which any claim relating thereto may be made.

10. Market Participant Fees

10.1.1 The *IESO* shall not less than annually *publish* and notify *market participants* of the fees or schedule of fees payable by *market participants* and persons who apply for authorization to become *market participants*, including the application fee referred to in section 3.1.2.1. Such fees or schedule of fees shall be those approved by the *Ontario Energy Board* from time to time pursuant to section 25 of the *Electricity Act, 1998*.

10.1.2 The *IESO* shall recover the relevant fees from each *market participant* or prospective *market participants* in such manner as the *IESO* determines appropriate, including by means of the inclusion of the fees in a billing statement.

10.1.3 Each *market participant* or prospective *market participant* shall pay to the *IESO* the fees stated by the *IESO* to be payable by the *market participant* or prospective *market participant* by the date or dates specified for payment.

RUL-8

Renewed Market Rules

Chapter 0.2

Participation - Appendices

Renewed Market Rules – Chapter 0.2: Participation - Appendices

0.2

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Table of Contents

Appendix 2.1 – [Intentionally left blank]

Appendix 2.2 – Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities

1.1 Voice Communications

1.1.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO:*

1.1.1.1 one *high priority path facility* and one *normal priority path facility* at the *dispatch centre*, *control centre* and *authority centre* for each of its *generation facilities* provided that either:

a. the *IESO* has determined that a *high priority path facility* and a *normal priority path facility* are required to enable the *IESO* to maintain *reliable* operation of the *IESO-controlled grid*; or

b. one of the applicable *generation facilities* is a *major generation facility*; or

c. the aggregate rated size of applicable *generation facilities* is 100 MVA or greater; or

d. any one of the applicable *generation facilities* is a *certified black start facility*;

1.1.1.2 subject to section 1.1.1.1, one *normal priority path facility* at the *dispatch centre*, *control centre* and *authority centre* for each of its *generation facilities* provided that the aggregate rated size of applicable *generation facilities* is less than 100 MVA;

1.1.1.3 one *high priority path facility* and one *normal priority path facility* for each of its *major generation facilities* that are attended *generation* stations;

1.1.1.4 one commercially available telephone for each of:

a. its *major generation facilities*, *significant generation facilities* and *minor generation facilities* that are *unattended*; and

b. its *self-scheduling generation facilities* with name-plate ratings of less than 10 MW,

the telephone number of which shall be provided by the *generator* to the *IESO*;

1.1.1.5 one *high priority path facility* and one *normal priority path facility* for each of its *major generation facilities*, *significant generation facilities* and *minor generation facilities* that is a *certified black start facility*; and

1.1.1.6 one *normal priority path facility* for each of its *significant generation facilities* and *minor generation facilities* that is attended and is not a *certified black start facility*.

1.1.2 Each *embedded generator* that is not a *market participant* or whose *embedded generation facility* is not associated with any *resources* shall, subject to section 1.1.11, provide and maintain the voice communication facilities referred to in sections 1.1.1.1 to 1.1.1.6, as may be applicable, in respect of each of its *embedded generation facilities* that:

1.1.2.1 includes a *generation unit* rated at 20 MVA or higher or that comprises *generation units* the ratings of which in the aggregate equals or exceeds 20 MVA; and

1.1.2.2 has been designated by the *IESO* for the purposes of this section 1.1.2 as requiring such voice communication facilities in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

1.1.3 Each *distributor* whose *distribution system* is *connected* to the *IESO-controlled grid* and that has control of any step-down transformer secondary breakers or low voltage feeder breakers for its loads shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO:*

1.1.3.1 one *high priority path facility* and one *normal priority path facility* at each location that controls such breakers if the *connection facilities connecting* such *distributor's distribution system* to the *IESO-controlled grid* have ratings that in aggregate equal or exceed 200 MVA; and

1.1.3.2 one *normal priority path facility* at each location that controls such breakers if the *connection facilities connecting* such *distributor's distribution system* to the *IESO-controlled grid* have ratings that in aggregate are less than 200 MVA.

1.1.4 Each *transmitter* whose *transmission system* or part thereof forms part of or is *connected* to the *IESO-controlled grid* shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO*:

1.1.4.1 one *high priority path facility* and one *normal priority path facility* at the dispatch or *control centre* for each such *transmission system*;

1.1.4.2 one *high priority path facility* and one *normal priority path facility* at the *authority centre* for each such *transmission system*;

1.1.4.3 one *high priority path facility* and one *normal priority path facility* for each attended transformer station forming part of such *transmission system*; and

1.1.4.4 one commercially available telephone for each *unattended* transformer station forming part of such *transmission system*, the telephone number of which shall be provided by the *transmitter* to the *IESO.*

1.1.5 Each *connected wholesale customer* that has control of any step-down transformer secondary breakers or low voltage feeder breakers for its loads shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO*:

1.1.5.1 one *high priority path facility* and one *normal priority path facility* at each location that controls such breakers for each of its *load facilities* that is *connected* to the *IESO-controlled grid* and that includes a *load facility* rated at 200 MVA or higher or that is comprised of sets of *load equipment* the ratings of which in the aggregate equals or exceeds 200 MVA; and

1.1.5.2 one *normal priority path facility* at each location that controls such breakers for each of its *load facilities* that is *connected* to the *IESO-controlled grid* and that is rated at less than 200 MVA.

1.1.6 Each *embedded load consumer* whose *embedded load facility*:

1.1.6.1 includes a *load facility* that is rated at 20 MVA or higher or is comprised of sets of *load equipment* the ratings of which in the aggregate equals or exceeds 20 MVA; and

1.1.6.2 has been designated by the *IESO* for the purposes of this section 1.1.6 as requiring voice communication facilities in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*, shall provide and maintain one *normal priority path facility* for each such *embedded load facility* for the purposes of communicating with the *IESO.*

1.1.7 Each *high priority path facility* referred to in this section 1.1 shall provide unimpeded voice communications between the *IESO* and the *facility* to which the *high priority path facility* relates and shall:

1.1.7.1 meet the applicable specifications and other requirements set forth in the *participant technical reference manual*;

1.1.7.2 have a receiving apparatus that is independent of any *normal priority path facility*;

1.1.7.3 have a communication channel that is and operates in a manner that is geographically and technologically distinct from any *normal priority path facility*;

1.1.7.4 permit the *IESO* to connect and communicate immediately, without the possibility of encountering a busy signal;

1.1.7.5 if an *attended facility*, at all times while the *facility* is attended be answered by live voice by a person in attendance at the *facility;*

1.1.7.6 [Intentionally left blank]

1.1.7.7 be secure from the effects of interruptions in power supply for a period of at least eight hours; and

1.1.7.8 [Intentionally left blank]

1.1.7.9 [Intentionally left blank]

1.1.7.10 not involve any manual intermediate switching.

1.1.8 Each *normal priority path facility* referred to in this section 1.1 shall comply with each of the following elements as may, except with respect to section 1.1.8.5, be commercially available:

1.1.8.1 meet the applicable specifications and other requirements set forth in the *participant technical reference manual*;

1.1.8.2 have a receiving apparatus that is independent of any *high priority path facility*;

1.1.8.3 have a communication channel that is and operates in a manner that is geographically and technologically distinct from any *high priority path facility*;

1.1.8.4 be part of a public service telephone network;

1.1.8.5 if an *attended facility,* at all times while the facility is attended, be answered by live voice by a person in attendance at the *facility*;

1.1.8.6 permit and implement caller identification and call waiting;

1.1.8.7 have a separate telephone number dedicated exclusively to receiving voice communications from the *IESO*;

1.1.8.8 be secure against interception of communications by unauthorized third parties; and

1.1.8.9 be secure against disclosure of communications to unauthorized third parties.

1.1.9 Each person that is required by this section 1.1 to provide and maintain voice communication facilities and that applies for authorization as a *market participant* in respect of a *facility* to which such voice communication facilities relate shall:

1.1.9.1 identify, during the authorization or registration processes, the voice communication facilities that it shall provide and maintain in accordance with this section 1.1, the owner of such voice communication facilities and the telephone number or access code, as the case may be, for such voice communication facilities;

1.1.9.2 notify the *IESO* of any change in the telephone number or access code, as the case may be, for the voice communication facilities referred to in section 1.1.9.1, or in the equipment forming part of such voice communication facilities, no less than four days prior to the change being effected; and

1.1.9.3 if it will cease to be the owner of the voice communication facilities referred to in section 1.1.9.1, notify the *IESO* of the succeeding owner of such facilities no less than four days prior to the date on which the change of ownership is effected.

1.1.10 Each person that is required by this section 1.1 to provide and maintain voice communication facilities and that does not apply for authorization as a *market participant* in respect of the *facility* to which such voice communication facilities relate shall:

1.1.10.1 notify the *IESO* of the voice communication facilities that it shall provide and maintain in accordance with this section 1.1, of the owner of such voice communication facilities and of the telephone number or access code, as the case may be, for such voice communication facilities;

1.1.10.2 notify the *IESO* of any change in the telephone number or access code, as the case may be, for the voice communication facilities referred to in section 1.1.10.1, or in the equipment forming part of such voice communication facilities, no less than four days prior to the change being effected; and

1.1.10.3 if it will cease to be the owner of the voice communication facilities referred to in section 1.1.10.1, notify the *IESO* of the succeeding owner of such facilities no less than four days prior to the date on which the change of ownership is effected.

1.1.11 The *IESO* shall provide to a person required by this section 1.1 to maintain a *high priority voice communication facility*, the communication channel for such *high priority voice communication facility* if the *IESO* determines that such communication channel cannot be made available to the person without substantial cost.

1.1.12 Each *electricity storage participant* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO:*

1.1.12.1 one *high priority path facility* and one *normal priority path facility* at the *dispatch centre*, *control centre* and *authority centre* for each of its *electricity storage facilities* provided that either:

a. the *IESO* has determined that a *high priority path facility* and a *normal priority path facility* are required to enable the *IESO* to maintain *reliable* operation of the *IESO-controlled grid*; or
b. one of the applicable *electricity storage facilities* is a *major electricity storage facility*; or
c. the aggregate of the *electricity storage facility sizes* of the applicable *electricity storage facilities* is 100 MVA or greater.

1.1.12.2 subject to section 1.1.12.1, one *normal priority path facility* at the *dispatch centre*, *control centre* and *authority centre* for each of its *electricity storage facilities* provided that the aggregate of the *electricity storage facility* size ratings of the applicable *electricity storage facilities* is less than 100 MVA;

1.1.12.3 one *high priority path facility* and one *normal priority path facility* for each of its *major electricity storage facilities* that are attended electricity storage stations;

1.1.12.4 one commercially available telephone for each of:

a. its *major electricity storage facilities*, *significant electricity storage facilities* and *minor electricity storage facilities* that are *unattended*; and

b. its *self-scheduling electricity storage facilities* with an *electricity storage facility size* of less than 10 MW,

the telephone number of which shall be provided by the *electricity storage participant* to the *IESO*;

1.1.12.5 one normal priority path facility for each of its *significant electricity storage facilities* and *minor electricity storage facilities* that is attended.

1.1.13 Each *embedded electricity storage participant* that is not a *market participant* or whose *embedded electricity storage facility* is not associated with any *resources* shall, subject to section 1.1.11, provide and maintain the voice communication facilities referred to in sections 1.1.12.1 to 1.1.12.6, as may be applicable, in respect of each of its *embedded electricity storage facilities* that:

1.1.13.1 includes an *electricity storage unit* with a rated *electricity storage unit size* of 20 MVA or higher or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 20 MVA; and

1.1.13.2 has been designated by the *IESO* for the purposes of this section 1.1.13 as requiring such voice communication facilities in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid.*

1.2 Technical Requirements for Monitoring and Control

1.2.1 Each *generator* shall, for the purposes of submitting to the energy management system referred to in MR Ch.5 s.12 the monitoring and control information required to be provided by a *generator* to the *IESO* pursuant to the provisions of MR Ch.4 and MR Ch.5:

1.2.1.1 provide, maintain and connect to each of its applicable *generation facilities* monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.1.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable *generation facilities* and the real-time communication network channel or channels provided by the *IESO*.

1.2.2 Each *connected wholesale customer* shall, for the purposes of submitting to the energy management system referred to in MR Ch.5 s.12 the monitoring and control information required to be provided by a *connected wholesale customer* to the *IESO* pursuant to the provisions of MR Ch.4 and MR Ch.5:

1.2.2.1 provide, maintain and connect to:

a. where directed by the *IESO* if *transmitter* data is not adequate, each of its *load facilities* that includes *load equipment* rated individually or in the aggregate at 20MVA or higher that is exclusively associated with a *non-dispatchable load* or *price responsive load*; and

b. each of its *load facilities* associated with a *dispatchable load*,

monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.2.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its *load facilities* referred to in section 1.2.2.1 and the real-time communication network channel or channels provided by the *IESO.*

1.2.3 Each *transmitter* shall, for the purposes of submitting to the energy management system referred to in MR Ch.5 s.12 the monitoring and control information required to be provided by a *transmitter* to the *IESO* pursuant to the provisions of MR Ch.4 and MR Ch.5:

1.2.3.1 provide, maintain and connect to each of its applicable transmission assets monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.3.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable transmission assets and the real-time communication network channel or channels provided by the *IESO.*

1.2.4 Each *distributor* shall, for the purposes of submitting to the energy management system referred to in MR Ch.5 s.12 the monitoring and control information required to be provided by a *distributor* to the *IESO* pursuant to the provisions of MR Ch.4 and MR Ch.5:

1.2.4.1 provide, maintain and connect to each of its applicable distribution assets monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.4.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable distribution assets and the real-time communication network channel or channels provided by the *IESO.*

1.2.5 Each *embedded load consumer* shall, for the purposes of submitting to the energy management system referred to in MR Ch.5 s.12 the monitoring and control information required to be provided by the *embedded load customer* to the *IESO* pursuant to the provisions of MR Ch.4 and MR Ch.5:

1.2.5.1 provide, maintain and connect to:

a. where directed by the *IESO* if *transmitter* or *distributor* data is not adequate, each of its applicable *load facilities* that includes *load equipment* rated individually or in the aggregate at 20 MVA or higher that is associated exclusively with a *non-dispatchable load* or *price responsive load*; and

b. each of its applicable *load facilities* associated with a *dispatchable load*

monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.5.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its *embedded load facilities* referred to in section 1.2.5.1 and the real-time communication network channel or channels provided by the *IESO.*

1.2.6 Each person referred to in this section 1.2 shall provide access to its equipment, installation space and a reliable power source that meet the specifications and other requirements of the *participant technical reference manual*.

1.2.7 Each *electricity storage participant* shall, for the purposes of submitting to the energy management system referred to in MR Ch.5 s.12 the monitoring and control information required to be provided by an *electricity storage participant* to the *IESO* pursuant to the provisions of MR Ch.4 and MR Ch.5:

1.2.7.1 provide, maintain and connect to each of its applicable *electricity storage facilities* monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.7.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting *facilities* enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable *electricity storage facilities* and the real-time communication network channel or channels provided by the *IESO.*

1.3 Dispatch Workstations

1.3.1 Each *market participant* other than those that are exclusively registered to participate as an *energy trader*, *virtual trader, TR participant*, a *capacity auction participant* with a *capacity obligation* through an *hourly demand response resource*, or any combination of the foregoing, shall, for the purposes of:

1.3.1.1 the provision to the *IESO* of real-time information required by the *IESO* to direct the operations of the *IESO-controlled grid*;

1.3.1.2 if the person is or will be associated with a *dispatchable resource*, the receipt of *dispatch instructions*; and

1.3.1.3 the exchange with the *IESO* of other information required to be submitted or received pursuant to MR Ch.7 or MR Ch.8, other than the submission, receipt of confirmation of and validation of *dispatch data*, *TR bids* in the *TR market* and *physical bilateral contract data*, provide, install and maintain a *dispatch workstation* that meets the specifications and other requirements set forth in the *participant technical reference manual* and that is configured to support communication with the real-time communication network channel or channels provided by the *IESO* in the manner described in the *participant technical reference manual*.

1.3.2 The *dispatch workstation* referred to in section 1.3.1 shall be located at:

1.3.2.1 the *facility* to which the *dispatch workstation* relates; or

1.3.2.2 the *authority centre* for the *facility* to which the *dispatch workstation* relates so as to permit a response to *dispatch instructions* within the time prescribed by the *participant technical reference manual*.

1.3.3 Each *market participant* that is required by this section 1.3 to provide, install and maintain a *dispatch workstation* shall:

1.3.3.1 prior to commencing participation in the *IESO-administered markets*, notify the *IESO* of the premises at which its *dispatch workstation* will be located; and

1.3.3.2 notify the *IESO* of any change in the location of its *dispatch workstation* no less than four days prior to the date on which the change will be effected.

1.4 Participant Workstations

1.4.1 Subject to section 1.6, each *market participant* shall, for the purposes of conducting secure communications or transactions with the *IESO* using *IESO*-supplied or approved software, provide, install and maintain a *participant workstation* that meets the specifications, definitions and other requirements set forth in the *participant technical reference manual*.

1.4.2 Each *participant workstation* required to be installed and maintained pursuant to section 1.4.1 shall:

1.4.2.1 where the *market participant* is exchanging the information referred to in section 1.4.1 by means of the internet, be configured to support internet communication in the manner described in the *participant technical reference manual* and, if a *TR participant*, to support communication with the communication protocol referred to in MR Ch.8 App.8.2; and

1.4.2.2 where the *market participant* is exchanging the information referred to in section 1.4.1 by means of the private network dedicated communication links, be configured to support communication between the *participant workstation* and the *IESO* in the manner described in the *participant technical reference manual* and, if a *TR participant*, to support communication with the communication protocol referred to in MR Ch.8 App.8.2.

1.5 Re-classification of Facilities

1.5.1 The *IESO* may, for the purposes of this Appendix 2.2 and of MR Ch.5 s.12:

1.5.1.1 re-classify a *small generation facility* as a *minor generation facility*, a *significant generation facility* or a *major generation facility*;

1.5.1.2 re-classify a *minor generation facility* as a *significant generation facility* or a *major generation facility*;

1.5.1.3 re-classify a *significant generation facility* as a *major generation facility*;

1.5.1.4 re-classify a *minor dispatchable load facility* as a *significant dispatchable load facility* or a *major dispatchable load facility*; and

1.5.1.5 re-classify a *significant dispatchable load facility* as a *major dispatchable load facility*,

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

1.5.1A The *IESO* may, for the purposes of this Appendix 2.2 and of MR Ch.5 s.12:

1.5.1A.1 re-classify a *small electricity storage facility* as a *minor electricity storage facility*, a *significant electricity storage facility* or a *major electricity storage facility*;

1.5.1A.2 re-classify a *minor electricity storage facility* as a *significant electricity storage facility* or a *major electricity storage facility*;

1.5.1A.3 re-classify a *significant electricity storage facility* as a *major electricity storage facility*;

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid.*

1.5.2 The *IESO* may, for the purposes of this Appendix 2.2 and of MR Ch.5 s.12:

1.5.2.1 re-classify a *major generation facility* as a *significant generation facility*, a *minor generation facility* or a *small generation facility*;

1.5.2.2 re-classify a *significant generation facility* as a *minor generation facility* or a *small generation facility*;

1.5.2.3 re-classify a *minor generation facility* as a *small generation facility*;

1.5.2.4 re-classify a *major dispatchable load facility* as a *significant dispatchable load facility* or a *minor dispatchable load facility*; and

1.5.2.5 re-classify a *significant dispatchable load facility* as a *minor dispatchable load facility*,

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

1.5.2A The *IESO* may, for the purposes of this Appendix 2.2 and of MR Ch.5 s.12:

1.5.2A.1 re-classify a *major electricity storage facility* as a *significant electricity storage facility*, a *minor electricity storage facility* or a *small electricity storage facility*;

1.5.2A.2 re-classify a *significant electricity storage facility* as a *minor electricity storage facility* or a *small electricity storage facility*;

1.5.2A.3 re-classify a *minor electricity storage facility* as a *small electricity storage facility*;

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

1.5.3 A person whose *facility* has been re-classified pursuant to section 1.5.1, 1.5.1A, 1.5.2 or 1.5.2A shall ensure that its *facilities* and equipment meet the requirements set forth in this Appendix 2.2 and in MR Ch.5 s.12 applicable to the class of *facility* in which its *facility* has been re-classified.

1.6 Terms and Conditions

1.6.1 Where a *market participant* conducts secure communications or transactions with the *IESO* in accordance with section 1.4, sections 1.6.2 to 1.6.5 shall apply.

1.6.2 Each *market participant* shall be solely responsible to ensure the authenticity, integrity and non-repudiation of communications or transactions, as described in the *participant technical reference manual*.

1.6.3 Each *market participant* agrees to:

1.6.3.1 be bound by an authenticated communication or transaction to the same extent, and with the same effect of law, as if the authenticated communication or transaction had existed in a manually signed or otherwise authenticated form;

1.6.3.2 acknowledge that the *IESO* will act in reliance on an authenticated communication or transaction, even where the authenticated communication or transaction contains an error;

1.6.3.3 accept the time-stamp in the validation response or the time stamp of the communication or transaction recorded by the *IESO* as the authoritative record. In the case of a discrepancy, the time stamp of the communication or transaction recorded by the *IESO* shall prevail; and

1.6.3.4 immediately notify the *IESO* if the *market participant* suspects any unauthorized, or inappropriate access to or activity on the *IESO's* systems or information.

1.6.4 The *IESO* may, without notice, temporarily suspend a *market participant's* ability to conduct secure communications or transactions if the *IESO* reasonably suspects unauthorized or inappropriate access to or activity on the *IESO's* systems or information. These suspensions will be for a period of time necessary to permit the thorough investigation of such suspended activity.

1.6.5 The *IESO* shall not be liable for any unauthorized activity and the damages or consequences that may result from the use of secure communications or transactions, unless such violation was solely and directly as a result of the actions of the *IESO*.

Appendix 2.3 – Prudential Support

1. Additional Provisions Regarding Prudential Support

1.1 Determination of Prudential Support Obligations

Prior to participating in the *real-time market* or the *day-ahead market*, the *IESO* shall deliver to each *market participant* a schedule, in the form set forth in the applicable *market manual,* setting out the determination by the *IESO* of that *market participant's prudential support obligations*, which shall be completed by the *IESO* on the basis of the determinations referred to in MR Ch. 2 ss.5, 5C and 5D. Such schedule shall be effective until amended and replaced in accordance with this Appendix.

1.2 Provision of Prudential Support

Prior to participating in the *real-time market* or the *day-ahead market*, each *market participant* shall deliver to the *IESO*:

1.2.1 a schedule, in the form set forth in the applicable *market manuals* completed by the *market participant* setting out the *prudential support* with which the *market participant* has elected to satisfy its *prudential support obligation* in respect of either or both *physical transactions* or *virtual transactions* as set forth in the schedule delivered to it by the *IESO* referred to in section 1.1; and

1.2.2 the *prudential support* as set out in that schedule.

In the event that the sum of all *prudential support* provided by the *market participant* to the *IESO* is a greater amount than required by the *market rules,* the *IESO* shall, upon written request by the *market participant*, return (or direct the custodian to return) to the *market participant* an amount equal to the difference between the value of all *prudential support* then held by or on behalf of the *IESO* and the *prudential support obligation* of the *market participant* at that time. The *IESO* shall return such amount within five *business days* of the receipt of the request for the return of the amount from the *market participant.* In the event the *market participant* has posted one or more different types of *prudential support*, the *IESO* shall return the type of *prudential support as* directed by the *market participant.* Upon the return by the *IESO* to the *market participant* of the amount of any *prudential support*, any security interest or lien granted on such *prudential support* will be released immediately and, to the extent possible, without any further action by either party.

1.3 Reduction of Prudential Support Obligation for Physical Transactions for Credit Rating

Where the *market participant*'s *prudential support obligation* for *physical transactions* reflects a reduction by reason of the *market participant*'s credit rating from a major bond rating agency identified in the list of such agencies *published* by the *IESO*, the *market participant* covenants and agrees to advise the *IESO* in writing immediately upon the *market participant* becoming aware of either a change in or loss of the then current credit rating or the decision of the bond rating agency to place the *market participant* on "credit watch status" or equivalent. Where, as a result of either any such change or loss in the then current rating or the placing of the *market participant* on "credit watch status", the *market participant* is no longer entitled under the *market rules* to the same reduction by way of credit rating, the *IESO* shall deliver to the *market participant* an amended schedule setting out the *market participant*'s revised *prudential support obligation* for *physical transactions*.

1.4 Prudential Support for Physical Transactions by way of a Third-Party Guarantee

Prudential support for *physical transactions* in the form of a guarantee provided by a third party pursuant to MR Ch.2 s.5.7.2.2 or 5.7.2.4 shall provide for payment by the guarantor to the *IESO* on demand up to the amount stated in the guarantee. The only conditions on the ability of the *IESO* to draw on the guarantee shall be the delivery of copies of an unpaid *invoice* previously issued to the *market participant* and a certificate of an officer of the *IESO* that a specified amount is owing by the *market participant* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate. Where the *market participant*'s *prudential support* includes a guarantee provided by a third party that has a credit rating from a major bond rating agency identified in the list of such agencies *published* by the *IESO*, the *market participant* covenants and agrees to advise the *IESO* in writing immediately upon the *market participant* becoming aware of a change in or loss of the then current credit rating issued to the guarantor. Where as a result of the loss of such credit rating, the *market participant* is no longer entitled to meet its *prudential support obligation* for *physical transactions* in whole or in part through the provision of such a guarantee, the *market participant* must provide alternative *prudential support* within the time frame mandated in MR Ch.2 s.5.2.

1.5 Reduction of Prudential Support Obligation for Physical Transactions for Payment History

Where the *market participant*'s *prudential support obligation* for *physical transactions* reflects a reduction by reason of evidence of the *market participant's* good payment history determined in accordance with MR Ch.2 s.5.8.4 or 5.8.5 and, for any reason, the *market participant* is no longer entitled under the *market rules* to the same amount of reduction by way of good payment history, the *IESO* shall deliver to the *market participant* an amended schedule setting out the *market participant*'s revised *prudential support obligation*.

1.6 Prudential Support by way of Letter of Credit

Where a portion of the *market participant*'s *prudential support* is in the form of a letter of credit pursuant to MR Ch. 2 s.5.7.2.1 or 5C.5.2.1, the following provisions shall apply:

1.6.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 2007 Revision, ICC Publication No. 600 or The International Standby Practices 1998;

1.6.2 the *IESO* shall be named as beneficiary in each letter of credit, each letter of credit shall be irrevocable, partial draws on any letter of credit shall not be prohibited and the letter of credit or the aggregate amount of all letters of credit shall be in the face amount of at least the amount specified in its then current schedule;

1.6.3 the only conditions on the ability of the *IESO* to draw on the letter of credit shall be the occurrence of an *event of default* by or in respect of the *market participant* and a certificate of an officer of the *IESO* that the *IESO* is entitled to draw on the letter of credit in accordance with the provisions of the *market rules* in the amount specified in the certificate as at the date of delivery of the certificate;

1.6.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. In either case it is the responsibility of the *market participant* to maintain the requisite amount of *prudential support*. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *market participant* shall arrange for and deliver alternative *prudential support* within the time frame mandated by the *market rules* so as to enable the *market participant* to be in compliance with the *market rules*; and

1.6.5 by including a letter of credit as part of its *prudential support*, the *market participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *market participant*.

1.7 Prudential Support by way of Cash or Treasury Bills

Where any portion of the *market participant*'s *prudential support* for *physical transactions* is in the form of treasury bills pursuant to MR Ch.2 s.5.7.2.3, the provision of such *prudential support* shall be reflected in a written instrument that is acceptable at the sole discretion of the *IESO* and the following provisions shall apply:

1.7.1 any such treasury bills shall be issued by the Government of Canada and for *IESO* purposes shall be valued at their current market value from time to time less two (2%) percent to take into account the potential eroding effects of interest rate increases on the value of such treasury bills;

1.7.2 the *IESO* shall retain the services of a custodian which shall retain the treasury bills as agent for the *IESO* and not the *market participant*; and

1.7.3 any interest income paid by the treasury bill shall be apportioned to the benefit of the *market participant's prudential support* for *physical transactions.*

The *IESO* shall have no obligation to pay interest on the cash proceeds from the maturity of a treasury bill, or on any cash deposit held by the *IESO* in accordance with MR Ch.2 s.5.7.2.5.

1.8 Replacement Schedules

The *IESO* and the *market participant* may or, where required to enable the *market participant* to be in compliance with the *market rules*, shall from time to time deliver to one another one or more additional schedules, which schedules shall be in the form approved by the *IESO* from time to time. Where the *IESO* delivers to the *market participant* an additional schedule, each such schedule shall replace the preceding schedule, and shall be effective from the date of its delivery to the *market participant* for all purposes thereafter until such time as a subsequent amended schedule is delivered by the *IESO* to the *market participant*. Where any such amended schedule shows an increase in the *market participant*'s *prudential support obligation* relative to the preceding schedule or requires the provision of alternative *prudential support*, the *market participant* shall deliver such additional or alternative *prudential support* as may be required so as to enable the *market participant* to be in compliance with the *market rules*. Where the *market participant* delivers an amended schedule, modified to reflect additional or alternative forms of *prudential support*, such amended schedule, provided that it is accompanied by such additional or alternative *prudential support*, shall replace the preceding schedule and shall be binding on the *market participant* for all purposes thereafter until such time as a subsequent amended schedule is delivered to the *IESO* by the *market participant*.

1.9 Dispute Resolution

If the *market participant* disagrees with the determination by the *IESO* of any of the amounts of *prudential support obligations* set out on a schedule and such dispute cannot be resolved by the *market participant* and the *IESO*, then the *market participant* shall submit the matter to dispute resolution under MR Ch.3 s.2. Notwithstanding the initiation of the dispute resolution process, the *market participant* shall provide such additional *prudential support* as may be required in order to continue participating in the *real-time market* or *day-ahead market* based on the determination by the *IESO* until the matter has been resolved.

2. Pledge of Prudential Support in the form of Cash or Treasury Bills

2.1 Pledge

Prudential support in the form of cash or treasury bills provided as part of the *market participant*'s *prudential support obligation* for *physical transactions* in respect of the *market participant*'s participation in the *real-time market* and *day-ahead market* shall be held by or on behalf of the *IESO* (together with all accretions thereto, all income therefrom and proceeds thereof) and the *market participant* shall assign to the *IESO* all of its present and future right, title and interest in and to such cash and treasury bills as general and continuing collateral security and as a pledge to secure:

2.1.1 subject to MR Ch.1 s.13, all indebtedness, obligations and liabilities of any kind, now or hereafter existing, direct or indirect, absolute or contingent, joint or several, of the *market participant* to the *IESO* in respect of the *market participant*'s participation in the *real-time market* and the *day-ahead market*; and

2.1.2 all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, reasonable legal fees on a substantial indemnity basis) incurred by or on behalf of the *IESO*, in the enforcement of its rights under the *market rules* in respect of the participation by the *market participant* in the *real-time market* and the *day-ahead market*.

3. Exercise of Rights and Remedies to Prudential Support

3.1 Exercise of Rights

Upon the occurrence of an *event of default*, the *IESO* shall be entitled to exercise its rights and remedies as set out in the *market rules,* or provided for at law or in equity. Without limiting the generality of the foregoing, such rights and remedies shall, in respect of the *prudential support* provided by the *market participant*, include setting-off and applying any and all *prudential support* held in the form of cash or treasury bills or proceeds of either cash or treasury bills against the indebtedness, obligations and liabilities of the *market participant* to the *IESO* in respect of the participation by the *market participant* in the *real-time market* and *day-ahead market*. When the *IESO* is reasonably certain that it will be issuing a first *notice of default levy* it shall *publish* the name of the *defaulting market participant.*

3.2 Remedies Cumulative

Each of the remedies available to the *IESO* under the *market rules* or at law or in equity is intended to be a separate remedy and in no way is a limitation on or substitution for any one or more of the other remedies otherwise available to the *IESO*. The rights and remedies expressly specified in the *market rules* or at law or in equity are cumulative and not exclusive. The *IESO* may in its sole discretion exercise any and all rights, powers, remedies and recourses available under the *market rules* or under any document comprising the *prudential support* provided by the *market participant* or any other remedy available to the *IESO* howsoever arising, and whether at law or in equity, and such rights, powers and remedies and recourses may be exercised concurrently or individually without the necessity of any election.

3.3 Application of Prudential Support against Actual Exposure

Except as may be otherwise provided in the *market rules,* all moneys received in respect of the realization of the *prudential support* provided by the *market participant* may, notwithstanding any appropriation by the *market participant* or any other person, be appropriated to such parts of the *market participant*'s *actual exposure* or its other obligations*,* any interest thereon owing pursuant to the *market rules* or the costs, charges, expenses and fees referred to in section 3.4 and in such order as the *IESO* sees fit, and the *IESO* shall have the right to change any appropriation at any time.

3.4 Payment of Expenses

The *market participant* agrees to pay to the *IESO* forthwith on demand all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, legal fees on a substantial indemnity basis) of or incurred by or on behalf of the *IESO* in the realization, recovery or enforcement of the *prudential support* provided by the *market participant* and enforcement of the rights and remedies of the *IESO* under the *market rules* or at law or in equity in respect of the participation by the *market participant* in the *real-time market* and the *day-ahead market.*

3.5 Deficiency

If the proceeds of the realization of any *prudential support* provided by the *market participant* are insufficient to pay all of the *actual exposure* of the *market participant* or its other obligations to the *IESO*, the *market participant* shall forthwith pay or cause to be paid to the *IESO* any such deficiency. The *IESO* shall provide a calculation of any such deficiency to the *market participant*.

RUL-9

Renewed Market Rules

Chapter 0.3

Administration, Supervision, Enforcement

Connecting Today.
Powering Tomorrow.

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

1. Introduction

1.1 Scope of Chapter

1.1.1 This Chapter sets forth:

1.1.1.1 the dispute resolution mechanism applicable to certain disputes arising under the *market rules*;

1.1.1.2 the manner in which market monitoring and surveillance responsibilities will be carried out;

1.1.1.3 the procedures pursuant to which the *market rules* may be amended;

1.1.1.4 the procedures which govern the protection, use and disclosure of *confidential information* by the *IESO* and *market participants*; and

1.1.1.5 the manner in which the *IESO* will monitor, assess and enforce compliance with the *market rules*.

2. Dispute Resolution

2.1 Interpretation and General Procedural Provisions

2.1.1 The provisions of this section 2 shall be liberally construed to secure the most expeditious, just and least expensive determination on its merits of every proceeding conducted hereunder.

2.1.2 Where no procedures are provided for in this section 2 or the applicable *market manual*, a *mediator* or an *arbitrator* may do whatever is reasonably necessary and permitted by law to enable the effective mediation or adjudication of any matter before the *mediator* or the *arbitrator*.

2.1.3 The parties to a dispute may agree to dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7. A *mediator,* an *arbitrator* or the *secretary* may, in the context of the resolution or the attempted resolution of a specific dispute pursuant to this section 2, dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7, including as to any prescribed time periods, if special circumstances or the public interest require, or with the consent of the parties to the dispute. The *secretary's* authority to dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7 lapses with respect to a particular dispute once a *mediator* or *arbitrator* is appointed in respect of that dispute.

2.1.4 The *IESO* shall from time to time *publish* and notify *market participants* of the address of the *secretary* for filing purposes.

2.1.5 Unless otherwise specified in this section 2 or otherwise directed by the *secretary*, a *mediator* or an *arbitrator*, only one copy of any document is required to be served or filed.

2.1.6 The following provisions of the *Arbitration Act, 1991* do not apply to any proceeding conducted under this section:

2.1.6.1 subsection 10(1)(b);

2.1.6.2 subsection 13(1)2;

2.1.6.3 subsection 23(1);

2.1.6.4 section 24;

2.1.6.5 subsections 25(3) to 25(5);

2.1.6.6 sections 34, 37, 39, 45, 48 and 53;

2.1.6.7 subsections 54(5) and 54(6); and

2.1.6.8 sections 55 and 56, insofar as they may be applicable to the fees payable to an *arbitrator* and to the extent that such fees have been approved by the *Ontario Energy Board*.

2.2 Application

2.2.1 Subject to sections 2.2.3 and 3.8 and to MR Ch.2 s.8.8.1, the dispute resolution regime provided for in this section 2 shall apply to:

2.2.1.1 any dispute between the *IESO* and any *market participant* which arises under the *market rules*, *market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules*, including with respect to any alleged violation or breach thereof, whether or not specifically identified in the *market rules* as a dispute to which this section 2 applies;

2.2.1.1A a contested matter pursuant to section 6.2B.5 and section 6.2B.9, except as otherwise provided in section 6.2B;

2.2.1.1B a dispute involving an order of the *IESO* issued pursuant to section 6.2B.15, except as otherwise provided in section 6.2B;

2.2.1.2 any denial by the *IESO* of authorization to any person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, out of or through the *IESO-controlled grid*, as to the denial of such authorization;

2.2.1.3 an application by a *generator* or *electricity storage participant* for compensation pursuant to MR Ch.5 s.6.7.5 in respect of an *outage* rejected by the *IESO*;

2.2.1.4 a *reviewable decision*;

2.2.1.5 a dispute referred to in MR Ch.9 s.6.10.1;

2.2.1.6 [intentionally deleted];

2.2.1.7 any dispute between the *IESO*, on the one hand, and any *market participant*, *connection applicant* or *metering service provider*, on the other hand, pursuant to the terms of any agreement or contract referred to in these *market rules* or in any policy, guideline or other document referred to in MR Ch.1 s.7.7 or any *market manual*, unless in respect of a given dispute the agreement or contract or the *licence* of a party to the dispute either provides for an alternative dispute resolution mechanism or provides that the dispute resolution regime provided in this section 2 shall not be applicable;

2.2.1.8 a dispute between *market participants* referred to in MR Ch.9 s.2.2.7 in respect of the apportionment of *energy* associated with *connection station service* and with site specific losses;

2.2.1.9 the *IESO's* determination under MR Ch.5 ss.3.2.5, 3.2.6, and 3.2.7 regarding the applicability of *reliability standards*;

2.2.1.10 a dispute referred to in MR Ch.6 s.10.4.8; and

2.2.1.11 a dispute referred to in section MR Ch.10 s.6C.1.5.

2.2.2 The dispute resolution regime provided for in this section 2:

2.2.2.1 shall apply to a dispute between *market participants* referred to in MR Ch.9 s.2.2.7 and MR Ch.5 s.8.4.2; and

2.2.2.2 may also apply to any other disputes between *market participants* where all of the *market participants* which are party to the dispute consent in writing to the application thereof.

2.2.2A A *market participant* that has, pursuant to section 2.2.2.2, consented to the application of the dispute resolution regime provided for in this section 2 may, prior to the date on which the *secretary* takes the action referred to in section 2.6.2.1 or 2.6.2.2, as the case may be, withdraw its consent in the event that a *respondent* to a crossclaim objects to the application of such regime.

2.2.3 The dispute resolution process provided for in this section 2 shall not apply to the following:

2.2.3.1 applications by any person to review a *market rule*, which applications shall be governed by section 4;

2.2.3.2 disputes with respect to a proposal to *amend* or not to *amend* any provision of the *market rules*;

2.2.3.3 disputes between the *IESO* and a *market participant* relating to the quantum of the fees chargeable by the *IESO* to the *market participant* to the extent that such fees have been approved by the *Ontario Energy Board*, unless the dispute relates to the manner of calculation of the fees payable by the *market participant* in any given case;

2.2.3.4 [Intentionally left blank]

2.2.3.5 disputes between the *IESO* and a *market participant* relating to a *suspension order* issued by the *IESO* or to a *termination order* issued by the *IESO*, in respect of which an appeal may be filed with the *Ontario Energy Board* pursuant to section 36 of the *Electricity Act, 1998*;

2.2.3.6 disputes between the *IESO* and a *market participant* to the extent that the *licence* of the *IESO* or of the relevant *market participant* provides for an alternative dispute resolution mechanism;

2.2.3.7 disputes between the *IESO* and a *market participant* relating to the standards, criteria or requirements established by a *standards authority* to the extent that an agreement with the relevant *standards authority* provides for an alternative dispute resolution mechanism;

2.2.3.8 an award of an *arbitrator* made pursuant to this section 2;

2.2.3.9 any dispute with respect to which these *market rules,* other than this section 2, provide for an alternative dispute resolution mechanism other than the independent review process described in MR Ch.7 s.22.8;

2.2.3.10 any dispute with respect to which these *market rules,* other than this section 2, provide for the non-application of the dispute resolution process provided for in this section 2;

2.2.3.11 a decision of a panel of the *IESO Board*:

(a) granting or rejecting an *exemption application*;

(b) respecting the terms and conditions of an *exemption*, other than with respect to the quantum of the costs payable by the *exemption applicant* or one or more *market participants* pursuant to MR Ch.1 s.14.5;

(c) removing or amending an *exemption* or the terms and conditions thereof, other than with respect to the quantum of the costs referred to in MR Ch.1 s.14.5;

(d) approving or denying the transfer of an *exemption*; or

(e) respecting *confidential information* provided to the *IESO* as part of or in respect of an *exemption application* including, without limitation the disclosure thereof; and

2.2.3.12 when considering an *exemption application*, including for certainty a reconsideration or transfer of an *exemption*, a determination or decision by a panel of the *IESO Board* regarding the interpretation of the provisions of any *market rule, market manual* or any standard, policy or procedure established by the *IESO* pursuant to the *market rules*.

2.2.4 Subject to such rights of appeal or review as may be prescribed by *applicable law,* an award of an *arbitrator* made pursuant to this section 2 is final and binding on the parties. Without limiting the generality of the foregoing, but subject to sections 2.2.5 and 3.8 and to MR Ch.2 s.8.8.1, where any dispute of a kind described in section 2.2.1 or 2.2.2 arises, the parties concerned shall comply with the procedures set forth in this section 2 before commencing a civil or other proceeding in relation to the dispute, including but not limited to the filing of an appeal pursuant to subsection 36(1) of the *Electricity Act, 1998*.

2.2.5 Nothing in this section 2 shall prevent a party to a dispute from making application to a court of competent jurisdiction in the Province of Ontario for urgent interlocutory or interim injunctive relief.

2.3 Continuing Obligations and Stay of Orders

2.3.1 Subject to section 2.3.3, where a dispute involves the payment or recovery of monetary amounts due under the *market rules*, the amount shall be due and payable at the time specified for payment under the *market rules* notwithstanding initiation of the dispute resolution process.

2.3.2 Subject to section 2.3.3, initiation of the dispute resolution process referred to in this section 2 does not stay implementation of an order made or a direction given to a *market participant* by the *IESO* pursuant to the *market rules*.

2.3.3 Where a dispute in respect of which the dispute resolution process has been initiated involves the payment of a financial penalty imposed upon a *market participant* by the *IESO* under section 6.2, the obligation of the *market participant* to pay the financial penalty shall be stayed pending the outcome of the dispute resolution process.

2.4 [Intentionally left blank – section deleted]

2.5 Notice of Dispute, Negotiation and Response

2.5.1 The complaining person (the "*applicant*") shall, within the time specified in section 2.5.1A, serve a written notice of the dispute (the "*notice of dispute*") on any *respondent*.

2.5.1A Subject to section 2.5.1B, a *notice of dispute* shall be served:

2.5.1A.1 in the case of an application referred to in section 2.2.1.3, within 20 *business days* of the date of receipt of notice by the *generator* or *electricity storage participant* of rejection by the *IESO* of the *outage* in respect of which compensation is claimed pursuant to MR Ch.5 s.6.7.5;

2.5.1A.2 in the case of a dispute that involves a *reviewable decision* referred to in MR Ch.6 s.5.3.9, within 20 *business days* of the date of receipt by the *metering service provider* of notice of the revocation of its registration by the *IESO*;

2.5.1A.3 in the case of a dispute referred to in section MR Ch.10 s.6C.1.5, within 20 *business days* of the *market participant* receiving the relevant *settlement statement* with the adustments specified in accordance with MR Ch.10 s.6C;

2.5.1A.4 in the case of a dispute referred to in MR Ch.9 s.6.10.1, except for those matters identified in MR Ch.9 s.6.8.12.4, within the time specified in MR Ch.9 s.6.10.2.3;

2.5.1A.4A in the case of a dispute referred to in MR Ch.9 s.2.2.7, within 20 *business days* of the date of receipt of the first *invoice* that reflects the apportionment that is the subject matter of the dispute;

2.5.1A.4B in the case of a dispute referred to in MR Ch.6 s.10.4.8, within 20 *business days* of:

(a) the *IESO* notifying the *market participant* of the *IESO's* determination if the *IESO* concludes pursuant to MR Ch.6 s.10.4.4.1 that no further action is required; or

(b) receipt of the *settlement statement* on which the adjustment is reflected if the *IESO* concludes an adjustment is required pursuant to MR Ch.6 s.10.4.4.2;

2.5.1A.4C in the case of a dispute involving an order, direction, instruction or decision of the *IESO*, including a matter referred to in MR Ch.9 s.6.8.12.4 that involves an order, direction, instruction or decision of the *IESO* relating to a compliance and enforcement action described in section 6, issued on or after January 1, 2004 not otherwise addressed by subsections 2.5.1A.1 to 2.5.1A.4A, within two years of the date of receipt of the order, direction, instruction or decision;

2.5.1A.4D in the case where the *market participant* contests the *notice of intention* under section 6.2B.3, within the timelines set out in section 6.2B.3 and the *response to the notice of intention* shall be deemed to constitute the *notice of dispute*;

2.5.1A.4E in the case of a dispute involving one or more orders referred to in section 6.2B.15, within the timelines set out in section 6.2B.16;

2.5.1A.4F 2.5.1A.4F in the case of a dispute referred to in MR Ch.7 s.7.6.5, within 20 *business days* of:

(a) the *IESO* notifying the *market participant* of its determination if the *IESO* determines pursuant to MR Ch.7 s.7.6.3.2that the *market participant* is not entitled to compensation; or

(b) the receipt of the *settlement statement* on which the compensation is reflected if the *IESO* determines pursuant to MR Ch.7 s.7.6.3.2 that the *market participant* is entitled to compensation;

2.5.1A.4G in the case of matters referred to in MR Ch.9 s.6.8.12.4, except for a compliance and enforcement action described in MR Ch.3 s.6, within 20 *business days* of the *market participant* receiving the relevant *settlement statement* with the adustments specified in accordance with the relevant provision;

2.5.1A.4H in the case of a dispute related to an independent review conducted pursuant to MR Ch.7 s.22.8, no later than 22 *business days* following the day on which the *IESO* registers *reference levels* and *reference quantities* for the relevant *resource* following completion of the independent review; and

2.5.1A.5 in all other cases, within the applicable limitation period set out in the *Limitations Act, 2002*.

2.5.1B Commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date* and in regards to sections 2.5.1A.1, 2.5.1A.3, 2.5.1A.4, 2.5.1A.4B, and 2.5.1A.4F, in no circumstance shall a *notice of dispute* be served more than 24 months following the earlier of (a) the initial date when the *IESO* would have the right or obligation to settle the transaction, charge or payment that is the subject of the dispute; or (b) the date on which the *IESO* issues an *invoice* in respect of the transaction, charge or payment that is the subject of the dispute. This section and section 2.5.1A shall apply whether or not the transaction, charge or payment that is the subject of the dispute was capable of being identified or discovered within the time specified in section 2.5.1A and this section 2.5.1B. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, in no circumstance shall a notice of dispute be served beyond the limitation period, if any, provided pursuant to *applicable law*.

2.5.2 The *notice of dispute* shall be in such form as may be established by the *IESO,* shall be signed by a person with authority to bind the *applicant* and shall specify, in reasonable detail and to the best of the *applicant*'s knowledge:

2.5.2.1 the nature of and basis for the complaint;

2.5.2.2 the *market rules* in issue;

2.5.2.3 the parties to the dispute and the name of any person having knowledge of or who may be directly affected by the dispute;

2.5.2.4 a concise summary of the facts underlying the dispute;

2.5.2.5 the relief sought and a summary of the grounds for such relief; and

2.5.2.6 any documentation upon which the *applicant* intends to rely in support of its complaint.

2.5.3 [Intentionally left blank – section deleted]

2.5.3A Upon service of a *notice of dispute,* the *applicant* and the *respondent* to a *notice of dispute* shall make good faith efforts to negotiate for a minimum period of thirty days to resolve the dispute between them. In regards to disputes where an *IESO* determination is still pending, as contemplated in MR Ch.9 s.6.8.15 and MR Ch.6 s.10.4.8, the thirty-day period to resolve the dispute through good faith negotiations shall not commence until the *IESO* has completed its determination. Each person who is a party to a dispute shall, to this end, designate an individual with authority to negotiate the matter in dispute and to participate in such negotiations. The parties to the dispute may conduct the good faith negotiations in any manner they so agree.

2.5.3B Communications made in the course of negotiations are confidential, are made without prejudice and are not subject to voluntary disclosure in any subsequent proceeding or to be voluntarily produced into evidence for any purpose other than as reflected in a settlement agreement.

2.5.3C In the event that a dispute is not settled through good faith negotiations, a party may file with the *secretary,* on written notice served on each other party, a copy of the *notice of dispute,* together with proof of service of the *notice of dispute* on each other party. The *notice of dispute* shall be accompanied by a summary of the *notice of dispute* for *publication* in accordance with section 2.9.2.1.

2.5.4 A *respondent* shall, within ten *business days* of the filing of a *notice of dispute* with the *secretary* under section 2.5.3C, serve a written response (the "*response*") on the *applicant* and on any *respondent* to a counterclaim or crossclaim identified in the *response*, and shall file with the *secretary* a copy of the *response,* together with proof of service of the *response* on the *applicant* and on any such *respondent*.

2.5.5 The *response* shall be in such form as may be established by the *IESO*, shall be signed by a person with authority to bind the *respondent* and shall specify, in reasonable detail and to the best of the *respondent's* knowledge:

2.5.5.1 the information referred to in sections 2.5.2.1 to 2.5.2.4, to the extent that the *respondent* disagrees with the information relating thereto set forth in the *notice of dispute*;

2.5.5.2 a concise *response* to the allegations made against the *respondent* in the *notice of dispute*;

2.5.5.3 the relief sought, a summary of the grounds for such relief and, where the relief sought includes a counterclaim or crossclaim against the *applicant* or against any other *respondent*, the information referred to in sections 2.5.2.1 to 2.5.2.4 as it pertains specifically to such counterclaim or crossclaim; and

2.5.5.4 any documentation upon which the *respondent* intends to rely in support of its *response*, including as to any counterclaim or crossclaim, and which was not identified by the *applicant*.

2.5.6 The *response* shall be accompanied by a summary of the *response* for *publication* in accordance with section 2.9.2.1.

2.5.6A A *respondent* to a counterclaim or crossclaim shall, within ten *business days* of service of a *response* or of a response to a counterclaim or crossclaim, serve a written response to the counterclaim or crossclaim on the *applicant* and on any other *respondent* and shall file with the *secretary* a copy of the response to the counterclaim or crossclaim, together with proof of service of the response to the counterclaim or crossclaim on the *applicant* and on any other *respondent*, including a *respondent* to a counterclaim or crossclaim identified in the response to the counterclaim or crossclaim.

2.5.6B The response to the counterclaim or crossclaim shall be in such form as may be established by the *IESO*, shall be signed by a person with authority to bind the *respondent* and shall specify, in reasonable detail and to the best of the *respondent's* knowledge:

2.5.6B.1 the information referred to in sections 2.5.2.1 to 2.5.2.4, to the extent that the *respondent* disagrees with the information relating thereto set forth in the *response* containing the counterclaim or crossclaim;

2.5.6B.2 a concise response to the allegations made against the *respondent* in the *response* containing the counterclaim or crossclaim;

2.5.6B.3 the relief sought, a summary of the grounds for such relief and, where the relief sought includes a counterclaim or a crossclaim against the *applicant* or another *respondent*, the information referred to in sections 2.5.2.1 to 2.5.2.4 as it pertains specifically to such counterclaim or crossclaim; and

2.5.6B.4 any documentation upon which the *respondent* intends to rely in support of its response to the counterclaim or crossclaim, including as to any counterclaim or crossclaim, and which was not identified by the *applicant* or by the *respondent* whose *response* contains the counterclaim or crossclaim.

2.5.6C The response to a counterclaim or crossclaim shall be accompanied by a summary of the response for *publication* in accordance with section 2.9.2.1.

2.5.7 Subject to sections 2.1.3 and 2.5.9, the *secretary* shall reject and shall not take any further action with respect to a *notice of dispute*, a *response*, or a response to a counterclaim or crossclaim that does not comply with the provisions of this section 2.5.

Where the *secretary* rejects a *notice of dispute*, a *response* or a response to a counterclaim or crossclaim pursuant to this section 2.5.7, the *secretary* shall so notify the *applicant* and the *respondent* filing the *response* or the response to the counterclaim or crossclaim, as the case may be, and shall provide written reasons for the rejection.

2.5.8 [Intentionally left blank – section deleted]

2.5.9 Where the *secretary* rejects a *response* or a response to a counterclaim or crossclaim pursuant to section 2.5.7:

2.5.9.1 such rejection shall be without prejudice to the right of the *applicant* or the *respondent* whose *response* includes the counterclaim or crossclaim, as the case may be, to proceed with the resolution of the dispute in accordance with section 2; and

2.5.9.2 where such rejection relates to a *response*, section 2.6.1 shall not apply to the dispute and the *applicant* may following receipt of the notice referred to in section 2.5.7 request that the *secretary* take the action referred to in section 2.7.1.

2.6 Mediation

2.6.1 Subject to sections 2.6.1A and 2.6.1B, no party to a dispute may proceed to arbitration of the dispute until such time as the mediation process described in this section 2.6 has been terminated in accordance with section 2.6.14.

2.6.1A Absent agreement of the parties, section 2.6.1 shall not apply to:

2.6.1A.1 an application by a *generator* or *electricity storage participant* for compensation pursuant to MR Ch.6 s.6.7.5 in respect of an *outage* rejected by the *IESO*;

2.6.1A.2 a dispute referred to in MR Ch.9 s.6.10.1, except those matters described in MR Ch.9 s.6.8.12.4;

2.6.1A.3 a dispute that involves a *reviewable decision* referred to in MR Ch.6 s. 5.3.9; or

2.6.1A.4 a dispute referred to in section 2.5.9.2.

2.6.1B Where all of the parties to a dispute so agree, the parties may dispense with mediation in respect of the dispute. In such a case, the parties shall file with the *secretary* a notice of intent to dispense with mediation in such form as may be established by the *IESO*.

2.6.2 Subject to section 2.6.2C, within five *business days* of the filing of a *notice of dispute* in respect of an application to which section 2.6.1A.1 applies or of the earlier of the filing of a *response* or of the expiry of the time for filing a *response* pursuant to section 2.5.4 in all other cases, the *secretary* shall, provided that the *secretary* is satisfied that the dispute is one to which section 2.2.1 or 2.2.2 applies and that the dispute has not been resolved:

2.6.2.1 in the case of a dispute referred to in section 2.6.1A, upon receipt of the notice referred to in section 2.6.1B or upon receipt of the request referred to in section 2.5.9.2, take the action referred to in section 2.7.1 or 2.7.1D, as the case may be; or

2.6.2.2 in any other case, subject to section 2.6.2A, assign one member of the *dispute resolution panel* who is independent of the parties to inquire into and act as *mediator* in respect of the dispute and shall advise the parties to the dispute as to the identity and address for service of the *mediator*.

Where the *secretary* is not satisfied that the dispute is one to which section 2.2.1 or 2.2.2 applies, the *secretary* shall so advise the parties.

2.6.2A Where all of the parties to a dispute so agree, they may appoint a qualified person that is not a member of the *dispute resolution panel* to mediate the dispute. In such a case, the parties shall advise the *secretary* as to the identity and address for service of the *mediator*.

2.6.2B A *mediator* appointed under section 2.6.2A shall not be required in any proceeding to give testimony with respect to information obtained in the course or resolving or attempting to resolve the dispute.

2.6.2C Where a *response* or a response to a counterclaim or crossclaim contains a counterclaim or crossclaim against another *respondent*, the *secretary* shall not take the action referred to in section 2.6.2.1 or 2.6.2.2 until five *business days* following:

2.6.2C.1 the filing of the response to a counterclaim or crossclaim in respect of the last counterclaim or crossclaim filed in the same dispute; or

2.6.2C.2 the expiry of the time for filing a response to a counterclaim or crossclaim pursuant to section 2.5.6A in respect of the last counterclaim or crossclaim filed in the same dispute,

whichever is the earlier.

2.6.3 The *mediator* shall fix a date, time and place for the mediation session, which date shall be no more than seven *business days* from the date of notice of his or her appointment or such later date as may be agreed by each party to the dispute, and shall attempt to assist the parties to resolve their dispute. The *mediator* may continue the mediation session at such times and places as the *mediator* determines in an effort to assist the parties in resolving their dispute.

2.6.4 Each party shall send to the mediation session a representative who has the authority to bind the party.

2.6.5 Prior to participating in a mediation session, the parties must sign and file with the *secretary* an agreement that statements made at a mediation session are confidential, are made without prejudice and are not subject to voluntary disclosure in any subsequent proceeding or to be voluntarily produced into evidence for any purpose.

2.6.6 Mediation sessions shall be private and there shall be no stenographic record of any mediation session. The parties and their representatives may attend mediation sessions. Other persons may attend only with the permission of all of the parties, with the consent of the *mediator* and upon such conditions including, but not limited to, conditions relating to confidentiality, as the *mediator* determines appropriate.

2.6.7 *Confidential information* disclosed to a *mediator* by the parties or by other persons in the course of the mediation shall not be divulged by the *mediator*. All records, reports or other documents prepared for the mediation and received by a *mediator* while serving in that capacity shall be treated as confidential unless all of the parties to the dispute otherwise agree.

2.6.8 The *mediator* may conduct joint and separate meetings with the parties and make oral and written recommendations for settlement. Recommendations for settlement made, and views expressed by, the *mediator* at such meetings or at a mediation session are confidential and are not subject to voluntary disclosure in any subsequent proceeding and are not voluntarily to be produced into evidence for any purpose.

2.6.9 The *mediator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide the *mediator* with any information or documentation which is not *confidential information* and which the *mediator* considers relevant to the conduct of the mediation, and the *mediator* shall provide any such information or documentation to the parties in advance of the mediation session at which such information or documentation is to be considered.

2.6.10 The *mediator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide the *mediator* with any information or documentation pertaining to a party to the dispute which is *confidential information* and which the *mediator* considers relevant to the conduct of the mediation. Such *confidential information* shall not, without the consent of the party to whom the *confidential information* relates, be disclosed by the *mediator* to the other parties to the dispute.

2.6.11 Whenever the *mediator* considers necessary, the *mediator* may, with the consent of the parties and upon such conditions relating to confidentiality as the *mediator* determines appropriate, obtain expert advice concerning technical aspects of the dispute. Arrangements for obtaining such advice shall be made by the *mediator* or a party, as the *mediator* shall determine.

2.6.12 If an agreement to resolve the dispute is reached through mediation, it shall be reduced to writing, signed by the parties and filed with the *secretary*. The terms of the agreement shall be confidential, provided that if, in the case of a dispute referred to in section 2.2.1, the agreement consists of, embodies or reflects an element which, in the opinion of the *IESO Board*, is an important matter of public policy or interest having regard to the provisions of the *Electricity Act, 1998*, the *IESO* shall *publish* a statement describing such important matter of public policy or interest.

2.6.13 The *mediator* may terminate the mediation by written notice of termination whenever, in the judgement of the *mediator*, further efforts at mediation would not contribute to a resolution of the dispute between the parties. The *mediator* shall provide each party with a copy of the written notice of termination and shall file a copy of the notice of termination with the *secretary*, in each case together with a copy of any agreed statement of fact and/or of issues referred to in section 2.6.15.

2.6.14 The mediation shall be terminated on the earlier of:

2.6.14.1 the date of execution by the parties of the agreement referred to in section 2.6.12;

2.6.14.2 the date of the notice of termination referred to in section 2.6.13; or

2.6.14.3 the date that is ten *business days*, or such longer period as may be agreed by each party to the dispute, from the date of the first mediation session.

2.6.15 If the parties are unable to reach any agreement to resolve the dispute on or prior to the date referred to in section 2.6.14.2 or 2.6.14.3 they shall nonetheless make good faith efforts to arrive at an agreed statement of fact and/or of issues relating to the dispute.

2.6.16 If the parties are unable to reach any agreement to resolve the dispute on or prior to the date referred to in section 2.6.14.3, the *mediator* shall issue a written notice of termination unless the *mediator* has, prior to that date, issued the written notice of termination referred to in section 2.6.13. The *mediator* shall provide each party with a copy of the notice of termination issued pursuant to this section 2.6.16, together with a copy of any agreed statement of fact and/or of issues referred to in section 2.6.15, and file a copy of the foregoing with the *secretary*.

2.6.17 The parties are responsible for their own costs and legal expenses incurred in respect of the mediation. The parties must bear equally the *costs of the mediation* unless otherwise agreed to by the parties.

2.6.18 Upon termination of the mediation, the *mediator* shall file with the *secretary* an invoice containing an itemized statement of the *costs of the mediation*, together with all bills and other supporting documentation relating thereto.

2.6.19 Upon receipt of the invoice referred to in section 2.6.18, the *secretary* shall provide a copy of the invoice to the *IESO* and the *IESO* shall submit an invoice to each of the parties to the mediation in respect of their respective shares of the *costs of the mediation*. Each party shall, within *ten business days* of the date of receipt of such invoice, pay to the *IESO* the amount owing thereunder. Such invoice shall be considered to create an obligation under the *market rules* to pay the amount specified in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

2.6.20 Where a *mediator* dies, resigns or otherwise becomes incapable of acting as *mediator* in respect of a dispute prior to termination of the mediation, subject to section 2.6.2A, the *secretary* shall assign another member of the *dispute resolution panel* to inquire into and act as *mediator* in respect of the dispute. With the consent of the parties to the mediation, the new *mediator* may continue the mediation. In the absence of such consent, the *mediator* shall commence the mediation anew and the time period prescribed in section 2.6.14.3 shall be extended accordingly.

2.7 Arbitration

2.7.1 Subject to section 2.7.1C, within five *business days* of:

2.7.1.1 the earlier of the filing of a *response* or of the expiry of the time for filing a *response* pursuant to section 2.5.4, where the dispute is one to which section 2.6.1A.1, 2.6.1A.2 or 2.6.1A.3 applies;

2.7.1.1A the filing of the request referred to in section 2.5.9.2, where the dispute is one to which that section applies;

2.7.1.2 the filing of a notice of intent to dispense with mediation pursuant to section 2.6.1B, where the dispute is one to which that section applies;

2.7.1.2A the filing of the *notice to elect* referred to section 6.2B.7 electing subsection 6.2B.7.1; or

2.7.1.3 the filing of the notice of termination referred to in section 2.6.13 or 2.6.16, in any other case,

the *secretary* shall, subject to section 2.7.1A, in accordance with the *Governance and Structure By-law* provide the parties with a list of at least three names of members of the *dispute resolution panel* available to arbitrate the dispute. No person who acted as a *mediator* in respect of a dispute may be included on the list of members available to arbitrate the same dispute.

2.7.1A Where all the parties to a dispute so agree, they may appoint a qualified person that is not a member of the *dispute resolution panel* to arbitrate the dispute. In such a case, the parties shall advise the *secretary* as to the identity and address for service of the *arbitrator*.

2.7.1B An *arbitrator* appointed under section 2.7.1A shall not be required in any proceeding to give testimony with respect to information obtained in the course or resolving or attempting to resolve the dispute.

2.7.1C Where a *response* or a response to a counterclaim or crossclaim filed in respect of a dispute to which section 2.6.1A applies contains a counterclaim or crossclaim against another *respondent*, the *secretary* shall not take the action referred to in section 2.7.1.1 until five *business days* following:

2.7.1C.1 the filing of the response to a counterclaim or crossclaim in respect of the last counterclaim or crossclaim filed in the dispute; or

2.7.1C.2 the expiry of the time for filing a response to a counterclaim or crossclaim pursuant to section 2.5.6A in respect of the last counterclaim or crossclaim filed in the dispute,

whichever is the earlier.

2.7.1D Within five *business days* of the filing of a *notice of dispute* in respect of an application to which section 2.6.1A.1 applies, subject to section 2.7.1A, the *secretary* shall in accordance with the *Governance and Structure By-law* provide the *applicant* with a list of at least three names of members of the *dispute resolution panel* available to determine the amount of any compensation payable to the *applicant*. Where the *applicant* fails to select an *arbitrator* within ten *business days* of receipt of such list, subject to section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the *arbitrator* in respect of the application and shall by written notice so advise the *applicant*. The *arbitrator* shall be deemed to have been appointed as of the date of such notice.

2.7.1E In the case of an application referred to in section 2.7.1D:

2.7.1E.1 sections 2.7.2, 2.7.8, 2.7.9, 2.7.10 and 2.7.32 shall not apply; and

2.7.1E.2 all other sections of this section 2.7 shall be read:

a. without regard to references to a *respondent*; and
b. by replacing all references to the word "party" or "parties" with the word "*applicant*".

2.7.2 The parties shall make good faith efforts to agree on the appointment of one of the members named on the list referred to in section 2.7.1 as the arbitrator to hear the dispute. Where the parties so agree, they shall by written notice so advise the *secretary*. Such member shall be the *arbitrator* for purposes of the resolution of the dispute and shall be deemed to have been appointed as of the date of such notice.

2.7.3 [Intentionally left blank]

2.7.4 [Intentionally left blank]

2.7.5 Where the parties to a dispute have failed to select an *arbitrator* within ten *business days* of receipt of the list referred to in section 2.7.1, or advise the *secretary* in accordance with section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the *arbitrator* in respect of the dispute and shall by written notice so advise the parties. The *arbitrator* shall be deemed to have been appointed as of the date of such notice.

2.7.6 An *arbitrator* shall be independent of the parties and shall act impartially. An *arbitrator* who is or becomes aware of circumstances that may give rise to a reasonable apprehension of bias shall promptly disclose them to the *secretary* and the parties.

2.7.7 An *applicant* shall, within thirty days of the appointment of the *arbitrator*, serve on any *respondent*, and file with the *arbitrator*, a written statement containing its submissions on each issue in dispute. At the same time, the *applicant* shall serve and file a list of all documents which it intends to file at the arbitration, copies of all such documents, and a list of witnesses intended to be called or to provide written evidence-in-chief at the hearing of the arbitration together with a concise written summary of the anticipated evidence of each witness. The *applicant* must indicate if it will be represented by legal counsel or some other representative and provide such person's name and address for service.

2.7.8 A *respondent* shall, within thirty days of the date of receipt of the *applicant's* materials referred to in section 2.7.7, serve on an *applicant* and on any other *respondent*, and file with the *arbitrator*, a written statement containing its submissions on each issue in dispute. At the same time, the *respondent* shall serve and file a list of all documents which it intends to file at the arbitration, copies of all such documents, and a list of witnesses intended to be called or to provide written evidence-in-chief at the hearing of the arbitration together with a concise written summary of the anticipated evidence of each witness. A *respondent* must indicate if it will be represented by legal counsel or some other representative and provide such person's name and address for service.

2.7.9 The *applicant* may, within ten days of receipt of the *respondent's* materials referred to in section 2.7.8, serve and file written reply submissions.

2.7.10 Where a *respondent* has made a counterclaim or a crossclaim in his or her *response*, the *respondent* shall, for purposes of the application of sections 2.7.7 to 2.7.9 and, where appropriate, of section 2.7.19, be treated as an *applicant* and the person against whom the counterclaim or the crossclaim has been made shall be treated as a *respondent* in respect of the counterclaim or crossclaim.

2.7.11 The *arbitrator* shall fix a date, time and place for the hearing following:

2.7.11.1 in the case of an application referred to in section 2.7.1B, the filing of the *applicant's* materials referred to in section 2.7.7; and

2.7.11.2 in all other cases, the service and filing of the *respondent's* materials referred to in section 2.7.8 or, where applicable, the materials of a *respondent* to the counterclaim or crossclaim referred to in section 2.7.10, which date shall be no more than sixty days from the date of the service and filing referred to in section 2.7.8 or, where applicable, of the service and filing referred to in section 2.7.10, whichever is the later, or such later date as may be agreed by each party to the arbitration. The *arbitrator* shall file with the *secretary* a notice of the date, time and place so fixed.

2.7.12 A *market participant* who might be directly affected by the award of the *arbitrator* in a dispute referred to in section 2.2.1 or 2.2.2.1 and, in the case of an application referred to in section 2.7.1D or of a dispute referred to in section 2.2.2.1, the *IESO*, may apply to the *arbitrator*, on notice to the parties, no less than five *business days* prior to the date of the hearing, for leave to intervene at the hearing. Parties may make submissions on the application for leave to intervene. The *arbitrator* may, in his or her sole discretion, grant leave to intervene to any *market participant* who demonstrates that it has an interest in the subject matter of the arbitration and may be directly affected by the decision in the arbitration, on such terms and subject to such rights of participation as the *arbitrator* considers reasonable.

2.7.13 The procedures governing the arbitration shall be determined by the *arbitrator*, except as provided for under the *market rules* and by sections 19 to 22, 25 (other than 25(3) to 25(5)) to 33, 36, 36 and 40 to 44 of the *Arbitration Act, 1991*.

2.7.13.1 The *arbitrator* shall dismiss the *notice of dispute* and take no further action with respect to the *notice of dispute* if the the *notice of dispute* was served outside of the timelines set forth in section 2.5.1A.

2.7.14 Nothing in writing shall be accepted in evidence at the hearing nor any witness be permitted to give evidence at the hearing, in both cases by or on behalf of an *applicant* or a *respondent*, except with leave of the *arbitrator*, unless the party has complied with the requirements set forth in section 2.7.7 or 2.7.8, as the case may be.

2.7.15 Any party to a dispute may apply to the *arbitrator* for, and the *arbitrator* may order, such further and other production as the *arbitrator* sees fit, provided that the *arbitrator* may not order the production by the *market surveillance panel* or the *market assessment unit* of *confidential information* which relates to a person who is not a party to the dispute. Evidence may be admitted by the *arbitrator* even if not admissible as evidence in a court of law.

2.7.16 The *arbitrator* may, with the consent of all parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide the *arbitrator* with any information or documentation which is not *confidential information* and which the *arbitrator* considers relevant to the conduct of the arbitration, and the *arbitrator* shall provide any such information or documentation to the parties in advance of the hearing at which such information or documentation is to be considered.

2.7.17 The *arbitrator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide the *arbitrator* with any information or documentation pertaining to a party which is *confidential information* and which the *arbitrator* considers relevant to the conduct of the arbitration. Subject to section 2.8.1, the *arbitrator* shall provide any such information or documentation to the parties in advance of the hearing at which such information or documentation is to be considered.

2.7.18 Whenever he or she considers necessary, the *arbitrator* may, upon such conditions as to confidentiality as the *arbitrator* determines appropriate and upon notice to the parties, obtain expert advice concerning technical aspects of the dispute. Arrangements for obtaining such advice shall be made by the *arbitrator* or a party, as the *arbitrator* shall determine, provided that where such arrangements are made by the *arbitrator*, the *arbitrator* shall provide to the parties advance notice of the identity of the expert advisor.

2.7.19 At the hearing, the *applicant* shall provide its case in chief, followed by the *respondent* in response, and then the *applicant* in reply.

2.7.20 Witnesses shall be examined under oath or affirmation and shall be made available for cross-examination. Nothing in this section 2.7.20 shall preclude the *arbitrator* from dispensing with the oral examination-in-chief of a witness provided that a written statement of the witness's evidence is provided in such form as the *arbitrator* determines appropriate.

2.7.21 Subject to section 2.8.1, the arbitration shall be open to the public and all documents filed will form part of the public record of the proceedings.

2.7.22 The *arbitrator* shall deliver his or her award in writing, with reasons, within 30 days of completion of the hearing or within such longer period as may be agreed by each party to the dispute.

2.7.23 The *arbitrator* shall file a copy of his or her award with the *secretary*.

2.7.24 Where, in the case of a dispute referred to in section 2.2.1.1 or 2.2.1.1A, the *arbitrator* concludes that a *market participant* has violated a provision of the *market rules*, the *arbitrator* may in his or her award impose such financial penalties, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable, provided that:

2.7.24.1 no financial penalty shall be imposed on a *market participant* unless the *arbitrator* determines that the breach of the *market rules* could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; and

2.7.24.2 in fixing the amount of the penalty, the *arbitrator* shall have regard to the criteria set forth in section 6.6.7.

An award of the *arbitrator* under this section shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998.*

2.7.25 Where, in the case of a dispute referred to in section 2.2.1.1 the *arbitrator* concludes that the *IESO* has violated, misinterpreted or misapplied a *market rule*, the *arbitrator* may, subject to MR Ch.1 s.13 and to any other provision of these *market rules* pertaining specifically to liability, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable. Without limiting the generality of the foregoing, where the *arbitrator* determines that the breach, misinterpretation or misapplication of a *market rule* by the *IESO* was intentional or could have been avoided by the exercise of due diligence by the *IESO*, the *arbitrator* shall direct the *IESO* to comply with the *market rules* or to interpret or apply the *market rules* in a particular manner. Any such direction may be included in the summary referred to in section 2.9.2.4.

2.7.25A Subject to MR Ch.1 s.13 and to any other provision of these *market rules* pertaining specifically to liability, the *arbitrator* may, in the case of a dispute referred to in section 2.2.1.2, 2.2.1.4 or 2.2.1.5, in addition to the orders referred to in section 2.7.26, 2.7.27 or 2.7.29, as the case may be, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable.

2.7.26 Where a dispute referred to in section 2.2.1.1 relates to the terms and conditions upon which the *IESO* has authorized a person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, the *arbitrator* may confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* on such other terms and conditions, if any, which the *arbitrator* determines are just and reasonable. An award of the *arbitrator* under this section 2.7.26 may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*.

2.7.27 The *arbitrator* may:

2.7.27.1 in the case of a dispute referred to in section 2.2.1.2, confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable;

2.7.27.2 in the case of a dispute referred to in section 2.2.1.5, and subject to section 2.7.29B, make such orders or directions as the *arbitrator* considers just and reasonable,

and an award of the *arbitrator* under this section 2.7.27 may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*.

2.7.27A Notwithstanding section 2.7.27, in regards to those matters specified in section 2.5.1B, an *arbitrator* shall not order the *IESO* to take any action or make any adjustment in regards to any *settlement amount* which was invoiced, or the *IESO* had the right or obligation to invoice, more than 24 months before the date on which the *market participant* served the *notice of dispute*. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, an *arbitrator* shall not order the *IESO* to take any action or make any adjustment in regards to such *settlement amount* beyond the limitation period, if any, provided pursuant to *applicable law*.

2.7.28 In the case of an application referred to in section 2.2.1.3, the *arbitrator* may determine that no compensation is payable to the *applicant* or may order the *IESO* to pay compensation to the *applicant* in such amount and within such time as may be fixed by the *arbitrator* in accordance with any applicable provisions of MR Ch.5 s.6.7.5.

2.7.29 In the case of a dispute referred to in section 2.2.1.4:

2.7.29.1 where the dispute relates to the *reviewable decision* referred to in MR Ch.6 s.2.1.2, the *arbitrator* may confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of the relevant *connection point* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the

IESO for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998*;

2.7.29.2 where the dispute relates to the *reviewable decision* referred to in MR Ch.6 s.5.3.9, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to reinstate the registration of the *metering service provider* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable and the award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25;

2.7.29.3 where the dispute relates to the *reviewable decision* referred to in MR Ch.6 s.5.1.12, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to register the person as a *metering service provider* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25; or

2.7.29.4 where the dispute relates to the *reviewable decision* referred to in MR Ch.6 s.4.4.3 or 6.1.5, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to register the *metering installation* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25.

2.7.29A In the case of a dispute referred to in section 2.2.2.1, the *arbitrator* may:

2.7.29A.1 determine an alternative apportionment of the *energy* associated with *connection station service* and with site specific losses amongst all applicable *market participants*; and

2.7.29A.2 determine whether, and the extent to which, any such alternative apportionment should be applied, by means of payments amongst the applicable *market participants*, to any period prior to the date on which the *IESO* gives effect to the proportions filed pursuant to MR Ch.9 s.2.2.8.

2.7.29B Subject to section 2.7.27A, in the case of a dispute referred to in MR Ch.9 s.6.10.1, the *arbitrator* may, in considering whether to order the *IESO* to adjust *settlement statements* of multiple *market participants*, take into account:

2.7.29B.1 the dollar amount that is the subject matter of the dispute;

2.7.29B.2 the time elapsed since the event that is the subject matter of the dispute took place; and

2.7.29B.3 the *IESO's* ability to perform such adjustments.

2.7.30 In the case of a dispute referred to in section 2.2.2.2, the *arbitrator* may make such award, including but not limited to an award of damages, as is just and reasonable in the circumstances.

2.7.31 [Intentionally left blank]

2.7.32 Subject to section 2.7.32A, the *arbitrator* may make such award as to costs as he or she determines just and reasonable provided that, except in exceptional cases:

2.7.32.1 where in the context of a dispute referred to in section 2.2.1 the award consists of damages for breach of the *market rules*, costs, including the *costs of the arbitration*, shall be awarded to the successful party;

2.7.32.2 where the award consists of the imposition of penalties on a *market participant*, costs, including the *costs of the arbitration*, shall be awarded to the *IESO*; and

2.7.32.3 where the award consists of the direction to the *IESO* to comply with the *market rules* or to interpret or apply a *market rule* in a particular manner pursuant to section 2.7.25, costs, including the *costs of the arbitration*, shall be awarded to the *market participant* seeking the direction.

2.7.32A Where an award relates to an application referred to in section 2.7.1D and:

2.7.32A.1 the award consists of a determination by the *arbitrator* that the *applicant* is not entitled to any compensation pursuant to MR Ch.5 s.6.7.5; or

2.7.32A.2 no award as to costs is made pursuant to section 2.7.32B,

the *applicant* shall be responsible for his or her own costs and legal expenses associated with his or her participation in the arbitration and, subject to any determination of the *arbitrator* pursuant to section 2.7.33, shall bear the *costs of the arbitration*.

2.7.32B Where an award relates to an application referred to in section 2.7.1D and the award consists of a determination by the *arbitrator* that the *applicant* is entitled to compensation pursuant to MR Ch.5 s.6.7.5, the *arbitrator* may determine that some or all of:

2.7.32B.1 the *applicant's* costs and legal expenses associated with his or her participation in the arbitration; and

2.7.32B.2 the *applicant's* share of the costs of the arbitration,

be recovered by the *applicant*. Where the *arbitrator* makes such an award as to costs, the amount of such recoverable costs shall be paid by the *IESO* and recovered by the *IESO* in the same manner as the compensation referred to in MR Ch.5 s.6.7.5.

2.7.33 A person who intervenes in an arbitration shall be responsible for his or her own costs and legal expenses associated with his or her participation in the arbitration. The *arbitrator* may, in appropriate circumstances, require that an intervenor bear a portion of the *costs of the arbitration*.

2.7.34 An award of the *arbitrator* shall be enforceable in the manner provided in the *Arbitration Act, 1991*.

2.7.35 Where, in the case of a dispute referred to in section 2.2.1, the award consists of the payment of monies to the *IESO* or to a *market participant*, such award shall be considered to create an obligation under the *market rules* to pay the amount stated in the award and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly. Except as may otherwise be provided in the award, any monies payable pursuant to an award shall be payable within 30 days of the date of the award.

2.7.36 Failure to comply with an award of an *arbitrator* in respect of a dispute referred to in section 2.2.1 constitutes a breach of the *market rules*.

2.7.37 Upon completion of an arbitration, the *arbitrator* shall file the record of the arbitration proceedings with the *secretary*. Where such record contains *confidential information* in respect of which a claim for confidentiality has been confirmed by the *arbitrator* pursuant to section 2.8.1, the *confidential information*, together with the stenographic record of any in camera hearings relating thereto, shall be sealed in an envelope clearly marked "CONFIDENTIAL" or otherwise identified as confidential and protected from disclosure prior to filing with the *secretary*.

2.7.38 Upon completion of the arbitration, the *arbitrator* shall file with the *secretary* an invoice containing an itemized statement of the *costs of the arbitration*, together with copies of all bills and other supporting documentation relating thereto.

2.7.39 Upon receipt of the invoice referred to in section 2.7.38, the *secretary* shall submit a copy of the invoice to the *IESO* and the *IESO* shall submit an invoice to each of the parties to the arbitration and, where applicable, each intervenor, in respect of their respective shares of the *costs of the arbitration*. Each such person shall, within ten *business days* of receipt of such invoice, pay to the *IESO* the amount owing thereunder. Such invoice shall be considered to create an obligation under the *market rules* to pay the amount specified in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

2.7.40 Where an *arbitrator* dies, resigns, is removed or otherwise becomes incapable of acting as an *arbitrator* in respect of a dispute prior to completion of the arbitration, a replacement shall, with the consent of all of the parties to the arbitration, be selected by the *secretary* from among the remaining members of the *dispute resolution panel* in accordance with the *Governance and Structure By-law*. In the absence of such consent, subject to section 2.7.1A, the *secretary* shall forthwith provide the parties with a revised list of at least three names of members of the *dispute resolution panel* available to fill the vacancy and the parties shall make good faith efforts to agree on the appointment of one of the members named in the list as the replacement *arbitrator*. Where the parties so agree, they shall so advise the *secretary*.

2.7.41 [Intentionally left blank]

2.7.42 Where the parties have failed to select a replacement *arbitrator* within ten *business days* of receipt of the list referred to in section 2.7.40, subject to section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the replacement *arbitrator* and shall by written notice so advise the parties.

2.7.43 With the consent of the parties to the arbitration, once the *arbitrator* has been replaced, the *arbitrator* may continue the arbitration. In the absence of such consent, the replacement *arbitrator* shall commence the arbitration anew.

2.8 Confidentiality

2.8.1 Any party may claim that a document, or information contained in a document, to be produced in the context of the arbitration of a dispute is *confidential information*. The party making such a claim shall provide to the *arbitrator* in writing the basis for its assertion. If the claim of confidentiality is confirmed by the *arbitrator*, having regard, where applicable, to the provisions of section 5, the *arbitrator* shall establish requirements for the protection of such document or information as may be necessary to protect the confidentiality and commercial value of such document or information, including requirements for disclosure of same only to counsel and/or other independent advisor who has filed an undertaking as to confidentiality satisfactory to the *arbitrator* and for in camera hearings at which only representatives of the disclosing party and such counsel and/or other independent advisor may be present.

2.8.2 Members of the *dispute resolution panel* shall enter into such confidentiality agreement as may be required by the *IESO Board*.

2.9 Record-Keeping and Publication

2.9.1 Subject to section 2.9.1A, the *secretary* shall maintain a record of all dispute resolution proceedings conducted under this section 2. Upon the completion of a given dispute resolution proceeding, the *secretary* shall transfer the record to the *IESO*, addressed to the Chair of the Board of Directors of the *IESO* for archiving. The Chair shall be responsible for ensuring that all measures are taken to prohibit access by any other person to any portion of such record which may be sealed and marked "CONFIDENTIAL" or otherwise identified as being confidential, except as may be required by *applicable law* or permitted by the provisions of section 5.

2.9.1A For the purposes of section 2.9.1, the record referred to therein shall not include any record pertaining to or arising from the mediation of a dispute other than:

2.9.1A.1 the name and address for service of the person appointed to act as the *mediator* in respect of the dispute;

2.9.1A.2 the agreement referred to in section 2.6.5;

2.9.1A.3 the settlement agreement referred to in section 2.6.12;

2.9.1A.4 the notice of termination of mediation referred to in section 2.6.13 or 2.6.16;

2.9.1A.5 the agreed statement of fact and/or issues referred to in section 2.6.13 or 2.6.16; and

2.9.1A.6 information and documentation pertaining to the *costs of the mediation*, including the invoice referred to in section 2.6.18.

2.9.2 The *secretary* shall arrange for *publication* by the *IESO* of the following:

2.9.2.1 the summaries referred to in sections 2.5.3C, 2.5.6 and 2.5.6C as may be applicable upon the appointment of the *arbitrator*;

2.9.2.2 notice of the appointment of an *arbitrator* and the address for service of the *arbitrator*;

2.9.2.3 notice of the date, time and place fixed for hearing pursuant to section 2.7.11; and

2.9.2.4 a summary of the award of an *arbitrator* filed pursuant to section 2.7.23, which may include the information required by section 2.7.25.

2.9.3 The *IESO* shall *publish* the fees payable to members of the *dispute resolution panel* involved in the resolution or the attempted resolution of a dispute pursuant to this section 2, as such fees may from time to time be fixed in accordance with the provisions of the *Governance and Structure By-law*.

2.10 Audit

2.10.1 The activities of the *dispute resolution panel* shall be audited in accordance with procedures adopted from time to time by the *IESO*.

3. Market Surveillance

3.1 [Intentionally left blank – section deleted]

3.2 Establishment and Staffing of Market Assessment Unit

3.2.1 A *market assessment unit* shall be established by the *IESO* to perform the functions given to it under the *market rules* and to support, in the manner agreed to by the *IESO* and the *OEB*, the *market surveillance panel.*

3.3 Market Monitoring Functions

3.3.1 The *market assessment unit* shall conduct such monitoring, evaluation, analysis and reporting activities in support of the work of the *market surveillance panel* as may be agreed between the *IESO* and the *OEB*.

3.3.1A Notwithstanding any other provision of MR Ch.3, the *IESO* shall provide the *market surveillance panel* with such information as it may require from time to time.

3.3.2 [Intentionally left blank – section deleted]

3.3.3 [Intentionally left blank – section deleted]

3.3.4 [Intentionally left blank – section deleted]

3.3.5 [Intentionally left blank – section deleted]

3.3.5A *Market participants* shall provide the *market assessment unit* with the data identified in the detailed catalogue adopted and published by the *market surveillance panel* in accordance with the *OEB* by-laws.

3.4 [Intentionally left blank – section deleted]

3.5 [Intentionally left blank – section deleted]

3.6 [Intentionally left blank – section deleted]

3.7 [Intentionally left blank – section deleted]

3.8 Dispute Resolution and Other Relief

3.8.1 The dispute resolution procedures under section 2 shall not apply to the activities of the *market assessment unit* under this section 3.

3.8.2 Nothing in this section 3 shall prevent the *IESO* or any other person from asserting any rights they may have under any *applicable law* or under the *market rules*.

4. Rule Amendments

4.1 Introduction and Interpretation

4.1.1 This section 4 sets forth the procedures pursuant to which *amendments* to the *market rules* may be made by the *IESO* and embodies the mechanism for review of the *market rules* for purposes of the application of subsection 35(4) of the *Electricity Act, 1998*.

4.1.2 This section 4 must be read and construed subject to the *Governance and Structure By-law.*

4.2 Amendment Process Generally

4.2.1 Under section 32 of the *Electricity Act, 1998*, the *IESO Board* has the authority and responsibility to *amend* these *market rules*. The *technical panel* is authorized, through the *Governance and Structure By-law*, to support the *IESO Board* in the development and consideration of *amendments* to the *market rules*. The *urgent rule amendment committee* is authorized, through the *Governance and Structure By-law*, to support the *IESO Board* in the development, consideration and making of *urgent rule amendments*.

4.2.2 In formulating *amendments* to the *market rules*, the *IESO Board*, the *technical panel* and the *urgent rule amendment committee* shall take into consideration the objects of the *IESO* as set forth in the *Electricity Act*, *1998*.

4.2.3 The *IESO Board* may review, from time to time, the work and proceedings of the *technical panel* and issue to the *technical panel* such directions as the *IESO Board* from time to time determines appropriate. Such directions may relate to one or more proceedings respecting particular proposed *amendments* to or reviews of the *market rules* or may be of more general application. For certainty, such directions may include termination of the consideration of a particular proposed *amendment* to, or review of, the *market rules.* The *technical panel* shall comply with such directions. In addition, nothing in this section 4 shall prohibit the *technical panel* from consulting with the *IESO Board* regarding the role the *technical panel* will play in reviewing a request for an *amendment* or review of the *market rules*.

4.2.4 A *market participant* or any other interested person may file a written submission (the "*amendment submission*") with the *IESO*, at such address as may be *published* by the *IESO* from time to time, to propose one or more *amendments* to the *market rules* or to identify any provision of the *market rules* in respect of which the *market participant* or the other interested person considers that an *amendment* or review may be necessary or desirable. The *amendment submission* shall include a statement of the reasons for which an *amendment* to or review of the *market rules* may be necessary or desirable.

4.2A Rule Amendments Initiated by the IESO Board

4.2A.1 The *IESO Board* may at any time determine on its own initiative or at the request of any person that an *amendment*, including a *minor amendment*, to or a review of a *market rule* may be necessary or desirable and shall *publish* and give notice of its intention to consider such *amendment* or review, together with a statement of the reason for which such *amendment* or review may be necessary or desirable:

4.2A.1.1 to all *market participants*;

4.2A.1.2 to the *technical panel*;

4.2A.1.3 where such *amendment* or review relates to or may affect any provision of section 2, to the *secretary* of the *dispute resolution panel*; and

4.2A.1.4 where such *amendment* or review relates to or may affect any provision of section 3, to the Chair of the *market surveillance panel*,

inviting such persons to make, within such reasonable period as shall be specified in the notice, written submissions to the *IESO Board* concerning the matter. The reasonable period shall not be less than 7 days.

4.2A.2 Sections 4.3.9 to 4.3.11 and 4.3.13 to 4.3.20 shall apply, with such modifications as the context may require, to consideration by the *IESO Board* of a proposed *amendment*, other than a *minor amendment* which shall be made in accordance with section 4.7, or review pursuant to this section 4.2A, it being understood that the references in those sections to the *technical panel* shall be considered references to the *IESO Board*, unless and to the extent that the *IESO Board* directs the *technical panel* to participate in the matter.

4.2A.3 Sections 4.7.1 to 4.7.6, other than sections 4.7.1.1 and 4.7.1.2, apply with such modifications as the context may require to consideration by the *IESO Board* of a *minor amendment* pursuant to this section 4.2A, it being understood that the references in those sections to the *technical panel* shall be considered references to the *IESO Board*, unless and to the extent that the *IESO Board* directs the *technical panel* to participate in the matter.

4.3 Requests for Review or Amendment of Market Rules

4.3.1 The provisions of this section 4.3 apply to requests made by the *IESO Board*, and *amendment submissions* made by a *market participant* or any other interested person for an *amendment* or review of the *market rules*, and do not apply:

4.3.1.1 except as expressly provided in section 4.4.3 or 4.2A.2, to proposed *amendments* to which sections 4.4 or 4.2A, respectively, apply;

4.3.1.2 to *urgent amendments* to the *market rules*, which shall be made in accordance with section 4.6; and

4.3.1.3 to *amendments* to the *market rules* which are required to be made or reconsidered further to an order of the *Ontario Energy Board* pursuant to the provisions of the *Electricity Act, 1998*, which shall be made in accordance with section 4.8.

4.3.2 Upon receipt of the *amendment submission,* the *technical panel* may request that the person submitting the *amendment submission* provide further particulars with respect to the *amendment submission*.

4.3.3 [Intentionally left blank]

4.3.4 [Intentionally left blank]

4.3.5 The *technical panel* shall report to the *IESO Board* and, where applicable, give notice to the *market participant* or other interested person who made an *amendment submission* as to whether the proposed *amendment* or the request for consideration of an *amendment* or review is, in the opinion of the *technical panel*:

4.3.5.1 of such a nature that consideration of the *amendment submission* is warranted and the extent of the consultation that the *technical panel* intends to take with *market participants* and other interested persons in the consideration of the *amendment*;

4.3.5.1A of such a nature that it raises only a *minor amendment*, in which case the *amendment submission* shall be dealt with in accordance with the provisions of section 4.7;

4.3.5.1B of such a nature that a clarification or interpretation of the applicable *market rule* is warranted, in which case the *amendment submission* shall be dealt with in accordance with the provisions of MR Ch.1 s.12; or

4.3.5.2 with reasons specified in the report and notice, of such a nature that no consideration of the *amendment submission* is warranted,

provided that the *technical panel* shall not make the determination referred to in section 4.3.5.2 where the request was made by the *IESO Board* unless the *IESO Board*, in its request, so permits.

4.3.6 The *technical panel* shall nonetheless further consider or not consider the *amendment submission*, as the case may be, if it is directed to do so by the *IESO Board.*

4.3.7 Where the *technical panel* decides or is required to further consider an *amendment submission* pursuant to section 4.3.5 or 4.3.6, the *IESO* shall *publish* and give notice to all *market participants* and to any person who made the *amendment submission,* of the particulars of the *amendment submission* and of any comments which the *technical panel* may wish to make in respect of the *amendment submission*. The notice and *publication* may, at the request of *technical panel*, invite *market participants* and other interested persons to make written submissions to the *technical panel* concerning the *amendment submission*, within such reasonable period as shall be determined by the *technical panel*, and as specified in the *publication* and notice. This reasonable period shall not be less than 7 days.

4.3.8 The written submissions referred to in section 4.3.7 must be filed with the *technical panel* within the time specified in the notice and *publication* and may indicate whether the *market participant* or the other interested person considers that a meeting is necessary or desirable in connection with the *amendment submission* and, if so, the reasons why such meeting is necessary or desirable.

4.3.9 The *technical panel* may at any time give notice, and invite *market participants* or other interested persons, to make such additional written submissions within such reasonable time as the *technical panel* determines appropriate.

4.3.10 The *technical panel* shall consider all written submissions received within the prescribed time pursuant to section 4.3.8 or 4.3.9 and may, where the *technical panel* considers it necessary or desirable, schedule and hold meetings in accordance with section 4.3.11.

4.3.10A In its consideration of an *amendment submission*, the *technical panel* shall also consider any unsolicited written submissions that are received in time for the *technical panel* meeting at which the applicable *amendment submission* is being considered.

4.3.11 The *technical panel* shall advise the *IESO Board* of the date, time and place scheduled for any meeting referred to in section 4.3.10 and the *IESO* shall, no less than seven days prior to the date fixed for a meeting, *publish* and give notice of same to *market participants* and to any person who filed written submissions pursuant to section 4.3.8 or 4.3.9. Any *market participant* and any other interested person may attend and, at the discretion of the *technical panel,* participate in any such meetings.

4.3.12 Where the *amendment submission* relates to or may affect:

4.3.12.1 any provision of section 2, the *technical panel* shall, prior to conducting any meetings pursuant to section 4.3.11 or, in the absence of such meetings, prior to voting on the matter, consult with the *secretary* of the *dispute resolution panel* with respect to the matter; and

4.3.12.2 any provision of section 3, the *technical panel* shall, prior to conducting any meetings pursuant to section 4.3.11 or, in the absence of such meetings, prior to voting on the matter, consult with the Chair of the *market surveillance panel* with respect to the matter.

4.3.13 The *technical panel* shall, as soon as reasonably practicable following any meetings and consultations which may have been held pursuant to sections 4.3.11 and 4.3.12, or any other consultations that the *technical panel* decides are appropriate, convene on one or more occasions as may be necessary to consider and vote on the *amendment* resulting from an *amendment submission*. Prior to the *technical panel* voting on an *amendment*, the *IESO* shall, at the request of *technical panel*, *publish,* and give notice to all *market participants* and to any person who made the *amendment submission* or written submission to which the proposed *amendment* relates, of the proposed *amendment* that will be the subject of the *technical panel's* vote. The notice and *publication* shall, at the request of the *technical panel*, invite *market participants* and other interested persons to make written submission to the *technical panel* concerning the subject *amendment*, within such reasonable period as shall be determined by the *technical panel* and specified in the notice and *publication*. This reasonable period shall not be less than 7 days.

4.3.14 Following the conclusion of the deliberations referred to in section 4.3.13, the *technical panel* shall submit a written report to the *IESO Board* setting out:

4.3.14.1 the recommendations of the *technical panel* and the reasons for its recommendations;

4.3.14.2 where the recommendations of the *technical panel* include a proposal to *amend* the *market rules*, a copy of the proposed text of the *amendment* and a summary of any objections to the *amendment submission* which may have been contained in the written submissions referred to in section 4.3.8, 4.3.9, 4.3.10A or 4.3.13 or brought to the attention of the *technical panel* during any meetings held pursuant to section 4.3.11 or otherwise;

4.3.14.3 a summary of the procedure followed by the *technical panel* in considering the matter;

4.3.14.4 a summary of the views of the *secretary* of the *dispute resolution panel* or the Chair of the *market surveillance panel*, as the case may be, provided during the consultations referred to in section 4.3.12;

4.3.14.5 a record of the vote of each member of the *technical panel* in respect of each of the recommendations made in the report;

4.3.14.6 a summary of any objections raised by any member of the *technical panel* to the recommendations, if such objecting member so requests; and

4.3.14.7 a statement of the objects of the *IESO* considered by the *technical panel* in formulating the *amendment* as required by section 4.2.2.

4.3.15 The *IESO* shall *publish* the recommendations contained in the report of the *technical panel* referred to in section 4.3.14 and give notice thereof to all *market participants* and to any person who made an *amendment submission* or written submission to which the recommendations relate. In this notice and *publication*, the *IESO* shall, at the request of the *technical panel*, invite *market participants* and other interested persons to make written submissions to the *IESO Board* concerning the subject *amendment*, within seven *business days* of the date of giving of notice, objecting to the *technical panel's* recommendation and setting forth the reasons for the objection. At the request of the *IESO Board*, the *technical panel* shall provide to the *IESO Board* copies of all written submissions received pursuant to section 4.3.8, 4.3.9, 4.3.10A or 4.3.13, together with particulars of any written submissions which were made before the *technical panel* during the course of any meetings that may have been held pursuant to section 4.3.11.

4.3.16 [Intentionally left blank]

4.3.17 As soon as reasonably practicable following receipt of the report of the *technical panel* referred to in section 4.3.14 or, where written submissions have been requested pursuant to section 4.3.15, following the expiry of the deadline for written submissions referred to in that section, the *IESO Board* shall convene on one or more occasions as may be necessary to consider the report of the *technical panel*, together with any written submissions received pursuant to section 4.3.15, and shall vote on the matter in accordance with the provisions of the *Governance and Structure By-law*.

4.3.18 Where the *IESO Board* decides against the adoption of an *amendment* to the *market rules*, the *IESO* shall *publish* such decision and shall give notice of the decision to all *market participants* and to any person who made an *amendment submission* or written submission to which the decision relates. Where the *IESO Board* decides in favour of the adoption of the *amendment* to the *market rules,* either as recommended by the *technical panel* or with changes made by the *IESO Board* in its consideration of the *amendment*, the *IESO* shall publish such decision, together with a copy of the *amendment*, in accordance with the provisions of the *Governance and Structure By-law* and the *Electricity Act, 1998*, and shall give notice of the decision to all *market participants* the *Ontario Energy Board* and to any person who made the *amendment submission* or written submission to which the decision relates.

4.3.19 Where, in accordance with the *Governance and Structure By-law*, the *IESO Board* refers a recommendation contained in a report of the *technical panel* either back to the *technical panel* for further consideration and vote, or to any other person that the *IESO Board* deems appropriate, the *IESO Board* shall so advise the *technical panel*, with reasons, and shall *publish* such decision and give notice of the decision to all *market participants* and to any person who filed an *amendment submission* or written submission to which the decision relates. The *technical panel* shall, as soon as reasonably practicable following receipt of the decision of the *IESO Board*, convene to reconsider its recommendation. The *technical panel* may enter into such further consultations with such persons, and conduct such meetings, as it determines appropriate for purposes of its reconsideration.

4.3.20 Sections 4.3.14 to 4.3.18 shall apply, with such modifications as may be required by the context, to the reconsideration of a recommendation pursuant to section 4.3.19.

4.4 Rule Amendments Initiated by the Technical Panel

4.4.1 The provisions of this section 4.4 do not apply to *minor amendments* proposed by the *technical panel*, which shall be made in accordance with section 4.7.

4.4.2 Where the *technical panel* on its own initiative determines at any time that an *amendment* to or a review of a *market rule* may be necessary or desirable, it shall submit a report of its intention to consider such *amendment* or review to the *IESO Board*, together with the reasons for its determination (the "*review notice*").

4.4.3 Sections 4.3.7 to 4.3.20 shall apply, with such modifications as the context may require, to consideration of the matter raised in the *review notice*, it being understood that the reference in those sections to an *amendment submission* shall be a reference to the *review notice*.

4.5 [Intentionally left blank]

4.6 Urgent Amendments

4.6.1 *Urgent amendments* to the *market rules* shall be made by the *IESO Board* or the *urgent rule amendment committee*, if so authorized by the *IESO Board* pursuant to the *Governance and Structure By-law*, following such consultations with such persons as the *urgent rule amendment committee* or the *IESO Board*, as the case may be, considers appropriate.

4.6.2 Where an *urgent amendment* is made pursuant to section 4.6.1 by the *urgent rule amendment committee*, such *amendment* shall forthwith be reported to the *IESO Board*.

4.6.3 The *IESO Board* shall, in accordance with the provisions of the *Governance and Structure By-law*, convene on one or more occasions as may be necessary to consider the report and vote to either:

4.6.3.1 confirm the *urgent amendment*, in the form made by the *urgent rule amendment committee* or in such form as the *IESO Board* deems appropriate; or

4.6.3.2 reject the *urgent amendment* and stay the implementation thereof.

4.6.4 Where an *urgent amendment* is made by the *IESO Board* or the *urgent rule amendment committee* pursuant to section 4.6.1, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of such *urgent amendment* and shall give notice thereof to all *market participants*.

4.6.5 Where an *urgent amendment* is confirmed by the *IESO Board* pursuant to section 4.6.3.1 in a form other than that made by the *urgent rule amendment committee*, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of such *urgent amendment* and shall give notice thereof to all *market participants*.

4.6.6 Where the *IESO Board* rejects and stays the implementation of an *urgent amendment* pursuant to section 4.6.3.2, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of its decision to all *market participants*.

4.7 Minor Amendments

4.7.1 If the *technical panel* considers that it is necessary or desirable to make a *minor amendment* to the *market rules*, either on its own initiative or upon receipt of an *amendment submission,* the *technical panel* shall hold such consultations with such persons, or ask for written submissions only from such *market participants*, if any, as the *technical panel* considers appropriate and shall:

4.7.1.1 where such *minor amendment* relates to or may affect any provision of section 2, consult with the *secretary* of the *dispute resolution panel*; or

4.7.1.2 where such *minor amendment* relates to or may affect any provision of section 3, consult with the Chair of the *market surveillance panel*,

and each of the *secretary* and the Chair shall consult such members of their respective panels as they determine appropriate prior to consulting with the *technical panel.*

4.7.2 After holding any consultations or receiving any written submissions pursuant to section 4.7.1, the *technical panel* shall convene on one or more occasions as may be necessary to consider and vote on the matter and shall thereafter submit a written report to the *IESO Board* containing the information set forth in section 4.3.14.

4.7.3 [Intentionally left blank]

4.7.4 [Intentionally left blank]

4.7.5 As soon as reasonably practicable following the receipt of the report of the *technical panel* referred to in section 4.7.2 the *IESO Board* shall convene on one or more occasions as may be necessary to consider and vote on the *minor amendment* in accordance with the *Governance and Structure By-law* and shall:

4.7.5.1 approve the *minor amendment* as submitted by the *technical panel* or with any changes that the *IESO Board* determines are appropriate; or

4.7.5.1A reject the *minor amendment*, or

4.7.5.2 refer the matter back to the *technical panel.*

4.7.5A The *IESO* shall *publish* the *IESO Board* decision made pursuant to section 4.7.5, together with a copy of the *amendment*, in accordance with the provisions of the *Governance and Structure By-law* and the *Electricity Act, 1998*, and shall give notice of the decision to all *market participants,* the *Ontario Energy Board* and to any person who made the *amendment submission* or made a written submission to which the decision relates.

4.7.6 Sections 4.3.7 to 4.3.20 shall, unless and to the extent that the *IESO Board* directs otherwise, apply with such modifications as the context may require to the further consideration by the *technical panel* of a matter referred to it under section 4.7.5.2.

4.8 Amendments Subject to Order of the Ontario Energy Board

4.8.1 Upon receipt of an order of the *Ontario Energy Board* made pursuant to the provisions of the *Electricity Act, 1998* from which no appeal, review or petition to the Lieutenant Governor in Council can or has been taken, the *IESO Board* shall either:

4.8.1.1 refer the matter, including consideration of any consequential *amendments* arising from the matter, to the *technical panel*, and the provisions of sections 4.3.7 to 4.3.20 shall, unless and to the extent that the *IESO Board* directs otherwise, apply with such modifications as the context may require to the reconsideration of the *amendment* to the *market rules* which is the subject of the order; or

4.8.1.2 following such consultations as the *IESO Board* considers appropriate, make an *amendment* to the *market rules* including any consequential *amendments* arising from the matter. The *IESO* shall *publish* the *amendment* and shall give notice of the *amendment* to all *market participants* and the *Ontario Energy Board*.

4.8.2 Upon receipt of an order of the *Ontario Energy Board* made pursuant to subsection 35(6) or 38(4) of the *Electricity Act, 1998* from which no appeal, review or petition to the Lieutenant Governor in Council can or has been taken, the *IESO Board* shall make an *amendment* to the *market rules* in the manner and within the time specified by the *Ontario Energy Board* in its order, including any consequential *amendments* arising from the matter, following such consultations as the *IESO Board* considers appropriate. The *IESO* shall *publish* the *amendment* and shall give notice of the *amendment* to all *market participants* and the *Ontario Energy Board*.

4.9 Experts and Other Assistance

4.9.1 The *technical panel* may, subject to the *Governance and Structure By-law* of the *IESO* and to budgetary approval of the Chief Executive Officer of the *IESO,* hire such consulting assistance and seek such expert external advice as may be necessary or desirable for the purpose of the fulfillment of its responsibilities under this section 4. Where the Chief Executive Officer of the *IESO* does not approve such request, the *technical panel* may appeal such decision to the Chair of the *IESO Board.*

4.9.1A Consultants and expert external advisors hired pursuant to section 4.9.1 shall enter into such confidentiality agreement as may be required by the Chair of the *technical panel*.

4.9.2 In carrying out any of its responsibilities under this section 4, the *technical panel* may, through the Chief Executive Officer of the *IESO*, solicit the assistance of any director, officer or employee of the *IESO* and may use the facilities of the *IESO*.

4.9.3 Where the *technical panel* at any time considers it necessary or desirable to do so, it may establish working groups to assist it in the fulfillment of its responsibilities under this section 4, which working groups shall operate in accordance with such terms and conditions, including as to the scope of their work and as to participation in such working groups, as the *technical panel* may reasonably determine to be appropriate. The *technical panel* shall notify the *IESO Board* of its intention to establish a working group and the *IESO* shall *publish* and give notice to all *market participants,* the person who made the *amendment submission* and any other interested party that made written submissions in respect of the proposed *amendment* to which the working group relates of such intention.

4.9.4 The *IESO Board* may, at any time in fulfilling its responsibilities under this section 4, including but not limited to for the purposes of section 4.8.2, call upon the assistance of the *technical panel*.

4.10 [Intentionally left blank]

4.11 [Intentionally left blank]

4.12 Audit

4.12.1 The activities of the *technical panel* shall be audited in accordance with procedures adopted from time to time by the *IESO*.

5. Accessibility and Confidentiality of Information

5.1 Accessibility

5.1.1 Subject to section 5.7.1, all persons shall have an equal opportunity for open and non-discriminatory access to all information, other than *confidential information*, required by the *market rules* to be made available to *market participants*, the *IESO* or other persons.

5.1.2 Subject to section 5.7.1, all information, other than *confidential information*, required by the *market rules* to be made available to *market participants*, the *IESO* or other persons shall be *published* or otherwise made available in the manner and within the time prescribed in the *market rules*. Where no time is specified in respect of the provision of a particular piece of information, such information shall be made available within a reasonable time.

5.1.3 All *market participants* shall have an equal opportunity for access to information, other than *confidential information*, made available pursuant to the *market rules*.

5.1.3A Notwithstanding sections 5.1.1, 5.1.2, 5.1.3 or any other sections of the *market rules*, the *IESO* may withhold information that if disclosed may, in the reasonable opinion of the *IESO*, pose a security threat to the *reliable* operations of the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions.

5.1.4 In this section 5:

5.1.4.1 a reference to the *IESO* shall include a reference to a panel established by the *IESO;* and

5.1.4.2 a reference to information shall mean information however recorded, whether in printed form, on film, by electronic means or otherwise.

5.2 Confidentiality

5.2.1 Each *market participant* and the *IESO* shall keep confidential any *confidential information* which comes into the possession or control of that *market participant* or the *IESO* or of which the *market participant* or the *IESO* becomes aware.

5.2.2 No *market participant* or the *IESO* shall:

5.2.2.1 disclose *confidential information* to any person except as permitted by the *market rules*;

5.2.2.2 permit access to *confidential information* by any person not authorized to have such access pursuant to the *market rules*; or

5.2.2.3 use or reproduce *confidential information* for a purpose other than the purpose for which it was disclosed or another purpose contemplated by the *market rules*.

5.2.3 Each *market participant* and the *IESO* shall:

5.2.3.1 prevent access to *confidential information* which is in its possession or control by any person not authorized to have such access pursuant to the *market rules*, including by appropriate means of destruction or disposal in cases where the *confidential information* is not required or is at the relevant time no longer required to be retained by it pursuant to the *market rules*; and

5.2.3.2 ensure that any person to whom it discloses *confidential information* observes the provisions of this section 5.2 in relation to that *confidential information*.

5.2.4 Each *market participant* and the *IESO* shall, promptly upon becoming aware of a breach or a threatened breach of the provisions of this section 5 with respect to an item of *confidential information*:

5.2.4.1 so notify any person to whom the *confidential information* relates or by whom it was provided;

5.2.4.1A if a *market participant*, so notify the *IESO*; and

5.2.4.2 take such reasonable steps as may be required to prevent or assist in the prevention of, as the case may be, the unauthorized disclosure, access to, use or reproduction of *confidential information* that may result from such breach or threatened breach.

5.2.5 Each *market participant* shall maintain internal measures relating to the protection of *confidential information* that enable the *market participant* to comply and monitor compliance with its obligations under this section 5.

5.2.6 The *IESO* shall maintain internal measures, including measures referred to in section 5.7.2, relating to the protection of *confidential information* that enable the *IESO* to comply and monitor compliance with its obligations under this section 5.

5.3 Exceptions

5.3.1 Unless prohibited by *applicable law* or by the provisions of these *market rules* other than this section 5, nothing in MR Ch.5 ss. 5.2, 5.4 or 5.5.1A shall prevent:

5.3.1.1 the disclosure, use or reproduction of information if the information is, at the time of disclosure, generally and publicly available other than as a result of a breach of confidence by the *market participant* or the *IESO* who wishes to disclose, use or reproduce the information or by any person to whom the *market participant* or the *IESO* has disclosed the information;

5.3.1.2 the disclosure of *confidential information* by a *market participant* or the *IESO* to:

a. a director, officer or employee of the *market participant* or of the *IESO* where such person requires the *confidential information* for the due performance of that person's duties and responsibilities and, in the case of the *IESO* for information that is classified highly confidential pursuant to section 5.4.2.6, where the person has the required security clearance assigned by the *IESO*; or

b. a legal or other professional advisor, auditor or other consultant of the *market participant* or of the *IESO* where such persons require the information for purposes of the *market rules* or of an agreement entered into pursuant to the *market rules* or for the purpose of advising the *market participant* or the *IESO* in relation thereto;

5.3.1.3 the disclosure, use or reproduction of *confidential information*:

a. by the *market participant* or person that provided the *confidential information* pursuant to the *market rules*;

b. with the consent of the *market participant* or person that provided the *confidential information* pursuant to the *market rules*; or

c. in the case of *settlement* data, *metering data* or data contained in the *metering registry*, by or with the consent of the *market participant* to whom such data relates;

5.3.1.4 the disclosure, use or reproduction of *confidential information* to the extent required by *applicable law* or by a lawful requirement of:

a. any government or governmental body, regulatory body, authority or agency having jurisdiction over a *market participant* or the *IESO* or an *affiliate* of a *market participant* or of the *IESO*; or

b. any stock exchange having jurisdiction over a *market participant*, the *IESO* or an *affiliate* of a *market participant* or the *IESO*;

5.3.1.5 except as otherwise provided in section 2, the disclosure, use or reproduction of *confidential information* if required in connection with legal proceedings, mediation, arbitration, expert determination or other dispute resolution mechanism relating to the *market rules* or to an agreement entered into pursuant to the *market rules* or for the purpose of advising a person in relation thereto;

5.3.1.5A if required by the *IESO Board* or a committee established by the *IESO Board*, the disclosure, use or reproduction of *confidential information* if required in connection with the issuance of *suspension*, *termination* or *disconnection orders* in respect of one or more *market participants* the revocation of the registration in respect of one or more *metering service providers* and any show cause hearings in respect thereof under MR Ch.6 s.5.3 or section 6.2A;

5.3.1.6 the disclosure of *confidential information* if required to ensure the safety of any person, prevent the damage of equipment, prevent the violation of any *applicable law*, or to maintain the *reliability* of the *IESO-controlled grid*;

5.3.1.7 the disclosure, use or reproduction of *confidential information* as an unidentifiable component of an aggregate sum;

5.3.1.8 the disclosure by the *IESO* of *confidential information* to a *transmitter* for the purposes of:

a. the safe and *reliable* management, operation and maintenance of its *transmission system* to the extent that *confidential information* is required pursuant to the terms of the *operating agreement*; or

b. the verification or reconciliation of the collection and administration of any applicable *transmission services charges*;

5.3.1.9 the disclosure by the *IESO* of *confidential information* to a *market participant*:

a. during an *emergency* or where the *IESO-controlled grid* is in an *emergency operating state* or a *high-risk operating state*; or

b. where an *emergency*, an *emergency operating state* or a *high-risk operating state* is anticipated by the *IESO*;

to the extent that such disclosure would, in the *IESO's* opinion:

c. assist the *market participant* in responding to the conditions referred to in sections 5.3.1.9(a) and 5.3.1.9(b); or

d. assist the *IESO* in restoring the *IESO-controlled grid* to a *normal operating state*;

5.3.1.10 disclosure by the *IESO* of *confidential information* to a *standards authority*, a *control area operator*, a *security coordinator* or an *interconnected transmitter*;

5.3.1.11 disclosure by the *IESO* of *confidential information* to the *market surveillance panel*;

5.3.1.12 subject to sections 5.3.7 and 5.3.8, disclosure by the *IESO* of *confidential information* to a *market monitoring unit* relating to an investigation regarding conduct or activities which may have an adverse impact on market efficiency or effective competition; or

5.3.1.13 subject to section 5.3.10 and at the sole discretion of the *IESO*, disclosure by the *IESO* of *confidential information* in the form of a *basecase,* for the purposes of conducting reliability based power system studies directly to, or to a consultant of, a *market participant*, a *connection applicant,* or to a person planning to construct or modify a *facility*.

5.3.2 Prior to making any disclosure pursuant to section 5.3.1.2(b), the person wishing to disclose the information shall inform the proposed recipient of the confidential nature of the *confidential information* to be disclosed and shall use all reasonable endeavours, including but not limited to the execution of an appropriate confidentiality agreement, to ensure that the recipient keeps the *confidential information* confidential in accordance with the provisions of section 5.2 and does not use the *confidential information* for any purpose other than that permitted under section 5.3.1.2(b).

5.3.3 Prior to making any disclosure pursuant to section 5.3.1.4, 5.3.1.5 or 5.3.1.5A, a person being requested or demanded to disclose the *confidential information* shall advise the person affected by the request or demand as soon as reasonably practicable so as where possible to permit the affected person to challenge such request or demand or seek terms and conditions in respect of any such disclosure.

5.3.4 In making any disclosure pursuant to section 5.3.1.6, the disclosing person shall advise the person affected by the disclosure as soon as is reasonably practicable and shall use all reasonable endeavours to protect the confidentiality of the *confidential information* insofar as may be reasonably practicable in the circumstances.

5.3.5 Where the *IESO* makes any disclosure pursuant to section 5.3.1.8:

5.3.5.1 [Intentionally left blank – section deleted]

5.3.5.2 the *transmitter* to whom the disclosure is made shall use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.8 and shall use all reasonable endeavours to protect the confidentiality of such *confidential information*.

5.3.6 Where the *IESO* makes any disclosure pursuant to section 5.3.1.9:

5.3.6.1 the *IESO* shall advise the *market participant* affected by the disclosure as soon as is reasonably practicable in the circumstances; and

5.3.6.2 the *market participant* to whom the disclosure is made shall use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.9 and shall use all reasonable endeavours to protect the confidentiality of such *confidential information* as may be reasonably practicable in the circumstances.

5.3.7 Where the *IESO* proposes to disclose any *confidential information* pursuant to section 5.3.1.12 the *IESO* shall either require the *market monitoring unit* to demonstrate that their governing documents limit further disclosure, or enter into a non-disclosure agreement with the *market monitoring unit.* The *market monitoring unit's* governing documents or non-disclosure agreement shall:

5.3.7.1 establish a legally enforceable obligation to treat *confidential information* provided by the *IESO* as confidential. Such obligation shall be of a continuing nature and survive the termination of any investigation for which the *confidential information* has been requested;

5.3.7.2 require the *market monitoring unit* to whom the disclosure is made to promptly notify the *IESO* of any third party requests for additional disclosure of the *confidential information* and seek appropriate relief to prevent or, if it is not possible to prevent, to limit disclosure in the event that a subpoena or other compulsory process seeks to require disclosure of *confidential information* provided by the *IESO*;

5.3.7.3 require the *market monitoring unit* to whom the disclosure is made to use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.12, and to use all reasonable endeavours to protect the confidentiality of such *confidential information* as may be reasonably practicable in the circumstances; and

5.3.7.4 require the *market monitoring unit* to whom the disclosure is made to destroy or return *confidential information* provided by the *IESO* at the conclusion or resolution of the investigation or five *business days* after a request to destroy or return *confidential information* from the *IESO* is received by the *market monitoring unit*.

5.3.8 Prior to making any disclosure pursuant to section 5.3.1.12, the *IESO* shall advise the *market participant* affected by the request as soon as reasonably practicable so as where possible to permit the affected *market participant* to challenge such request or seek terms and conditions in respect of any such disclosure. The *IESO* shall not be required to advise the affected *market participant* if the *IESO* reasonably determines that such notification will jeopardize the investigation.

5.3.9 *Confidential information* provided by a *market monitoring unit* to the *IESO* shall be destroyed or returned to the *market monitoring unit* that provided the *confidential information* at the conclusion or resolution of the investigation or five *business days* after a request to destroy or return *confidential information* from the *market monitoring unit* is received by the *IESO.*

5.3.10 Prior to making any disclosure pursuant to section 5.3.1.13, the *IESO* shall enter into a non-disclosure agreement directly with, or with the consultant of, a *market participant,* a *connection applicant,* or with a person planning to construct or modify a *facility*. The non-disclosure agreement shall:

5.3.10.1 establish a legally enforceable obligation to treat *confidential information* provided by the *IESO* as confidential. Such obligation shall be of a continuing nature and survive the completion of any reliability based power system study for which the *confidential information* was required;

5.3.10.2 require that the *confidential information* so disclosed is used solely for the purposes referred to in the non-disclosure agreement and in section 5.3.1.13, and to use all reasonable efforts to protect the confidentiality of such *confidential information*; and

5.3.10.3 require the destruction or return of the *confidential information* provided by the *IESO* at the conclusion of the reliability based power system study, or five *business days* after a request for the destruction or return of the *confidential information* from the *IESO* is received.

5.4 Classification of Information

5.4.1 The *IESO* shall establish the following three levels of *confidentiality classification* for information that may be in the possession or control of the *IESO*:

5.4.1.1 public;

5.4.1.2 [Intentionally left blank]

5.4.1.3 [Intentionally left blank]

5.4.1.4 [Intentionally left blank]

5.4.1.5 confidential; and

5.4.1.6 highly confidential.

5.4.2 Subject to section 5.4.3, information in the possession or control of the *IESO* that is listed in the *information confidentiality catalogue* and that is identified therein as:

5.4.2.1 public is information that is not *confidential information* including, but not limited to, information required by the *market rules* or the *licence* of the *IESO* to be *published*, and may be disclosed to, accessed by, reproduced or used by any person without restriction;

5.4.2.2 [Intentionally left blank]

5.4.2.3 [Intentionally left blank]

5.4.2.4 [Intentionally left blank]

5.4.2.5 confidential is *confidential information* that is provided to the *IESO* by a *market participant*, a *standards authority*, a *security coordinator*, a *control area operator*, an *interconnected transmitter*, or that is provided to the *IESO* by a person other than a *market participant* and that relates to a *market participant*; or that originates with or is created by the *IESO* and that relates to a *market participant*, and may only be disclosed by the *IESO* to or accessed by:

a. where the *confidential information* was provided to the *IESO* by a person, that person;

b. any person that the *IESO* has reasonable grounds to believe has been authorized by the person referred to in section 5.4.2.5(a) to access or receive such *confidential information*;

c. any authorized person within the *IESO*; and

d. the *market participant* to whom the *confidential information* relates.

5.4.2.6 highly confidential is *confidential information* that is provided to the *IESO* by a *market participant,* or by a person other than a *market participant,* or that originated within or is created by the *IESO*, and requires restricted access within the *IESO*, and may only be disclosed by the *IESO* to or accessed by:

a. where the *confidential information* was provided to the *IESO* by a person, that person;

b. any person that the *IESO* has reasonable grounds to believe has been authorized by the person referred to in section 5.4.2.6(a) to access or receive such *confidential information*; and

c. any person within the *IESO* that has the required security clearance assigned by the *IESO* and requires the *confidential information* for the purpose of the due performance of that person's duties and responsibilities.

5.4.3 Where:

5.4.3.1 the *information confidentiality catalogue* provides, in respect of any particular item of *confidential information*, that such *confidential information* is to be automatically re-classified within a different *confidentiality classification* following the expiry of the period of time identified in the *information confidentiality catalogue*, such *confidential information* shall be deemed for all purposes to be re-classified within such other *confidentiality classification* on and after the expiry of such period of time;

5.4.3.2 *confidential information* is re-classified by the *IESO* within a different *confidentiality classification* in accordance with any one of sections 5.5.3 to 5.5.6, such *confidential information* shall be deemed for all purposes to be re-classified within such other *confidentiality classification* on and after the date of such re-classification.

5.4.4 Where the *IESO* amends the *information confidentiality catalogue* to include an additional item of information, the *IESO* shall classify such information within the *confidentiality classification* that is, in the *IESO's* opinion, appropriate having regard to:

5.4.4.1 the adverse impact that disclosure of the information may reasonably be expected by the *IESO* to have on:

a. the person that provides the information;
b. the person to whom the information relates or such other person as the *IESO* has reasonable grounds to believe may be adversely affected by disclosure of the information;
c. the efficient operation of the *IESO-administered markets*;
d. the *reliable* operation of the *IESO-controlled grid*;
e. the *IESO*; and
f. the security of the *integrated power system*, the *IESO-administered markets* or those of neighbouring jurisdictions.

5.4.4.2 [Intentionally left blank]

5.4.4.3 [Intentionally left blank]

5.4.4.4 [Intentionally left blank]

5.4.4.5 [Intentionally left blank]

5.4.4.6 the proprietary nature and degree of confidentiality of the information, to the extent known by the *IESO*; and

5.4.4.7 the *IESO's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *IESO* is a party.

5.4.5 Where a *market participant* provides to the *IESO* information that is not listed in the *information confidentiality catalogue*, the *IESO* shall:

5.4.5.1 subject to sections 5.4.6, 5.4.7, 5.4.9.2 and 5.4.10, classify that information within the *confidentiality classification* designated by the *market participant* in accordance with section 5.4.11 at the time that it provides such information to the *IESO* or pursuant to section 5.4.9.2(b); and

5.4.5.2 respect any restrictions requested by the person to be imposed in respect of the disclosure, use, reproduction or provision of access to such information that are additional to the restrictions pertaining to that *confidentiality classification* as described in section 5.4.2 unless, in the *IESO's* opinion, such additional restrictions:

a. would interfere with the ability of the *IESO* to maintain the *reliability* of the *IESO-controlled grid* or to operate the *IESO-administered markets* in an efficient manner; or

b. are inconsistent with the *IESO's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *IESO* is a party.

5.4.6 Where the *IESO* disagrees with the *confidentiality classification* designated by a *market participant* pursuant to section 5.4.5.1, the *IESO* shall so notify the *market participant*, which notice shall specify:

5.4.6.1 the grounds upon which the *IESO* disagrees with the *confidentiality classification* designated by the *market participant*;

5.4.6.2 the *confidentiality classification* that the *IESO* considers to be appropriate for the information; and

5.4.6.3 the time within which the *market participant* may make representations to the *IESO* in support of the *confidentiality classification* designated by it.

5.4.7 Following the time noted in section 5.4.6.3, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* shall:

5.4.7.1 where it agrees with the *confidentiality classification* designated by the *market participant*, classify the information within such *confidentiality classification*; or

5.4.7.2 where it continues to disagree with the *confidentiality classification* designated by the *market participant*, classify the information within the *confidentiality classification* referred to in section 5.4.6.2 or, subject to section 5.4.8, such other *confidentiality classification* that the *IESO* considers to be appropriate for the information,

and shall so notify the *market participant*.

5.4.8 For the purposes of section 5.4.7.2, the *IESO* shall not classify the information within a *confidentiality classification* other than the *confidentiality classification* referred to in section 5.4.6.2 unless such other *confidentiality classification* has, pursuant to section 5.4.2, associated with it provisions relating to disclosure and access that are more restrictive than those associated with the *confidentiality classification* referred to in section 5.4.6.2.

5.4.9 Where a *market participant* fails to designate a *confidentiality classification* for information submitted to the *IESO* pursuant to section 5.4.5.1 at the time at which it submits such information to the *IESO*, the *IESO* shall:

5.4.9.1 as soon as reasonably practicable following receipt of the information, notify the *market participant* that it must, within five *business days* of the date of receipt of the notice, designate a *confidentiality classification* for the information, failing which the *IESO* will classify the information within the confidential *confidentiality classification*; and

5.4.9.2 temporarily classify the information within the confidential *confidentiality classification* until:

a. the expiry of the period referred to in section 5.4.9.1 or within such longer period of time as may be agreed between the *IESO* and the *market participant*; or

b. the date on which the *market participant* designates a *confidentiality classification* for the information,

whichever is the earlier.

5.4.10 Where a *market participant* fails to designate a *confidentiality classification* for information submitted to the *IESO* pursuant to section 5.4.5.1 within the time referred to in section 5.4.9.2(a), the *IESO* shall classify the information within the confidential *confidentiality classification*.

5.4.11 For the purposes of sections 5.4.5.1 and 5.4.9.2(b), a *market participant* shall designate the *confidentiality classification* for information submitted pursuant to those sections having regard to:

5.4.11.1 the adverse impact that disclosure of the information may reasonably be expected by the *market participant* to have on itself;

5.4.11.2 the adverse impact that disclosure of the information may reasonably be expected by the *market participant* to have on any person to whom the information relates or on such other person as the *market participant* may have reasonable grounds to believe may be adversely affected by disclosure of the information;

5.4.11.3 the proprietary nature and degree of confidentiality of the information; and

5.4.11.4 the *market participant's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *market participant* is a party.

5.5 Reclassification of Information

5.5.1 The *confidentiality classification* of any *confidential information* that is referred to in the *information confidentiality catalogue*, that is in the possession or control of the *IESO* and that has not been automatically re-classified in accordance with section 5.4.3.1 shall be reviewed by the *IESO*:

5.5.1.1 in the case of *confidential information* other than *confidential information* classified as highly confidential, no less than once in every three calendar years; and

5.5.1.2 in the case of *confidential information* classified by the *IESO* as highly confidential, no less than once in every seven calendar years,

with a view to determining, in accordance with section 5.5.2, whether the *confidential information* can be re-classified within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than those associated with the existing *confidentiality classification*.

5.5.2 The *IESO* shall make the determination referred to in section 5.5.1 having regard to the factors noted in section 5.4.4.

5.5.3 Where the *IESO* determines, in accordance with the review conducted pursuant to section 5.5.1 that *confidential information* can be re-classified within another *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification*, the *IESO* shall:

5.5.3.1 [Intentionally left blank]

5.5.3.2 [Intentionally left blank]

5.5.3.3 where the *confidential information* was provided by a *market participant* or relates to a particular *market participant*, notify the *market participant* that provided the *confidential information* or to which the *confidential information* relates of its intention to re-classify the *confidential information*, which notice shall specify:

a. the grounds upon which the *IESO* has determined it appropriate to re-classify the *confidential information*;

b. the *confidentiality classification* that the *IESO* considers appropriate for purposes of the re-classification of the *confidential information*; and

c. the time within which the *market participant* may object to the re-classification of the *confidential information*.

5.5.4 Where:

5.5.4.1 a *market participant* fails, within the time referred to in section 5.5.3.3(c), to object to the re-classification of *confidential information* that relates to it but that was not provided by it to the *IESO*, the *IESO* may re-classify the information within the *confidentiality classification* referred to in section 5.5.3.3(b) or within such other *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are more restrictive than the *confidentiality classification* referred to in section 5.5.3.3(b), and shall notify the *market participant* accordingly;

5.5.4.2 a *market participant* fails, within the time referred to in section 5.5.3.3(c), to object to the re-classification of *confidential information* that was provided by it to the *IESO*, the *IESO* shall not re-classify the *confidential information*; or

5.5.4.3 a *market participant* objects to the re-classification of *confidential information* within the time referred to in section 5.5.3.3(c), the *IESO* shall not re-classify the *confidential information* except as may be agreed between the *IESO* and the *market participant*.

5.5.5 The *IESO* shall, at the request of a *market participant*, re-classify *confidential information* provided by that *market participant* within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification* provided that the *IESO* is satisfied that such re-classification would not be inconsistent with the factors referred to in section 5.4.4.

5.5.6 Where a *market participant* indicates, at the time at which it designates a *confidentiality classification* for *confidential information* pursuant to section 5.4.5.1, that the *confidential information* may be automatically re-classified within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification*, the *IESO* shall re-classify such *confidential information* accordingly provided that the *IESO* is satisfied that such re-classification would not be inconsistent with the factors referred to in section 5.4.4.

5.5.7 Amendments to the *information confidentiality catalogue* shall be subject to review by the *technical panel* and approval by the *IESO Board* until the end of 2003.

5.6 Cost of Access and Electronic Data Sharing

5.6.1 Nothing in this section 5 shall prevent information which is made available by means of electronic communications from being provided on a read-only basis.

5.6.2 Each *market participant* and any other person accessing, retrieving or storing information *published* or otherwise made available by the *IESO* shall be responsible for its own costs of accessing, retrieving or storing such information.

5.7 Conditions of Access

5.7.1 Where a request for access to or disclosure of information in the possession or control of the *IESO* is made by a *market participant* pursuant to these *market rules*, the *IESO* shall only provide such access or disclosure if:

5.7.1.1 the *IESO* is satisfied that it is not precluded by these *market rules* from providing such access or disclosure to the *market participant;* and

5.7.1.2 the provision of such access or disclosure would not impose a significant burden on the *IESO*, having regard to the *IESO's* resources.

5.7.2 Where the *IESO* makes *confidential information* accessible by means of electronic communications, the *IESO* shall implement access control protocols that differentiate between *market participants* but that need not differentiate between individuals, whether within the same *market participant* or otherwise.

6. Enforcement

6.1 Introduction

6.1.1 This section sets forth the rules pursuant to which the *IESO* shall monitor, assess and enforce compliance with the *market rules*, including by means of the imposition of financial penalties, the issuance of non-compliance letters, *suspension orders, termination orders* and *disconnection orders* and the taking of such other enforcement actions as provided for in these *market rules*.

6.1.2 The *IESO* shall undertake such monitoring as it considers necessary to determine whether *market participants* are complying with the *market rules*.

6.2 Procedures Concerning Alleged Breaches of the Market Rules

6.2.1 This section shall not apply to the issuance by the *IESO* of a *suspension order* or a *termination order*, which shall be governed by the provisions of section 6.3A or 6.4, respectively, or to the issuance by the *IESO* of an order referred to in section 6.2A.1, which shall be governed by the applicable provisions of section 6.2A and 6.5.

6.2.1A This section 6 shall not apply in respect of:

6.2.1A.1 a breach of any performance standard set forth in the *market rules*; or

6.2.1A.2 a failure to pass a test set forth in the *market rules* or, where applicable, the *Ontario power system restoration plan*,

by an *ancillary service provider* in the provision of *regulation* or *black start capability* under a *contracted ancillary service* contract, which shall be governed, by the provisions of section 7 and by MR Ch.5 ss. 4.10.2.1 and 4.10.2.2.

6.2.2 Where the *market rules* provide for consequences or sanctions in respect of a breach by a *market participant* of a particular *market rule* or *market rules*, those consequences or sanctions shall apply in the circumstances and in the manner provided for in the relevant sections of the *market rules* in addition to such sanctions as may be imposed pursuant to this section 6.2.

6.2.3 If the *IESO* considers, on its own initiative or upon receipt of written information from any person, that a *market participant* may have breached or may be breaching the *market rules* and that, in the circumstances and if the breach is established, it would be appropriate that a sanction or sanctions be imposed on that *market participant*, the *IESO* shall notify the *market participant* of:

6.2.3.1 details of the alleged breach and of the time within which the breach must be remedied;

6.2.3.2 details of the evidence on the basis of which the *IESO* considers that the *market participant* may have breached or may be breaching the *market rules*;

6.2.3.3 details of the sanctions which may be imposed if the breach is established;

6.2.3.4 the time within which the *market participant* may make written representations in response to the allegations; and

6.2.3.5 the right of the *market participant* to request a meeting with the *IESO* to discuss the matter.

6.2.4 Following expiry of the time noted in section 6.2.3.4, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* may:

6.2.4.1 determine that the *market participant* has not breached the *market rules*;

6.2.4.2 subject to section 6.2.5, determine that the *market participant* is in breach of the *market rules*;

6.2.4.3 request that the *market participant* provide further information in relation to the alleged breach; or

6.2.4.4 conduct such further investigation into the matter as the *IESO* determines appropriate.

6.2.5 Where a *market participant* has requested a meeting pursuant to section 6.2.3.5, the *IESO* shall provide the *market participant* with a reasonable opportunity to meet with the *IESO* to discuss the allegations. In such case, the *IESO* shall not make the determination noted in section 6.2.4.2 until such reasonable opportunity has been given.

6.2.6 A *market participant* shall comply with any request for information made by the *IESO* pursuant to section 6.2.4.3.

6.2.7 Subject to section 6.2.7A, where the *IESO* determines that a *market participant* has breached the *market rules*, the *IESO* may by order do any one or more of the following:

6.2.7.1 direct the *market participant* to do, within a specified period, such things as may be necessary to comply with the *market rules*;

6.2.7.2 direct the *market participant* to cease, within a specified period, the act, activity or practice constituting the breach;

6.2.7.3 impose additional or more stringent record-keeping or reporting requirements on the *market participant*;

6.2.7.4 issue a non-compliance letter in accordance with section 6.6;

6.2.7.5 impose financial penalties in accordance with section 6.6 indicating the time within which payment of the financial penalty must be made to the *IESO*, provided that no such penalties shall be imposed unless the *IESO* is satisfied that the breach could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; or

6.2.7.6 take such other action as may be provided for in Appendix 3.1 in respect of the *market rule* that has been breached by the *market participant*.

6.2.7A If the *IESO* is satisfied that the *market participant* has breached MR Ch.1 s.10A, and the *IESO* proposes to issue one or more orders under section 6.2.7, the *IESO* shall serve a *notice of intention* on the *market participant* in accordance with section 6.2B. The *IESO* may include in the *notice of intention* any or all alleged breaches of the *market rules* that were included in the notice issued under section 6.2.3. If the *IESO* does not include in the *notice of intention* an alleged breach described in the notice issued under section 6.2.3, excluding an alleged breach of MR Ch.1 s.10A, then the *IESO* may make one or more orders under section 6.2.7 respecting that alleged breach.

6.2.8 An order imposing financial penalties on a *market participant* pursuant to section 6.6 shall, subject to section 2.3.3, be considered to create an obligation under the *market rules* to pay the amount stated in the order and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

6.2.9 Failure to comply with an order of the *IESO* made pursuant to section 6.2.7 constitutes a breach of the *market rules*.

6.2A Persistent Breaches of the Market Rules

6.2A.1 If a *market participant* has breached the *market rules* on a persistent basis, the *IESO* may:

6.2A.1.1 issue that *market participant* a *suspension order* under section 6.3A;

6.2A.1.2 issue that *market participant* a *termination order* under section 6.4; or

6.2A.1.3 deregister some or all of the *market participant's facilities* and any associated *resources* under section 6.5.

6.2A.2 Where the *IESO* intends to act pursuant to section 6.2A.1, the *IESO* shall provide the *market participant* with a notice stating:

6.2A.2.1 the nature of the action to be taken;

6.2A.2.2 the grounds and any evidence on which the *IESO* relies on in support of the intended action;

6.2A.2.3 the time within which the *market participant* may make written representations to the *IESO* as to why such action should not be taken; and

6.2A.2.4 the right of the *market participant* to request a hearing before the *IESO Board* or a committee of the *IESO Board* established for such purpose to show cause why such action should not be taken.

6.2A.3 The *IESO* shall provide a copy of any notice issued under section 6.2A.2 to the *OEB* and to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are connected.

6.2A.4 If the *market participant* has requested a hearing, the *IESO Board* or a committee of the *IESO Board* established for such purpose shall conduct a hearing providing the *market participant* with a reasonable opportunity to show cause as to why such action should not be taken against it. Following the hearing, the *IESO Board* or the committee of the *IESO Board* established for such purpose may:

6.2A.4.1 approve the action that the *IESO* intends to take; or

6.2A.4.2 make any other appropriate order, including an order referred to in section 6.2.7.

6.2A.5 If the *market participant* has not requested a hearing, the *IESO* shall consider any written representations received from the *market participant* and may take any action specified in the notice issued under section 6.2A.2 or make any other appropriate order, including an order referred to in section 6.2.7.

6.2A.6 The *IESO* shall *publish* a notice of any actions taken under section 6.2A.4 or 6.2A.5 and provide a copy to the *OEB* and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are connected.

6.2B Alleged Breaches of Section 10A of Chapter 1

6.2B.1 For the purposes of section 6.2B, excluding sections 6.2B.19 and 6.2B.20, a reference to MR Ch.1 s.10A shall be deemed to include all breaches described in the *notice of intention*.

6.2B.2 If the *IESO* is satisfied that the *market participant* has breached MR Ch.1 s.10A, the *IESO* shall, prior to making any order under section 6.2.7, serve a written *notice of intention* on the *market participant*. The notice shall set out the following:

6.2B.2.1 the *market rules* that the *IESO* is satisfied that the *market participant* has breached;

6.2B.2.2 the reasons the *IESO* intends to determine that the *market participant* has breached MR Ch.1 s.10A;

6.2B.2.3 the proposed order or orders under section 6.2.7;

6.2B.2.4 the *market participant's* right to contest the *notice of intention* pursuant to section 6.2B.3; and

6.2B.2.5 the time within which the *market participant* may contest the *notice of intention*.

6.2B.3 If the *market participant* wishes to contest the *notice of intention*, it shall serve a *response to the notice of intention* on the *IESO* within 20 *business days* of receipt of the *notice of intention*.

6.2B.4 If the *market participant* does not contest the *notice of intention* within 20 *business days* of the receipt of the *notice of intention*, the *IESO* may determine that the *market participant* has breached MR Ch.1 s.10A and impose one or more orders under section 6.2.7.

6.2B.5 If the *market participant* contests the *notice of intention*, the *market participant* and the *IESO* shall attempt to resolve the matter through good faith negotiations in accordance with sections 2.5.3A and 2.5.3B, except that the *response to the notice of intention* shall replace the *notice of dispute* referred to in section 2.5.3A and shall be served in accordance with section 2.5.1A.4D.

6.2B.6 Notwithstanding sections 2.5.3C and 2.5.4, if the parties are unable to resolve the matter through good faith negotiations, the mediation process described in section 2.6 shall apply and either party may file with the *secretary* on written notice to each other party a copy of the *notice of intention* and *response to the notice of intention* together with proof of service. The *secretary* and *mediator* shall rely on the *notice of intention* and *response to the notice of intention* in lieu of the *notice of dispute* and *response* for the purposes of section 2.6. The *IESO* shall provide a summary of the matter for *publication* in accordance with section 2.9.2.1.

6.2B.7 If the parties are unable to resolve the matter through the mediation process, then within 5 *business days* of the filing of the written notice terminating the mediation process, as referred to in section 2.6.1B, 2.6.13 or 2.6.16, the *market participant* shall file with the *secretary* and serve on the *IESO* a *notice to elect* electing one of the following available options:

6.2B.7.1 that the matter be referred to an *arbitrator* pursuant to the process described in section 2.7;

6.2B.7.2 that the *IESO* apply to the *Ontario Energy Board* to make a determination and findings of fact as described in section 6.2B.11; or

6.2B.7.3 not to pursue the matter under either subsections 6.2B.7.1 or 6.2B.7.2.

6.2B.8 Where the *market participant* elects not to pursue the matter under section 6.2B.7.3 or does not make any election as described in section 6.2B.7, the *IESO* may determine that the *market participant* has breached MR Ch.1 s.10A and impose one or more orders under section 6.2.7.

6.2B.9 Where the *market participant* elects that the matter be referred to an *arbitrator* pursuant to section 6.2B.7.1, section 2.7 shall apply. For the purposes of section 2.7, the *IESO* shall be deemed to be the *applicant* and the *market participant* shall be deemed to be the *respondent*.

6.2B.10 Where the *market participant* elects that the *IESO* apply to the *Ontario Energy Board* pursuant to section 6.2B.7.2, the *IESO* shall bring the application to the *Ontario Energy Board* within 20 *business days* of the service of the *notice to elect*.

6.2B.11 In an application brought pursuant to section 6.2B.10, the *IESO* shall request that the *Ontario Energy Board* make the following:

6.2B.11.1 a determination of whether the *market participant* has breached MR Ch.1 s.10A; and

6.2B.11.2 findings of fact relevant to the imposition of one or more orders by the *IESO* under section 6.2.7.

6.2B.12 Where the *IESO* applies for a hearing before the *Ontario Energy Board* pursuant to section 6.2B.10 and the *Ontario Energy Board* dismisses the proceeding without a hearing under subsection 4.6(1)(b) of the *Statutory Powers Procedure Act*, the *notice to elect* shall be deemed to be a request for arbitration under section 6.2B.7.1 and the *IESO* shall refer the matter to an *arbitrator* in accordance with section 6.2B.9.

6.2B.13 Where the *Ontario Energy Board* holds a hearing referred to in section 6.2B.11 and determines that the *market participant* has not breached MR Ch.1 s.10A, subject to any rights of appeal or review, the *IESO* shall adopt the *Ontario Energy Board*'s findings.

6.2B.14 Where the *Ontario Energy Board* holds a hearing referred to in section 6.2B.11 and determines that the *market participant* has breached MR Ch.1 s.10A, subject to any rights of appeal or review, the matter shall return to the *IESO* and the *IESO* shall adopt the *Ontario Energy Board's* determination on breach.

6.2B.15 Where the matter returns to the *IESO* under section 6.2B.14, the *IESO* may issue one or more orders pursuant to section 6.2.7 and, in doing so:

6.2B.15.1 shall adopt and apply all findings of fact made by the *Ontario Energy Board;* and

6.2B.15.2 may adopt and apply any information from the record of the hearing before the *Ontario Energy Board*,

that are relevant to the order or orders under section 6.2.7 but may not rely on any additional evidence.

6.2B.16 If the *market participant* wishes to dispute the *IESO*'s order or orders issued pursuant to section 6.2B.15, it shall serve a *notice of dispute* on the *IESO* within 20 *business days* of receipt of the order or orders.

6.2B.17 Where the *market participant* disputes the order or orders issued by the *IESO* pursuant to section 6.2B.15, the *market participant* and the *IESO* shall attempt to resolve the matter in accordance with sections 2.5 and 2.6.

6.2B.18 The arbitration process set out in section 2.7 shall not apply to disputes as described in section 6.2B.16. An order issued under section 6.2B.15 may be appealed as provided for in section 36 of the *Electricity Act, 1998* upon the filing of a notice under section 2.6.1B, 2.6.13 or 2.6.16 terminating the mediation process.

6.2B.19 The *IESO* shall, pursuant to section 6.2B.2, serve a *notice of intention* no later than six years after the day on which the alleged breach of MR Ch.1 s.10A was discovered by the *IESO*. Where the *IESO* fails to serve a *notice of intention* within the time provided, no finding of breach of MR Ch.1 s.10A shall be made pursuant to the *market rules* in respect of that conduct.

6.2B.20 For the purposes of section 6.2B.19, the term "discovered" has the meaning prescribed in section 5(1) of the *Limitations Act, 2002*.

6.3 Events of Default

6.3.1 An *event of default* occurs if a *market participant* or the person that has provided *prudential support* or *capacity prudential support* in relation to the *market participant*:

6.3.1.1 does not make a payment in full required under the *market rules* when due;

6.3.1.2 fails to provide payment in full of any amount claimed by the *IESO* under any *prudential support* or *capacity prudential support;*

6.3.1.3 fails to provide and maintain *prudential support* or *capacity prudential support* required to be supplied under the *market rules* within the time required;

6.3.1.4 has a licence (including a *licence*), permit or other authorization necessary to carry on its principal business suspended, revoked or otherwise cease to be in full force and effect, provided that where a *market participant* holds more than one *licence* and only one such *licence* has been suspended, revoked or otherwise ceases to be in full force and effect, the *event of default* and any action taken by the *IESO* with respect thereto shall relate only to such *licence*;

6.3.1.5 ceases or threatens to cease to carry on its business or a substantial part of its business;

6.3.1.6 becomes insolvent or is unable to pay all or some of its debts when they fall due for payment;

6.3.1.7 seeks to enter into an arrangement, composition or compromise with, or makes an assignment for the benefit of, all or any class of its creditors;

6.3.1.8 has a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction appointed in respect of any of its property that is used in or relevant to the performance of its obligations under the *market rules* or its *licence*;

6.3.1.9 is the subject of an order appointing an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any jurisdiction;

6.3.1.10 is wound up, dissolved, or otherwise has ceased to exist or is the subject of an application for winding up or dissolution, or any analogous procedure, under the laws of any jurisdiction, unless the notice of winding up or dissolution is discharged or withdrawn; or

6.3.1.11 ceases to satisfy any material requirement imposed upon it as a condition of its authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

6.3.2 A *market participant* shall notify the *IESO* immediately upon:

6.3.2.1 the occurrence of an *event of default* or any circumstance that may give rise to an *event of default* referred to in sections 6.3.1.4 to 6.3.1.11; or

6.3.2.2 the appointment of a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction in respect of any property of the *market participant* or the *market participant's prudential support* provider, or *capacity prudential support* provider.

6.3.3 Where a *market participant* or a person providing *prudential support* or *capacity prudential support* on behalf of that *market participant* commits an *event of default,* the *IESO* may:

6.3.3.1 issue to the *market participant* a *notice of intent to suspend* stating that the *market participant* will be suspended unless it remedies the *event of default* within 2 *business days* or such longer period as specified in the notice;

6.3.3.2 immediately draw upon part or all of the *market participant's prudential support* or *capacity prudential support* for either the amount of any money owing to the *IESO* under the *market rules* or where the *market participant's prudential support* or *capacity prudential support* is due to expire or terminate and has not been replaced as required under MR Ch.2 s.5.2.5 or s.5B.2.4 the undrawn part of the *prudential support* or *capacity prudential support* notwithstanding the provisions of MR Ch.2 s.5.7.2.5

until such time as the *market participant* has replaced its *prudential support* or *capacity prudential support*; and

6.3.3.3 set-off any amounts due or credited to the *market participant* under the *market rules* and any program administered through the billing and *settlement* systems of the *IESO* against any amounts owed by the *market participant.*

6.3.4 Where the *IESO* issues a *notice of intent to suspend* under section 6.3.3.1 or a *suspension order* under sections 6.3A.1.1 and 6.3A.1.2 to a *market participant* that is a party to a *physical bilateral contract,* the *IESO* shall:

6.3.4.1 deem any *physical bilateral contract quantities* to be zero for the period from the date the *event of default* occurs until it is remedied if that *market participant* is the *selling market participant*; or

6.3.4.2 rescind or refuse to accept any initial or revised *physical bilateral contract data* relating to a *dispatch day* after the date of the *event of default* if that *market participant* is the *buying market participant*.

6.3.5 [Intentionally left blank – section deleted]

6.3.6 A *market participant* may remedy an *event of default* by:

6.3.6.1 satisfying any outstanding financial or other obligations that gave rise to the *event of default,* including any applicable *default interest* and any costs and expenses incurred by the *IESO* as a result of the *event of default*; and

6.3.6.2 proving to the reasonable satisfaction of the *IESO* that the facts or circumstances which constituted the *event of default* no longer exist.

6.3.7 Notwithstanding that the *event of default* has been remedied, the *IESO* may impose any condition on the right of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including:

6.3.7.1 establishing a lower *trading limit* in respect of the *market participant* than would otherwise be the case under MR Ch.2 ss.5.3, 5C.1 and 5D.2, as applicable;

6.3.7.2 establishing a more frequent continuing schedule of payments than would otherwise be the case under MR Ch.9; or

6.3.7.3 imposing a more stringent *prudential support obligation* than would otherwise be the case under MR Ch.2 ss.5, 5B, 5C and 5D as applicable .

6.3A Suspension of a Market Participant

6.3A.1 The *IESO* may issue a *suspension order* to a *market participant* if:

6.3A.1.1 the *market participant* has not remedied an *event of default* within the time specified in the *notice of intent to suspend*;

6.3A.1.2 an *event of default* specified in sections 6.3.1.5 to 6.3.1.10 has occurred in relation to the *market participant*; or

6.3A.1.3 the *IESO* has determined under section 6.2A that a *suspension order* should be issued because the *market participant* has persistently breached the *market rules*.

6.3A.2 The *IESO* shall *publish* the details of the *suspension order* and provide a copy of the *suspension order* to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *suspended market participant* is connected.

6.3A.3 To the extent specified in the *suspension order,* a *suspended market participant* is ineligible to trade or enter into any transaction in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

6.3A.4 The *IESO* may do one or more of the following to give effect to a *suspension order*:

6.3A.4.1 reject any *bid*, *offer* or *TR bid* submitted by the *suspended market participant*;

6.3A.4.2 set-off any amounts otherwise due to the *suspended market participant* against any amounts owed by the *suspended market participant* under the *market rules*;

6.3A.4.3 issue a *disconnection order* to the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *suspended market participant's facilities* are connected and provide a copy to the *OEB*; or

6.3A.4.4 make such further order or issue such directions to the *suspended market participant* as the *IESO* determines appropriate.

6.3A.5 The *IESO* shall lift a *suspension order* if the *event of default* which triggered its issuance is remedied to the satisfaction of the *IESO* and there are no other *events of default* in existence with respect to the *suspended market participant*.

6.3A.6 Notwithstanding that the *suspension order* has been lifted, the *IESO* may impose any condition on the right of a *market participant* that has been subject of a *suspension order* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.4 Termination of a Market Participant

6.4.1 The *IESO* may issue a *termination order* to a *market participant* if:

6.4.1.1 the *market participant* is a *suspended market participant* and has not remedied the *event of default* that triggered the *suspension order* within 5 *business days* of the issuance of the *suspension order*;

6.4.1.2 the *market participant* is a *suspended market participant* and has notified the *IESO* that the *market participant* is not likely to remedy the *event of default* that triggered the issuance of the *suspension order*;

6.4.1.3 the *market participant* has been wound up, dissolved, or otherwise has ceased to exist; or

6.4.1.4 the *IESO* has determined under section 6.2A that a *termination order* should be issued because the *market participant* has persistently breached the *market rules*.

6.4.2 The *IESO* shall *publish* the details of the *termination order* and provide a copy of the *termination order* to the *OEB* and to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected.

6.4.3 When the *IESO* issues a *termination order*, it may at the same time, if it has not already done so, issue a *disconnection order* to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

6.4.4 A *terminated market participant* that re-applies for authorization shall be required to comply with the provisions of MR Ch.2 s.3. The *IESO* may impose any conditions on the right of the *terminated market participant* to participate in *the IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of *the IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.5 De-Registration of a Market Participant's Facilities

6.5.1 The *IESO* may deregister some or all of a *market participant's facilities* and any associated *resources* if the *IESO* has determined under section 6.2A that the *market participant* has persistently breached the *market rules*.

6.5.2 Deregistering some or all of a *market participant's facilities* or *resources* terminates all of the rights of the *market participant* in respect of those *facilities* or *resources* to participate in the *IESO-administered markets* or in respect of those *facilities* or *resources* to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of those *facilities* or *resources*.

6.5.3 If the *IESO* deregisters some or all of a *market participant's facilities* or *resources*, it may at the same time issue a *disconnection order* to the relevant *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* which is subject of the deregistration are connected and provide a copy to the *OEB*.

6.5.4 A *market participant* that wishes to re-register *facilities* or *resources* that have been deregistered shall comply with the provisions of section 2 of Chapter 7. The *IESO* may impose any conditions on right of the *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.5A Disconnection Order

6.5A.1 Each *transmitter, distributor* and other *market participant* to whom a *disconnection order* is issued pursuant to sections 6.3A.4.3, 6.4.3 or 6.5.3 shall, subject to this section 6.5A, on the date and at the time specified in the *disconnection order*, *disconnect* the *facilities* or equipment referred to in the *disconnection order*.

6.5A.2 Nothing in this section 6.5A is intended to prevent a *transmitter, distributor* or other *market participant* from taking action to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*; provided, however, that such *transmitter, distributor* or other *market participant* shall coordinate to the fullest extent practicable any such action with the *IESO*.

6.5A.3 Without limiting the generality of MR Ch.1 s.8.3, a *disconnection order* may be issued by the *IESO* to a *transmitter, distributor* or other *market participant* pursuant to sections 6.3A.4.3, 6.4.3 or 6.5.3 by voice communication.

6.6 Non-compliance Letters and Financial Penalties

6.6.1 This section 6.6 sets forth the manner in which the *IESO* will pursuant to section 6.2.7 issue non-compliance letters and fix financial penalties to be imposed on *market participants* for breaches of the *market rules*.

6.6.2 Where the *IESO* has determined that it is appropriate to issue a letter of non-compliance or impose a financial penalty upon a *market participant*, the *IESO* shall:

6.6.2.1 determine the level of non-compliance by the *market participant* in accordance with section 6.6.3;

6.6.2.2 determine the rate of recurrence of non-compliance by the *market participant* in accordance with section 6.6.4;

6.6.2.3 based on the determinations made in accordance with sections 6.6.2.1 and 6.6.2.2, issue a non-compliance letter or impose a financial penalty; and

6.6.2.4 where a determination is made to impose a financial penalty, fix the amount of the penalty in accordance with section 6.6.6.

6.6.2A When determining the particular level of non-compliance referred to in section 6.6.2.1, the *IESO* shall establish:

- whether all of the conditions for a level have been met; and
- that the manner and time, proposed by the *market participant*, within which the non-compliance event will be remedied are reasonable under the circumstances.

If a *market participant*

- meets some but not all of the conditions of any single level; or
- proposes a manner and time in which the non-compliance event will be remedied that are not reasonable under the circumstances in the opinion of the *IESO*,

then the *IESO* shall assign what it considers to be the appropriate non-compliance level.

6.6.3 The *IESO* shall determine the level of non-compliance referred to in section 6.6.2.1 as follows:

6.6.3.1 Level "L1" shall apply where the *market participant*:

i. failed to comply, in part, with the requirements of a *market rule*, and
ii. on its own initiative informed the *IESO* on a timely basis of:
    - the reasons for the non-compliance, and
    - the manner and time in which the non-compliance will be remedied.

6.6.3.2 Level "L2" shall apply where the *market participant*:

i. failed to comply in whole with the requirements of a *market rule*, and
ii. on its own initiative informed the *IESO* on a timely basis of:
    - the reasons for the non-compliance, and

- the manner and time in which the non-compliance will be remedied.

6.6.3.3 Level "L3" shall apply where the *market participant*:

i. failed to comply, in whole or in part, with the requirements of a *market rule*,

ii. did not on its own initiative inform the *IESO* on a timely basis of the non-compliance; but

iii. did inform, at the *IESO's* request and within the time specified in the request, the *IESO* of:

- the reasons for the non-compliance, and
- the manner and time in which the non-compliance will be remedied.

6.6.3.4 Level "L4" shall apply where the *market participant*:

i. failed to comply, in whole or in part, with the requirements of a *market rule*,

ii. did not on its own initiative inform the *IESO* on a timely basis of the non-compliance; and

iii. did not inform, at the *IESO's* request and within the time specified in the request, the *IESO* of:

- the reasons for the non-compliance, and
- the manner and time in which the non-compliance will be remedied.

6.6.4 The *IESO* shall determine the rate of recurrence of non-compliance referred to in section 6.6.2.2 based on the frequency and duration with which the *market participant* has been found by the *IESO* to be in breach of the *market rules*.

6.6.5 [Intentionally left blank – section deleted]

6.6.6 Where the *IESO* has determined, based on the determinations made under section 6.6.2, that the applicable sanction is the imposition of a financial penalty, the *IESO* shall, subject to section 6.6.6A, consider the factors listed in section 6.6.7 and impose a financial penalty on the *market participant* within the ranges set out in the following table.

Level of Non-Compliance	Range of Sanctions
L1	Non-compliance letter or up to $2,000.00

Level of Non-Compliance	Range of Sanctions
L2	Non-compliance letter or up to $4,000.00
L3	Non-compliance letter or up to $6,000.00
L4	$1,000.00 to $10,000.00

6.6.6A The *IESO* may impose on a *market participant* a financial penalty in excess of the amount otherwise provided for in section 6.6.6 and no greater than $1,000,000 per occurrence, where:

6.6.6A.1 the *market participant* has breached a *market rule* while a declaration that the *IESO controlled grid* is in an *emergency operating state* or a *high-risk operating state* was in effect;

6.6.6A.2 the *market participant* breached a *market rule* while a declaration that *market operations* have been suspended was in effect;

6.6.6A.3 the *IESO Board* determines that the impact of the *market participant*'s breach of a *market rule* on either the *IESO-administered markets* or the *reliability* of the *integrated power system* is particularly severe; or

6.6.6A.4 the rate of recurrence of non-compliance by the *market participant* with the *market rules* is of such frequency or duration as to warrant the imposition of a higher financial penalty.

6.6.6B Where at least one of the conditions of 6.6.6A are met and the *IESO* has determined that the applicable sanction is the imposition of a financial penalty, the *IESO* shall, consider the factors listed in section 6.6.7 and impose a financial penalty on the *market participant* within the ranges set out in the following table.

	Non-Compliance Level (Severity and Breach History)							
Impact Level	**Low**		**Moderate**		**High**		**Severe**	
	Range Limit		Range Limit		Range Limit		Range Limit	
	Min	Max	Min	Max	Min	Max	Min	Max
Low Little or None	$2,000	$25,000	$2,000	$50,000	$3,000	$75,000	$5,000	$100,000
Medium Material	$2,000	$100,000	$4,000	$250,000	$6,000	$450,000	$10,000	$600,000

	Non-Compliance Level (Severity and Breach History)							
High Severe	$4,000	$250,000	$8,000	$500,000	$12,000	$750,000	$20,000	$1,000,000

The *IESO* shall establish the penalty range at the intersection of the determined impact level and non-compliance level in accordance with the applicable *market manual* as follows:

6.6.6B.1 The *IESO* shall determine the impact level by examining all the impacts of the breach under investigation and selecting an appropriate impact level; and

6.6.6B.2 The *IESO* shall determine the non-compliance level by examining breach history contributions, severity, and any aggravating or mitigating adjustments.

6.6.7 In fixing the amount of the financial penalty within the ranges described in the tables set forth in sections 6.6.6 and 6.6.6B, the *IESO* shall have regard to:

6.6.7.1 the circumstances in which the breach occurred;

6.6.7.2 the severity of the breach;

6.6.7.3 the extent to which the breach was inadvertent, negligent, deliberate or otherwise;

6.6.7.4 the length of time the breach remained unresolved;

6.6.7.5 the actions of the *market participant* on becoming aware of the breach;

6.6.7.6 whether the *market participant* disclosed the matter to the *IESO* on its own or whether it was prompted to do so;

6.6.7.7 any benefit that the *market participant* obtained or may have obtained as a result of the breach;

6.6.7.8 any previous breach by the *market participant* of the *market rules* or of the conditions of its *licence*;

6.6.7.9 the actual or potential impact of the breach on other *market participants*;

6.6.7.10 the actual or potential impact of the breach on the *IESO-administered markets* as a whole;

6.6.7.10A the actual or potential impact of the breach on the *reliability* of the *integrated power system*;

6.6.7.11 any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach;

6.6.7.12 the immediacy of the threat that the breach poses to the *reliability* of the *integrated power system* or the *IESO-administered market*;

6.6.7.13 presence and quality of the *market participant*'s compliance program;

6.6.7.14 whether on its own initiative, a *market participant* has undertaken to reasonably compensate the *IESO-administered market* for the value of any benefit it obtained as a result of the breach; and

6.6.7.15 such other matters as the *IESO* considers appropriate.

6.6.8 Where MR Ch.3 App. 3.1 provides for the imposition of a formula-based penalty in respect of the breach of a *market rule*, the *IESO* may issue a letter of non-compliance pursuant to section 6.6.2.3 or impose a financial penalty upon the *market participant*, the amount of which shall be determined by the application of the following formula:

$$P = D \times T \times C$$

Where:

P = the amount of the financial penalty, in dollars

D = the deviation from the applicable obligation in the *market rules*, expressed in terms of MW, MVAR, kV, power factor or other determinant, as specified in Appendix 3.1 in respect of the particular *market rule*

T = the duration of the breach, expressed in hours or fractions of hours

C = the amount determined in accordance with section 6.6.9 in respect of the particular *market rule*

6.6.9 The amount C referred to in section 6.6.8 shall be determined, in respect of the breach of a particular *market rule*, by multiplying the *market price* prevailing at the time of the breach by an amount determined by the *IESO* having regard to the criteria set forth in section 6.6.7 and to the factors noted in sections 6.6.6A.1 to 6.6.6A.4, where applicable.

6.6.10 Where MR Ch.3 App.3.1 specifies more than one sanction in respect of the breach of a particular *market rule*, the *IESO* may impose all of the sanctions so specified on the *market participant* provided that no financial penalty may be imposed in respect of a breach for which the *IESO* has issued a letter of non-compliance pursuant to section 6.6.2.3. Nothing in this section 6.6.10 shall prevent the *IESO* from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a letter of non-compliance has been issued or if there is any repetition or continuation of such breach.

6.6.10A In respect of a breach of MR Ch.7 s.7.5.8A, the *IESO* may:

6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the *market participant* pursuant to sections 6.6.2.3, and 6.6.6; and

6.6.10A.2 adjust *settlement amounts* paid or payable to a *registered market participant* such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts* that the *registered market participant* received or avoided due to an act or omission or a course of conduct of either the *registered market participant* alone or the *registered market participant* by agreement or arrangement with one or more other *market participants* that led to the breach of MR Ch.7 s.7.5.8A.

6.6.11 Nothing in this section 6.6 shall preclude the *IESO* from making an order under one or more of sections 6.2.7.1, 6.2.7.2, 6.2.7.3 or 6.2.7.6 in respect of a breach of the *market rules* with respect to which a sanction has been imposed pursuant to this section 6.6.

6.6.12 [Intentionally left blank]

6.6.13 [Intentionally left blank – section deleted]

6.6.14 No additional financial penalty may be imposed in respect of a breach of the *market rules* for which a financial penalty has already been imposed pursuant to this section 6.6 provided that nothing in this section 6.6.14 shall prevent the *IESO* from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a financial penalty has been imposed or if there is any repetition or continuation of such breach.

6.7 Officers and Agents

6.7.1 If any director, officer, employee partner or agent of a *market participant* does any act or refrains from doing any act which if done or omitted to be done, as the case may be, by a *market participant* would constitute a breach of the *market rules*, such act or omission shall be deemed for the purposes of this section 6 to be the act or omission of the *market participant*.

7. Financial Penalties for Certain Contracted Ancillary Service Providers

7.1 Penalties Specified in Contracts

7.1.1 An *ancillary service provider* providing *regulation* or *black start capability* under a *contracted ancillary service* contract that:

7.1.1.1 breaches any performance standard set forth in the *market rules*; or

7.1.1.2 fails to pass a test set forth in the *market rules*, the *contracted ancillary service* contract or, where applicable, the *Ontario power system restoration plan*,

in respect of such *contracted ancillary service* shall be subject to such financial penalties and other *sanctions* as may be specified in the applicable *contracted ancillary service* contract and to the provisions of MR Ch.5 s.4.10.2.1.

RUL-10

Renewed Market Rules

Chapter 0.3

Administration, Supervision, Enforcement - Appendices

Connecting Today. Powering Tomorrow.

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Table of Contents

Appendix 3.1 – Application of Enforcement Actions

Non-compliance	**Enforcement Action**
Chapter 4, section 3.1.2	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 4, section 3.3.1.6	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 4, section 6.1.6	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 5, section 3.4.1.1	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.4.1.2	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required including its restoration (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.5.1.1	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required including its restoration (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.6.1.1	Formula based penalty as per section 6.6.8 where; D= nominal generation capacity (*MCR*) barring declared limitations (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9

Non-compliance	Enforcement Action
Chapter 5, section 3.7.1.1	Formula based penalty as per section 6.6.8 where; D= load shedding capability required (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 6.3.10	Formula based penalty as per section 6.6.8 where: D = the amount by which the *offer* made is less than the MW which the *generator* had agreed would be *offered* in support of the *planned outage* or the extension to or rescheduling of an *outage.* C = *market price* x amount to be determined by the *IESO* under section 6.6.9
App 5.1, section 1.2.1	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.4	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.2	Formula based penalty as per section 6.6.8 where; D= ramp rate deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.5	Formula based penalty as per section 6.6.8 where; D= ramp rate deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.

Non-compliance	Enforcement Action
App 5.1, section 1.2.3	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.6	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
Chapter 5, section 10.3.3	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 10.3.4	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 10.3.5	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9

RUL-11

Renewed Market Rules

Chapter 0.4

Grid Connection Requirements

0.4

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5. An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

1. Introduction

1.1.1 This Chapter sets forth rules to assist the *IESO* in maintaining the *reliability* of the *IESO-controlled grid* by:

1.1.1.1 requiring all *market participants* to adhere to established standards for all equipment *connected* to the *IESO-controlled grid* and to comply with certain other obligations relating generally to *connection* to the *IESO-controlled grid* and to participation in the *IESO-administered markets*; and

1.1.1.2 setting forth certain *reliability*-related obligations of *embedded generators* and *embedded electricity storage participants* that may not be *market participants*.

1.1.2 MR Ch.1 s.7.5 does not apply to this Chapter and any action or event that is required to occur on or by a stipulated time or day under this Chapter or pursuant to a direction, instruction, or order made by the *IESO* under this Chapter shall occur on or by that time, whether or not a business hour, or on or by that day, whether or not a *business day*, unless otherwise specified in this Chapter or in the direction, instruction or order of the *IESO*.

1.1.3 [Intentionally left blank]

1.1.4 Nothing in this Chapter is intended to prevent *market participants* from acting to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*, provided that the *market participants* coordinate any such actions that may affect the *reliability* of the *IESO-controlled grid* with the *IESO* to the fullest extent practicable.

2. Equipment Standards

2.1.1 All *market participants* shall ensure that their equipment and *facilities* connected to the *IESO-controlled grid* adhere to all applicable *reliability standards*.

2.1.2 All *market participants* shall maintain and operate their equipment and *facilities* in accordance with *applicable law*, *good utility practice* and all applicable *reliability standards*.

2.1.3 The standards described in this Chapter shall be implemented through compliance with the requirements of this Chapter, through *connection agreements* between *transmitters* and *market participants* that are *connected* or seek to *connect* to the

IESO-controlled grid and through *operating agreements* between the *IESO* and *transmitters*.

2.1.4 [Intentionally left blank]

2.1.5 No *transmitter* or *market participant* shall place into service a new or modified *connection facility* until the *IESO* has determined that the *connection facility* complies with this Chapter.

2.1.6 Nothing in this Chapter shall be deemed to interfere with the right of each *transmitter* and *distributor* to establish standards and criteria for the design, construction, and operation of equipment connected to their systems, provided that such standards and criteria:

2.1.6.1 are applied in a non-discriminatory manner to all *market participants* and *connection applicants connecting* or seeking to *connect* to the *IESO-controlled grid*;

2.1.6.2 satisfy *reliability standards* and any minimum general performance standards set forth in MR Ch.4 App.4.1; and

2.1.6.3 shall be subject to review by the *IESO* in the event there is a dispute regarding compliance with this section 2.1.6 and to the right of the *IESO* to override the application of such standards and criteria in the event it determines that they do not so comply.

2.1.7 Subject to compliance with the standards set forth in this Chapter and to sections 6.1.6 and 6.1.7, each *market participant* and *connection applicant* shall have the right to *connect* to the *IESO-controlled grid* or to modify its existing *connection facilities* to the *IESO-controlled grid* without undue delay.

3. Performance Standards and Obligations of Market Participants

3.1 General Requirement

3.1.1 The minimum general performance standards for all equipment *connected* to the *IESO-controlled grid* are set forth in Appendix 4.1. Specific performance standards applicable to the equipment of *generators*, *electricity storage participants, connected wholesale customers, distributors connected* to the *IESO-controlled grid* and *transmitters* are set forth in Appendices 4.2 to 4.4, respectively.

3.1.2 Each *market participant* shall ensure that its equipment connected to the *IESO-controlled grid* meets all applicable performance standards in Appendix 4.1 and each *generator*, *electricity storage participant, connected wholesale customer, distributor* connected to the *IESO-controlled grid* and *transmitter* shall ensure that its equipment connected to or forming part of the *IESO-controlled grid* meets all applicable performance standards in Appendices 4.2 to 4.4, respectively.

3.1.3 Each *embedded generator* or *embedded electricity storage participant* shall ensure that its equipment meets all applicable performance requirements in Appendix 4.3.

3.2 Development of Rules for Waivers of Standards

3.2.1 [Intentionally left blank]

3.2.2 [Intentionally left blank]

3.2.3 A *generator* or *electricity storage participant* may comply with its requirement to provide reactive power either by modifying any of its *generation units* or *electricity storage units* that do not comply with any standard with respect to the provision of reactive power, or by obtaining reactive power from other appropriate *generation units, electricity storage units* or *market participants.* The *IESO* shall determine whether these other *generation units, electricity storage units* or *market participants* are in sufficiently close electrical proximity to the non-compliant *generation unit* or *electricity storage unit* so as to provide the comparable or equivalent reactive power.

3.3 Obligations of Transmitters

3.3.1 Each *transmitter* shall:

3.3.1.1 [Intentionally left blank]

3.3.1.2 coordinate the design of equipment proposed to be *connected* to the *IESO-controlled grid* to achieve compliance with this Chapter;

3.3.1.3 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.3.1.4 [Intentionally left blank]

3.3.1.5 satisfy the data requirements set forth in this Chapter to model the static and dynamic performance of the *IESO-controlled grid*;

3.3.1.6 obtain the prior approval of the *IESO* for all changes in or removals of equipment or *facilities connected* to the *IESO-controlled grid* that could impact on the *reliable* operation of the *IESO-controlled grid*;

3.3.1.7 operate its portion of the *IESO-controlled grid* such that, during a *normal operating state*, electricity may be transferred continuously at a *connection point*;

3.3.1.8 operate its portion of the *IESO-controlled grid* such that the fault level at any *connection point* does not exceed the limits specified in the relevant *connection agreement*;

3.3.1.9 operate its portion of the *IESO-controlled grid* to minimize the number and duration of interruptions at a *connection point*;

3.3.1.9A follow *good utility practice* to promptly return *transmission facilities* and equipment to service after an interruption;

3.3.1.10 [Intentionally left blank]

3.3.1.11 [Intentionally left blank]

3.3.1.12 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.3.1.13 upon the request of the *IESO*, enter into an *operating agreement* with the *IESO*.

3.4 Obligations of Generators

3.4.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall:

3.4.1.1 [Intentionally left blank]

3.4.1.2 [Intentionally left blank]

3.4.1.3 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of its equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.4.1.4 [Intentionally left blank]

3.4.1.5 [Intentionally left blank]

3.4.1.6 operate its equipment in accordance with its *connection agreement*;

3.4.1.7 [Intentionally left blank]

3.4.1.8 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.4.1.9 notify the *IESO* upon the submission of a *connection request* to a *transmitter*.

3.5 Obligations of Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

3.5.1 Each *connected wholesale customer* and each *distributor connected* to the *IESO-controlled grid* shall:

3.5.1.1 [Intentionally left blank]

3.5.1.2 [Intentionally left blank]

3.5.1.3 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of its equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.5.1.4 [Intentionally left blank]

3.5.1.5 [Intentionally left blank]

3.5.1.6 operate its equipment in accordance with its *connection agreement*;

3.5.1.7 [Intentionally left blank]

3.5.1.8 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.5.1.9 notify the *IESO* of the submission of a *connection request* to a *transmitter* pursuant to section 3.5.1.1.

3.6 Obligations of Electricity Storage Participants

3.6.1 Each *electricity storage participant* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall:

3.6.1.1 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of its equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.6.1.2 operate its equipment in accordance with its *connection agreement*;

3.6.1.3 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.6.1.4 notify the *IESO* upon the submission of a *connection request* to a *transmitter.*

4. Connection Agreements

4.1.1 Each *connected wholesale customer* and each *distributor*, *generator* and *electricity storage participant* connected to the *IESO-controlled grid* shall have a signed *connection agreement*, in such form as may be prescribed by the *OEB*, with the applicable *transmitter* with whom it is *connected.*

4.1.2 *Market participants* shall have signed connection agreements for each embedded *facility*, in such form as may be prescribed by the *OEB*, with the applicable *distributor* with whom it is *connected.*

5. Compliance, Inspection, Testing, and Monitoring

5.1 General Requirements

5.1.1 Each *transmitter*, *generator, electricity storage participant, connected wholesale customer* or *distributor connected* to the *IESO-controlled grid* shall have the obligation to test and monitor its equipment to ensure and maintain compliance with all applicable *reliability standards* required by these *market rules*. The requirement to conduct and pay for such activities shall be specified in each *connection agreement*. If any *transmitter*, *generator, electricity storage participant, distributor* or *connected wholesale customer connected* to the *IESO-controlled grid* in respect of which no relevant waiver has been granted by the *IESO* fails to comply with the provisions of this Chapter, the *IESO* shall notify the *transmitter* and the *connecting* party of such non-compliance and shall ask that the parties achieve prompt compliance with this Chapter, subject to the imposition of such penalties for failure to comply as may be specified in these *market rules*. Pending such compliance, the *IESO* may direct the *transmitter* and the *connecting* party to operate their respective equipment and *facilities* so as to maintain the *reliability* of the *IESO-controlled grid*.

5.1.2 The results of all compliance monitoring and performance testing required by this Chapter to be performed shall be made available to the *IESO* upon request.

5.1.3 Each *transmitter, generator, electricity storage participant, distributor* and *connected wholesale customer connected* to the *IESO-controlled grid* shall maintain records that set forth the results of all performance testing and monitoring conducted to demonstrate compliance with this Chapter in each case for 7 years from the date of the testing or monitoring activity. Each *transmitter, generator, electricity storage participant, distributor* and *connected wholesale customer* shall make such records available to the *IESO* upon request.

5.1.4 Parties to a *connection agreement* shall bear the cost of monitoring and testing their equipment and *facilities* for compliance with this Chapter. The *IESO* may request a *transmitter, generator, electricity storage participant, distributor* or *connected wholesale customer connected* to the *IESO-controlled grid* to attach to its equipment or *facilities* such test or monitoring equipment as the *IESO* determines appropriate and that is not required by the relevant *connection agreement* to be so attached, provided that such test or monitoring equipment does not adversely affect the performance of the connecting party's equipment or *facilities*. If the test or monitoring equipment required by the *IESO* is intended to provide a general benefit to the *IESO-controlled grid*, and is not otherwise required to ensure compliance of the specific *market participant's* equipment, the *IESO* shall bear the costs of such additional test or monitoring equipment and the costs of operating and attaching such equipment to the *transmitter's, generator's, electricity storage participant's, distributor's* or *connected wholesale customer's* equipment or *facilities*. All such costs shall be subject to verification and audit by the *IESO*.

5.1.5 Parties to a *connection agreement* that propose to perform a test on equipment that requires a change to the normal operation of such equipment shall give such prior notice to the *IESO* as the *IESO* shall require if such test could have an adverse impact on the *reliable* operation of the *IESO-controlled grid*. If the *IESO* determines that the proposed test could adversely affect the *reliability* of the *IESO-controlled grid*, the *IESO* may direct that the parties modify the testing procedure or the time scheduled for the test to avoid any threat to *reliability*. If such activities cannot avoid a threat to *reliability* to a degree acceptable to the *IESO*, the *IESO* shall not permit the test.

5.1.6 Where the *IESO* believes that the equipment of a *transmitter*, *generator*, *electricity storage participant, distributor* or *connected wholesale customer connected* to the *IESO-controlled grid* does not comply with the requirements of this Chapter, and that such non-compliance poses a threat to the *reliable* operation of the *IESO-controlled grid*, the *IESO* may direct the *transmitter, generator, electricity storage participant, distributor* or *connected wholesale customer* to modify such equipment to comply with this Chapter.

5.1.7 Section 5.1.6 applies regardless of whether a waiver has been granted to the relevant *transmitter, generator, electricity storage participant, distributor* or *connected wholesale customer* by the *IESO* in respect of the non-complying equipment.

5.2 IESO-Required Tests of Generators and Electricity Storage Participants

5.2.1 In addition to any tests required by a *connection agreement*, the *IESO* may require a *generator* or *electricity storage participant* to test any *generation facility* or *electricity storage facility* connected to the *IESO-controlled grid* in order to determine whether such *facility* meets the requirements of this Chapter. The relevant *generator* or *electricity storage participant* shall comply with such request. If possible, the *IESO* shall permit such tests to be performed during the next scheduled *planned outage* of the *facility*. If the *IESO* determines that a test is required for *reliability* reasons prior to the next scheduled *planned outage* of the *facility*, the *IESO* shall cooperate with the *generator* or *electricity storage participant* to ensure that the test is conducted in a manner designed to create the minimum impact on the operation of that *facility*.

5.2.2 Tests conducted under this section 5.2 shall be conducted in accordance with procedures that have been agreed upon by the *IESO* and the relevant *generator* or *electricity storage participant*. The *IESO* shall provide the relevant *generator* or *electricity storage participant* with the parameters of the model derived from such tests.

5.2.3 Section 5.1.4 shall apply to determine the allocation to and the recovery by the *IESO* of any costs incurred by a *generator* or *electricity storage participant* to assist in the performance of the tests required under this section 5.2.

5.3 IESO-Required Tests of Interconnections

5.3.1 The *IESO* may perform or require *transmitters* to perform tests to verify the magnitude of the power transfer capability of *interconnections* whenever:

5.3.1.1 a new *interconnection* between the *IESO-controlled grid* and a *neighbouring electricity system* is placed into operation, augmented or substantially modified; or

5.3.1.2 the *IESO* has reasonable grounds to believe that power transfer capability across that *interconnection* has materially changed.

5.3.2 Prior to performing or directing the performance of the tests referred to in section 5.3.1, the *IESO* shall provide as much advance notice as practicable to *market participants* and other *interconnected transmitters* whose systems, equipment or *facilities* could be materially affected by the tests. All *market participants* shall cooperate with the *IESO* and/or the relevant *transmitter* in planning, preparing for and conducting tests to assess the technical performance of *interconnections* on the *IESO-controlled grid*.

5.3.3 The *IESO* may temporarily direct the operation of *generation facilities* or *electricity storage facilities* during the testing of *interconnections* if and to the extent necessary to obtain operational conditions on the *IESO-controlled grid* that are required in order to achieve valid test results. The *IESO* shall plan the timing of tests so that the duration of the tests and the variation in the *dispatch* of any associated *generation resource* or *electricity storage resource* relative to its *dispatch* under non-test conditions are minimized to the extent possible.

5.3.4 Any costs that are incurred by a *generator* or *electricity storage participant* to assist in the performance of the tests required under section 5.3 that are otherwise unrecoverable shall be recovered from *market participants* in accordance with MR Ch.9 s.4.14.12. All such costs shall be subject to verification and audit by the *IESO* before being so recovered.

6. Establishing or Modifying IESO-Controlled Grid Facilities and Connections

6.1 General Requirements

6.1.1 Subject to the *reliability standards* required by these *market rules* and to sections 6.1.7, 6.1.22 and 6.1.23, the requirements associated with the design and construction of *connections* to the *IESO-controlled grid* shall be established between the *connecting market participant* or *connection applicant* and the *transmitter* with whom the *market participant* or *connection applicant* seeks to *connect*.

6.1.2 [Intentionally left blank]

6.1.3 [Intentionally left blank]

6.1.4 [Intentionally left blank]

6.1.5 The *IESO* shall, upon receipt of a *request for connection assessment* referred to in section 6.1.6, assess the impact of a new or modified *connection* to the *IESO-controlled grid* on the *reliability* of the *integrated power system* by means of a *connection assessment* conducted in accordance with the provisions of sections 6.1.14 to 6.1.18.

6.1.6 A *connection applicant* shall:

6.1.6.1 file a *request for connection assessment* to obtain the assessment referred to in section 6.1.5 and the approval of the *IESO* in accordance with the provisions of sections 6.1.14 to 6.1.18; and

6.1.6.2 where applicable, obtain the approval of the *IESO* pursuant to section 6.1.22.

Without limiting the generality of sections 6.1.14 and 6.1.15, the *IESO* shall define the form and content of information required for a *request for connection assessment*. The *connection applicant* shall notify the *transmitter* of the filing of such request for *connection assessment.*

6.1.7 If the *IESO* determines as part of a *connection assessment* that a new or modified *connection* will have an adverse effect on the *reliability* of the *integrated power system,* the *IESO* shall describe such adverse effects in its report on the *connection assessment* and of the system upgrades required to mitigate such adverse effects. No *market participant, connection applicant* or *transmitter* shall establish such new or modified *connection* unless the required system upgrades described in the *connection assessment* are designed and implemented to the satisfaction of the *IESO*.

6.1.8 [Intentionally left blank]

6.1.9 Each *transmitter* shall, subject to obtaining any required approvals therefor and to the completion by the *IESO* of a *connection assessment* in accordance with section 6.1.5 and sections 6.1.14 to 6.1.18, and, if applicable, such further assessment and resulting approval as contemplated by sections 6.1.22 and 6.1.23, undertake the design and construction of any upgrades to its portion of the *IESO-controlled grid* that are required by the *IESO* to ensure the *reliability* of the *IESO-controlled grid*.

6.1.10 Each *transmitter* shall, if required by its *licence*, or an order of the *OEB* or by an agreement between the *transmitter* and the *connection applicant*, use its best efforts to undertake the design and construction of any *connection facilities* that are necessary to bring about any new or modified *connections* to the *IESO-controlled grid* that have been the subject of a *connection assessment* completed in accordance with sections 6.1.14 to 6.1.18 and, if applicable, sections 6.1.22 and 6.1.23 on a timely basis and in accordance with the requirements of this Chapter.

6.1.11 [Intentionally left blank]

6.1.12 [Intentionally left blank]

6.1.13 [Intentionally left blank]

6.1.14 The *IESO* shall establish procedures describing the manner and timing for the processing of *requests for connection assessment.*

6.1.15 A *connection applicant* shall file with the *IESO*:

6.1.15.1 a *request for connection assessment*, the supporting documentation referred to in section 6.1.6 and such other supporting documentation that meets the requirements of the procedures referred to in section 6.1.14;

6.1.15.2 a deposit in such amount as may be specified in the procedures referred to in section 6.1.14; and

6.1.15.3 an executed agreement in the form set forth in the procedures referred to in section 6.1.14 pursuant to which the *connection applicant* agrees, subject to section 6.1.17, to pay to the *IESO* an amount equal to all of the costs and expenses incurred by the *IESO* in completing the *connection assessment* associated with the *request for connection assessment* subject to section 6.1.17.

6.1.16 The *IESO* shall process each *request for connection assessment* in accordance with the procedures referred to in section 6.1.14 and as follows:

6.1.16.1 the *IESO* shall, unless the *request for connection assessment* is withdrawn or deemed to have been withdrawn pursuant to the procedures referred to in section 6.1.14, conduct a *connection assessment* in respect of the subject-matter of the *request for connection assessment* in accordance with the procedures referred to in section 6.1.14;

6.1.16.2 the *IESO* shall provide to the *connection applicant* and to the applicable *transmitter* a copy of the report of the results of the completed *connection assessment* referred to in section 6.1.16.1;

6.1.16.3 provided that the *connection applicant* has met the requirements of section 6.1.15, within such time as may be specified in the procedures referred to in section 6.1.14, the *IESO* shall conduct a *connection assessment* in respect of the subject-matter of the *request for connection assessment* in accordance with the procedures referred to in section 6.1.14;

6.1.16.4 the *IESO* shall provide to the *connection applicant* and the applicable *transmitter* a copy of the report of the results of the completed *connection assessment* referred to in section 6.1.16.3, together with notice of its approval or disapproval of the new or modified *connection* that is the subject-matter of the *connection assessment*;

6.1.16.5 the *IESO* shall advise the *Ontario Energy Board* of the results of the *connection assessment* referred to in section 6.1.16.3; and

6.1.16.6 provided that the *connection applicant* has, within such time or times following the date of completion of the *connection assessment* that relates to its *request for connection assessment* as may be specified in the procedures referred to in section 6.1.14, filed with the *IESO* such confirmation or evidence, as the case may be and as may be specified in such procedures, of its intention to proceed with the new or modified *connection* that is the subject-matter of its *request for connection assessment*:

a. the *connection applicant* shall retain the priority allocated to its *request for connection assessment*; and

b. the *IESO* shall include the results of such *connection assessment* in such subsequent *connection assessment*, conducted within the times specified in the procedures referred to in section 6.1.14, as may be appropriate.

6.1.17 Where the *IESO* conducts a *connection assessment* that relates to two or more *requests for connection assessment*, the *IESO* shall apportion the costs relating to the *connection assessment* amongst the applicable *connection applicants* in accordance with the procedures referred to in section 6.1.14 and shall reflect such apportionment in the agreement referred to in section 6.1.15.3.

6.1.18 Where:

6.1.18.1 the *IESO* conducts a *connection assessment* that relates to two or more *requests for connection assessment*; and

6.1.18.2 one or more of the *connection applicants* withdraws or is deemed to have withdrawn its *request for connection assessment*,

the *IESO* shall apportion the costs relating to the *connection assessment* amongst applicable *connection applicants* in accordance with the procedures referred to in section 6.1.14.

6.1.19 [Intentionally left blank]

6.1.20 The *IESO* shall submit an *invoice* to each *connection applicant* upon completion of the *connection assessment* which relates to the *connection applicant's request for connection assessment* in an amount equal to:

6.1.20.1 all of the *IESO's* costs and expenses relating to the processing of the *connection applicant's request for connection assessment* and to the conduct of the *connection assessment;* or

6.1.20.2 where section 6.1.17 or 6.1.18 applies, the portion of the costs and expenses referred to in section 6.1.20.1 apportioned to the *connection applicant*;

minus

6.1.20.3 the amount of any deposit paid pursuant to section 6.1.15.2.

6.1.21 A *connection applicant* shall, within ten *business days* of receipt of an *invoice* referred to in section 6.1.20, pay to the *IESO* the amount owing thereunder. Such *invoice* shall be considered to create an obligation under the *market rules* to pay the amount specified therein and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

6.1.22 No *connection applicant* shall establish a new or modify an existing *connection* to the *IESO-controlled grid* in a manner that differs materially from the configuration or technical parameters that were used by the *IESO* as the basis upon which it approved such new or modified *connection* in accordance with section 6.1.14 to 6.1.18 unless the applicable *connection applicant* has obtained the approval of the *IESO* for the change in configuration or technical parameter.

6.1.23 The *IESO* shall approve a change in configuration or technical parameter referred to in section 6.1.22 unless the *IESO* determines that such change will have an adverse effect on the *reliability* of the *integrated power system*. Where the *IESO* does not approve such change, no *connection applicant* shall establish the applicable new or modify the applicable existing *connection* to the *IESO-controlled grid* unless the required system upgrades described in the *connection assessment* are designed and implemented to the satisfaction of the *IESO*.

6.1A Upgrades to Ensure Reliability

6.1A.1 Each *transmitter* shall, subject to obtaining any required approvals therefor, undertake the design and construction of any upgrades to its portion of the *IESO-controlled grid* that are required by the *IESO* to ensure the *reliability* of the *IESO-controlled grid*.

6.2 Voluntary Disconnection

6.2.1 A *connected market participant* may *disconnect* from the *IESO-controlled grid* any *facility* that has been de-registered in accordance with section 2.4 of Chapter 7 following the completion of all applicable operating and decommissioning procedures referred to in the *connection agreement* applicable to the *facility*.

6.3 Disconnection by Transmitter, Distributor or Market Participant

6.3.1 A *transmitter* may *disconnect* from the *IESO-controlled grid* the *facilities* or equipment of a *market participant* in accordance with the *market rules* and *applicable law*.

6.3.1A Subject to section 6.4.3, a *transmitter* shall notify the *IESO* prior to *disconnecting* from the *IESO-controlled grid* the *facilities* or equipment of a *market participant* for any reason other than in response to a *disconnection order*.

6.3.2 Each *transmitter*, *distributor* and other *market participant* to whom a *disconnection order* is issued pursuant to section 6.4 shall, subject only to MR Ch.5 s.3.4.1.5 or s.3.7.1.5, as the case may be, on the date and at the time specified in the *disconnection order*, *disconnect* the *facilities* or equipment referred to in the *disconnection order*.

6.3.3 Without limiting the generality of MR Ch.1 s.8.3, a *disconnection order* may be issued by the *IESO* to a *transmitter*, *distributor* or other *market participant* pursuant to section 6.4 by voice communication.

6.4 Disconnection During an Emergency or For Safety or Reliability Reasons

6.4.1 During an *emergency*, the *IESO* may:

6.4.1.1 direct a connected *market participant* to reduce the power transferred at the *connection point* to zero in an orderly manner; and

6.4.1.2 issue a *disconnection order* to a *transmitter*, *distributor* or other *market participant* directing such *transmitter*, *distributor* or other *market participant* to *disconnect* a person's *facilities* or equipment from the *IESO-controlled grid*, its *transmission system*, its *distribution system* or from a host *market participant*, as the case may be.

6.4.2 Where the *IESO* becomes aware of a threat to the safety of any person, damage to equipment, or the environment or to the *reliability* of the *integrated power system* that requires urgent action, the *IESO* may issue a *disconnection order* directing the relevant *transmitter* or *distributor* to *disconnect* a person's *facilities* or equipment from the *IESO-controlled* grid, its *transmission system* or its *distribution* system, as the case may be.

6.4.2A Where the *IESO* becomes aware that a person has *connected facilities* or equipment to the *IESO-controlled grid*:

6.4.2A.1 without the approval of the *IESO* including, where applicable, but not limited to the approval referred to in section 6.1.22;

6.4.2A.2 in a manner that does not comply with the requirements of the *market rules* or *applicable law*;

6.4.2A.3 in a manner that does not comply with the requirements identified in a *connection assessment* associated with that person's *facilities* or equipment; or

6.4.2A.4 where applicable, in a manner other than that determined satisfactory by the *IESO* pursuant to section 6.1.7 or 6.1.23,

the *IESO* may issue a *disconnection order* directing the relevant *transmitter* to *disconnect* the person's *facilities* or equipment from the *IESO-controlled grid*.

6.4.2B Where the *IESO* becomes aware that a *generator* or *electricity storage participant* has synchronized (respectively) either a *generation resource,*or an *electricity storage resource* to the *IESO-controlled grid* other than in accordance with section 11.2 of Chapter 7, the *IESO* may issue a *disconnection order* directing the relevant *transmitter* to *disconnect* the *generation unit* or *electricity storage unit* from the *IESO-controlled grid*.

6.4.3 A *transmitter* may, in accordance with the provisions of its *licence,* any code issued by the *OEB* with which the *transmitter* is required to comply, or the *market rules*, immediately *disconnect* from the *IESO-controlled grid* the *facilities* or equipment of a person where:

6.4.3.1 such action is urgently required to ensure the safety of any person, prevent the damage of equipment, or the environment;

6.4.3.2 the urgency is such that there is insufficient time to notify the *IESO* prior to such action being taken; and

6.4.3.3 the *transmitter* is the operator of a *connection facility*.

A *transmitter* that *disconnects* a person's *facilities* or equipment pursuant to this section 6.4.3 shall promptly inform the *IESO* that such action has been taken.

6.5 Obligation to Reconnect After Disconnection

6.5.1 A *transmitter*, *distributor* or other *market participant* to whom a *disconnection order* was issued pursuant to section 6.4 shall, in accordance with the direction referred to in section 6.5.2, reconnect the relevant *facilities* or equipment to the *IESO-controlled grid*, its *transmission system*, its *distribution system* or to the host *market participant*, as the case may be, once:

6.5.1.1 the *transmitter*, *distributor* or other *market participant*, as the case may be, and the *IESO* are satisfied that the *emergency* which prompted the *disconnection* no longer exists; or

6.5.1.2 where the *disconnection* occurred for reasons other than an *emergency,* the *transmitter*, *distributor* or other *market participant*, as the case may be, and the *IESO* are satisfied that the reason for the *disconnection* no longer exists.

6.5.2 A *transmitter*, *distributor* or other *market participant* to whom a *disconnection order* was issued pursuant to section 6.4 may reconnect the relevant *facilities* and equipment only under direction from the *IESO* provided that the person whose *facilities* or equipment were *disconnected* has carried out any demonstration required pursuant to section 6.5.3 to the reasonable satisfaction of the *transmitter*, the *distributor* or other *market participant*, as the case may be, and the *IESO*.

6.5.3 Prior to reconnection, the *transmitter*, *distributor* or other *market participant*, as the case may be, or the *IESO* may require the person whose *facilities* or equipment were *disconnected* to demonstrate that it has taken all necessary steps to prevent the recurrence of any event that prompted the *disconnection* that was within the control of the person.

6.5.3A A *transmitter* that has *disconnected* from the *IESO-controlled grid* the *facilities* or equipment of a person in circumstances other than where it has received from the *IESO* a *disconnection order* directing it to do so shall inform the *IESO* prior to reconnecting such *facilities* or equipment.

6.5.4 Any agreement between a *transmitter* and a *market participant* as to the payment of any costs associated with *disconnection* and reconnection shall be contained in their *connection agreement.*

7. Provision of Connection-Related Information

7.1 Provision of Information

7.1.1 [Intentionally left blank]

7.1.2 A *market participant* that becomes aware of any material change to or inconsistency with any information or data previously supplied to another *market participant* or to the *IESO* in accordance with a new or modified *connection* that could affect the *reliability* of the *IESO-controlled grid* shall promptly notify the *IESO* and such other *market participant* in writing of that change or inconsistency.

7.1.3 Each *generator* or *electricity storage participant* whose *facility* is *connected* to the *IESO-controlled grid*, *connected wholesale customer* and *distributor* connected to *the IESO-controlled grid*, and *transmitter* shall provide to the *IESO connection-related reliability information* as applicable prior to placing any *connected facility* into service.

7.1.4 Each *embedded generator* whose *embedded generation facility* includes a *generation unit* rated at greater than 10 MVA and that is designated by the *IESO* for the purposes of this section 7.1 shall provide to the *IESO connection-related reliability information* as may be requested by the *IESO*.

7.1.5 Each *embedded generator* that:

7.1.5.1 participates in the *IESO-administered markets* and whose *embedded generation facility* includes a *generation unit* rated at 1 MW or higher;

7.1.5.2 is not a *market participant* and whose *embedded generation facility* includes a *generation unit* rated at 10 MVA or higher,

and that is not required to provide data pursuant to section 7.1.4, shall provide the *IESO* with applicable *connection-related reliability information*.

7.1.6 Each *variable generator* shall provide data to the *IESO* in accordance with the applicable *market manual* for the purposes of deriving forecasts of the amount of *energy* that the *variable generator* is capable of producing.

7.1.7 Each *embedded electricity storage participant* whose *embedded electricity storage facility* includes an *electricity storage unit* with an *electricity storage unit size* greater than 10 MVA and that is designated by the *IESO* for the purposes of this section 7.1

shall provide to the *IESO connection-related reliability information* as may be requested by the *IESO*.

7.1.8 Each *embedded electricity storage participant* that:

7.1.8.1 participates in the *IESO-administered markets* and whose *embedded electricity storage facility* includes an *electricity storage unit* with an *electricity storage unit size* of 1 MW or higher;

7.1.8.2 is not a *market participant* and whose *embedded electricity storage facility* includes an *electricity storage unit* with a maximum *electricity storage unit size* of 10 MVA or higher,

and that is not required to provide data pursuant to section 7.1.7, shall provide the *IESO* with applicable *connection-related reliability information*.

7.2 [Intentionally left blank]

7.3 Monitoring Information Provided by Generators to the IESO

7.3.1 Subject to section 7.3.2, in order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each:

7.3.1.1 *generator* (i) whose *generation facility* is *connected* to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

7.3.1.2 *embedded generator* (i) that is not a *market participant* or whose *embedded generation facility* is not associated with any *resources*; (ii) whose *embedded generation facility* includes a *generation unit* rated at greater than 20 MVA or that comprises *generation units* the ratings of which in the aggregate exceeds 20 MVA; and (iii) that is designated by the *IESO* for the purposes of this section 7.3.1 as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*,

shall provide the *IESO* with the data listed in Appendix 4.15 on a continual basis. Such data shall not be modified by the *generator* and shall be provided:

7.3.1.3 with equipment that meets the requirements set forth in MR Ch.2 App 2.2; and

7.3.1.4 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.19.

7.3.2 Section 7.3.1 does not apply to:

7.3.2.1 a *small generation facility*;

7.3.2.2 a *self-scheduling generation facility* that has a name-plate rating of less than 10 MW; or

7.3.2.3 an *intermittent generation resource* that is comprised solely of a *generation unit* rated at less than 20 MW or of *generation units* the ratings of which in the aggregate is less than 20 MW unless designated by the *IESO* at the time of registration as affecting the *reliability* of the *IESO-controlled grid*.

7.3.2A Each *variable generator* not otherwise subject to any communication requirements specified in this chapter shall at a minimum, meet the medium performance standards set forth in Appendix 4.19 for the purposes of providing data in accordance with section 7.1.6.

7.3.3 [Intentionally left blank – section deleted]

7.3.4 The *IESO* shall *publish,* as soon as practicable following each *dispatch hour*, the actual *generation capacity* (in MW) and hourly *energy* production (in MWh) for each *generation unit* based on information provided to it by *market participants. Generation capacity* and *energy* production for *generation units* with rating less than 20 MVA can be aggregated by station.

7.3.5 The *IESO* shall, as soon as practicable prior to each *dispatch hour*, use reasonable efforts to provide a confidential forecast produced by the *forecasting entity* to each *registered market participant* for each of their *variable generation facilities* as specified in the applicable *market manual*.

7.3.6 The *IESO* shall, as soon as practicable following each *dispatch hour,* provide the confidential forecast produced by the *forecasting entity* for each *dispatch interval* in the preceding *dispatch hour,* to each *registered market participant* for each of their *variable generation facilities* as specified in the applicable *market manual.*

7.3A Monitoring Information Provided by Electricity Storage Participants to the IESO

7.3A.1 Subject to section 7.3A.2, in order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each:

7.3A.1.1 *electricity storage participant* (i) whose *electricity storage facility* is *connected* to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

7.3A.1.2 *embedded electricity storage participant* (i) that is not a *market participant* or whose *embedded electricity storage facility* is not associated with any *resources*; (ii) whose *embedded electricity storage facility* includes an *electricity storage unit* with a rated *electricity storage unit size* greater than 20 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which exceed 20 MVA; and (iii) that is designated by the *IESO* for the purposes of this section 7.3A.1 as being required to provide such data in order to enable the *IESO* to maintain the reliability of the *IESO-controlled grid*,

shall provide the *IESO* with the data listed in Appendix 4.24 on a continual basis. Such data shall not be modified by the *electricity storage participant* and shall be provided:

7.3A.1.3 with equipment that meets the requirements set forth in MR Ch.2 App.2.2; and

7.3A.1.4 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.25.

7.3A.2 Section 7.3A.1 does not apply to:

7.3A.2.1 a *small electricity storage facility*

7.3A.3 The *IESO* shall *publish,* as soon as practicable following each *dispatch hour*, the actual *electricity storage capacity* (in MW) and hourly injections of *energy* (in MWh) for each *electricity storage unit* based on information provided to it by *market participants. Electricity storage capacity* and *energy* production for *electricity storage units* with a rated *electricity storage unit size* of less than 20 MVA can be aggregated by station.

7.4 Monitoring Information Provided by Transmitters to the IESO

7.4.1 In order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each *transmitter* shall provide the *IESO* with the data listed in Appendix 4.16 on a continual basis. Such data shall not be modified by the *transmitter* and shall be provided:

7.4.1.1 with equipment that meets the requirements set forth in MR Ch.2 App2.2; and

7.4.1.2 in accordance with the performance standards set forth in Appendix 4.20 and, subject to section 7.6A, Appendix 4.21.

7.5 Monitoring Information Provided to the IESO by Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

7.5.1 In order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each *connected wholesale customer* and each *distributor connected* to the *IESO-controlled grid* shall provide the *IESO* with the data listed in Appendix 4.17 on a continual basis. Such data shall not be modified by the *connected wholesale customer* or *distributor connected* to the *IESO-controlled grid*, as the case may be, and shall be provided:

7.5.1.1 with equipment that meets the requirements set forth in MR Ch.2 App.2.2; and

7.5.1.2 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.22.

7.5.2 A *distributor* that is not *connected* to the *IESO-controlled grid* and that is designated by the *IESO* for the purposes of this section 7.5.2 as being required to provide the data listed in Appendix 4.17 in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid* shall comply with the obligations set forth in section 7.5.1.

7.6 Monitoring Information Provided by Embedded Load Customers to the IESO

7.6.1 In order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each *embedded load consumer* that is designated by the *IESO* for the purposes of this section 7.6.1 as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid* shall provide the *IESO* with the data listed in Appendix 4.18 on a continual basis. Such data shall not be modified by the *embedded load consumer* and shall be provided:

7.6.1.1 with equipment that meets the requirements set forth in MR Ch.2 App2.2; and

7.6.1.2 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.23.

7.6A Alternative Arrangements for Submission of Data Measurements

7.6A.1 *Market participants* may propose to the *IESO* an alternative arrangement to make data measurements or equipment status changes available to the *IESO* communications interface within times different than those specified in Appendix 4.19, 4.21, 4.22, 4.23, or 4.25.

7.6A.2 Where an alternative arrangement proposed pursuant to section 7.6A.1 relates to the requirement to make data measurements or equipment status changes available at the *IESO* communications interface within less than 2 seconds from the change in field monitored quantity or field status change, as the case may be, the *IESO* shall approve the alternative arrangement if:

7.6A.2.1 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of providing the data measurements or equipment status changes in such a manner that such data will be displayed on the communications terminals located at the *IESO's* principal and back-up control centres within less than 8 seconds from the change in field monitored quantity or field status change; and

7.6A.2.2 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of meeting such other *reliability*-related performance standards and other requirements as may be specified by the *IESO*, including but not limited to time consistency of data, and loss of data from electrically adjacent stations.

7.6A.3 Where an alternative arrangement proposed pursuant to section 7.6A.1 relates to the requirement to make data measurements or equipment status changes available at the *IESO* communications interface within less than 10 seconds from the change in field monitored quantity or field status change, as the case may be, the *IESO* shall approve the alternative arrangement if:

7.6A.3.1 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of providing the data measurements or equipment status changes in such a manner that such data will be displayed on the communications terminals located at the *IESO's* principal and back-up control centres within less than 20 seconds from the change in field monitored quantity or field status change; and

7.6A.3.2 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of meeting such other *reliability*-related performance standards and other requirements as may be specified by the *IESO,* including but not limited to time consistency of data, and loss of data from electrically adjacent stations.

7.6A.4 Upon approval of an alternative arrangement proposed and reviewed under this section, the *IESO* may incorporate the alternative arrangement as an alternative standard in the *market rules*.

7.7 Reliability, Maintenance and Repair of Monitoring and Control Equipment

7.7.1 Each person referred to in section 7.3.1, 7.4.1, 7.5.1, 7.5.2 or 7.6.1, as the case may be, shall maintain the monitoring and control equipment referred to in Appendices 4.15 to 4.18 as applicable, in accordance with *good utility practice* and shall ensure that such equipment:

7.7.1.1 has an overall mean time between failures of:

a. no less than three years; or

b. no less than five years, if the equipment is designated by the *IESO* as significant for purposes of enabling the *IESO* to maintain the *reliability* of the *IESO-controlled grid*;

7.7.1.1A each person referred to in section 7.7.1 shall report and schedule with the *IESO* all planned changes to monitoring equipment referred to in section 7.7.1.1 and associated potential and current transformers and other devices affecting the accuracy or the reliability of such equipment;

7.7.1.2 is secure from the effects of interruptions in power supply for a period of at least eight hours.

7.7.2 Each person referred to in section 7.7.1 and 7.3.2A shall respond to an *outage* of or defect in the equipment referred to in section 7.7.1 or the applicable *market manual*:

7.7.2.1 immediately, in the case of equipment relating to *facilities* to which the high performance information monitoring standard applies pursuant to Appendices 4.19 to 4.23 and Appendix 4.25 other than *significant generation facilities, significant dispatchable load facilities* and *significant electricity storage facilities*.

7.7.2.2 no later than the next day following the day on which the *outage* or defect is discovered, in the case of equipment relating to *significant generation facilities, significant electricity storage facilities, significant dispatchable load facilities*, *variable generation,* and *facilities* to which the medium performance information monitoring standard applies pursuant to Appendices 4.19 to 4.23 and Appendix 4.25.

7.7.3 Each person referred to in section 7.7.1 and 7.3.2A shall ensure that the equipment referred to in section 7.7.1 or the applicable *market manual* is restored to a fully operational state following an *outage* of or defect in such equipment as follows:

7.7.3.1 in the case of equipment relating to the *facilities* referred to in section 7.7.2.1, within 24 hours of the time at which the *outage* or defect is discovered;

7.7.3.2 in the case of equipment relating to the *facilities* referred to in section 7.7.2.2, within 48 hours of the time at which the *outage* or defect is discovered; and

7.7.3.3 in all other cases, within 14 days of the time at which the *outage* or defect is discovered.

7.7.4 The *IESO* may direct a person referred to in section 7.7.1 and 7.3.2A to respond and restore the equipment referred to in section 7.7.1 or the applicable *market manual* to a fully operational state following an *outage* of or defect in such equipment within such longer or shorter time periods than those referred to in sections 7.7.2 and 7.7.3 based on the immediate or short-term impact of the unavailability of the equipment on the *reliable* operation of the *IESO-controlled grid*, provided that where a person is directed to respond and restore any such equipment in less than 24 hours, the person shall use commercial best efforts to achieve such direction.

7.7.5 Each person referred to in section 7.7.1 shall notify the *IESO* of any *planned outage* of the equipment referred to in section 7.7.1 no less than four days prior to the *planned outage*.

7.8 Re-Classification of Facilities

7.8.1 The *IESO* may, for the purposes of sections 7.3 to 7.6:

7.8.1.1 re-classify a *small generation facility* as a *minor generation facility*, a *significant generation facility* or a *major generation facility*;

7.8.1.2 re-classify a *minor generation facility* as a *significant generation facility* or a *major generation facility*;

7.8.1.3 re-classify a *significant generation facility* as a *major generation facility*;

7.8.1.4 re-classify a *minor dispatchable load facility* as a *significant dispatchable load facility* or a *major dispatchable load facility*; and

7.8.1.5 re-classify a *significant dispatchable load facility* as a *major dispatchable load facility*,

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

7.8.2 The *IESO* may, for the purposes of sections 7.3 to 7.6:

7.8.2.1 re-classify a *major generation facility* as a *significant generation facility*, a *minor generation facility* or a *small generation facility*;

7.8.2.2 re-classify a *significant generation facility* as a *minor generation facility* or a *small generation facility*;

7.8.2.3 re-classify a *minor generation facility* as a *small generation facility*;

7.8.2.4 re-classify a *major dispatchable load facility* as a *significant dispatchable load facility* or a *minor dispatchable load facility*; and

7.8.2.5 re-classify a *significant dispatchable load facility* as a *minor dispatchable load facility*,

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

7.8.2A The *IESO* may, for the purposes of sections 7.3A:

7.8.2A.1 re-classify a *small electricity storage facility* as a *minor electricity storage facility*, a *significant electricity storage facility* or a *major electricity storage facility*;

7.8.2A.2 re-classify a *minor electricity storage facility* as a *significant electricity storage facility* or a *major electricity storage facility*;

7.8.2A.3 re-classify a *significant electricity storage facility* as a *major electricity storage facility*;

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

7.8.2B The *IESO* may, for the purposes of sections 7.3A:

7.8.2B.1 re-classify a *major electricity storage facility* as a *significant electricity storage facility*, a *minor electricity storage facility* or a *small electricity storage facility*;

7.8.2B.2 re-classify a *significant electricity storage facility* as *a minor electricity storage facility* or a *small electricity storage facility*;

7.8.2B.3 re-classify a *minor electricity storage facility* as a *small electricity storage facility*;

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid.*

7.8.3 A person whose *facility* has been re-classified pursuant to section 7.8.1, 7.8.2, 7.8.2A or 7.8.2B shall:

7.8.3.1 ensure that its *facilities* and equipment meet the requirements set forth in section 7.3, 7.4, 7.5 or 7.6, as the case may be; and

7.8.3.2 comply with the requirements of section 7.7,

applicable to the class of *facility* in which its *facility* has been re-classified*.*

RUL-12

Renewed Market Rules

Chapter 0.4

Grid Connection Requirements - Appendices

Renewed Market Rules – Chapter 0.4: Grid Connection Requirements - Appendices

0.4

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Distribution List

Name	**Organization**

Table of Contents

Appendix 4.1 – IESO-Controlled Grid Performance Standards

Ref	Item	Requirement
	Transmission System	
1	Frequency variations	All *equipment* shall be capable of continuously operating in the range between 59.5 Hz and 60.5 Hz.
2	Voltage variations	Under normal conditions voltages are maintained within the range below. Transmission Voltage: Nominal (kV) 500 230 115 Maximum Continuous (kV) 550 250* 127* Minimum Continuous (kV) 490 220 113 *In northern Ontario, the maximum continuous voltage for the 230 and 115 kV systems can be as high as 260 kV and 132 kV respectively
3	[Intentionally left blank]	
4	[Intentionally left blank]	
5	[Intentionally left blank]	
6	[Intentionally left blank]	
7	[Intentionally left blank]	

Ref	Item	Requirement
8	[Intentionally left blank]	

Appendix 4.2 – Requirements for Generation and Electricity Storage Facilities Connected to the IESO-Controlled Grid

The performance requirements set out below shall apply to *generation facilities* subject to a *connection assessment* finalized after September 21, 2020. Performance of alternative technologies shall be comparable with that of conforming conventional synchronous generation with an equal apparent power rating.

These performance requirements shall also apply to *electricity storage units* at all times while connected to the *IESO-controlled grid*, unless the *IESO* identifies specific performance requirements that are not applicable to an *electricity storage unit* for those with a *connection assessment* finalized after January 18, 2021. Due consideration will be given to inherent limitations.

Each *facility* that was authorized to *connect* to the *IESO-controlled grid* prior to September 21, 2020 shall remain subject to the performance requirements in effect for each associated system at the time its authorization to *connect* to the *IESO-controlled grid* was granted or agreed to by the *market participant* and the *IESO* (i.e. the "original performance requirements"). These original performance requirements shall prevail until the main elements of an associated system (e.g. governor control mechanism, main exciter, power inverter) are replaced or substantially modified. At that time, the associated system that is replaced or substantially modified shall meet the applicable performance requirements detailed below. All other systems, not affected by replacement or substantial modification, shall remain subject to the original performance requirements.

Category	*Generation facilities* or *electricity storage facilities* directly connected to the *IESO-controlled grid* shall have the capability to:
1. Off-Nominal Frequency Operation	Operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region bounded by straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz) and the straight lines on a log-linear scale defined by the points (0.0 s, 61.8 Hz), (8 s, 61.8 Hz), and (600 s, 60.6 Hz).
2. Speed/Frequency Regulation	Regulate speed/frequency with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the *IESO*. Regulation deadband shall not be wider than ±0.06%. Speed/frequency shall be controlled in a stable fashion in both interconnected and island operation. A sustained 9% change of applicable

Category	*Generation facilities* or *electricity storage facilities* directly connected to the *IESO-controlled grid* shall have the capability to:
	rated active power as defined in category 4 after 10 s in response to a step change of speed of 0.5% during interconnected operation shall be achievable. Due consideration will be given to inherent limitations such as mill points and gate limits when evaluating active power changes. Control systems that inhibit primary frequency response shall not be enabled without *IESO* approval.
3. Voltage Ride-Through	Ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration. For Inverter-based units, momentary current cessation or reduction of output current during system disturbances is not permitted without *IESO* approval.
4. Active Power	Continuously supply all levels of active power output within a +/- 5% range of its rated terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. For *electricity storage facilities*, rated active power values shall be separately specified for both injection and withdrawal operations. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted.
5. Reactive Power	Continuously (i.e., dynamically) inject or withdraw reactive power at the high-voltage terminal of the main output transformer[1] up to 33% of the applicable rated active power at all levels of active power, and at the typical *transmission system* voltage, except where a lesser continually available capability is permitted with the *IESO's approval*. A conventional synchronous unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on *generation unit* rated apparent power is acceptable. Reactive power losses or charging between the high-voltage terminal of the main output transformer and the *connection point* shall be addressed in a manner permitted by *IESO* approval.
6. Automatic Voltage Regulator (AVR)	Regulate voltage automatically within ±0.5% of any setpoint within ±5% of rated voltage at the low-voltage terminal of the main output transformer if the transformer impedance is not more than 13% based on the rated apparent power of the *generation facility* or *electricity storage facility* or at a point approved by the *IESO*. Reactive power-voltage droop or AVR reference

[1] A main output transformer steps up the voltage from the *generation unit/facility* to the transmission voltage level.

Category	*Generation facilities* or *electricity storage facilities* directly connected to the *IESO-controlled grid* shall have the capability to:
	load current compensation shall not be enabled without *IESO* approval. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output.
7. Excitation System for Synchronous Machines Greater than 20 MVA or any Synchronous Machines *within Facilities* Greater than 75 MVA	Provide (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage, respectively, while supplying the field winding of the *generation unit* or *electricity storage unit* operating at nominal voltage under open circuit conditions; (b) An excitation transformer impedance not greater than 10% on excitation system base; (c) A voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) A linear response between ceilings.
8. Power System Stabilizer (PSS) for Synchronous Machines within Facilities Greater than 75 MVA	Provide (a) A change of power and speed input configuration; (b) Positive and negative output limits not less than ±5% of rated AVR voltage; (c) Phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the *IESO*, and (d) Gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits poorly damped exciter modes of oscillation at maximum active output unless otherwise specified by the *IESO*. Due consideration will be given to inherent limitations. For *electricity storage units, Power System Stabilizer shall be disabled while withdrawing*.
9. Phase Unbalance	Provide an open circuit phase voltage unbalance not more than 1% and operate continuously with a phase voltage unbalance as high as 2% at the high-voltage terminal of its main output transformer.
10. Armature and Field Limiters	Provide short-time capabilities specified in IEEE/ANSI 50.13 and continuous capability determined by either maximum field current, maximum stator current, core-end heating, or minimum field current. More restrictive limiting functions, such as steady state stability limiters, shall not be enabled without *IESO* approval.
11. Technical Characteristics	Exhibit, at the high-voltage terminal of its main output transformer, performance comparable to an equivalent synchronous *generation unit* with characteristic parameters within typical ranges. Inertia, unsaturated transient impedance, transient time constants, and saturation coefficients shall be within typical ranges (e.g. H > 1.2 Aero-derivative, H > 1.2 Hydroelectric units less than 20 MVA, H > 2.0 Hydroelectric units 20 MVA or

Category	*Generation facilities* or *electricity storage facilities* directly connected to the *IESO-controlled grid* shall have the capability to:
	larger, H > 4.0 Other synchronous units, X'd < 0.5, T'd0 > 2.0, and S1.2 < 0.5) except where permitted by *IESO* approval.
12. Reactive Power Response to Voltage Changes of Inverter-Based Units	For a constant voltage at the high-voltage terminal of the main output transformer, achieve a sustained reactive power change of 30% of *generation facility* or *electricity storage facility* rated apparent power at the low-voltage terminal of the main output transformer within 3s following a step change no larger than 4% to the AVR voltage reference. AVR response to the voltage error signal must be consistent over the entire operating range.

Appendix 4.3 – Requirements for Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

The performance requirements set out below shall apply to *connected wholesale customers* and *distributors* that are connecting equipment or *facilities* to the *IESO-controlled grid* or to their *distribution systems* after January 18, 2021.

Equipment connected within a *connected wholesale customer's* or *distributor's facilities* or *distribution systems* that was authorized to *connect* prior to January 18, 2021 shall remain subject to the performance requirements in effect at the time its authorization to *connect* was granted (i.e. the "original performance requirements"). These original performance requirements shall prevail until the main elements of an associated system are replaced or substantially modified. At that time, the associated system that is replaced or substantially modified shall meet the applicable performance requirements detailed below. All other systems not affected by replacement or substantial modification, shall remain subject to the original performance requirements.

Category	***Requirement***
1. Power Factor	*Connected wholesale customers* and *distributors* connected to the *IESO-controlled grid* shall operate at a power factor within the range of 0.9 lagging to 0.9 leading as measured at the *defined meter point*.
2. Under Frequency Load Shedding	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* may be required to participate in under frequency load shedding
3. Remedial Action Schemes	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* may be required to participate in *remedial action schemes*.
4. Voltage Reduction	*Distributors* connected to the *IESO-controlled grid* with directly *connected load facilities* of aggregated rating above 20 MVA and with the capability to regulate *distribution* voltages under load, shall install and maintain *facilities* and equipment to provide *voltage reduction capability*.
5. [Intentionally left blank]	
6. [Intentionally left blank]	
7. [Intentionally left blank]	

Category	*Requirement*
8. [Intentionally left blank]	
9. Testing and Compliance Monitoring	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* shall test and maintain their equipment in accordance with all applicable *reliability standards*.
10. Metering	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* shall comply with metering codes and standards set by the *IESO*.
11. Voltage Ride-Through	Equipment connected within a *connected wholesale customer's* or a *distributor's facility* or *distribution system* that is connected to the *IESO-controlled grid* shall ride through routine switching events and design criteria contingencies on the *transmission system* assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless either disconnected by configuration or a failure to do so has been assessed and confirmed by the *IESO* as having no material adverse effect on the operation of the *IESO-controlled grid*.
12*. Generation Units* and *Electricity Storage Units*	Any *generation unit* or *electricity storage unit* connected within a *connected wholesale customer's* or a *distributor's facility* or *distribution system* that is connected to the *IESO-controlled grid* shall meet, at a minimum, the performance requirements for Off-Nominal Frequency Operation (category 1), Speed/Frequency Regulation (category 2), and Voltage Ride-Through (category 3) specified in Appendix 4.2. If a *connected wholesale customer* injects active power into the *IESO-controlled grid*, all performance requirements specified in Appendix 4.2 are applicable to the *generation units* and *electricity storage units* installed within their *facility*. Note: These performance requirements shall apply to *electricity storage units* and *generation units* at all times while connected within a *connected wholesale customer's* or *distributor's facilities* or *distribution system* that is connected to the *IESO-controlled grid*, unless the *IESO* identifies specific performance requirements that are not applicable to an *electricity storage unit* or *generation unit* for those with a *connection assessment* finalized after January 18, 2021. Due consideration will be given to inherent limitations.

Appendix 4.4 – Transmitter Requirements

Ref	*Item*	*Requirement*
1	Abrupt Voltage Changes	Voltage changes shall not normally exceed 4% of steady state rms for capacitor switching operations. Voltage changes shall not normally exceed 10% of steady state rms for line switching operations
2	Frequency Variations	All equipment shall be capable of continuous operation within the range of 59.5 to 60.5 Hz and have the capability to operate for 10 minutes in the range 58 to 61.5 Hz.
3	Load Shedding Facilities	Each *transmitter* shall comply with *IESO* requirements for automatic under-frequency load shedding in accordance with its *operating agreement.* Each *transmitter* shall be able to manually drop up to 50% of its load within 10 minutes.
4	Automatic Reclosure	Transmission circuits shall be equipped with timed, single-shot automatic re-closing facilities. Reclosure shall only be initiated by protections that operate when it is highly likely that the fault is not permanent. Reclosure within 5 seconds of fault detection is allowed only in exceptional circumstances. Angle supervision shall be provided on all breakers rated at 230 kV and above. Automatic reclosure shall remain enabled only for a limited period of time, usually about 40 seconds, following initiation.
5	Thermal Ratings	• *Market participants* that own and operate transmission equipment shall provide the *IESO* with the continuous and limited time thermal ratings for their transmission circuits and transformers. • *Market participants* shall provide this information to the *IESO* via a data link with a minimum update rate of 5 minutes or as agreed to by the *IESO*. For backup and pre-dispatch purposes, *market participants* shall provide a thermal rating table in a suitable format to facilitate *IESO* applications to perform thermal rating interpolation. • Where other equipment (e.g. wavetraps) is more limiting, *market participants* shall provide the *IESO* with the thermal rating of the most restrictive element. • *Generators* and *connected wholesale customers* that own and operate transmission equipment that is part of the *IESO-controlled grid* shall provide the *IESO* with the continuous and limited time thermal ratings for their transmission circuits and transformers only if required by the *IESO* to maintain *reliable* operation of the *IESO-controlled grid*. • Limited time thermal ratings shall be 15-minute ratings, unless mutually agreed by the *IESO* and *market participant.*

Ref	*Item*	*Requirement*
6	Protective System Requirements	Protection systems shall be constructed and maintained in accordance with all applicable *reliability standards*.
7	*IESO* Information Requirements	The *transmitter* shall provide any information that the *IESO* deems necessary to direct the operation of the *IESO-controlled grid*. This Information, including, but not limited to, voltages, flows, and equipment status shall be telemetered continually to the *IESO*.
8	Voltage Reduction	*Transmitters* with the ability to regulate *distribution* voltages under load shall install and maintain facilities and equipment to provide *voltage reduction capability*.
9	Telecommunications	Communication channels shall have a level of reliability that is consistent with the required performance of the associated protection system. Telecommunications shall be designed to assure adequate signal transmission during transmission disturbances and may be provided with means to verify proper signal performance. Equipment may be monitored to assess its readiness and be powered by batteries or other sources independent of the *IESO*.
10	Testing and Compliance Monitoring	*Transmitters* shall test and maintain their equipment in accordance with all applicable *reliability standards.*
11	Metering	*Transmitters* shall comply with the metering codes and standards set by the *IESO*.

Appendix 4.5 – [Intentionally left blank]

Appendix 4.5A – [Intentionally left blank]

Appendix 4.6 – [Intentionally left blank]

Appendix 4.7 – [Intentionally left blank]

Appendix 4.8 – [Intentionally left blank]

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Appendix 4.11 – [Intentionally left blank]

Appendix 4.12 – [Intentionally left blank]

Appendix 4.13 – [Intentionally left blank]

Appendix 4.14 – [Intentionally left blank]

Appendix 4.15 – IESO Monitoring Requirements: Generators

The following information, as a minimum, shall be available on a continual basis to the *IESO* from:

(a) any *generator* (i) whose *generation facility* is connected to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

(b) any *embedded generator* (i) that is not a *market participant* or whose *embedded generation facility* is not associated with any *resources*; (ii) whose *embedded generation facility* includes a *generation unit* rated at greater than 20 MVA or that comprises *generation units* the ratings of which in the aggregate exceeds 20 MVA; and (iii) that is designated by the *IESO* for the purposes of section 7.3.1 of this Chapter as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

TYPE	SCADA INFORMATION REQUIREMENTS
Major generation facility	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the *IESO* as required for: (i) determination of operating *security limits*; (ii) to maintain *reliable* operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *generation units* rated greater than or equal to 100 MVA, the standard requirement as defined in part a) for each *generation unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *generation units* rated at less than 100 MVA: (i) for a group of *generation units* if those *generation units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *generation units*, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as

TYPE	SCADA INFORMATION REQUIREMENTS
	defined in part a) for each *generating unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). d) For *generation facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid* or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each *generating unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). e) For frequency changers: (i) total MW and MX at either frequency; or (ii) if so designated by the *IESO* as required for determination of operating *security limits*, total MW and MX at both frequencies. f) For synchronous condensers: (i) total MX. 2. Voltage: a) For each *generation unit*, unit terminal voltage, except if *generation units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *generation units*. 3. Frequency: a) For each *generation unit* or *generation facility* providing *black start capability*, frequency of the applicable *generation unit* or *generation facility*. 4. Equipment Status a) Unit mode (i.e. generator, condenser, pump) for each *generation unit* capable of different modes of operation. b) *AGC* status for each *generation unit* associated with a *resource* providing *regulation*. c) AVR and Stabilizer Status for each *generating unit* with a rated capacity ≥ 100 MVA. Stabilizer status reporting is only required if it can be switched off by *generation facility* personnel remotely or at the *facility*. d) AVR and Stabilizer status for each *generation unit* with a rated capacity ≤ 100 MVA if the status of this equipment is designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid*. Stabilizer status reporting is only

TYPE	SCADA INFORMATION REQUIREMENTS
	required if it can be switched on or off by *market participant* operating personnel remotely or at the *facility*. e) Synchronizing Breaker status for each *generation unit*. Where a *generation facility* is designed such that no low voltage synchronizing breaker is installed for each *generation unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *generation unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where a *generation facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. f) *Remedial Action Scheme* status for each applicable *generation unit*.
Significant generation facility and minor generation facility connected to IESO-controlled grid	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX): a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the *IESO* as required for: (i) determination of operating *security limits*; (ii) to maintain *reliable* operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *generation facilities* that have not been aggregated pursuant to Chapter 7 section 2.3: (i) for a group of *generation units* if those *generation units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *generation units*, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); (ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as defined in part a) for each *generating unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *generation facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW and gross MX* or *net*

TYPE	SCADA INFORMATION REQUIREMENTS
	MX shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid* or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each *generating unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). d) For frequency changers: (i) total MW and MX at either frequency; or (ii) if so designated by the *IESO* as required for determination of operating *security limits*, total MW and MX at both frequencies. e) For Synchronous Condensers: (i) Total MX. 2. Voltage: a) For *generation units* that are VAR *dispatchable*, unit terminal voltage, except if the *generation units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *generation units*. 3. Frequency: a) For each *generation unit* or *generation facility* providing *black start capability*, frequency of the applicable *generation unit* or *facility.* 4. Equipment Status a) Unit mode (i.e. generator, condenser, pump) for each *generation unit* capable of different modes of operation. b) AVR and Stabilizer Status for each *generation unit* if the status of this equipment is designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid*. Stabilizer status reporting is only required if it can be switched on or off by *market participant* operating personnel remotely or at the *facility*. c) Synchronizing Breaker Status for each *generation unit*. Where a *generation facility* is designed such that no low voltage synchronizing breaker is installed for each *generation unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *generation unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where a *generation facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. d) *Remedial Action Scheme* status for each applicable *generation unit*.

TYPE	SCADA INFORMATION REQUIREMENTS
Self-scheduling generation facility with a name-plate rating of less than 10 MW	None
Intermittent *generation resource*	• if a major generation facility, as described above for a major generation facility • if a significant generation facility, as described above for a significant generation facility • if a *minor generation facility*, as described above for a *minor generation facility* if designated by the *IESO* at the time of registration as affecting the *reliability* of the *IESO-controlled grid* • if a small generation facility, none
Small generation facility	None
Minor generation facility that is embedded in a distribution system and registered as a dispatchable generator	• Total active power (MW) output of the individual *generation unit* or of the aggregated resource. • Unit status if the *facility* is comprised of a single *generation unit*. • Aggregated resource status if the *facility* is comprised of aggregated resources, i.e. if at least one unit of the aggregated resource is synchronized, the aggregated resource is synchronized or if no unit in the aggregated resource is synchronized, the aggregated resource is not synchronized. • Reactive Power (MX) output, if requested by the *IESO* for reliable operation of the *IESO-controlled grid*, of individual *generation units* or of the aggregated resource.

Type	Synchrophasor Data Requirements
Generation facility	The following are required unless otherwise specified by the IESO: (1) For *generation units* rated greater than or equal to 100 MVA (name-plate rating), each *generation unit* shall provide positive

Type	Synchrophasor Data Requirements
	sequence voltage phasor, positive sequence current phasor and frequency from generator terminal. (2) For *generation units* connected to the IESO-controlled grid through a common connection point, whose aggregated rated size is greater than or equal to 100 MVA (aggregate nameplate rating), positive sequence voltage phasor, aggregated positive sequence current phasor and frequency shall be provided from the generation facility side of the connection point to the grid. (3) For *generation units*, regardless of rated size, whose output power flow is a part of an Interconnection Reliability Operating Limit (IROL) definition, positive sequence voltage phasor, positive sequence current phasor and frequency shall be provided at the terminals defining the IROL.

Unless otherwise specified by the IESO, synchrophasor data requirements shall comply with the corresponding Market Manual.

Appendix 4.16 – IESO Monitoring Requirements: Transmitters

The following information regarding the *IESO-controlled grid*, as a minimum, shall be available on a continual basis to the *IESO* from *transmitters*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

Equipment Type	Voltage Level	Monitored Status	Monitored SCADA Quantities
Station Bus			
Bus Voltage	50 kV and higher		Specified phase-phase and phase to ground voltages measured at different buses. Note: a line voltage may be used if bus PTs are not available.
Frequency	50 kV and higher		As directed by the *IESO* for points on the *IESO-controlled grid* that are significant for reliability purposes. High accuracy PTs & measurements of frequency are required at a number of stations at the discretion of the *IESO*.
TRANSFORMATION			

Equipment Type	Voltage Level	Monitored Status	Monitored SCADA Quantities
Autotransformers	50 kV and above	Isolating switches As described in the "Reactive Devices" section below for ancillary equipment associated with the transformer	Megawatts and Megavars for the high voltage winding for each transformer Megawatts and Megavars for the low voltage winding for each transformer, if other than station service is connected to the tertiary winding. ULTC tap positions for the transformer The *IESO* may require the monitoring of any Off-Load Tap Changer positions.
Phase Shifting Transformers	50 kV and higher	Bypass and isolating switches	Voltage, MW and MVAR may be required as directed by the *IESO* All transformer tap positions
Step Down Transformers	50 kV and higher	Bypass and isolating switches	MW and MVAR Phase to ground Voltage, for each winding measured on the high voltage side. Where only LV PTs are available: MW and phase to phase voltages for each LV winding ULTC tap positions.
Voltage Regulating Transformers	50 kV and higher	Bypass and isolating switches	MW and MVAR may be required as directed by the *IESO* ULTC tap positions for the transformer The *IESO* may require the monitoring of any Off-Load Tap Changers.

Equipment Type	Voltage Level	Monitored Status	Monitored SCADA Quantities
Isolating Devices			
Breakers and Switches	50 kV and higher including connected tertiaries	All Circuit breakers, including bus tie breakers All breakers connecting loads for each tertiary winding of autotransformer other than that for Station Service Each capacitor breaker All line disconnect switches All transformer disconnect and by-pass switches All bus sectionalizing switches All isolating switches for reactors and capacitors where circuit breakers are not provided All in line switches as specified Note: The status of breaker isolating switches is not required	

Equipment Type	Voltage Level	Monitored Status	Monitored SCADA Quantities
	Below 50 kV	Breakers of Low Voltage Capacitors, Reactors, Transformers that are part of or have an impact on the *IESO-controlled grid* or that are subject to a contracted ancillary services contract including by means or within the scope of an *operating agreement* Each reactor or condensor breaker.	
Isolating and by-pass switches	50 kV and higher	Isolating and bypass switches for each transformer Bus sectionalizing switches Reactor and capacitor isolation	
Circuits			
Circuit forming part of the *IESO-controlled grid*	50 kV and higher		MW and MVAR line flow at each terminal
Circuit that is an interconnection with another control area	50 kV and higher		• MW and MVAR line flow • (MW from the billing meter point) where practical
Special Protection Schemes			
Remedial Action Schemes (RAS)	50 kV and higher	As directed by the *IESO* on a case-by-case basis. Where	As directed by the *IESO* on a case-by-case basis.

Equipment Type	Voltage Level	Monitored Status	Monitored SCADA Quantities
		so directed, must include all associated capacitors and reactors breaker status.	
Reactive Devices			
Capacitors, Synchronous Condensors, Reactors, Static Var Compensators, FACTS	All levels designated by the *IESO* as affecting the *reliability* of the *IESO-controlled grid*	Breaker Status	MVARs where output is variable.

Equipment Type	Voltage Level	Monitored Syncrophasor Quantities
Station Buses (a) 500 kV station (b) *Bulk Power System (BPS)* Required to restore IESO-controlled grid from generating facilities providing *black-start capability*.	50 kv and higher	Positive sequence voltage phasor magnitude Positive sequence voltage phasor angle
		Frequency
Circuits defining Interconnection Reliability Operating Limits (IROL) and interties	50 kv and higher	Positive sequence current phasor magnitude measured at terminals Positive sequence current angle magnitude measured at terminals

Equipment Type	Voltage Level	Monitored Syncrophasor Quantities
		Positive sequence voltage phasor magnitude measured at terminals Positive sequence voltage phasor angle measured at terminals
		Frequency
Static Var Compensators (SVCs), Synchronous condensers, and Static synchronous compensators (STATCOMs)	Below 50 kv	Positive sequence current phasor magnitude measured at terminals Positive sequence current angle magnitude measured at terminals
		Positive sequence voltage phasor magnitude measured at terminals Positive sequence voltage phasor angle measured at terminals
		Frequency

Unless otherwise specified by the IESO, *synchrophasor* data requirements shall comply with the corresponding Market Manual.

Appendix 4.17 – IESO Monitoring Requirements: Connected Wholesale Customers and Distributors

The following information, as a minimum, shall be available on a continual basis to the *IESO* from all *distributors connected* to the *IESO-controlled grid*, *distributors* designated pursuant to section 7.5.2 and *connected wholesale customer*s. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. A *connected wholesale customer* that is also a *generator* shall also comply with the applicable requirements of Appendix 4.15.

TYPE	MONITORED QUANTITIES
Distributor connected to the *IESO-controlled grid* or designated pursuant to section 7.5.2	• Where high voltage (HV) Potential Transformers (PTs) are available: Circuits: (where applicable) • Megawatt (MW), megavars (MVARs) and direction of power flow at each terminal connected to the *IESO-controlled grid*. Transformers: • MW, MVARS • phase to ground voltages for each HV winding as specified by the *IESO* • Where only low voltage PTs are available: • MW, MVARs for each Low Voltage (LV) winding, and • phase to phase voltage for each LV winding as specified by the *IESO*. • Under Load Tap Changer (ULTC) tap positions. • Off Load Tap Changer (OLTC) tap positions may be required, as directed by the *IESO* • Status of breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid*, or that are subject to a contracted ancillary services contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the connected *wholesale customer* • Status of: • All breakers 50 kV and above. • All line disconnect switches 50 kV and above.

TYPE	MONITORED QUANTITIES
	• All transformer disconnect and by-pass switches 50 kV and above. • All bus sectionalising switches 50 kV and above. • transformer LV winding breakers and bus tie breakers for DESN type step-down transformers connected to the *IESO-controlled grid* The status of breaker isolating switches is not required. • *Remedial Action Schemes* as directed by the *IESO* on a case by case basis.
Connected wholesale customers	For: • All dispatchable loads; and Each *load facility* that includes *load equipment* rated individually or in the aggregate at 20 MVA or higher associated exclusively with a *non-dispatchable load* or *price responsive load*, in each case where directed by the *IESO* if transmitter data is not adequate the following shall be monitored: Where high voltage PTs are available: Circuits: (where applicable) • Megawatts (MW), and Megavars (MVAR) and direction of power flow at each terminal connected to the *IESO-controlled grid*. Transformers: • Megawatts (MW), and Megavars (MVAR) and • phase to ground voltages for each HV winding as specified by the *IESO*. Where only low voltage PTs are available: • MW, MVARs from each LV winding, and • phase to phase voltages for each LV winding as specified by the *IESO*. • Under Load Tap Changer (ULTC) tap positions. • Off Load Tap Changer (OLTC) tap positions may be required, as directed by the *IESO* • Status of: • All breakers 50 kV and above. • All line disconnect switches 50 kV and above. • All transformer disconnect and by-pass switches 50 kV and above. • All bus sectionalising switches 50 kV and above.

TYPE	MONITORED QUANTITIES
	• Transformer LV winding breakers and bus tie breakers for DESN type step-down transformers connected to the *IESO-controlled grid* • Breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid* or that are subject to a contracted *ancillary services* contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the *connected wholesale customer* The status of breaker isolating switches is not required • *Remedial Action Schemes (RAS)* as directed by the IESO

Appendix 4.18 – IESO Monitoring Requirements: Embedded Load Consumers

The following information, as a minimum, shall be available on a continual basis to the *IESO* from all *embedded load consumers* designated by the *IESO* pursuant to section 7.6.1. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. An *embedded load consumer* that is also a *generator* shall also comply with the applicable requirements of Appendix 4.15.

TYPE	SIZE	MONITORED QUANTITIES
Dispatchable load		• Megawatts (MW), • megavars (MVAR) as designated by the *IESO* as required to maintain *reliable* operation of the *IESO-controlled grid*, • phase to phase voltages as specified by the *IESO*, and • status of breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid* or that are subject to a *contracted ancillary services* contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the *embedded load consumer*
Non-dispatchable load or price responsive load	For a *load facility* that includes *load equipment* rated individually or in the aggregate at 20MVA or higher that is associated exclusively with a *non-dispatchable load* or *price responsive load*	Where directed by the *IESO* if *transmitter* or *distributor* data is not sufficient, • MW, MVAR, • phase to phase voltages as specified by the *IESO*; and • status of breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid* or that are subject to a *contracted ancillary services* contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the *embedded load consumer*

Appendix 4.19 – IESO Monitoring Requirements: Generator Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *generators* referred to in section 7.3.1 of this Chapter when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

FUNCTION	**Major generation facility or significant generation facility** **(High Performance)**	**Minor generation facility and intermittent *generation resource* designated pursuant to section 7.3.2.3** **(Medium Performance)**	**Small generation facility**
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	1. Less than 10 seconds from change in field monitored quantity or 2. If the *minor generation facility* is embedded within a *distribution system,* less than one minute from change in field monitored quantity unless otherwise designated by the *IESO* to maintain the	Not applicable

FUNCTION	**Major generation facility or significant generation facility (High Performance)**	**Minor generation facility and intermittent *generation resource* designated pursuant to section 7.3.2.3 (Medium Performance)**	**Small generation facility**
		reliability of the *IESO-controlled grid*.	
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	1. Less than 10 seconds from field status change or 2. If the *minor generation facility* is embedded within a *distribution system*, less than one minute from change in equipment status unless otherwise designated by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.	Not applicable
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
IESO scan period for Equipment Status	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
Data Skew	Maximum: 4 seconds	Not applicable	Not applicable

FUNCTION	Major generation facility or significant generation facility (High Performance)	Minor generation facility and intermittent *generation resource* designated pursuant to section 7.3.2.3 (Medium Performance)	Small generation facility
[Intentionally left blank – section deleted]			
[Intentionally left blank – section deleted]			

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

Appendix 4.20 – IESO Monitoring Requirements: Transmitter Performance Standards

The following performance levels, as a minimum, shall be achieved on a continual basis by all *transmitters* when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

PERFORMANCE LEVEL	FACILITIES
For transmission facilities or assets designated by the *IESO* as high performance at the time of registration, must meet the high performance levels in Appendix 4.21	All facilities and assets at 50 kV and above which are monitored for system limits such as transformer or switching stations All transformer and switching stations with interconnected ties An RTU which collects information at several locations on the *electricity system* Step-down transformer facilities that supply a *dispatchable load facility* that is required to meet high performance monitoring standard All other facilities where medium performance is not specified below
For transmission facilities or assets designated by the *IESO* as medium performance at the time of registration, must meet the medium performance levels in Appendix 4.21	Step-down transformer facilities that supply a *dispatchable load facility* that is required to meet medium performance monitoring standard Step-down transformer facilities that supply a *load facility* that includes *load equipment* rated individually or in the aggregate at 20 MVA or higher associated exclusively with a *non-dispatchable load* or *price responsive load*

PERFORMANCE LEVEL	FACILITIES
	Facilities and assets at 50 kV and above designated by the *IESO* as requiring medium performance

Appendix 4.21 – IESO Monitoring Requirements: Transmitter Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *transmitters* when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

FUNCTION	Transmission facilities or assets identified as high performance in Appendix 4.20	Transmission facilities or assets identified as medium performance in Appendix 4.20
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	Less than 10 seconds from change in field monitored quantity
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	Less than 10 seconds from field status change
Data Skew	Maximum: 4 seconds	N/A
IESO scan period for data measurements	Maximum: 4 seconds*	Minimum:** 4 seconds
IESO scan period for equipment status	Maximum: 4 seconds*	Minimum:** 4 seconds

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

Appendix 4.22 – IESO Monitoring Requirements: Distributors and Connected Wholesale Customer Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *distributors connected* to the *IESO-controlled grid*, *distributors* designated pursuant to section 7.5.2 and *connected wholesale customers* when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. A *connected wholesale customer* that is also a *generator* shall also comply with the requirements of Appendix 4.19.

FUNCTION	**Major Dispatchable Load Facility and Significant Dispatchable Load Facility** **(High Performance)**	***Minor Dispatchable Load Facility* and *Load Facilities****** that includes *load equipment* rated individually or in the aggregate at 20 MVA or higher associated exclusively with a *non-dispatchable load* or *price responsive load*** **(Medium Performance)**
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	Less than 10 seconds from change in field monitored quantity
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	Less than 10 seconds from field status change
Data skew	Maximum:* 4 seconds	Not applicable

FUNCTION	Major Dispatchable Load Facility and Significant Dispatchable Load Facility (High Performance)	*Minor Dispatchable Load Facility* and *Load Facilities**** that includes *load equipment* rated individually or in the aggregate at 20 MVA or higher associated exclusively with a *non-dispatchable load* or *price responsive load* (Medium Performance)
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds
IESO scan period for equipment status	Maximum:* 4 seconds	Minimum:** 4 seconds

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

*** Where directed by the *IESO* if *transmitter* data is not adequate.

Appendix 4.23 – IESO Monitoring Requirements: Embedded Load Consumers Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *embedded load consumers* designated pursuant to section 7.6.1 when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. An *embedded load consumer* that is also a *generator* shall also comply with the requirements of Appendix 4.19.

FUNCTION	**Major Dispatchable Load Facility and Significant Dispatchable Load Facility** **(High Performance)**	***Minor Dispatchable Load Facility* and *Load Facility**** that includes *load equipment* rated individually or in the aggregate at 20 MVA or higher associated exclusively with a *non-dispatchable* load or *price responsive load* (Medium Performance)**
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	1. Less than one minute from change in field monitored quantity; or 2. Less than 10 seconds from change in field monitored quantity if designated by the *IESO* as required to maintain *reliable* operation of the *IESO-controlled grid*.
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	1. Less than one minute from change in field monitored quantity; or 2. Less than 10 seconds from field status change if designated by the *IESO* as required to maintain *reliable* operation of the *IESO-controlled grid*.
Data skew	Maximum:* 4 seconds	Not applicable
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds
IESO scan period for equipment status	Maximum:* 4 seconds	Minimum:** 4 seconds

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

*** Where directed by *IESO* if *transmitter* or *distributor* data is not adequate.

Appendix 4.24 – IESO Monitoring Requirements: Electricity Storage Participants

The following information, as a minimum, shall be available on a continual basis to the *IESO* from:

(a) any *electricity storage participant* (i) whose *electricity storage facility* is *connected* to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

(b) any *embedded electricity storage participant* (i) that is not a *market participant* or whose *embedded electricity storage facility* is not associated with any *resources*; (ii) whose *embedded electricity storage facility* includes an *electricity storage unit* with an *electricity storage unit* size rated at greater than 20 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit* size ratings of which exceeds 20 MVA; and (iii) that is designated by the *IESO* for the purposes of section 7.3.1 of this Chapter as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

TYPE	INFORMATION REQUIREMENTS
Major electricity storage facility	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) injected or withdrawn a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the *IESO* as required for: (i) determination of operating *security limits*; (ii) to maintain *reliable* operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *electricity storage units* with an *electricity storage unit size* greater than or equal to 100 MVA, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *electricity storage units* with an *electricity storage unit size* of less than 100 MVA: (i) for a group of *electricity storage units* if those *electricity storage units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *electricity storage*

TYPE	INFORMATION REQUIREMENTS
	units, and total *gross MW* and *gross MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). d) For *electricity storage facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid* or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). 2. State of Charge and Charge Limit a) For each *electricity storage unit* or *electricity storage facility*, the *state of charge* of the applicable *electricity storage unit* or *electricity storage facility* b) For each *electricity storage unit* or *electricity storage facility*, the economic maximum charge limit and the economic minimum charge limit expressed in MWh as per the applicable *market manual*. 3. Base point a) For each *electricity storage unit* or *electricity storage facility* associated with a *resource* providing *regulation*, the basepoint, if applicable, of the *electricity storage unit* expressed in MW, according to the applicable *market manual*. 4. Dynamic Maximum and Minimum Power a) For each *electricity storage unit* or *electricity storage facility*, the economic maximum power mode and economic minimum power mode, expressed in MW. 5. Voltage: a) For each *electricity storage unit*, unit terminal voltage, except if *electricity storage units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *electricity storage units*. 6. Equipment Status

TYPE	INFORMATION REQUIREMENTS
	a) Voltage Control status and stabilizer status (if applicable) for each *electricity storage unit* with an *electricity storage unit size* > 100 MVA. When applicable, stabilizer status reporting is only required if it can be switched off by electricity storage participant personnel remotely or at the facility. b) AGC status for each *electricity storage unit* associated with a *resource* providing *regulation*. c) Voltage control status and stabilizer status (if applicable) for each *electricity storage unit* with an *electricity storage unit size* < 100 MVA if the status of this equipment is designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the *IESO-controlled grid*. When applicable, stabilizer status reporting is only required if it can be switched on or off by market participant operating personnel remotely or at the *facility*. d) Synchronizing Breaker status for each *electricity storage unit*. Where a *electricity storage facility* is designed such that no low voltage synchronizing breaker is installed for each *electricity storage unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the electricity storage unit must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. e) Where a *electricity storage facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. f) *Remedial Action Scheme* status for each applicable *electricity storage unit*.
Significant electricity storage facility and minor electricity storage facility connected to IESO-controlled grid	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) injected or withdrawn: a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX* facility. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the IESO as required for: (i) determination of operating security limits; (ii) to maintain reliable operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating security limits. b) For *electricity storage facilities* that have not been aggregated pursuant to Chapter 7 section 2.3: (i) for a group of *electricity storage units* if those *electricity storage units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these electricity storage units, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the IESO as required using the criteria listed above in part a);

TYPE	INFORMATION REQUIREMENTS
	(ii) if designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid or for compliance monitoring purposes, the standard requirement as defined in part a) for each electricity storage unit shall be provided, and gross MW and gross or net MX for each electricity storage unit shall be provided if designated by the IESO as required using the criteria listed above in part a). c) For *electricity storage facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the IESO as required using the criteria listed above in part a); or (ii) if so designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each electricity storage unit shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the IESO as required using the criteria listed above in part a). 2. Voltage: a) For *electricity storage units* that are VAR dispatchable, unit terminal voltage, except if the electricity storage units are connected to a common low voltage bus section, then the bus section voltage is adequate for those electricity storage units. 3. State of Charge and Charge Limit a) For each *electricity storage unit* or *electricity storage facility*, the *state of charge* of the applicable *electricity storage unit* or *electricity storage facility* b) For each *electricity storage unit* or *electricity storage facility*, the economic maximum charge limit and the economic minimum charge limit expressed in MWh as per the applicable *market manual*. 4. Dynamic Maximum and Minimum Power a) For each *electricity storage unit* or *electricity storage facility*, the economic maximum power mode and economic minimum power mode, expressed in MW. 5. Base point a) For each *electricity storage unit* or *electricity storage facility* associated with a *resource* providing *regulation*, the basepoint, if applicable, of the storage unit expressed in MW, according to the applicable *market manual*. 6. Equipment Status a) Automatic Voltage Control and stabilizer status (if applicable) for each *electricity storage unit* if the status of this equipment is designated by the IESO as required for determination of operating security limits or to maintain

TYPE	INFORMATION REQUIREMENTS
	reliable operation of the IESO-controlled grid. When applicable, stablizer status reporting is only required if it can be switched on or off by the *market participant* operating personnel remotely or at the facility. b) Synchronizing Breaker Status for each *electricity storage unit*. Where an *electricity storage facility* is designed such that no low voltage synchronizing breaker is installed for each *electricity storage unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *electricity storage unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where an *electricity storage facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. c) *Remedial Action Scheme* status for each applicable *electricity storage unit*.
Self-scheduling electricity storage facility with a name-plate rating of less than 10 MW	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) injected or withdrawn: a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the IESO as required for: (i) determination of operating *security limits*; (ii) to maintain reliable operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *electricity storage facilities* that have not been aggregated pursuant to Chapter 7 section 2.3: (i) for a group of *electricity storage units* if those *electricity storage units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *electricity storage units*, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); (ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *electricity storage facilities* that have been aggregated pursuant to Chapter 7 section 2.3:

TYPE	INFORMATION REQUIREMENTS
	(i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the IESO as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for *dispatch* compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). 2. Voltage: a) For *electricity storage unit*s that are VAR dispatchable, unit terminal voltage, except if the *electricity storage units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *electricity storage units*. 3. State of Charge and Charge Limit a) For each electricity storage unit or electricity storage facility, the state of charge of the applicable *electricity storage unit* or *electricity storage facility* b) For each *electricity storage unit* or *electricity storage facility* the economic maximum charge limit, the economic minimum charge limit expressed in MWh 4. Dynamic Maximum and Minimum Power a) For each *electricity storage unit*, the economic maximum power mode and economic minimum power mode, expressed in MW. 5. Base point a) For each *electricity storage unit* associated with a *resource*, providing *regulation* the basepoint of the applicable *electricity storage unit* expressed in MW according to the applicable *market manual*. 6. Equipment Status a) Automatic Voltage Control status and Stabilizer status (if applicable) for each *electricity storage unit* if the status of this equipment is designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid*. When applicable, stablizer status reporting is only required if it can be switched on or off by *market participant* operating personnel remotely or at the *facility*. b) Synchronizing Breaker Status for each *electricity storage unit*. Where an *electricity storage facility* is designed such that no low voltage synchronizing breaker is installed for each *electricity storage unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *electricity storage unit* must be provided. Where this results in access to

TYPE	INFORMATION REQUIREMENTS
	the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where an *electricity storage facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. c) *Remedial Action Scheme* status for each applicable *electricity storage unit*.
Small electricity storage facility	None
Minor electricity storage facility that is embedded in a distribution system and registered as a dispatchable electricity storage participant	Monitored Quantities 1. Total active power (MW) output of the individual *electricity storage unit* or of the aggregated resource. a) Unit status if the *facility* is comprised of a single *electricity storage unit*. b) Aggregated resource status if the *facility* is comprised of aggregated resources, i.e. if at least one unit of the aggregated resource is synchronized, the aggregated resource is synchronized or if no unit in the aggregated resource is synchronized, the aggregated resource is not synchronized. c) Reactive Power (MX) output, if requested by the *IESO* for reliable operation of the *IESO-controlled grid*, of individual *electricity storage units* or of the aggregated resource. d) Unit terminal voltage (kV) if requested by the IESO for reliable operation of the *IESO controlled grid* 2. State of Charge and Charge Limit a) For each electricity storage unit or electricity storage facility, the state of charge of the applicable electricity storage unit or electricity storage facility expressed as a percentage b) For each *electricity storage unit* or *electricity storage facility*, the economic maximum charge limit, the economic minimum charge limit expressed in MWh 3. Dynamic Maximum and Minimum Power a) For each *electricity storage unit* or *electricity storage facility*, the economic maximum power mode and economic minimum power mode, expressed in MW. 4. Base point a) For each *electricity storage unit* or *electricity storage facility* associated with a *resource*, providing *regulation*, the basepoint, if applicable, of the *electricity storage unit* expressed in MW according to the applicable *market manual*.

Appendix 4.25 – IESO Monitoring Requirements: Electricity Storage Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *electricity storage participants* referred to in section 7.3.A of this Chapter when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

FUNCTION	*Major electricity storage facility* **or** *significant electricity storage facility* **(High Performance)**	*Minor electricity storage facility* **and** *self-scheduling electricity storage facility* **(***electricity storage facility unit size* **<10MW)** **(Medium Performance)**	*Small electricity storage facility*
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	1. Less than 10 seconds from change in field monitored quantity or 2. If the *minor electricity storage facility* is *embedded within a distribution system,* less than one minute from change in field monitored quantity unless otherwise designated by	Not applicable

FUNCTION	*Major electricity storage facility* or *significant electricity storage facility* (High Performance)	*Minor electricity storage facility* and *self-scheduling electricity storage facility* (*electricity storage facility unit size* <10MW) (Medium Performance)	*Small electricity storage facility*
		the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.	
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	1. Less than 10 seconds from field status change or 2. If the *minor electricity storage facility* is *embedded* within a *distribution system*, less than one minute from change in equipment status unless otherwise designated by the *IESO* to maintain the	Not applicable

FUNCTION	*Major electricity storage facility* **or** *significant electricity storage facility* **(High Performance)**	*Minor electricity storage facility* **and** *self-scheduling electricity storage facility* **(***electricity storage facility unit size* **<10MW) (Medium Performance)**	*Small electricity storage facility*
		reliability of the *IESO-controlled grid*.	
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
IESO scan period for Equipment Status	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
Data Skew	Maximum: 4 seconds	Not applicable	Not applicable

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

RUL-13

Renewed Market Rules

Chapter 0.5

Power System Reliability

ieso
Connecting Today.
Powering Tomorrow.

0.5

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Market Rules

Reviewed by
Technical Panel
Legal Affairs

Approved by
IESO Board

Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5. An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

B.1 Exceptions

B.1.1 Notwithstanding section A.1.1, the *legacy market rules* shall apply to any request for *one-day advance approval* of a *planned outage* submitted pursuant to section 6.4.1E prior to the commencement of the *market transition*, including where the requested *planned outage* would occur following the commencement of the *market transition*.

1. Purposes, Interpretation and General Principles

1.1 Purposes of Chapter 5 and Interpretation

1.1.1 Pursuant to section 6 of the *Electricity Act, 1998*, one of the objects of the *IESO* is to maintain the *reliability* of the *IESO-controlled grid*. This Chapter of the *market rules* sets forth:

1.1.1.1 rules governing maintenance of the *reliability* of the *IESO-controlled grid*;

1.1.1.2 conditions under which the *IESO* shall have authority to intervene in the *IESO-administered markets* and issue directions to *market participants* so as to maintain the *reliability* of the *IESO-controlled grid* and of electricity service;

1.1.1.3 procedures to be used by the *IESO*, including the issuance of directions, in the event of an *emergency,* an *emergency operating state* or a *high-risk operating state;*

1.1.1.4 minimum requirements for communication and information exchange between the *IESO* and *market participants* relating to the *reliability* of the *IESO-controlled grid*; and

1.1.1.5 the *IESO's* reporting requirements associated with its responsibilities for maintaining the *reliability* of the *IESO-controlled grid*.

1.1.2 [Intentionally left blank]

1.1.3 In the event of a contradiction or inconsistency between the provisions of this Chapter 5 and any other provision of the *market rules*, the provisions of this Chapter 5 shall govern. In performing any act, power, or duty under the *market rules*, the *IESO* shall have due regard to and, when necessary to ensure the *reliability* of the *IESO-controlled grid*, give precedence to the provisions of this Chapter 5.

1.2 General Principles

1.2.1 To the fullest extent possible consistent with maintaining the *reliability* of the *IESO-controlled grid*, the *IESO* shall apply the *market rules* relating to *reliability* so as to minimize the *IESO's* intervention into the operation of the *IESO-administered* *markets*. However, the maintenance of a *reliable IESO-controlled grid* shall be considered of paramount importance under these *market rules*, and the *IESO* shall have authority to intervene in the *IESO-administered markets* to the extent necessary to maintain the *reliability* of the *IESO-controlled grid*.

1.2.2 In all cases, except as otherwise noted in this Chapter, where the *IESO* takes action under this Chapter, it shall attempt to coordinate its actions with affected *market participants* unless, in the *IESO's* opinion, conditions dictate the need for immediate action.

1.2.3 Nothing in this Chapter is intended to prevent *market participants* from acting to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*, provided that any such actions that may affect the *reliability* of the *IESO-controlled grid* are coordinated with the *IESO* to the fullest extent practicable and are, in any event, reported or notified to the *IESO* where required by these *market rules* to be so reported or notified.

1.2.4 MR Ch.1 s.7.5 does not apply to this Chapter and any action or event that is required to occur on or by a stipulated time or day under this Chapter, or under a direction, instruction or order of the *IESO* issued pursuant to this Chapter, shall occur on or by that time, whether or not a business hour, or on or by that day, whether or not a *business day*, unless otherwise specified in this Chapter.

1.2.5 Unless a direction, instruction or order of the *IESO* provides otherwise, wherever this Chapter specifies that an action is to be taken "promptly" or "immediately", such action shall be taken as soon as possible after receiving the direction, instruction or order from the *IESO* or after becoming aware that an action is to be taken or is required not to be taken but in all events within five minutes, subject only to delay necessitated to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*.

1.2.6 Subject to section 1.2.7, *reliability standards* established by a *standards authority* that have not otherwise been stayed or revoked and referred back to the *standards authority* for further consideration by the *Ontario Energy Board* shall be declared in force in Ontario upon the later date of:

1.2.6.1 the *reliability standards* being declared in force in the United States or, for *NPCC* reliability criteria, when declared in force by *NPCC*; and

1.2.6.2 the expiry of the period for initiating a review before the *Ontario Energy Board* and the conclusion of any such review;

and shall cease to be in force in Ontario when they cease to be in force in the United States, provided that where a *reliability standard* is being retired and replaced with a new or amended version, the previous version shall remain in effect in Ontario until the later of the completion of the conditions in sections 1.2.6.1 and 1.2.6.2.

1.2.7 Notwithstanding section 1.2.6, where a *reliability standard* approved by *NERC* failed to achieve approval by the *NERC* registered ballot body as specified in *NERC*'s Rules of Procedure, the *reliability standard* will not be in force in Ontario unless and until the *IESO* determines, in consultation with affected *market participants*, that all or part of the *reliability standard* is in force in Ontario. The *IESO* shall *publish* notice of its determination and where applicable, such *reliability standard* will come into effect in accordance with section 1.2.6.

2. IESO-Controlled Grid and Operating States

2.1 Scope of IESO-Controlled Grid

2.1.1 The specific *facilities* included within the *IESO-controlled grid* shall be identified in the *operating agreements* between the *IESO* and each *transmitter* that are entered into in accordance with the Electricity Act, 1998. To the extent the *IESO* concludes, on its own initiative or further to a request made by a *market participant*, that, in order to meet its obligations to *reliably* operate the *IESO-controlled grid* or administer the *IESO-administered markets*, additional *transmission systems* or distribution *facilities* should be included within the *IESO-controlled grid*, the *IESO* shall negotiate to amend the applicable *operating agreement* to include such *transmission systems or facilities* or to conclude an *operating agreement* with the *transmitter* or owner of such *facilities* with whom no *operating agreement* has yet been concluded, as the case may be.

2.1.2 Subject to the licence of the *IESO* or of the applicable *transmitter* or *distributor*, if the *IESO* and a *transmitter* or *distributor* are unable to reach agreement on the inclusion of *facilities* within the *IESO-controlled grid*, the matter shall be resolved using the dispute resolution procedures in the applicable *operating agreement* or, in the absence of same, the procedures set forth in MR Ch.3 s.2.

2.2 Normal Operating State

2.2.1 The *IESO-controlled grid* shall be considered as being in a *normal operating state* when:

2.2.1.1 the voltage magnitudes at all energized busbars at any switchyard or substation of the *IESO-controlled grid* are within the ratings set by relevant *transmitters*;

2.2.1.2 the current flows on all transmission *facilities* of the *IESO-controlled grid* are within the equipment ratings established by the relevant *transmitters*;

2.2.1.3 all other electric plant forming part of, or having or likely to have a material impact on the operation of, the *IESO-controlled grid* is being operated within the equipment ratings defined by the relevant *transmitters*, *generators, electricity storage participants,* and *distributors*;

2.2.1.4 all *interconnected systems* having or likely to have a material impact on the operation of the *IESO-controlled grid* are being operated within the equipment ratings that are jointly established between the *IESO* and the relevant *transmitters*;

2.2.1.5 the configuration of the *IESO-controlled grid* is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and

2.2.1.6 conditions on the *IESO-controlled grid* are secure in accordance with the requirements set forth in Section 5.

2.3 Emergency Operating State

2.3.1 The *IESO-controlled grid* shall be considered as being in an *emergency operating state* when observance of *security limits* under a *normal operating state* will either:

2.3.1.1 require *curtailment*; or

2.3.1.2 restrict transactions on *interconnected systems* during an *emergency* on the *IESO-controlled grid* or on a *neighbouring electricity system*.

2.3.2 The *IESO* shall not take any action or refrain from taking any action that will, in the *IESO*'s opinion, be reasonably likely to lead to an *emergency operating state*.

2.3.3 The *IESO* shall promptly inform *market participants* when an *emergency operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During an *emergency operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required to restore the *IESO-controlled grid* to a *normal operating state* and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

2.3.3A Without limiting the generality of section 2.3.3 and notwithstanding any other provision of the *market rules*, the *IESO* may, when the *IESO-controlled grid* is in an *emergency operating state*, acquire *emergency energy* in accordance with all applicable *reliability standards* and any applicable *interconnection agreement* in order to maintain the *reliability* of the *IESO-controlled grid.* The *IESO* shall not exercise this power where *market participants* have *offered* to provide sufficient quantities of *energy*, eligible for *dispatch* or scheduling, to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*. The costs associated with the acquisition of such *emergency energy* paid by the *IESO* pursuant to the applicable *interconnection agreement* shall be recovered in accordance with MR Ch.9 s.4.14.12.

2.3.4 Further provisions relating to system and *market operations* during *emergency* conditions are set forth in MR Ch.7.

2.4 High-Risk Operating State

2.4.1 The *IESO-controlled grid* shall be considered to be in a *high-risk operating state* when the observance of *security limits* under a *normal operating state* will expose the *integrated power system* to a significantly higher than normal probability of one or more *contingency events* and associated consequences, or of a condition that may lead to, but is not yet, an *emergency*. The conditions under which the *IESO-controlled grid* may be considered as entering into or exiting a *high-risk operating state* shall be defined in the *IESO*'s operating procedures, it being understood that, without limiting the generality of the foregoing, a *high-risk operating state* is normally associated with adverse or extreme weather conditions or equipment-related problems that could lead to a *contingency event* on the *IESO-controlled grid* that is not expected under a *normal operating state*.

2.4.2 The *IESO* shall not take any action or refrain from taking any action that will, in the opinion of the *IESO*, be reasonably likely to lead to a *high-risk operating state*.

2.4.3 The *IESO* shall promptly inform *market participants* when a *high-risk operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During a *high-risk operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions and increase *reliability* on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

2.5 Conservative Operating State

2.5.1 The *IESO-controlled grid* shall be considered to be in a *conservative operating state* when the impact of a *contingency event* on the *IESO-controlled grid* could be more severe than under a *normal operating state*. Under a *conservative operating state* the *IESO-controlled grid* will be operated within equipment and *security limits* established for a *normal operating state*. The *IESO-controlled grid* will be in a heightened state of readiness due to anticipated, or actual, stresses on the grid itself, or due to the *IESO's* loss of ability to effectively monitor the *IESO-controlled grid*. Conditions that may require a *conservative operating state* are listed in the applicable *market manual*.

2.5.2 The *IESO* shall promptly inform *market participants* when a *conservative operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During a *conservative operating state*, the *IESO* shall have the authority to take such action or refrain from taking such action consistent with *good utility practice* as may be required and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

3. Obligations and Responsibilities

3.1 Objectives

3.1.1 This section 3 sets forth the responsibilities, obligations and authorities of the *IESO* and each *market participant* in order to maintain the *reliability* of the *IESO-controlled grid*.

3.2 Obligations of the IESO

3.2.1 The *IESO* shall direct the operations of the *IESO-controlled grid* pursuant to the provisions of all applicable *operating agreements* and shall maintain the *reliability* of the *IESO-controlled grid*. The *IESO's* responsibilities in this regard shall include, but are not limited to, the monitoring of, and the issuing of orders, directions or *dispatch instructions* to *facilities* and any associated *resources.*

3.2.2 The *IESO* shall carry out its obligations in accordance with all applicable *reliability standards.*

3.2.3 In order to meet its obligations under this Chapter and under other provisions of the *market rules*, the *IESO* shall maintain written operating procedures and instructions and shall make same available for inspection at all times by *market participants*. The *IESO Board* may *amend* the *market rules* to include any such operating procedures and instructions within the *market rules*.

3.2.4 [Intentionally left blank – section deleted]

Identification of Reliability Standards

3.2.5 The *IESO* shall maintain a mapping containing *reliability standards* applicable to each class of *market participants,* as per the applicability criteria, and provide *market participants* with the ability to retrieve those *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant*. The *IESO* may revise its applicability determination under this section at any time on notice to the *market participant*. If required, the *IESO* shall consult with *market participants* to finalize *reliability standards'* obligations or requirements that apply to a *market participant.*

3.2.6 The *IESO* shall inform *market participants* when an amendment to a *reliability standard* or a new *reliability standard* will come into effect in Ontario, and update the mapping containing *reliability standards* applicable to each class of *market participants* to provide *market participants* with the ability to retrieve the new or amended *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant*. The *IESO* may revise its applicability determination under this section at any time on notice to the *market participant*.

3.2.7 A *market participant* may request the *IESO* review a determination under section 3.2.5 or 3.2.6 with respect to that *market participant*. The *IESO* shall, following consideration of any representations made by the *market participant,* determine whether the *reliability standards'* obligations or requirements apply to that *market participant*.

3.2A Technical Feasibility Exceptions

3.2A.1 The *IESO* may:

3.2A.1.1 [Intentionally left blank – section deleted]

3.2A.1.2 approve a *TFE application*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *TFE application*, in whole or in part with such approval or disapproval being a *reviewable decision*;

3.2A.1.3 upon the request of a *market participant* amend or transfer a *technical feasibility exception*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2A.1.4 terminate or amend an approved *technical feasibility exception*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate. Such termination or amendment is a *reviewable decision*.

3.2A.2 A *TFE applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *technical feasibility exceptions* by filing with the *IESO* a *TFE application* for each required *technical feasibility exception*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *TFE applicant* may withdraw a *TFE application* at any time.

3.2A.3 Upon request by the *IESO*, a *TFE applicant* shall provide to the *IESO*:

3.2A.3.1 [Intentionally left blank – section deleted]

3.2A.3.2 any supporting documentation; and

3.2A.3.3 an executed agreement pursuant to which the *TFE applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in processing the *TFE application* and maintaining an approved *technical feasibility exception* until such time as the *technical feasibility exception* is no longer in effect.

3.2A.4 The *IESO* shall process a *TFE application* in accordance with Ontario-adapted *NERC* procedures for processing *TFE applications* as set out in the applicable *market manual*.

3.2A.5 Where applicable, for each *TFE application,* the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable, which is a *reviewable decision*, and which will form part of the executed agreement set out in section 3.2A.3.3 and will monitor expenditures against the processing costs of a *TFE application* and where that threshold is reached:

3.2A.5.1 the *IESO* shall advise the *TFE applicant* of the work and costs incurred to date;

3.2A.5.2 the *IESO* shall provide an estimate to the *TFE applicant* of the further work and costs necessary to complete the processing of the *TFE application*; and

3.2A.5.3 the *TFE applicant* may choose to continue with the processing of the *TFE application* or discontinue the processing of the *TFE application*. In the event that the *TFE applicant* chooses to discontinue the processing by withdrawing the *TFE application*, the *IESO* shall issue an *invoice* to the *TFE applicant* for the reasonable costs incurred by the *IESO* to that point.

3.2A.6 The *IESO* may utilize an independent third party to review a *TFE application* and any changes to an approved *technical feasibility exception* submitted by a *TFE applicant*.

3.2A.7 The *IESO* may consult with *NERC* or *NPCC* in its assessment of a *TFE application* and any changes to an approved *technical feasibility exception*.

3.2A.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *technical feasibility exception* shall be a breach of the *market rules* and the *IESO* may terminate the approved *technical feasibility exception* and require the *TFE applicant* to become compliant with the applicable *NERC reliability standard*.

3.2A.9 Subject to section 3.2A.4, all *technical feasibility exceptions* which remain in effect are subject to periodic review, in accordance with the applicable *market manual*, to verify continuing justification for the *technical feasibility exception*.

3.2A.10 The *IESO* may submit *invoices* to the *TFE applicant* for costs and expenses incurred by the *IESO* in processing the *TFE application* and maintaining the approved *technical feasibility exception* until such time as the *technical feasibility exception* is no longer in effect, less in each case, the amount of any deposit paid pursuant to section 3.2A.2 not previously applied against the *IESO's* costs and expenses. The submission of *invoices* to the *TFE applicant* is a *reviewable decision*.

3.2A.11 A *TFE applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2A.5.3 or 3.2A.10, pay to the *IESO* the amount owing.

3.2B Bulk Electric System Exceptions

3.2B.1 A *BES exception applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *bulk electric system exceptions* by filing with the *IESO* a *BES exception request* for each required *bulk electric system exception*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *BES exception applicant* may withdraw a *BES exception request* at any time.

3.2B.2 The *IESO* may review, reject or accept a *BES exception request* in whole or in part.

3.2B.3 The *IESO* shall process a *BES exception request* in accordance with the Ontario-adapted *NERC* procedure for processing *BES exception requests* as set out in the applicable *market manual*.

3.2B.4 Upon request by the *IESO*, a *BES exception applicant* shall provide to the *IESO*:

3.2B.4.1 a substantive review deposit amount;

3.2B.4.2 any supporting documentation; and

3.2B.4.3 an executed agreement pursuant to which the *BES exception applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in processing the *BES exception request*.

3.2B.5 Where applicable, for each *BES exception request*, the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable and which will form part of the executed agreement set out in section 3.2B.4.3 and will monitor expenditures against the processing costs of a *BES exception request* and where that threshold is reached:

3.2B.5.1 the *IESO* shall advise the *BES exception applicant* of the work and costs incurred to date;

3.2B.5.2 the *IESO* shall provide an estimate to the *BES exception applicant* of the further work and costs necessary to complete the processing of the *BES exception request*; and

3.2B.5.3 the *BES exception applicant* may choose to continue with the processing of the *BES exception request* or discontinue the processing of the *BES exception request*. In the event that the *BES exception applicant* chooses to discontinue the processing by withdrawing the *BES exception request*, the *IESO* shall issue an *invoice* to the *BES exception applicant* for the reasonable costs incurred by the *IESO* to that point. The issuance of such an *invoice* is a *reviewable decision*.

3.2B.6 The *IESO* may utilize an independent third party to review a *BES exception request* submitted by a *BES exception applicant*.

3.2B.7 After receiving a recommendation from the *IESO* on a *BES exception request*, the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* may:

3.2B.7.1 [Intentionally left blank]

3.2B.7.2 approve or disapprove a *BES exception request*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *BES exception request*, in whole or in part, with such approval or disapproval being a *reviewable decision*;

3.2B.7.3 upon the request of a *market participant* or a *connection applicant* amend or transfer a *bulk electric system exception*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2B.7.4 terminate or amend an approved *bulk electric system exception*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate. Such termination or amendment is a *reviewable decision*.

3.2B.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *bulk electric system exception* shall be a breach of the *market rules* and the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* may terminate the approved *bulk electric system exception* and require the *BES exception applicant* to become compliant with the applicable *NERC reliability standards.*

3.2B.9 All *bulk electric system exceptions* are subject to periodic review, in accordance with the applicable *market manu*al, to verify continuing justification for the *bulk electric system exception* and may be referred to the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* in accordance with section 3.2B.7.

3.2B.10 The *IESO* shall submit an *invoice* to a *BES exception applicant* upon completion of the processing of that applicant's *BES exception request* in an amount equal to all of the *IESO's* costs and expenses relating to the processing of the *BES exception applicant's BES exception request* less the amount of any deposit paid pursuant to section 3.2B.4.1. The submission of an *invoice* to a *BES exemption applicant* is a *reviewable decision*.

3.2B.11 A *BES exception applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2B.5.3 or 3.2B.10, pay to the *IESO* the amount owing.

3.3 Reliability-Related Information

3.3.1 The *IESO* shall *publish* a list of the categories of *reliability*-related information that it shall provide to *market participants*, the time periods within which such information will be provided, and the manner in which such information will be provided. Such information shall include, but not be limited to, information designed to:

3.3.1.1 enable *market participants* to initiate procedures to manage the potential risk of any action taken by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*;

3.3.1.2 assist *market participants* in meeting their obligations under this Chapter; and

3.3.1.3 notify *market participants* of any operating changes or decisions that may have an impact on their operations, *facilities* or equipment.

3.3.2 The *IESO* shall *publish* a catalogue of the *reliability*-related information that the *IESO* shall require from *market participants*, including the information referred to in section 14.1.3, the time periods within which such information will be provided and the manner in which such information will be provided. At the same time, the *IESO* shall *publish* initial monitoring indices that the *IESO* shall use in evaluating the information so provided.

3.3.3 *Market participants* shall provide the *IESO* with the information referred to in section 3.3.2 within the time and in the manner required.

3.3.4 Subject to the confidentiality provisions of MR Ch.3 and MR Ch.4, the *IESO* shall, if requested to do so by a *market participant*, provide to that *market participant* *reliability*-related information not contained in the list referred to in section 3.3.1, provided that the *IESO* shall be under no obligation to provide any information that, in the *IESO's* opinion, would provide the requesting *market participant* with an undue advantage in the *IESO-administered markets*. In order to prevent any such undue advantage, the *IESO* may provide *market participants* with notice of the request prior to providing such information and may make the information requested by a *market participant* simultaneously available to all *market participants*.

3.4 Obligations of Transmitters

3.4.1 Each *transmitter* shall operate and maintain its transmission *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.4.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.4.1.2 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.4.1.3 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment;

3.4.1.4 promptly informing the *IESO* of any change or anticipated change in the capability of its transmission *facilities* or the status of its equipment or *facilities* forming part of the *IESO-controlled grid*, and of any other change or anticipated change in its transmission *facilities* that could have a material effect on the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets;* and

3.4.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *transmission system* for *reliability* purposes, unless the *transmitter* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *transmitter* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above.

3.4.2 Each *transmitter* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.5 Obligations of Wholesale Customers

3.5.1 Each *connected wholesale customer* shall operate and maintain its *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.5.1.1 ensuring there are controls, monitoring, and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.5.1.2 promptly informing the *IESO* of any change or anticipated change in the status of any *facility* or equipment that it operates and is associated with the *resource* that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets;*

3.5.1.3 promptly complying with the *IESO's* directions, including directions to *disconnect* equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *connected wholesale customer* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *connected wholesale customer* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.5.1.4 [Intentionally left blank]

3.5.1.5 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more; relative to the average weekday *demand* of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates and that has been specifically designated by the *IESO* for this purpose.

3.5.2 Each *wholesale consumer* that is an *embedded market participant* shall provide, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

3.5.2.1 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *resource* associated with an *embedded load facility*, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more relative to the average weekday *demand* of that *resource*; and

3.5.2.2 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of such *resource* that has been specifically designated by the *IESO* for this purpose.

3.5.3 Each *wholesale customer* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2*.*

3.6 Obligations of Generators (Embedded and Non-embedded)

3.6.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall operate and maintain its *generation facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities related to *reliability*. Such obligation shall include, but not be limited to, the following:

3.6.1.1 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.6.1.2 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment*,* as required by the *IESO* to *reliably* operate the *IESO-controlled grid*;

3.6.1.3 promptly informing the *IESO* of any change or anticipated change in the status of any *generation facility* or related equipment that it operates and is associated with the *resource* that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *generation facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets.* Such change shall include, but not be limited to, any change in status that could affect the maximum output of a *generation unit*, the minimum load of a *generation unit*, the ability of a *generation unit* to operate with *automatic voltage regulation*, or the availability of a *generation unit* to provide *ancillary services* (unless no application has been made to provide *ancillary services* to the *IESO-administered markets* in respect of a given *generation unit);*

3.6.1.4 promptly informing the *IESO* if any of the *generation facilities* that it operates are unable for any reason to operate in accordance with the schedules determined pursuant to MR Ch.7;

3.6.1.5 providing the *IESO* with current information showing the maximum unit capabilities of each of its *generation units* to facilitate *dispatch* in an *emergency operating state*. Such maximum unit capabilities shall consist of the maximum physical-rating of the *generation unit* and shall not be limited to the unit capabilities contained in the *offers* submitted for the *resource* associated with such *generation unit* pursuant to MR Ch.7; and

3.6.1.6 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *generator* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *generator* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above.

3.6.2 Each *generator* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.7 Obligations of Distributors

3.7.1 Each *distributor* shall operate and maintain its distribution *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.7.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.7.1.2 promptly informing the *IESO* of any change or anticipated change in the capability of its equipment or distribution *facilities* connected to the *IESO-controlled grid* that could have a material effect on the *reliable* operation of the *IESO-controlled grid* or the operation of the *IESO-administered markets*;

3.7.1.3 promptly informing the *IESO* of any event or circumstance in its service territory that could have a material effect on the *reliability* of the *IESO-controlled grid;*

3.7.1.4 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for equipment and distribution *facilities* that are included within the *IESO-controlled grid*;

3.7.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *distribution system* for *reliability* purposes, unless the *distributor* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *distributor* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above;

3.7.1.6 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any portion of a *facility* that is not associated with a *resource*, that draws electrical *energy* from or injects electrical *energy* into its *distribution system*, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by that *facility* of 20 MW or more relative to the average weekday demand or supply of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any portion of a *facility* that is not associated with a *resource*, that draws electrical *energy* from or injects electrical *energy* into its *distribution system* and that has been specifically designated by the *IESO* for this purpose, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by such *facility* relative to the average weekday *demand* or supply of that *facility*;

3.7.2 Each *distributor* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.8 Obligations of Electricity Storage Participants (Embedded and Non-embedded)

3.8.1 Each *electricity storage participant* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall operate and maintain its *electricity storage facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities related to *reliability*. Such obligations shall include, but not be limited to, the following:

3.8.1.1 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.8.1.2 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment, as required by the *IESO* to *reliably* operate the *IESO-controlled grid*;

3.8.1.3 promptly informing the *IESO* of any change or anticipated change in the status of any *electricity storage facility* or related equipment that it operates and is associated with the *resource* that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *electricity storage facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets.* Such change shall include, but not be limited to, any change in status that could affect its range of injections and withdrawals of *energy*, *state of charge*, the ability of an *electricity storage unit* to operate with *automatic voltage regulation*, or the availability of an *electricity storage unit* to provide *ancillary services* (unless no application has been made to provide *ancillary services* to the *IESO-administered markets* in respect of a given *electricity storage unit);*

3.8.1.4 promptly informing the *IESO* if any of the *electricity storage facilities* that it operates are unable for any reason to operate in accordance with the schedules determined pursuant to MR Ch.7;

3.8.1.5 providing the *IESO* with current information showing the maximum unit capabilities to inject electricity, for each of its *electricity storage units* to facilitate dispatch in an *emergency operating state.* Such maximum unit capabilities shall consist of the maximum amount in MWs that can be injected at that point in time, and for how long, and shall not be limited to the unit capabilities contained in the *offers* submitted for the *resource* associated with such *electricity storage unit* pursuant to MR Ch.7;

3.8.1.6 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *electricity storage participant* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *electricity storage participant* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.8.1.7 providing the *IESO* with current information showing the maximum unit capabilities to withdraw energy, for each of its *electricity storage units* to facilitate dispatch in an *emergency operating state*. Such maximum unit capabilities shall consist of the maximum amount in MWs that can be withdrawn at that point in time, and for how long, and shall not be limited to the unit capabilities contained in the *bids* submitted for the *resource* associated with such *electricity storage unit* pursuant to MR Ch.7;

3.8.2 Each *electricity storage participant* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2*.*

4. System Reliability

4.1 Objectives

4.1.1 The objective of this section 4 is to set forth the requirements to ensure the availability of sufficient capacity and *ancillary services* to the *IESO-administered markets.*

4.2 Standards for Ancillary Services

4.2.1 The *IESO* shall operate the *IESO-administered markets* and contract for *ancillary services*, including by means or within the scope of an *operating agreement* or another agreement of similar nature, to ensure that sufficient *ancillary services* are available to ensure the *reliability* of the *IESO-controlled grid*. *Ancillary services* shall be procured by the *IESO* in accordance with this Chapter and MR Ch.7.

4.2.2 The requirements for *ancillary services* shall be determined based on all applicable *reliability standards* and actual and expected conditions on the *IESO-controlled grid.* Requirements for *ancillary services* may be adjusted from time to time by the *IESO* to take into account, among other things, variations in *integrated power system* conditions, real-time *dispatch* constraints, *contingency events*, the prevailing level of system risks or vulnerability, and the results of assessments of the voltage and dynamic stability of the *integrated power system*.

4.2.3 The *IESO* shall, in accordance with the procedures set forth in MR Ch.3 s.4, periodically review the operation of the *IESO-administered markets* for *ancillary services* to determine whether any revision to the requirements and standards for *ancillary services* is required for *reliability* purposes. As a minimum, the *IESO* shall conduct such reviews to accommodate revisions to applicable criteria established by relevant *standards authorities*.

4.3 Generic Performance Requirements for Ancillary Services

4.3.1 *Ancillary services* may be provided to the *IESO* only by *facilities* or *resources* in accordance with MR Ch.7. *Ancillary services* may be offered to the *IESO* in its daily and hourly *physical markets* or provided to the *IESO* under *contracted ancillary service* contracts through the *IESO's ancillary services procurement markets* or by means or within the scope of *operating agreements* or another agreement of a similar nature. Prior to entering into a contract with any *ancillary service provider*, the *IESO* shall determine whether the *facilities, resources* and procedures of such *ancillary service provider* meet the applicable requirements for registration in respect of the *ancillary service(s)* to be provided and are otherwise in compliance with the technical requirements of this Chapter. The *IESO* shall not contract for *ancillary services* with an *ancillary services provider* whose *facilities* or *resources* are not in compliance with such requirements.

4.3.2 In order to make the determination referred to in section 4.3.1, the *IESO* may require each *ancillary service provider* to demonstrate through physical tests or other appropriate means specified by the *IESO* that the *facilities,* equipment, or their associated *resources*, as the case may be, that will be used to provide the *ancillary service* meet the performance standards for each *ancillary service* set forth in Appendix 5.1 or in the applicable *market manual*.

4.4 Regulation

4.4.1 The *IESO* shall maintain sufficient *regulation* to allow the *IESO* to meet all applicable *reliability standards.*

4.4.2 The *IESO* shall determine the quantity of *regulation* capacity needed for each hour of the following day. As a minimum, the requirement shall be +/- 100 MW, with a ramp rate of 50 MW/min.

4.4.3 If the *IESO* is unable to comply with applicable *reliability standards*, it shall take corrective action to achieve compliance with applicable *reliability standards* within three months.

4.4.4 *Area control error (ACE)* shall be calculated by the *IESO* in accordance with section 4.4.5 and all applicable *reliability standards*. Control signals shall be sent from the *IESO* to *facilities* associated with *resources* providing *regulation*, as required by the *IESO*.

4.4.5 The calculation of *ACE* shall occur at least every four seconds.

4.4A Assistance to Other Control Areas

4.4A.1 Notwithstanding any other provision of the *market rules*, when a *transmission system* in another *control area* is in a state identical or comparable to an *emergency operating state*, the *IESO* may, in accordance with all applicable *reliability standards* and any applicable *interconnection agreement*, provide *emergency energy* to the *control area* within which such other *transmission system* is located in order to maintain the *reliability* of such *transmission system.* The *IESO* shall only provide *emergency energy* to another *control area* in circumstances where *energy* could not be obtained by that *control area* using the *offer* and *bid* processes described in MR Ch.7. The compensation associated with the provision of such *emergency energy* that is received by the *IESO* pursuant to the applicable *interconnection agreement* shall be distributed in accordance with MR Ch.9 s.4.14.13.

4.5 Operating Reserve

4.5.1 *Operating reserve* is capacity that, for any given operating interval or *dispatch interval*, is in excess to that required to meet anticipated requirements for *energy* for that operating interval or *dispatch interval*, and is available to the *integrated power system* for *dispatch* by the *IESO* within a specified time period, such as 10 minutes or 30 minutes. *Operating reserve* may be provided by *generation resources, electricity storage resources, dispatchable loads* and *boundary entity resources* to the extent that each meets the applicable requirements to be a *resource* in respect of each category of *operating reserve*. Neighbouring *control areas* may also provide *operating reserve* through simultaneous activation of *operating reserve* and regional reserve sharing programs. *Operating reserve* is required to:

4.5.1.1 cover or offset unanticipated increases in load during a *dispatch day* or *dispatch hour*;

4.5.1.2 replace or offset capacity lost due to the *forced outage* of generation, electricity storage or transmission equipment; or

4.5.1.3 cover uncertainty associated with the performance of *generation resources*, *electricity storage resources* or *dispatchable loads* in responding to the *IESO's dispatch instructions*.

4.5.2 The *IESO* shall maintain sufficient *operating reserve* to meet all applicable *reliability standards.*

4.5.2A In the event of an *operating reserve* deficiency, the *IESO* may apply voltage reductions and/or reduce the *thirty-minute operating reserve* requirements in compliance with the applicable *reliability standards*.

4.5.3 The *IESO* shall maintain, as a minimum, total *operating reserve* that is the sum of the *ten-minute operating reserve* requirement and the *thirty-minute operating reserve* requirement.

4.5.4 Part of the requirement for *ten-minute operating reserve* shall be synchronized with the *IESO-controlled grid* consistent with section 4.5.9.

4.5.5 The *IESO* shall ensure that *operating reserve* is distributed throughout the *IESO-controlled grid* such that sufficient *operating reserve* can be activated and delivered to any location on the *integrated power system*.

Simultaneous Activation of Reserve

4.5.6 The *IESO* may simultaneously activate with nearby systems its *ten-minute operating reserve* to respond to *contingency events* in accordance with agreements between the *IESO* and such systems. Similarly, such systems may activate their *operating reserve* when requested to meet *contingency events* in the *IESO control area* in accordance with agreements between the *IESO* and such systems. Such simultaneous activation of *operating reserve* is solely for the purpose of maintaining the *reliability* of *interconnected systems* and shall not alter the *operating reserve* requirements of the *IESO*.

Regional Reserve Sharing

4.5.6A The *IESO* may participate in regional reserve sharing programs with neighbouring *control areas*. Subject to availability and deliverability of the associated *energy*, the *IESO* may count towards its *ten-minute operating reserve* requirement a contribution of up to 100 MW from neighbouring *control areas* in accordance with applicable regional reserve sharing programs and applicable *reliability standards.* The *IESO* shall activate *energy* from regional reserve sharing programs in accordance with applicable *reliability standards*.

Ten-Minute Operating Reserve

4.5.7 *Ten-minute operating reserve* is capacity that is available to the *integrated power system* in excess of anticipated requirements for *energy* and that can be made available and used within ten minutes. It includes *resources* that are either synchronized or non-synchronized with the *IESO-controlled grid*.

4.5.8 The *IESO* shall maintain sufficient *ten-minute operating reserve* to meet the requirements of all applicable *reliability standards.* This shall be at least equal to the largest first contingency loss sustainable on the *IESO-controlled grid*.

4.5.9 *Ten-minute operating reserve* shall be synchronized with the *IESO-controlled grid* to the extent required by all applicable *reliability standards*.

4.5.10 If, for any reason, there is a deficiency of *ten-minute operating reserve*, the *IESO* shall replace such *operating reserve* in accordance with the applicable *reliability standards* referenced in the *market manuals*.

4.5.11 The *IESO* shall, in accordance with MR Ch.7, *publish* daily its estimates of the quantity of *ten-minute operating reserve* that is required for each hour of the following day.

4.5.12 A *boundary entity resource* that is used as *ten-minute operating reserve* shall be treated as *operating reserve* that is non-synchronized with the *IESO-controlled grid*.

4.5.13 The reduction in load that can be effected by curtailing pumping hydroelectric *generation facilities* is eligible to be treated as *operating reserve* that is synchronized with the *IESO-controlled grid*.

4.5.14 The reduction in load that can be effected by curtailing withdrawals from *electricity storage facilities* is eligible to be treated as *operating reserve* that is synchronized with the *IESO-controlled grid*.

4.5.15 [Intentionally left blank]

4.5.16 [Intentionally left blank]

4.5.17 [Intentionally left blank]

Thirty-Minute Operating Reserve

4.5.18 *Thirty-minute operating reserve* is capacity in excess of anticipated requirements for *energy* that can be made available and used within thirty-minutes and that is not included as *ten-minute operating reserve*.

4.5.19 Subject to section 4.5.20, the requirement for *thirty-minute operating reserve* shall be at least equal to one-half of the largest *second contingency loss* sustainable on the *IESO-controlled grid*. However, when a *generation unit* is commissioning and is one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall be at least equal to the *second contingency loss*.

4.5.20 If such a commissioning *generation unit* is not one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall be at least equal to the larger of one-half of the *second contingency loss* or the output of the commissioning *generation unit.*

4.5.21 The requirement for *thirty-minute operating reserve* shall be maintained in accordance with the applicable *reliability standards* referenced in *the market manuals*.

4.6 Reactive Support and Voltage Control

4.6.1 *Reactive support service* and *voltage control service* is the control and maintenance of prescribed voltages on the *IESO-controlled grid*. The devices that supply reactive power to the *integrated power system* include but are not limited to, capacitors, static VAR compensators, reactors, synchronous *generation facilities*, and synchronous condensers.

4.6.1A The *IESO* shall direct the operation of the *IESO-controlled grid* to meet all applicable *reliability standards* with respect to the *dispatch* of *resources* associated with the provision of reactive power.

4.6.2 The *IESO* shall ensure that sufficient *reactive support service* and *voltage control service* is available throughout the *IESO-controlled grid* to meet all applicable *reliability standards* for *reactive support service* and *voltage control service*. Voltage levels shall be maintained within acceptable levels within the *IESO-controlled grid*. As part of its assessment of system *adequacy* under the *market rules*, the *IESO* shall on a continual basis assess whether sufficient *reactive support service* and *voltage control service* is available to the *IESO*.

4.6.3 The *IESO* shall direct providers of *reactive support service* and *voltage control service* to take any actions necessary to maintain stable voltage levels in accordance with *reliability standards* and to prevent the collapse of voltages on the *IESO-controlled grid*.

4.6.4 The *IESO* shall obtain reactive power capability to maintain *reactive support service* and *voltage control service* in accordance with all applicable *reliability standards*. *Reactive support service* and *voltage control service* shall be made available by *market participants* from, but not limited to, the following:

4.6.4.1 reactive power produced from within the standard power factor range of a *generation facility* as described in MR Ch.4*,* which shall be *dispatchable* by the *IESO*;

4.6.4.2 equipment owned by *market participants* (capacitors, SVCs, synchronous condensers and reactors) that is made available to the *IESO* pursuant to the *market rules* and any *operating agreement* between the *IESO* and a *market participant*; and

4.6.4.3 reactive power produced outside the standard power factor range of a *generation facility* as required in MR Ch.4 (synchronous condensers or hydroelectric units in condense mode) as acquired by the *IESO* through *contracted ancillary services* contracts.

4.7 Black Start Service

4.7.1 [Intentionally left blank]

4.7.2 The *IESO* shall determine the required amounts and locations of *black start capability* across the *IESO-controlled grid*, as required to satisfy the requirements of the *Ontario power system restoration plan* and all applicable *reliability standards.* The *IESO* shall notify *market participants* of these requirements before entering into agreements for the provision of *certified black start facilities*.

4.7.3 *Ancillary service providers* providing *certified black start facilities* must also be *restoration participants*.

4.8 Reliability Must-Run Resources

4.8.1 The *IESO* may need to call on specific *resources*, excluding *non-dispatchable loads* or *price responsive loads*, to maintain the *reliability* of the *IESO-controlled grid* whenever sufficient *resources* for the provision of *physical services*, other than *contracted ancillary services*, are not otherwise offered in the *IESO-administered markets*. Such applicable *resources* are referred to as *reliability must-run resources* and shall be procured either through *reliability must-run contracts* in accordance with this section 4.8 and MR Ch.7 ss.9.6 and 9.7 or by means of the process for directing the submission of *dispatch data* referred to in MR Ch.7 ss.3.3.10 to 3.3.17.

4.8.2 The *IESO* shall identify all *reliability must-run resources* in respect of which it wishes to conclude *reliability must-run contracts* and may enter into *reliability must-run contracts* with the *registered market participant* or prospective *registered market participant* for such *reliability must-run resources*. Where the *IESO* identifies such a *reliability must-run resource*, the *registered market participant* or prospective *registered market participant* for such *reliability must-run resource* shall, subject to MR Ch.7 s.9.6.4, contract with the *IESO* to supply *physical services*, other than *contracted ancillary services*, to the *IESO-controlled grid* for *reliability* purposes in accordance with MR Ch.7 ss. 9.6 and 9.7. Each such *reliability must-run contract* shall provide the *IESO* with the ability to call on the *reliability must-run resources* covered by the *reliability must-run contract* in accordance with MR Ch.7 s.9 and shall comply with MR Ch.7.

4.8.3 [Intentionally left blank]

4.8.4 The provisions of this section 4.8 and of any *reliability must-run contracts* shall be consistent with the provisions of the *licence* of the *IESO* that incorporate the terms of any directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the *Ontario Energy Board Act, 1998* or that incorporate terms imposed by the *Ontario Energy Board* in furtherance of the exercise of its powers under subsection 70(5) of the *Ontario Energy Board Act, 1998*. In the event of any inconsistency between such terms and the provisions of this section 4.8 or of any *reliability must-run contracts*, such terms shall govern.

4.9 Auditing and Testing of Ancillary Services

4.9.1 The *IESO* shall test *facilities* and any associated *resources* that will or do provide *ancillary services* to the *IESO-controlled grid.* The *IESO* shall use such tests to determine whether to register each *facility* as one or more *resources* for the provision of *ancillary services* and to ensure that each applicable *facility* or *resource* continues to meet the requirements for registration to provide the relevant *ancillary services.*

4.9.2 Tests of the *facilities* and *resources* of *ancillary service providers* or of prospective *ancillary service providers* referred to in section 4.9.1 shall include, but not be limited to, testing in the manner set forth in this section 4.9.2, to determine whether the *ancillary service provider* can supply the *ancillary services* which it wishes to supply or has contracted or been registered to supply:

4.9.2.1 the *IESO* may test the synchronized *ten-minute operating reserve* capability of a *generation facility*, *load facility* associated with a *dispatchable load* or an *electricity storage facility* by issuing unannounced *dispatch instructions* requiring the associated *resource* to ramp up or reduce demand, in either case to its ten-minute capability;

4.9.2.2 the *IESO* may test the non-synchronized *ten-minute operating reserve* capability of a *generation facility*, *electricity storage facility* or *load facility* associated with a dispatchable load by issuing unannounced dispatch instructions requiring the associated *resource* to come on line and ramp up or to reduce demand, in either case to its ten-minute capability;

4.9.2.3 the IESO may test the *thirty-minute operating reserve* capability of a *generation facility*, *electricity storage facility* or *load facility* associated with a *dispatchable load* by issuing unannounced *dispatch instructions* requiring the associated *resource* to come on line and ramp up or to reduce demand, in either case to its thirty-minute capability;

4.9.2.4 a *certified black start facility* must perform tests on auxiliary and control equipment and alternate sources of power in accordance with and using the testing criteria and testing frequency requirements specified in the *Ontario power system restoration plan*;

4.9.2.4A a *certified black start facility* must pass the tests required for *certified black start facilities* in accordance with and using the testing criteria specified in the *Ontario power system restoration plan*;

4.9.2.4B the *IESO* may direct line energization tests of a *certified black start facility* to determine whether the *certified black start facility* can energize a transmission path specified by the *IESO*;

4.9.2.5 the *IESO* may test the *reactive support* and *voltage control* that has been contracted from a *facility* that is a *generation facility* or *electricity storage facility* by issuing unannounced *dispatch instructions* requiring the associated *resource* to provide such support within its contracted capability; and

4.9.2.6 the *IESO* shall at least annually test a *resource* providing *regulation* for compliance with the performance standards referred to in sections 1.1.3 and 1.1.4 of Appendix 5.1 in accordance with the testing procedures specified in the applicable *contracted ancillary services* contract.

4.9.3 The costs incurred by the *IESO* in conducting and evaluating any tests pursuant to section 4.9.1 or 4.9.2 shall be recovered by the *IESO* as part of the costs to the *IESO* of contracting for the applicable *ancillary service* in accordance with MR Ch.9 s.4.2.

4.9.4 Any costs incurred by the *ancillary service provider* in conducting any tests pursuant to section 4.9.1 or 4.9.2 shall be borne by the *ancillary service provider*.

4.10 Consequences of Failure to Pass a Test

4.10.1 If an *ancillary service provider's facility* or *resource* fails a test performed pursuant to section 4.9.1 or 4.9.2 in respect of an *ancillary service*, the *IESO* shall not schedule such *ancillary service* from such *facility* or *resource* until the *ancillary service provider* demonstrates that it can provide the relevant *ancillary service*.

4.10.2 Without prejudice to the application of section 4.10.1, an *ancillary service provider* whose *facility* or *resource* fails a test performed pursuant to section 4.9.1 or 4.9.2:

4.10.2.1 in the case of an ancillary service provider providing a certified black start facility or regulation under a contracted ancillary service contract:

a. where there is sufficient information available to determine the date as of which the applicable *contracted ancillary service* was not provided, the *IESO* may require the *ancillary service provider* to refund the compensation it has received for such *contracted ancillary service* from such date to the date of the failed test; or

b. in all other cases, the *ancillary service provider* shall provide such refund of compensation, if any, as may be specified in its *contracted ancillary service* contract;

4.10.2.2 in the case of an *ancillary service provider* providing a *certified black start facility* or *regulation* under a *contracted ancillary service* contract, shall be subject to such penalties and sanctions as may be specified in its *contracted ancillary service* contract; and

4.10.2.3 in the case of any other *ancillary service provider*, shall be subject to financial penalties in accordance with MR Ch.3 s.6.6 and to such other sanctions as may be provided for in these *market rules*.

4.11 Emergency Conditions

4.11.1 Notwithstanding any other provision of the *market rules*, when the *IESO-controlled grid* is in an *emergency operating state*, the *IESO* may acquire *ancillary services* from any *market participant*, whether or not such *market participant* satisfies all of the standards and registration requirements applicable in respect of such *ancillary services*.

5. System Security

5.1 Objectives and General Obligations

5.1.1 The objective of this section is to detail the procedures necessary to enable the *IESO* to ensure the *security* of the *IESO-controlled grid* in accordance with all applicable *reliability standards.*

5.1.2 In order to maintain the *security* of the *IESO-controlled grid*, the *IESO* shall:

5.1.2.1 monitor the real-time operating status of the *IESO-controlled grid*;

5.1.2.2 establish and *publish security limits* for all *facilities* that are part of the *IESO-controlled grid*;

5.1.2.3 establish and *publish* criteria and margins to be used in the development of *security limits* and a process for reviewing and revising such criteria and margins;

5.1.2.4 establish available *transmission transfer capabilities* in accordance with all applicable *reliability standards* and manage the use of transmission in accordance with such *transmission transfer capabilities* and the *market rules*;

5.1.2.5 direct the operation of *facilities* that are part of the *IESO-controlled grid* within the appropriate *security limits* and in accordance with the applicable *operating agreements*;

5.1.2.6 direct any *market participant* to take or to refrain from taking any action necessary to maintain the *IESO-controlled grid* in a *normal operating state*;

5.1.2.7 act as the *control area operator* and as *security coordinator* for the province of Ontario and interact with other *control area operators*, *security coordinators* and *interconnected transmitters* as required to establish *security limits* and rules for interconnected operations including, but not limited to, entering into *interconnection agreements* with adjacent *control area operators*, *security coordinators* and *interconnected transmitters* that provide for interconnected operations, other than with respect to the physical *facility* and equipment requirements for *interconnections* which shall be the responsibility of *transmitters*. In the event of flows or exchanges of *physical services* across the *interconnections* or *interties* which are not directly attributable to the transactions of *market participants*, the *IESO* may provide for such exchanges through the sale or purchase of these *physical services* in the *IESO-administered markets*;

5.1.2.8 represent Ontario in the context of the work of *standards authorities* with respect to the *reliable* operation of the *IESO-controlled grid* and the *interconnected systems*, and the operation of the *IESO-administered markets*, other than with respect to the physical *facility* and equipment requirements for *reliability* of the *IESO-controlled grid* which shall be the responsibility of the relevant *transmitters*, *distributors* and *generators* as applicable;

5.1.2.9 investigate major operational incidents on the *IESO-controlled grid* and initiate plans to manage abnormal situations or significant deficiencies which, in the *IESO's* opinion, threaten the *reliability* of the *IESO-controlled grid*;

5.1.2.10 issue directions to market participants in order to manage high-risk operating states and emergency operating states; and

5.1.2.11 assess the future *reliability* of the *IESO-controlled grid*.

5.2 Security Limits

5.2.1 The *IESO* shall establish and *publish security limits* to prevent, contain and alleviate the effects of *contingency events*. Such *security limits* shall be as described in section 5.2.4 and shall be observed by the *IESO* in the minute-to-minute operation of the *IESO-controlled grid*.

5.2.2 The IESO shall calculate and publish transmission transfer capabilities.

5.2.3 *Market participants* shall immediately respond to directions from the *IESO* to alter their operations to stay within the *security limits* and *transmission transfer capabilities* established by the *IESO*.

5.2.4 Two types of *security limits* shall be established by the *IESO*:

5.2.4.1 *security limits* based on the dynamic response of the *IESO-controlled grid*, including transient stability limits, voltage stability limits, dynamic stability limits, and voltage decline limits; and

5.2.4.2 *security limits* based on the ratings of equipment, including the thermal ratings of lines and transmission equipment (e.g. the design characteristic of lines and equipment and weather conditions) and the short circuit capability of equipment.

5.2.5 Each *market participant* shall:

- establish thermal ratings for the equipment that it owns and that is part of the *IESO-controlled grid*, and
- provide such ratings (including continuous and limited time ratings) to the *IESO* in a form suitable for *IESO* monitoring

The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of the thermal rating for such equipment as communicated to the *IESO* by the relevant *market participants*.

5.2.6 The *IESO* shall respect all pre-and post-contingency *security* criteria that are used to establish *security limits*.

5.3 The Use of Tie-Lines and Associated Facilities

5.3.1 The *IESO-controlled grid* is interconnected with utilities in Canada and the United States via *tielines* such that *interconnected systems* can be used to help maintain the *security* of the *IESO-controlled grid*.

5.3.2 With respect to the use of *tielines*:

5.3.2.1 the *IESO* shall use reasonable efforts to conduct studies on a coordinated basis with adjacent *control areas* so that normal and emergency transfer limits on all *tielines* are established or reaffirmed at least annually;

5.3.2.2 the *IESO* shall use reasonable efforts to cooperate with other *control area operators* to determine and reaffirm total *transmission transfer capability* with other *control areas* at least annually;

5.3.2.3 the *IESO* shall operate the *IESO-controlled grid* so that there is no net transfer of reactive power, provided that reactive power may be exchanged or transferred from one system to another under contractual agreement with adjacent *control areas;*

5.3.2.4 the maximum net scheduled interchange across *tielines* shall not exceed the lower of the continuous rating of the *tielines* or the incremental transfer capability of the first *contingency event*;

5.3.2.5 for *interconnected systems* that are entirely controlled by phase-shifters, such as Manitoba and Minnesota, the *IESO* shall maintain MW flows at the scheduled transfer level;

5.3.2.6 unless there is prior agreement to that effect between *control areas*, the *IESO* shall not move phase shifters or make changes to fixed-tap positions; and

5.3.2.7 the *IESO* shall abide by all applicable *reliability standards* with respect to the management of *tielines*.

5.3.3 Each *market participant* shall comply with all relevant *reliability standards* relating to the *reliability* of *interconnections* and:

5.3.3.1 each *registered market participant* submitting an *energy offer* or an *energy bid* in respect of a *boundary entity resource* shall comply with the scheduling and notification procedures for the source or sink *control area*, as applicable, and any intervening *control areas* and with all other applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access;

5.3.3.2 each *registered market participant* submitting an *offer* to provide *operating reserve* in respect of a *boundary entity resource* shall comply with all applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access; and

5.3.3.3 the notification of the activation of the *energy* associated with an *operating reserve offer* and the scheduling coordination shall be the responsibility of the *IESO*.

5.3.4 Where:

5.3.4.1 the quantity of a *physical service* delivered to or withdrawn from the *IESO-controlled grid* by a *registered market participant* is reduced relative to that *registered market participant's* most recent valid *bid* or *offer*; and

5.3.4.2 such reduction is initiated pursuant to *reliability standards* by an entity, other than the *IESO*, having authority under such *reliability standards*;

the *registered market participant* shall not be entitled to compensation for any financial loss suffered as a result of such action.

Where such reduction was initiated by the *IESO*, the *registered market participant* shall be entitled to compensation, which shall be calculated and paid in accordance with MR Ch.9 ss.3.4 and 3.5.

5.4 Reliability Policy for Area Supply

5.4.1 In coordination with *transmitters*, the *IESO* may develop and apply specific *security* criteria in areas of the *IESO-controlled grid* where the consequences of *contingency events* are localized and do not have a significant adverse impact on the *reliability* of the *IESO-controlled grid* ("*local areas*").

5.4.2 The following criteria shall be used to assess the *security* of a *local area*, as determined at the boundary between the *local area* and the remainder of the *IESO-controlled grid*, on the one hand, and individual and collective *connection points* of the *IESO-controlled grid*, on the other:

5.4.2.1 the extent to which severe *contingency events* are experienced; and

5.4.2.2 the *reliability* of transmission *facilities* which directly affect the exchange of electricity to the *local area*.

5.4.3 The *IESO* shall coordinate with *transmitters* to review the performance at *connection points* at least once annually in order that they can jointly assess the *reliability* of *local areas*.

5.5 Interconnection Assistance

5.5.1 The *IESO* shall use and support *interconnected systems* in accordance with agreements between the *IESO* and other *security coordinators, control area* *operators* or *interconnected transmitters* and to the extent necessary to maintain the *security* of the *IESO-controlled grid*.

5.5.1A Information provided to the *IESO* under an *interconnection agreement* by a *security coordinator, control area operator* or *interconnected transmitter* and identified by the person providing the information as confidential shall be *confidential information* and shall not be disclosed or made available without the prior written consent of the particular *security coordinator, control area operator* or *interconnected transmitter*.

5.5.2 In requesting assistance from *market participants* and from other *security coordinators*, the *IESO* shall take effective action in the *IESO control area* prior to, or concurrently with, similar action being taken by the *interconnected system* providing assistance.

5.5.3 All agreements entered into by the *IESO* and other *security coordinators* relating to *security* shall meet all applicable *reliability standards*.

5.6 Inadvertent Interchange

5.6.1 Inadvertent interchange is the difference between the scheduled interchange on a single *interconnection*, or the sum of scheduled interchanges with several *interconnected systems*, on the one hand, and the actual metered flow on the *interconnection* point(s), on the other.

5.6.2 Inadvertent interchange shall be addressed in any agreement relating to *security* between the *IESO* and other *security coordinators*. The means used to mitigate inadvertent interchange shall respect all applicable *reliability standards.*

5.7 The Management of Violations to Security Limits

5.7.1 When there is a violation of a *security limit* on the *IESO-controlled grid* while in a *normal operating state*, the sequence of control actions taken by the *IESO* shall be defined in its operating procedures and instructions.

5.7.2 The operating procedures and instructions of the *IESO* shall allow the use of market mechanisms to the maximum extent possible for purposes of responding to violations of *security limits*.

5.7.3 Where market mechanisms fail or are not sufficient to maintain the *security* of the *IESO-controlled grid*, the *IESO* may direct *market participants* to take actions to either prevent the loss of *non-dispatchable load* or *price responsive load* or to prepare for *contingency events*.

5.8 Operation Under an Emergency Operating State

5.8.1 Once an *emergency operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.8.1.1 coordinating with other *security coordinators*;

5.8.1.2 issuing directions to *market participants* to reduce *demand* through voltage reductions and interruptions in accordance with section 10.3;

5.8.1.3 operate to those *security limits* appropriate for an *emergency operating state* to allow for increased power transfers; and

5.8.1.4 acquiring *emergency energy* in accordance with section 2.3.3A;

5.9 Operation Under a High-Risk Operating State

5.9.1 Once a *high-risk operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.9.1.1 operating to *security limits* appropriate for a *high-risk operating state*;

5.9.1.2 coordinating with neighbouring *security coordinators*;

5.9.1.3 issuing directions to *market participants* to reduce *demand* through voltage reductions or interruptions in accordance with section 10.3; and

5.9.1.4 temporarily and selectively increase the level of *security* on the *IESO-controlled grid*.

5.9A Operation Under a Conservative Operating State

5.9A Once a *conservative operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.9A.1 coordinating with neighbouring *control area operators*; and

5.9A.2 requesting *market participants* to monitor the *IESO-controlled grid* on the *IESO's* behalf.

5.9A.3 direct *market participants* to suspend all non-urgent maintenance and switching activities on *facility* elements for which outages must be reported or involve elements that could impact the operations of the *IESO-controlled grid.*

5.10 Restoration of System Security Following a Contingency Event

5.10.1 *Market participants* shall be prepared for, shall be able to manage and shall take such actions as may be necessary to restore *security* of the *IESO-controlled grid* following a *contingency event,* as directed by the *IESO*.

5.10.2 The *IESO* shall establish:

5.10.2.1 procedures that identify the steps necessary to restore the operation of the *IESO-controlled grid* to an *emergency operating state* respecting corresponding *security limits*, within 30 minutes;

5.10.2.2 procedures to attempt to restore supply first to individual loads identified by *market participants* as critical in nature, once the minimum acceptable level of *security* on the *IESO-controlled grid* has been restored; and

5.10.2.3 in consultation with relevant *market participants*, procedures to restore the operation of the *IESO-controlled grid* and of *facilities connected* to a *transmission system* that forms part of the *IESO-controlled grid* following automatic *outages*.

6. Outage Coordination

6.1 Introduction

6.1.1 The objectives of this section 6 are to enable the *IESO* to review and assess the impact of *outage* schedules on the fulfillment by the *IESO* of its *reliability*-related responsibilities under the *Electricity Act, 1998*, its *licence*, and the *market rules*, to require *market participants* to obtain the approval of the *IESO* in respect of *planned outage* schedules and to permit the *IESO* to reject, revoke *advance approval* of and recall *outages* that may have an impact on the *reliability* of the *IESO-controlled grid* or a material impact on the operation of the *IESO-administered markets*.

6.1.2 The *IESO* shall maintain a database of all submissions to the *outage* planning and scheduling process.

6.1.3 The *IESO* shall develop, and include in the applicable *market manual*, a full list of the equipment and *facilities* the *outage* of which must be reported to and scheduled with the *IESO* in accordance with this section 6. The *IESO* shall use as the basis for including *facilities* and equipment on this list that any change or anticipated change to the *facilities* or equipment could have a material effect on the value of an operating *security limit*, the *reliable* operation of *IESO-controlled grid* or operation of the *IESO-administered markets*, including, but not be limited to, the following:

6.1.3.1 *facilities* forming part of the *IESO-controlled grid*;

6.1.3.2 *generation facilities*, *electricity storage facilities* and auxiliary equipment connected to the *IESO-controlled grid* or in respect of which a *generator* or *electricity storage participant* is participating in the *real-time markets*;

6.1.3.3 protection systems; and

6.1.3.4 communication equipment, including related hardware and software systems.

6.1.4 [Intentionally left blank]

6.1.5 Nothing in this section 6 shall relieve a *market participant* from its responsibility for and arising from the performance of all work relating to any *outage* or test, whether in respect of energized or de-energized *facilities* or equipment, including, but not limited to, its responsibility in respect of worker safety.

6.1.6 No *market participant* shall remove equipment or *facilities* from service except in accordance with this section 6 unless such removal from service is necessary to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*. If any equipment or *facilities* are removed from service for these reasons, the *market participant* shall promptly notify the *IESO*.

6.1.7 The *IESO* shall coordinate *outages* with *market participants* except that, with respect to *outages* to any portion of the *transmission system* during a *normal operating state*, the applicable *transmitter* shall, pursuant to the Transmission System Code, coordinate the *outage* with affected *market participants* directly connected to that portion of the *transmission system* unless the *IESO* determines it necessary to coordinate such activities in order to maintain *reliability*.

6.2 Outage Planning

6.2.1 Each *market participant* shall inform the *IESO* of its long-term plans for *outages* in accordance with the provisions of this section 6.2.

6.2.2 Each *market participant* shall establish its *outage* planning process in such manner as will enable it to comply with its reporting and scheduling obligations under this section 6. Without limiting the generality of the foregoing, *market participants* shall be required to plan *outages* in advance of the anticipated date of the *planned outage* in accordance with the submission requirements of this section 6.

Requests for Advance Approval

6.2.2A A *market participant* may request *quarterly advance approval*, *weekly advance approval*, *three-day advance approval* or *one-day advance approval* for a *planned outage* of equipment or *facility* in accordance with this section 6 and the applicable *market manual*.

IESO Obligation to Consider Planned Outages for Advance Approval

6.2.2B The *IESO* shall consider all *planned outages* submitted under section 6.2.2A for *advance approval* in accordance with this section 6 and the processes specified in the applicable *market manual*.

IESO Obligation to Include Planned Outages in Daily and Quarterly Assessments

6.2.3 The *IESO* shall include in the daily assessments referred to in section 7.3.1.4 all *planned outages* that are to occur in the immediately following 34 calendar days as reported or scheduled by *market participants*. The *IESO* shall include in the quarterly assessments referred to in section 7.3.1.2 all *outages* planned or scheduled to occur in the immediately following 18 months as reported or scheduled by *market participants*.

Transmitter Generator and Electricity Storage Participant Obligation to Provide Planned Outage Information for 18-Month Assessments

6.2.4 To support the 18-month assessments referred to in section 7.3.1.2, and subject to section 6.2.5, for those *facilities* and equipment on the list developed in accordance with section 6.1.3, *transmitters, generators* and *electricity storage participants* shall, as frequently as may be necessary to maintain the accuracy of the information provided, report to the *IESO* the *outage* plans for transmission *facilities* forming part of the *IESO-controlled grid* and for *generation facilities*, or *electricity storage facilities* respectively, as follows:

6.2.4.1 for *outages* starting three months or more in the future, those with a scheduled duration of five days or more; and

6.2.4.2 for *outages* starting less than three months in the future, those with a scheduled duration of four hours or more.

Exclusions of Outages for Generation Facilities or Electricity Storage Facilities

6.2.5 Notwithstanding any other provision of section 6, *outages* to the following *generation facilities* or *electricity storage facilities* do not need to be reported to support the 18-month assessments referred to in section 7.3.1.2:

6.2.5.1 in the case of all *generators, generation facilities* having a *capacity* of less than 20 MW;

6.2.5.2 in the case of a *generator* whose total available capacity inside the *IESO control area* exceeds 4000 MW, *generation facilities* that represent less than 0.5 percent of the total *capacity* of such *generator,* unless the *generation facilities* have been identified by the *IESO* as affecting the *reliability* of the *IESO-controlled grid.* The *IESO* shall notify the relevant *generators* of any *generation facilities* so identified; or

6.2.5.3 in the case of all *electricity storage participants*, *electricity storage facilities* with an *electricity storage facility size* of less than 20 MW.

6.3 Outage Scheduling with the IESO

Planned Outages

6.3.1 Subject to section 6.1.3 and 6.4, each *market participant* shall submit its current schedule of all *planned outages*, regardless of duration, to the *IESO*.

6.3.2 A *planned outage* submitted by a *market participant* pursuant to section 6.3.1 shall represent the intent of the *market participant* to take the relevant equipment out of service at the scheduled time and to return the relevant equipment to service at the scheduled time.

6.3.3 [Intentionally left blank – section deleted]

Forced Outages

6.3.4 Each *market participant* shall to the maximum extent possible notify the *IESO* in advance of a *forced outage* and provide a brief description of the nature and causes of the *forced outage.* When such advance notice cannot be given, the *market participant* shall promptly notify the *IESO* of the occurrence of a *forced outage* and provide a brief description of the nature and causes of the *forced outage*.

6.3.5 Whenever, in the opinion of the *IESO*, a *forced outage* has had a significant impact on the *reliability* of the *IESO-controlled grid*, or gives rise to potential *reliability* concerns, the *IESO* may require the *market participant* experiencing the *forced outage* to provide a detailed description of the nature and causes of the *forced outage* to the *IESO*. Such description of the *forced outage* shall be provided as soon as practicable and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO* in any given case, following the start of the *forced outage.* The *IESO* may also require the *market participant* experiencing the *forced outage* to provide a detailed description of the steps that the *market participant* intends to take to prevent any recurrence of the circumstances that led to the *forced outage*. Such description shall also be provided as soon as practical and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO*, following the start of the *forced outage*.

Replacement Energy to Support Planned Outages

6.3.6 A *generator* or *electricity storage participant* may, no later than the time specified in section 6.4.1, in requesting a *planned outage* in accordance with section 6.3.1, notify the *IESO* that the *generator* or *electricity storage participant* shall arrange replacement *energy offers* in the form of an import to support the *outage* request. A *generator* or *electricity storage participant* may, when requesting an extension to an *outage* under section 6.4.7 or resubmitting an *outage* under section 6.4.10, notify the *IESO* that the *generator* or *electricity storage participant* shall arrange replacement *energy offers* in the form of an import to support the *outage* extension or resubmission. For certainty, this section shall not under any circumstances impose any explicit or implicit obligation on either a *generator* or *electricity storage participant* to so notify the *IESO*, or if so notified, the *IESO* to approve or accept any such arrangement. Upon notice to the *IESO*, a *generator* or *electricity storage participant* may withdraw the arrangement for replacement *energy offers* at any time up to final approval of the *outage* or up to the final approval of the extension to or resubmitting of the *outage.*

6.3.7 The *generator* or *electricity storage participant* shall provide the following information to the *IESO* when in accordance with section 6.3.6 it either submits a *planned outage* request or requests the extension to or resubmission of an *outage*:

6.3.7.1 Subject to the approval of the *IESO*, the *intertie zone (s)* through which the replacement *energy* is intended to be scheduled; and,

6.3.7.2 The *registered market participant* associated with a *boundary entity resource* that shall submit the *offers* and, pursuant to MR Ch.7 s.7.5.8A, schedule the replacement *energy* if *dispatched* by the *IESO.*

6.3.8 The *IESO* may limit the number and aggregate size of *outages* supported by replacement *energy* and, where the number and aggregate size of *outages* is limited the *IESO* shall determine the priority of the *outages*, in accordance with sections 6.4.13 through 6.4.20.

6.3.9 The *IESO* may specify and inform the *generator* or *electricity storage participant* of the minimum amount of replacement *energy* in megawatts and the duration of *offers* necessary to support the *planned outage* request or the request for the extension to or rescheduling of the *outage*.

6.3.10 If the *registered market participant* associated with a *boundary entity resource* referred to in section 6.3.7.2 fails to submit *offers* for the replacement *energy,* that have been arranged by the *generator* or *electricity storage participant*, the *generator* or *electricity storage participant* shall be subject to the financial penalties calculated in accordance with the provisions of MR Ch.3 s.6.6.8.

6.4 Submission of Outage Schedules and IESO Approval of Outage Schedules

6.4.1 In order to obtain *IESO* approval of a *planned outage*, a *market participant* shall submit a *planned outage* with the *IESO* under the timelines specified in sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E. At the time of the submission, the *market participant* shall:

6.4.1.1 provide information about the recall of the *planned outage*, including the time required to return the *facilities* or equipment to service and other applicable conditions of recall; and

6.4.1.2 [Intentionally left blank – section deleted]

6.4.1.3 confirm, if applicable and as specified in the applicable *market manual*, the request for *weekly advance approval* for the *planned outage*.

6.4.1A [Intentionally left blank – section deleted]

6.4.1B If requesting *quarterly advance approval* of a *planned outage*, the *market participant* shall submit the *planned outage* with the *IESO* no later than 00:00 EST on the first day of the month that is three months prior to the start of a six month period, beginning with the next calendar quarter, in which the *planned outage* is scheduled to start.

6.4.1C If requesting *weekly advance approval* of a *planned outage*, the *market participant* shall submit the *planned outage* with the *IESO* no later than 16:00 EST on the third Friday prior to the start of the week, starting Monday, in which the *planned outage* is scheduled to start, and confirm the request for *weekly advance approval* in accordance with section 6.4.1.3.

6.4.1D If requesting a *three-day advance approval* of a *planned outage*, the *market participant* shall submit the *planned outage* with the *IESO* no later than 16:00 EST on the fifth *business day* prior to the start date of a *planned outage*.

6.4.1E If requesting *one-day advance approval* of a *planned outage* the *market participant* shall submit the *planned outage* with the *IESO* no later than 10:00 EST on the second *business day* prior to the start date of the *planned outage*.

6.4.2 Where the scheduling of *planned outages* submitted by different *market participants* conflicts such that the *planned outages* cannot both or all be approved by the *IESO*, the *IESO* shall inform the affected *market participants* and request that they resolve the conflict. Should the conflict remain unresolved, the *IESO* shall determine which of the *planned outages* can be approved on the basis of the priority accorded to each *planned outage* pursuant to sections 6.4.13 to 6.4.20.

6.4.3 No *planned outage* shall occur or be permitted by a *market participant* to occur unless:

6.4.3.1 the *planned outage* has been submitted with the *IESO* in accordance with sections 6.4.1 or 6.4.6;

6.4.3.2 the *planned outage* has been approved by the *IESO* in accordance with this section 6.4;

6.4.3.3 immediately prior to the scheduled commencement of the *planned outage* or at a pre-arranged time specified by the *IESO* when providing the *advance approval* referred to in sections 6.4.4.4B, 6.4.4.4C, 6.4.4.5 and 6.4.4.5A, the *market participant* has requested from the *IESO* and has received the *IESO*'s final approval to the *planned outage*; and

6.4.3.4 the removal from service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4.4.6.

6.4.4 The *IESO* shall:

6.4.4.1 provide *advance approval* for a *planned outage* submitted to it pursuant to section 6.4.1 and shall provide its final approval to the *planned outage* pursuant to section 6.4.3.3 unless it determines, based primarily on the quarterly assessments referred to in section 7.3.1.2 and on the daily assessments referred to in section 7.3.1.4, that the *planned outage,* including but not limited to a *planned outage* identified by an *embedded generator,* will or is reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid* or as otherwise described in section 6.4.4A*;*

6.4.4.2 assess each *planned outage* submitted under section 6.4.1;

6.4.4.3 following receipt of an *outage* submission pursuant to section 6.2.1, 6.3.1, or 6.4.1, advise the relevant *market participant* of the existence of any conflict with a *planned outage* planned by another *market participant*;

6.4.4.4 if the *market participant* submitted the *planned outage* with the *IESO* under section 6.4.1, advise the relevant *market participant* of the expected outcome of the approval process;

6.4.4.4A [Intentionally left blank – section deleted]

6.4.4.4B if the *market participant* submitted its *planned outage* for *quarterly advance approval* under section 6.4.1B, advise the *market participant* whether or not *quarterly advance approval* of the *planned outage* has been granted no later than the end of the month that is one month prior to the start of the six month period, starting with the next calendar quarter, in which the *planned outage* is scheduled to start. Where the *IESO* does not grant *quarterly advance approval*, the *IESO* shall subsequently consider the *planned outage* for either *quarterly advance approval* in accordance with this section 6.4.4.4B, *weekly advance approval* in accordance with section 6.4.4.4C, or *three-day advance approval* in accordance with section 6.4.4.5, and as specified in the applicable *market manual*;

6.4.4.4C if the *market participant* submitted its *planned outage* for *weekly advance approval* under section 6.4.1C or if the *IESO* considered the *planned outage* for *weekly advance approval* in accordance with section 6.4.4.4B, and if the *market participant* confirmed the request for *weekly advance approval* in accordance with section 6.4.1.3, advise the *market participant* of the *weekly advance approval* or rejection of the *planned outage* no later than 16:00 EST on the second Friday prior to the week, starting Monday, in which the *planned outage* is scheduled to start.

6.4.4.5 if the *market participant* submitted its *planned outage* for *three-day advance approval* under section 6.4.1D, or if the *IESO* considered the *planned outage* for *three-day advance approval* in accordance with section 6.4.4.4B, advise the *market participant* of the *three-day advance approval* or rejection of the *planned outage* no later than 16:00 EST on the third *business day* prior to the day on which the *planned outage* is scheduled to commence;

6.4.4.5A if the *market participant* submitted its *planned outage* and request for *one-day advance approval* under section 6.4.1.E, advise the *market participant* of the *one-day advance approval* or rejection of the *planned outage* no later than 8:00 EST on the *business day* prior to the day on which the *planned outage* is scheduled to commence; and

6.4.4.6 when providing the final approval referred to in section 6.4.4.1, advise the *market participant* if the submitted *planned outage* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*. If it is known in advance, the *IESO* will advise the *market participant* of this requirement when providing the *advance approval* referred to in sections 6.4.4.4B, 6.4.4.4C, 6.4.4.5 or 6.4.4.5A or as soon as possible thereafter.

6.4.4A The *IESO* may refuse to provide *advance approval* to a *transmitter's planned outage* if:

6.4.4A.1 the *transmitter's planned outage* is to a *connection facility* that would prevent the delivery of electricity to the *IESO-controlled grid* from a *generation unit* or *electricity storage unit* that has committed capacity to an external *control area* in accordance with MR Ch.7 s.20.2;

6.4.4A.2 the *IESO* is advised by the *market participant* that has committed its capacity to an external *control area* in accordance with MR Ch.7 s.20.2, that the external *control area operator* has determined that a *transmitter's planned outage* would result in an unacceptable risk of an adequacy shortfall to the *external control area,* as may be specified in the applicable *capacity export agreement*; and

6.4.4A.3 the *market participant* that has committed its capacity to an external *control area* in accordance with MR Ch.7 s.20.2 has demonstrated to the *IESO* that it has made best efforts to reschedule the *planned outage* with the *transmitter*, as prescribed in the applicable *market manual*.

6.4.5 Where the *IESO* does not provide *advance approval* of a *planned outage* or does not give its final approval to a *planned outage* pursuant to section 6.4.4 or 6.4.4A, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid.* Upon the resubmission of the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant.*

Requests for Late Submissions of Planned Outages

6.4.6 A *market participant* may make a request to the *IESO* for approval of a *planned outage* after the deadlines in sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E have expired, where the request represents an unexpected opportunity to accomplish work that would otherwise have been unable to proceed. The *IESO* may consider such late submissions where the opportunity presents a low risk to the *reliability* of the *IESO-controlled grid* and a low risk to the *IESO*.

Extensions

6.4.7 Each *market participant* shall notify the *IESO* if a *planned outage* which has been approved by the *IESO* will have a duration which exceeds the duration originally approved by the *IESO*, which notice shall include a request that the *IESO* approve the extension. Unless the extension is due to a *forced outage* condition, such notice shall be provided to the *IESO* in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E and will be treated as a new *outage* request.

6.4.8 If the *IESO* determines that an extension to the duration of a *planned outage* will or is reasonably likely to adversely affect the *reliability* of the *IESO-controlled grid* or will or is reasonably likely to require the re-scheduling of a *planned outage* submitted to the *IESO* pursuant to section 6.4.1 or the revoking of *advance approval*, or recall of a *planned outage* approved pursuant to section 6.4.4, the *IESO* shall reject such extension and the *market participant* shall use its reasonable best efforts to ensure that the duration of the *planned outage* does not exceed the duration originally approved by the *IESO* or such longer period as the *IESO* may advise in rejecting the extension requested.

Revoke Advance Approvals

6.4.9 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, or as provided in section 6.4.9.3, revoke an *advance approval* of a *planned outage*. Without limiting the generality of the foregoing, the *IESO* may revoke an *advance approval* if:

6.4.9.1 the *IESO* determines that a *conservative operating state,* an *emergency operating state* or a *high-risk operating state* is occurring or is reasonably likely to occur at the time at which the *planned outage* would otherwise take place;

6.4.9.2 necessary to avoid recalling a *planned outage* pursuant to section 6.4.11; or

6.4.9.3 the *transmitter's planned outage* is to a *connection facility* that would prevent the delivery to the *IESO-controlled grid* of electricity from a *generation unit* or *electricity storage unit* that has committed capacity to an external *control area* in accordance with MR Ch.7 s.20.2; and

6.4.9.3.1 the *IESO* is advised by the *market participant* that has committed its capacity to an external *control area* in accordance with MR Ch.7 s. 20.2, that the external *control area operator* has determined that a *transmitter's planned outage* would result in an unacceptable risk of an adequacy shortfall to the *external control area,* as may be specified in the applicable *capacity export agreement*; and

6.4.9.3.2 the *market participant* that has committed its capacity to an external *control area* in accordance with MR Ch.7 s.20.2 has demonstrated to the *IESO* that it has made best efforts to reschedule the *planned outage* with the *transmitter*, as prescribed in the applicable *market manual*.

A *planned outage* that receives *advance approval* under section 6.4.4 but does not receive final approval pursuant to section 6.4.3.3 shall be considered to have had its *advance approval* revoked.

6.4.10 Where the *IESO* revokes *advance approval* of a *planned outage* pursuant to section 6.4.9, the *market participant* may elect either to resubmit or to cancel the *outage*. When the *market participant* elects to resubmit the *outage*, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid* and not pose an unacceptable risk to the adequacy of an external *control area* to which capacity has been committed. In re-scheduling the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant*. A *planned outage* that is re-scheduled under this section must be resubmitted in accordance with the submission requirements in sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E. To maintain the priority date of the approved *planned outage* prior to the revocation of the *advance approval*; the *planned outage* must be resubmitted in accordance with section 6.4.16.

Recalls

6.4.11 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, recall a *planned outage* that has already commenced, having due regard to the time needed to return the *facilities* or equipment to service as identified by the relevant *market participant* pursuant to section 6.4.1.1 and shall so advise the relevant *market participant*. Such *market participant* shall arrange for the accelerated return to service of the *facilities* or equipment in accordance with the schedule identified by the *market participant* pursuant to section 6.4.1.1. The *IESO* shall not recall a *planned outage* unless further control action is required and it has revoked *advance approval* or rejected requests for approval of all other *planned outages* the revocation or rejection of which could eliminate the need to recall the *planned outage* that has already commenced.

Embedded Generators

6.4.12 Each *distributor* shall, in reporting to the *IESO* pursuant to sections 6.2 and 6.3, identify to the *IESO* any *outages* that potentially constrain an *embedded generator* or an *embedded electricity storage facility* that is connected to its *distribution system.*

Determining Outage Priority

6.4.13 The *IESO* shall assign a priority date to each *outage* submission received by the *IESO*. Where the *IESO* is required or permitted by this section 6 to approve, reject, revoke *advance approval* of or recall one or more *planned outages*, such *planned outages* shall:

6.4.13.1 be given advance or final approval in order of priority determined on the basis of sections 6.4.14 to 6.4.20; and

6.4.13.2 be rejected, be resubmitted, have *advance approval* revoked or be recalled in reverse order of priority determined on the basis of sections 6.4.14 to 6.4.20.

6.4.14 Where an *outage* is granted *advance approval* in accordance with sections 6.4.4.4B, 6.4.4.4C, 6.4.4.5 and 6.4.4.5A:

6.4.14.1 outages granted quarterly advance approval take priority over outages granted weekly advance approval, three-day advance approval or one-day advance approval; and

6.4.14.2 outages granted weekly advance approval take priority over outages granted three-day advance approval or one-day advance approval; and

6.4.14.3 outages granted three-day advance approval take priority over outages granted one-day advance approval; and

6.4.14.4 within quarterly advance approval, weekly advance approval, three-day advance approval and one-day advance approval, an outage with an earlier priority date takes priority over other outages granted the same level of advance approval.

6.4.15 Where a *market participant* gives notice of a change in the commencement, duration or nature of a *planned outage* relative to the most recent *outage* submission, the *IESO* shall revise the priority date with the time at which such notice was received by the *IESO.* The revised priority date shall be used by the *IESO* in determining the priority to be given to the *planned outage*. Where such notice reflects only a shortening in the duration of a *planned outage* relative to the most recent *outage* submission for that *planned outage*, the priority date associated with such previous *outage* submission shall be retained in determining the priority to be given to the *planned outage*.

6.4.16 Where:

6.4.16.1 the *IESO* revokes *advance approval* of a *planned outage* prior to the commencement thereof; and

6.4.16.2 the *market participant* subsequently re-submits the *planned outage* with the *IESO*, in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E, within five *business days* of the revocation;

the priority date of the approved *planned outage* prior to the revocation of *advance approval* shall be deemed to be the priority date of the re-submitted *planned outage* for purpose of determining the priority to be given to the *planned outage*.

6.4.17 Where:

6.4.17.1 the *IESO* rejects *advance approval* of a *planned outage* in accordance with section 6.4.4.4C, 6.4.4.5 or 6.4.4.5A;

6.4.17.2 the *market participant* resubmits the *planned outage* to the *IESO,* in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E, within five *business days* of the rejection; and

6.4.17.3 this was the first time the *planned outage* had been rejected,

the priority date of the *planned outage* prior to the rejection will be deemed to be the priority date of the re-submitted *planned outage* for purposes of determining the priority to be given to the *planned outage*.

6.4.18 [Intentionally left blank – section deleted]

6.4.19 Where:

6.4.19.1 the *IESO* recalls a *planned outage* that has already commenced; and

6.4.19.2 the *market participant* resubmits the *planned outage* to the *IESO*, in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E within five *business days* of the recall,

the priority date of the *planned outage* prior to the recall will be deemed to be the priority date of the re-submitted *planned outage* for purposes of determining the priority to be given to the *planned outage*.

6.4.20 Where:

6.4.20.1 the *IESO* does not grant *quarterly advance approval* of a *planned outage* that was scheduled to start in the first three months of a six month period, starting with the next calendar quarter; and

6.4.20.2 the *market participant* re-submits the *planned outage* for *quarterly advance approval* no later than the start of the six month period, starting with the next calendar quarter, in which the *planned outage* that was not granted *quarterly advance approval* was scheduled to start; and

6.4.20.3 the scheduled start date of the re-submitted *outage* which was not granted *quarterly advance approval* is revised to a date which is after the first three months of the six month period, starting with the next calendar quarter;

the priority date of the *planned outage* which was not granted *quarterly advance approval* will be deemed to be the priority date of the re-submitted *planned outage* for purposes of determining the priority to be given to the *planned outage*.

6.4A Return of Equipment or Facilities to Service

6.4A.1 No *market participant* shall return to service any equipment or *facilities* that are undergoing a *planned outage* unless:

6.4A.1.1 immediately prior to its return to service, or at a pre-arranged time specified by the *IESO*, the *market participant* has requested and has received the *IESO's* approval to return the equipment or *facilities* to service; and

6.4A.1.2 the return to service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4A.2.3.

6.4A.2 The *IESO* shall:

6.4A.2.1 approve the return to service of equipment or *facilities* that are undergoing a *planned outage* unless it determines that such return to service will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*;

6.4A.2.2 promptly notify the *market participant* if a determination is made that a return to service of equipment or *facilities* will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*; and

6.4A.2.3 when providing the approval referred to in section 6.4A.2.1, advise the *market participant* if the return to service of equipment or *facilities* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*.

6.4A.3 Where the *IESO* does not approve the return to service of equipment or *facilities* pursuant to section 6.4A.2.1, the *IESO* shall, subject to final confirmation by the *IESO* pursuant to 6.4A.1, advise the *market participant* when the equipment or *facilities* may be returned to service.

6.4B Notification of Commencement and Completion of Planned Outages

6.4B.1 Each *market participant* shall notify the *IESO*:

6.4B.1.1 subject to section 6.4.3.3, of the commencement of a *planned outage* at the time the relevant equipment or *facilities* are removed from service; and

6.4B.1.2 subject to section 6.4A.1.1, of the completion of a *planned outage* at the time the relevant equipment or *facilities* are fully returned to service.

6.5 Information

6.5.1 Each *transmitter,* each *generator* and each *electricity storage participant* shall provide to the *IESO* such *outage* information as may be requested by the *IESO* to enable the *IESO* to review and schedule *outages*.

6.5.2 Subject to the confidentiality provisions of MR Ch.3, the *IESO* shall *publish* the *planned outage* information provided to it pursuant to section 6.5.1.

6.5.3 Notwithstanding any other provision of these *market rules*, *planned outage* information that is provided to the *IESO* by *market participants* pursuant to this Chapter may be exchanged between the *IESO* and other *security coordinators, control area operators*, and *interconnected transmitters* who are signatories to the *NERC confidentiality agreement* or who are otherwise legally bound to withhold the information from any person competing with the *market participant* that provided the information.

6.5.4 The *IESO* shall *publish generator outage* information aggregated by fuel type based on information provided to it by *market participants* and may also *publish* the *outage* information for *electricity storage participants*.

6.6 Tests

6.6.1 A *market participant* who wishes to engage in a test that could affect the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets* shall provide the information referred to in section 6.6.2 to the *IESO*.

6.6.2 As a minimum, the information referred to in section 6.6.1 shall identify:

6.6.2.1 the equipment involved;

6.6.2.2 the relevant details of contracts or agreements as they relate to the test activities;

6.6.2.3 preferred and alternative dates and times for the conduct of the test activities;

6.6.2.4 unusual system configurations or setup;

6.6.2.5 the expected impact of the test activities on power flows, voltage and frequency, and of any other dynamic that could interfere with the *reliability* of the *IESO-controlled grid*;

6.6.2.6 details of special readings or observations, as available; and

6.6.2.7 the names of and methods of communication with personnel who will be involved in the test activities and who may be contacted with respect thereto.

6.6.3 Tests covered by the requirements of this section 6.6 shall include, but are not limited to:

6.6.3.1 the deliberate application of short circuits;

6.6.3.2 stability tests of generation facilities, electricity storage facilities and transmission facilities;

6.6.3.3 planned actions which could cause abnormal voltage, frequency or overload; and

6.6.3.4 planned abnormal station or system configurations with inherent risk.

6.6.4 The *IESO* shall permit a test referred to in this section 6.6 to be performed if the *IESO* determines that the performance of the test will not have an adverse effect on the *reliability* of the *IESO-controlled grid* or on the operation of the *IESO-administered markets.*

6.6.5 In permitting a test to be performed, the *IESO* shall endeavour to permit the test to be performed at the time and on the date preferred as identified by the *market participant* pursuant to section 6.6.2.3.

6.6.6 This section 6.6 also applies to tests conducted pursuant to MR Ch.4 s.5.

6.6.7 During performance testing, a *market participant* shall keep the *IESO* informed of the expected operating capability of the *market participant's generation facility* or *electricity storage facility* using the outage management process as specified in the applicable *market manual*.

6.7 Compensation

Revoke Advance Approvals or Recalls

6.7.1 *Transmitters* whose *outages* are rejected or have *advance approvals* revoked or have *outages* recalled by the *IESO* shall not be entitled to compensation for any costs, losses or damage associated with such rejection, revocation or recall.

6.7.2 *Generators*, *electricity storage participants, distributors* or *wholesale consumers* whose *outages* have *advance approval* revoked or have *outages* recalled by the *IESO* shall, subject to the exceptions defined in sections 6.7.3A and 6.7.3B, be entitled to compensation for out-of-pocket expenses associated with such revocation or recall only if:

6.7.2.1 the *outage* was originally provided *advance approval* by the *IESO* pursuant to 6.4.4 and was submitted in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E;

6.7.2.2 the *outage* was recalled or had *advance approval* revoked by reason of a material error in the *IESO's* demand forecast, a failure of *generation facilities* within the *IESO control area,* a failure of *facilities* forming part of the *IESO-controlled grid* or a failure of *interconnection facilities*; and

6.7.2.3 the out-of-pocket expenses exceed $1000.00.

6.7.3 [Intentionally left blank – section deleted]

6.7.3A A *market participant* shall not be entitled to compensation under section 6.7.2 with respect to a *planned outage* of its *generation facility* or *electricity storage facility* that received a *quarterly advance approval* or *weekly advance approval* and that *advance approval* was subsequently revoked by the *IESO* if:

6.7.3A.1 the *IESO* revoked the *advance approval* as a result of a *forced outage* of another *generation facility* or *electricity storage facility* with the same *registered market participant* as the *generation facility* or *electricity storage facility* that was the subject of the *planned outage* and the *forced outage* occurred before 16:00 E.S.T. on the third *business day* prior to the scheduled start of the *planned outage*; or

6.7.3A.2 the *advance approval* was revoked as a result of a delayed return to service from a *planned outage* or *forced outage* of another *generation facility* or *electricity storage facility* with the same *registered market participant* as, respectively, the *generation facility* or *electricity storage facility* that was the subject of the *planned outage*.

6.7.3B A *market participant* shall not be entitled to compensation under section 6.7.2 with respect to a *planned outage* that is granted *quarterly advance approval* and scheduled to start in the last three months of a six month period, starting with the current calendar quarter, and where the *quarterly advance approval* is subsequently revoked no later than one month prior to the start of the next calendar quarter.

6.7.4 The out-of-pocket expenses claimed by *generators*, *electricity storage participants, distributors* or *wholesale consumers* pursuant to section 6.7.2 shall be subject to verification and audit by the *IESO* and shall, where paid, be recovered by the *IESO* in accordance with MR Ch.9 s.4.14.12.

6.7.5 A *generator*, *electricity storage participant, distributor* or *wholesale consumer* shall not be entitled to compensation for any costs, expenses, losses or damage associated with an *outage* which has been rejected by the *IESO* provided that, in exceptional circumstances and where a *generator*, *electricity storage participant, distributor* or *wholesale consumer* has suffered substantial financial harm as a direct result of such rejection, the *generator*, *electricity storage participant, distributor* or *wholesale consumer* may request that an *arbitrator* be appointed pursuant to MR Ch.3 s.2 to determine whether and the amount of any compensation which the *generator*, *electricity storage participant, distributor* or *wholesale consumer* shall be entitled to recover as a result of the rejection of the *outage* by the *IESO.* In the case of *generators* or *electricity storage participants*, no such compensation shall be recoverable under this section 6.7.5 unless the *generator* or *electricity storage participant* demonstrates that the amount claimed cannot be recovered through *market prices*.

6.7.6 Each act of revocation or recall by the *IESO* shall be treated separately for compensation purposes.

7. Forecasts and Assessments

7.1 Forecasts Prepared by the IESO

7.1.1 The *IESO* shall produce and *publish* the following ongoing *demand* forecasts for Ontario or parts thereof:

7.1.1.1 on a daily basis, a forecast of *demand* for each of the 34 days following the current day, by hour; and

7.1.1.2 on a quarterly basis, a forecast of *demand* for the next 18 months, by week.

7.1.2 The forecasts referred to in section 7.1.1 shall be prepared by the *IESO* in such form as may be specified in the applicable *market manual,* shall be used in conducting the assessments referred to in section 7.3, and shall, in the case of the forecast referred to in section 7.1.1.2, be included in the reports referred to in section 7.3.1.2.

7.1.3 The *IESO* shall *publish* the method to be used to perform the forecasts described in section 7.1.1.

7.1.4 If required by the *IESO* for the purpose of enabling the *IESO* to produce the forecasts referred to in section 7.1.1, each *distributor, connected wholesale customer, electricity storage participant* or other load-serving entity shall provide to the *IESO* the load forecasts described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual*.

7.2 Basis for IESO Forecasts

7.2.1 The *IESO* shall develop forecasts of peak *demand* and *energy demand*, by area, that may be based in part on forecasts provided pursuant to section 7.1.4 if required.

7.3 Advance Assessments of System Reliability

7.3.1 The *IESO* shall prepare for the purposes referred to in section 7.4 and based on the information received pursuant to section 7.5.1 and such other information as the *IESO* considers appropriate, and *publish,* the following reports of its findings in relation to such *reliability* assessments:

7.3.1.1 [Intentionally left blank – section deleted]

7.3.1.2 on a quarterly basis and no later than 5 *business days* prior to the end of each calendar quarter, an assessment covering an eighteen-month period commencing with the following calendar month;

7.3.1.3 [Intentionally left blank – section deleted]

7.3.1.4 on a daily basis and not later than 20:30 EST on each day, an assessment covering a 34-day period commencing on the following day; and

7.3.1.5 as required, an assessment of the *reliability* of the *IESO-controlled grid*.

7.3.2 Any information derived from the s*ecurity* and *adequacy* assessment process shall be used to provide a basis for informing *market participants* about expected conditions on the *IESO-controlled grid* and in the *IESO-administered markets*. It is expected that the information will trigger appropriate responses under other market processes, such as *outage* coordination, and transmission investment planning.

7.3A Liability

7.3A.1 Notwithstanding MR Ch.1 s.13.1.2, no *market participant* shall be entitled to compensation from the *IESO* for any costs, loss or damage sustained by the *market participant* as a result of any difference between:

7.3A.1.1 *demand* as forecasted pursuant to section 7.1.1 and actual *demand*;

7.3A.1.2 conditions on the *IESO-controlled grid* as forecasted in the assessments referred to in section 7.3.1 and actual conditions on the *IESO-controlled grid*; or

7.3A.1.3 information contained in succeeding forecasts *published* pursuant to section 7.1.1 or reports *published* pursuant to section 7.3.1 that cover in whole or in part the same time frame.

7.3B Succession of Forecasts and Reports

7.3B.1 Each forecast *published* pursuant to section 7.1.1 or report *published* pursuant to section 7.3.1 shall, to the extent that it covers in whole or in part the same time frame as that covered in a previous *published* forecast or report, supercede such previous *published* forecast or report.

7.4 Purpose of Assessments

7.4.1 [Intentionally left blank – section deleted]

7.4.2 The *IESO* shall conduct the quarterly assessments referred to in section 7.3.1.2 to:

7.4.2.1 provide forecasts, by month, of expected *demand*, *generation capacity*, *electricity storage capacity* and transmission capacity, *energy* capability of *generation resources*, and *electricity storage resources* and the possibility of any *security*-related events on the *IESO-controlled grid* that could require contingency planning by *market participants* or by the *IESO*;

7.4.2.2 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that could give rise to shortfalls in *generation capacity* and *electricity storage capacity* and thus provide information by which *market participants* could act to reschedule *outage* plans to avoid such projected shortfalls; and

7.4.2.3 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of the regional power systems to match generation and *demand*.

7.4.3 [Intentionally left blank – section deleted]

7.4.4 The *IESO* shall conduct the daily assessments referred to in section 7.3.1.4 to:

7.4.4.1 provide forecasts of:

7.4.4.1.1 expected hourly *demand*, *generation capacity*, *electricity storage capacity*, *energy* capability of *generation resources* and *electricity storage resources*, exports and imports of *energy*, and *operating reserve* requirements;

7.4.4.1.2 expected transmission limits with all elements in-service; and

7.4.4.1.3 expected transmission limits with *outages*;

that may affect the *security* of the *IESO-controlled grid* or affect operational decisions to be taken by the *IESO* that must be made more than a day in advance;

7.4.4.2 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of regional power systems to match generation and *demand*, on a daily and hourly basis, particularly in peak seasons and in peak hours; and

7.4.4.3 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that may give rise to shortfalls in *generation* *capacity* and thereby assist *market participants* in finalizing *outage* plans and submitting *outage* schedules to the *IESO*.

7.4.5 The *IESO* shall conduct the assessments referred to in section 7.3.1.5 to:

7.4.5.1 meet its obligations to maintain the *reliability* of the *IESO-controlled grid*;

7.4.5.2 meet the requirements of *standards authorities*; and

7.4.5.3 assist the *OEB* in meeting their objectives.

7.5 Information Requirements

7.5.1 Each *market participant* shall, for the purpose of enabling the *IESO* to perform the *reliability* assessments referred to in section 7.3.1, provide to the *IESO* the information described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual*.

7.6 The Reporting of Reliability Assessments

7.6.1 The reports referred to in section 7.3.1 shall be prepared by the *IESO* in such form and shall contain such information as may be specified in the applicable *market manual.*

7.7 Updated and Related Reports

Interim Updates

7.7.1 The *IESO* may *publish* additional updated versions of any of the assessment reports referred to in section 7.3.1 in the event of changes that, in the *IESO*'s opinion, are significant and should be communicated to *market participants*.

Related Reports

7.7.2 From the material and assessments in the assessment reports referred to in section 7.3.1, the *IESO* may produce additional related reports as required by relevant *standards authorities*, the *IESO Board*, the *OEB*, and the Government of Ontario.

Advisory Notices

7.7.3 The *IESO* may *publish* notifications in the event of changes that occur between scheduled *publication* times of the assessment reports referred to in section 7.3.1.4, in accordance with the applicable *market manual*. Where applicable, the corresponding information shall be included by the *IESO* in a subsequent *publication* of a scheduled report under section 7.3.1.4.

7.8 [Intentionally left blank – section deleted]

7.9 Provision of Information to Transmitters

7.9.1 Notwithstanding any other provision of these *market rules*, the *IESO* may, if necessary to enable *transmitters* to prepare plans for the expansion or modification of the *IESO-controlled grid*, provide to relevant *transmitters* information provided by *market participants* pursuant to this Chapter regarding their forecasts and plans. Any such information which is *confidential information* shall be provided to *transmitters* on a confidential basis and the receiving *transmitter* shall use all reasonable endeavours to protect such *confidential information* and shall use such *confidential information* solely for the purpose of preparing plans for the expansion or modification of the *IESO-controlled grid*.

7.9.2 Where the *IESO* intends to disclose to a *transmitter confidential information* pertaining to a *market participant* pursuant to section 7.9.1, the *IESO* shall provide the *market participant* with advance notice of such intention and shall provide the *market participant* with a reasonable opportunity to make representation as to why the *confidential information* should not be disclosed.

7.10 IESO Actions

Actions Within Next Twelve Months

7.10.1 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that requires action to be initiated within the next twelve months in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may:

- conduct and *publish* a *reliability* assessment in accordance with section 7.3.1.5; and
- take any additional steps necessary to ensure that the *reliability* of the *IESO-controlled grid is* maintained.

7.10.2 If the *IESO* does not believe that *market participants* have or will voluntarily put forward reasonable commitments for technically feasible options to alleviate the condition identified in section 7.10.1, the *IESO* may direct the *transmitter(s)* in the relevant location(s) to prepare a detailed proposal for the enhancement of the *IESO-controlled grid*. The *transmitter(s)* shall submit the proposal to the *OEB* and other governmental agencies having authority to approve the proposal, in the form of an application for approval of the enhancement. The *IESO* shall notify the *OEB* of its identification of the adverse condition.

Actions Beyond the Next Twelve Months

7.10.3 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that does not require action to be initiated within the next twelve months, the *IESO* shall notify the *OEB* of its determination.

Actions Independent of IESO Recommendations

7.10.4 Nothing in this section 7.10 is intended to limit the ability of any *market participant* to file for approval a proposal to invest in *facilities* on the *integrated power system* that are not the subject of specific recommendations made by the *IESO*. A *market participant* interested in sponsoring a new or modified *connection* to the *IESO-controlled grid* may submit a *request for connection assessment* in accordance with MR Ch.4 s.6.1.6.

8. Remedial Action Schemes

8.1 Objectives

8.1.1 *Remedial action schemes* ("*RAS*") have been installed in a number of locations on the *IESO-controlled grid* which automatically initiate one or more of the following control actions:

8.1.1.1 load rejection;

8.1.1.2 generation rejection;

8.1.1.3 generation runback;

8.1.1.4 shunt capacitor switching;

8.1.1.5 shunt reactor switching; and

8.1.1.6 cross-tripping.

For further certainty, any of the control actions listed above may be applied by the *IESO* to *electricity storage facilities* if and as applicable.

8.1.2 The *IESO* shall direct the arming of *RASs* installed on the *IESO-controlled grid* as necessary to:

8.1.2.1 increase the capability of power transfers on the *IESO-controlled grid;* or

8.1.2.2 provide additional *security* beyond that required to manage *contingency events* in a *normal operating state*.

8.1.3 New *RASs* shall be installed and utilized on the basis of agreements between and/or among the parties involved.

8.2 Responsibilities of the IESO

8.2.1 The *IESO* shall classify all *RASs* and obtain approval for their use in accordance with all applicable *reliability standards.*

8.2.2 The *IESO* shall determine the need for utilizing an *RAS* for *security* reasons.

8.2.2A The *IESO* shall direct the arming of all *RASs* installed on the *IESO-controlled grid* in accordance with applicable *reliability standards* and applicable agreements including those negotiated under section 8.4.2.

8.2.3 The *IESO* shall direct the arming of an *RAS* to mitigate the adverse effects of specific extreme *contingency events* and to mitigate congestion provided that there are no overriding concerns related to the *security* of the *IESO-controlled grid*.

8.2.4 The *IESO* shall establish and *publish* criteria for arming and activation of *RASs* in sufficient detail and precision to allow a *market participant* whose *facility* forms part of an *RAS* to understand the conditions under which that *RAS* would be armed and activated. Prior to establishing changes to such criteria, the *IESO* shall consult with, and, where practicable, gain the agreement of, the *market participant* whose *facility* is part of the *RAS* to the intended changes. In the event that agreement cannot be reached, the *IESO* may change the criteria for the *RAS* if necessary to maintain *reliable* operation of the *IESO-controlled grid*.

8.2.5 The *IESO* shall from time to time review or cause to be reviewed the performance of *RASs*.

8.2.6 In the event that a *market participant* applies to the *IESO* for compensation under section 8.4.1, the *IESO* shall, upon verification that the amount being claimed is correct, pay such compensation by crediting the *market participant's preliminary settlement statement* for the last day of the month on the next *preliminary settlement statement* in which the *IESO* can reasonably incorporate the compensation.

8.3 Responsibilities of RAS Equipment Owners

8.3.1 Owners of *RAS* equipment shall:

8.3.1.1 maintain *RAS* equipment in accordance with all applicable *reliability standards*;

8.3.1.2 test and report operating statistics associated with an *RAS* to the *IESO* on an annual basis;

8.3.1.3 report the performance of an *RAS* when requested to do so by the *IESO*;

8.3.1.4 evaluate and notify the *IESO* of any request from affected *market participants* for permanent exemptions from *connection* to the *RAS*; and

8.3.1.5 provide written notice to the *IESO* of any proposal to install a new, or modify an existing, *RAS*, which notice shall be provided with sufficient lead time and in sufficient detail for the *IESO* to review and seek, if necessary, approval from the relevant *standards authorities* for such new or modified *RAS*; and

8.3.1.6 specify to the *IESO* and *market participants* whose *facilities* form part of an *RAS* the means used to arm the *RAS*.

8.4 Responsibilities of Market Participants Whose Facilities Form Part of an RAS

8.4.1 A *market participant* with a *facility* associated with a *non-quick start resource* and that is part of an *RAS* may apply to the *IESO* for compensation, if:

8.4.1.1 that *facility* is tripped offline as a result of the activation of the *RAS*;

8.4.1.2 the *non-quick start resource* associated with such *facility* does not receive a real-time make whole payment *settlement amount* pursuant to MR Ch.9 s.3.5 in relation to such *energy* for the same *metering interval*;

8.4.1.3 the *non-quick start resource* associated with such *facility* does not receive a *day-ahead market* balancing credit pursuant to MR Ch.9 s.3.3 in relation to such *energy* for the same *metering interval*;

8.4.1.4 the *day-ahead market locational marginal price* is less than the *real-time market locational marginal price* at the *delivery point* for the *non-quick start resource* associated with such *facility*; and

8.4.1.5 the actual quantity of *energy* the *non-quick start resource* associated with such *facility* injects into the *IESO-controlled grid* is less than its *day-ahead schedule*.

The amount of compensation that may be claimed is the difference between the applicable *real-time market locational marginal price* and the applicable *day-ahead market locational marginal price* at the *delivery point* for the *non-quick-start resource* multiplied by the difference between the *non-quick start resource's day-*

ahead schedule and the actual quantity of *energy* it injects into the *IESO-controlled grid*.

8.4.2 *Market participants* whose *facilities* form part of an existing *RAS* or may form part of a new *RAS* may request notification and/or status annunciation of *RAS* arming, disarming and activation and may enter into agreements with the *RAS* equipment owner/operator and the *IESO* to determine the appropriate status annunciation and notification. The *market participant*, *RAS* equipment owner/operator and the *IESO* shall use the following criteria in determining and implementing the appropriate status annunciation and/or notification:

8.4.2.1 licensing/legal requirements of the *market participant* related to the operation of its *facility* that is part of the *RAS*;

8.4.2.2 practicality of status annunciation and/or notification;

8.4.2.3 cost-effectiveness of status annunciation and/or notification;

8.4.2.4 the status annunciation and/or notification does not adversely impact the intended use of the *RAS*; and

8.4.2.5 comparison to the notification and annunciation of *RAS* arming and activation provided to other *market participants* whose *facilities* form part of an *RAS.*

In the event that they cannot agree on the status annunciation and notification requirements and implementation, the *RAS* owner/operator, the *IESO* and the *market participant* shall use the dispute resolution provisions in MR Ch.3 s.2 to resolve the issue.

8.4.3 *Market participants* whose *facilities* form part of an *RAS* shall notify the *IESO* in accordance with the applicable *market manual* or applicable agreements including those negotiated under section 8.4.2 if the *facility* is unavailable for *RAS* arming.

8.4.4 If an *RAS* has been armed and the *market participant* whose *facility* forms part of the *RAS* reasonably believes that a subsequent activation of that *RAS* would endanger the safety of any person, damage equipment or violate any *applicable law*, the *market participant* whose *facility* is part of that *RAS* may take action in accordance with applicable agreements including those negotiated under section 8.4.2 or may request that the *IESO* disarm the *RAS*. Upon such a request, the *IESO* shall, as soon as the *IESO* can take action to maintain reliable operation of the *IESO-controlled grid*, disarm the *RAS*.

9. Voltage Control

9.1 General

9.1.1 No *market participant* shall make changes in equipment status or operations that could materially adversely affect the voltage profile of the *IESO-controlled grid* without the prior approval of the *IESO*. To this end, each *market participant* shall notify the *IESO* of the *market participant's* intention to make any such change. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid.*

9.2 Under Load Tap Changers

9.2.1 The *IESO* shall direct the operation of under loads tap changers installed on auto-transformers on the *IESO-controlled grid* to control the voltage profile of the *IESO-controlled grid* while ensuring that acceptable voltages at the *connections* to *IESO-controlled grid* are maintained. No *market participant* shall make any changes to such taps without the prior approval of the *IESO*. The *IESO* shall approve such changes unless it determines that such changes could affect the *IESO's* ability to control voltage on the *IESO-controlled grid*, that procedures for such changes cannot be adopted or both.

9.2A Under Load Tap Changers – Connection Transformers

9.2A.1 The *IESO* shall not direct the operation of under load tap changers on *connections* to the *IESO-controlled grid* unless, in the *IESO's* opinion, the operation of such equipment otherwise will or is likely to affect the *reliability* of the *IESO-controlled grid.*

9.3 Off Load Tap Changers

9.3.1 No *market participant* shall make any changes to off load taps of transformers on the *IESO-controlled grid* without the prior approval of the *IESO.* The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid.*

10. Demand Control

10.1 Introduction

10.1.1 This section 10 applies in situations on the *integrated power system* where there is insufficient capacity available to satisfy expected *demand*, where operating problems (such as frequency, voltage levels or thermal over-loads) exist which affect the ability to serve *demand*, or where there is a breakdown on any part of the *IESO-controlled grid*. This section 10 identifies actions that the *IESO* may take or direct *market participants* to take to assist in achieving reductions in *demand* to either avoid or alleviate such situations.

10.1.2 Pursuant to MR Ch.7, the *IESO* shall continuously inform *market participants* of conditions on the *IESO-controlled grid* that may require the *IESO* to initiate reductions in *demand* by *non-dispatchable loads* or *price responsive loads*.

10.2 Demand Control Initiated by a Market Participant

10.2.1 *Market participants* shall notify the *IESO* of any action initiated by them to control *demand* in accordance with this section 10.2.

10.2.2 Each *market participant* that can intentionally and directly cut withdrawals by a *dispatchable load* or by a *dispatchable electricity storage resource* shall provide the following information to the *IESO*:

10.2.2.1 the proposed date, time, and duration of the cuts by *connection point* on the *IESO-controlled grid*, by hour;

10.2.2.2 the proposed MW reduction of *demand* by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.2.3 the details of the actual decrease in the withdrawals by a *dispatchable load* or the withdrawals by a *dispatchable electricity storage resource* that was achieved.

10.2.3 Each *transmitter* and *distributor* that intends to initiate a voltage reduction shall:

10.2.3.1 by 10:00 EPT each day, notify the *IESO* of all such planned voltage reductions and consequent reduction in load for the following day;

10.2.3.2 immediately notify the *IESO* of a voltage reduction that is planned after 10:00 EPT for the following day;

10.2.3.3 the proposed date, time, and duration of the voltage reduction by *connection point* on the *IESO-controlled grid*, by hour;

10.2.3.4 the proposed MW reduction by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.3.5 details of the actual voltage reduction achieved, in MWs.

10.2.4 Each *distributor* or *transmitter* that intends to initiate a *disconnection* in load (including, but not limited to, interruptible loads and demand management activities) shall:

10.2.4.1 by 10:00 EPT each day, notify the *IESO* of all such planned *disconnections* in load and consequent reduction in loads for the following day;

10.2.4.2 immediately notify the *IESO* of a *disconnection* in load that is planned after 10:00 EPT for the following day;

10.2.4.3 the proposed date, time, and duration of the *disconnection* in load by *connection point* on the *IESO-controlled grid*, by hour;

10.2.4.4 the proposed reduction, in MWs, of loads by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.4.5 details of the actual reduction in loads achieved, in MWs.

10.2.5 Each *distributor* and *transmitter* that has operational control over load shall:

10.2.5.1 make arrangements that enable it to *disconnect* load immediately under an *emergency operating state* declared by the *IESO*;

10.2.5.2 make arrangements that enable it to apply *disconnections* to load to individual or specific groups of *connection points* on the *IESO-controlled grid* as determined in a coordinated fashion by the *IESO* and *market participants*;

10.2.5.3 provide the *IESO* in writing, by week 24 in each calendar year, its total forecasted peak *demand* for the immediately following twelve-month period, by *connection point* on the *IESO-controlled grid*; and

10.2.5.4 provide the *IESO* in writing, by week 24 in each calendar year, the total forecasted peak *demand* for the immediately following twelve-month period that can be *disconnected* within the following time scales: immediately, 15 minutes, 1 hour and more than 1 hour. This information shall be provided by *connection point* on the *IESO-controlled grid.*

10.2.6 No *distributor* or *transmitter* that has *disconnected* load pursuant to section 10.2.4 shall reconnect the load until directions have been received from the *IESO* permitting it to do so. Such *distributor* or *transmitter* shall commence restoration of load immediately following receipt of such directions.

10.3 Demand Control Initiated by the IESO in an Emergency Operating State

10.3.1 When an *emergency operating state* has been declared by the *IESO*, the actions available to the *IESO* to safeguard the *security* of the *IESO-controlled grid* may include issuing directions to *market participants* to reduce *demand* for electricity.

10.3.2 Whenever possible, the *IESO* shall issue a warning by 16:00 EST on the previous day when requesting a reduction of *demand* through voltage reductions or interruptions.

10.3.3 Each *market participant* that receives a direction from the *IESO* to reduce *demand* shall achieve the reduction in *demand* within 5 minutes of receipt of the direction and shall notify the *IESO* that it has done so.

10.3.4 Each *market participant* may interchange customers to whom the *demand* reduction has been applied provided the necessary *demand* reduction required by the *IESO* is achieved by the interchange.

10.3.5 No *market participant* that has reduced *demand* pursuant to this section 10.3 shall restore *demand* until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence restoration of *demand* immediately following receipt of such directions.

10.3.6 The *IESO* shall maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the *Ontario Electricity Emergency Plan* regarding exclusions to load management activities that are undertaken for the purpose of controlling *demand*.

10.3.7 The *IESO* shall *publish* an estimate of aggregate load *curtailed* as soon as practicable following the return to a *normal operating state*.

10.4 Under-Frequency Load Shedding

10.4.1 Automatic under-frequency load shedding shall be accomplished to maintain the frequency of the *IESO-controlled grid* and to restore the *IESO-controlled grid* to normal frequency following frequency deviations outside of the range established by the *IESO*.

10.4.2 Each *transmitter* shall, where possible and upon receipt of an under-frequency alarm or an indication of declining frequency and voltage, identify to the *IESO* frequency values for stations under its control.

10.4.3 Each *transmitter* shall undertake the following actions immediately and independently as pre-authorized by the *IESO* pursuant to the Operating Agreement between the *transmitter* and the *IESO*:

10.4.3.1 when frequency is between 58.5 and 59.0 Hz, take immediate independent action to shed 25% of controlled load. The block of load to be shed shall not include load connected to under-frequency load-shedding relays; or

10.4.3.2 when frequency is below 58.5 Hz, take immediate independent action to shed affected load until the frequency is restored to 59.0 Hz or, in the case of known *electrical island* situations, to 60 Hz.

10.4.4 Each affected *transmitter* shall notify the *IESO* of the approximate amounts and locations of loads that were shed and of conditions on the *IESO-controlled grid*.

10.4.5 Once loads have been shed to maintain the frequency of the *IESO-controlled grid*, the *IESO* shall immediately report conditions on the *IESO-controlled grid* to affected *transmitters*.

10.4.6 Each *distributor* and *connected wholesale customer*, in conjunction with the relevant *transmitter*, shall make arrangements to enable the *disconnection* of automatic under-frequency *demand* of at least 30% of its total peak customer *demand*.

10.4.7 The *demand* of each *distributor* and *connected wholesale customer* that is subject to automatic under-frequency load shedding pursuant to section 10.4.6 shall be split into discrete MW blocks. The number, location, size and associated low frequency settings of these blocks shall be as specified by the *IESO*. Such specifications shall be established by the *IESO*, following consultations with the relevant *market participants*, by week 24 in each calendar year to cover the immediately following twelve-month period.

10.4.8 No *market participant* shall restore load that has been shed pursuant to this section 10.4 until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence the restoration of load immediately following receipt of such direction.

10.4.9 Each *distributor* and *connected wholesale customer* shall provide the *IESO* with an estimate of the *demand* reduction that has occurred as a result of *disconnecting* under-frequency *demand*.

10.4.10 The amount of load rejected by automatic under-frequency load shedding shall conform to the minimum requirements set forth in all applicable *reliability standards.*

10.4.11 The *IESO* shall, maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the applicable *market manual* regarding exclusions to load management activities that are undertaken for the purpose of shedding load during under-frequency conditions.

10.5 Generator Obligations During Abnormal Frequency

10.5.1 Abnormal frequency excursions on the *IESO-controlled grid* may require immediate actions by *generators* to restore the frequency to an acceptable level.

10.5.2 A g*enerator* that observes a frequency excursion greater than 60.2 Hz or less than 59.8 Hz shall immediately report this condition to the *IESO* and shall carry out frequency restoration actions as directed by the *IESO*.

10.5.3 No *generator* shall be precluded by the restoration actions referred to in section 10.5.2 from taking action for the purpose of ensuring the safety of any person, preventing the damage of equipment, or preventing the violation of any *applicable law*. Any such directives shall be immediately reported to the *IESO.*

10.5A Electricity Storage Participant Obligations During Abnormal Frequency

10.5A.1 Abnormal frequency excursions on the *IESO-controlled grid* may require immediate actions by *electricity storage participants* to restore the frequency to an acceptable level.

10.5A.2 An *electricity storage participant* that observes a frequency excursion greater than 60.2 Hz or less than 59.8 Hz shall immediately report this condition to the *IESO* and shall carry out frequency restoration actions as directed by the *IESO*.

10.5A.3 No *electricity storage participant* shall be precluded by the restoration actions referred to in section 10.5A.2 from taking action for the purpose of ensuring the safety of any person, preventing the damage of equipment, or preventing the violation of any *applicable law*. Any such directives shall be immediately reported to the *IESO.*

11. Emergency Preparedness and System Restoration

11.1 Objective

11.1.1 The objective of this section 11 is to establish the means by which the *IESO* and *market participants* will fulfil their respective *emergency* preparedness and system restoration obligations, including regular and real-time testing; the preparation by the *IESO* of the *Ontario electricity emergency plan* and the *Ontario power system restoration plan*; the preparation by *market participants* of *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*; and the preparation of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan*. This objective will be met through co-operation and in consultation with all relevant *market participants.*

11.2 Emergency Preparedness Plans and Ontario Electricity Emergency Plan

11.2.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario electricity emergency plan* describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *electricity system,* having regard to the mitigation of the impact of an *emergency* on public health and safety as identified in each *market participant's emergency preparedness plan.*

11.2.2 The *IESO* shall file with the *Minister* the *Ontario electricity emergency plan* and such other emergency plans as the *Minister* may require pursuant to subsection 39(1) of the *Electricity Act, 1998*.

11.2.3 In order to assist the *IESO* in fulfilling its responsibilities under section 39 of the *Electricity Act, 1998*, each *market participant* shall prepare and submit to the *IESO* an *emergency preparedness plan* and such other *emergency* preparedness-related information as the *IESO* considers necessary. Each *market participant* shall ensure that its *emergency preparedness plan* complies with section 11.2.4 and is submitted to the *IESO* during registration to become a *market participant*, or at such later times as the *IESO* shall specify.

11.2.4 Each *market participant* shall ensure that its *emergency preparedness plan*:

11.2.4.1 describes such planning, testing, information, communication and other elements designated by the *IESO*;

11.2.4.2 complies with such *emergency* planning criteria as may be designated by the *IESO*;

11.2.4.3 complies with all relevant *reliability standards*;

11.2.4.4 is consistent with the *emergency* planning and preparedness procedures established by relevant government authorities;

11.2.4.5 indicates the manner in which the impact of an *emergency* on public health and safety will be mitigated;

11.2.4.6 indicates the manner in which the *market participant* will minimize the cutting and expedite the restoration of critical loads and priority loads during short and prolonged *emergencies*; and

11.2.4.7 is submitted with a statement certified by an officer or equivalent of the *market participant* stating that the *emergency preparedness plan* is a true and complete copy as at the date of the certification.

11.2.5 The *IESO* shall assist *market participants* in the development of *emergency preparedness plans* for the purpose of ultimately establishing *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*.

11.3 Ontario Power System Restoration Plan and Restoration Participant Attachments

11.3.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario power system restoration plan* for restoring the *security* of the *IESO-controlled grid* following a major *contingency event* or *emergency* as required by all applicable *reliability standards* and considered prudent by the *IESO* for Ontario.

11.3.2 The *Ontario power system restoration plan* shall cover each of the planning, testing, information, load reduction, load restoration, communication and other elements described in section 10 and section 11 and such other elements as the *IESO* deems necessary to implement effective system restoration.

11.3.3 The *Ontario power system restoration plan* shall include, but not be limited to:

11.3.3.1 plans for managing major disturbances on the *IESO-controlled grid* that blackout all or a portion of the *IESO-controlled grid*;

11.3.3.2 plans for the testing and verification of *emergency* preparedness facilities and procedures; and

11.3.3.3 descriptions of the roles of the *IESO* and various *restoration participants* in the *Ontario power system restoration plan*.

11.3.4 The *IESO* shall file with the *Minister* the *Ontario power system restoration plan* and such other restoration documentation as the *Minister* may require under subsection 39(1) of the *Electricity Act, 1998*.

11.3.5 Each *restoration participant* shall prepare and submit to the *IESO* a *restoration participant attachment* to the *Ontario power system restoration plan* and such other system restoration-related information as the *IESO* considers necessary. Each *restoration participant* shall ensure that its *restoration participant attachment* complies with section 11.3.6 and is submitted to the *IESO* during registration to become a *market participant*, or at such later times as the *IESO* shall specify.

11.3.6 Each *restoration participant* shall ensure that its *restoration participant attachment*:

11.3.6.1 includes the elements described in section 11.3.7;

11.3.6.2 complies with such restoration planning criteria as may be designated by the *IESO*; and

11.3.6.3 complies with all relevant *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

11.3.7 Each *restoration participant* shall ensure that its *restoration participant attachment* includes:

11.3.7.1 a statement describing that the *restoration participant*: (i) has an operator training program in place, (ii) uses trained operating personnel, and (iii) maintains operator training records;

11.3.7.2 documentation detailing organizational responsibility for co-ordinating with the *IESO* the development of and participation in system restoration drills. Such development and participation shall be conducted by the *restoration participant* at its own expense;

11.3.7.3 a statement describing the program in place to test the *restoration participant's* equipment as may be designated in the *Ontario power system restoration plan*. Such testing shall be conducted by the *restoration participant* at its own expense;

11.3.7.4 a statement of policy and supporting documentation demonstrating how the *restoration participant* will minimize the cutting and expedite the restoration of critical loads and priority loads under system restoration conditions;

11.3.7.5 any other documentation that the *IESO* deems necessary to support or facilitate the successful implementation of the *Ontario power system restoration plan*; and

11.3.7.6 a statement certified by an officer or equivalent of the *market participant* stating that the *restoration participant attachment* is a true and complete copy as at the date of the certification.

11.3.8 [Intentionally left blank]

11.3.9 The *IESO* shall assist *restoration participants* in the development of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan* for the purpose of ultimately establishing one integrated restoration plan for Ontario.

11.3.10 Each *restoration participant* shall ensure that the guidelines and procedures applicable to it and set forth in the *Ontario power system restoration plan* are carried out by trained operating staff with sufficient authority to take any action that may be necessary to ensure that all relevant equipment is operated in a timely, stable and reliable manner.

11.3.11 The *IESO* shall direct *market participants* in restoring the *IESO-controlled grid* following major disturbances. Each such *market participant* shall be responsible for carrying out these *IESO* directions, in accordance with the provisions of the *Ontario power system restoration plan.*

11.4 Review and Audit

11.4.1 The *IESO* shall review each *emergency preparedness plan* and each *restoration participant attachment* submitted to it, in accordance with sections 11.2.3 and 11.4.3, and shall prepare and provide to the relevant *market participant* or *restoration participant* a *record of review* indicating the changes, if any, required to be made and the date by which the revised *emergency preparedness plan* or *restoration participant attachment* must be submitted with the *IESO*.

11.4.2 Each *market participant* shall make such changes to its *emergency preparedness plan* or *restoration participant attachment* as may be required by the record of review and shall submit to the *IESO* a revised *emergency preparedness plan* or *restoration participant attachment* within the time specified in the record of review or within such other period as may be agreed with the *IESO*.

11.4.3 Each *restoration participant* shall review its *emergency preparedness plan* and *restoration participant attachment* at least annually, or as required, and shall, following such review, submit to the *IESO*:

11.4.3.1 a statement certified by an officer or equivalent of the *restoration participant* confirming that the review has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.3.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the review, together with a statement certified by an officer or equivalent of the *restoration participant* identifying such amendments, as the case may be. Each *restoration participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.3 complies with section 11.2.4 or 11.3.6, respectively.

11.4.4 When directed by the *IESO*, the *market participant* shall have an independent audit of its *emergency preparedness plan* and/or *restoration participant attachment* conducted. The independent audit may be conducted by, without limitation, the *market participant's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of conducting such an audit shall be borne by the *market participant*. Each *market participant* shall, following such audit, submit to the *IESO* a copy of the audit report, together with:

11.4.4.1 a statement certified by an officer or equivalent of the *market participant* confirming that the audit has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.4.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the audit, together with a statement certified by an officer or equivalent of the *market participant* identifying such amendments, as the case may be. Each *market participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.4 complies with section 11.2.4 or 11.3.6, respectively.

11.4.5 The *IESO* shall review its *emergency preparedness plan,* the *Ontario electricity emergency plan* and the *Ontario power system restoration plan* at least annually, or as required. When directed by the *Minister*, the *IESO* shall have an independent audit conducted of these plans. The independent audit may be conducted by, without limitation, the *IESO's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of such an audit shall be borne by the *IESO*.

11.5 [Intentionally left blank]

11.6 Emergency Facilities

11.6.1 The *IESO* may evacuate its principal control centre in the event that a circumstance arises that poses a hazard to *IESO* personnel. During and following such evacuation, operation of the *IESO-controlled grid* shall be effected in accordance with this section 11.6.

11.6.2 The *IESO-administered markets* shall continue to operate during an evacuation of the *IESO*'s principal control centre unless conditions exist that would warrant a suspension of market operations as described in MR Ch.7.

11.6.3 During the interval between the evacuation of the *IESO's* principal control centre and the establishment of a backup control centre:

11.6.3.1 the *IESO* shall designate an interim emergency system coordinator to act in its stead, as required; and

11.6.3.2 all *generators, electricity storage participants* and *transmitters* shall manage their *facilities* and support the emergency system coordinator in the operation of the *IESO-controlled grid.*

11.6.4 The *IESO* shall test the backup control centre and associated procedures and facilities on a regular basis, and each *market participant* connected to the *IESO-controlled grid* shall, at its own expense and as directed by the *IESO*, support and actively participate in evacuation tests and simulations.

11.7 Testing

11.7.1 Each *market participant* shall ensure that the capability and reliability of its personnel, procedures, and equipment are maintained to the extent necessary to fulfill its obligations under its *emergency preparedness plan* and its *restoration participant attachment*.

11.7.2 The *IESO* shall develop, schedule, implement and conduct such tests as are provided for in the *Ontario electricity emergency plan* and the *Ontario power system restoration plan.*

11.7.3 [Intentionally left blank]

11.7.4 Each *market participant* shall support and actively participate, at its own expense and as directed by the *IESO*, in the implementation and testing of its *emergency preparedness plan*, its *restoration participant attachment*, the *Ontario electricity* *emergency plan,* the *Ontario power system restoration plan* and voice communications facilities.

11.7.5 The *IESO* shall schedule the tests referred to in section 11.7.4 at an appropriate time of the year and time of day, in consideration of the needs of *market participants* and of the desire to minimize their costs relating to such tests. To the extent practicable, such tests of the *restoration participant attachment* shall be scheduled in a manner consistent with the *outage* coordination process described in section 6.

11.8 Enforcement

11.8.1 Failure by a *market participant* to take any action required to be taken in, or to act in a manner consistent with, its *emergency preparedness plan*, its *restoration participant attachment* or its accountabilities within the *Ontario power system restoration plan* shall be deemed to constitute a breach of the *market rules.*

12. Communications

12.1 Communication Methods

12.1.1 Communication between the *IESO* and:

12.1.1.1 *market participants*;

12.1.1.2 *embedded generators* required by MR Ch.2 App.2.2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both;

12.1.1.3 *embedded load consumers* required by MR Ch.2 App.2.2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both; and

12.1.1.4 *embedded electricity storage participants* required by MR Ch.2 App.2.2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control, or both;

shall take place through a combination of methods as identified in MR Ch.2 App.2.2 and as directed by the *IESO* pursuant to section 12.2.3.2.

12.1.2 For the purposes of section 12.1.1 and with the exception of section 12.1.2A, the *IESO* shall provide and maintain, at its cost, a dedicated, real-time communication network from the *IESO's* facilities to the communication terminal point between such network and:

12.1.2.1 the monitoring and control devices; and

12.1.2.2 where applicable, the *dispatch workstation*

of the persons referred to in sections 12.1.1.1 to 12.1.1.3 to enable communication between the *IESO* and such persons.

12.1.2A Subject to section 12.1.6, for a *variable generator* that is a *registered market participant*, the *registered market participant* shall, if a dedicated communication network in accordance with section 12.1.2 is not already in place, provide and maintain, at its cost, a dedicated, internet based real-time communication network from the *IESO's* facilities to the communication terminal point between such network and a *dispatch workstation.* Any such internet-based real-time communication network shall meet the applicable specifications and other requirements set forth in the *participant technical reference manual.*

12.1.3 The *IESO* shall provide real-time communication network channels to the persons referred to in sections 12.1.1.1 to 12.1.1.3 as follows:

12.1.3.1 one communication channel and, where available and justified for *reliable* operation of the *IESO-controlled grid* and efficient operation of the *IESO-administered markets*, a redundant physically diverse communication channel, for:

a. each *facility* to which the high performance information monitoring standard applies in accordance with MR Ch.4 Apps.4.19 to 4.23, and

b. each *facility* that is providing monitoring information for two or more *facilities*;

12.1.3.2 one communication channel for each *facility* to which the medium performance information monitoring standard applies in accordance with MR Ch.4 Apps.4.19 to 4.23.

12.1.4 The *IESO* may, in respect of a given *facility*, provide additional real-time network communication channels in addition to those referred to in section 12.1.3 where the *IESO* considers, based on the size and location of the *facility*, and, where applicable, the number of *facilities* monitored at a single *facility*, that such additional channels are desirable for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.1.5 Where a *market participant* wishes to submit *dispatch data*, *physical bilateral contract data*, or *TR bids* in the *TR market* using private network dedicated communication links, all costs associated with such use, including but not limited to the cost of the provision and maintenance of the required communication channel, shall be borne by the *market participant*.

12.1.6 Where problems exist which require methods of communication other than those referred to in section 12.1.1 or 12.1.2A, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.2 Voice Communication

12.2.1 [Intentionally left blank]

12.2.2 [Intentionally left blank]

12.2.3 Each *market participant*, *embedded generator*, *embedded electricity storage participant* and *embedded load consumer* shall provide and maintain:

12.2.3.1 the applicable voice communication facilities required by MR Ch.2 App. 2.2 and that meet the requirements of that Appendix; and

12.2.3.2 such additional or other voice communication facilities as the *IESO* may direct in respect of *facilities* that the *IESO* considers to be significant for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.2.4 Each person referred to in section 12.2.3 shall ensure that the overall mean time between failures of the voice communication facilities referred to in section 12.2.3 is no less than five years.

12.2.5 Each person referred to in section 12.2.3 shall respond to an outage of or defect in the voice communication facilities referred to in section 12.2.3:

12.2.5.1 immediately, in the case of an outage of or defect in a *high priority path facility*; and

12.2.5.2 no later than the next day following the day on which the outage or defect is discovered, in the case of an outage of or defect in a *normal priority path facility.*

12.2.6 Each person referred to in section 12.2.3 shall ensure that the voice communication facilities referred to in section 12.2.3 are restored to a fully operational state following an *outage* of or defect in such facilities as follows:

12.2.6.1 in the case of the *high priority path facilities* referred to in section 12.2.5.1, within 24 hours of the time at which the *outage* or defect is discovered;

12.2.6.2 in the case of the *normal priority path facilities* referred to in section 12.2.5.2, within 48 hours of the time at which the *outage* or defect is discovered; and

12.2.6.3 in all other cases, within 14 days of the time at which the *outage* or defect is discovered.

12.2.7 The *IESO* may direct a person referred to in section 12.2.3 to respond and restore a voice communication facility to a fully operational state following an *outage* of or defect in such facility within such longer or shorter time periods than those referred to in sections 12.2.5 and 12.2.6 based on the immediate or short-term impact of the unavailability of the voice communication facility on the *reliable* operation of the *IESO-controlled grid*.

12.2.8 Each person referred to in section 12.2.3 shall notify the *IESO* of any *planned outage* of the voice communication facilities referred to in section 12.2.3 no less than four days prior to the *planned outage*.

12.2.9 The *IESO* shall:

12.2.9.1 maintain, at each of its principal control centre and back-up control centre, *high priority path facilities* and *normal priority path facilities* that meet the requirements of MR Ch.2 App.2.2 ss.1.1.7 and 1.1.8, respectively, for the purpose of voice communication with the persons referred to in section 12.2.3 and with neighbouring *security coordinators*; and

12.2.9.2 ensure that its voice communication facilities include facilities that permit telephone conference calls between six parties.

12.2.10 The *IESO* shall develop, in consultation with all relevant *market participants*, test plans and procedures for voice communication during an *emergency* on or a major disturbance of the *IESO-controlled grid*.

12.2.11 Each person referred to in section 12.2.3 shall, at its own expense, not less than annually or more frequently as may be directed by the *IESO*, monitor and test its voice communication facilities and shall, at its own expense and as directed by the *IESO*, support and actively participate in the testing of voice communication facilities.

12.2.12 Where problems exist which require methods of communication other than those referred to in section 12.2.3, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.3 Electronic Data

12.3.1 Energy management system information shall be exchanged between the communication system of the *IESO* and the communication system of each *market participant* in order to support real-time functions such as:

12.3.1.1 the monitoring of the *IESO-controlled grid*;

12.3.1.2 the control and analysis of generation facilities and electricity storage facilities;

12.3.1.3 an analysis of the *security* of the *IESO-controlled grid*;

12.3.1.4 the scheduling of generation facilities and electricity storage facilities;

12.3.1.5 the monitoring of compliance with *dispatch instructions*; and

12.3.1.6 reports.

12.3.2 The *IESO* and *market participants* shall exchange energy management system information between their respective communication systems via dedicated data circuits.

12.3.3 For the exchange of schedules referred to in MR Ch.7 and of *outage* and planning data between *market participants* and the *IESO*, a computer path distinct from the energy management system path shall be used. Communications shall occur over separate data links using a different protocol than that used for energy management system information. Real-time *dispatch instructions* for *generation facilities, electricity storage facilities,* transmission *facilities* and load shall be communicated electronically through the energy management system path and shall be integrated with the energy management system messaging system for logging purposes.

12.4 Voice Links and Other Communications

12.4.1 The *IESO* shall develop and notify all *market participants* of standard operating terms, abbreviations and definitions that shall be approved for use in communications between the *IESO* and *market participants*. Such approved, standard operating terms, abbreviations and definitions shall wherever possible be used by the *IESO* and *market participants* in their communications with one another.

12.4.2 All communications between a *market participant* and the *IESO* with respect to the *reliability* of the *IESO-controlled grid* shall be recorded and the records shall be retained by the *IESO* for 7 years.

12.4.3 The *IESO* shall maintain a log of activities related to the *reliable* operation of the *IESO-controlled grid.*

13. Prior Arrangements

13.1 Market Participant Review of Arrangements

13.1.1 Each *market participant* shall review any contractual or other arrangements relating to the *reliability* of the *IESO-controlled grid* which it may have with other *market participants* or with *interconnected systems* on the date of coming into force of this Chapter for the purpose of determining whether such arrangements are consistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter. Where such contractual or other arrangement is consistent with the requirements and obligations imposed on the *market participant* by this Chapter, no further action with respect to such contract or arrangement is required.

13.1.2 Where a *market participant* determines that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter, the *market participant* shall:

13.1.2.1 negotiate an amendment to the contract or a modification to the arrangement which removes the inconsistency; or

13.1.2.2 report the inconsistency to the *technical panel*, which shall make a determination as to whether the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*.

13.1.3 Where the *technical panel* determines under section 13.1.2 or 13.1.4 that the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*, the *IESO* shall take appropriate actions to mitigate the effect of the inconsistency until the inconsistency is removed.

13.1.4 Where the *IESO* becomes aware that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on a *market participant* by, this Chapter, it may report the inconsistency to the *technical panel* notwithstanding that the inconsistency may not have been reported by the *market participant* and the *technical panel* shall make the determination referred to in section 13.1.2.2 in respect of that inconsistency.

14. Information and Reporting Requirements

14.1.1 The *reliable* operation of the *IESO-controlled grid* requires the rapid and continuous flow of accurate information among the *IESO*, *market participants* and *interconnected systems*, with due regard for maintaining the confidentiality of information where appropriate. To that end, the *IESO* shall establish and periodically up-date and inform all *market participants* with respect to the specific information it requires from *market participants* for *reliability* purposes.

14.1.2 Each *market participant* shall provide the information referred to in section 14.1.1 to the *IESO* in the manner and within the time prescribed by the *IESO.* By submitting such information to the *IESO,* a *market participant* is considered to have fulfilled any requirement under a *reliability standard* to report such information to one or more *standards authorities*. The *IESO* shall provide such information to other *standards authorities,* as required.

14.1.3 The *IESO* shall establish a catalogue of reporting requirements listing the *reliability*-related information to be exchanged between the *IESO* and *market participants.* Such reporting requirements shall include, but not be limited to, the following:

14.1.3.1 each *market participant* shall report to the *IESO* the planned implementation of a change to a setting on a fixed-tap transformer. This information shall be reported to the *IESO* in writing one week prior to the date scheduled for implementation of such change, provided that where such change is effected on an unplanned, emergency basis, the information shall be reported to the *IESO* within one *business day* of implementation of the change;

14.1.3.2 each *market participant* shall report to the *IESO* any change in equipment and *facilities* to that which has been provided pursuant to MR Ch.4;

14.1.3.3 each *market participant* shall report to the *IESO* a list of all of its equipment for which periodic maintenance has been performed on *remedial action schemes* in the previous 12 months, as required by relevant *standards authorities*. This information shall be reported no later than the first day of December in each year;

14.1.3.4 each *market participant* shall provide to the *IESO* a report describing any modification proposed to be made to protection on a primary relay. The report shall be delivered to the *IESO* within one week of the date on which the *IESO* approves such modification pursuant to MR Ch.4 s.6, or, where the modification is effected on an unplanned, emergency basis, within one week of the date of modification;

14.1.3.5 each *market participant* shall annually provide to the *IESO* a written summary of actions taken to control *demand* in the previous 12 months;

14.1.3.6 each *market participant* shall annually provide to the *IESO* a written summary of automatic under-frequency load shedding activities taken in the previous 12 months; and

14.1.3.7 each *market participant* shall annually provide to the *IESO* a report of *reliability*-related performance measures for transmission *facilities* and *connections* to the *IESO-controlled grid* in accordance with all applicable *reliability standards*.

14.1.4 Each *market participant* shall provide to the *IESO* such data as may be required by the *IESO* to enable it to satisfy a request by a *standards authority.*

14.1.5 The *IESO* shall file such reports including, but not limited to, disturbance reports, and participate in such discussions as may be required by relevant *standards authorities*. Each *market participant* shall provide to the *IESO* such information and reports as may be required by the *IESO* to facilitate preparation by the *IESO* of such disturbance reports.

RUL-14

Renewed Market Rules

Chapter 0.5

Power System Reliability - Appendices

0.5

Renewed Market Rules – Chapter 0.5: Power System Reliability - Appendices

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Table of Contents

Appendix 5.1 – Performance Standards for Ancillary Services

1.1 Regulation

1.1.1 A *market participant* whose *resource* is providing *regulation* shall submit to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided pursuant to MR Ch.4.

1.1.2 The telemetering between the energy management system referred to in section 12 of Chapter 5 and a *resource* providing *regulation* shall indicate:

1.1.2.1 whether the *resource* is synchronized to the *IESO-controlled grid,* associated with a *facility* connected to a *distribution system,* or associated with a *facility* connected to another *market participant's facility*;

1.1.2.2 whether the *resource* is providing *regulation* or not; and

1.1.2.3 the net injection or withdrawal of the *resource*.

1.1.3 A *resource* providing *regulation* must achieve at least the ramp rate specified in its *contracted ancillary services* contract for the full amount of *regulation* capacity offered in such contract.

1.1.4 A *resource* providing *regulation* must be able to adjust its output or consumption at least at the ramp rate specified in its *contracted ancillary services* contract to the maximum and minimum values specified in such contract.

1.1.5 No *market participant* shall *offer* for a *resource* to provide *regulation* capacity that exceeds an amount equal to the *resource's* maximum ramp rate multiplied by ten minutes.

1.1.6 A *facility* associated with a *resource* providing *regulation* must be capable of receiving control signals sent from the *IESO* at the rate of at least one signal every two seconds. If the *regulation* control signals are received by a *control centre*, the *control centre* must forward these signals to the *facility* associated with the *resource* providing *regulation* within two seconds of having received the signal from the *IESO*.

1.1.7 All *facilities* associated with *resources* providing *regulation* must meet, at a minimum, the performance requirements for off-nominal frequency, speed/frequency regulation and voltage ride through specified in MR Ch.4 App.4.2.

For greater certainty, the foregoing obligation applies to all such *facilities* providing *regulation*, regardless of size, technology or connection location.

1.2 Operating Reserve

Ten-Minute Operating Reserve

1.2.1 An *ancillary service provider* offering *ten-minute operating reserve* shall ensure that each *resource* that it has scheduled to provide *ten-minute operating reserve* is available for *dispatch* as scheduled.

1.2.2 An *ancillary service provider* offering *ten-minute operating reserve* shall be capable of achieving at least the ramp rate stated in its *offer* for the full amount of *ten-minute operating reserve* offered.

1.2.3 When activated by the *IESO*, *ten-minute operating reserve* shall be available for *dispatch* for at least one hour.

Thirty-Minute Operating Reserve

1.2.4 An *ancillary service provider* offering *thirty-minute operating reserve* shall ensure that each *resource* that it has scheduled to provide *thirty-minute operating reserve* is available for *dispatch* as scheduled.

1.2.5 An *ancillary service provider* offering *thirty-minute operating reserve* shall be capable of achieving at least the ramp rate stated in its *offer* for the full amount of *thirty-minute operating reserve* offered.

1.2.6 When activated by the *IESO*, *thirty-minute operating reserve* shall be available for *dispatch* for at least one hour.

1.3 Reactive Support and Voltage Control – Generation Facilities and Electricity Storage Facilities

1.3.1 All *facilities* associated with a *generation unit* or an *electricity storage unit* that provides *reactive support service* and *voltage control service* must be capable of meeting the requirements specified in MR Ch.4.

1.3.2 Subject to section 1.3.6, *automatic voltage regulation* shall be in service and in automatic mode as indicated in MR Ch.4 unless the *generation unit* or *electricity storage unit* is specifically directed by the *IESO* to operate the *automatic voltage regulation* in manual mode.

1.3.3 Subject to section 1.3.4, *generation units* or *electricity storage units* providing *reactive support service* and *voltage control service* shall be operated to within the standard power factor range described in MR Ch.4 App.4.2.

1.3.4 The *IESO* may direct a a *generation unit* providing *reactive support service* and *voltage control service* to operate in an under- or over-excited state for a certain period of time in order to maintain prescribed voltages on the *IESO-controlled grid*. Such direction may require the *generation unit* to operate in condense mode or to reduce active power output in order to increase its ability to provide reactive power.

1.3.4A The *IESO* may direct an *electricity storage unit* to provide *reactive support service* and *voltage control service* to absorb reactive power or inject reactive power for a certain period of time in order to maintain the prescribed voltages on the *IESO-controlled grid*. If applicable and required, the *IESO* may direct such *electricity storage unit* to reduce the withdrawal or injection of active power in order to increase its ability to provide reactive power.

1.3.5 Unless otherwise specified by the *IESO*, each *generation unit* or *electricity storage unit* providing *reactive support service* and *voltage control service* shall respond to voltage or reactive power schedules immediately following receipt of the *IESO's* request. Where the *generation unit* or *electricity storage unit* cannot be *dispatched* as directed by the *IESO*, the *ancillary service provider* shall immediately provide the *IESO* with notice to this effect.

1.3.6 Each *ancillary service provider* shall:

1.3.6.1 notify the *IESO* immediately upon the *forced outage* of the *automatic voltage regulation* at its *generation unit* or *electricity storage unit* being forced out of service; or

1.3.6.2 for *planned outages,* prior to the *automatic voltage regulation* being removed from its *generation unit* or *electricity storage unit* for maintenance, follow the procedures outlined in section 6 of Chapter 5.

1.3.7 Following a *contingency event*, each *generation unit* or *electricity storage unit* shall automatically respond to provide or absorb the reactive power in accordance with its established maximum and minimum reactive power capabilities. Each *ancillary service provider* shall immediately notify the *IESO* whenever its *generation unit or electricity storage unit* cannot perform to its established maximum and minimum reactive power capabilities.

1.4 Reactive Support and Voltage Control – Facilities that are neither Generation nor Electricity Storage

1.4.1 Except for *forced outages* and *planned outages* coordinated with the *IESO* pursuant to these *market rules*, each *transmitter* shall keep its transmission assets in service at all times unless released from service by the *IESO* or directed by the *IESO* to be removed from service pursuant to this section 1.4.

1.4.2 The *IESO* may direct a *transmitter* to remove transmission assets from service to the extent necessary to maintain *reactive support service* and *voltage control service*.

1.4.3 Each *connected wholesale customer*, *transmitter* and *distributor connected* to the *IESO-controlled grid* providing *reactive support service* and *voltage control service* shall respond immediately following receipt of a direction from the *IESO* with respect to directions concerning but not limited to, static capacitors, static VAR compensators and reactors. For directions concerning synchronous condensers, the response time will be as soon as practicable recognizing the device characteristics and operating state of the device at the time of receipt of the *IESO's* direction. Each such *ancillary service provider* shall immediately notify the *IESO* whenever the devices referred to in this section 1.4.3 cannot be switched in accordance with the *IESO* direction.

1.5 Black Start

1.5.1 A *certified black start facility* will be tested and/or assessed for its ability to comply with the performance standards as specified in its *contracted ancillary services* contract for *certified black start facilities*.

1.5.2 Prior to registering a *generation facility* as a *certified black start facility,* the *IESO* shall be satisfied that the *generator* has demonstrated through completion of tests and assessments that the *generation facility* can provide sufficient MWs and MVARs to:

1.5.2.1 energize or assist in energizing the specified transmission path within the applicable time period referred to in section 1.5.7;

1.5.2.2 provide *energy* requirements along such transmission path, including the requirements of any load connected to the transmission path; and

1.5.2.3 provide start-up power to the *generation facility* as specified by the *IESO* which will meet the objectives and priorities of the *Ontario power system restoration plan*.

1.5.3 A *certified black start facility* will be tested and/or assessed for its ability to maintain voltage within emergency voltage limits over a range of loading from no external load to full external load in accordance with *reliability standards*.

1.5.4 A *certified black start facility* must be equipped with governors that are capable of operating in an isochronous mode.

1.5.5 Adequate transmission capacity shall be available to connect the *certified black start facility* to the source providing station services to other specified generation stations referred to in 1.5.8.

1.5.6 A *generator* operating a *certified black start facility* shall make efforts consistent with *good utility practice* to comply with a direction from the *IESO* to deliver power without assistance from the electrical system unless:

1.5.6.1 the *certified black start facility* is on an *outage*, which *outage* is not a removal of the *certified black start facility* from service caused by the de-energization of the electrical network to which the *certified black start facility* is connected, or

1.5.6.2 where to do so would endanger the safety of any person, damage equipment, or violate any *applicable law*, or operating limit.

1.5.7 A *certified black start facility* will be tested and/or assessed for its ability to start and energize the applicable transmission path specified in 1.5.2.1 as follows:

1.5.7.1 if the *certified black start facility* is comprised of a hydroelectric *generation unit* or a *generation unit* that generates using aero-derivative gas turbines, within 30 minutes of the initiation of the black start process;

1.5.7.2 if the *certified black start facility* is comprised of a *generation unit* that generates using industrial gas turbines, within 60 minutes of the initiation of the black start process;

1.5.7.3 if the *certified black start facility* is comprised of a *generation unit* that generates using hot, steam-driven turbines, within 2.5 hours of the initiation of the black start process; and

1.5.7.4 if the *certified black start facility* is in another operating state or is comprised of an unspecified technology, within such time as may be specified in its *contracted ancillary services* contract for *certified black start facilities*.

1.5.8 A *certified black start facility* will be tested and/or assessed for its ability to provide startup power for the period of time it takes to switch the applicable transmission path specified in section 1.5.2.1 into service and to complete the start-up process at the generating station specified in section 1.5.2.3.

1.5.9 A *certified black start facility*:

1.5.9.1 referred to in section 1.5.7.1, 1.5.7.2 or 1.5.7.3 will be tested and/or assessed for its ability to complete three successive starts within eight hours of the initiation of the black start process; or

1.5.9.2 referred to in section 1.5.7.4, will be tested and/or assessed for its ability to complete such number of successive starts within such period of time as may be specified in its *contracted ancillary services* contract for *certified black start facilities*.

1.5.10 A *certified black start facility* will be tested and/or assessed for its ability to produce the range of reactive power required by the *IESO-controlled grid* as described in MR Ch.4, 5 and 7.

1.5.11 A *certified black start facility* must participate in the training activities and restoration drills referred to in sections 11.3.7.1 and 11.3.7.2 of Chapter 5, respectively.

RUL-15

Renewed Market Rules

Chapter 0.6

Wholesale Metering

Connecting Today.
Powering Tomorrow.

0.6

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5. An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

1. Introduction

1.1 Application and Interpretation

1.1.1 This Chapter applies to the following:

1.1.1.1 the *IESO*;

1.1.1.2 *market participants*; and

1.1.1.3 *metering service providers*.

1.1.2 Nothing in this Chapter shall affect the obligation of any *market participant*, *metered market participant* or *metering service provider* to comply with all applicable *federal metering requirements* provided that, where this Chapter or a policy or standard established by the *IESO* pursuant to this Chapter prescribes a higher standard than that prescribed by *federal metering requirements*, the relevant *market participant*, *metered market participant* or *metering service provider* shall, for purposes of this Chapter, comply with such higher standard.

1.1.3 This Chapter does not apply to an *intertie metering point*.

1.1.4 This Chapter does not apply to a *metering installation* that is not used or required by these *market rules* to be used for *settlement* purposes in the *IESO-administered markets.*

1.2 Purpose

1.2.1 The purpose of this Chapter is to set out the rights and obligations of *market participants, metered market participants* and the *IESO*, and the rights, obligations and qualifications of *metering service providers* associated with the measurement of *energy*; the registration, provision, installation, commissioning, maintenance, repair, replacement, inspection, testing and audit of *metering installations;* and the provision, security and accuracy of *metering data* relating to the *day-ahead market, real-time market* or the *procurement markets.*

1.2.2 Nothing in this Chapter shall preclude a *metered market participant* from applying, or from permitting a *metering service provider* to apply, evolving technologies and processes relating to *metering* as they become available provided that such application is effected in accordance with section 12.1.1.

2. Requirements for Metering Installations

2.1.1 Subject to section 2.1.5, the *IESO* shall not permit a person to participate in the *day-ahead market, real-time market* or the *procurement markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid,* in respect of a *connection point*, other than an *interconnection*, or in respect of an *embedded connection point* unless the *IESO* is satisfied that:

2.1.1.1 the *connection point* or *embedded connection point* has an associated *metering installation* that, subject to section 4.4, complies with the requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter. A single *metering installation* may be associated with more than one *connection point* or *embedded connection point*;

2.1.1.2 if the person is or will be the *metered market participant* for the *metering installation* referred to in section 2.1.1.1:

a. the person has entered into an agreement under section 3.1.2.2(a) in relation to the *metering installation* or is a *metering service provider*, and

b. if the person is also an *embedded market participant*, has advised the relevant *distributor* or *transmitter* of the entering into of the agreement referred to in section 2.1.1.2(a); and

2.1.1.3 either

a. such *metering installation* has been and continues to be registered with the *IESO* in accordance with the procedures referred to in section 6.1.2., or

b. such *metering installation* has been registered with the *IESO* in accordance with the procedures referred to in section 6.1.2 and the registration has expired provided that the *IESO* determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*.

2.1.2 The *IESO* shall refuse to permit a person to participate in the *day-ahead market, real-time market* or the *procurement markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid,* in respect of any *connection point*, other than an *interconnection*, or an *embedded connection point* if the conditions set forth in section 2.1.1 are not satisfied. Such refusal is a *reviewable decision*.

2.1.3 [Intentionally left blank – section deleted]

2.1.4 This Chapter applies in respect of a *metering installation* that measures the consumption of *energy* in accordance with MR Ch.9 s.2.2.

Temporary Withdrawal of Electricity without a Registered Wholesale Meter

2.1.5 The *IESO* may permit a *market participant* to withdraw electricity temporarily from the *IESO-controlled grid* at a *connection point* without a *metering installation* being registered with the *IESO* for that *connection point* under the conditions specified in the applicable *market manual.*

3. Metered Market Participants

3.1 General Obligations

3.1.1 Each *metered market participant* shall:

3.1.1.1 ensure that, subject to section 4.4, each *metering installation* in respect of which it is the *metered market participant* complies with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

3.1.1.2 comply with the obligations imposed on *metered market participants* in Appendix 6.1 and in any policy or standard established by the *IESO* pursuant to this Chapter; and

3.1.1.3 coordinate electronic access, by persons other than the *IESO*, to each *metering installation* in respect of which it is the *metered market participant* so as to prevent such persons from accessing the *metering installation* at a time or in a manner that may adversely affect the ability of the *IESO* to access the *metering data* in that *metering installation* in accordance with the notice given pursuant to section 8.1.7.

3.1.2 Each *metered market participant* shall:

3.1.2.1 if registered as a *metering service provider*:

a. subject to section 4.4, register, provide, install, commission, maintain, repair, replace, inspect and test each *metering installation* in respect of which it is the *metered market participant* in accordance with the provisions of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter;

b. comply with all of the obligations imposed on *metering service providers* in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

c. provide to the *IESO* the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and update such information as required to maintain such information current; and

d. where the *metering installation* is associated with more than one *connection point*, *defined meter point* or *facility*, on a timely basis review and update the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and provide it to the *IESO*:

   i. annually; and

   ii. when material changes are made to the *IESO-controlled grid* downstream of the *metering installation* including the application by another *metered market participant* to register a different *metering installation* downstream of the *metering installation*; or

3.1.2.2 if not registered as a *metering service provider*:

a. enter into an agreement with a *metering service provider* for the registration, provision, installation, commissioning, maintenance, repair, replacement, inspection and testing by that *metering service provider* of each *metering installation* in respect of which it is the *metered market participant*;

b. ensure that its *metering service provider* provides the *IESO* with the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and updates such information as required to maintain that information current;

c. where the *metering installation* is associated with more than one *connection point*, *defined meter point* or *facility*, on a timely basis ensure that its *metering service provider* reviews and updates the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and provide it to the *IESO*:

   i. annually; and

   ii. when material changes are made to the *IESO-controlled grid* downstream of the *metering installation* including the application by another *metered market participant* to register a different *metering installation* downstream of the *metering installation*; and

d. be liable to the imposition of financial penalties and other sanctions, in accordance with MR Ch.3, in respect of the failure by each *metering service provider* that acts as a *metering service provider* for a *metering installation* in respect of which it is the *metered market participant* to comply with the obligations imposed on *metering service providers* in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

3.1.3 Nothing in section 3.1.2 shall prevent a *metered market participant* from entering into an agreement with one *metering service provider* for the provision, installation and commissioning of a *metering installation* and entering into a separate agreement with another *metering service provider* under which that other *metering service provider* assumes responsibility for all subsequent maintenance, repair, replacement, inspection and testing of that *metering installation.*

3.1.4 Each *metered market participant* shall bear all costs and expenses associated with:

3.1.4.1 the registration, provision, installation, commissioning, maintenance, repair, replacement and inspection of each *metering installation* for which it is the *metered market participant*;

3.1.4.2 the routine testing, as described in section 7.1.1, of each *metering installation* in respect of which it is the *metered market participant*;

3.1.4.3 the testing, other than the routine testing referred to in section 3.1.4.2, and audit of each *metering installation* in respect of which it is the *metered market participant* where such costs and expenses are required to be borne by the *metered market participant* pursuant to section 7.3.1;

3.1.4.4 the security and accuracy of all *metering data* recorded in each *metering installation* for which it is the *metered market participant* and the transfer of such *metering data* to the communication interface of the *metering database*; and

3.1.4.5 gaining its own access to the *metering registry*, the *metering database* and the *metering data* recorded in each *metering installation* for which it is the *metered market participant*.

3.1.5 Nothing in section 3.1.4 shall prevent a *metered market participant* from entering into an agreement with a person pursuant to which agreement such person agrees to indemnify the *metered market participant* in respect of some or all of the costs and expenses referred to in section 3.1.4.

3.2 Transitional Arrangements

3.2.1 Notwithstanding any other provision of this Chapter, a person that owns a *metering installation* that is in service on the date of coming into force of this section 3.2 or that is brought into service between the date of coming into force of this section 3.2 and the *market commencement date* shall, unless an election is made by such person pursuant to section 3.2.2, apply for registration as a *metering service provider* and shall act as the *metering service provider* in respect of such *metering installation* from the *market commencement date* until the earliest expiry date of any seal period of any *meter* forming part of such *metering installation*. Once such seal period expires, the *metered market participant* for the *metering installation* shall make such alternative arrangements as may be necessary to comply with the provisions of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter.

3.2.2 A person that owns a *metering installation* that is in service on the date of coming into force of this section 3.2 may elect to enter into an agreement with a *metering service provider* pursuant to which that *metering service provider* acts as the *metering service provider* in respect of such *metering installation*.

3.2.3 Notwithstanding section 3.1.2.2(c), a *metering service provider* designated as such pursuant to section 3.2.1 or 3.2.2, shall, in addition or in lieu of any liability that may be imposed on a *metered market participant* pursuant to section 3.1.2.2(c), be liable to the imposition of financial penalties and other sanctions, in accordance with the enforcement provisions of MR Ch.3, in respect of a failure by the *metering service provider* to comply with the obligations imposed on *metering service providers* in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter, and for such purposes, *metering service providers* shall be deemed as *market participants*. Such *metering service providers* shall only be subject to such liability in respect of *metering installations* for which they are designated as *metering service providers* pursuant to section 3.2.1 or 3.2.2 and only until the earliest expiry date of any seal period of any *meter* forming part of the *metering installation.*

4. Metering Installation

4.1 Metering Installation Standards

4.1.1 Subject to sections 4.1.2, 4.4, and 4.6, each *metering installation* shall:

4.1.1.1 contain *meters* that are of a type that are described on the list of conforming *meters* established by the *IESO*;

4.1.1.2 be comprised of two *meters*, at least one of which shall be a *revenue meter* that meets or exceeds the 0.2% accuracy class of ANSI standard C12.20*;*

4.1.1.3 have *instrument transformers* whose current transformers and voltage transformers meet or exceed the 0.3% accuracy class of ANSI standard C57.13;

4.1.1.4 meet the accuracy requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.1.5 meet the security requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.1.6 be capable of collating *metering data* into *dispatch intervals*;

4.1.1.7 be capable of separately registering and recording flows in each direction where bi-directional active *energy* flows may occur;

4.1.1.8 be capable of allowing remote access to the *metering data* contained in the *metering installation* in the manner set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.1.9 be capable of storing *metering data* for at least 35 days; and

4.1.1.10 comply with all other requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.1.2 A *metering installation* may exceed the level of accuracy and other requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.1.3 No *metering installation* shall be placed into service unless:

4.1.3.1 it has been commissioned in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.3.2 the communication equipment forming part of the *metering installation* has successfully passed an end-to-end test; and

4.1.3.3 it has been registered with the *IESO* in accordance with the procedures described in section 6.1.2.

4.1.4 The *IESO* shall, upon request by a *metered market participant* or a *metering service provider*, review conceptual drawings for a metering installation proposed to be installed by the *metered market participant* or the *metering service provider*.

4.1.5 A *metered market participant* or a *market participant,* with the agreement of the relevant *metered market participant*, may arrange for a *metering installation* to contain features in addition to those specified in section 4.1.1 and in the requirements, policies or standards referred to in that section.

4.1.6 Subject to section 4.1.7, where a *metering installation* is intended to be used for a purpose in addition to the collection, recording and storage of *metering data* and the transfer of *metering data* to the *IESO,* the *metered market participant* for the *metering installation* shall:

4.1.6.1 ensure that such use shall not interfere with the ability of the *metering installation* to perform or function in accordance with section 4.1.1 and the requirements, policies and standards referred to in that section;

4.1.6.2 obtain the prior approval of the *IESO* for such use and shall co-ordinate with any person that uses the *metering installation* for such other purposes to ensure that such use does not interfere with the ability of the *metering installation* to perform or function in accordance with section 4.1.1 and with the requirements, policies and standards referred to in that section; and

4.1.6.3 ensure that such use complies with all applicable *federal metering requirements.*

4.1.7 Each *metered market participant* shall ensure that any *instrument transformer* forming part of a *metering installation* in respect of which it is the *metered market participant* is not used for a purpose other than the measurement of *energy* for *settlement* purposes unless:

4.1.7.1 the instrument transformer is part of a *main/alternate metering installation*;

4.1.7.2 the *instrument transformer* is not connected to the *revenue meter* that has been designated by the *metered market participant* as the main *revenue meter* as reflected in the registration information pertaining to the *main/alternate metering installation*; and

4.1.7.3 the *instrument transformer* is operated within the rated burden limits for the accuracy class referred to in section 4.1.1.4.

or

4.1.7.4 the *metering installation* is registered under section 4.6 and the *IESO* has approved the placing of additional loads on the *instrument transformer* under section 4.6.6.

4.1A Metering Installations for Segregated Mode of Operation

4.1A.1 Subject to section 4.4, no *metered market participant* may operate a *resource* in a *segregated mode of operation* unless the *metering installation* for the associated *facility* generates *metering data* that reads zero, or is capable of such adjustment as may be required to ensure that such *metering data* reads zero, when the *resource* is operating in a *segregated mode of operation*.

4.2 Defined Meter Point and Error Correction Factors

4.2.1 Subject to section 4.4, each *metered market participant* shall ensure, in respect of each *metering installation* for which it is the *metered market participant*, that:

4.2.1.1 subject to sections 4.2.2 and 4.2.2A, the *meter point* is located at the *defined meter point* for the *facility* to which the *metering installation* relates and otherwise complies with all requirements for *meter points* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.2.2 The *IESO* shall permit a *metering installation* to be registered in respect of a *facility* notwithstanding that the *meter point* is not located at the *defined meter point* provided that all transfers of *energy* at any points of supply or consumption for the *facility* to which the *metering installation* relates are separately metered in a manner satisfactory to the *IESO.*

Metering Installation Associated with More than One Defined Meter Point and/or Facility

4.2.2A The *IESO* shall permit a *metering installation* to be associated with more than one *facility* notwithstanding that the *meter point* is not located at the *defined meter points* for the *facilities,* provided that all transfers of *energy* at any points of supply or consumption for the *facilities* to which the *metering installation* are associated, are determined in a manner satisfactory to the *IESO.*

Where a *metered market participant* intends that such a *metering installation* is to be used for determining *settlement amounts* instead of one or more pre-existing downstream *metering installations,* the *IESO* shall not permit the use of the upstream *metering installation* for determining *settlement amounts* unless the *metered market participant* demonstrates, to the satisfaction of the *IESO* in accordance with the applicable *market manual*, the accuracy of the *energy* transfer measurements of the upstream *metering installation* relative to the downstream *metering installations*.

4.2.2B When developing the conditions of satisfaction referred to in section 4.2.2A, the *IESO* shall be guided by the principle that all *market participants* are to be held financially whole by the use of the upstream *metering installation*.

4.2.3 The *IESO* shall, in respect of *metering data* recorded in the *metering database* that was obtained from a *metering installation* whose *meter point* is not located at the *defined meter point* for a *facility* to which the *metering installation* relates, adjust the *metering data* on the basis of the site-specific loss adjustments referred to in section 4.2.4 or 4.2.5.1 and, where applicable, on the basis of the loss adjustments provided pursuant to section 4.2.5.2.

4.2.4 Where the *defined meter point* in respect of a *facility* is a *connection point* and the *meter point* of the *metering installation* for that *facility* is located other than at the *defined meter point*, the *metering service provider* for the relevant *metering installation* shall provide to the *IESO*, at the time of registration of the *metering installation*, in accordance with section 4.2.6, the parameters for site specific loss adjustments required to reflect losses between the *meter point* and the *defined meter point*.

4.2.5 Where the *defined meter point* in respect of a *facility* is an *embedded connection point* and the *meter point* is not located at the *defined meter point*, the *metering service provider* for the relevant *metering installation* shall provide to the *IESO*, at the time of registration of the *metering installation*:

4.2.5.1 the parameters for site specific loss adjustments to reflect losses between the *meter point* and the *defined meter point* associated with the *embedded facility*, in accordance with section 4.2.6; and

4.2.5.2 the loss adjustments required to reflect losses between the *defined meter point* associated with the *connected facility* and the *defined meter point* associated with the *embedded facility*, obtained where applicable from the relevant *transmitter* or *distributor*, as the case may be depending on the owner of the *facilities* to which the *facility* to which the *meter point* relates is connected.

4.2.6 The parameters for site specific loss adjustments referred to in sections 4.2.4 and 4.2.5.1 shall comply with the requirements of any site specific loss adjustment policy or standard established by the *IESO* and shall be updated by each *metering service provider* as may be required by the *IESO*.

4.2.7 Each *metering service provider* shall provide to the *IESO* measurement error correction factors for each *metering installation* in respect of which it acts as a *metering service provider* in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter.

4.3 Use of Metering Data and Metering Data Collection

4.3.1 *Metering data* shall be used by the *IESO* for *settlement* purposes following completion of the validation and, where applicable, substitution and estimation processes, in the manner set forth in MR Ch.9.

4.3.2 Each *metering installation* shall:

4.3.2.1 have a communication link to the relevant telecommunication network, and, where required, isolation equipment approved under applicable telecommunications laws and regulations; and

4.3.2.2 be capable of remote communication by electronic means from the site of the *metering installation* to the communication interface of the *metering database.*

4.3.3 Each *metered market participant* shall ensure that all *metering data* contained in each *metering installation* for which it is the *metered market participant* is made available and transferred to the communication interface of the *metering database* in accordance with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter. The *IESO* may use *data collection systems* operated by meter data management agencies for the purpose of the transfer of *metering data* to the *metering database*.

4.3.4 Each *metered market participant* shall ensure that all *metering data* in each *metering installation* for which it is the *metered market participant* is transferred to the communication interface of the *metering database* in a manner that preserves the security from access and the accuracy of such *metering data* as described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.3.5 The *IESO* shall ensure that all *metering data* that has been transferred to the communication interface of the *metering database* is transferred from such communication interface to the *metering database* in a manner that preserves the security of access and the accuracy of such *metering data* as described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.3.6 No *metered market participant* shall use a protocol or data format in respect of the transfer of *metering data* from a *metering installation* to a *data collection system* unless that protocol or data format has been approved by the *IESO.*

4.3.7 Each *metered market participant* shall ensure that *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* that is transferred to the communication interface of the *metering database* is in a data format that is compatible with the data format used by the *IESO* for the retrieval of *metering data* from such communication interface.

4.4 Alternative Metering Installation Standards

Obligations of Metered Market Participants

4.4.1 A *metered market participant* with a *metering installation* registered under section 4.4.3, shall ensure that the *metering installation* meets the requirements set forth in the alternative standards specified in Appendix 6.2.

Registration Under the Alternative Metering Installation Standard

4.4.2 A *metering service provider* applying to register a *metering installation* under the alternative standards specified in Appendix 6.2 shall submit to the *IESO*:

4.4.2.1 an application for registration specifying the alternative *metering installation* standard(s) for which registration is sought;

4.4.2.2 applicable supporting information as specified in Appendix 6.2; and

4.4.2.3 information otherwise required by this Chapter or the applicable *market manual*.

4.4.3 The *IESO* shall register the *metering installation* provided that, in the opinion of the *IESO,* the *metering service provider* meets the requirements of section 4.4.2. Where the *IESO* is not satisfied that the requirements of section 4.4.2 have been met, it shall refuse to register the *metering installation*. The *IESO* shall so notify the applicant, together with the reasons for refusal. Such a refusal is a *reviewable decision.*

Expiry and Revocation of Registration

4.4.4 Registration granted under section 4.4.3, in respect of a particular alternative standard, shall expire on the earlier of:

4.4.4.1 the date specified in Appendix 6.2 for that alternative standard; and

4.4.4.2 the date on which registration is revoked by the *IESO* under section 4.4.6.

4.4.5 Subject to section 4.4.8, prior to the expiry of registration of a *metering installation* under the alternative standard, the *metered market participant* for that *metering installation* shall ensure that the *metering installation* is brought into full compliance with the applicable requirements set forth in this Chapter and in any policy or standard established by the *IESO* under this Chapter.

4.4.6 The *IESO* may revoke registration granted under section 4.4.3 in the circumstances described in Appendix 6.2.

4.4.7 If the *IESO* revokes the registration for a *metering installation* under section 4.4.6, the *metered market participant* for that *metering installation* shall ensure that the *metering installation* is brought into full compliance with the applicable requirements of this Chapter within the time specified in Appendix 6.2 and shall so notify the *IESO.*

Retaining Registration Under the Alternative Standard

4.4.8 Prior to the expiry of registration of a *metering installation* under the alternative standards specified in sections 1.2, 1.6, 1.7, 1.8, 1.9, 1.11, 1.12, and 1.13 of Appendix 6.2, the *metered market participant* may apply to the *IESO* to retain registration under those sections. The *IESO* shall grant the *metered market participant* the right to retain registration if, in the opinion of the *IESO,* the changes required for the *metering installation* meet the criteria specified in the applicable *market manual.* The *IESO* shall recover the cost of processing the application from the *metered market participant* in accordance with the applicable *market manual.*

Estimation of Metering Data for Settlement Purposes

4.4.9 Where a *metered market participant* fails to comply with section 4.4.5 or 4.4.7, the *IESO* shall take such action with respect to the estimation of *metering data* for *settlement* purposes as specified in section 1.14 of Appendix 6.2.

4.5 Alternative Metering Installation Standards for Embedded Generation Facilities

4.5.1 A *transmission customer* that has an *embedded generation facility* that:

4.5.1.1 registers that *generation facility* for the purpose of determining transmission charges;

4.5.1.2 is rated less than 20 MW; and

4.5.1.3 meets the applicable Ontario Uniform Transmission Rate Schedule requirements with respect to the transmission *delivery point* through which the *generation facility* is connected to the *transmission system* and attracts Line or Transformation Connection Service charges;

shall either comply with the *metering installation* standards specified elsewhere in this Chapter 6 or with the alternative *metering installation* standards specified in this section 4.5 for that *embedded generation facility*.

4.5.2 A *transmission customer* that chooses to meet the alternative *metering installation* standards of this section 4.5 for an *embedded generation facility* shall, in accordance with the applicable *market manual*, have their *metering service provider*:

4.5.2.1 register with the *IESO* a *metering point* for that *embedded generation facility.*

4.5.3 Within three months of the calendar year end, the *transmission customer* shall, for each *embedded generation facility* for which a *metering point* has been registered under the alternative *metering installation standards* of this section 4.5, in the manner specified in the applicable *market manual*:

4.5.3.1 determine the annual adjustment dollar value for the applicable *transmission services charges* based on the impact of the actual output of the *embedded generation facility*;

4.5.3.2 obtain agreement of the *transmitter* as to this adjustment amount; and

4.5.3.3 submit this information to the *IESO*.

4.5.4 In the event that the *IESO* does not receive the information specified in section 4.5.3 within the time specified in section 4.5.3, the *IESO* shall use the *maximum continuous rating* for the *embedded generation facility*, provided to the *IESO* at the time of the *meter point* registration referred to in section 4.5.2.

4.5.5 The *IESO* shall adjust the applicable *transmission services charge settlement amounts* by any such amount, submitted in accordance with section 4.5.3 or by the amount determined under section 4.5.4, for the *transmission customer* and the *transmitter*. The *IESO* shall make this adjustment on the applicable *settlement statement* for the last day of the month in which the adjustment information is received or the last day of the month in which the *IESO* determines the adjustment amount, whichever is applicable.

4.6 Metering Installation Standards for Embedded Generation Facilities Under 2 MVA or Injecting Less than 17 GWh Per Annum

4.6.1 A *market participant* that has a registered *minor generation facility* embedded within a *distribution system* and which either injects less that 17 gigaWatt-hours per annum or has a nameplate rating less than 2 MVA shall be eligible to register with the *IESO* a *metering installation* for that *generation facility* comprised of a standalone *meter.*

4.6.2 The standalone *meter* shall be either a main *meter* or an alternate *meter* from the *IESO's* conforming *meter* list.

4.6.3 The *metering service provider* for the *metering installation* registered under section 4.6.1 shall not be required to submit an emergency *instrument transformer* restoration plan otherwise required under section 1.3.2.17 of Appendix 6.5.

4.6.4 If there is a failure of an *instrument transformer* at a *metering installation* registered in accordance with this section, the *IESO* shall estimate the *metering data* from the *metering installation* for *settlement* purposes in accordance with section 11.1.4A of Chapter 6 for the duration of the failure.

4.6.5 The *metered market participant* for a *meter* registered in accordance with this section shall not be required to meet the testing requirements specified in section 1.2 of Appendix 6.3.

4.6.6 The *metered market participant* for a *metering installation* registered in accordance with this section shall, subject to *IESO* approval, be permitted to place additional loads on its *instrument transformer*.

4.6.7 Within three months from the date of notification by the *IESO*, a *metered market participant* shall make a *metering installation* fully compliant with the *metering* *installation* standards specified elsewhere in Chapter 6 if the *energy* threshold recorded by the standalone *meter* exceeds 17 gigaWatt-hours per annum.

5. Metering Service Providers

5.1 Registration

5.1.1 No person may perform the activities required by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter to be performed by a *metering service provider* unless that person has been registered by the *IESO* as a *metering service provider.*

5.1.2 No person shall be registered by the *IESO* as a *metering service provider* unless the person demonstrates to the satisfaction of the *IESO* that the person has the qualifications described in Appendix 6.4.

5.1.3 Any person including, but not limited to, a *market participant* or a *metered market participant*, that wishes to be registered by the *IESO* as a *metering service provider* shall file with the *IESO*:

5.1.3.1 a completed application for registration as a *metering service provider* in such form as shall be established by the *IESO*;

5.1.3.2 an executed agreement, in such form as shall be established by the *IESO*, pursuant to which the person agrees, among other matters, to be bound by and comply with the provisions of the *market rules* applicable to *metering service providers*; and

5.1.3.3 the application fee established from time to time by the *IESO*, and approved by the *OEB*, to defray the costs of processing the application, conducting the systems and procedures tests and audits referred to in section 5.1.6 and conducting the review referred to in section 5.1.13.

5.1.4 The *IESO* shall, within ten *business days* of receiving an application for registration as a *metering service provider* or within such longer period of time as may be agreed between the *IESO* and the applicant, notify the applicant of any further information or clarification that is required in support of its application if, in the *IESO's* opinion, the application is:

5.1.4.1 incomplete; or

5.1.4.2 contains information with respect to which the *IESO* requires clarification.

5.1.5 If the further information or clarification which is requested by the *IESO* pursuant to section 5.1.4 is not provided to the *IESO's* satisfaction within fifteen *business days* of the request or within such longer period of time as may be agreed between the *IESO* and the applicant, the applicant shall be deemed to have withdrawn its application for registration as a *metering service provider.*

5.1.6 The *IESO* may, if the applicant does not have ISO 9000 certification, conduct such audits or tests of the applicant's systems and procedures as the *IESO* determines appropriate.

5.1.7 The *IESO* shall, within twenty *business days* of:

5.1.7.1 receipt of the application for registration as a *metering service provider*;

5.1.7.2 receipt of the further information or clarification requested under section 5.1.4; or

5.1.7.3 the conduct of any audits or tests referred to in section 5.1.6,

whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, notify the applicant that the *IESO* intends to register the person as a *metering service provider* upon completion of the review referred to in section 5.1.13, on such terms and conditions as the *IESO* considers appropriate, if the applicant has demonstrated to the *IESO*'s satisfaction that it has the qualifications set forth in Appendix 6.4. If the applicant has ISO 9000 certification, the *IESO* shall, together with the notice of intention to register the applicant, refund that portion of the application fee referred to in section 5.1.3.3 that is attributable to the costs of conducting the systems and procedures tests and audits referred to in section 5.1.6.

5.1.8 If the *IESO* is not satisfied that the applicant has demonstrated that it has the qualifications set forth in Appendix 6.4, the *IESO* shall, within twenty *business days* of receipt of the application for registration as a *metering service provider*, of receipt of the further information or clarification requested under section 5.1.4 or of any audits or tests referred to in section 5.1.6, whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, notify the applicant that the *IESO* intends to deny its application for registration as a *metering service provider*. Such notice shall identify the deficiency in the applicant's qualifications that formed the grounds for the issuance of the notice.

5.1.9 An applicant to whom a notice is issued in accordance with section 5.1.8 shall have 20 *business days* from the date of receipt of such notice, or such longer period of time as may be agreed between the *IESO* and the applicant, in which to rectify the deficiency in its qualifications identified in such notice and to notify the *IESO* of such rectification.

5.1.10 Where the *IESO* is satisfied that, with the rectification described in section 5.1.9, the applicant has demonstrated that it meets the qualifications set forth in Appendix 6.4, the *IESO* shall notify the applicant that the *IESO* intends to register the person as a *metering service provider* upon completion of the review referred to in section 5.1.13, on such terms and conditions as the *IESO* considers appropriate.

5.1.11 Where:

5.1.11.1 an applicant to whom a notice is issued in accordance with section 5.1.8 fails to rectify the deficiency in its qualifications within the time specified in that section; or

5.1.11.2 the rectification described in section 5.1.9 is not such as to satisfy the *IESO* that the applicant meets the qualifications set forth in section 5.2.3,

the *IESO* shall:

5.1.11.3 notify the applicant in writing that its application for registration as a *metering service provider* has been denied;

5.1.11.4 if the *IESO* has not conducted the systems and procedures tests and audits referred to in section 5.1.6, return to the applicant that portion of the application fee referred to in section 5.1.3.3 that is attributable to the costs of conducting such tests and audits; and

5.1.11.5 return to the applicant that portion of the application fee referred to in section 5.1.3.3 that is attributable to the costs of conducting the review described in section 5.1.13.

5.1.12 Denial by the *IESO* of an application for registration as a *metering service provider* is a *reviewable decision*.

5.1.13 The *IESO* shall review with each applicant referred to in sections 5.1.7 and 5.1.10:

5.1.13.1 the procedures for the registration of *metering installations* described in this Chapter and in the procedures established by the *IESO* pursuant to section 6.1.2 of this Chapter; and

5.1.13.2 the performance standards for *metering service providers* set forth in the applicable *market manual*.

5.1.14 The *IESO* shall, within five *business days* of completion of the review referred to in section 5.1.13, register the person as a *metering service provider*, on such terms and conditions as the *IESO* considers appropriate, and shall notify the applicant accordingly.

5.1.15 Each applicant for registration as a *metering service provider* and each *metering service provider* shall forthwith notify the *IESO* of any circumstances that result or are likely to result in a change in the information provided in the person's application for registration as a *metering service provider* or any updates thereto.

5.1.16 The *IESO* shall establish, maintain, update and *publish*:

5.1.16.1 a list of all persons that have been registered as *metering service providers*; and

5.1.16.2 a list of each *metering service provider* whose registration as a *metering service provider* has been revoked pursuant to section 5.3.

5.2 Activities and Standards for Metering Service Providers

5.2.1 The activities described in section 1.3 of Appendix 6.1 shall be performed by a *metering service provider*.

5.2.2 Each *metering service provider* shall comply with all of the obligations imposed on *metering service providers* in Appendix 6.1 and in any policy or standard established by the *IESO* pursuant to this Chapter.

5.2.3 Each *metering service provider* shall meet all performance standards as set forth in the applicable *market manual*.

5.2.4 Where the provision of written meter-related materials or of post-registration familiarization and competency updating or upgrading to a *metering service provider* imposes a significant expense on the *IESO*, such documentation, assistance or training may be provided upon payment by the *metering service provider* of a reasonable fee.

5.3 Revocation of Registration of Metering Service Providers

5.3.1 The *IESO* may revoke the registration of a *metering service provider* where the *metering service provider*:

5.3.1.1 has been found to be in breach of the *market rules* applicable to *metering service providers* on a persistent basis;

5.3.1.2 fails to meet the performance standards set forth in the applicable *market manual* on a consistent basis;

5.3.1.3 has been found to be in breach of a material provision of the agreement referred to in section 5.1.3.2; or

5.3.1.4 ceases to satisfy any material qualification for registration as a *metering service provider* or any material requirement imposed upon it as a condition of registration as a *metering service provider*.

5.3.2 Where the *IESO* intends to revoke the registration of a *metering service provider*, the *IESO* shall give notice to the *metering service provider* and to all *metered market participants* for whom the *metering service provider* is, to the *IESO's* knowledge, acting as *metering service provider*. The notice shall specify:

5.3.2.1 the grounds upon which the *metering service provider's* registration is proposed to be revoked and details of any evidence on which the *IESO* is relying in support of its intention to revoke such registration;

5.3.2.2 that the *metering service provider* may within 10 *business days* make written representations as to why its registration should not be revoked; and

5.3.2.3 the right of the *metering service provider* to request a hearing before the *IESO Board* or a committee of the *IESO Board* established for such purpose to show cause why its registration should not be revoked.

5.3.3 Following expiry of the time noted in section 5.3.2.2, and after consideration of any representations made by the *metering service provider* pursuant to that section, the *IESO* may:

5.3.3.1 subject to section 5.3.4, revoke the *metering service provider's* registration; or

5.3.3.2 make such order as the *IESO* determines appropriate, including but not limited to an order:

a. directing the *metering service provider* to do, within a specified period, such things as may be necessary to comply with the *market rules* applicable to *metering service providers*;

b. directing the *metering service provider* to cease, within a specified period, the act, activity or practice constituting a breach of the *market rules* or a breach of a material provision of the agreement referred to in section 5.1.3.2; and

c. imposing additional or more stringent terms and conditions in respect of the continued registration of the *metering service provider*.

5.3.4 Where the *metering service provider* has requested a hearing pursuant to section 5.3.2.3, the *IESO Board* or a committee of the *IESO Board* established for such purpose shall conduct a hearing providing the *metering service provider* with a reasonable opportunity to show cause as to why its registration should not be revoked by the *IESO*. In such case, the *IESO* shall not revoke the *metering service provider's* registration under section 5.3.3.1 until such hearing has been held.

5.3.5 All rights of a *metered service provider* to perform the activities of a *metering service provider* under this Chapter shall be terminated upon revocation of the *metering service provider's* registration.

5.3.6 The *IESO* shall, immediately upon revoking the registration of a *metering service provider*, notify each *metered market participant* for whom the *metering service provider* was, to the *IESO's* knowledge, acting as *metering service provider* at the time of revocation, of the revocation of the *metering service provider's* registration.

5.3.7 A *metering service provider* whose registration has been revoked by the *IESO* remains subject to and liable for all of its liabilities and financial obligations as a *metering service provider* which were incurred or arose under the *market rules* prior to the date on which it's registration is revoked regardless of the date on which any claim relating thereto may be made.

5.3.8 A *metering service provider* whose registration has been revoked and that wishes to be re-registered a *metering service provider* shall be required to re-apply for registration in accordance with section 5.1. The *IESO* may impose such terms and conditions on the registration of the *metering service provider* as the *IESO* determines appropriate in the circumstances, whether or not such terms and conditions are otherwise applicable to other *metering service providers*.

5.3.9 A decision by the *IESO* to revoke the registration of a *metering service provider* is a *reviewable decision* and shall be without prejudice to the right of the *IESO* to impose upon the *metered market participant* for whom the *metering service provider* is acting as *metering service provider* sanctions or financial penalties in accordance with MR Ch.3 in respect of any breach of the *market rules* that formed the grounds for revocation of the *metering service provider's* registration.

6. Registration of Metering Installations and Metering Registry

6.1 Registration of Metering Installations

6.1.1 Subject to section 6.1.1A, no person shall use a *metering installation* for the measurement of *energy* for *settlement* purposes relating to the *day-ahead market, real-time market* or the *procurement markets* unless the *metering installation* has been registered by the *IESO* in accordance with this section 6.1 and that registration has not expired.

6.1.1.A A person may only use a *metering installation* for the measurement of *energy* for *settlement* purposes relating to the *day-ahead market, real-time market* or the *procurement markets* if the *metering installation* has been registered by the *IESO* in accordance with this section 6.1 and the registration has expired provided that the

IESO determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*.

6.1.2 The *IESO* shall establish in the applicable *market manual* the procedures to be followed by *metering service providers* for the registration of *metering installations*. Such procedures shall include, but not be limited to, an identification of:

6.1.2.1 the information and documentation required to be submitted by a *metering service provider* in support of the registration of a *metering installation* including, but not limited to, the information described in sections 1.2, 1.3 and, where applicable, 1.3A of Appendix 6.5; and

6.1.2.2 the tests required to be conducted in respect of a *metering installation* prior to registration.

6.1.2A Each *metered market participant* for a *metering installation* that will be used for the purpose of the calculation and collection by the *IESO* of charges for *transmission service* shall, request the *metering service provider* for that *metering installation* to submit the *meter point* documentation for that *metering installation* and any updates thereto, to the *transmitter* identified by the *metered market participant* for the purpose of soliciting the written confirmation of that *transmitter's* approval referred to in section 1.3A of Appendix 6.5.

6.1.2B Each *metering service provider* to whom a request has been made pursuant to section 6.1.2A shall as soon as practicable submit the relevant *meter point* documentation or update referred to in that section to each *transmitter* identified in such request.

6.1.3 The *IESO* shall refuse to register a *metering installation*:

6.1.3.1 where the *metering installation* does not comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter; or

6.1.3.2 where the *metering installation* will be used for the calculation and collection of charges for *transmission service*, the relevant portion of the *meter point* documentation submitted in support of the application to register the *metering installation* is not accompanied by such confirmation of each applicable *transmitter* referred to in section 1.3A of Appendix 6.5.

6.1.4 Where the *IESO* refuses to register a *metering installation* pursuant to section 6.1.3, the *IESO* shall so notify the *metering service provider*, together with reasons for the refusal.

6.1.5 Refusal by the *IESO* to register a *metering installation* is a *reviewable decision*.

6.1.6 Each *metering service provider* shall, at the request of the *metered market participant* for a *metering installation*, provide that *metered market participant* with copies of all information, including but not limited to *meter point* documentation and data, submitted by the *metering service provider* in support of the application to register the *metering installation*, and of all updates to such information submitted to the *IESO* by the *metering service provider.*

6.1.7 Each *metering service provider* shall, at the request of a *transmitter* that has given confirmation of its approval of a portion of the applicable *meter point* documentation or any update thereto referred to in section 1.3A of Appendix 6.5, as may be applicable, provide that *transmitter* with copies of such *meter point* documentation submitted by the *metering service provider* in support of the application to register the *metering installation* and of all updates thereto submitted to the *IESO* by the *metering service provider*.

6.1.8 No *metering service provider* to whom a request has been made pursuant to section 6.1.2A has been made shall submit to the *IESO* any updates to any *meter point* documentation for a *metering installation* that will be used for the purpose of the calculation and collection by the *IESO* of charges for *transmission service* unless such updates are accompanied by the confirmation of the approval of each applicable *transmitter* referred to in section 1.3A of Appendix 6.5.

6.2 Metering Registry

6.2.1 The *IESO* shall establish and maintain a *metering registry* containing the information specified in Appendix 6.5 in respect of each *metering installation* that provides *metering data* used by the *IESO* for *settlement* purposes.

6.2.2 The *IESO* shall record in the *metering registry* the results of all tests provided to it pursuant to section 7.1.2, the results of any tests conducted pursuant to section 7.2.5 and any changes confirmed to it pursuant to section 9.3.1.3.

6.2.3 The data recorded in the *metering registry* in respect of a registered *metering installation* shall be available to:

6.2.3.1 the *metered market participant* for that *metering installation* and an authorized agent of such *metered market participant*;

6.2.3.2 the *metering service provider* for that *metering installation*;

6.2.3.3 any *market participant* whose *settlement statement* is determined on the basis of the *metering data* recorded in that *metering installation* and an authorized agent of such *market participant;* and

6.2.3.4 any *transmitter* or *distributor* to whose system a *facility* in respect of the *metering installation* relates is connected.

6.2.4 Data recorded in the *metering registry* is *confidential information* and the *IESO* shall ensure that such data is not accessible by or disclosed by the *IESO* to any person other than the *IESO* and the persons referred to in sections 6.2.3.1 to 6.2.3.4 or as otherwise permitted by MR Ch.3 s.5 or any policy of the *IESO* established pursuant to that section.

7. Testing and Auditing of Metering Installations

7.1 Testing and Auditing

7.1.1 Each *metered market participant* shall ensure that each *metering installation* in respect of which it is the *metered market participant* is inspected and tested by its *metering service provider* in accordance with the requirements set forth in Appendix 6.3.

7.1.2 Each *metered market participant* shall ensure that its *metering service provider* provides to the *IESO* the results of each test referred to in section 7.1.1.

7.1.3 The *IESO* shall review the results of all tests provided to it pursuant to section 7.1.2.

7.1.4 Where, following the review referred to in section 7.1.3, the *IESO* determines that an audit of a *metering installation* is required to assess the compliance of the *metering installation* with the requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter, the *IESO* shall arrange for the audit of the *metering installation*. The *metered market participant* for the *metering installation* shall ensure that the *IESO's* auditor is provided with unrestricted access to such *metering installation* for the purpose of such audit provided that the *IESO* has given the *metered market participant* notice of the audit no less than 5 *business days* in advance. *Metered market participant* shall carry out any additional testing the *IESO's* auditor may require within 30 days of being requested to do so, or within such other time as the *metered market participant* and the *IESO's* auditor may agree. Notice of the audit shall specify:

7.1.4.1 the name of the person that will be conducting the audit; and

7.1.4.2 the date of the audit and the time at which the audit is expected to commence and conclude.

7.1.5 The *IESO* may carry out periodic, random and unannounced audits of a *metering installation* for the purpose of ascertaining whether the *metering installation* complies with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter. The *metered market participant* for the *metering installation* shall ensure that the *IESO's* auditor is provided with unrestricted access to the *metering installation* for the purpose of such audit.

7.1.6 The *IESO* shall, as soon as practicable, make the results of any audit conducted pursuant to section 7.1.4 or 7.1.5 available to the *metered market participant* for the *metering installation* to which the audit relates.

7.1.7 Each *metered market participant* shall, as soon as practicable, make the results of all tests conducted pursuant to section 7.1.1 and of all audits conducted pursuant to sections 7.1.4 and 7.1.5 available to the *distributor* or *transmitter* to whose system the *facility* to which the *metering installation* relates is connected.

7.2 Tests and Audits of Metering Data

7.2.1 A *market participant* may request the *IESO* to conduct an audit to determine the consistency between the *metering data* recorded in the *metering database* and the *metering data* recorded in the *metering installation* whose *meter point* is used to determine that *market participant's settlement statement*.

7.2.2 The *IESO* shall give the *metered market participant* in respect of the *metering installation* that will be the subject of an audit pursuant to section 7.2.1 notice of the audit no less than 5 *business days* in advance. Notice of the audit shall specify:

7.2.2.1 the name of the person that will be conducting the audit; and

7.2.2.2 the date of the audit and the time at which the audit is expected to commence and conclude.

7.2.3 The *IESO* shall conduct the audit referred to in section 7.2.1 and the *metered market participant* for the *metering installation* referred to in section 7.2.1 shall, provided that notice has been given in accordance with section 7.2.2, ensure that the *IESO's* auditor is provided with unrestricted access to the *metering installation* for the purpose of such audit.

7.2.4 The *IESO* shall, as soon as practicable, make the results of an audit conducted pursuant to section 7.2.1 available to the *market participant* that requested the audit and, if such *market participant* is not the *metered market participant* for the *metering installation*, to such *metered market participant.*

7.2.5 Provided that the *metering service provider* for a *metering installation* has provided to the *IESO* the necessary *meter* register dial readings pursuant to section 1.2.4 of Appendix 6.3 or such dial readings are available in the manner described in section 7.2.6, the *IESO* shall, no less than:

7.2.5.1 twice in each successive twelve-month period following the date of registration of a *metering installation* that is not a *main/alternate* *metering installation* and that is associated with a *facility* that has a minimum rated transformer or circuit capacity of less than 10 MW; or

7.2.5.2 four times in each successive twelve-month period following the date of registration of a *metering installation* that is not a *main/alternate metering installation* and that is associated with a *facility* that has a minimum rated transformer or circuit capacity of 10 MW or more,

compare the *metering data* recorded in such *metering installation* over a given period of time with the *metering data* recorded in the *metering database* from that *metering installation* for the same period. The *IESO* shall, as soon as practicable, make the results of the comparison effected pursuant to this section available to the *metered market participant* for the *metering installation*.

7.2.6 The procedure referred to in section 7.2.5 may be executed during the transfer of the *metering data* to the *metering database* if the *meter* within the *metering installation* is capable of transmitting the necessary *meter* register dial readings.

7.2.7 An error detected as a result of the procedure referred to in section 7.2.5 that exceeds one multiplier, calculated as the current transformer ratio times the voltage transformer ratio times the *meter* register multiplier, shall be recorded by the *IESO* as an *outage* or defect, and the *IESO* shall so notify the *metered market participant* and issue a trouble call to the *metering service provider* in accordance with section 11.1.3.1.

7.2.8 If an audit conducted pursuant to section 7.2.1 or a comparison performed pursuant to section 7.2.5 reveals a discrepancy between the *metering data* recorded in a *metering installation* and the *metering data* recorded in the *metering database*, the *metering data* in the *metering installation* shall govern for *settlement* purposes.

7.3 Costs of Tests and Audits

7.3.1 The costs and expenses associated with the inspection and testing of a *metering installation* referred to in section 7.1.1 shall be paid by the *metered market participant* responsible for that *metering installation*, and the costs and expenses of review of such tests referred to in section 7.1.3 shall be paid by the *IESO*.

7.3.2 The costs and expenses associated with the audit of a *metering installation* referred to in section 7.1.4, the periodic, random and unannounced audits referred to in section 7.1.5, the security audits referred to in section 9.1.3, or the *connection station service* audit referred to in MR Ch.9 s.2.2.3, shall be paid as follows:

7.3.2.1 the *IESO* shall pay all of its costs as described in the applicable *market manual*; and

7.3.2.2 the *metered market participant* responsible for that *metering installation* shall pay all costs incurred by any of the *metered market participant, metering service provider*, and *facility* owner as described in the applicable *market manual*.

Where the *metering installation* is shown by the test or audit not to comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, thereby requiring for any reason a re-test or additional inspection or re-audit or any additional work by the *IESO*, the *metered market participant* responsible for that *metering installation* shall bear the costs of that re-test, inspection, audit and remedial work, including but not limited to any and all costs incurred by the *IESO*.

7.3.3 The costs and expenses associated with the *metering data* audit referred to in section 7.2.1 shall be paid as follows:

7.3.3.1 the *IESO* shall pay all of its costs for the purposes of the *metering data* audit as described in the applicable *market manual*; and

7.3.3.2 the *market participant* who requested the *IESO* to conduct the audit shall pay all costs incurred by the *metered market participant*, *metering service provider* and *facility* owner as described in the applicable *market manual*.

Where the *metering installation* is shown by the *metering data* audit not to comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, the *metered market participant* responsible for that *metering installation* shall bear the costs incurred for any re-audit or remedial work, including reimbursement of all costs incurred by the *market participant* who requested the *IESO* to conduct the *metering data* audit which demonstrated the non-compliance.

7.3.4 The costs and expenses associated with the *metering data* audit referred to in section 7.2.5 shall be paid as follows:

7.3.4.1 the *IESO* shall pay all of its costs for the purposes of the *metering data* audit as described in the applicable *market manual*; and

7.3.4.2 the *metered market participant* responsible for that *metering installation* shall pay all costs incurred by any of the *metered market participant, metering service provider*, and *facility* owner costs as described in the applicable *market manual*.

Where the *metering installation* is shown by the *metering data* audit not to comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, thereby requiring for any reason a retest or an additional inspection or re-audit or any additional work by the *IESO*, the *metered market participant* responsible for that *metering installation* shall bear the costs of any such re-test, inspection, audit and remedial work, including but not limited to any and all *IESO* costs.

7.3.5 The costs and expenses associated with the implementation of the safety requirements and practices referred to in section 7.4.1, including but not limited to the costs associated with training the *IESO's* auditor in respect of such requirements or practices and of accompanying the *IESO's* auditor during an audit referred to in sections 7.1.4, 7.1.5, 7.2.3 and 9.1.3 and MR Ch.9 s.2.2.3, shall be borne by the *metered market participant* for the *metering installation* that is undergoing the audit.

7.4 Safety Requirements and Practices During Audits

7.4.1 The *IESO* shall use reasonable efforts to ensure that, in performing an audit referred to in section 7.1.4, 7.1.5 or 7.2.3, the *IESO's* auditor complies with such reasonable and *bona fide* safety requirements and practices of:

7.4.1.1 the owner of the *metering installation*; or

7.4.1.2 the owner of the *facility* within which the *metering installation* is located,

or both, as may be applicable, as may be made known to the *IESO's* auditor.

7.4.2 The *metered market participant* for a *metering installation* shall, subject to section 7.4.3, ensure that the *IESO's* auditor is, at all times while conducting an audit referred to in section 7.1.4, 7.1.5 or 7.2.3, accompanied by a qualified representative of:

7.4.2.1 the owner of the *metering installation*; or

7.4.2.2 the owner of the *facility* within which the *metering installation* is located,

or both, as may be applicable, responsible for ensuring the safety of the *IESO's* auditor during the audit.

7.4.3 A *metered market participant* for a *metering installation* that is undergoing an audit referred to in section 7.1.4, 7.1.5 or 7.2.3 shall not be required to ensure the accompaniment of the *IESO's* auditor referred to in section 7.4.2 if the *metered market participant* has, prior to the date of the audit, provided the *IESO's* auditor with adequate information pertaining to hazards on the site and sufficient technical and safety training so as to ensure that the *IESO's* auditor may safely conduct the audit unaccompanied having regard to the *bona fide* safety requirements and practices of:

7.4.3.1 the owner of the *metering installation*; or

7.4.3.2 the owner of the *facility* within which the *metering installation* is located,

or both, as may be applicable, in effect on the date of the audit.

7.4.4 The *IESO* auditor shall have successfully completed safety training in general industry safety practice, such a vehicle parking and electrical safety awareness, from an entity recognized by the *IESO* for such purpose, including but not limited to the Electrical & Utilities Safety Association of Ontario, the former Ontario Hydro and corporations referred to in subsection 48(2) of the *Electricity Act, 1998*.

7.4.5 An *IESO* auditor who will be working on, or testing, the *metering installations* shall have successfully completed, in addition to the training referred to in section 7.4.4, specific training in inspection and testing of *meter installations* from an entity recognized by the *IESO* for such purpose, including but not limited to the Electrical & Utilities Safety Association of Ontario, the former Ontario Hydro and corporations referred to in subsection 48(2) of the *Electricity Act, 1998*.

8. Ownership of and Rights of Access to Data

8.1.1 The *metering data* in a *metering installation* shall be owned by the *metered market participant* for that *metering installation* and the *metered market participant* shall at all times have access to such *metering data*, subject only to sections 8.1.6 and 8.1.7.

8.1.2 Subject to sections 8.1.6 and 8.1.7, a *metered market participant* may at any time extract real-time information, billing data and spin-off data directly from a *metering installation* for which it is the *metered market participant*.

8.1.3 Unless otherwise permitted by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter, no *metered market participant* shall in any manner modify a *meter* within a *metering installation* in respect of which it is the *metered market participant,* any *metering data* recorded in the *metering installation* or the clock time of a *meter* within the *metering installation.*

8.1.4 Each *metered market participant* shall ensure that no person referred to in sections 8.1.5.1 to 8.1.5.4 modifies a *meter* within a *metering installation* in respect of which it is the *metered market participant,* any *metering data* recorded in the *metering installation* or the clock time of any *meter* within the *metering installation* unless otherwise permitted by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter.

8.1.5 Each *metered market participant* shall ensure that the persons entitled to have either direct or remote access to *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* are limited to the following:

8.1.5.1 a *market participant* whose *settlement statement* relates to *energy* flowing through that *metering installation* and an authorized agent of such *market participant*;

8.1.5.2 a *metering service provider* that provides services in respect of the *metering installation* under the terms of an agreement with the *metered market participant,* to the extent necessary to permit work authorized under the agreement or otherwise by the *metered market participant*;

8.1.5.3 the *transmitter* or *distributor* to whose system the *facility* in respect of the *metering installation* is connected;

8.1.5.4 an authorized agent of the *metered market participant*; and

8.1.5.5 the *IESO*.

8.1.6 Each *metered market participant* shall ensure that electronic access to *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* shall only be provided where passwords in accordance with section 9.2 have been allocated. Otherwise, access to *metering data* shall be allowed only from the *metering database* and only by the *metered market participant* and the persons described in sections 8.1.5.1 to 8.1.5.5.

8.1.7 The *IESO* shall notify the *metered market participant* in respect of a *metering installation* of the time period within which it intends to initiate routine access to *metering data* recorded in that *metering installation*. The *metered market participant* shall ensure that no person other than the *IESO* accesses such *metering data* at a time or in a manner that may adversely affect the ability of the *IESO* to access the *metering data* during such time period.

8.1.8 The *IESO* may initiate access to *metering data* recorded in a *metering installation* at a time other than the time referred to in section 8.1.7 where such access is necessary for the performance by the *IESO* of its responsibilities under these *market rules,* and shall make reasonable efforts to notify the *metered market participant* or the *metering service provider* for such *metering installation* of its intention to initiate such access.

9. Security of Metering Installations and Data

9.1 Security of Metering Equipment

9.1.1 Each *metered market participant* shall ensure that:

9.1.1.1 each *metering installation* in respect of which it is the *metered market participant* is secure from access by persons other than the *IESO*, the person that acts as *metering service provider* in respect of such *metering installation* and, for the purpose of section 4.1A.1, the *metered market participant*;

9.1.1.2 all associated links, circuits and information storage and processing systems are secured by means of seals or other devices approved by the *IESO;*

9.1.1.3 the *meter* box is physically secure, locked and sealed by means of devices approved by the *IESO* so as to enable detection of access by persons other than the *IESO*, the person that acts as *metering service provider* in respect of such *metering installation* and, for the purposes of section 4.1A.1, the *metered market participant;*

9.1.1.4 the data connections to the *meter's* communication ports are secure from access by persons other than persons authorized by it to have access to such data connections; and

9.1.1.5 the *metering installation* meets all of the requirements pertaining to the security of *metering installations* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

9.1.2 Subject to any limitations prescribed by *federal metering requirements*, the *IESO* may override any of the security devices fitted to a *metering installation* without prior notice to the *metered market participant* or the *metering service provider* for such *metering installation.*

9.1.3 The *IESO* may audit the security measures applied to each registered *metering installation* from time to time as determined appropriate by the *IESO.*

9.2 Security Controls

9.2.1 Each *metered market participant* shall ensure that the *metering data* recorded in each *metering installation* in respect of which it is the *metered market participant* is:

9.2.1.1 protected from direct local or remote electronic access, including during the transfer of such *metering data* to the communication interface of the *metering database,* by persons other than itself and those persons described in sections 8.1.5.1 to 8.1.5.5, by ensuring that its *metering service provider* implements suitable password and other security controls in accordance with the requirements of this section 9.2; and

9.2.1.2 during delivery of the *metering data* to the *IESO* other than by electronic means, protected from access by persons other than itself and those persons described in sections 8.1.5.1 to 8.1.5.5 regardless of the medium, including but not limited to diskette, magnetic tape, electronic cartridge and paper, on or in which such *metering data* is transcribed, transferred or stored for purposes of such delivery.

9.2.2 Each *metering service provider* shall, except as otherwise permitted by this section 9.2, keep all records of passwords for electronic access to *metering data* confidential.

9.2.3 Subject to section 9.2.4, each *metering service provider* shall provide, in respect of each *metering installation* in respect of which it is the *metering service provider*, 'read-only' passwords to the *IESO,* to the *metered market participant* for the *metering installation*, to any *market participant* whose *settlement statement* is determined on the basis of the *metering installation's meter point*, and to any relevant *transmitter* or *distributor,* as the case may be depending upon the owner of the *facilities* to which the *facility* to which the *metering installation* relates is connected. Each *metering service provider* shall provide the *IESO* with a password allowing 'read plus synchronize time' access to the *meter* in each *metering installation* for which it is the *metering service provider*.

9.2.4 Where separate 'read-only' and 'read plus synchronize time' passwords are not available, the *metering service provider* shall provide the password for each *metering installation* only to the *IESO*.

9.2.5 Each *metering service provider* shall hold 'read-only', 'read plus synchronize time' and 'read plus write' passwords for each *metering installation* for which it is the *metering service provider*, where available, and shall forward a copy of such passwords to the *IESO*.

9.2.6 A *metering service provider* may, and at the request of the *IESO* shall, change one or more of the passwords relating to a *metering installation* in respect of which it is the *metering service provider* and shall provide the changed password to any person to whom the previous password was provided in accordance with section 9.2.3.

9.2.7 The *IESO* may reveal the passwords referred to in sections 9.2.3, 9.2.5 and 9.2.6 to a *metering service provider* that has assumed responsibility as a *metering service provider* for a *metering installation* in the event that the passwords cannot be obtained on a timely basis by that *metering service provider* by any other means.

9.3 Changes to Metering Equipment, Parameters and Settings

9.3.1 Each *metered market participant* shall ensure that changes to equipment, parameters or settings within a *metering installation* in respect of which it is the *metered market participant* that may affect the collection, security or accuracy of any *metering data* recorded in that *metering installation* shall be:

9.3.1.1 authorised by the *IESO* prior to the change being made;

9.3.1.2 implemented by a *metering service provider* who shall obtain an end reading, ensure that the *metering data* recorded in the *metering installation* is transferred to the *metering database* prior to the change and obtain a start reading once the change has been completed; and

9.3.1.3 confirmed to the *IESO* within 1 *business day* after the change has been made.

9.3.2 Each *metered market participant* shall ensure that the *IESO* is provided with alternative *metering data* acceptable to the *IESO* while changes to equipment, parameters or settings within a *metering installation* in respect of which it is the *metered market participant* are being made.

9.3.2A An adjustment required to be made to a *metering installation* to enable it to generate *metering data* that reads zero while the *generation resource* associated with the *facility* to which such *metering installation* relates is operating in a *segregated mode of operation* shall:

9.3.2A.1 be deemed not to be a change to equipment, parameters or settings for the purposes of sections 9.3.1 and 9.3.2 and of section 1.3.2.22 of Appendix 6.1; and

9.3.2A.2 shall be effected while at all times maintaining the security of the *metering installation* in accordance with the requirements pertaining to the security of *metering installations* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

9.3.3 The *IESO* shall, upon request by a *metered market participant* or a *metering service provider*, review conceptual drawings for any change to equipment, parameters or settings within a *metering installation* proposed to be made by the *metering market participant* or the *metering service provider.*

9.4 Changes to Metering Data

9.4.1 Each *metered market participant* shall ensure that no alterations to the original *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* are effected. Each *metered market participant* shall ensure that no on-site testing of a *metering installation* in respect of which it is the *metered market participant* that might cause the *meter* to register false data is performed until such time as the *metering data* has been transferred to the *metering database*.

10. Processing of Metering Data for Settlement Purposes

10.1 Metering Database

10.1.1 The *IESO* shall establish and maintain a *metering database* containing *metering data* transferred from each *metering installation* registered with the *IESO* and each *metering installation* whose registration has expired but whose continued use has been determined by the *IESO* to be necessary for the efficient operation of the *IESO-administered markets.*

10.1.2 The *IESO* may use the databases of meter data management agencies to form part of the *metering database.*

10.1.3 The *metering data* recorded in the *metering database* in respect of a registered *metering installation* shall be accessible by electronic means by:

10.1.3.1 the *metered market participant* for that *metering installation* and an authorized agent of such *metered market participant*;

10.1.3.2 the *metering service provider* for that *metering installation*;

10.1.3.3 any *market participant* whose *settlement statement* is determined on the basis of the *metering data* recorded in that *metering installation* and an authorized agent of such *market participant;* and

10.1.3.4 any *transmitter* or *distributor* to whose system a *facility* in respect of which the *metering installation* relates is connected.

10.1.4 *Metering data* recorded in the *metering database* is *confidential information* and the *IESO* shall ensure that such *metering data* is not accessible by or disclosed by the *IESO* to any person other than the *IESO* and the persons referred to in sections 10.1.3.1 to 10.1.3.4, or as otherwise permitted by MR Ch.3 s.5 or any policy of the *IESO* established pursuant to that section.

10.1.5 The *metering database* shall include:

10.1.5.1 original *energy* readings, substitutions, estimations and calculated values;

10.1.5.2 *energy* readings, both loss adjusted and totalized, to their respective *delivery points* for the purposes of the *IESO-administered markets*; and

10.1.5.3 *energy* readings, both loss adjusted and totalized, to their respective *delivery points* defined for the purposes of *transmission services charges* as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

10.2 Remote Acquisition of Data

10.2.1 The *IESO* shall initiate the remote acquisition of *metering data* recorded in a *metering installation* and shall store the *metering data* so acquired in the *metering database* for *settlement* purposes.

10.2.2 If remote acquisition from a *metering installation* becomes unavailable, the *IESO* shall arrange, in consultation with the *metered market participant* or the *metering service provider* for that *metering installation*, an alternative means of transferring the relevant *metering data* from the *metering installation* to the communication interface of the *metering database* or to the *metering database,* as the case may be.

10.3 Periodic Energy Metering

10.3.1 *Metering data* relating to the amount of active *energy* and, where relevant, reactive *energy* passing through a *metering installation* shall be collated by *dispatch intervals*.

10.4 Errors Relating to Metering Installations and Metering Data

10.4.1 If a test, review, inspection or audit, carried out in accordance with section 7, of a *metering installation* or of *metering data* demonstrates errors in excess of those prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter and the *IESO* is not aware of the time at which that error arose, the error shall be deemed to have occurred at a time which is half way between (i) the time of the most recent test, review, inspection or audit which demonstrated that the *metering installation* complied with the relevant measurement standard and (ii) the time when the error was detected.

10.4.2 If a *metered market participant* becomes aware of an error in excess of those prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, the *metered market participant* shall provide notice to the *IESO* of such error within two *business days* of becoming aware of such error and such notice shall include a general description of the error.

10.4.3 As soon as reasonably practicable after either receiving a notice from a *metered market participant* in accordance with section 10.4.2, or after the *IESO* otherwise becomes aware of an error in excess of those prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, the *IESO* shall determine the scope of the issue and the necessary corrections, if any. The *IESO* shall use the information provided in and with a notice issued by the *metered market participant* in accordance with section 10.4.2 and any other information available to the *IESO,* including conducting an audit of the relevant *metering installations* in accordance with section 7, to determine the scope of the issue and the necessary corrections, if any.

10.4.4 Following the *IESO's* determination pursuant to section 10.4.3, the *IESO* shall inform the *metered market participant* of the *IESO's* determination, provide the *metered market participant* the opportunity to respond within ten *business days*, and, after considering any such response, take one of the following actions:

10.4.4.1 if the *IESO* concludes that no error has occurred or such error is within acceptable parameters prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, it shall take no further action; or

10.4.4.2 subject to section 10.4.7, if the *IESO* concludes that an error has occurred outside of the acceptable parameters prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, it shall:

(a) make appropriate corrections to *metering data* contained in the *metering database* to effect a correction for that error in respect of the period since the error occurred or was deemed to have occurred in accordance with section 10.4.1; and

(b) if the *IESO* concludes that an adjustment or correction is required to a *final settlement statement* or a *recalculated settlement statement,* shall make the adjustment on one or more of the next scheduled *recalculated settlement statements.*

10.4.5 If the *IESO* does not make a determination pursuant to section 10.4.3 before the date for issuing a *settlement statement,* the *IESO* shall issue such *settlement statement* without taking into account the error.

10.4.6 Any changes required to be made to a *final settlement statement* or *recalculated settlement statement* as a result of the process described in this section 10.4 shall be included as a debit or credit in the *recalculated settlement statements* issued for each affected *metered market participant* as an *adjustment period allocation*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *metered market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

10.4.7 Commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date*, the *IESO* shall not make any correction under section 10.4.4.2 in regards to any *settlement amounts* which were invoiced, or should have been invoiced, more than 23 months before the day on which the *IESO* issues the *settlement statement* referred to in section 10.4.4.2. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, the *IESO* shall not make any correction under section 10.4.4.2 in regards to any *settlement amount* beyond the limitation period, if any, provided pursuant to *applicable law*. Additionally, where a *metering service provider* fails to conduct a review, test, or audit, in accordance with section 1.3.2.3 of Appendix 6.1, section 1.4.3 of Appendix 6.3, or section 1.5.3 of Appendix 6.3, as the case may be, the *IESO* shall not take any action under section 10.4.4.2 in regards to any *settlement amount* pertaining to the *metering installation* and/or *meter point* documentation which was not tested, reviewed, or audited that arose prior to the date on which the *metering service provider* failed to conduct the applicable test, review or audit.

10.4.8 If a *metered market participant* disagrees with the *IESO*'s determination and action taken in accordance with section 10.4.4 or the *IESO* has not made its determination prior to earlier of either the date referred to in section 10.4.7 or twelve months after the date of the notice referred to in section 10.4.2, the *metered market participant* may pursue their disagreement through the dispute resolution process outlined in MR Ch.3 s.2.

11. Performance of Metering Installation

11.1.1 Each *metering service provider* shall ensure that *metering data* from each *metering installation* in respect of which it acts as a *metering service provider* is made available to the *IESO* for each *dispatch interval,* in accordance with the requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter and in accordance with the following:

11.1.1.1 95 percent or more of the *metering data* shall be available to the *IESO* on the first *business day* following the day on which the *dispatch interval* occurs; and

11.1.1.2 95 percent of the attempts by the *IESO* to initiate access to the *metering data* must be successful on the first attempt.

11.1.2 Where either a *metered market participant* or a *metering service provider* becomes aware that a *metering installation* in respect of which it is the *metered market participant* or the *metering service provider* has gone out of service, is defective or malfunctions, it shall notify the *IESO* of the *outage,* defect or malfunction within 1 *business day* of becoming aware of same. In addition, the *metered market participant* shall:

11.1.2.1 where the *outage,* defect or malfunction relates to any portion of the *metering installation* other than an *instrument transformer*, ensure that the *metering installation* or the defective portion thereof is replaced or repairs are made to the *metering installation* as soon as practicable and in any event within 2 *business days* of the date of the notice referred to in section 11.1.2 or within such longer period of time as may be agreed by the *IESO;* and

11.1.2.2 where the *outage,* defect or malfunction relates to an *instrument transformer*:

a. ensure that the *instrument transformer* is replaced as soon as practicable and in any event within 12 weeks of the date of the notice referred to in section 11.1.2 or within such longer period of time as may be agreed by the *IESO*; and

b. subject to section 4.6, ensure that the emergency restoration plan referred to in section 1.3.2.17 of Appendix 6.5 is implemented within 2 *business days* of the date of the notice referred to in section 11.1.2 and remains in effect until such time as the *instrument transformer* has been replaced.

11.1.3 Where the *IESO* becomes aware, other than by means of the notice referred to in section 11.1.2, that a *metering installation* has gone out of service, is defective or malfunctions, the *IESO* shall:

11.1.3.1 promptly notify the *metered market participant* for that *metering installation* of the *outage*, defect or malfunction and issue a trouble call to the *metering service provider* for that *metering installation*;

11.1.3.2 where the *outage,* defect or malfunction relates to any portion of the *metering installation* other than an *instrument transformer*, direct the *metered market participant* to ensure that the *metering installation* or the defective portion thereof is replaced or that repairs are made to the *metering installation* as soon as practicable and in any event within 2 *business days* of the date of the notice referred to in section 11.1.3.1 or within such longer period of time as may be specified by the *IESO*; and

11.1.3.3 where the *outage,* defect or malfunction relates to an *instrument transformer*, direct the *metered market participant* to:

a. ensure that the *instrument transformer* is replaced as soon as practicable and in any event within 12 weeks of the date of the notice referred to in section 11.1.3.1 or within such longer period of time as may be specified by the *IESO*; and

b. ensure that the emergency restoration plan referred to in section 1.3.2.17 of Appendix 6.5 is implemented within 2 *business days* of the date of the notice referred to in section 11.1.3.1 and remains in effect until the *instrument transformer* has been replaced.

11.1.4 Where an *outage* or malfunction of or the defect in a *metering installation* is not rectified in accordance with and within the time period specified in section 11.1.2.1, 11.1.2.2, 11.1.3.2 or 11.1.3.3 and is, in the *IESO's* opinion, likely to have a significant impact on one or more *market participants* other than the *metered market participant* for that *metering installation*, the *IESO* shall so notify the *metered market participant* for that *metering installation*. Within one *business day* of receipt of such notice, the *metered market participant* shall notify the *IESO* as to the:

11.1.4.1 [Intentionally left blank]

11.1.4.2 [Intentionally left blank]

11.1.4.3 corrective action taken or arranged by the *metered market participant* to rectify the *outage* or malfunction of or the defect in the *metering installation*.

The *IESO* shall estimate the *metering data* for *settlement* purposes in accordance with section 11.1.4A from the date referred to in section 11.1.5 until the date on which the *outage* or malfunction of or defect in the *metering installation* is rectified.

11.1.4A For the purposes of sections 11.1.4.3 and 11.1.4B.2, estimation of *metering data* shall be based on the following:

11.1.4A.1 in the case of a *metering installation* for a *generationresource*, production shall be estimated at zero;

11.1.4A.2 in the case of a *metering installation* for a*load resource*, withdrawal for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that *load resource* during the twelve-month period preceding the date of the notice referred to in section 11.1.2 or 11.1.3.1, as the case may be; or

11.1.4A.3 in the case of a *metering installation* for an *electricity storageresource*, the injections shall be estimated at zero and the withdraws for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that *electricity storage resource* during the twelve-month period preceding the date of the notice referred to in section 11.1.2 or 11.1.3.1 as the case may be.

11.1.4B Where a *metered market participant* fails to notify the *IESO* pursuant to section 11.1.4 as to the action that it wishes to take or to have taken, the *IESO* shall:

11.1.4B.1 [Intentionally left blank]

11.1.4B.2 estimate the *metering data* for *settlement* purposes in accordance with section 11.1.4A from the second *business day* after the date on which notice was given to the *metered market participant* pursuant to section 11.1.4 until the date on which the *outage* or malfunction of or defect in the *metering installation* is rectified.

11.1.5 The *IESO* shall not commence to estimate *metering data* pursuant to section 11.1.4.3:

11.1.5.1 where the *outage*, defect or malfunction relates to any portion of the *metering installation* other than an *instrument transformer*, until 3 *business days* have elapsed from the date on which the notice was given to the *metered market participant* pursuant to section 11.1.4; and

11.1.5.2 where the *outage*, defect or malfunction relates to an *instrument transformer* and the emergency restoration plan referred to in section 1.3.2.17 of Appendix 6.5:

a. has been implemented within the time required by section 11.1.2.2(b) or 11.1.3.3(b), as the case may be, until the expiry of the period referred to in section 11.1.2.2(a) or 11.1.3.3(a), as the case may be; or

b. has not been implemented within the time required by section 11.1.2.2(b) or 11.1.3.3(b), until 3 *business days* have elapsed from the date on which the notice was given to the *metered market participant* pursuant to section 11.1.4, provided that where such emergency restoration plan is thereafter implemented, the *IESO* shall cease the estimation of *metering data* until the expiry of the period referred to in section 11.1.2.2(a) or 11.1.3.3(a), as the case may be.

11.1.6 Where the *IESO* becomes aware that *metering data* reads other than zero in respect of a time during which the *generation resource* associated with the *facility* to which such *metering installation* relates was operating in a *segregated mode of operation,* the *IESO* shall for *settlement* purposes deem such *metering data* to have read zero during such time.

11.2 Meter Time

11.2.1 Each *metering installation* and the *metering database* shall be referenced to eastern standard time in the Province of Ontario.

11.2.2 The *IESO* shall synchronize each *meter* clock to within ±5 seconds of eastern standard time in the Province of Ontario, or to such greater standard of accuracy as can be reasonably achieved by the *IESO*, at the time of commissioning of a *metering installation* and thereafter whenever it reads a *meter.*

12. Evolving Technologies and Processes and Development of the Market

12.1.1 Subject to any restrictions imposed by *federal metering requirements*, a *metered market participant* may use or permit the use of evolving technologies or processes that:

12.1.1.1 meet or exceed the performance and functional requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter; or

12.1.1.2 facilitate the efficient development of the *IESO-administered markets*,

if agreed between the *metered market participant*, the relevant *transmitter* or *distributor,* as the case may be depending on the owner of the *facilities* to which the *facility* in respect of the relevant *metering* installation is connected, and the *IESO*.

13. Responsibilities of the IESO

13.1.1 The *IESO* shall:

13.1.1.1 establish and administer a process for the registration of *metering service providers*;

13.1.1.2 maintain and operate facilities necessary for *settlement* in accordance with this Chapter and MR Ch.9;

13.1.1.3 provide a communication interface for the *metering database* and ensure that *metering data* is transferred from such communication interface to the *metering database* and stored in the *metering database* in a reliable, secure and accurate manner;

13.1.1.4 ensure that *metering data* is stored in the *metering database* for 13 months in accessible format and for an additional 6 years in archive;

13.1.1.5 establish *metering*-related policies and standards including, but not limited to, policies or standards for *metering installations*; site specific loss adjustments; transfers of *metering data* to the *metering database*; *metering data* security requirements; and the inspection, testing and audit of *metering installations*; the security of *metering installations* and measurement error correction;

13.1.1.6 audit *metering installations* in accordance with this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter;

13.1.1.7 where necessary, issue trouble calls to *metering service providers, metered market participants* or both and monitor the status of each trouble call, the response time and the resolution of the trouble call;

13.1.1.8 monitor the performance of *metering service providers* against the performance standards set forth in the applicable *market manual*;

13.1.1.9 establish such *metering*-related familiarization and competency updating or upgrading programs for *metering service providers* and *metered market participants* as the *IESO* determines appropriate;

13.1.1.10 initiate and perform any end-to-end testing required prior to registration of a *metering installation*;

13.1.1.11 periodically monitor the registration status of each *metering service provider* and of each *metering installation;*

13.1.1.12 carry out the *metering data* summation process; and

13.1.1.13 prevent access to information recorded in the *metering database* or the *metering registry* in respect of each *metering installation* by any person other than the persons entitled to such access in respect of a given *metering installation* pursuant to section 6.2.3 or 10.1.3, respectively.

RUL-16

Renewed Market Rules

Chapter 0.6

Wholesale Metering - Appendices

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Table of Contents

Appendix 6.1 – Metering Obligations

1.1 Introduction

1.1.1 This Appendix sets forth certain obligations of *metered market participants* and *metering service providers* in respect of *metering*.

1.2 Obligations of Metered Market Participants

1.2.1 Each *metered market participant* shall:

1.2.1.1 ensure that its contracts relating to each *metering installation* in respect of which it is the *metered market participant* contain such terms and conditions related to the *metering installation* as may be required for compliance with the *market rules*;

1.2.1.2 ensure that every *meter* and *instrument transformer* used in a *metering installation* in respect of which it is the *metered market participant* that may be used for *settlement* purposes has been approved for use by Measurement Canada and has been obtained from a manufacturer that:

a. has obtained approval of type from Measurement Canada, which approval shall, in the case of a *meter*, be evidenced by the time-limited seal placed on the *meter* by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada); and

b. agrees to provide, upon request, the approval number to the *metered market participant's metering service provider* and to the *IESO*;

1.2.1.3 ensure that each *meter* forming part of a *metering installation* in respect of which it is the *metered market participant* that may be used for *settlement* purposes has been shop tested, verified and/or re-verified for accuracy in accordance with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter sealed and/or re-sealed in accordance with all applicable *federal metering requirements* by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada);

1.2.1.4 ensure that sealed *meters* are provided to its *metering service provider* by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) in accordance with the schedule agreed between the *metered market participant* and such person;

1.2.1.5 ensure that records required by *federal metering requirements* or requested by its *metering service provider* are provided to its *metering service provider* by any accredited meter verifier providing any of the services referred to in sections 1.2.1.2 to 1.2.1.4 in respect of the *metering installation*;

1.2.1.6 ensure that any person that provides any of the services referred to in sections 1.2.1.2 to 1.2.1.5 agrees to:

a. provide it with copies of any test results or certificates within 30 days of being requested to do so; and

b. carry out any additional testing required for the resolution of a *metering*-related disputes within 30 days of being requested to do so; and

1.2.1.7 ensure that, an adjustment is made to a *metering installation* to enable it to generate *metering data* that reads zero while the *generation resource(s)* associated with the *facility* to which such *metering installation* relates is operating in a *segregated mode of operation.*

1.3 Metering Service Providers

1.3.1 The following activities shall be performed by *metering service providers* in accordance with the requirements of this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter*:*

1.3.1.1 the provision, installation, commissioning, maintenance, repair, replacement, inspection and testing of *metering installations*;

1.3.1.2 the registration of *metering installations* with the *IESO* and the preparation of all *meter point* documentation and other documentation, other than the written confirmation referred to in section 1.3A.1 of Appendix 6.5, required to be submitted in support of the application for registration; and

1.3.1.3 the resolution of trouble calls relating to *metering installations* and *metering data* in accordance with sections 1.3.2.14 and 1.3.2.15 of this Appendix.

1.3.2 Each *metering service provider* shall, in respect of each *metering installation* in respect of which it is the *metering service provider*:

1.3.2.1 conduct routine testing and maintenance of the *metering installation* in accordance with Appendix 6.3;

1.3.2.2 prepare the *meter point* documentation referred to in Appendix 6.5 in accordance with that Appendix, ensure that such *meter point* documentation and all other documentation referred to in section 1.3.1.2 of this Appendix is maintained up to date and provide the *IESO* with any updates to such *meter point* documentation and other documentation, and make such *meter point* documentation available to the *metered market participant* for the *metering installation* upon request;

1.3.2.3 conduct an annual review of all documentation pertaining to the *metering installation* and *meter point* documentation provided to the *IESO* in accordance with Appendix 6.5 and within two *business days* of becoming aware of an error, notify the *IESO* of such errors pertaining to the *metering installation* or within such *meter point* documentation;

1.3.2.4 provide technical assistance at the site of the *metering installation* with respect to access to *metering data* by persons authorized by this Chapter to have such access;

1.3.2.5 provide such support for investigations, audits, tests and the resolution of disputes relating to the *metering installation*, including the provision of complete and accurate documentation, as may be requested by the *IESO*;

1.3.2.6 replace equipment sealed by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) before the expiry of the seal period;

1.3.2.7 ensure, by means of the placement of sufficient seals on test links, fuses and the *meter* box or otherwise in accordance with any policy or standard established by the *IESO* pursuant to this Chapter, that access to the *metering installation* by a person not authorized by this Chapter to have such access can be detected;

1.3.2.8 advise the *IESO* of any error messages or equipment failures detected and repair or replace any failed equipment in accordance with section 11 of this Chapter;

1.3.2.9 provide *meter* readings to the *IESO* as may be required under this Chapter, under any policy or standard established by the *IESO* pursuant to this Chapter or as may be requested by the *IESO*;

1.3.2.10 maintain such records of all inspections, tests, audits and activities that may affect the collection, security or accuracy of *metering data* contained in, and of any changes made to, the *metering installation* and provide such records to the *IESO* as may be requested by the *IESO* or required pursuant to this Chapter or any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.11 maintain all records required to be maintained by owners of *metering installation* pursuant to *federal metering requirements,* whether or not the *metering service provider* is the owner of the *metering installation*;

1.3.2.12 assist with end-to-end testing of the *metering installation* as may be required under this Chapter or any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.13 submit to the *IESO* the information required by this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter to be submitted for storage in the *metering registry* or the *metering database* using the software designated by the *IESO,* and in such data format as may be approved by the *IESO,* for such purpose;

1.3.2.14 establish, maintain and operate a trouble call service and acknowledge receipt of each trouble call issued by the *IESO* by 3:00 pm on the next *business day* following the date of issuance of the trouble call;

1.3.2.15 promptly respond to all trouble calls issued by the *IESO*;

1.3.2.16 attend to the repair or replacement of a *metering installation* within the time prescribed in section 11 of this Chapter;

1.3.2.17 maintain and implement effective procedures to ensure that *metering data* is not compromised during the maintenance, repair, replacement, inspection or testing of the *metering installation* or during the retrieval or storage of *metering data* or the transfer of the *metering data* to the communication interface with the *metering database*;

1.3.2.18 ensure that information submitted to the *IESO* in support of a request for an adjustment to *metering data* is correct, accurate and auditable;

1.3.2.19 ensure that all portable testing equipment is fit for its intended purpose and calibrated with devices traceable to federal measurement standards so as to create an audit trail for calibration;

1.3.2.20 establish procedures for the transfer of *metering data* to the *metering database* when the *metering data* cannot be made available to the *IESO* by means of remote access;

1.3.2.21 maintain spare stock sufficient to repair or replace failed *metering installations* within the time limits specified in section 11 of this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.22 obtain the prior approval of the *IESO* prior to carrying out procedures or effecting any changes to the equipment, parameters or settings of a *metering installation* that may affect the collection, security or accuracy of any *metering data* stored in the *metering installation*;

1.3.2.23 ensure that each *metering installation* is sealed with uniquely numbered seals and maintain a register of such numbers;

1.3.2.24 implement appropriate recovery processes to enable the recovery of any lost or destroyed records that are required to be kept pursuant to this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.25 attend any post-registration familiarization and competency updating or upgrading sessions as may be required by the *IESO*;

1.3.2.26 handle *meters* in accordance with the requirements of the accredited meter verifier, within the meaning of the *Electricity and Gas Inspection Act* (Canada), that sealed the *meters;* and

1.3.2.27 ensure that the *metering installation* is suitable for the range of operating conditions to which it will be exposed and that all equipment within the *metering installation* operates within the limits established for such equipment in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

1.3.3 Each *metering service provider* shall ensure that all members of its personnel that may be entering or may have cause to enter a *facility* owned by a person other than the *metering service provider* for the performance of the *metering service provider's* obligations pursuant to:

1.3.3.1 this Chapter 6;

1.3.3.2 any policy or standard established by the *IESO* pursuant to this Chapter 6; or

1.3.3.3 the agreement referred to in MR Ch.6 s. 5.1.3.2,

are familiar with and adhere to the safety requirements and practices of the owner of such *facility*.

Appendix 6.2 – Alternative Metering Installation Standards

1.1 Introduction

1.1.1 This appendix applies to *metering installations*:

- in service on April 17, 2000; or
- that are the subject of an application for registration filed prior to the *market commencement date* and in respect of which the major components were ordered or procured on or before May 17, 2000.

1.1.2 This Appendix sets forth:

1.1.2.1 the alternative standards and accompanying conditions that must be met in respect of a *metering installation* registered under MR Ch.6 s.4.4.3;

1.1.2.2 the information that must be submitted by a *metering service provider* in support of an application referred to in MR Ch.6 s.4.4.2;

1.1.2.3 the circumstances in which the *IESO* may revoke the registration granted pursuant to MR Ch.6 s.4.4.3; and

1.1.2.4 the time at which registration granted by the *IESO* under MR Ch.6 s.4.4.3 expires. Where the time at which registration expires is specified to be the earliest expiry date of the seal period of any *meter* within the *metering installation*, that date shall be the earliest expiry date of the seal period of any *meter* within the *metering installation* as of the *market commencement date*.

1.1A Metering Installation Not Comprised of Two Meters

1.1A.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the dual *meter* requirement referred to in MR Ch.6 s.4.1.1.2shall meet the following conditions:

1.1A.1.1 the *meter* within the *metering installation* is one in respect of which Measurement Canada has granted approval of type;

1.1A.1.2 a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) has verified and sealed the *meter* within the *metering installation*;

1.1A.1.3 the seal period for the *meter*, including the seal period for the *data logger* if sealed separately from the remainder of the *meter*, within the *metering installation* has not expired;

1.1A.1.4 the *metering installation* shall be capable of collating *metering data* into *dispatch intervals*; and

1.1A.1.5 [Intentionally left blank – section deleted]

1.1A.1.6 the *meter* contained in the *metering installation* shall be capable of time synchronization by the *IESO* to eastern standard time.

1.1A.2 Registration of a *metering installation* that meets the conditions set out in section 1.1A.1 shall expire on the earliest expiry date of the seal period of the *meter* within the *metering installation*, including the expiry date of the seal period of the *data logger* if sealed separately from the remainder of the *meter.* Registration of a *metering installation* shall not expire in instances where there are multiple *metering installations* served by a single *data logger* whose seal expires.

1.2 Compliance with Blondel's Theorem

1.2.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with Blondel's theorem shall:

1.2.1.1 comply with rulings issued by Measurement Canada on two and one-half element *metering*; and

1.2.1.2 have a magnitude of maximum error satisfactory to the *IESO*.

1.2.2 The *metering service provider* shall provide to the *IESO* the magnitude of maximum error for both active power and reactive power for a *metering installation* that does not comply with Blondel's theorem.

1.2.3 Where the magnitude of maximum error referred to in section 1.2.2 is less than or equal to 0.2%, no correction factor shall be applicable.

1.2.4 Where the magnitude of maximum error referred to in section 1.2.2 exceeds 0.2%, the *IESO* shall apply to the *metering data* a fixed correction factor based on the actual maximum error figure submitted by the *metering service provider*, subject to the following:

1.2.4.1 *energy flows* in respect of injections shall not be increased; and

1.2.4.2 *energy flows* in respect of withdrawals shall not be decreased.

1.2.5 Where the magnitude of maximum error referred to in section 1.2.2 exceeds 3.0%, registration relating thereto shall expire.

1.3 [Intentionally left blank – section deleted]

1.4 Accuracy

1.4.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the accuracy requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.4.1.1 the *meters* within the *metering installation* are ones in respect of which Measurement Canada has granted approval of type;

1.4.1.2 a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) has verified and sealed the *meters* within the *metering installation*; and

1.4.1.3 the seal period for the *meters* within the *metering installation* have not expired.

1.4.2 Registration of a *metering installation* that meets the conditions set out in section 1.4.1 shall expire on the earliest expiry date of the seal period of any *meter* within the *metering installation*.

1.5 Functional Requirements

1.5.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the functional requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.5.1.1 the *meters* within the *metering installation* are ones in respect of which Measurement Canada has granted approval of type;

1.5.1.2 a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) has verified and sealed the *meters* within the *metering installation*;

1.5.1.3 the seal periods for the *meters* within the *metering installation* have not expired;

1.5.1.4 the *metering installation* shall be capable of collating *metering data* into *dispatch intervals*; and

1.5.1.5 [Intentionally left blank – section deleted]

1.5.1.6 the *meters* contained in the *metering installation* shall be capable of time synchronization by the *IESO* to eastern standard time.

1.5.2 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that met conditions set out in section 1.5.1 if the *metering installation* fails to comply with the requirements of any of sections 1.5.1.4 to 1.5.1.6, in which case the *metered market participant* shall ensure that the *meters* within the *metering installation* are replaced with *meters* that comply with the functional requirements set forth in this Chapter 6 and in any policy or standard established by the *IESO* pursuant to this Chapter 6 within 2 *business days* of the date of notice of such revocation.

1.5.3 Registration of a *metering installation* that meets the conditions set out in section 1.5.1 shall expire on the earliest expiry date of the seal period of any *meter* within the *metering installation*.

1.6 Instrument Transformers – Power Switching

1.6.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the power system switching requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.6.1.1 all switching devices that may affect the accuracy of any *metering data* recorded in the *metering installation* shall be identified to the *IESO*;

1.6.1.2 an alternate source of *metering data* is provided;

1.6.1.3 correction factors have been provided to and approved by the *IESO* in accordance with this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter; and

1.6.1.4 loss adjustment factors have been provided to and approved by the *IESO* in accordance with this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter.

1.6.2 *Metering data* from a *metering installation* in respect of which registration has been granted under MR Ch.6 s.4.4.3 that met the conditions set out in section 1.6.1 shall be the subject of adjustment by the correction and loss adjustment factors referred to in sections 1.6.1.3 and 1.6.1.4 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.6.3 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that met the conditions set out in section 1.6.1 if the conditions set forth in any one of sections 1.6.1.1 to 1.6.1.4 are not met or if the *metered market participant* fails to:

1.6.3.1 notify the *IESO*, in the manner set forth in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter, of the duration of any power switching operation relating to the *metering installation* no later than 24 hours after the operation has taken place; or

1.6.3.2 install additional or corrected *metering installations* in circumstances where power switching operations affect the *metering data* in the existing *metering installation* more than twice in any twelve-month period,

in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the power switching requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.6.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.6.1 shall expire on the date that the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.7 Instrument Transformers – Accuracy Requirements

1.7.1 Subject to section 1.7.1A, each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the 0.3% accuracy requirements of ANSI standard C57.13, as evidenced by factory test cards complete with serial numbers, for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.7.1.1 the *instrument transformer* shall be of a type approved for use by Measurement Canada;

1.7.1.2 the *instrument transformer* shall:

a. [Intentionally left blank]

b. be tested on-site for accuracy in the manner described in, and meet the accuracy test point requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter with correction factors approved by the *IESO* in the manner described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter; or

c. be demonstrated, to the satisfaction of the *IESO,* by means of the provision to the *IESO* of copies of the manufacturer's records, to be identical to an *instrument transformer* that has been tested on-site for accuracy, provided that installation or other documents have been provided to the *IESO* demonstrating that the applied burden for the *instrument transformer* is either identical to that of the tested *instrument transformer* or within the correction factors applied to that *instrument transformer*; and

1.7.1.3 the *instrument transformer* complies with the security requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

1.7.1A Notwithstanding section 1.7.1.2, the *IESO* shall accept the following as proof of accuracy of *instrument transformers*:

1.7.1A.1 *instrument transformer* nameplate data, where the nameplate contains the required ANSI accuracy information and is affixed to the *instrument transformer*; and

1.7.1A.2 Measurement Canada-type approval information, where such approval contains the required ANSI accuracy information.

1.7.2 *Metering data* from a *metering installation* for which registration has been granted under MR Ch.6 s.4.4.3 that met the conditions set out in section 1.7.1 shall be the subject of adjustment by the correction factors referred to in section 1.7.1.2(b) in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.7.3 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that met the conditions set out in section 1.7.1 if the conditions set forth in any one of sections 1.7.1.1 to 1.7.1.3 are not met, in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the accuracy requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.7.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under MR Ch.6 s.4.4.8 the registration of a *metering installation* that met the conditions set out in section 1.7.1 shall expire on the date that the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.8 Instrument Transformers – Secondary Cabling

1.8.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the secondary cabling requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.8.1.1 each *meter* shall be connected to the *instrument transformer* in the manner described in the *meter point* documentation submitted in support of the application for registration of the *metering installation*;

1.8.1.2 fixtures, including but not limited to AC outlets and voltage test points, that may allow access to the *instrument transformer* secondaries by persons not authorized by this Chapter to have such access shall be removed, if possible, or disabled or made inaccessible by a sealed cover;

1.8.1.3 the secondary cabling otherwise complies with as many of the requirements described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter as is practicable and any requirements not so complied with have been identified to the *IESO*;

1.8.1.4 where the secondary cabling does not meet all of the requirements described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter, measurement error correction factors have been provided to and approved by the *IESO* in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter; and

1.8.1.5 where the error introduced by the secondary cabling exceeds 0.02%, correction factors have been provided to and approved by the *IESO.*

1.8.2 *Metering data* from a *metering installation* in respect of which registration has been granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.8.1 shall be the subject of adjustment by the correction factors referred to in sections 1.8.1.4 and 1.8.1.5 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.8.3 The *IESO* may, by notice to the *metered market participant* in respect of the *metering installation* to which the registration relates, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.8.1 if the conditions set forth in any one of sections 1.8.1.1 to 1.8.1.5 are not met, in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the secondary cabling requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.8.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under MR Ch.6 s.4.4.8 the registration of a *metering installation* that meets the conditions set out in section 1.8.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.9 Parallel Current Transformer Secondaries

1.9.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the prohibition on parallel current transformer secondaries set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.9.1.1 current transformers shall have the same nominal ratio and the same secondary ampere rating;

1.9.1.2 paralleled secondaries shall be connected to the same phase;

1.9.1.3 phasing shall be consistent on both primary and secondary circuits;

1.9.1.4 paralleling of secondaries shall be done at the test links directly connected to the *meter*;

1.9.1.5 each *meter point* shall have its own current test links;

1.9.1.6 paralleled secondaries shall be used to sum currents from no more than two *meter points*;

1.9.1.7 a common point shall exist at the primary voltage to which each of the measured flows is connected;

1.9.1.8 the primaries of the voltage transformers for the paralleled installation must be connected to the common point referred to in section 1.9.1.7;

1.9.1.9 the burden on any current transformer shall not exceed the rated burden;

1.9.1.10 the burden shall be kept as low as practicable and shall take into account the effects of common secondary leads and worst-case unbalance as described in section 1.9.1.11;

1.9.1.11 worst-case unbalance shall include operation of secondary fusing or single phase primary power;

1.9.1.12 the *meter* shall be rated at twice the secondary rating of one current transformer;

1.9.1.13 current transformers shall not operate below 10% of the secondary ampere rating under normal or expected operating conditions;

1.9.1.14 the primaries of the current transformers shall not be paralleled;

1.9.1.15 where a switching device exists between the primary connection point of the current transformers, the *IESO* shall be notified whenever the paralleled current transformers are operated with the switching device open;

1.9.1.16 the *metered market participant* shall identify the time, date and duration, and current and voltage readings for both *meter points* before, after, and at regular intervals during any period of disconnection; and

1.9.1.17 correction factors shall be provided to and approved by the *IESO* in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter.

1.9.2 *Metering data* from a *metering installation* in respect of which registration has been granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.9.1 shall be the subject of adjustment by the correction factors referred to in section 1.9.1.17 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.9.3 The *IESO* may, by notice to the *metered market participant* in respect of the *metering installation* to which the registration relates, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.9.1 if the conditions set forth in any one of sections 1.9.1.1 to 1.9.1.17 are not met, in which case the *metered market participant* shall ensure that each parallel current transformer secondary within the *metering installation* is removed within 8 weeks of the date of notice of such revocation.

1.9.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under MR Ch.6 s.4.4.8 the registration of a *metering installation* that meets the conditions set out in section 1.9.1 shall expire on the date on which work or upgrading that is, in the *IESO's* opinion, substantial is carried out at the *metering installation's meter point*.

1.10 Meter Installation Enclosures

1.10.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the enclosure requirements for *metering installations* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.10.1.1 the *metering installation* is, in the *IESO's* opinion, secure; and

1.10.1.2 the *metering installation* complies with as many of the enclosure requirements described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter as is practicable and any requirements not so complied with have been identified to the *IESO*.

1.10.2 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.10.1 if the conditions set forth in any one of sections 1.10.1.1 or 1.10.1.2 are not met, in which case the *metered market participant* shall ensure that each *metering installation* complies with the enclosure requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 2 *business days* of the date of notice of such revocation.

1.10.3 Registration of a *metering installation* that meets the conditions set out in section 1.10.1 shall expire on the earliest expiry date of the seal period of any *meter* within the *metering installation*.

1.11 Instrument Transformers – Primary Connection Point

1.11.1 Each *metering installation* for which registration is being sought under MR Ch.6 s.4.4.2 that does not comply with the primary connection point proximity requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.11.1.1 in the case of a *metering installation* relating to a *load facility,* or an *electricity storage facility*:

a. the *metering installation* shall minimize the voltage drop between the voltage transformer and the current transformer;

b. the *metering installation* shall minimize the leakage of current between the voltage transformer and the current transformer; and

c. where the maximum error introduced by any physical separation of the primaries of the voltage transformer and the current transformer exceeds 0.02% for either active or reactive power flows, a constant correction factor has been provided to and approved by the *IESO* in the manner described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter; or

1.11.1.2 in the case of a *metering installation* relating to a *generation facility*:

a. the *metering installation* shall, where a current transformer is located on the grounded of the *generation facility*, minimize the leakage of current between the voltage transformer and the current transformer; and

b. where the maximum error introduced by leakage current between the location of the current transformer and the location of the corresponding voltage transformer exceeds 0.02% for either active or reactive power flows, a constant correction factor has been provided to and approved by the *IESO* in the manner described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

1.11.2 *Metering data* from a *metering installation* in respect of which registration has been granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.11.1 shall be the subject of adjustment by the correction factors referred to in section 1.11.1.1 or 1.11.1.2, as the case may be, in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.11.3 The *IESO* may, by notice to the *metered market participant* in respect of the *metering installation* to which the registration relates, revoke registration of a *metering installation* granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.11.1 if the conditions set forth in section 1.11.1.1 or 1.11.1.2 are not met, in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the primary connection point proximity requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.11.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under MR Ch.6 s.4.4.8 the registration of a *metering installation* that meets the conditions set out in section 1.11.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.12 Instrument Transformer – Primary Cable

1.12.1 A *metering service provider* that seeks to register a *metering installation* under MR Ch.6 s4.4.2 that does not comply with the permissible primary cable error factor requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall provide to the *IESO*, for the *IESO*'s approval, a constant correction factor.

1.12.2 *Metering data* from a *metering installation* in respect of which registration has been granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.12.1 shall be the subject of adjustment by the correction factor referred to in section 1.12.1 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.12.3 If the *IESO* does not grant the *metered market participant* the right to retain registration under MR Ch.6 s.4.4.8, the registration of a *metering installation* that meets the conditions set out in section 1.12.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.13 Instrument Transformers – Burdens

1.13.1 A *metering service provider* that seeks to register a *metering installation* under MR Ch.6 s.4.4.2 that does not comply with the prohibition against errors resulting from calculated burdens for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall provide to the *IESO*, for the *IESO*'s approval, a correction factor.

1.13.2 *Metering data* from a *metering installation* in respect of which registration has been granted under MR Ch.6 s.4.4.3 that meets the conditions set out in section 1.13.1 shall be the subject of adjustment by the correction factor referred to in section 1.13.1 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.13.3 If the *IESO* does not grant the *metered market participant* the right to retain registration under MR Ch.6 s.4.4.8 the registration of a *metering installation* that meets the conditions set out in section 1.13.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.14 Estimation Pending Rectification

1.14.1 Where registration has been revoked or expires pursuant to any section of this Appendix, the *IESO* may for *settlement* purposes estimate the *metering data* recorded in the *metering installation* in the manner described in section 1.14.2 with effect:

1.14.1.1 [Intentionally left blank]

1.14.1.2 in the case of revocation from the date specified in the notice of revocation issued by the *IESO*; or

1.14.1.3 in the case of expiry, from the date of expiry,

to the date on which the *IESO* is satisfied that the corrective action referred to in the relevant section of this Appendix has been taken.

1.14.2 For the purposes of section 1.14.1, estimation of *metering data* shall be based on the following:

1.14.2.1 in the case of a *metering installation* for a *generation facility*, production shall be estimated at zero;

1.14.2.2 in the case of a *metering installation* for a load, withdrawal for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that load during the twelve-month period preceding the applicable date referred to in section 1.14.1.2 or 1.14.1.3; or

1.14.2.3 in the case of a *metering installation* for an *electricity storage unit*, the injections shall be estimated at zero and the withdraws for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that load during the twelve-month period preceding the applicable date referred to in section 1.14.1.2 or 1.14.1.3

Appendix 6.3 – Inspecting and Testing Requirements

1.1 Routine Testing

1.1.1 The routine tests referred to in sections 1.2 to 1.4 of this Appendix shall be carried out by a *metering service provider* in accordance with section 1.5 of this Appendix.

1.2 On-Site Reconciliation and Meter Register Dial Readings

1.2.1 Subject to MR Ch.6 ss.4.6.5 and 1.2.3, on-site reconciliation shall be conducted to confirm whether the *energy* measured by a *meter* over a given period of time was accurately transmitted to the *meter's data logger* within the *meter*.

1.2.2 Each *metering service provider* shall record an error detected as a result of the procedure referred to in section 1.2.1 that exceeds one multiplier, calculated as the current transformer ratio times the voltage transformer ratio times the *meter* register multiplier, as an *outage* or defect and shall report the error as such to the *IESO* in accordance with MR Ch.6 s.11.1.2.

1.2.3 On-site reconciliation shall not be required if the *meter's data logger* is built into the *meter* and both the *meter* and the *meter's data logger* are enclosed in a single housing.

1.2.4 Where a *meter* within a *metering installation* is not capable of transmitting *meter* register dial readings during the remote acquisition of *metering data* as described in MR Ch.6 s.7.2.6 the *metering service provider* shall provide such readings to the *IESO* so as to enable the *IESO* to perform the comparison described in section 7.2.5 of this Chapter.

1.3 Spot Check of Meter Operation

1.3.1 The active and reactive demand recorded by a *meter* shall be compared with the active and reactive demand measured by a high-accuracy test set installed in parallel with the *meter* or by such other means as may be acceptable to the *IESO*.

1.3.2 Each *metering service provider* shall record an error detected as a result of the procedure referred to in section 1.3.1 that exceeds ± 0.5% on kW and ± 1% on kVAR as an *outage* or defect and shall report the error as such to the *IESO* in accordance with section 11.1.2 of this Chapter.

1.3.3 Each *metering service provider* shall ensure that any *meter* in respect of which an error that exceeds the thresholds referred to in section 1.3.2 is bench tested by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) and shall make the results of such bench test available to the *IESO,* to the *metered market participant* for the *metering installation* of which the *meter* forms part, and to the *distributor* or *transmitter* to whose system the *facility* to which the *metering installation* relates is connected.

1.3.4 No *metering service provider* or *metered market participant* shall dispose of a *meter* in respect of which an error that exceeds the thresholds referred to in section 1.3.2 without the prior approval of the *IESO*.

1.4 Instrument Transformer Checks

1.4.1 The testing of currents and voltages applied to a *meter*, supported by independent confirmation of primary current and voltage, shall be used to test the correct operation of all *instrument transformers*.

1.4.2 The procedure referred to in section 1.4.1 may be conducted by a *metering service provider* by remote means if the *meter* is capable of transmitting the applied currents and voltages and if primary current and voltage can be independently confirmed by remote access.

1.4.3 Each *metering service provider* shall conduct the procedure referred to in section 1.4.1 in respect of each *metering installation* for which it acts as a *metering service provider* at the commissioning of any new *metering installation* and for all existing *metering installations* at the earliest of the following:

a. as per the *instrument transformer's* manufacturer's recommended maintenance schedule;

b. when the *IESO* has evidence that the *instrument transformer's* accuracy has been compromised; and

c. in any event, no less than once every eighteen months. For greater clarity, the first instrument transformer check after *RSS commencement date* will be earlier of (a) six years after the last instrument transformer check; and (b) the date that is eighteen months after *RSS commencement date*.

1.5 Frequency of Routine Testing

1.5.1 Each *metering service provider* shall conduct the routine tests referred to in sections 1.2 to 1.3 of this Appendix in respect of each *metering installation* for which it acts as a *metering service provider,* that is not a *main/alternate metering installation* and that is associated with a *facility* that has an average annual maximum monthly load of less than 10 MW as follows:

1.5.1.1 once every six months following the date of registration of the *metering installation*, in the case of the procedure referred to in section 1.2.1; and

1.5.1.2 once every twelve months following the date of registration of the *metering installation*, in the case of each of the procedures referred to in sections 1.3.1.

1.5.2 Each *metering service provider* shall conduct the routine tests referred to in sections 1.2 to 1.3 of this Appendix in respect of each *metering installation* for which it acts as a *metering service provider,* that is not a *main/alternate metering installation* and that is associated with a *facility* that has an average annual maximum monthly load of 10 MW or more as follows:

1.5.2.1 once every 3 months following the date of registration of the *metering installation*, in the case of the procedure referred to in section 1.2.1; and

1.5.2.2 once every six months following the date of registration of the *metering installation*, in the case of each of the procedures referred to in sections 1.3.1.

1.5.3 Each *metering service provider* shall conduct the routine tests specified in section 1.3.1, for each *metering installation* that is registered under section 4.6 of Chapter 6 for which it acts as a *metering service provider*, once every eighteen months following the date of registration of the *metering installation*. For greater clarity, the first routine test after *RSS commencement date* will be earlier of (a) three years after the last routine test; and (b) the date that is eighteen months after *RSS commencement date.*

1.5.4 Each *metering service provider* shall test the currents and voltages applied to a *meter*, for each *metering installation* that is comprised of an alternate *meter* and that is registered under MR Ch.6 s.4.6 for which it acts as a *metering service provider,* once every 6 months following the date of registration of the *metering installation*. This test may be conducted by remote means if the *meter* is capable of transmitting the applied currents and voltages.

1.6 Non-Routine Tests

1.6.1 Each *metered market participant* shall ensure that tests to determine *instrument transformer* burden and error correction, and ratiometer, megger, oil analysis, partial discharge and dielectric tests are conducted from time to time as may be determined appropriate by the *metered market participant* or its *metering service provider* or as may be required by the *IESO.*

Appendix 6.4 – Metering Service Provider Qualifications

1.1 Qualifications

1.1.1 Each person that wishes to be registered by the *IESO* as a *metering service provider* shall demonstrate to the satisfaction of the *IESO* that it has:

1.1.1.1 an adequate number of personnel having the qualifications described in sections 1.1.1.2 to 1.1.1.7 to permit it to perform all of the functions and obligations of a *metering service provider* under this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter and to meet the performance standards set forth in MR Ch.6 s.5.2.3;

1.1.1.2 personnel that has successfully completed a metering training program relating to *metering installations* provided by an entity recognized by the *IESO* for such purpose, including but not limited to the Municipal Electric Association, the former Ontario Hydro and the corporations referred to in subsection 48(2) of the *Electricity Act, 1998*;

1.1.1.3 personnel that has recent training in procedures pertaining to the provision, installation, commissioning, repair, maintenance, replacement, inspection and testing of *metering installations*, in the preparation of *metering*-related documentation, in the calculation of site specific loss adjustments and error correction factors and in the resolution of trouble calls;

1.1.1.4 personnel that has successfully completed electrical safety training provided by an entity recognized by the *IESO* for such purpose, including but not limited to the Electrical & Utilities Safety Association of Ontario, the former Ontario Hydro and the corporations referred to in subsection 48(2) of the *Electricity Act, 1998*;

1.1.1.5 personnel that has demonstrated experience with *federal metering requirements*;

1.1.1.6 personnel that has demonstrated experience with the investigation and reporting of incidences of tampering with *metering installations* and *metering data*;

1.1.1.7 personnel that has demonstrated experience with procedures for maintaining the security, validity and integrity of *metering data*, including the collection of static and dynamic *metering data* and the reading of *metering data* prior to and after the repair or replacement of *metering installations*;

1.1.1.8 the necessary equipment, materials, systems and procedures to enable it to perform all of the functions and obligations of a *metering service provider* under this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter and to meet the performance standards set forth in MR Ch.6 s.5.2.3; and

1.1.1.9 all licences and other authorizations required by *applicable law*, all of which are valid and in good standing.

Appendix 6.5 – Metering Registry and Meter Point Documentation

1.1 Introduction

1.1.1 This Appendix sets forth certain of the information that is required to be contained in the *metering registry* and describes the *meter point* documentation that each *metered market participant* must provide to the *IESO* in support of an application to register a *metering installation*.

1.2 Metering Registry Information

1.2.1 The *IESO* shall ensure that the *metering registry* contains the following information respecting each registered *metering installation* and such other information as the *IESO* considers appropriate, including information respecting *metering installations* whose registration has expired but whose continued use has been determined by the *IESO* to be necessary for the efficient operation of the *IESO-administered markets*:

1.2.1.1 the *defined meter point* for the *connection point* associated with the *metering installation*;

1.2.1.2 where applicable, the *defined meter point* for the *embedded connection point* associated with the *metering installation*;

1.2.1.3 identification and name of the *metered market participant* for the *metering installation*;

1.2.1.4 identification and name of the *metering service provider* for the *metering installation*;

1.2.1.5 contacts for purposes of communicating with the *metering service provider*; and

1.2.1.6 those portions of the *meter point* documentation referred to in sections 1.3.2.2, 1.3.2.3, 1.3.2.4, 1.3.2.5, 1.3.2.6, 1.3.2.8, 1.3.2.12, 1.3.2.13 and 1.3.2.16.

1.2.2 The information referred to in section 1.2.1 relating to each *metering installation* shall be the information as provided to the *IESO* by the *metering service provider* for that *metering installation* in support of its application to register the *metering installation.* Where the *metering service provider* gives notice to the *IESO* of a change in any of the information referred to section 1.2.1, the *IESO* shall update the *metering registry* accordingly.

1.3 Meter Point Documentation

1.3.1 *Meter point* documentation that:

1.3.1.1 complies with the provisions of this section 1.3, of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter; and

1.3.1.2 that is in such form as may be required by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter or as may otherwise be established by the *IESO*,

shall be provided to the *IESO* by the relevant *metering service provider* in support of an application for registration of a *metering installation* and shall be updated by the *metering service provider* such as to maintain the *meter point* documentation current.

1.3.2 The *meter point* documentation referred to in section 1.3.1 shall be a package containing the following and such other documentation and information as the *IESO* may require in respect of each *metering installation*:

1.3.2.1 a single line drawing showing the electrical location of the *metering installation* and of each *meter* within the *metering installation*;

1.3.2.2 a totalization table indicating:

a. the *meters* to be summed for a single *market participant* and the sign of summation; and
b. information pertaining to each data channel comprising each point of summation in sufficient detail to permit summation, site specific loss adjustments and measurement error correction;

1.3.2.3 the unique identifier assigned by the *IESO* to the *metering installation* for purposes of the *metering database*, cross-referenced to the location of the *metering installation*;

1.3.2.4 the unit of measurement used to measure *energy* flowing through the *metering installation*;

1.3.2.5 the name and operating designation of the transformer station, distribution station and feeder normally supplying the *meter point*;

1.3.2.6 the site-specific loss adjustment and measurement error correction factors to be applied, including the sign of the loss adjustment;

1.3.2.7 data supporting loss adjustment and measurement error correction factors, including engineering calculations and power flow studies;

1.3.2.8 [Intentionally left blank – section deleted]

1.3.2.9 a written description of the location of the *meter point* of the *metering installation*;

1.3.2.10 the location and address of the *defined meter point* of the *metering installation*;

1.3.2.11 the location and address of the *meter point* of the *metering installation*, if the *meter point* is not located at the *defined meter point*;

1.3.2.12 the pulse multiplier and *meter* multiplier for the *metering installation*;

1.3.2.13 details of the *data logger* of the *meter* within the *metering installation* and of the modem speed;

1.3.2.14 the burdens connected to each *instrument transformer* contained within the *metering installation*;

1.3.2.15 the *instrument transformer* ratios available and in use;

1.3.2.16 the unique internal *meter* identifier, the telephone number, the passwords and the protocol translation program name for the *metering installation*; and

1.3.2.17 the emergency restoration plan required in respect of the *outage* or malfunction of or a defect in an *instrument transformer*.

1.3.3 The documentation relating to loss adjustment and measurement error correction factors and the documentation relating to *instrument transformer* burdens required by section 1.3.2 to form part of the *meter point* documentation for a *metering installation* shall be stamped by a registered professional engineer.

1.3.4 The *metering service provider* for a *metering installation* that measures the consumption of *energy* referred to in MR Ch.9 s.2.2.1.1 or that measures the consumption of *station service* shall provide to the *IESO*, in support of the application to register the *metering installation*, the proportions referred to in MR Ch.9 s.2.2.4.1 or 2.2.4.2(a), as may be applicable, to the extent that such proportions have been agreed in the manner specified in those sections and in such form as may be required by the applicable *market manuals*.

1.3A Transmitter Confirmation of Meter Point Documentation

1.3A.1 No *metering service provider* to whom a request has been made pursuant to section 6.1.2A of Chapter 6 shall submit to the *IESO* the *meter point* documentation referred to in section 1.3 in respect of a *metering installation* that will be used for the calculation and collection of charges for *transmission service* unless the relevant portion of the *meter point* documentation is accompanied by the confirmation of the approval of each applicable *transmitter* referred to in MR Ch.10 s. 3.1.3, 5.1.3, 6.1.3 or 6A.1.2.2, as may be applicable.

1.4 Other

1.4.1 The *IESO* shall ensure that the *metering registry* contains, in respect of each registered *metering installation* and *metering installations* whose registration has expired but whose continued use has been determined by the *IESO* to be necessary for the efficient operation of the *IESO-administered markets*, the identification number assigned by the *IESO* to the *defined meter point* for that *metering installation.*

RUL-17

Renewed Market Rules

Chapter 0.7

System Operations and Physical Markets

0.7

Renewed Market Rules – Chapter 0.7: System Operations and Physical Markets

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO-administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

A.2 The *IESO* shall establish a working group the objective of which will be to assist in identifying unintended outcomes of the market power mitigation framework and recommending means to address such unintended outcomes. The working group shall serve as an advisory body to the *IESO* and the *technical panel* and shall consist of both *IESO* staff and representatives from potentially impacted parties. The working group will perform its function until a date that is one year following the *market transition completion*, or for such longer period as may be agreed to as between the *IESO*, the *technical panel*, and the working group.

B.1 Exceptions

B.1.1 Section 22.10.3 shall come into force on the first *business day* that is at least 30 days after the day the *IESO* designates the first *potential constrained area* pursuant to section 22.10.1.

1. Introductory Rules

1.1 Application

1.1.1 The rules in this Chapter apply to:

1.1.1.1 the *IESO*;

1.1.1.2 any person who causes or permits electricity or any *physical service* to be conveyed into, through or out of the *integrated power system*;

1.1.1.3 any *registered market participant* that submits *dispatch data* with respect to any *resource*; and

1.1.1.4 *transmitters*.

1.1.2 In this Chapter, a reference to the term "area" in the context of *operating reserve* shall be construed as a reference to a portion of the *IESO control area* designated as such by the *IESO* and within which the *IESO* may impose limits on the amount of *ten-minute operating reserve* that can be scheduled from *resources* located within that portion for the purpose of meeting the total requirement for *ten-minute operating reserve* within the *IESO control area*.

1.2 Scope of the Physical Markets

1.2.1 The *IESO* shall administer three types of *physical markets*: the *day-ahead market*, the *real-time market* and the *procurement markets*.

1.2.2 The *IESO* shall administer, the following markets:

1.2.2.1 a *day-ahead market* in *energy*, measured in MWh (comprised of *physical transactions* and *virtual transactions*);

1.2.2.2 a *day-ahead market* in several classes of *operating reserve*, measured in MW (comprised of *physical transactions)*;

1.2.2.3 a *real-time market* in *energy*, measured in MWh (comprised of *physical transactions)*; and

1.2.2.4 a *real-time market* in several classes of *operating reserve*, measured in MW (comprised of *physical transactions)*.

1.2.3 The *IESO* shall administer, in accordance with section 9, the following *procurement markets* to procure certain *physical services* required for *reliable* operation of the *electricity system*:

1.2.3.1 markets for *contracted ancillary services*, including *regulation*, *reactive support service* and *voltage control service*, and *blackstart capability*; and

1.2.3.2 a market for *reliability must-run contracts*.

1.3 Coordination with Control Areas Outside the IESO Control Area

1.3.1 The *IESO* shall, where required or appropriate under duly constituted regional *reliability* agreements with one or more other *control areas* and subject to any confidentiality agreements entered into with *market participants* or as part of such *reliability* agreements, share with other *control area operators* all relevant information concerning physical system operations in relation to the *electricity system*.

1.4 Delivery in Respect of Extra-provincial Intertie Transactions

1.4.1 Where *energy* or an *ancillary service* is being conveyed:

1.4.1.1 into the *IESO-controlled grid* from an *intertie zone* outside the Province of Ontario; or

1.4.1.2 out of the *IESO-controlled grid* to an *intertie zone* outside the Province of Ontario,

delivery of such *energy* or *ancillary service* to or from, as the case may be, the *boundary entity* shall, for all purposes under these *market rules*, be deemed to occur on the Ontario portion of the applicable *intertie*.

1.5 Planned Outages for Maintenance and Upgrades of IESO-Administered Markets Software, Hardware and Communication Systems

1.5.1 The *IESO* may, from time to time, undertake *planned outages* on *IESO-administered markets* software, hardware or communication systems for the purpose of maintenance and/or upgrades to those systems. These *planned outages* may result in temporary disruptions to some market activities, including but not limited to submission of *dispatch data*, scheduling, pricing, issuing of *dispatch instructions* and *IESO* report *publishing*.

1.5.2 The *IESO* shall, in respect of a *planned outage* referred to in section 1.5.1:

1.5.2.1 Notify all *market participants*, as far in advance as reasonably practicable, of the timing and duration of the *planned outage*;

1.5.2.2 Maintain normal *market operations* during the *planned outage* to the greatest extent practicable; and

1.5.2.3 Limit the impact and duration of the *planned outage*, and any resulting disruption to *market operations* to the greatest extent practicable.

1.5.3 If a *planned outage* referred to in section 1.5.1 is expected to result in a disruption to normal *market operations*, the *IESO* shall notify all *market participants* of the expected disruption and shall specify any required alternative procedures that will be in effect for the duration of the disruption. These alternative procedures shall be designed so as to permit normal *market operations* to the greatest extent practicable. These alternative procedures may include, but are not limited to:

1.5.3.1 Submission of *dispatch data* by an alternate means and/or in an alternative form pursuant to section 3.1.2; and

1.5.3.2 Establishment of *administrative prices* pursuant to section 8.4A.

1.5.4 *Market participants* shall comply with the alternative procedures specified by the *IESO* in section 1.5.3.

1.6 IESO Authorities and Obligations Regarding the Operation of the IESO-Administered Markets

1.6.1 The following parameters of the *day-ahead market calculation engine*, *pre-dispatch calculation engine* and *real-time calculation engine* shall be as specified from time to time by the *IESO Board*:

1.6.1.1 the *maximum market clearing price;*

1.6.1.2 the *maximum operating reserve price*;

1.6.1.3 the constraint violation penalties; and

1.6.1.4 the *settlement floor price* for *energy*.

1.6.2 The *IESO Board* shall establish floor prices for *energy offers* from a *registered market participant* associated with a *variable generation resource* and for *energy* *offers* from a *generation resource* that has a component classified as *flexible nuclear generation*, in accordance with the applicable *market manual*.

1.6.3 The *IESO* shall establish the following limits for *virtual transactions* for any *virtual transaction zone*:

1.6.3.1 *energy* lamination volume limit; and

1.6.3.2 *offer* or *bid* quantity limit.

1.6.4 The *IESO* shall suspend the *day-ahead market* or *real-time market* as required in accordance with section 13. If the *IESO* suspends the *day-ahead market* or *real-time market*, the *IESO* shall:

1.6.4.1 inform *market participants* of the suspension the impacted trade date, hours and cause of error if practicable;

1.6.4.2 inform *market participants* of when normal *market operations* is expected to resume; and

1.6.4.3 subject to section 13.6, apply *administrative prices* in accordance with section 8.4A.

1.6.5 Unless otherwise directed by the *IESO Board*, the *IESO* shall no less than once every two calendar years, commission and *publish* the results of an independent review of the operation and application of the *day-ahead market calculation engine*, *pre-dispatch calculation engine*, and *real-time* calculation engine and the related *dispatch* processes and procedures. The *IESO* shall use the results of such review to determine the need or otherwise for improvements in the calculation engines and related procedures in meeting the objectives of the *market rules* and/or the mathematical representation of the *electricity system* or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than two years following the *market transition completion*.

1.6.6 If the *IESO* determines the *publication* of specific types of information from calculation engine results may facilitate anti-competitive behaviour, the *IESO* may limit the *publication* of such information through an *urgent amendment* to these *market rules*. The *IESO* shall advise the *market surveillance panel* of the matter. The *IESO Board* may request the advice of the *market surveillance panel* of the need or otherwise for the *urgent amendment* to remain in effect.

2. Registration for Physical Operations in the Day-Ahead Market and Real-Time Market

2.1 Requirements for Operating on the Grid

2.1.1 No person shall conduct *physical transactions* in the *day-ahead market* or in the *real-time market* or cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* unless:

2.1.1.1 that person is authorized to be a *market participant* in accordance with MR Ch.2;

2.1.1.2 the *facility* to or from which the electricity or *physical service* is to be so conveyed or the *boundary entity* to which the electricity or *physical service* relates has either been registered by the *IESO* as a *resource* pursuant to section 2.2 or section 2.2A, as the case may be, or is exempt from registration under section 2.1.3;

2.1.1.3 subject to section 2.1.1A, where such *resource* associated with a *generation facility* that is connected electrically to a neighbouring *control area,* and the electricity or *physical service* is to be conveyed out of the *integrated power system* over a *radial intertie*:

a. the person complies with the requirements of Appendix 7.7;

b. the person has entered into a *connection agreement;*

c. the *IESO* has entered into an *interconnection agreement* with the *control area operator*, *security coordinator* or *interconnected transmitter* for the relevant *radial intertie*; and

d. the *interconnection agreement* referred to in section 2.1.1.3(c) supports the implementation of the requirements of Appendix 7.7;

2.1.1.4 in accordance with sections 22.1.3 and 22.6.3, that person has provided to the *IESO* all relevant materials the *IESO* may require to determine *reference levels* and *reference quantities* for that person's *resources* and the *IESO* has registered all applicable *reference levels* and *reference quantities* for that person's *resources*;

2.1.1.5 that person has disclosed all of its *market control entities* to the *IESO;*

2.1.1.6 that person has designated a *market control entity for physical withholding* in accordance with section 22.9 for each of its *resources* that is a *dispatchable generation resource*, *dispatchable electricity storage resource* or a *dispatchable load*; and

2.1.1.7 that person has completed all applicable processes to register its *facilities* and any associated *resources* set out in the applicable *market manual*.

2.1.1A Section 2.1.1.3 shall not apply in respect of:

2.1.1A.1 the delivery of electricity or a *physical service* out of the *integrated power system* over a *radial intertie* where such delivery is required to provide support in the case of an *emergency* in a *control area*;

2.1.1A.2 the delivery of electricity or a *physical service* out of the *integrated power system* over a *radial intertie* where such delivery is required to provide support in the case of an *outage* in a *control area*; or

2.1.1A.3 the delivery of electricity or a *physical service* out of the *integrated power system* over an *intertie* that is configured as a *radial intertie* following and as a result of a *contingency event.*

2.1.2 A *market participant* shall not submit, and the *IESO* shall not accept, any *dispatch data* with respect to a *resource*, including a *boundary entity resource,* unless:

2.1.2.1 that *resource,* has been registered for the provision of the *physical service(s)* to which the *dispatch data* relate, or, in the case of a *boundary entity resource*, the *IESO* has authorized the *market participant* to use it for the provision of the *physical service(s)* to which the *dispatch data* relate;

2.1.2.2 that *market participant* is the *registered market participant* for that *resource*; and

2.1.2.3 the *dispatch data* are consistent with: (i) the registration information defining the capabilities of the *resource*; (ii) the *market participant's* reasonable expectations of the current actual capabilities of the *resource*; and (iii) any revision in registration information requested by the *IESO* under section 7.5.6.2 or other provision of these *market rules*.

2.1.3 Subject to section 2.3, no person that intends to participate in the *IESO-administered markets* or to cause or permit *electricity* or any *physical service* to be conveyed into, through or out of the *integrated power system* shall be required to register a *facility* to or from which the *electricity* or *physical service* is to be so conveyed as a *facility* and any associated *resources* registered with the *IESO* if such *facility* is embedded within a *distribution system*, a *load facility*, a *generation facility* or an *electricity storage facility* and that:

2.1.3.1 in the case of a *generation facility*, has a maximum rated *generation capacity,* net of auxiliary requirements, of less than 1 MW;

2.1.3.2 in the case of a *load facility*, has a maximum load capacity of less than 1 MW;

2.1.3.3 in the case of a *distribution system*, has a maximum load capacity of less than 1 MW; or

2.1.3.4 in the case of an *electricity storage facility*, has a maximum capacity for *energy* for each of injections and withdrawals*,* net of auxiliary requirements, of less than 1 MW.

2.2 Facility and Associated Resources Registration

2.2.0 The *IESO* shall establish and maintain *boundary entity resources* and *virtual zonal resources,* which shall be set out in the applicable *market manual*.

2.2.1 The *IESO* shall establish a process for registering a *facility* and any associated *resources* or for using a *boundary entity resource* and for registering a *market participant* as a *registered market participant*. Such process shall be set out in the applicable *market manual* and shall include, but not be limited to, the certifications referred to in sections 2.2.3.3 and 2.2.3.4 and the testing and inspection referred to in section 2.2.3.5.

2.2.2 A *market participant* may request to register a *facility* or any associated *resources* or to use a *boundary entity resource*:

2.2.2.1 for the delivery or withdrawal of specific *physical services* pursuant to the provisions of this section 2.2 and, if applicable, section 21.2.

2.2.3 The *IESO* shall approve a request to register a *facility* and any associated *resources* or to use a *boundary entity resource* if:

2.2.3.1 the *market participant* submits:

a. the registration information required by this section 2.2;

b. in the case of a *facility connected* to the *IESO-controlled grid*, a copy of the *connection agreement* pertaining to the *facility* and entered into with the applicable *transmitter*; and

c. in the case of a *generation facility*, an *electricity storage facility*, or a *load facility* associated with a *dispatchable load*, embedded within a *distribution system*, a copy of the *connection agreement* pertaining to the *facility* and entered into with the applicable *distributor*;

2.2.3.2 the *IESO* is satisfied on reasonable grounds that the *facility* is capable of operating as described in the registration information or as otherwise provided by the *market rules* in respect of the relevant *physical service*;

2.2.3.3 the *market participant* certifies to the *IESO* that all of the *facilities* and equipment to which its request for registration relates comply with all applicable technical requirements, other than those referred to in MR Ch.2 s.6.2 , set forth in these *market rules* applicable to all *market participants*, the class of *market participant* of which the *market participant* forms part and the *IESO-administered market* in which the *market participant* wishes to participate;

2.2.3.4 the *market participant* certifies to the *IESO* that it has adequate qualified employees or other personnel and organizational and other arrangements that are sufficient to enable the *market participant* to perform all of the functions and obligations applicable to *market participants*, the class of *market participant* of which the *market participant* forms part and the *IESO-administered market* in which the *market participant* wishes to participate in respect of all of the *facilities,* equipment and any associated *resources* to which its request for registration relates;

2.2.3.5 the *market participant* successfully completes such testing and permits such inspection as the *IESO* may require for the purposes of testing or inspecting whether all of the *facilities* and equipment to which its request for registration relates meet all applicable technical requirements, other than those referred to in MR Ch.2 s.6.2, set forth in these *market rules* applicable to all *market participants*, the class of *market participant* of which the *market participant* forms part and the *IESO-administered market* in which the *market participant* wishes to participate;

2.2.3.6 the *market participant* certifies to the *IESO* in writing that all of the *facilities* and equipment to which its request for registration relates complies with the requirements identified in any applicable *preliminary assessment* or *system impact assessment* associated with that *market participant's facilities* or equipment; and

2.2.3.7 the *market participant* certifies to the *IESO* that all of the *facilities*, equipment and any associated *resources* to which its request for registration relates does not differ materially from the configuration or technical parameters that were used by the *IESO* as the basis for which it issued any applicable approvals for such new or modified *connection* in accordance with MR Ch.4 ss.6.1.14 – 6.1.18, unless the applicable *market participant* or *connection applicant* has obtained the approval of the *IESO* for the change in configuration or technical parameter in accordance with MR Ch.4 s.6.1.22.

2.2.4 The *market participant* designated in the registration information as the *market participant* authorized to submit *dispatch data* with respect to a *resource* shall be the *registered market participant* for that *resource*. The *registered market participant* designated for a *resource* may not be changed without the prior approval of the *IESO*.

2.2.5 The *IESO* shall define the form and content of information, as further specified in the applicable *market manual*, required for registration as a *facility* with associated *resources* where applicable in accordance with this section 2.2.

2.2.6 Where the *facility* sought to be registered is within the *IESO control area*, the information required for registration as a *facility* or as an associated *resource*, as the case may be, shall, subject to any lesser requirements that may be *published* by the *IESO* in respect of the information required for registration of a given class or size of *facility* or any associated *resource*, include, but not be limited to:

2.2.6.1 the identity of the owner and the operator of the *facility* and any associated *resources*;

2.2.6.2 the identity of the *market participant* authorized to submit *dispatch data* with respect to the *resource*;

2.2.6.3 for a *connected facility*, information demonstrating that the *facility* has met the *connection* requirements set forth in MR Ch.4;

2.2.6.4 information demonstrating that the *market participant* designated as the *registered market participant* for the *facility* and its associated *resources* has the operational control necessary to assure delivery or withdrawal of the relevant *physical services* as described in the registration information;

2.2.6.5 for a *connected facility*, the location of the *facility* and the identity of the *primary RWM* that will measure the flow of *energy* between the *resource* and the *IESO-controlled grid*;

2.2.6.6 for a *facility* embedded within a *distribution system* or within a *connected facility* within the *IESO control area* that is *connected* to the *IESO-controlled grid*, the location of that *facility*, the identity of the *primary RWM(s)* through which *energy* will flow between that *facility* and the *IESO-controlled grid* and information demonstrating that *energy* can flow to and from the identified *primary RWM(s)* with allocations and loss factors specified in the registration information;

2.2.6.7 standing technical data defining the ability of the *facility* and any associated *resouces* to deliver or withdraw each *physical service* for which registration is sought including, where relevant, the trade-off functions among *energy* and *operating reserve;*

2.2.6.8 for a *resource* that will be subject to the *IESO's dispatch instructions*, certification that the *resource* has a minimum rated *generation capacity*, net of auxiliary requirements, or a minimum *dispatchable load* capacity, of 1 MW, or for an *electricity storage resource* an ability to inject a minimum of 1 MW and withdraw a minimum of 1 MW. Individual *generation units, electricity storage units* or sets of *load equipment* may be aggregated to meet this minimum capacity requirement if they meet the aggregation requirements of section 2.3; and

2.2.6.9 [Intentionally left blank – section deleted]

2.2.6.10 for any *resources* associated with a *cogeneration facility* or *enhanced combined cycle facility* choosing to be either a *dispatchable* or *self-scheduling generation resource*, and the *registered market participant* wishes the compliance bands used to determine whether or not the *resource* is in compliance with its *dispatch instructions* or its current schedule, information as outlined in the applicable *market manual* concerning the impact that the production or supply of the other forms of useful *energy* within the *facility* has on *energy* production. The *IESO* may audit this information, which is to be used to determine appropriate compliance bands as outlined in section 3.3.8, at any time.

2.2.6A A *registered market participant* for a hydroelectric *generation resource* may submit, in addition to any relevant documentation that the *IESO* may request, the following *resource*-specific information as applicable:

2.2.6A.1 *forbidden regions*;

2.2.6A.2 a *start indication value*. A *registered market participant* that elects to submit a *start indication value* shall provide one or more *start indication values* not exceeding the number of *generation units* associated with the *resource*;

2.2.6A.3 whether it intends to submit *hourly must run*; and

2.2.6A.4 *forebay* and any associated *time lags.*

2.2.6B A *registered market participant* for a *dispatchable generation resource* shall submit to the *IESO* the *minimum loading point*, the *minimum generation block run-time*, and the *minimum run-time* for the *generation resource* if the *minimum loading point* for the *resource* is greater than zero MW and if the *minimum generation block run-time* for the *resource* is greater than one hour.

2.2.6C [Intentionally left blank – section deleted]

2.2.6D The *IESO* may request, and the *registered market participant* for a *dispatchable generation resource* or a *dispatchable electricity storage resource* shall submit to the *IESO*, the following information:

2.2.6D.1 *start-up time*; and

2.2.6D.2 *minimum shut-down time*.

2.2.6E If no *resource* specific data is submitted to the *IESO* for a *generation resource's minimum loading point*, *forbidden regions*, or *period of steady operation* in accordance with sections 2.2.6A, and 2.2.6B, the *IESO* shall assign default values of zero for that data.

2.2.6F If *resource*-specific data is submitted to the *IESO* in accordance with sections 2.2.6A, 2.2.6B or 2.2.6G the *IESO* shall respect the data as submitted in its determination of the *day-ahead schedule* in accordance with section 4, the *pre-dispatch schedule* in accordance with section 5, and the *real-time schedule* in accordance with section 6.

2.2.6G In accordance with the applicable *market manuals*, a *registered market participant* that operates a *combined cycle plant* that is composed of *generation resources* that are not aggregated under section 2.3 shall submit to the *IESO*:

2.2.6G.1 the required data for each *resource* associated with that *combined cycle plant*, including the steam turbine *resource's minimum loading point*; and

2.2.6G.2 if the *registered market participant* intends to designate any *resources* associated with its non-aggregated *combined cycle plant* as a *pseudo-unit,* the required data for that *pseudo-unit* including the *steam turbine percentage share* and *duct firing 10-minute operating reserve capability*.

2.2.6H [Intentionally left blank – section deleted]

2.2.6I Subject to section 2.2.6G, the *IESO* shall determine, in accordance with the applicable *market manual*, the *pseudo-unit* technical parameters based on the *resource* specific data submitted under section 3.

2.2.6J [Intentionally left blank – section deleted]

2.2.6K A *registered market participant* for a *dispatchable generation resource* shall submit to the *IESO*:

2.2.6K.1 the *elapsed time to dispatch*; and

2.2.6K.2 *period of steady operation*.

2.2.7 To use a *boundary entity* and its associated *boundary entity resources*, a valid *interconnection agreement* over the relevant *interconnection* must have been entered into prior to the approval of the request. In addition, the information required to use the *boundary entity resources* shall include, but not be limited to:

2.2.7.1 identification of the *intertie registered wholesale meter(s)* through which the *physical services* will be delivered to or withdrawn from the *IESO-controlled grid*, which shall determine the *intertie zone* within which the *boundary entity* is deemed to be located;

2.2.7.2 information confirming that the *market participant* authorized to submit *dispatch data* with respect to the *boundary entity resource* holds all licences, permits or other authorizations that may be required to permit such *market participant* to deliver or withdraw the *physical services* to or from the *intertie zone* within which the *boundary entity resource* is deemed to be located;

2.2.7.3 information demonstrating compliance with applicable requirements of all relevant *standards authorities* and completion of the necessary *transmission service* arrangements with affected *control areas*;

2.2.7.4 the identity of the *market participant* authorized to submit *dispatch data* with respect to the *boundary entity resource*; and

2.2.7.5 information defining the maximum quantities of each *physical service* that the *market participant* authorized to submit *dispatch data* in respect of the *boundary entity resource* is entitled to inject into or withdraw from the *IESO-controlled grid* in respect of the *boundary entity resource* including, where relevant, the trade-off functions among *energy* and *operating reserves.*

2.2.8 In addition to the information required by section 2.2.6 or 2.2.7, as the case may be, the registration information for a *resource* that will provide *operating reserves* shall include information in a form approved by the *IESO* demonstrating the ability of the *resource* to:

2.2.8.1 provide *energy* and *operating reserve* according to the trade-off functions described in, and with the *response* times indicated in, the registration information; and

2.2.8.2 deliver, when the *resource* is called upon to do so by the *IESO*, *energy* at the specified rate (in MWh/hour or MW) in accordance with its *operating reserve offer* for at least one hour.

2.2.9 A *market participant* may request to register as a *self-scheduling generation facility* any *generation facility*:

2.2.9.1 that has a name-plate rating of individual components of equipment that collectively adds up to 1 MW or more but is less than 10 MW; or

2.2.9.2 that is a *cogeneration facility* or *enhanced combined cycle facility* that has a name plate rating of individual components of equipment that collectively adds up to 10 MW or more provided that the *IESO* determines that there are no adverse impacts on the *reliable* operation of the *IESO-controlled grid* of the *facility* being registered as a *self-scheduling generation facility* .

2.2.9A Except as the *IESO* may authorize under section 21.3.2, a *market participant* may request to register a *facility* and any associated *resources* as a *self-scheduling electricity storage facility* if:

2.2.9A.1 the *facility* is comprised of individual *electricity storage units* with *electricity storage unit sizes* that collectively add up to a total *electricity storage facility size* of 1 MW or more but less than 10 MW and meets the condition of section 2.1.3.4.

2.2.10 A *self-scheduling generation facility* may be registered:

2.2.10.1 to provide *energy* and *reactive support service* and *voltage control service*; and

2.2.10.2 as a *certified black start facility*.

2.2.11 The *IESO* shall approve a request for registration as an *electricity storage facility* or a *self-scheduling generation facility* if the information required by this section 2.2 is provided and the *IESO* determines that the participation of that *facility* and and any associated *resources* will not have a material adverse effect on power system *security*.

2.2.12 A *self-scheduling generation facility* or a *self-scheduling electricity storage facility* whose request for *facility* registration has been approved by the *IESO* is a *facility* with associated *resources* registered by the *IESO*.

2.2.13 A *market participant* may apply to register a *generation facility* associated with an *intermittent generation resource*, if it has a name-plate rating of not less than 1 MW.

2.2.14 A *generation facility* associated with an *intermittent generation resource* may not be registered to provide any *physical service* other than *energy* and *reactive support service* and *voltage control service*.

2.2.15 The *IESO* shall approve a request under section 2.2.13 if the information required by this section 2.2 is provided and the *IESO* determines that intermittent operation of the *resource* will not have a material adverse impact on power system *security*.

2.2.16 A *generator* with an *intermittent generation resource* whose request for *facility* registration has been approved by the *IESO* is a *facility* with associated *resources* registered by the *IESO*.

2.2.17 For the purposes of this Chapter, a *distribution system connected* to the *IESO-controlled grid* must be a *facility* that is registered by the *IESO*.

2.2.18 The *IESO* shall develop procedures and requirements for registering a *distribution system*. Such procedures shall include, but not be limited to, the certifications referred to in sections 2.2.3.3 and 2.2.3.4 and the testing and inspection referred to in section 2.2.3.5.

2.2.19 A *market participant* for a *load resource* may request to change that *resource's* load participation type as either a *dispatchable load*, *non-dispatchable load*, or *price responsive load* as follows:

2.2.19.1 a request to change from a *non-dispatchable load* to a *dispatchable load* shall be submitted at least 180 calendar days prior to the effective date of the change;

2.2.19.2 a request to change from a *non-dispatchable load* to a *price responsive load* shall be submitted at least 75 calendar days prior to the effective date of the change;

2.2.19.3 a request to change from a *dispatchable load* or *price responsive load* to a *non-dispatchable load* shall be submitted at least 75 calendar days prior to the effective date of the change;

2.2.19.4 a request to change from a *dispatchable load* to a *price responsive load* shall be submitted at least 75 calendar days prior to the effective date of the change; and

2.2.19.5 a request to change from a *price responsive load* to a *dispatchable load* shall be submitted at least 180 calendar days prior to the effective date of the change.

2.2.20 Once the change to a *non-dispatchable load* takes effect in accordance with section 2.2.19.3, the *market participant* shall not change that *resource's* load participation type back to a *dispatchable load* or a *price responsive load* in accordance with sections 2.2.19.1 or 2.2.19.2, as the case may be, for at least 180 calendar days from the effective date of the change.

2.2.21 A *registered market participant* for a *generation resource* shall be eligible for the real-time generator offer guarantee or day-ahead generator offer guarantee if, as part of the registration process under this section 2.2, the *market participant* provides the *resource* specific information required for a *GOG-eligible resource*.

2.2A Registration of Commissioning Generation Facilities

2.2A.1 A *market participant* may apply to register a *commissioning generation facility*, in accordance with section 2.2, for the purpose of being permitted to convey electricity or a *physical service* into, through or out of the *integrated power* *system* or of participating in the *day-ahead market* or *real-time market* during the period in which the *commissioning generation facility* is undergoing the commissioning tests referred to in section 2.2A.4.

2.2A.2 The *IESO* shall approve an application to register a *commissioning generation facility* if the *IESO* is satisfied that the *commissioning generation facility* meets the requirements provided by section 2.2 applicable to *generation facilities* associated with a *self-scheduling generation resource,* except for section 2.2.9.1. Any such registration shall expire upon completion by the *commissioning generation facility* of the final commissioning test submitted to and approved by the *IESO* pursuant to section 2.2A.4.

2.2A.3 Upon expiry of the registration referred to in section 2.2A.2, a *market participant* shall not participate in the *day-ahead market* or *real-time market* nor cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* in respect of a former *commissioning generation facility* unless such former *commissioning generation facility* has been registered, other than pursuant to this section 2.2A, in accordance with section 2.2.

2.2A.4 Where a *commissioning generation facility* has been registered by the *IESO* pursuant to section 2.2A.2, the *market participant* for that *commissioning generation facility* shall, while such registration is in effect:

2.2A.4.1 ensure that the *commissioning generation facility*:

a. complies with all of the provisions of these *market rules* applicable to *self-scheduling generation resources* and associated *generation facilities*; and

b. notwithstanding section 2.2A.4.1(a), where it will seek to be registered other than pursuant to this section 2.2A, in accordance with section 2.2 as other than a *self-scheduling generation resource* and associated *generation facility*, complies with all of the applicable requirements of section 2.1.1.4 and MR Ch.4 s.7.3; and

2.2A.4.2 submit to the *IESO*, for approval and in accordance with section 2.2A.5, information detailing the commissioning test plans for the *commissioning generation facility*.

2.2A.5 The detailed commissioning test plans, referred to in section 2.2A.4.2 shall be submitted to the *IESO* for approval and shall be scheduled in accordance with the procedures applicable to the *outage* coordination process described in MR

Ch.5 s.6 and with any applicable *market manual* and shall include, but not be limited to:

2.2A.5.1 the time required for the *commissioning generation facility* to synchronize to and de-synchronize from the *IESO-controlled grid*;

2.2A.5.2 *energy* and reactive output levels;

2.2A.5.3 the timing of and ramp rates associated with changes in *energy* and reactive output levels; and

2.2A.5.4 run-back or trip tests for the *commissioning generation facility*.

2.2A.6 Except as otherwise provided in this section 2.2A, where a *commissioning generation facility* has been registered by the *IESO* pursuant to section 2.2A.2, the *IESO* shall, while such registration is in effect,

2.2A.6.1 For purposes of the *settlement process*, treat the *commissioning generation facility* as the type of *resource* for which it has sought registration; and

2.2A.6.2 For the purposes of the *day-ahead market*, *pre-dispatch process* and *real-time dispatch process,* treat the *resource* as a *self-scheduling generation resource*.

2.2B [Intentionally left blank – section deleted]

2.2C [Intentionally left blank – section deleted]

2.2D Registration of Commissioning Electricity Storage Facilities

2.2D.1 A *market participant* may apply to register a *commissioning electricity storage facility*, in accordance with section 2.2, for the purpose of being permitted to convey electricity or a *physical service* into, through or out of the integrated power system or of participating in the *day-ahead market* or *real-time market* during the period in which the commissioning *electricity storage facility* is undergoing the commissioning tests referred to in section 2.2D.4.

2.2D.2 The *IESO* shall approve an application to register a *commissioning electricity storage facility* if the *IESO* is satisfied that the *commissioning electricity storage facility* meets the requirements provided by section 2.2 applicable to *electricity storage facilities* associated with a *self-scheduling electricity storage resource* except for section 2.2.9A.1. Any such registration shall expire upon completion by the *commissioning electricity storage facility* of the final commissioning test submitted to and approved by the *IESO* pursuant to section 2.2D.4.

2.2D.3 Upon expiry of the registration referred to in section 2.2D.2, a *market participant* shall not participate in the *day-ahead market* or *real-time market* nor cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* in respect of a former *commissioning electricity storage facility* unless such former *commissioning electricity storage facility* has been registered, other than pursuant to this section 2.2D, in accordance with section 2.2.

2.2D.4 Where a *commissioning electricity storage facility* has been registered by the *IESO* pursuant to section 2.2D.2, the *market participant* for that *commissioning electricity storage facility* shall, while such registration is in effect:

2.2D.4.1 ensure that the *commissioning electricity storage facility*:

a. complies with all of the provisions of these *market rules* applicable to *self-scheduling electricity storage resources* excluding section 3.4.1.7 and associated *electricity storage facilities*; and

b. notwithstanding section 2.2D.4.1(a), where it will seek to be registered other than pursuant to this section 2.2D, in accordance with section 2.2 as other than a *self-scheduling electricity storage resource* and associated *electricity storage facility*, complies with all of the applicable requirements of section 2.1.1.4 and MR Ch.4 s.7.3A ; and

2.2D.4.2 submit to the *IESO*, for approval and in accordance with section 2.2D.5, information detailing the commissioning test plans for the *commissioning electricity storage facility*.

2.2D.5 The detailed commissioning test plans, referred to in section 2.2D.4.2 shall be submitted to the *IESO* for approval and shall be scheduled in accordance with the procedures applicable to the *outage* coordination process described in MR Ch.5 s.6 and with any applicable *market manual* and shall include, but not be limited to:

2.2D.5.1 the time required for the *commissioning electricity storage facility* to synchronize to and de-synchronize from the *IESO-controlled grid*;

2.2D.5.2 *energy* and reactive output levels;

2.2D.5.3 the timing of and ramp rates associated with changes in *energy* and reactive output levels; and

2.2D.5.4 run-back or trip tests for the *commissioning electricity storage facility*.

2.2D.6 Except as otherwise provided in this section 2.2D, where a *commissioning electricity storage facility* has been registered by the *IESO* pursuant to section 2.2D.2, the *IESO* shall, while such registration is in effect;

2.2D.6.1 For purposes of the *settlement process*, treat the *commissioning electricity storage facility* as the type of *resource* for which it has sought registration; and

2.2D.6.2 For the purposes of the *day-ahead market*, *pre-dispatch process* and *real-time dispatch process,* treat the *resource* that is registered to inject as a *self-scheduling electricity storage resource*, and the *resource* registered to withdraw, as the type of *resource* for which it has sought registration.

2.3 Aggregated Generation Units, Electricity Storage Units or Sets of Load Equipment as Resources

2.3.1 A *market participant* may request that the *IESO* aggregate several of its *resources* associated with either *generation units, electricity storage units* or sets of *load equipment*, respectively, for one or more of the following purposes: (i) participating in the *day-ahead market*; or (ii) delivering or withdrawing one or more *physical services* in the *real-time market*, or the *procurement markets*. Upon *IESO* approval, the aggregated *resources* associated with either *generation units, electricity storage units* or sets of *load equipment* shall, except as specifically stated in the registration information or the *IESO*'s approval of the aggregation, be treated as a single *resource*:

2.3.1.1 either for the provision or withdrawal of the approved *physical services* by the *registered market participant* for purposes of the submission of *dispatch data*; and

2.3.1.2 by the *IESO*, for purposes of the scheduling and *dispatch* processes described in this Chapter.

2.3.2 The *IESO* shall approve a request for the aggregation of *resources* associated with either *generation units, electricity storage units* or sets of *load equipment* into a single *resource* unless:

2.3.2.1 the registration information for the *resources* associated with either *generation units, electricity storage units* or sets of *load equipment* proposed to be aggregated fails to satisfy the conditions of section 2.2;

2.3.2.2 the registration information fails to demonstrate one or more of the following in respect of the *resources* associated with either *generation units, electricity storage units* or sets of *load equipment* proposed to be aggregated;

a. that they are all located within the *IESO control area*;

b. subject to section 2.3.2A, that they are all *connected* to the *IESO-controlled grid* at the same *connection point*;

c. that the *resource* is under the operational control of a single *market participant* and that such *market participant* is authorized to submit *dispatch data* for it;

d. that operational communication between each of them and the *IESO* meets all applicable standards and protocols; or

e. that they all have relevant metering systems to be used for *settlements* purposes that satisfy the requirements of MR Ch.6; or

2.3.2.3 one or more of the *resources* associated with *generation units*, *electricity storage units* or sets of *load equipment* proposed to be aggregated is or includes a *resource*:

a. whose *offer* or *bid* information or whose in-service or out-of-service status affects the numerical value of operating *security limits* in any manner;

b. whose *offer* or *bid* information or whose in-service or out-of-service status is information required by the *IESO* for conducting detailed *security* and *resource* adequacy assessment;

c. whose *offer* or *bid* information or whose in-service or out-of-service status is information required to be submitted to the *market assessment unit* or the *market surveillance panel* in furtherance of their respective functions and obligations under the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and these *market rules*; or

d. whose *offer* or *bid* information, or whose in-service or out-of-service status or other information is required by *applicable law*, by *licence*, by the *Ontario Energy Board* or by a *standards authority* to be submitted to or obtained by the *IESO*.

2.3.2.4 the *market participant* fails to provide the certification referred to in section 2.2.3.3 in respect of any of the *facilities*;

2.3.2.5 the *market participant* fails to provide the certification referred to in section 2.2.3.4 in respect of any of the *facilities*; or

2.3.2.6 the *market participant* fails to successfully complete the testing or to permit the inspection referred to in section 2.2.3.5 in respect of any of the *facilities.*

2.3.2A Notwithstanding section 2.3.2.2b, the *IESO* may approve a request for the aggregation of *resources* associated with either *generation units, electricity storage units* or sets of *load equipment* into a single *resource* that are not all *connected* to the *IESO-controlled grid* at the same *connection point*, provided that, in the sole judgement of the *IESO*, they can be represented as a single point of injection or withdrawal without compromising the *reliability* of the *IESO-controlled grid*. Aggregation for the purposes of calculating *transmission service charges* is specified in the then current *Ontario Energy Board* Transmission Rate Order.

2.3.3 If a proposed aggregation of *resources* meets one or more of the above conditions, the *IESO:*

2.3.3.1 shall provide to the *market participant* whose application is denied the reasons for such denial.

2.3.4 Approval of the aggregation of *resources* shall be withdrawn by the *IESO* where, for any reason, one or more of the aggregated *resources* commences to meet any one or more of the conditions described in section 2.3.2. The *IESO* shall give notice of the withdrawal to the *market participant* authorized to submit *dispatch data* in respect of the aggregated *resources* and shall cease to treat those *resources* as a single *resource* as of the date and time specified in the notice for such purpose. The date and time so specified shall not be less than two days from the date and time at which the notice of withdrawal is given to the *market participant*. If the *market participant* subsequently wishes to thereafter re-aggregate the *resources*, it shall be required to re-apply to the *IESO* for approval of the aggregation in accordance with section 2.3.1.

2.3.5 A *market participant* authorized to submit *dispatch data* for aggregated *resources* may give notice to the *IESO* that it no longer wishes to aggregate those *resources*. The *IESO* shall acknowledge receipt of the *market participant's* notice and shall cease to treat those *resources* as a single *resource* as of the date and time specified in the acknowledgement of receipt for that purpose. The date and time so specified shall be as soon as reasonably practicable following the date of receipt by the *IESO* of the *market participant's* notice. If the *market participant* subsequently wishes to re-aggregate the *resources*, it shall be required to submit a new request to the *IESO* for approval of the aggregation in accordance with section 2.3.1.

2.4 De-registration of Facilities

2.4.1 A *market participant* that wishes to de-register a *facility* and any associated *resources* that have been registered in accordance with this section 2, other than a *boundary entity resource*, which is being removed from service, shall file with the *IESO* a notice of request to de-register in such form as may be specified by the *IESO;* provided, however, that a *market participant* shall not be entitled to file such a notice if it is no longer the beneficial owner of the *facility*.

2.4.2 Within ten *business days* of the date of receipt of the notice referred to in section 2.4.1, the *IESO* shall notify the *market participant* and the *transmitter* to whose *transmission system* the *facility* is *connected* as to whether the *IESO* requires a technical assessment of the impact of the removal from service of the *registered facility* on the *reliability* of the *IESO-controlled grid* and, if so, of the expected date of completion of such assessment. Such date shall not be more than 45 days from the date of issuance by the *IESO* of such notice or such later date as may be agreed between the *IESO* and the *market participant*.

2.4.3 Where the notice issued by the *IESO* pursuant to section 2.4.2 indicates that the *IESO* does not require a technical assessment or where the *IESO* conducts a technical assessment and concludes the removal from service of the *facility* will not or is not likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid*, the *market participant* shall file with the *IESO* a notice setting forth the date upon which the *market participant* wishes the *IESO* to de-register the *facility*. Such date shall not be less than five *business days* from the date of receipt by the *market participant* of the notice issued by the *IESO* pursuant to section 2.4.2 and, as applicable, shall be subject to the date on which the *facility* has been *disconnected* as confirmed by the relevant *transmitter* to the *IESO*.

2.4.4 Where section 2.4.3 applies, the *IESO* shall:

2.4.4.1 if the *facility* is not *connected* to the *IESO-controlled grid*, de-register the *facility* promptly upon completion of the technical assessment if applicable, or as of the date specified in the notice filed by the *market participant* pursuant to section 2.4.3, whichever is the later, and shall so notify the *market participant*, the *metering service provider* for the *metering installation* that relates to the *registered facility,* and any *market participant* within which the *registered facility* is embedded; or

2.4.4.2 if the *facility* is connected to the *IESO-controlled grid*:

a. issue to the relevant *transmitter* a *disconnection order* directing the relevant *transmitter* to *disconnect* the *facility* from the *IESO-controlled grid* on the date specified in the *disconnection order* which shall be no earlier than the date specified in the notice filed by the *market participant* pursuant to section 2.4.3; and

b. de-register the *facility* as of the date on which the relevant *transmitter* confirms to the *IESO* that the *facility* has been *disconnected* from the *IESO-controlled grid*.

and shall notify the *market participant* accordingly.

2.4.5 Where the *IESO* conducts the technical assessment referred to in section 2.4.2 and concludes that the removal from service of the *facility* will or is likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid,* the *IESO* and the *market participant* shall commence the process described in sections 9.6 and 9.7 and in MR Ch.5 s.4.8 with a view to concluding a *reliability must-run contract* for that *facility*. The *facility* shall not be removed from service during the course of such process.

2.4.6 [Intentionally left blank – section deleted]

2.4.6.1 [Intentionally left blank – section deleted]

2.4.6.2 [Intentionally left blank – section deleted]

2.4.7 A *transmitter* that receives a *disconnection order* from the *IESO* pursuant to section 2.4.4.2(a) shall:

2.4.7.1 subject only to MR Ch.5 s.3.4.1.5 and to the completion of any operating and decommissioning procedures contemplated in the *connection agreement* applicable to the *facility*, *disconnect* the *facility* from the *IESO-controlled grid* on the date and at the time specified in the *disconnection order*, and

2.4.7.2 promptly inform the *IESO* once the *facility* has been *disconnected* from the *IESO-controlled grid.*

Planned Retirements of Generation and Electricity Storage Facilities

2.4.8 Each *generator* shall provide the *IESO* not less than six months advance notice of the commencement of the planned retirement of any one of its *generation facilities* and any associated *resources* that have been registered in accordance with this section 2, including notification of any plans the *generator* may have to construct replacement *facilities* for those being retired.

2.4.9 Each *electricity storage participant* shall provide the *IESO* not less than six months advance notice of the commencement of the planned retirement of any one of its *electricity storage facilities* and associated *resources* that have been registered in accordance with this section 2, including notification of any plans the *electricity storage participant* may have to construct replacement *facilities* for those being retired.

2.5 Transfer of Registration of Facilities

2.5.1 A *market participant* that wishes to transfer the registration of a *facility* and any associated *resources* that has been registered in accordance with this section 2*,* as a result of the proposed transfer of the *facility* to another person by sale, assignment, lease, transfer of control or other means of disposition shall, not less than 10 *business days* prior to the date on which the transfer is proposed to take effect, file with the *IESO* and the relevant *transmitter* or *distributor*, a notice of request to transfer the registration of the *facility* in such form as may be specified by the *IESO*. Such notice shall specify:

2.5.1.1 the identity of the transferee and whether the transferee is or intends to be a *market participant*; and

2.5.1.2 the date upon which the transfer is proposed to take effect,

and shall be accompanied by a written declaration by the proposed transferee that it is willing and able to assume control of the *facility* and any associated *resources* and to comply with all provisions of these *market rules* and of any *reliability must-run contract* or *contracted ancillary services* contract applicable to such *facility.*

2.5.2 If the proposed transferee satisfies or is capable of satisfying the requirements of section 2.2, the *IESO* shall approve a request to transfer the registration of a *facility* and any associated *resources* unless the proposed transferee is a *suspended market participant* or is otherwise ineligible under these *market rules* to be a *market participant*.

2.5.3 Where the *IESO* approves a request to transfer the registration of a *facility*, the *IESO* shall transfer the registration of the *facility* to the proposed transferee:

2.5.3.1 on the date referred to in section 2.5.1.2, provided that the proposed transferee was a *market participant* at the time of filing of the notice referred to in section 2.5.1 and remains a *market participant* on such date; or

2.5.3.2 on such later date as may reasonably be required to permit the *IESO* to effect the transfer following the later of the date of authorization of the proposed transferee as a *market participant* and the date on which the proposed transferee meets the requirements of section 2.2.

2.5.4 Upon completion of the transfer of the *facility*, the proposed transferee will have to post with the *IESO prudential support* or *capacity prudential support* as applicable, equal to the proposed transferee's *prudential support obligation* or *capacity prudential support obligation*. Until the proposed transferee has done so, the transferring *market participant* shall continue to be liable for the obligations of the proposed transferee in the *IESO-administered markets*. Such obligations shall include, without limitation, the cost of electricity withdrawn from the *IESO-controlled grid* by the proposed transferee and related charges as determined by the *IESO* in accordance with MR Ch.9. The *prudential support obligation* and/or *capacity prudential support obligation* as applicable of the transferring *market participant* shall include all such amounts whether or not the transferring *market participant* has complied with the provisions of this section 2.5.

3. Data Submissions for the Day-Ahead Market and the Real-Time Market

3.1 General Dispatch Data Submission Requirements

3.1.1 Each *registered market participant* shall submit its *dispatch data* to the *IESO* through the *electronic information system* or, when not available, by such alternative means and/or in such alternative simplified form as may be specified by the *IESO* pursuant to section 3.1.2.3.

3.1.2 The *IESO* shall:

3.1.2.1 stamp all *dispatch data* with the time that it was received by the *IESO*;

3.1.2.2 within five minutes, confirm receipt of all such *dispatch data* through the *electronic information system*; and

3.1.2.3 specify alternative means and/or an alternative simplified form of submitting and confirming *dispatch data* when the *electronic information system* is unavailable.

3.1.3 *Dispatch data* submitted on a *resource* with the latest time stamp shall replace any *dispatch data* previously submitted on the *resource* for the corresponding *dispatch day* or *dispatch hour*, subject to section 3.1.4.

3.1.4 The *IESO* may reject any *dispatch data* that does not comply with this section 3 and shall provide to the *registered market participant* submitting such rejected *dispatch data* the reasons for such rejection. Nothing in section 3.1.4 shall limit the *IESO's* rights under section 22.13.1 or shall be construed as an *IESO* determination under MR Ch.3 s.6.

3.1.4A For the purposes of this section 3, where the *IESO* has approved the submission of *dispatch data,* such approval shall not be construed as the *IESO's* determination that the *dispatch data* is compliant with any applicable obligations under these *market rules,* and shall not prejudice the *IESO's* rights or remedies under MR Ch.3 s.6.

3.1.5 A *registered market participant* that does not receive from the *IESO* confirmation of receipt of *dispatch data* in accordance with section 3.1.2.2 shall immediately contact the *IESO* by telephone or facsimile seeking confirmation of receipt.

3.1.6 A *registered market participant* shall, if requested by the *IESO*, resubmit *dispatch data* by such means as may be specified by the *IESO* in the request.

3.1.7 For the purposes of this section 3, *dispatch data* that is submitted to the *IESO* through the electronic information system or by other means and that the *IESO* has rejected pursuant to section 3.1.4, or is otherwise not valid, shall be deemed not to have been submitted to the *IESO*.

3.1.8 *Dispatch data* submitted during the *dispatch day* to which it applies shall only be submitted for the remaining *dispatch hours* of that *dispatch day.*

General Submission Requirements

3.1.9 A *registered market participant* shall submit *dispatch data* in the *day-ahead market* or *real-time market*, as may be permitted under this section 3, to be eligible for *dispatch* or to otherwise provide *physical services.*

3.1.10 *Dispatch data* submitted in the *day-ahead market* in accordance with section 3.2 shall be used as a *dispatch data* submission into the *real-time market* where applicable, unless the *dispatch data* is subsequently resubmitted or revised.

Establishing an Availability Declaration Envelope

3.1.11 A *registered market participant* that intends for its *dispatchable generation resources*, *dispatchable electricity storage resources*, *dispatchable loads*, or *hourly demand response resources* to be eligible for *dispatch* by the *IESO* for a given *dispatch hour* of a *dispatch day* shall establish an *availability declaration envelope* by submitting a *bid* or *offer*, as applicable, for *energy* in the *day-ahead market* in accordance with section 3.2.1 on the *resource* for the applicable *dispatch hour*, subject to section 3.1.14.

3.1.12 If a *registered market participant* for a *dispatchable generation resource* or a *dispatchable electricity storage resource* does not establish an *availability declaration envelope*, the *resource* shall not operate in the *real-time market* without the approval of the *IESO* under section 3.1.14.

3.1.13 If a *registered market participant* for a *dispatchable load* or an *hourly demand response resource* does not establish an *availability declaration envelope,* the *resource* shall not operate in the *real-time market* as a *dispatchable load or hourly demand response resource* without the approval of the *IESO* under section 3.1.14, except for the portion of *energy* identified to be consumed as a *non-dispatchable load* in accordance with section 3.3.3.1.

3.1.14 The *IESO* shall approve an increase to the *availability declaration envelope* of a *resource* if:

3.1.14.1 the *resource* returns from *outage* earlier than planned in accordance with the provisions of MR Ch.5 s.6;

3.1.14.2 the *IESO* has solicited additional *offers* or *bids;*

3.1.14.3 the increase will avoid an *emergency operating state* or *high-risk operating state*;

3.1.14.4 the increase is required in order to prevent the *resource* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*; or

3.1.14.5 the increase does not exceed the materiality threshold specified in the applicable *market manual.*

3.2 Dispatch Data Submissions in the Day-Ahead Market

Submissions During the Day-Ahead Market Submission Window

3.2.1 A *registered market participant* that submits *dispatch data* for the *day-ahead market*, shall submit such *dispatch data* during the *day-ahead market submission window* unless the *registered market participant* has submitted s*tanding dispatch data* in accordance with section 3.3.9. A *registered market participant* may also submit *dispatch data* for the *day-ahead market* during the *day-ahead market restricted window* as permitted by section 3.2.4.

3.2.2 A *registered market participant* may submit revised *dispatch data* into the *day-ahead market* provided that it is submitted during the *day-ahead market submission window* or as permitted by section 3.2.4.

3.2.3 A *registered market participant* for a *dispatchable load* may, in the *dispatch data* submitted under sections 3.2.1 and 3.2.2, identify all or a portion of the *energy* to be consumed at such *resource* as *non-dispatchable load* in accordance with the applicable *market manual*.

Submissions During the Day-Ahead Market Restricted Window

3.2.4 During the *day-ahead market restricted window*, *dispatch data* submissions shall require *IESO* approval in accordance with section 3.2.5.

3.2.5 The *IESO* may approve *dispatch data* submitted during the *day-ahead market restricted window* if the *IESO* is unable to receive *dispatch data* submissions during the *day-ahead market submission window* due to a failure in or *planned outage* of the software, hardware or communications systems that support the submission of *dispatch data*, as determined by the *IESO*.

3.2.6 The *IESO* shall use the most recent *dispatch data* submitted by *registered market participants*, provided that it is received by the *IESO* before 10:00 EPT on each day prior to the relevant *dispatch day* or submitted with the *IESO's* approval pursuant to section 3.2.5, as inputs into the *day-ahead market calculation engine* in accordance with section 3.

3.3 Dispatch Data Submissions in the Real-Time Market

3.3.1 The *IESO* shall use the following types of *dispatch data* submitted by *registered market participants* to determine the *pre-dispatch schedule* in accordance with section 5 and Appendix 7.5A:

3.3.1.1 *dispatch data* submitted in the *day-ahead market* that has been converted in accordance with section 3.1.10; and

3.3.1.2 *dispatch data* submitted during the *pre-dispatch process*.

3.3.2 For the purposes of this section 3.3, any *dispatch data* submission made during the *pre-dispatch process* on a *resource* for any *dispatch hour* shall be deemed to constitute a revision to *dispatch data* or revised *dispatch data*.

Submissions During the Real-Time Market Unrestricted Window for Hourly Dispatch Data Parameters

3.3.3 Subject to this section 3.3.3, a *registered market participant* may submit revised hourly *dispatch data* parameters described in sections 3.5.3 and 3.5.4 with respect to any *dispatch hour* during the *real-time market unrestricted window*.

3.3.3.1 During the *real-time market unrestricted window,* notwithstanding section 2.2.20, a *registered market participant* may, for any one or more of its *dispatchable loads*, identify all or a portion of the *energy* to be consumed at such *resources* as a *non-dispatchable load* by submitting revised *dispatch data* in accordance with the applicable *market manual*.

3.3.3.2 A *registered market participant* for a *dispatchable load*, *hourly demand response resource* or *dispatchable electricity storage resource* that has established its *availability declaration envelope* may revise its *bid* during the *real-time market unrestricted window* provided that the revised *bid* does not increase the *resource's availability declaration envelope* which, for the avoidance of doubt, excludes the portion of *energy* a *dispatchable load* identified to be consumed as a *non-dispatchable load*. Revised *bids* that seek to increase the *resource's availability declaration envelope* shall require *IESO* approval under section 3.1.14 or in accordance with the applicable *market manual*.

3.3.3.3 Subject to sections 3.3.3.4 to 3.3.3.13, a *registered market participant* for a *dispatchable generation resource* or a *dispatchable electricity storage resource* that has established its *availability declaration envelope* may revise its *offer* during the *real-time market unrestricted window* provided that the revised *offer* does not increase the *resource's availability declaration envelope*. Revised *offers* that seek to increase the *resource's availability declaration envelope* shall require *IESO* approval under section 3.1.14 or in accordance with the applicable *market manual*.

3.3.3.4 During the *real-time market unrestricted window* for *dispatch hours* where a *GOG-eligible resource* has received a *day-ahead operational schedule*, its *registered market participant* shall not increase its (i) *speed no-load offer*, or (ii) *energy offer* price for quantities up to and including its *minimum loading point*, above the latest *offer* submitted for the corresponding *dispatch hour* under section 3.1.11.

3.3.3.5 Starting at 20:00 EST on the day prior to the relevant *dispatch day*, for *dispatch hours* where a *GOG-eligible resource* has not received a *day-ahead operational schedule*, its *registered market participant* shall not increase its (i) *speed no-load offer*, or (ii) *energy offer* price for quantities up to and including its *minimum loading point*, above the latest *offer* submitted for the corresponding *dispatch hour*.

3.3.3.6 During the *real-time market unrestricted window*, for *dispatch hours* where a *GOG-eligible resource* has received a *day-ahead operational commitment*, its *registered market participant* shall not increase its *start-up offers* above the latest *offer* submitted for the corresponding *dispatch hour* under section 3.1.11.

3.3.3.7 Starting at 20:00 EST on the day prior to the relevant *dispatch day,* for *dispatch hours* where a *GOG-eligible resource* has not received a *day-ahead operational commitment*, its *registered market participant* shall not increase its *start-up offers* above the latest *offer* submitted for the corresponding *dispatch hour.*

3.3.3.8 Subject to 3.3.3.9, during *the real-time market unrestricted window*, for *dispatch hours* where a *GOG-eligible resource* (i) has received a *binding pre-dispatch advisory schedule*, and (ii) has not received a *day-ahead operational schedule*, its *registered market participant* shall not increase its *energy offer* prices above *the energy offer* prices submitted for the corresponding *dispatch hour*:

a. used at the time of establishing the *binding pre-dispatch advisory schedule;* and

b. for quantities above the *resource's minimum loading point* and up to and including the quantity scheduled by the *binding pre-dispatch advisory schedule*.

3.3.3.9 The restrictions in section 3.3.3.8 shall not apply in the following circumstances:

a. for the remaining *dispatch hours* of the *binding pre-dispatch advisory schedule* when the *GOG-eligible resource* has received a notice of de-commitment in accordance with section 10.2.1; or

b. for the *dispatch hours* where a steam turbine *resource* associated with a *pseudo-unit* experiences a *forced outage* and the *registered market participant* submits an *outage* slip to the *IESO* for that steam turbine *resource.* Under such circumstances, the *energy offer* price increase for the *pseudo-unit* shall be limited to the *energy offer reference level* of the *resource* associated with the *single cycle mode* of operation.

3.3.3.10 Subject to 3.3.3.11, during the *real-time market unrestricted window*, for *dispatch hours* where *a GOG-eligible resource* (i) has received a *binding pre-dispatch advisory schedule*, and (ii) has not received a *day-ahead operational schedule*, its *registered market participant* shall not increase its *energy offer* prices above the *energy offer* prices submitted for the corresponding *dispatch hour*:

a. used at the time of establishing the *binding pre-dispatch advisory schedule*; and

b. for quantities that exceed the *resource's binding pre-dispatch advisory schedule*.

3.3.3.11 The restrictions in section 3.3.3.10 shall not apply in the following circumstances:

a. for the remaining *dispatch hours* of *the binding pre-dispatch advisory schedule* when the *GOG-eligible resource* has received a notice of de-commitment in accordance with section 10.2.1; or

b. for the *dispatch hours* where a steam turbine *resource* of a *pseudo-unit* experiences a *forced outage* and the *registered market participant* submits an *outage* slip to the *IESO* for that steam turbine *resource.* Under such circumstances, the *energy offer* price increase for the *pseudo-unit* shall be limited to the *energy offer reference level* of the *resource* associated with the *single cycle mode* of operation; or

c. for the *dispatch hours* for which the *IESO* has temporarily revised the *resource's energy offer reference level* in accordance with section 22.5.8, and the following requirements are satisfied:

i. The revision occurs after the *binding pre-dispatch advisory schedule* is published and prior to the *mandatory window;* and

ii. The revision applies to the quantities that exceed the *resource's binding pre-dispatch advisory schedule*.

3.3.3.12 Subject to 3.3.3.13, during the *real-time market unrestricted window*, for *dispatch hours* where *a GOG-eligible resource* (i) has received a *binding pre-dispatch advisory schedule*, (ii) has not received a *day-ahead operational schedule*, and (iii) has submitted an *operating reserve offer*, its *registered market participant* shall not increase its *operating reserve offer* prices above the *operating reserve offer* prices submitted for the corresponding *dispatch hour* used at the time of establishing the *binding pre-dispatch advisory schedule*.

3.3.3.13 The restrictions in section 3.3.3.12 shall not apply:

a. for the remaining *dispatch hours* of the *binding pre-dispatch advisory schedule* when the *GOG-eligible resource* has received a notice of de-commitment in accordance with section 10.2.1; or

b. for the *dispatch hours* where the steam turbine *resource* of a *pseudo-unit* experiences a *forced outage* and the *registered market participant* submits an *outage* slip to the *IESO* for that steam turbine *resource.* Under such circumstances, the *operating reserve offer* price increase for the *pseudo-unit* shall be limited to the *operating reserve offer reference level* of the *resource* associated with the *single cycle mode* of operation.

Replacement Energy Offers – Forced Outage Revisions During the Real-Time Market Unrestricted Window and Mandatory Window

3.3.4 A *registered market participant* for a *generation resource* associated with a hydroelectric *generation facility*, a *combined cycle plant*, an *enhanced combined cycle facility* or a *cogeneration facility* that experiences a *forced outage* may submit revised *dispatch data* on a related *generation resource*, with respect to any *dispatch hour* up until 10 minutes prior to the beginning of that *dispatch hour*. If the revised *dispatch data* is submitted less than 10 minutes prior to the beginning of that *dispatch hour*, the revised *dispatch data* will apply to the subsequent *dispatch hour*. This section is subject to the following conditions:

a. The submission of revised *dispatch data* takes place no later than one hour after the *generation resource* experiences the *forced outage* and is limited to the maximum MW amount *offered* by the *generation resource* experiencing the *forced outage;*
b. The *registered market participant* whose *generation resource* experienced a *forced outage* notifies the *IESO*, in accordance with the applicable *market manual*, of its intention to submit revised *dispatch data* for the related *generation resource* for the next available *dispatch hour* and of its intention to provide replacement *energy* from the related *generation resource*;
c. Where the related *generation resource* is not synchronized, the *registered market participant* notifies the *IESO* of its intention to synchronize the related *generation resource* and the *IESO* determines synchronization will have no adverse impact on the *reliability* of the *IESO-controlled grid;*
d. The related generation resource and the generation resource experiencing the forced outage have the same registered market participant; and
e. The related generation resource and the generation resource experiencing the forced outage have the same metered market participant.

3.3.4.1 For the purposes of this section 3.3, related *generation resources* are *generation resources* that, in the case of a hydroelectric *generation facility*, can utilize the water of the *generation resource* experiencing the *forced outage* without delay. In the case of *combined cycle plants, enhanced combined cycle facilities* or *cogeneration facilities,* related *generation resources* are *generation resources* that can make up the loss in steam production to the steam turbine *resource* that would otherwise have been produced by the gas turbine *resource* experiencing the *forced outage.*

3.3.4.2 In the period after the notification and before the market tools process the revised *dispatch data,* the *IESO* shall approve the replacement *energy offer* from the related *generation resource*, provided there is no adverse impact on the *reliability* of the *IESO-controlled grid.* The *market participant* may choose to provide replacement *energy* from a related *generation resource* without submitting revised *dispatch data* for the current *dispatch hour* or, if within 10 minutes of the next *dispatch hour*, the current and subsequent *dispatch hour*.

3.3.4.3 The related *generation resource* that submits revised *dispatch data* under section 3.3.4 shall not be entitled to the *day-ahead operational commitment*, *pre-dispatch operational commitment*, *day-ahead market generator offer* guarantee *settlement amount* or *real-time market generator offer* guarantee *settlement amount* that was received by the *resource* that experienced the *forced outage*.

Revisions During the Real-Time Market Mandatory Window for Hourly Dispatch Data Parameters

3.3.5 A *registered market participant* may submit revised hourly *dispatch data* parameters described in sections 3.5.3 and 3.5.4 during the *real-time market mandatory window*, in accordance with the applicable *market manual,* only in circumstances where it would otherwise be permitted to submit such revised *dispatch data* on the *resource* in the *real-time market unrestricted window* after 20:00 EST on the day prior to the relevant *dispatch day,* provided that the *IESO* approves the submission of such revised *dispatch data*. Notwithstanding the foregoing, the *IESO* shall approve revisions to hourly *dispatch data* during the *real-time market mandatory window* in the following circumstances:

3.3.5.1 the submission of replacement *energy offers* in accordance with section 3.3.4;

3.3.5.2 the submission of revised *dispatch data* due to a *pre-dispatch schedule* that a *resource* reasonably expects to differ in schedule, delivery or withdrawal in accordance with section 3.3.8;

3.3.5.3 the submission of revised *dispatch data* in accordance with section 3.3.11 where the *registered market participant* has been issued a direction by the *IESO* in accordance with 3.3.10.2;

3.3.5.4 the submission of revised *dispatch data* identifying all or a portion of a *dispatchable load's* consumption as a *non-dispatchable load* in accordance with section 3.3.3.1; or

3.3.5.5 the submission of revised *dispatch data* on an *electricity storage resource* in accordance with section 21.5.

3.3.6 Where pursuant to section 3.3.5, the approval of the *IESO* is required for the submission of revised *dispatch data*, the *IESO* shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, or, for clarity, otherwise contravenes the requirements under section 3.3.5, approve the submission of revised *dispatch data* where:

3.3.6.1 the revision is required in order to reflect a proposed change in the operational status of the *resource* designed solely to prevent the *resource* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*.

The *IESO* may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

Revisions During the Real-Time Market Restricted Window for Daily Dispatch Data Parameters

3.3.7 Subject to 3.3.7.1, 3.3.7.2 and 3.3.7.4, during the *real-time market restricted window*, a *registered market participant* may submit revised *dispatch data* for daily *dispatch data* parameters described in sections 3.5.21 and 3.5.22, in accordance with the applicable *market manual,* if the revision is required in order to reflect a proposed change in the operational status of the *resource* designed solely to prevent the *resource* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*.

3.3.7.1 During the *real-time market restricted window*, a *registered market participant* shall not submit revised *dispatch data* for the following daily *dispatch data* parameters:

a. *minimum loading point*; or

b. *minimum generation block run-time*.

3.3.7.2 Subject to 3.3.7.3, during the *real-time market restricted window*, a *registered market participant* may revise its submission of *single cycle mode* for any reason.

3.3.7.3 During the *real-time market restricted window*, a *registered market participant* shall not revise its submission of *single cycle mode* where:

a. the *pseudo-unit* has received a *day-ahead operational commitment* for any of the remaining hours of the *dispatch day*;

b. the *pseudo-unit* has received a *pre-dispatch operational commitment* for any of the remaining hours of the *dispatch day*; or

c. the *pseudo-unit* is synchronized;

unless the *pseudo-unit* is operating in combined cycle mode, and the associated steam turbine *resource* of the *pseudo-unit* experiences a *forced outage* and the *registered market participant* submits a *forced outage* slip for the steam turbine *resource.*

3.3.7.4 During the *real-time market restricted window*, a *registered market participant* may revise its submission of certain daily *dispatch data* parameters for the reasons prescribed in the applicable *market manual.*

Obligation to Revise Dispatch Data

3.3.8 Notwithstanding any other provision of this section 3.3 and with the exception of testing specified in MR Ch.5 s.6.6, a *registered market participant* shall as soon as practical, submit to the *IESO* revised *dispatch data* for any *resource* in respect of which it is the *registered market participant* if, for any *dispatch hour* in the current *pre-dispatch schedule,* the quantity of any *physical service* scheduled for that *resource* differs from the quantity the *registered market participant* reasonably expects to be delivered or withdrawn in the *dispatch hour* by more than the greater of:

(i) 2 percent;

(ii) such absolute amount as may be determined by the *IESO* based on considerations of *reliability* and *resource* specific characteristics;

(iii) in the case of a *resource associated* with a *cogeneration facility* that is either a *dispatchable* or *self-scheduling generation resource*, such amount based on the impact that the production of the other forms of useful *energy* within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10, and the *IESO*; and

(iv) in the case of a *resource associated* with an *enhanced combined cycle facility* that is either a *dispatchable* or *self-scheduling generation resource*, such amount based on the impact that the recovery of waste heat from an industrial process/processes within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10;

and the *IESO*:

3.3.8.1 shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, include such change as an input in respect of any subsequent schedule determined following receipt of the change; and

3.3.8.2 may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

Standing Dispatch Data

3.3.9 A *registered market participant* may submit *standing dispatch data* on a *resource* which shall:

3.3.9.1 define the *dispatch data* for each *dispatch hour* of each *dispatch day* or for the duration of the *dispatch day*;

3.3.9.1A in respect of each *dispatch day* for which it is in effect, be deemed for the purposes of this section 3.3 and section 22 to be *dispatch data,* submitted at 06:00 EPT for the *day-ahead market submission window* on the day prior to the relevant *dispatch day*; and

3.3.9.2 remain in effect until the expiration date specified in the *standing dispatch data* unless earlier withdrawn or earlier revised by the *registered market participant*:

a. as *standing dispatch data* prior to 06:00 EPT on the day prior to the relevant *dispatch day*;
b. as *dispatch data* for the *dispatch day* in accordance with sections 3.3.3 to 3.3.8; or
c. as *dispatch data* for the *dispatch day* in accordance with sections 3.2.

IESO Authorities to Direct Submission or Revision of Dispatch Data

3.3.10 Notwithstanding sections 3.3.3, 3.3.4, 3.3.5, 3.3.7 and 3.3.8, where the *IESO* determines, on the basis of the *day-ahead schedule* or any subsequent *pre-dispatch schedule* determined in accordance with section 5, that a revision to *dispatch data* will not allow it to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may, subject to sections 3.3.15 and 3.3.16:

3.3.10.1 refuse to permit a revision to the quantity element of *dispatch data* submitted by a *registered market participant*; or

3.3.10.2 direct a *registered market participant* to submit or to resubmit a revision to the quantity element of its *dispatch data*, or both. The *IESO* shall notify the *registered market participant* of a refusal referred to in section 3.3.10.1 and shall include in any direction issued pursuant to section 3.3.10.2 a description of the revised *dispatch data* to be submitted or resubmitted by the *registered market participant*.

3.3.11 A *registered market participant* to which a direction has been issued pursuant to section 3.3.10.2 shall submit revised *dispatch data* to the *IESO* in accordance with the terms of the direction within two hours of the time of receipt of the direction.

3.3.12 If the *IESO* determines, on the basis of the *day-ahead schedule* or any subsequent *pre-dispatch schedule* determined in accordance with section 5, that it requires the supply of *energy, ancillary services* other than *contracted ancillary services*, or both from additional *resources* in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* shall determine if there are additional *resources* that have not submitted *dispatch data* and that can, to the *IESO's* knowledge, be made available within the time required in order to help maintain the *reliability* of the *IESO-controlled grid*.

3.3.13 Subject to sections 3.3.14 to 3.3.16, the *IESO* may direct the *registered market participant* for an additional *resource* identified pursuant to section 3.3.12 to submit *dispatch data*, and shall include in such direction a description of the *dispatch data* to be submitted by the *registered market participant*.

3.3.14 A *registered market participant* to which a direction is issued pursuant to section 3.3.13 shall submit *dispatch data* to the *IESO* in accordance with the terms of the direction within two hours of the time of receipt of the direction.

3.3.15 The *IESO* shall not issue a direction pursuant to section 3.3.10 or 3.3.13 for the purposes of addressing a lack of overall *adequacy* of the *IESO-controlled grid*.

3.3.16 Where a *resource* to which a direction issued pursuant to section 3.3.10.2 or 3.3.13 relates has a *reliability must-run contract* with the *IESO*, any such direction shall, subject to the time period for the submission of *dispatch data* referred to in sections 3.3.11 and 3.3.14, be consistent with the terms of such *reliability must-run contract*.

3.3.17 Nothing in sections 3.3.10 to 3.3.16 shall preclude the application of the provisions of section 22, MR Ch.9 s.5 or of MR Ch.9 App.9.4 in respect of *dispatch data* that is revised or submitted in accordance with sections 3.3.10 to 3.3.16.

3.4 The Form of Dispatch Data

3.4.1 *Dispatch data* shall relate to a specified *dispatch hour* or *dispatch day* of the current or next *dispatch day*, as the case may be, and to a specified *resource*, shall comply with sections 3.5 to 3.11, and shall take one of the following forms:

3.4.1.1 for a *dispatchable generation resource*, or a *dispatchable electricity storage resource* proposing to inject *energy*, an *offer* to provide a physical service to the *day ahead-market* or *real-time market*;

a. for a *dispatchable* *variable generation resource*, an *offer* to provide a *physical service* to the *day ahead-market* or *real-time market* reflecting the *resource's* full capacity available for production, determined in accordance with the applicable *market manual*.

3.4.1.2 for a *dispatchable load*, or a *dispatchable electricity storage resource* proposing to withdraw *energy*, a *bid* to take *energy* from the *day ahead-market* or *real-time market*;

3.4.1.3 for a *self-scheduling generation resource* or a *self-scheduling electricity storage resource*, a *self-schedule* for the provision of *energy* to the *day ahead-market* or *real-time market*;

3.4.1.4 for an *intermittent generation resource*, a forecast of *energy* expected to be provided to the *day ahead-market* or the *real-time market*;

3.4.1.5 for a *boundary entity resource*, an *offer* to sell *energy* or a *bid* to purchase *energy* in the *day-ahead-market* or the *real-time market*;

3.4.1.6 for a *capacity market participant* with an *hourly demand response resource* or a *capacity dispatchable load resource*, a *demand response energy bid* to reduce its *energy* consumption in the *day ahead-market* or the *real-time market*;

3.4.1.7 for a *price responsive load* or a *self-scheduling electricity storage resource* that intends to withdraw *energy*, a *bid* to purchase *energy* from the *day-ahead market*; and

3.4.1.8 for a *virtual transaction*, an *offer* or *bid* for *energy* on a *virtual zonal resource* in the *day-ahead market*.

3.4.2 Each *offer* for *energy* or *operating reserve* or *bid* for *energy* shall contain prices, each with an associated quantity. A price and the associated quantity in an *offer* or *bid* is a *price-quantity pair* and shall comply with sections 3.5 and 3.6, as applicable, and the following:

3.4.2.1 the quantity in any *price-quantity pair*, other than in the first *price-quantity pair*, shall be an increasing cumulative quantity representing the maximum quantity the *registered market participant* is *offering* to sell or *bidding* to buy, respectively, at the associated price in the *price-quantity pair*;

3.4.2.2 in any *offer*, the price in each *price-quantity pair* must not decrease as the associated quantity increases; and

3.4.2.3 in any *bid*, the price in each *price-quantity pair* must not increase as the associated quantity increases.

3.4.3 Every submission of an *offer* on a *dispatchable generation resource* shall specify a price of *energy* in $/MWh, at and below which the *IESO* may schedule a *generation resource* to zero in the *day-ahead market,* or, in the *real-time market,* instruct a *registered market participant* for the *generation resource* to reduce its *energy* output to zero. Such price represents the lowest price in the *price-quantity* pairs submitted for that *generation resource,* and may be zero or negative but may not be less than the negative *maximum market clearing price*.

3.4.4 Every submission of a *self-schedule* on a *self-scheduling generation resource*, or a forecast of intermittent generation for an *intermittent generation resource*, shall specify a price, in $/MWh, at and below which the applicable *registered market participant* reasonably expects to reduce the *energy* schedule in the *day-ahead market* to zero, or, in the *real-time market,* reduce its *energy* output of such *self-scheduling generation resource* or *intermittent generation resource* to zero. Such price may be zero or negative but may not be less than the negative *maximum market clearing price*.

3.4.5 Every submission of an *offer* for an *electricity storage resource* proposing to inject *energy* shall specify a price of *energy* in $/MWh, at and below which the *IESO* may instruct a *registered market participant* for the *electricity storage resource* to reduce its *energy* schedule in the *day-ahead* market to zero, or, in the *real-time* market, reduce its injections to zero. Such price represents the lowest price in the *price-quantity* pairs submitted for that *electricity storage resource,* and may be zero or negative but may not be less than the negative *maximum market clearing price*.

3.4.6 Every submission of a *self-schedule* on a *self-scheduling electricity storage resource* shall specify a price, in $/MWh, at and below which the applicable *registered market participant* reasonably expects to reduce its *energy* schedule in the *day-ahead* market to zero or, in the *real-time* market, reduce its injections of *energy* from the *self-scheduling electricity storage resource* to zero. Such price may be zero or negative but may not be less than the negative *maximum market clearing price*.

3.4.7 Every submission of a *bid* on a *dispatchable* load or a *dispatchable electricity storage resource* proposing to withdraw *energy* shall specify a price of *energy*, in $/MWh, at and above which the *IESO* may instruct the *dispatchable load* or *electricity storage resource*, as the case may be, to reduce its *energy* schedule in the *day-ahead* market to zero, or, in the *real-time* market, reduce its *energy* withdrawals to zero. Every submission of a *bid* to withdraw *energy* on a *price responsive load* or a *self-scheduling electricity storage resource* shall specify a price of *energy*, in $/MWh, at and above which the *IESO* may instruct the *price responsive load* or *self-scheduling electricity storage resource* to reduce its *energy* schedule in the *day ahead* market to zero. Such price represents the highest price in the *price-quantity* pairs submitted for that *dispatchable load*, *electricity storage resource, price responsive load* or *self-scheduling electricity storage resource,* and shall not be greater than the *maximum market clearing price*.

3.5 Energy Offers and Energy Bids

3.5.1 A *registered market participant* may have no more than one *energy offer* or one *energy bid* submitted on a given *resource* for any *dispatch hour*.

3.5.2 All *energy offers* and *energy bids* shall be submitted using such forms as may be specified by the *IESO*, which forms shall require, at a minimum, provision of all of the information specified in Appendices 7.1 and 7.2, respectively, except where the *IESO* specifies an alternative means and/or an alternative simplified form pursuant to section 3.1.2.3.

Hourly Dispatch Data Parameters

3.5.3 For each *dispatch hour,* each *energy offer* and *energy bid* shall include the following hourly *dispatch data* parameters where applicable:

3.5.3.1 *price-quantity pairs* in accordance with sections 3.5.5, 3.5.9 – 3.5.11, and 3.10.1.5;

3.5.3.2 hourly ramp quantities and the corresponding ramp up and ramp down values in accordance with section 3.5.7; and

3.5.3.3 a ramp rate applicable to all categories of *operating reserve* being *offered* in accordance with section 3.5.8.

3.5.4 For each *dispatch hour,* each *energy offer* may include the following hourly *dispatch data* parameters where applicable:

3.5.4.1 a *start-up offer* in accordance with section 3.5.12;

3.5.4.2 a *speed no-load offer* in accordance with section 3.5.13;

3.5.4.3 a *minimum hourly output* in accordance with sections 3.5.14 and 3.5.15;

3.5.4.4 an *hourly must-run* in accordance with sections 3.5.16 and 3.5.17; and

3.5.4.5 *variable generation forecast quantity* in accordance with sections 3.5.18.

3.5.5 Subject to 3.5.5.6, each *energy offer* or *energy bid* must contain at least two and, may contain up to 20 *price-quantity pairs* for each *dispatch hour*. *Price-quantity pairs* shall be submitted in accordance with this section:

3.5.5.1 The price in each such *price-quantity pair* shall be not more than the *maximum market clearing price* and not less than the negative *maximum market clearing price* and shall be expressed in dollars and whole cents per MWh.

3.5.5.2 The quantity in each such *price-quantity pair* shall:

a. in the case of a *resource* other than a *boundary entity resource*, be expressed in MW (or MWh/hour) to one decimal place and shall not be less than 0.0 MW (or 0.0 MWh/hour); or

b. in the case of a *boundary entity resource*, be expressed in whole MW (or MWh/hour) and shall not be less than 0 MW (or 0 MWh/hour).

3.5.5.3 The quantity in the first *price-quantity pair* shall be 0.0 MW (or 0.0 MWh/hour) or 0 MW (or 0 MWh/hour) as applicable.

3.5.5.4 The price in the second *price-quantity pair* shall be the same as the price in the first *price-quantity pair*.

3.5.5.5 The quantity in the second *price-quantity pair* shall be greater than or equal to the *minimum hourly output* submitted in accordance with section 3.5.14.

3.5.5.6 The number of *price-quantity pairs* submitted on a *pseudo-unit* shall not exceed 20 divided by the number of combustion turbine *resources* within the *generation facility,* rounded down to the next whole number.

3.5.5.7 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource*, shall submit in one of its *price-quantity pairs* a quantity that is equal to its *minimum loading point* submitted in accordance with section 3.5.29.

3.5.5.8 The prices in each *price-quantity pair* on a *variable generation resource* or a *generation resource* that has a component classified as *flexible nuclear generation* shall not be less than the floor prices specified in section 1.6.2.

3.5.6 Prices in *energy offers* and *energy bids* may be negative and such negative price shall imply:

3.5.6.1 when in an *energy offer*, that the *registered market participant* is willing to pay up to that price for each MWh of *energy* it is scheduled in the *day-ahead market* or injects rather than reduce its output in the *real-time market*; and

3.5.6.2 when in an *energy bid*, that the *registered market participant* is willing to take or dispose of excess *energy*, but only if paid at least that price for each excess MWh it is scheduled in the *day-ahead market,* or taken or disposed of in the *real-time market*.

3.5.7 Each *energy offer* or *energy bid*, other than an *energy offer* or *energy bid* on a *price responsive load*, a *boundary entity resource*, a *self-scheduling electricity storage resource* that intends to withdraw, or a *virtual zonal resource*, shall contain at least one and up to five sets of hourly ramp quantities and its corresponding ramp up and ramp down values for each *dispatch hour*. Ramp quantities and corresponding ramp up and ramp down values shall be submitted in accordance with this section:

3.5.7.1 The hourly ramp quantity shall be expressed in MW to one decimal place, be greater than 0.0 MW and increase monotonically;

3.5.7.2 The hourly ramp quantity shall constitute the maximum MW quantity at which the corresponding ramp up and ramp down values apply;

3.5.7.3 The last hourly ramp quantity shall be greater than or equal to the maximum quantity of the *price-quantity pairs* submitted in an hour*;* and

3.5.7.4 The hourly ramp up and ramp down values in each such set shall be expressed in MW/minute to one decimal place, be greater than 0.0 MW/min and be less than or equal to the maximum *offer* or *bid* ramp rate, as applicable, specified during the registration process determined by the *IESO* in accordance with section 2.2.

3.5.8 Each *energy offer* associated with a *dispatchable generation resource*, *dispatchable electricity storage resource* or *dispatchable load* shall contain one ramp rate applicable for all categories of *operating reserve* being *offered*. Each such *operating reserve* ramp rate shall:

3.5.8.1 be greater than or equal to half the registered *reference level* associated with the *operating reserve* ramp rate;

3.5.8.2 in the case of a *dispatchable generation resource* or *dispatchable electricity storage resource*, be less than or equal to the maximum *offer* ramp rate for *operating reserve* specified during the registration process in accordance with section 2.2; and

3.5.8.3 in the case of a *dispatchable load* or *dispatchable electricity storage resource* be less than or equal to the maximum *bid* ramp rate for *operating reserve* specified during the registration process in section 2.2.

3.5.9 The largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.9.1 the maximum output or withdrawal of *energy* in an hour indicated in the registration information for the relevant *resource;*

3.5.9.2 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *resource*, as estimated by the *registered market participant* for that *resource*;

3.5.9.3 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

a. the capacity of any radial line connecting the relevant *facility* to the *connection point*;

b. the maximum injection or withdrawal as specified in the *connection agreement* applicable to the relevant *facility*; or

c. the maximum injection or withdrawal otherwise permitted by the relevant *transmitter*;

3.5.9.4 for a *virtual zonal resource*, the quantity referred to in section 3.10.1.3.

3.5.10 Where one or more *electricity storage facilities* and one or more other *generation facilities* are all:

3.5.10.1 connected at the same *connection point*;

3.5.10.2 registered to the same *registered market participant,* and

3.5.10.3 none of the *facilities* or any associated *resources* are providing *contracted ancillary services* or participating in the *operating reserve market*;

section 3.5.9 shall not apply to those *facilities* or any associated *resources*. Instead, the largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* for such *resources* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.10.4 the maximum output of *energy* in an hour indicated in the registration information for the relevant *resource*;

3.5.10.5 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *resource*, as estimated by the *registered market participant* for that *resource*; or

3.5.10.6 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

a. the capacity of any radial line connecting the relevant *facility* to the connection point; or

b. the maximum injection or withdrawal as specified in the *connection agreements* applicable to the relevant *facilities* or to the maximum injection or withdrawal otherwise permitted by the relevant *transmitter,* calculated as the total net injections and withdrawals for all *generation facilities* and *electricity storage facilities* registered to the same *registered market participant* at the same *connection point*.

3.5.11 Where one or more *electricity storage facilities* and one or more other *generation facilities* are all:

3.5.11.1 connected at the same *connection point*;

3.5.11.2 registered to the same *registered market participant*, and

3.5.11.3 any of the *facilities* or any associated *resources* are providing *contracted ancillary services* or participating in the *operating reserve market*;

sections 3.5.9 and 3.5.10 shall not apply to those *facilities* or any associated *resources*. Instead, the largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* for each such *resources* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.11.4 the maximum output of *energy* in an hour indicated in the registration information for the relevant *resource*;

3.5.11.5 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *resource*, as estimated by the *registered market participant* for that *resource*; or

3.5.11.6 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

a. the capacity of any radial line connecting the relevant *facility* to the *connection point*; or

b. the maximum injection or withdrawal will be what is specified in the *connection agreement* applicable to the relevant *facility* or the maximum injection or withdrawal otherwise permitted by the relevant *transmitter,* and the sum of all *energy offers* or the sum of all *energy bids* from all *facilities* shall not exceed these limits.

3.5.12 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource*, may submit a *start-up offer* for each *thermal state*. The *start-up offer* shall be expressed in whole dollars between 0 and 999,999.

3.5.13 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource*, may submit a *speed no-load offer*. The *speed no-load offer* shall be expressed in whole dollars between 0 and 99,999.

3.5.14 A *registered market participant* for a *dispatchable* hydroelectric *generation resource* may submit a *minimum hourly output* that the *registered market participant* reasonably expects to be necessary to prevent the *resource* from operating in a manner:

3.5.14.1 that would require spill restrictions; and

3.5.14.2 that would endanger the safety of any person, damage equipment, or violate any *applicable law*.

3.5.15 *Minimum hourly output* shall be submitted only in accordance with this section:

3.5.15.1 *Minimum hourly output* shall be expressed in MW, up to one decimal place and be greater than or equal to 0.0 MW;

3.5.15.2 *Minimum hourly output* shall not exceed the largest quantity in the *price-quantity pairs* for that hour; and

3.5.15.3 The sum of all *minimum hourly output* submissions in a given *dispatch day* shall not exceed the *dispatchable* hydroelectric *generation resource's maximum daily energy limit* submitted under section 3.5.25.

3.5.16 A *registered market participant* for a *dispatchable* hydroelectric *generation resource* may submit an *hourly must run* if it has submitted the required information in accordance with section 2.2.6A.3, and that *registered market participant* reasonably expects the submission of *hourly must run* to be necessary to prevent the *resource* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*.

3.5.17 *Hourly must run* shall be submitted only in accordance with this section:

3.5.17.1 *Hourly must run* shall be expressed in MW, up to one decimal place and be greater than or equal to 0.0 MW;

3.5.17.2 *Hourly must run* shall not exceed the largest quantity in the associated *price-quantity pairs* for that hour; and

3.5.17.3 The sum of all *hourly must run* submissions in a *dispatch day* on (i) a *dispatchable* hydroelectric *generation resource* that is not registered on a *forebay*; or (ii) all *dispatchable* hydroelectric *generation resource*s that are registered on the same *forebay*, shall not exceed the *maximum daily energy limit* submitted on the *resource* or the *forebay*, as applicable.

3.5.18 A *registered market participant* for a *dispatchable variable generation resource* may submit a *variable generation forecast quantity* only in accordance with this section:

3.5.18.1 the *variable generation forecast quantity* shall be expressed in MWh per hour to one decimal place and must be greater than or equal to 0.0 MW; and

3.5.18.2 the *variable generation forecast quantity* shall not exceed the maximum registered *generation capacity* in accordance with section 3.5.9.1.

Linked Wheeling Through Transactions

3.5.19 All *linked wheeling through transactions* shall consist of:

3.5.19.1 an individual *energy offer* from a *boundary entity resource* injecting *energy* into the *IESO-controlled grid* and an *energy bid* from a *boundary entity resource* withdrawing *energy* from the *IESO-controlled grid*; or

3.5.19.2 an individual *energy offer* from a *boundary entity resource* injecting *energy* into the *IESO-controlled grid* and an *energy bid* from a *boundary entity resource* withdrawing *energy* from the *IESO-controlled grid,* and an identification of the desire for these to be linked, in accordance with the applicable *market manual*. The *IESO* shall assess these *offers* and *bids* as linked transactions. The *IESO* shall schedule and *dispatch* the linked *offers* and *bids* such that both are equal to the lower of the *offer* or *bid* that would otherwise be scheduled and *dispatched*.

3.5.20 An *energy bid* submitted by a *registered market participant* on a *boundary entity resource* in respect of the withdrawal from the *IESO-controlled grid* of *energy* destined for an *intertie zone* in the United States of America shall constitute a declaration by a *registered market participant* for the *boundary entity resource* of an intention to export *energy* in the circumstances described in paragraphs 1(b) to 1(d) of Part V of Schedule VI of the Excise Tax Act (Canada).

Daily Dispatch Data Parameters

3.5.21 For each *dispatch day,* an *energy offer* may include the following daily *dispatch data* parameters where applicable which will apply to each *dispatch hour* within the *dispatch day*:

3.5.21.1 Downstream *linked forebay*, *time lag* and *MWh ratio* in accordance with section 3.5.23;

3.5.21.2 *Forbidden regions* in accordance with 3.5.24;

3.5.21.3 *Maximum daily energy limit* in accordance with section 3.5.25;

3.5.21.4 *Minimum daily energy limit* in accordance with section 3.5.26;

3.5.21.5 *Single cycle mode* in accordance with section 3.5.27; and

3.5.21.6 *Maximum number of starts per day* in accordance with section 3.5.28.

3.5.22 For each *dispatch day,* an *energy offer* and *energy bid* shall include the following daily *dispatch data* parameters where applicable which will apply to each *dispatch hour* within the *dispatch day*:

3.5.22.1 *Minimum loading point* in accordance with section 3.5.29;

3.5.22.2 *Minimum generation block run-time* in accordance with section 3.5.30;

3.5.22.3 *Minimum generation block down-time* in accordance with section 3.5.31;

3.5.22.4 *Lead time* in accordance with section 3.5.32;

3.5.22.5 *Ramp up energy to minimum loading point* in accordance with section 3.5.33;

3.5.22.6 Daily ramp quantities and the corresponding ramp up and ramp down values in accordance with section 3.5.34; and

3.5.22.7 *Thermal state* in accordance with section 3.5.35.

3.5.23 A *registered market participant* for a *dispatchable* hydroelectric *generation resource* that intends to establish a *linked forebay* shall submit the corresponding set of *dispatch data* consisting of (i) the downstream *linked forebay*, (ii)*time lag*, and (iii)*MWh ratio*, if the *registered market participant* reasonably expects that the submission of the above daily *dispatch data* parameters is necessary to prevent the *resource* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*. The downstream *linked forebay*, *time lag* and *MWh ratio* shall be submitted only in accordance with this section:

3.5.23.1 the downstream *linked forebay* shall consist of a *forebay* that is registered downstream to the relevant *forebay* within the *cascade group*, registered in accordance with section 2.2.6A.4;

3.5.23.2 the *time lag* shall be expressed as a whole number that is greater than or equal to 0 and less than or equal to the registered *time lag;* and

3.5.23.3 *MWh ratio* shall be expressed up to two decimal places and shall be greater than 0.00.

3.5.24 A *registered market participant* for a *dispatchable* hydroelectric *generation resource* that has one or more *forbidden regions* registered in accordance with section 2.2.6A.1, may submit, subject to section 3.5.24.1, no more than five *forbidden regions* as daily *dispatch data* parameters. Each *forbidden region* shall be submitted only in accordance with this section in order to apply to a given *dispatch day*:

3.5.24.1 The number of *forbidden regions* submitted shall not exceed the number of *forbidden regions* registered for the applicable *resource;*

3.5.24.2 The *registered market participant* shall submit a quantity for both the upper limit and lower limit for the applicable *forbidden region,* expressed in MW up to one decimal place;

3.5.24.3 The quantity submitted for the upper limit shall be greater than the quantity submitted for the lower limit of that *forbidden region*;

3.5.24.4 The quantity submitted for the upper limit of a *forbidden region* shall be less than or equal to the registered upper limit of that *forbidden region*;

3.5.24.5 The quantity submitted for the lower limit of a *forbidden region* shall be greater than or equal to the registered lower limit of that *forbidden region*; and

3.5.24.6 If more than one *forbidden region* is submitted in a given *dispatch day*, the lower limit for each successive *forbidden region* shall be greater than the upper limit of the previously submitted *forbidden region*.

3.5.25 A *registered market participant* for a *dispatchable electricity storage resource* or a *dispatchable generation resource* other than a *nuclear generation resource* may submit a *maximum daily energy limit*. *Maximum daily energy limit* shall be submitted only in accordance with this section:

3.5.25.1 *Dispatchable* hydroelectric *generation resources* that are registered on the same *forebay* shall be collectively bound by the same *maximum daily energy limit*;

3.5.25.2 *Maximum daily energy limit* shall be expressed in MWh, up to one decimal place, and shall be greater than or equal to 0.0 and less than or equal to 999,999.9;

3.5.25.3 *Maximum daily energy limit* shall be greater than or equal to the *energy* required to operate the *generation resource* at *minimum loading point* for the *minimum generation block run-time*, submitted in accordance with sections 3.5.29 and 3.5.30, as applicable; and

3.5.25.4 For *dispatchable* hydroelectric *generation resources,* the *maximum daily energy limit* shall be greater than or equal to the *minimum daily energy limit* submitted for the *dispatch day* on (i) the *resource* where it is not registered on a *forebay*; or (ii) all the *resources* registered on the *forebay*.

3.5.26 A *registered market participant* for a *dispatchable* hydroelectric *generation resource* may submit a *minimum daily energy limit* if the submission is necessary to prevent the *resource* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*. *Minimum daily energy limit* shall be submitted only in accordance with this section:

3.5.26.1 *Dispatchable hydroelectric generation resources* that are registered on the same *forebay* shall be collectively bound by the same *minimum daily energy limit*;

3.5.26.2 *Minimum daily energy limit* shall be expressed in MWh up to one decimal place, shall be greater than or equal to 0.0, and less than or equal to the lesser of:

a. 999,999.9,

b. the sum of all hourly *energy* quantities submitted for the *dispatch day* on (i) the *resource* where it is not registered on a *forebay;* or (ii) all the *resources* registered on the *forebay;* as applicable; and

c. the *maximum daily energy limit* submitted for the dispatch day on (i) the *resource* where it is not registered on a *forebay*; or (ii) all the *resources* registered on the *forebay*;

as applicable.

3.5.27 A *registered market participant* for a *pseudo-unit* may submit single cycle mode.

3.5.28 A *registered market participant* for a *dispatchable generation resource* (i) that is a *non-quick start resource* and is not a nuclear *generation resource*, or (ii) that is a hydroelectric *generation resource* provided that it has registered a *start indication value* in accordance with 2.2.6A.2, may submit a *maximum number of starts per day*. *Maximum number of starts per day* shall be submitted only in accordance with this section:

3.5.28.1 Subject to section 3.5.28.2, *maximum number of starts per day* shall be submitted as a whole number less than or equal to 24; and

3.5.28.2 *Maximum number of starts per day* for *dispatchable* hydroelectric *generation resources* registered as an aggregated *resource* in accordance with section 2.3 shall not exceed 24 multiplied by the number of *start indication values* registered to the *resource* during registration.

3.5.29 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource*, shall submit a *minimum loading point*. *Minimum loading point* shall be submitted only in accordance with this section:

3.5.29.1 For a steam turbine *resource* that is registered with a *combined cycle plant* and not registered for *resource* aggregation, the *registered market participant* shall submit a *minimum loading point* for each combustion turbine *resource* within that *generation facility*, to reflect the n-on-1 *minimum loading point*. A *registered market participant* shall submit at least one n-on-1 *minimum loading points* and no more than the lesser of (i) four or (ii) the number of combustion turbine *resources* within that *generation facility.* N-on-1 *minimum loading points* shall be submitted in increasing numerical order*;*

3.5.29.2 *Minimum loading point* shall be greater than 0.0 MW, up to one decimal place, and shall not exceed the lesser of:

a. 9999.9 MW; or

b. the maximum registered *generation capacity* in accordance with section 3.5.9.1 and the applicable *market manual*.

3.5.30 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a *nuclear generation resource*, shall submit a *minimum generation block run-time*. *Minimum generation block run-time* shall be submitted only in accordance with this section:

3.5.30.1 *minimum generation block run-time* shall be a whole number greater than or equal to zero; and

3.5.30.2 *minimum generation block run-time* shall not exceed 24.

3.5.31 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource*, shall submit *minimum generation block down-time* for each of its *thermal states*. *Minimum generation block down-time* shall be submitted only in accordance with this section:

3.5.31.1 *minimum generation block down-time* shall be a whole number greater than or equal to zero;

3.5.31.2 *minimum generation block down-time* submitted for the hot *thermal state* shall not exceed *minimum generation block down-time* submitted for the warm *thermal state*, and *minimum generation block down-time* submitted for the warm *thermal state* shall not exceed *minimum generation block down-time* submitted for the cold *thermal state*;

3.5.31.3 the *minimum generation block down-time* shall not exceed 24 for the hot *thermal state*; and

3.5.31.4 *the minimum generation block down-time* shall not exceed 99 for the warm or cold *thermal state*.

3.5.32 A *registered market participant* for a *GOG-eligible resource* shall submit a *lead time* for each of its *thermal states*; however, a *registered market participant* for a *dispatchable generation resource* (i) that is a *non-quick start resource*, and (ii) is not a nuclear *generation resource* or a *GOG-eligible resource*, may, but for the avoidance of doubt, is not required to, submit a *lead time* for each of its *thermal states*. *Lead time* shall be submitted only in accordance with this section:

3.5.32.1 *lead time* for each *thermal state* shall be a whole number greater than or equal to zero;

3.5.32.2 *lead time* submitted for the hot *thermal state* shall not exceed *lead time* submitted for the warm *thermal state*, and *lead time* submitted for the warm *thermal state* shall not exceed *lead time* submitted for the cold *thermal state*; and

3.5.32.3 *lead time* shall not exceed the lesser of:

a. 24 for each *thermal state*; or

b. the *minimum generation block down-time* for the corresponding *thermal state* submitted in accordance with section 3.5.31.

3.5.33 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource*, shall submit *ramp up energy to minimum loading point*, consisting of its *ramp hours to minimum loading point* and its corresponding *energy per ramp hour*, for each *thermal state*. *Ramp up energy to minimum loading point* shall be submitted only in accordance with this section:

3.5.33.1 *Ramp hours to minimum loading point* for each *thermal* state shall be a whole number greater than or equal to zero;

3.5.33.2 *Ramp hours to minimum loading point* shall not exceed the lesser of:

a. 12 for each *thermal state;* or

b. the *lead time* for the corresponding *thermal state* submitted in accordance with section 3.5.32.

3.5.33.3 The *energy per ramp hour* for each *thermal state* shall be expressed in MWhs up to one decimal place and be greater than or equal to the greater of:

a. 0.1; or

b. the *energy per ramp hour* for the previous hour for the corresponding *thermal state*, as applicable.

3.5.33.4 The *energy per ramp hour* for each *thermal state* shall be less than or equal to the *minimum loading point*.

3.5.34 Each *registered market participant* that submits an *energy offer* or *energy bid*, other than an *energy offer* or *energy bid* on a *price responsive load*, *boundary entity resource*, *self-scheduling storage resource* that intends to withdraw, or *virtual zonal resource*, shall submit at least one and up to five sets of daily ramp quantities and its corresponding ramp up and ramp down values for each *dispatch day*. Daily ramp quantities and corresponding ramp up and ramp down values shall be submitted in accordance with this section:

3.5.34.1 The daily ramp quantity shall be expressed in MW to one decimal place, be greater than 0.0 MW and increase monotonically;

3.5.34.2 The daily ramp quantity shall constitute the maximum MW quantity at which the corresponding ramp up and ramp down values apply;

3.5.34.3 The last daily ramp quantity shall be greater than or equal to the maximum *offer* quantity submitted for the *dispatch day*; and

3.5.34.4 The daily ramp up and ramp down values in each such set shall be expressed in MW/minute to one decimal place, be greater than 0.0 MW/minute and be less than or equal to the daily maximum *offer* or *bid* ramp rate, as applicable, specified during the registration process in accordance with section 2.2.

3.5.35 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource* shall submit a *thermal state*.

3.6 Operating Reserve Offers

3.6.0 A *registered market participant* may submit an *offer* to provide *operating reserve* from an eligible *dispatchable generation resource*, a *dispatchable load*, a *dispatchable electricity storage resource* or a *boundary entity resource*, as applicable, in accordance with MR Ch.5 s.4.5.1.

3.6.1 A *registered market participant* may not submit, for any *resource*, more than one *offer* to provide each class of *operating reserve* in any *dispatch hour*.

3.6.2 Each submitted *offer* to provide *operating reserve* must contain at least two and may contain up to five *price-quantity pairs*. The price in each such *price-quantity pair* shall be not more than the *maximum operating reserve price* and not less than zero and shall be expressed in dollars and whole cents per MW. The quantity in each such *price-quantity pair* shall:

3.6.2.1 in the case of a *resource* other than a *boundary entity resource*, be expressed in MW to one decimal place and shall not be less than 0.0 MW; or

3.6.2.2 in the case of a *boundary entity resource*, be expressed in whole MW and shall not be less than 0 MW.

The quantity in the first *price-quantity pair* shall be 0.0 MW (or 0.0 MWh/hour) or 0 MW (or 0 MWh/hour) as applicable. The price in the second *price-quantity pair* shall be the same as the price in the first *price-quantity pair*.

3.6.3 Each *offer* to provide *operating reserve* shall be accompanied by a corresponding *energy offer* or *energy bid* for at least the same MW quantity *offered* for *operating reserve*.

3.6.4 *Offers* to supply *operating reserve* shall be submitted in such form as may be specified by the *IESO*, which form shall require, at a minimum, provision of all of the information specified in Appendix 7.3, except where the *IESO* specifies an alternative means and/or an alternative simplified form pursuant to section 3.1.2.3.

3.6.5 Each *offer* to provide *operating reserve* associated with a *dispatchable generation resource* or *dispatchable electricity storage resource* that proposes to inject *energy* shall contain a *reserve loading point* for each applicable class of *operating reserve offered*.

3.6.6 A *registered market participant* for a *dispatchable generation resource* or a *dispatchable electricity storage resource* shall not submit an *offer* to provide *operating reserve* if the *registered market participant* has estimated, in accordance with sections 3.5.9.2, that its *resource* cannot be scheduled to a quantity greater than or equal to its *reserve loading point* or is otherwise unable to provide the *operating reserve*.

3.6.7 A *registered market participant* for a *dispatchable generation resource* or a *dispatchable electricity storage resource* shall withdraw an *offer* to provide *operating reserve* as soon as practicable, if, for any *dispatch hour* in the current *pre-dispatch schedule*, the *resource* cannot provide the scheduled *operating reserve* because the *resource's pre-dispatch schedule* for *energy* is less than its *reserve loading point*.

3.7 Self-Scheduling Generation Resources

3.7.1 A *registered market participant* for a *self-scheduling generation resource* shall submit *dispatch data* for the *day-ahead market* indicating the amount of *energy* that the *registered market participant* reasonably expects to be provided by that *self-scheduling generation resource* in each *dispatch hour*. Such *dispatch data* shall:

3.7.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO* by providing, at a minimum, the information specified in Appendix 7.1; and

3.7.1.2 comply with section 3.4.4.

3.7.2 A *registered market participant* for a *self-scheduling generation resource* associated with a *cogeneration facility* or an *enhanced combined cycle facility* shall ensure its *facility* operates in accordance with its *dispatch data* within the tolerances for updating *dispatch data* outlined in section 3.3.8.

3.8 Self-Scheduling Electricity Storage Resources

3.8.1 A *registered market participant* for a *self-scheduling electricity storage resource* shall submit dispatch data in the *day-ahead market* indicating the amount of energy that the *registered market participant* reasonably expects to be injected or withdrawn by that *self-scheduling electricity storage resource* in each *dispatch hour*. Such *dispatch data* shall:

3.8.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO* by providing, at a minimum,the information specified in Appendix 7.1 and 7.2; and

3.8.1.2 in the case of a *self-scheduling electricity storage resource* that intends to inject, comply with section 3.4.6, and in the case of a *self-scheduling electricity storage resource* that intends to withdraw, comply with section 3.4.7.

3.9 Intermittent Generation Resources

3.9.1 A *registered market participant* for an *intermittent generation resource* shall submit *dispatch data* for the *day-ahead market* indicating its best forecast of the amount of *energy* that the *intermittent generation resource* will inject in each *dispatch hour*. Such *dispatch data* shall:

3.9.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO* by providing, at a minimum, the information specified in Appendix 7.1; and

3.9.1.2 comply with section 3.4.4.

3.10 Virtual Zonal Resources

3.10.1 A *virtual trader* for a *virtual zonal resource* shall submit an *energy offer* or *bid* in the *day-ahead market* in accordance with the following requirements, in addition to the applicable requirements provided by sections 3.4 and 3.5:

3.10.1.1 Each *energy offer* or *bid* shall be submitted to the *IESO* by providing, at a minimum, the information specified in Appendix 7.1 and 7.2, as applicable;

3.10.1.2 Each quantity in a subsequent *price-quantity pair* shall be at least 1.0 MW greater than the previous quantity;

3.10.1.3 The largest *energy* quantity in any *dispatch hour* shall not exceed the *IESO*-determined *virtual transaction offer* or *bid* quantity limit established in accordance with section 1.6.3;

3.10.1.4 The *virtual trader's IESO*-estimated submitted-but-not-cleared cumulative dollar exposure resulting from such *energy offer* or *bid* shall not exceed the *virtual trader's trading limit* for *virtual transactions;*

3.10.1.5 The number of *price-quantity pairs* submitted by a *virtual trader* on all *virtual zonal resources* for each *dispatch day* shall not exceed the *virtual transaction energy* lamination volume limit established in accordance with section 1.6.3; and

3.10.1.6 The absolute value of the sum of the *energy bid* and *offer* quantities submitted by a *virtual trader* on all *virtual zonal resources* for each *dispatch day* shall not exceed the *virtual trader's maximum daily trading limit*.

3.11 Price Responsive Loads

3.11.1 A *registered market participant* for a *price responsive load* that intends to consume *energy* in the *real-time market* shall submit an *energy bid* in the *day-ahead market*. Such *dispatch data* shall:

3.11.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, by providing, at a minimum, the information specified in Appendix 7.2; and

3.11.1.2 comply with section 3.4.7.

3.11.2 For a set of *load equipment* that is associated with both a *price responsive load* and an *hourly demand response resource*, the sum of the maximum *bid* quantities submitted on each such *price responsive load* and *hourly demand response resource* shall not exceed the maximum quantity permitted under 3.5.9.1 for the *price responsive load*.

3.12 Transmission System Information

3.12.1 Each *transmitter* whose *transmission system* is part of the *IESO-controlled grid* shall provide the *IESO* with the *transmission system* information described in Appendix 7.4 in such form as the *IESO* may specify.

3.12.2 Each *transmitter* referred to in section 3.12.1 shall update the information described in Appendix 7.4 so that it is current at:

3.12.2.1 15:00 EST on the day which is two days prior to the relevant *dispatch day*;

3.12.2.2 05:00 EST on the day prior to the relevant *dispatch day*;

3.12.2.3 10:00 EPT on the day prior to the relevant *dispatch day*; and

3.12.2.4 any time subsequent to 10:00 EPT on the day prior to the relevant *dispatch day* up to the beginning of the relevant *dispatch hour* if there is a material change in the information required by this section.

3A. The Scheduling Process

3A.1 Information Used by the IESO to Determine Schedules and Prices

3A.1.1 The *IESO* shall determine a random daily *dispatch* order for *variable generators* that are *registered market participants* in accordance with the applicable *market manual*.

3A.1.2 The *IESO* shall represent power flow relationships between locations on the *IESO-controlled grid* and between the *IESO control area* and adjoining *control areas* for use in Appendices 7.5, 7.5A, 7.6.

3A.1.3 The *IESO* shall use an *IESO-controlled grid model,* with constraints for *interconnections* represented as *intertie* limits for each *intertie zone* or multiple *intertie zones*.

3A.1.4 Limits on *intertie* flows between the *integrated power system* and neighbouring *transmission systems* shall be based on:

3A.1.4.1 a simple model that assumes that each *intertie meter* is *connected* to an isolated *intertie zone* by a single transmission line;

3A.1.4.2 the *IESO's* best estimate of the maximum flow on the single transmission line to each *intertie zone*, given the status of the neighbouring *transmission systems* and expected or actual unscheduled flows (including as unscheduled flows any flows planned by the *IESO* to balance interchange accounts with other *control area operators*). The *IESO's* best estimate of the maximum flow on the single transmission line to an *intertie zone* may reflect the *integrated power system's* limited capability to supply and export *energy* to an *intertie zone* and applicable neighbouring *transmission system* without scheduling imported *energy* to supply the exported *energy*; and

3A.1.4.3 a net *interchange scheduling* limit to represent the *integrated power system's* ability to respond to hourly *interchange schedule* deviations and maintain the *reliability* of the *IESO-controlled grid.*

3A.1.5 Constraints on the use of the *IESO-controlled grid* shall be determined by the *IESO* as necessary to maintain *reliable* system operations, which shall include, at a minimum, the following:

3A.1.5.1 the largest applicable *contingency events* and any increments above these required to satisfy applicable *reliability standards*;

3A.1.5.2 *security* constraints on identified *facilities*;

3A.1.5.3 minimum requirements for each class of *operating reserve*;

3A.1.5.4 the *IESO*'s commitments to neighbouring *transmission systems* for *operating reserve* and *regulation*;

3A.1.5.5 the availability and need for contracted *ancillary services* and *reliability must-run resources*; and

3A.1.5.6 *reliability* constraints associated with *interchange schedules* as referred to in section 3A.1.4.3.

3A.1.6 The *IESO* shall determine the most recent projections of forecast data and other information pertaining to the *electricity system* which relates to future periods of time, as are available to the *IESO*.

3A.1.7 The *IESO* shall determine the demand forecasts.

3A.2 Uses of the Pre-Dispatch Calculation Engine and Real-Time Calculation Engine

3A.2.1 The *IESO* shall, as far as practical, use the outputs of the *pre-dispatch calculation engine* and *real-time calculation engine* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because the *pre-dispatch calculation engine* or *real-time calculation engine* is only an approximation of a complex physical reality and may sometimes malfunction, the *IESO* may modify or override the results of the *pre-dispatch calculation engine* and the *real-time calculation engine* when issuing *dispatch instructions* pursuant to section 7.

4. The Day-Ahead Market

4.1 Day-Ahead Market Scheduling Process

4.1.1 The *IESO* shall determine *day-ahead schedules* in order to create financially binding obligations on the day prior to the relevant *dispatch day* to facilitate *settlement*, and to provide itself and *market participants* with advance information and projections necessary to plan the physical operation of the *electricity system*.

4.2 Determining the Day-Ahead Schedule

4.2.1 When determining the *day-ahead schedule* applicable to the first hour of the next *dispatch day*, the *IESO* may disregard the net *interchange schedule* limit.

4.3 Day-Ahead Market Scheduling Process Failure

4.3.1 If the *IESO* fails to produce valid results, the *IESO* may rerun the *day-ahead market calculation engine* before *day-ahead market expiration*. Where the *IESO* reruns the *day-ahead market calculation engine*, the *IESO* shall notify *market participants* of the rerun and of any revised inputs in accordance with the applicable *market manual*.

4.3.2 The *IESO* shall declare a failure of the *day-ahead market* by 15:30 EPT if it does not *publish day-ahead market* results in accordance with sections 4.7.2.

4.3.3 If the *IESO* declares a failure of the *day-ahead market*:

4.3.3.1 as soon as reasonably practicable after the failure, the *IESO* shall notify *market participants* of the failure of the *day-ahead market* for the relevant *dispatch day*; and

4.3.3.2 *registered market participants* shall not be subject to sections 3.1.11, 3.1.12, and 3.1.13 for the relevant *dispatch day*.

4.4 Administration of the Day-Ahead Market Calculation Engine

4.4.1 The *IESO* shall administer the *day-ahead market calculation engine* in accordance with Appendix 7.5.

4.5 Information Used by the Day-Ahead Market Calculation Engine

4.5.1 The *IESO* shall use the most current valid information in accordance with Appendix 7.5 as inputs to the *day-ahead market calculation engine*.

4.6 Passes of the Day-Ahead Market Calculation Engine

4.6.1 The *day-ahead market calculation engine* shall determine commitments, schedules, and prices over a 24-hour period for *energy* and *operating reserve*. The *day-ahead market calculation engine* shall execute three passes, which shall include the:

4.6.1.1 Market Commitment and Market Power Mitigation Pass in accordance with section 7 of Appendix 7.5;

4.6.1.2 Reliability Scheduling and Commitment Pass in accordance with section 17 of Appendix 7.5; and

4.6.1.3 DAM Scheduling and Pricing Pass in accordance with section 19 of Appendix 7.5.

4.7 Publishing Day-Ahead Market Information

Daily information

4.7.1 Prior to the *day-ahead market restricted window* or as soon as practicable thereafter, the *IESO* shall *publish* the following information for the next *dispatch day*:

4.7.1.1 *intertie* scheduling limits; and

4.7.1.2 area *operating reserve* constraints.

4.7.2 As soon as practicable after the *day-ahead market calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *day-*

ahead market calculation engine, the *IESO* shall *publish* the following hourly information for the *day-ahead market* results for the next *dispatch day*:

4.7.2.1 any area *operating reserve* shortfalls;

4.7.2.2 the forecast of expected total system load, total system losses, available *energy*, and *operating reserve* requirements;

4.7.2.3 binding *security* constraints;

4.7.2.4 aggregated *energy offers* and *bids* submitted and cleared for each *virtual transaction zone*;

4.7.2.5 *locational marginal prices* for *energy* and *operating reserve* in the *IESO control area*;

4.7.2.6 *virtual zonal prices*;

4.7.2.7 the *day-ahead market Ontario zonal price*; and

4.7.2.8 *locational marginal prices* for *energy* and *operating reserve* for each *intertie zone*.

Other information

4.7.3 The *IESO* shall *publish* the daily *dispatch* order determined randomly by the *IESO* in accordance with section 3A.1.1 for *variable generation resources* at least once each calendar month in accordance with the applicable *market manual.*

4.7.4 The *IESO* shall *publish* the shadow prices for each binding *security* constraint that are used to generate *locational marginal prices* by the *day-ahead market calculation engine* no sooner than five calendar days after the *trading day*.

4.7.5 As soon as practicable after the *day-ahead market calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *day-ahead market calculation engine,* and the conditions set out in section 10.5.1 of Appendix 7.5 are met, the *IESO* shall *publish* a summary of the hours in the study period related to global market power conditions for *energy*.

4.8 Issuing Market Participant-Specific Day-Ahead Information

4.8.1 As soon as practicable after the *day-ahead market calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *day-ahead market calculation engine,* the *IESO* shall issue daily the following information to any appropriate *market participants* for the applicable *resources*:

4.8.1.1 a summary of the *dispatch data* submitted for the *day-ahead market* for the associated *resources;*

4.8.1.2 the calculated modelled data for *combined cycle plants;*

4.8.1.3 *day-ahead schedules* for *energy* and *operating reserve*;

4.8.1.4 *day-ahead operational commitments*;

4.8.1.5 schedules to provide *contracted ancillary services*;

4.8.1.6 any requirements to submit an *offer* or *bid* under a *reliability must-run contract*;

4.8.1.7 the *availability declaration envelopes*; and

4.8.1.8 a notice that there has been a failure of the conduct test and price impact test in accordance with section 14 of Appendix 7.5, if applicable.

5. The Pre-Dispatch Process

5.1 Pre-Dispatch Scheduling Process

5.1.1 The *IESO* shall determine *pre-dispatch schedules* in order to provide itself and *market participants* with advance information and projections necessary to plan the physical operation of the *electricity system*.

5.1.2 The *IESO* shall prepare a revised *pre-dispatch schedule* for each *dispatch day* whenever the *IESO* determines that changed circumstances have made the previous *pre-dispatch schedule* materially incorrect. A revised *pre-dispatch schedule* shall be determined only for *dispatch hours* following the changes that make it necessary.

5.1.3 Each time the *IESO* determines a *pre-dispatch schedule*, it shall also determine the associated projected *market prices* for *energy* and *operating reserve*.

5.2 Determining the Pre-Dispatch Schedule

5.2.1 The *IESO* shall use the *pre-dispatch calculation engine* with revised inputs reflecting the changes in conditions or projections to determine each *pre-dispatch schedule*.

5.2.2 The quantity for *energy* or *operating reserve* in a *registered market participant's pre-dispatch schedule* for a *boundary entity resource,* for any hour after the first two hours relative to the current *dispatch hour*, shall not exceed the corresponding quantity for that hour in the *registered market participant*'s *day-ahead schedule* for the *boundary entity resource*. Notwithstanding the foregoing, the *IESO* may permit the quantity of any *energy* or *operating reserve* in a *registered market participant*'s *pre-dispatch schedule* for a *boundary entity resource* to exceed the corresponding quantity for the hour in the *registered market participant*'s *day-ahead schedule* for the *boundary entity resource*, in the following circumstances:

5.2.2.1 if the *IESO* determines that it is necessary to maintain *reliability*;

5.2.2.2 if the *IESO* declares a failure of the *day-ahead market*;

5.2.2.3 for *energy* scheduled to carry out (a) an *energy* import that is supported by a *system-backed capacity import resource* or a *generator-backed capacity import resource,* or (b) *called capacity export*; or

5.2.2.4 for the purpose of mitigating an over-generation condition.

5.2.3 Subject to sections 10.3.1 and 11.4.1, the *IESO* shall ensure that the scheduled output for a *resource* will meet or exceed its *minimum loading point* for all hours of its *day-ahead operational commitment*, or previous *pre-dispatch operational commitment* in future iterations of the *pre-dispatch schedule* in accordance with section 4.3.6 of Appendix 7.5A.

5.3 Pre-Dispatch Scheduling Process Failure

5.3.1 If the *IESO* fails to produce valid results, the *IESO* may revise inputs to the *real-time calculation engine* as it considers appropriate based on the best available information, which may include but is not limited to:

5.3.1.1 the most recent valid *pre-dispatch schedule*; or

5.3.1.2 the most recent valid *day-ahead schedule*.

5.3.2 If the *IESO* fails to produce valid results, the *IESO* may direct and instruct *resources* to carry out actions consistent with the objectives of the *pre-dispatch process*, based on the best available information. Without limiting the generality of the foregoing, the *IESO* may issue *start-up notices*, notices of decommitment, and *pre-dispatch operational commitments*.

5.4 Administration of the Pre-Dispatch Calculation Engine

5.4.1 The *IESO* shall administer the *pre-dispatch calculation engine* in accordance with Appendix 7.5A.

5.5 Information Used by the Pre-Dispatch Calculation Engine

5.5.1 The *IESO* shall use the most current valid information in accordance with Appendix 7.5A and the applicable *market manuals* as inputs to the *pre-dispatch calculation engine.*

5.6 Passes of the Pre-Dispatch Calculation Engine

5.6.1 The *pre-dispatch calculation engine* shall determine commitments, schedules and prices over the pre-dispatch look-ahead period for *energy* and *operating reserve* in accordance with section 2.1 of Appendix 7.5A. The *pre-dispatch calculation engine* shall execute the Pre-Dispatch Scheduling Process Pass as described in section 7 of Appendix 7.5A.

5.7 Publishing Pre-Dispatch Information

Hourly Information

5.7.1 As soon as practicable after the *pre-dispatch calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *pre-dispatch calculation engine*, the *IESO* shall *publish* hourly the following information in respect of the *pre-dispatch process*:

5.7.1.1 *locational marginal prices* for *energy* and *operating reserve* in the *IESO control area*;

5.7.1.2 *virtual zonal prices*;

5.7.1.3 the pre-dispatch *Ontario zonal price*;

5.7.1.4 *locational marginal prices* for *energy* and *operating reserve* for each *intertie zone*;

5.7.1.5 the forecast of expected total system load, total system losses, available *energy*, and *operating reserve* requirements for the forecast period;

5.7.1.6 any area *operating reserve* shortfalls;

5.7.1.7 a list of the network constraints and *security* constraints that affected the *pre-dispatch schedule*;

5.7.1.8 area *operating reserve* constraints; and

5.7.1.9 *intertie* scheduling limits.

Daily Reports

5.7.2 The *IESO* shall *publish* daily the updated cumulative *locational marginal prices* for hourly *energy* and *operating reserve* in respect of the *pre-dispatch process*.

Other Information

5.7.3 The *IESO* shall *publish* the daily *dispatch* order determined randomly by the *IESO* in accordance with section 3A.1.1 for *variable generation resources* at least once each calendar month in accordance with the applicable *market manual.*

5.7.4 The *IESO* shall *publish* a summary of the hours in the day prior to the relevant *dispatch day* related to global market power conditions for *energy* that meet the conditions in section 10.5.1 of Appendix 7.5A on the day following the relevant *dispatch day*.

5.8 Issuing Market Participant-Specific Pre-Dispatch Information

5.8.1 The most recently issued *pre-dispatch schedule* shall supersede all previous *pre-dispatch schedules* for the same *dispatch hours*.

Hourly Information

5.8.2 As soon as practicable after the *pre-dispatch calculation engine* produces valid results, and, for the avoidance of doubt, there is not a failure of the *pre-dispatch calculation engine*, the *IESO* shall issue hourly the following information in respect of the *pre-dispatch process* to any appropriate *market participants* for the applicable *resources*:

5.8.2.1 the *interchange schedules* for *energy* and *operating reserve*;

5.8.2.2 *extended pre-dispatch operational commitments*;

5.8.2.3 the *pre-dispatch schedules* for *energy* and *operating reserve*;

5.8.2.4 *stand-alone pre-dispatch operational commitments*;

5.8.2.5 *advanced pre-dispatch operational commitments*;

5.8.2.6 the *minimum generation block down-times* used by the *pre-dispatch calculation engine* to infer the *thermal state*;

5.8.2.7 for each *dispatch hour*, the aggregate *reliability must-run resources* that the *IESO* has directed to submit *offers* or *bids*;

5.8.2.8 schedules to provide *contracted ancillary services*;

5.8.2.9 any requirements to submit an *offer* or *bid* under a *reliability must-run contract*;

5.8.2.10 the calculated modelled data for *combined cycle plants;*

5.8.2.11 a notice that there has been a failure of the conduct test and price impact test in accordance with section 14 of Appendix 7.5A, if applicable;

5.8.2.12 the cumulative *energy* schedules relative to the *minimum daily energy limit* and *maximum daily energy limit*; and

5.8.2.13 the actual and forecast number of starts.

Other Information

5.8.3 The *IESO* shall issue to any appropriate *market participants* as soon as practicable, the approval or rejection of an *availability declaration envelope* expansion request pursuant to section 3.1.14.

6. The Real-Time Market

6.1 Real-Time Market Scheduling Process

6.1.1 The *IESO* shall determine *real-time schedules* and use these as the primary determinant for the physical operation of *resources* specified in section 7.1.1A*.*

6.1.2 The *IESO* shall determine a *real-time schedule*, for *dispatchable generation resources*, *dispatchable electricity storage resources*, and *dispatchable loads*, for every *dispatch interval* two minutes before the *dispatch interval* to which it applies.

6.1.3 The *IESO* shall determine, for a *registered market participant*, the *real-time schedule* for a *boundary entity resource*, consisting of an *interchange schedule* for each *dispatch hour* using the outcome of the *pre-dispatch schedule* determined as at the preceding *dispatch hour* and modified as required by the *IESO*.

6.1.4 Where the *IESO* modifies an *interchange schedule* during the *dispatch hour*, it shall assign an *interchange schedule* value for each *dispatch interval* of the impacted *dispatch hour* to reflect any modifications.

6.2 Determining the Real-Time Schedule

6.2.1 The *IESO* shall use the information described in greater detail in the applicable *market manual* and Appendix 7.6 to determine a *real-time schedule* for each *dispatch interval* as follows:

6.2.1.1 *interchange schedule data* shall be input as constant values for the given *dispatch hour* unless otherwise specified by the *IESO* and shall be derived in accordance with the outputs of *the pre-dispatch calculation engine* for each *dispatch hour* as determined under Appendix 7.5A;

6.2.1.2 *intertie* flows at the beginning of each *dispatch interval* shall be set at the *IESO's* best estimate of their actual values, as determined from real-time system data or applicable *interchange schedules* to reflect actual unscheduled flows; and

6.2.1.3 *intertie* flows at the end of each *dispatch interval* shall be set at the value ascribed to such flows in the relevant *interchange schedule*.

6.3 Administration of the Real-Time Calculation Engine

6.3.1 The *IESO* shall administer the *real-time calculation engine* in accordance with Appendix 7.6.

6.4 Information Used by the Real-Time Calculation Engine

6.4.1 The *IESO* shall use the most current valid information in accordance with Appendix 7.6 and the applicable *market manuals* as inputs to the *real-time calculation engine*.

6.5 Passes of the Real-Time Calculation Engine

6.5.1 The *real-time calculation engine* shall determine schedules and prices over the real-time look-ahead period for *energy* and *operating reserve*. The *real-time calculation engine* shall execute the Real-Time Scheduling and Pricing Pass as described in section 7 of Appendix 7.6;

6.6 Publishing Real-Time Information

Five-minute Information

6.6.1 As soon as practicable after the *real-time calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *real-time calculation engine*, the *IESO* shall *publish* the following information:

6.6.1.1 *locational marginal prices* for *energy* and *operating reserve* in the *IESO control area*;

6.6.1.2 *virtual zonal prices*;

6.6.1.3 the *real-time market Ontario zonal price*;

6.6.1.4 *locational marginal prices* for *energy* and *operating reserve* for each *intertie zone*; and

6.6.1.5 the total *energy* and *operating reserve* in *real-time schedules*, the total system load and total system losses, and Ontario *demand.*

Hourly Information

6.6.2 As soon as practicable after the start of the next *dispatch hour* after the *real-time calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *real-time calculation engine*, the *IESO* shall *publish* the following information for each *dispatch interval* of that *dispatch hour*:

6.6.2.1 any area *operating reserve* shortfalls;

6.6.2.2 a list of network and *security* constraints that affected the *real-time schedule;*

6.6.2.3 the total import and export schedules and actual flows of *energy* between the *IESO-controlled grid* and each *intertie zone;* and

6.6.2.4 total *operating reserve* scheduled, and total *energy* from such *operating reserve,* by area.

6.6.3 The *IESO* shall, within one hour after each *dispatch hour*, *publish* information concerning system results and events during that *dispatch hour*. This information shall include, but is not limited to:

6.6.3.1 transmission capacity between the *IESO-controlled grid* and each *intertie zone*; and

6.6.3.2 any *outages* of transmission *facilities.*

Other information

6.6.4 The *IESO* shall *publish* the shadow prices for the binding constraints that are used to generate *locational marginal prices* by the *real-time calculation engine* no sooner than five days after the *trading day.*

Monthly Reports

6.6.5 The *IESO* shall no less than once in each calendar month, *publish* a report listing and giving reasons for all significant differences between *dispatch instructions* issued and the results of the *real-time calculation engine*.

6.6.6 The *IESO* shall *publish* the daily *dispatch* order determined randomly by the *IESO* in accordance with section 3A.1.1 for *variable generation resources* at least once each calendar month in accordance with the applicable *market manual.*

6.7 Issuing Market Participant-Specific Real-Time Information

Five-minute Information

6.7.1 As soon as practicable after the *real-time calculation engine* produces valid results, and for the avoidance of doubt, there is not a failure of the *real-time calculation engine*, the *IESO* shall issue:

6.7.1.1 *real-time schedules* for *energy* and *operating reserve* for each *dispatch interval*; and

6.7.1.2 the schedule to provide *contracted ancillary services*.

Hourly Information

6.7.2 The *IESO* shall, within one hour after each *dispatch hour*, issue the following information to any appropriate *market participants* for the applicable *resources:*

6.7.2.1 a summary of *dispatch instructions* for that *dispatch hour* related to *energy* and *operating reserve*; and

6.7.2.2 the calculated modelled data for *combined cycle plants* used by the *real-time calculation engine.*

6.7.3 For each *boundary entity resource* in respect of which the *dispatch instructions* for a given *dispatch hour* provides for the *dispatch* of more than 0 MW or for a reduction to 0 MW relative to the previous *dispatch hour*, the *IESO* shall*,* as soon as practical and consistent with relevant *reliability standards,* but no later than the start of the *dispatch hour* to which it relates, issue the following information for each such *boundary entity resource* to the appropriate *registered market participant* for that *boundary entity resource:*

6.7.3.1 the *interchange schedule* for *energy* and *operating reserve* for that *resource*; and

6.7.3.2 any request of that *resource* to submit an *offer* or *bid* under a *reliability must-run contract* and the schedule to provide *contracted ancillary services*.

Daily Information

6.7.4 The *IESO* shall issue daily to any appropriate *market participants*, following the *dispatch day*, the summary of the *dispatch data* used by the *real-time calculation engine*.

7. IESO Dispatch Instructions

7.1 Purpose and Timing of Dispatch Instructions

7.1.1 The *IESO* shall determine *dispatch instructions* for each *resource* as described in this section 7, as the primary means of coordinating the real-time operation of the *electricity system*.

7.1.1A The *IESO* shall only issue *dispatch instructions* for a *physical service* to *dispatchable generation resources*, *dispatchable loads*, or *dispatchable storage resources*, and, to the extent authorized by the *market rules*, *resources* other than *boundary entity resources* for a given *dispatch interval* when there is a change in the quantity of a *physical service* to be scheduled from that *resource* during that *dispatch interval* relative to the last *dispatch instruction* issued to the *resource* and with which the *registered market participant* has confirmed compliance with the last *dispatch instruction* in accordance with section 7.1.2 and 7.1.2A

7.1.1B Where the *IESO*:

7.1.1B.1 is not required to issue a *dispatch instruction* to a *resource* specified in section 7.1.1A for a given *dispatch interval* by virtue of section 7.1.1A or 7.2.1A; or

7.1.1B.2 for any reason fails to issue a *dispatch instruction* to a *resource* specified in section 7.1.1A for a given *dispatch interval*,

subject to section 7.1.1B1, the last *dispatch instruction* issued to the *resource* and with which the *registered market participant* has confirmed compliance in accordance with sections 7.1.2 and 7.1.2A shall, for all purposes under these *market rules* but subject to section 7.1.4 and 7.4.3, be deemed to be the *dispatch instruction* issued for that *dispatch interval* for that *resource*.

7.1.1B1 Section 7.1.1B shall apply until the *registered market participant* for a *variable generation resource* is issued a *release notification* for that *resource*.

7.1.1C Notwithstanding the identification of a portion of the *energy* to be consumed by a *dispatchable load* as a *non-dispatchable load* under section 3.3.3.1*,* the *IESO* shall issue *dispatch instructions* in accordance with the applicable *market manual* to that *resource* including that portion that has been identified pursuant to section 3.3.3.1.

7.1.2 Subject to section 7.1.1A, the *IESO* shall issue *dispatch instructions* for each *resource* specified in section 7.1.1A, for which a *dispatch instruction* is required no later than the start of each *dispatch interval* or, where section 7.1.4 or 7.4.3 applies, within a *dispatch interval*. The *IESO* shall:

7.1.2.1 issue such *dispatch instructions* using the systems and protocols defined in the applicable *market manual*; and

7.1.2.2 record and time-stamp all such *dispatch instructions*, store such records for at least seven years and make such records available for purposes of audit and dispute resolution in accordance with these *market rules*.

7.1.2A Each *registered market participant* shall:

7.1.2A.1 acknowledge receipt of; and

7.1.2A.2 confirm its intention to comply or not to comply with,

each *dispatch instruction* issued to it in accordance with section 7.1.2 in respect of each of its *resources*, using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.2A1 The *IESO* shall issue a *release notification* to a *registered market participant* for a *variable generation resource* if the *resource* is not required to be at or below forecasted output. Each *registered market participant* for a *variable generation resource* shall acknowledge receipt of each *release notification* using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.2B Confirmation by a *registered market participant* of its intention not to comply with a *dispatch instruction* pursuant to section 7.1.2A shall constitute non-compliance with the *dispatch instruction* by the *registered market participant* for all purposes under these *market rules*, including but not limited to section 7.5.

7.1.2C Where a *registered market participant* associated with a *dispatchable load* has identified all or a portion of the *energy* to be consumed at that *resource* as *non-dispatchable load* under section 3.3.3.1 and the *IESO* has issued a *dispatch instruction* requiring a reduction of such non-dispatchable consumption pursuant to section 7.1.1C, the *registered market participant* shall confirm its intention not to comply with each such *dispatch instruction* in accordance with section 7.1.2A and the applicable *market manual*.

7.1.2D Confirmation by a *registered market participant* of its intention not to comply with a *dispatch instruction* pursuant to section 7.1.2C shall not constitute non-compliance with the *dispatch instruction* by the *registered market participant* for all purposes under these *market rules*, including but not limited to section 7.5.

7.1.3 The *IESO* shall issue *dispatch instructions*, for greater certainty, in the form of *interchange schedules*, for each *boundary entity resource*, for which a *dispatch instruction* is required prior to each *dispatch hour*. The *IESO* shall:

7.1.3.1 [Intentionally left blank]

7.1.3.2 issue such *dispatch instructions* using the systems and protocols defined in the applicable *market manual*; and

7.1.3.3 record and time-stamp all such *dispatch instructions,* store such records for at least seven years and make such records available for purposes of audit and dispute resolution in accordance with these *market rules*.

7.1.3A Each *registered market participant* shall acknowledge receipt of each *dispatch instruction* issued to it in accordance with section 7.1.3 in respect of each of its *boundary entity resources* using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.4 The *IESO* may issue *dispatch instructions* within the *dispatch interval*, instructing any *resource* with a valid *energy offer* or *bid*, to increase or decrease *energy* production or consumption as specified in its *offers* or *bids* for *energy*. When a *dispatch instruction* is issued within a *dispatch interval* pursuant to this section 7.1.4, the last *dispatch instruction* for *energy* or each class of *operating reserve,* as the case may be, shall be the sole *dispatch instruction* used for *settlement* purposes for that *dispatch interval.*

7.1.5 Where a *contingency event* is occurring or has occurred, the *IESO* may temporarily cease issuing *dispatch instructions* in the manner otherwise required by section 7.1.2. In such cases, *registered market participants* shall comply with section 7.1.1B or 7.4.3, as the case may be.

7.1.6 The *IESO* shall, on a reasonable efforts basis, determine and issue *dispatch* advisories for each *dispatchable resource*, for information purposes only. *Dispatch* advisories are determined and issued every 5 minutes to each *dispatchable resource* to provide an indication of potential future *dispatch instructions* and *operating reserve* schedules.

7.2 Information Used to Determine Dispatch Instructions

7.2.1 Subject to 7.2.1A, the *IESO* shall use reasonable efforts to ensure that the *dispatch instructions* issued with respect to each *resource* specified in section 7.1.1A, for each *dispatch interval,* are consistent with the most recent *real-time schedule* for that *resource* and *dispatch interval*.

7.2.1A The *IESO* shall not be required to issue *dispatch instructions,* or, in the event that the *IESO* does issue *dispatch instructions*, shall not be required to satisfy the requirements of section 7.2.1 if:

7.2.1A.1 the *security* and *adequacy* of the system would be endangered by implementing the most recent *real-time schedule*;

7.2.1A.2 the *real-time calculation engine* has failed, or has produced a *real-time schedule* that is clearly and materially in error;

7.2.1A.3 material changes have occurred subsequent to the *IESO's* determination of the most recent *real-time schedule*, including a failure of an element of a *transmission system* or failure of a *resource* to follow *dispatch instructions*; or

7.2.1A.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13.

7.2.2 If the *IESO* anticipates that an over-generation or an under-generation condition may occur, it shall issue advisory notices in accordance with section 12.1 but shall continue using the procedures described in sections 4, 5 and 6 to determine *day-ahead schedules*, *pre-dispatch schedules*, *real-time schedules* and the associated *market prices.*

7.2.3 If the *IESO* determines prior to issuing *dispatch instructions* that the market responses to the *market prices* will be sufficient to eliminate the over-generation or under-generation condition, the *IESO* shall take no *emergency* action and shall issue advisory notices so indicating.

7.2.4 If the *IESO* determines prior to issuing *dispatch instructions* that market responses will not eliminate the over-generation or under-generation condition, it shall declare an *emergency operating state* to resolve the conditions in accordance with section 7.7.

7.2.5 Subject to section 7.2.5A, the *IESO* shall use reasonable efforts to ensure that the *dispatch instructions* issued with respect to each *boundary entity resource*, for each *dispatch hour* are consistent with the *pre-dispatch schedule* for that *dispatch hour* as determined in accordance with section 6.1.3.

7.2.5A The *IESO* shall not be required to issue *dispatch instructions*, or, in the event that the *IESO* does issue *dispatch instructions*, shall not be required to satisfy the requirements of section 7.2.5 if:

7.2.5A.1 the *security* and *adequacy* of the system would be endangered by implementing the *pre-dispatch schedule*;

7.2.5A.2 the *pre-dispatch calculation engine* has failed, or has produced a *pre-dispatch schedule* that is clearly and materially in error;

7.2.5A.3 material changes have occurred subsequent to the *IESO's* determination of the *pre-dispatch schedule*, including a failure of an element of a *transmission system* or failure of a *resource* to follow *dispatch instructions*;

7.2.5A.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13;

7.2.5A.5 an external *control area operator* calls a *called capacity export* in accordance with section 20; or

7.2.5A.6 the *interchange schedule* violates the net *interchange schedule* limit.

7.3 The Content of Dispatch Instructions

7.3.1 The *IESO* shall, subject to section 7.1.1A, issue *dispatch instructions* for each *dispatch interval* to each *resource* specified in section 7.1.1A indicating for that *dispatch interval*:

7.3.1.1 the rate at which *energy* is to be injected into or withdrawn from the *IESO-controlled grid* (in MW) at the end of the *dispatch interval*;

7.3.1.2 the amount of each class of *operating reserve* that is to be in a condition to respond to a *dispatch instruction* issued pursuant to section 7.4.3 calling for additional *energy* production or reductions of *energy* withdrawals; and

7.3.1.3 the amount of *reactive support* and *regulation* that is to be provided under *contracted ancillary service* contracts or *reliability must-run contracts* or as a consequence of any requirement to provide *reactive support* and *regulation* which derives from the application of these *market rules*.

7.3.2 The *dispatch instructions* for any *resource* specified in section 7.1.1A shall:

7.3.2.1 be consistent with the current operating status of that *resource* and with any operational constraints described in the most recent *dispatch data* submitted by the *registered market participant* for that *resource*; and

7.3.2.2 be used by the *IESO* for the purpose of declaring the *resource* as non-conforming in accordance with section 7.5.4.

7.3.3 [Intentionally left blank – section deleted]

7.3.4 The *IESO* shall issue *dispatch* instructions for each *dispatch hour* to each *boundary entity resource*, indicating for that *dispatch hour*:

7.3.4.1 the rate at which *energy* is to be injected into or withdrawn from the *IESO-controlled grid* (in minutes) from the specified *intertie zone*, which rate shall be consistent with all relevant *reliability standards*;

7.3.4.2 the amount of each class of *operating reserve* that is scheduled and the ramp rates associated with the *energy* if called on; and

7.3.4.3 the amount of *reactive support* and *regulation* that is to be provided under *reliability must-run contracts* or as a consequence of any requirement to provide same which derives from the application of these *market rules.*

7.3.5 The *dispatch instructions* for any *boundary entity resource* shall:

7.3.5.1 be consistent with the current *dispatch data* for that *resource* and with any *interconnection* limitations associated with the *resource*.

7.4 IESO Dispatch of Operating Reserve

7.4.1 The *IESO* shall:

7.4.1.1 subject to section 7.1.1A, issue to each *resource* specified in section 7.1.1A, which has made an *offer* for the delivery of *operating reserve* for a particular *dispatch hour*, *dispatch instructions* for each *dispatch* *interval* consistent with the results of the *real-time calculation engine* and the procedures detailed in section 6, instructing the *registered market participant* responsible for that *resource* as to the quantity of *operating reserve* that is to be provided by that *resource* in that *dispatch interval*; and

7.4.1.2 issue to each *boundary entity resource,* which has made an *offer* for the delivery of *operating reserve* for a particular *dispatch hour*, *dispatch instructions* for that *dispatch hour* consistent with the results of the *pre-dispatch calculation engine* and the procedures detailed in section 6, instructing the *registered market participant* responsible for that *resource* as to the quantity of *operating reserve* to be provided by that *resource* in that *dispatch hour.*

7.4.2 Each *resource* to which section 7.4.1 applies shall maintain unused *generation capacity, electricity storage capacity,* or load reduction capacity during that *dispatch interval*, consistent with the *dispatch instructions* issued to it under these *market rules*, so as to be able to increase *energy* production or reduce *energy* withdrawal as soon as possible upon being instructed to do so by the *IESO* pursuant to section 7.4.3.

7.4.2.1 A *market participant* shall be subject to the *operating reserve* non-accessibility charge *settlement amount* in accordance with MR Ch.9 s.3.10 if it fails to maintain unused *generation capacity, electricity storage capacity,* or load reduction capacity equal to or greater than its total amount of scheduled *operating reserve* during any *interval* in which it is scheduled to provide *operating reserve* but is not *dispatched* to increase *energy generation* or reduce *energy* withdrawal pursuant to section 7.4.3. The *market participant* may also be subject to compliance actions in accordance with MR Ch.3 s.6.

7.4.3 Where a *contingency event* has occurred or is occurring, the *IESO* may issue *dispatch instructions* within the *dispatch interval*, instructing a *resource* specified in section 7.1.1A, providing *operating reserve* to begin increasing *energy* production or reducing *energy* withdrawal as specified in its *offers* of *operating reserve*. *Dispatch instructions* issued in respect of a *boundary entity resource* providing *operating reserve* shall be such as to ensure that the *energy* associated with each *offer* of *operating reserve* is scheduled by the *IESO* in a manner consistent with all relevant *reliability standards* for activation of *operating reserve* and as agreed upon by the entity scheduling the resulting *energy* transfer.

7.4.4 The *IESO* shall, when *dispatching resources* providing *operating reserve* to produce *energy* pursuant to section 7.4.3, call first on the *resource* in each area that has *offered* the lowest price (in $/MWh) for *energy* produced from scheduled *operating reserve* in that area. If such *resource* is instructed to produce *energy* but does not do so as rapidly as instructed, or if the *IESO* needs additional *energy* from *operating reserve* in that area, the *IESO* shall call upon the *resource offering* the next-lowest price for *energy* from *operating reserve*. If the *IESO* determines that calling upon *resources* in strict order of increasing price of *energy* would mean that it would be unable to respond in a timely fashion to a contingency for which the *IESO* would issue a *dispatch instruction* pursuant to section 7.4.3, the *IESO* may call upon *resources* out of such strict order but shall as far as is practical call *resources* to reflect the intent of this section 7.4.4.

7.4.5 When *operating reserves* are activated as a result of a *contingency event*, the otherwise applicable *ten-minute operating reserve* requirements shall be reduced by a corresponding amount and shall subsequently be recovered to pre-contingency levels in a manner consistent with MR Ch.5 ss.4.5.10 and 4.5.21.

7.4.6 A *market participant* that failed to maintain unused *generation* (or load reduction) *capacity* equal to or greater than their total amount of scheduled *operating reserve* shall be subject to the real-time make-whole payment reversal *settlement amount* and the real-time *generator offer* guarantee claw back *settlement amount* in accordance with MR Ch.9 s.3.10.

7.5 Compliance with Dispatch Instructions

7.5.1 Each *registered market participant* shall ensure that each of its *resources* complies with *dispatch instructions* issued to it under these *market rules*. Without limiting the generality of MR Ch.3 s.6.2, non-compliance with *dispatch instructions* other than for the reasons referred to in section 7.5.3 shall be a breach of the *market rules* and may be sanctioned in accordance with MR Ch.3 s.6.2 and with this section 7.5.

7.5.2 A *registered market participant* that expects its *resource* specified in section 7.1.1A, to operate in a manner that, for any reason, differs materially from the *dispatch instructions* issued to it in accordance with these *market rules* shall so notify the *IESO* as soon as possible. The *IESO* shall *publish* guidelines defining when a difference is material and how notice shall be provided for the purposes of this section 7.5.2 and of section 7.5.3.

7.5.3 Compliance with a *dispatch instruction* for a *resource* specified in section 7.1.1A, is not required if such compliance would endanger the safety of any person, damage equipment, or violate any *applicable law*. A *market participant* that departs from *dispatch instructions* for any such reason shall so notify the *IESO* in accordance with section 7.5.2.

7.5.4 If failure by a *resource* specified in section 7.1.1A, to comply with a dispatch instruction endangers *electricity system reliability*, the *IESO* shall declare the *resource* to be non-conforming and shall take any actions allowed by sections 7.5.6 to 7.5.7 or any other provisions of these *market rules* which the *IESO* determines appropriate.

7.5.5 [Intentionally left blank – section deleted]

7.5.6 If the *IESO* declares a *resource* to be non-conforming under section 7.5.4:

7.5.6.1 the *IESO* shall require the *registered market participant* for that *resource* to explain the reason for the non-compliance and shall record the response;

7.5.6.2 if the *IESO* determines that the *resource* is physically incapable of implementing the *dispatch instructions*, the *IESO* may require revision in the registration information for the non-conforming *resource*; and

7.5.6.3 if the *IESO* is not satisfied that the *resource* will respond to future *dispatch instructions*, the *IESO* may direct the *resource* to follow, as closely as practicable, an output or withdrawal profile specified by the *IESO*, and shall thereafter represent the *resource* as a *self-scheduling generation resource*, *self-scheduling electricity storage resource* or *non-dispatchable load* having the specified profile until the non-conforming *resource* satisfies the *IESO* that it has remedied the conditions causing the non-conformance.

7.5.7 Until the *registered market participant* for a non-conforming *resource* responds to the requirements of this section 7.5 to the satisfaction of the *IESO*, such *resource* shall continue to be designated as non-conforming, and such failure to respond on the part of that *registered market participant* may be referred by the *IESO* to the *market surveillance panel* at any time.

7.5.8 The *IESO* shall assume that a *boundary entity resource* will comply fully with all *dispatch instructions* for *energy* or *operating reserves* upon confirmation of the relevant *interchange schedule* with the appropriate scheduling entity.

7.5.8A A *registered market participant* associated with a *boundary entity resource* shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule *energy* and *operating reserve*, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.

7.5.8B The *IESO* may take actions pursuant to MR Ch.3 s.6.6.10A and shall assess a real-time import or export failure charge as determined in MR Ch.9 s.3.7 where a *registered market participant* associated with a *boundary entity resource* fails to schedule *energy* or *operating reserve*, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable *interchange schedule*, other than for bona fide and legitimate reasons as determined by the *IESO.* Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the *market participant* or due to *IESO* or external scheduling entity error or action, including those reasons specified in the applicable *market manual*.

7.5.9 In addition to any other sanction or consequence provided for in these *market rules*, the *IESO* may disqualify from future participation in the *operating reserve market* any *resource* that consistently fails to increase *energy* generation or reduce *energy* withdrawal when called upon in accordance with Chapter 7.

7.6 Dispatch Scheduling Errors

7.6.1 A *dispatch scheduling error* shall be deemed to have occurred if either:

7.6.1.1 an *arbitrator* determines that the *IESO* has made a *dispatch scheduling error*; or

7.6.1.2 the *IESO* declares that it has made a *dispatch scheduling error*, on its own initiative, including pursuant to MR Ch.9 s.6.9 or further to a *notice of disagreement* filed or other *settlement* dispute initiated by a *market participant* pursuant to MR Ch.9 ss.6.8 or 6.10.

7.6.2 When a *dispatch scheduling error* has occurred, the *IESO* shall not adjust *market prices* but shall, subject to section 7.6.3 and notwithstanding MR Ch.1 s.13.1.2, be strictly liable to compensate a *market participant* for damages suffered by the *market participant* as a result of the *dispatch scheduling error,* assessed in accordance with MR Ch.1 s.13.1.4.

7.6.3 A *market participant* that wishes to claim compensation pursuant to section 7.6.2 shall:

7.6.3.1 where the *dispatch scheduling error* was determined to have been made pursuant to section 7.6.1.1, request the *arbitrator* to determine the *market participant's* entitlement to and amount of, if any, such compensation; and

7.6.3.2 where the *dispatch scheduling error* was determined to have been made pursuant to section 7.6.1.2, request that the *IESO* determine the *market participant's* entitlement to and amount of, if any, such compensation,

with the amount, if any, in either case being determined in accordance with section 7.6.4.

7.6.4 Any amount determined by an *arbitrator* or by the *IESO,* as the case may be, pursuant to section 7.6.3 or 7.6.5 shall be assessed in accordance with MR Ch.1 s.13.1.4 and shall only include such amount as may be required to account for *settlement amounts* outlined in MR Ch.9 ss.3.1, 3.2. 3.8, 4.7 and 4.8.

7.6.5 If a *market participant* wishes to dispute a determination made by the *IESO* pursuant to section 7.6.3.2, it shall submit the matter to the dispute resolution process set forth in MR Ch.3 s.2 and shall, if the good faith negotiations referred to in MR Ch.3 ss.2.5.3A and 2.5.3B fail to resolve the matter, request in the *notice of dispute* that the *arbitrator* determine the *market participant's* entitlement to the compensation referred to in section 7.6.2, the amount, if any, of such compensation or both, as the case may be.

7.7 Additional IESO Powers in Emergency and High-Risk Conditions

7.7.1 During real-time operations, the *IESO* is responsible for declaring an *emergency operating state* or a *high-risk operating state* under circumstances described in MR Ch.5 ss.2.3 and 2.4.

7.7.2 The *IESO's* primary responsibility in an *emergency operating state* or a *high-risk operating state* is to preserve system *reliability*, with a secondary responsibility to restore normal system conditions and operation of the *IESO-administered markets* as soon as practicable.

7.7.3 Where an *emergency operating state* or a *high-risk operating state* has been declared, the *IESO* may implement any of the actions detailed in MR Ch.5 ss.2.3, 2.4, 5.8 and 5.9.

7.7.4 The *IESO* may determine any additional compensation payable in respect of *physical services* acquired during an *emergency operating state* or a *high-risk operating state*.

8. Determining Market Prices and Economic Operating Points

8.1 Purpose and Timing of Determining Market Prices

8.1.1 The *IESO* shall use the procedures in this section 8 to determine the *market prices* for *energy* and *operating reserve* in the *IESO control area* and the *intertie zones* that are used for the market *settlement process* pursuant to the provisions of MR Ch.9.

8.1.2 Subject to section 8.4A, the *IESO* shall determine *market prices* for *energy* and *operating reserve* in accordance with sections 8.2 and 8.3, and *publish* such *market prices* in accordance with sections 4, 5 and 6, respectively.

8.2 Market Prices for the Day-Ahead Market and the Real-Time Market

8.2.1 The *IESO* shall determine *market prices* for *energy* and *operating reserve* (a) for the *day-ahead market* using the *day-ahead market calculation engine*, and (b) for the *real-time market*, using the *pre-dispatch calculation engine* and *real-time calculation engine*.

8.2.2 The *market prices* produced in accordance with section 8.2.1 may be the prices that are used for *settlement* purposes, subject to MR Ch.9 s.2.12.1.

8.3 Ex-Post Determination of Economic Operating Points

8.3.1 For the purposes of calculating *day-ahead market* and *real-time market* make-whole payment *settlement amounts* in accordance with MR Ch.9 ss.3.4 and 3.5, the *IESO* shall determine economic operating points within six calendar days of the applicable *dispatch day* in accordance with sections 8.3.2, 8.3.3 and 8.3.4.

8.3.2 For each *resource* eligible to receive a *day-ahead market* make-whole payment *settlement amount* in accordance with MR Ch.9 s.3.4.1*,* the *IESO* shall determine lost cost economic operating points for *energy* and *operating reserve* for each hour of the *day-ahead market* in accordance with Appendix 7.8.

8.3.3 For each *resource* eligible to receive a *real-time market* make-whole payment *settlement amount* in accordance with MR Ch.9 s.3.5.1, the *IESO* shall determine lost cost economic operating points and lost opportunity cost economic operating points for *energy* and *operating reserve* for each *dispatch interval* of the *real-time market* in accordance with Appendix 7.8.

8.3.4 If the *IESO* has established an *administrative price* in accordance with section 8.4A, the economic operating points determined in accordance with section 8.3.2 and 8.3.3 shall be calculated using the *administrative price,* as applicable.

8.4 [Intentionally left blank]

8.4A Administrative Pricing

8.4A.1 This section 8.4A applies only in respect of the establishment of *administrative prices* for *energy* and *operating reserve* for the *day-ahead market* and *real-time market*.

8.4A.2 Subject to section 8.4A.3, the *IESO* shall establish *administrative prices* for the *real-time market* and the *day-ahead market*, where applicable, within four *business days* of the affected *dispatch day* when:

8.4A.2.1 the *real-time market* for *energy* or *operating reserve* has been suspended in accordance with section 13;

8.4A.2.2 the *IESO* is unable to *publish* a *market price* for *energy* or *operating reserve* for the *real-time market* in accordance with section 8.1.2 due to a failure in or *planned outage* of the software, hardware or communications systems that supports the operation of the *real-time calculation engine*;

8.4A.2.3 the *IESO* determines, pursuant to the price error materiality thresholds established by the *IESO,* that a *published market price* for *energy* or *operating reserve* for the *real-time market* is incorrect due to circumstances provided for in section 8.4A.3B; or

8.4A.2.4 the *IESO* determines, pursuant to the price error materiality thresholds established by the *IESO*, that a *published market price* for *energy* or *operating reserve* for the *day-ahead market* is incorrect due to circumstances provided for in section 8.4A.3C and the error is isolated to *market price* calculations or *publishing,* and has not impacted *day-ahead schedules*;

and all such *administrative prices* shall be the *market prices* for *energy* and *operating reserve* for the applicable *dispatch hour* in the *day-ahead market* or *dispatch interval* in the *real-time market* for all purposes under these *market rules*.

8.4A.3 The *IESO* is not required to establish *administrative prices* in the circumstances provided by sections 8.4A.2.3 or 8.4A.2.4 if the *IESO* is not aware of those circumstances before such time as is practicable for the *IESO* to establish *administrative prices* within four *business days* of the affected *dispatch day.*

8.4A.3A The *IESO* shall inform *market participants* as soon as practicable whenever a *published market price* is an *administrative price*.

8.4A.3B For the purposes of section 8.4A.2.3, a published *energy* or *operating reserve market price* will be subject to *administrative prices* if it is incorrect due to an input in the *real-time calculation engine* and relates to any of the following:

8.4A.3B.1 the formation of an *electrical island*

8.4A.3B.2 the loss or corruption of inputs to the *pre-dispatch calculation engine* or *real-time calculation engine* due to an:

(a) operational telemetering failure;

(b) *IESO-administered markets* software failure; or

(c) *IESO* business process failure.

8.4A.3C For the purposes of section 8.4A.2.4, a published *energy* or *operating reserve market price* will be subject to *administrative prices* if it is incorrect due to the loss or corruption of the *day-ahead market calculation engine* data due to an *IESO* business process failure.

Administration of Prices Due to Failures or Planned Outages of Market Systems, Publication of Incorrect Prices, Implementation of an Emergency Control Action

8.4A.4 In circumstances where *administrative prices* are required under sections 8.4A.2.2, 8.4A.2.3, or 8.4A.2.4 the *IESO* shall use the best available *dispatch data* to establish *administrative prices* that would, to the extent practical, reflect the *market prices* that would have otherwise been produced by the *day-ahead market* or *real-time market*, but for the event causing *market prices* to be administered.

8.4A.5 Where the *IESO* establishes *administrative prices* pursuant to sections 8.4A.2.2, 8.4A.2.3, or 8.4A.2.4, the *market prices* for the applicable *dispatch hour* in the *day-ahead market* or *dispatch interval* in the *real-time market* shall be as the *IESO* determines appropriate consistent with the principle stated in section 8.4A.4, and shall be the *market prices* from one, or a combination of, the following methods to establish *administrative prices*:

8.4A.5.1 the recalculated *market prices* determined using software that replicates the applicable calculation engine;

8.4A.5.2 the hourly *market prices* determined by the *day-ahead market calculation engine* that correspond to the same hour and *dispatch day* that the *IESO* is administering *real-time market prices*;

8.4A.5.3 the *market prices* for an electrically similar *delivery point* or *intertie metering point* in the same *dispatch interval* where the *market price* has not been administered;

8.4A.5.4 the *market prices* from the closest preceding *dispatch interval* that has not been administered, up to a maximum of 12 *dispatch intervals*;

8.4A.5.5 the *market prices* from the closest subsequent *dispatch interval* that has not been administered, up to a maximum of 12 *dispatch intervals*; or

8.4A.5.6 using an hourly average *market price* for *energy* and *operating reserve* for the applicable *dispatch intervals* from the corresponding hour or hours of the four immediately preceding *business days* or non-*business days*, as the case may be, excluding those hours from any day in which an *administrative price* has been established under this section. Prices for the excluded hours shall be replaced by prices that have not been administered under this section from the corresponding hours of the most recent earlier *business days* or non-*business days*, as the case may be. For greater certainty, where the *IESO* is determining the *administrative price* for a *business day*, it shall use the immediately preceding *business days* and where the *IESO* is determining the *administrative price* for a non-*business day*, it shall use the immediately preceding non-*business days.*

Administration of Prices Due to Market Suspension

8.4A.6 Where the *IESO* establishes *administrative prices* during a market suspension pursuant to section 8.4A.2.1, it shall establish the *administrative price* as one of the following, as the *IESO* determines appropriate:

8.4A.6.1 where *market operations* have been suspended for reasons other than a failure in the software that generates *market prices* and operations of the *IESO-controlled grid* are based to some extent on market-based information and signals, a *market price* calculated using that software; or

8.4A.6.2 where operations of the *IESO-controlled grid* are being conducted without regard to the market, for the *IESO control area* and the *intertie zones,* using the method to establish *administrative prices* detailed in section 8.4A.5.6.

Make-Whole Payments and Administrative Prices

8.4A.7 Where the *IESO* has established an *administrative price* pursuant to section 8.4A.2, the *IESO* shall determine any applicable *day-ahead market* and *real-time* *market* make-whole payment *settlement amounts* in accordance with MR Ch.9 ss.3.4 and 3.5 using the *administrative price*.

Conditions to Cease the Administration of Prices

8.4A.8 The *IESO* shall cease to apply *administrative prices*:

8.4A.8.1 where section 8.4A.2.1 applies, from the commencement of the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2;

8.4A.8.2 where section 8.4A.2.2 applies due to a failure in software, hardware or communications systems, from the commencement of the first *dispatch interval* after the failure referred to in that section has been rectified;

8.4A.8.3 where section 8.4A.2.2 applies due to a *planned outage* of software, hardware or communications systems, from the commencement of the first *dispatch interval* after the *planned outage* referred to in that section has been completed; and

8.4A.8.4 where section 8.4A.2.3 or 8.4A.2.4 applies, from the commencement of the first *dispatch interval* after the cause of the incorrect *market prices* referred to in those sections have been corrected.

9. IESO Procurement Markets

9.1 Introduction

9.1.1 The *IESO* shall procure, primarily through contracts, certain *physical services* that are needed to maintain *reliable* system operations but that are not *offered* in the *day-ahead market* or *real-time market*. The *IESO* may also enter into contracts allowing it to direct the operations of specific *generation facilities, electricity storage facilities* or *load facilities* that are critical to system *reliability* under certain conditions. This section 9 describes such *physical services* and the manner in which the *IESO* shall procure them.

9.2 Definition of Contracted Ancillary Services

9.2.1 Subject to sections 9.4 and 9.5.2, the *IESO* shall procure *contracted ancillary services* through contracts between the *IESO* and *ancillary service providers* that are *registered market participants* who have demonstrated the ability to provide such *contracted ancillary services* from *facilities* or *resources* in accordance with the performance standards and other applicable requirements of MR Ch.5 s.4. *Contracted ancillary services* shall meet all applicable standards set forth in MR

Ch.5 s.4 and shall be procured such as to enable the *IESO* to meet its obligations thereunder.

9.2.2 The principal *contracted ancillary services* that the *IESO* will procure pursuant to section 9.2.1 are:

9.2.2.1 *regulation*: this *ancillary service* allows total system generation to match total system load (plus losses) minute-by-minute or even second-by-second as required on an electricity grid;

9.2.2.2 *voltage control* and *reactive support*: this *ancillary service* involves the control and maintenance of prescribed voltages at specific locations, using defined reactive capacity, *energy* and manoeuvrability to support system operations. *Reactive support* is provided by *generation units*, *electricity storage units* as well as by synchronous condensers, capacitors and other electrostatic equipment that is often owned and operated by *transmitters*; and

9.2.2.3 *black start capability*: this *ancillary service* involves *generation facilities* that are tested and/or assessed for their ability to be a *certified black start facility*, and from which the *IESO* may direct the delivery of power without assistance from the electrical system.

9.2.2.4 [Intentionally left blank – section deleted]

9.2.3 The *IESO* shall procure each *contracted ancillary service*:

9.2.3.1 in sufficient quantities and at the appropriate locations to enable the *IESO* to meet its obligations under MR Ch.5 to ensure *reliable* operation of the *electricity system*, in accordance with all applicable *reliability standards*; and

9.2.3.2 using, to the extent practicable, competitive processes appropriate to the specific technical and market characteristics of each *contracted ancillary service*, to acquire each *contracted ancillary service* at competitively determined prices.

9.3 Contracted Ancillary Service Contracts

9.3.1 The *IESO* shall enter into *contracted ancillary service* contracts with *ancillary service providers*. Such agreements shall, subject to sections 9.3.4 and 9.3.6:

9.3.1.1 [Intentionally left blank – section deleted]

9.3.1.2 compensate any *ancillary service provider* for levels of service above those required to be provided by the *connection* requirements of MR Ch.4.

9.3.2 Subject to section 9.3.6, the *IESO* shall use one or a combination of the following processes to conclude *contracted ancillary service* contracts with *ancillary service providers*:

9.3.2.1 where practical, the *IESO* shall employ a competitive tendering or negotiation process to identify multiple potential *ancillary service providers* and to determine competitive prices and other terms for the *contracted ancillary service* contracts; or

9.3.2.2 the *IESO* may negotiate *contracted ancillary service* contracts with a single potential *ancillary service provider* where the *IESO* determines that this will result in reasonable prices and other terms.

9.3.3 [Intentionally left blank]

9.3.4 The provisions of sections 9.3.1 and 9.5.1 shall be subject to any contrary provisions contained in:

9.3.4.1 any *licence*; or

9.3.4.2 the terms of any *contracted ancillary service* contract the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*.

9.3.5 Each person that:

9.3.5.1 has entered into a *contracted ancillary service* contract with the *IESO*; and

9.3.5.2 is not, at any time during the term of such *contracted ancillary service* contract, the *registered market participant* for that *facility* or *resource*,

shall ensure that the *registered market participant* for that *facility* or *resource* complies with the provisions of the *contracted ancillary service* contract.

9.3.6 Where the *IESO* and the *ancillary service provider* are unable to reach agreement upon the terms and condition of a proposed *ancillary service* contract, or an amendment to an *ancillary service* contract, the matter shall be determined by the *Ontario Energy Board*.

9.4 The Effect of Grid Connection Requirements

9.4.1 The *IESO* may at any time direct a *facility* or *resource* to provide the level of any *ancillary service* that the *facility* or *resource* is required to provide as a condition of any *licence* or as a result of any *connection* requirements provided for in MR Ch.4.

9.4.2 Subject to section 9.4.4, a *facility* or *resource* shall not be entitled to compensation from the *IESO* for any *ancillary service* that must be provided pursuant to the *connection* requirements provided for in MR Ch.4 unless and until the *IESO* develops a market for such *ancillary service* that pays all providers of the *ancillary service* and/or that requires any *facility* or *resource* to pay for the failure to supply up to some standard that may be less than that attributable to the *connection* requirement.

9.4.3 If the *IESO* directs a *facility* or *resource* to provide a level of any *ancillary service* above the levels required by the *licence* applicable to that *facility* or *resource* or any *connection* requirements provided for in MR Ch.4 and the *facility* or *resource* is not otherwise subject to a *contracted ancillary service* contract with the *IESO*, the *IESO* shall compensate the *facility* or *resource* for any costs, including lost opportunity costs, incurred by the *facility* or *resource* in complying with the *IESO*'s direction.

9.4.4 If the *IESO* directs a *facility* associated with a *generation unit* or an *electricity storage unit* to provide *reactive support* within the range required by the *connection* requirements provided for in MR Ch.4, the *IESO* shall only be required to compensate the associated *market participant* for a *generation unit* or *electricity storage unit* to the extent that the *generation unit* or *electricity storage unit* incurs additional costs, provided that such additional costs are demonstrated to the satisfaction of the *IESO* to have been incurred in order to comply with the *IESO's* direction.

9.4.5 If the *IESO* directs a *facility* associated with a *generation unit* or an *electricity storage unit* to provide *reactive support* within the range required by the *connection* requirements provided for in MR Ch.4 or as stipulated in the applicable *contracted ancillary service* contract, and that *generation unit* or *electricity storage unit* has to reduce its active power output in order to comply with the *IESO*'s direction, the associated *market participant* for a *generation unit* or *electricity storage unit* shall not be entitled to a *real-time market* make-whole payment *settlement amount* for that reduction in active power output.

9.5 Payment for Ancillary Services and Recovery of Costs

9.5.1 Subject to sections 9.3.4 and 9.3.6, the price payable by the *IESO* under a *contracted ancillary service* contract may cover any of the following:

9.5.1.1 the cost of being available to provide a *contracted ancillary service* if instructed by the *IESO* to do so;

9.5.1.2 the out-of-pocket costs and the opportunity costs of actually providing the *contracted ancillary service* when instructed by the *IESO* to do so; and

9.5.1.3 such other compensation as the *IESO* determines to be fair and reasonable under the circumstances.

9.5.2 The *IESO* is authorized, when necessary to maintain system *reliability* or when the *IESO-controlled grid* is in an *emergency operating state* to direct a *facility* or *resource* to provide any class of *contracted ancillary services* even though the *IESO* does not have a *contracted ancillary service* contract with that *facility* or *resource*. When this occurs:

9.5.2.1 the *IESO* shall compensate the associated *market participant* for a *facility* or *resource* for any costs, including opportunity costs, it incurs in complying with the *IESO's* direction; and

9.5.2.2 any dispute about the compensation payable pursuant to section 9.5.2.1 shall be resolved using the dispute resolution process set forth in MR Ch.3 s.2.

9.5.3 The *IESO* shall, in accordance with MR Ch.9 s.4.2, recover from *market participants* any costs it incurs in procuring *ancillary services*.

9.6 Definition and Principles of Must-Run Contracts

9.6.1 The *IESO* may, under the conditions and in accordance with the processes specified in this section 9.6, enter into a *reliability must-run contract* with the *registered market participant* or the prospective *registered market participant* for a *reliability must-run resource.* Where the *IESO* and a *registered market participant* or prospective *registered market participant* enter into a *reliability must-run contract* with respect to a given *reliability must-run resource*, the *IESO* may direct that *reliability must-run resource* to operate in specific ways for reasons of *reliability*, other than for reasons of a lack of overall *adequacy* of the *IESO-controlled grid*, regardless of whether *dispatch data* has been submitted with respect to that *reliability must-run resource*. Nothing in this section shall be construed as preventing the *IESO* from taking such other action in respect of such *reliability must-run resource* as may be permitted by these *market rules* to address a concern for overall *adequacy.*

9.6.2 Subject to section 9.6.4, the *IESO* may enter into a *reliability must-run contract* based on studies performed by the *IESO* that indicate:

9.6.2.1 in accordance with section 9.6.3, that a *reliability must-run resource* is required to be available for the purposes of *reliability*, other than in situations of overall *adequacy* of the *IESO-controlled grid*; or

9.6.2.2 a *reliability must-run resource* is likely to be *dispatched* to supply more or less *energy* than otherwise required to assist in addressing a transmission flow constraint on the *IESO controlled-grid* or a *security limit* and that such a contract would avail to the mutual benefit of the parties.

9.6.3 The studies referred to in section 9.6.2.1 shall include a consideration of whether concerns regarding *reliability*, other than regarding a lack of overall *adequacy* of the *IESO-controlled grid*, can be addressed by means of the process for directing the submission of *dispatch data* or for imposing a restriction on the revision of *dispatch data* referred to in sections 3.3.10 to 3.3.17 or of the process by which the *IESO* approves *outages* pursuant to MR Ch.5 s.6.

9.6.4 The *IESO* shall enter into a *reliability must-run contract* pursuant to section 9.6.2.2 in respect of a *reliability must-run resource* only where the *registered market participant* or the prospective *registered market participant* for the *reliability must-run resource* so agrees.

9.6.5 Where:

9.6.5.1 the *IESO* would be required to reject, revoke *advance approval* of, or recall the *planned outage* of a *resource* pursuant to MR Ch.5 s.6 but for the availability of a *reliability must-run resource*; and

9.6.5.2 the *reliability must-run resource* referred to in section 9.6.5.1 has planned a temporary reduction in staff that would restrict or prevent operation of that other *resource,*

the *IESO* may enter into a *reliability must-run contract* in respect of the *reliability must-run resource* referred to in section 9.6.5.1 provided that:

9.6.5.3 staffing adequate to permit that *reliability must-run resource* to operate under the *reliability must-run contract* can be arranged by that *reliability must-run resource* within the time required; and

9.6.5.4 the conclusion of the *reliability must-run contract* referred to in section 9.6.5.3 would avoid the need for the *IESO* to reject, revoke *advance approval* of, or recall the *planned outage* referred to in section 9.6.5.1.

9.6.6 The *IESO* may call upon a *reliability must-run resource* that is subject to a *reliability must-run contract* if and only if the *IESO* determines that *market participants* will not *offer* sufficient *physical services* into the *real-time markets* to enable the *IESO* to maintain *reliability*, other than in respect of a lack of overall *adequacy* of the *IESO-controlled grid*.

9.6.7 Subject to section 9.6.13, the *IESO* shall use one or a combination of the following processes to conclude *reliability must-run contracts* pursuant to section 9.6.2:

9.6.7.1 where practical, the *IESO* shall employ a competitive tendering or negotiation process to identify multiple potential suppliers and to determine competitive prices and other terms for the *reliability must-run contract*; or

9.6.7.2 the *IESO* may negotiate *reliability must-run contracts* with a single potential supplier where the *IESO* determines that this will result in reasonable prices and other terms.

9.6.8 Subject to sections 9.6.11 and 9.6.13:

9.6.8.1 the *IESO* may develop standard forms of *reliability must-run contracts* for use in conjunction with sections 9.6 and 9.7,

provided that

9.6.8.2 a standard form *reliability must-run contract* developed for use in conjunction with a *reliability must-run resource* that has planned a temporary reduction in staff that would restrict or prevent its operation, including but not limited to the circumstances described in section 9.6.5, shall provide compensation only for the out-of-pocket costs including, but not limited to, the costs of providing adequate staffing, incurred solely to permit the *reliability must-run resource* to be prepared to provide *physical services* if *dispatched* to do so, but no such compensation shall be payable in respect of *dispatch intervals* when the *reliability must-run resource* is *dispatched* to provide such *physical services* and is entitled to payment therefore as a result of such *dispatch*.

9.6.9 Subject to sections 9.6.11 and 9.6.13, the *IESO* may include in any *reliability must-run contract,* other than a standard form *reliability must-run contract* referred to in section 9.6.8.2, the compensation provisions referred to in section 9.6.8.2 or such other compensation provisions as the *IESO* determines appropriate.

9.6.10 [Intentionally left blank]

9.6.11 The provisions of sections 9.6.8, 9.6.9 and 9.7.1 shall be subject to any contrary provisions contained in:

9.6.11.1 any *licence*; or

9.6.11.2 the terms of any *reliability must-run contract* the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*.

9.6.12 [Intentionally left blank]

9.6.13 Where the *IESO* and the *registered market participant* or prospective *registered market participant* are unable to reach agreement upon the terms and condition of a *proposed reliability must-run contract*, or an amendment to a *reliability must-run contract*, the matter shall be determined by the *Ontario Energy Board*.

9.7 Terms and Conditions of Must-Run Contracts

9.7.1 Subject to sections 9.6.11 and 9.6.13, the *IESO* shall include in each *reliability must-run contract* terms and conditions that address, at a minimum, the following:

9.7.1.1 the duration of the *reliability must-run contract*, which shall not exceed 1 year;

9.7.1.2 the situations in which the *reliability must-run resources* may be called;

9.7.1.3 the situations under which some or all of the terms of the *reliability must-run contract* may be suspended;

9.7.1.4 the nature and timing of any advance notice required for the *IESO* to call upon the *reliability must-run resources*;

9.7.1.5 payment terms, including the amount and timing of any availability payment;

9.7.1.6 agreed *dispatch data* that the *IESO* shall use to *dispatch* the *reliability must-run resource* when it is called by the *IESO* to operate in various modes under the *reliability must-run contract*, and provisions for the revision of such *dispatch data*, when necessary;

9.7.1.7 the process for amending the terms of the *reliability must-run contract*; and

9.7.1.8 any penalties payable by either party for failure to satisfy its obligations under the *reliability must-run contract*.

9.7.2 The *IESO* shall, in accordance with MR Ch.9 s.4.2, recover through charges on *market participants* the incremental costs of its *reliability must-run contracts* above any normal payments for *energy* and *operating reserves* recovered in the *real-time market.*

9.8 Publication of Procurement Contract Information

9.8.1 The *IESO* shall treat information relating to the procurement of *contracted ancillary services* and *reliability must-run contracts* as follows:

9.8.1.1 the *IESO* shall *publish* annually the total costs of all contracted *ancillary services* subject to contracted *ancillary service* contracts and of all *reliability must-run contracts*;

9.8.1.2 the *IESO* shall *publish* annually the quantities of each *contracted ancillary service* covered under *contracted ancillary service* contracts and the quantities of each *physical service* provided under *reliability must-run contracts*, together with estimates of any additional quantities the *IESO* expects to acquire during the next 12 months;

9.8.1.3 where the *IESO* obtains *contracted ancillary services* or *reliability must-run contracts* in the absence of market power, the commercial terms of the *contracted ancillary service* contracts and of the *reliability must-run contracts* shall be treated as *confidential information*; and

9.8.1.4 where the *IESO* obtains *contracted ancillary services* or *reliability must-run contracts* in the presence of market power, as confirmed by the *market surveillance panel*, the *IESO* shall *publish* the relevant terms and conditions of the contracts, except for price which shall not be disclosed, in order to encourage competition.

9.9 Dispute Resolution

9.9.1 Subject to the *licence* of the *IESO* and of the relevant *market participant*, all disputes arising pursuant to a *contracted ancillary services* contract or a *reliability must-run contract* shall be resolved using the dispute resolution process set forth in MR Ch.3 s.2.

10. Instructions for Generator Offer Guarantee Eligible Resources

10.1 Start-Up Notice

10.1.1 Subject to section 10.1.7, the *IESO* shall issue a *start-up notice* for (a) a *day-ahead operational commitment* other than those issued under section 10.1.2, or (b) *pre-dispatch operational commitment*, no later than 30 minutes after the hour corresponding to the applicable *pre-dispatch calculation engine* run that is immediately prior to the *resource's* start up procedures as required by its *lead time*.

10.1.2 Subject to section 10.1.7, the *IESO* shall issue a *start-up notice* prior to the first run of the *pre-dispatch calculation engine* for the relevant *dispatch day* if the *lead time* of a *day-ahead operational commitment* requires a *generation resource* to start-up in advance of the *pre-dispatch process*.

10.1.3 The *IESO* may issue a *start-up notice* for a *reliability* commitment at any time, if the *IESO* determines that it is necessary to maintain system *reliability*.

10.1.4 A *registered market participant* for a *GOG-eligible resource* shall acknowledge receipt of a *start-up notice* and shall indicate whether it reasonably expects the *resource* to operate in accordance with the *start-up notice:*

10.1.4.1 if the *start-up notice* has been issued in accordance with section 10.1.1*,* no later than 15 minutes prior to the start of the next *dispatch hour*; or

10.1.4.2 in circumstances other than those described in section 10.1.4.1, as soon as reasonably practicable after the receipt of such *start-up notice*.

10.1.5 If a *registered market participant* for a *GOG-eligible resource* indicates that it reasonably expects to operate in accordance with a *start-up notice* in accordance with section 10.1.4, the *registered market participant* shall immediately notify the *IESO* as soon as possible if it expects its *resource* to operate in a manner that, for any reason, differs materially from the *start-up notice*.

10.1.6 Subject to section 10.1.7, the *IESO* shall use reasonable efforts to ensure that a *start-up notice* issued:

10.1.6.1 in accordance with section 10.1.1(a), is consistent with the *resource's* most recent *pre-dispatch schedule;*

10.1.6.2 in accordance with section 10.1.1(b), is consistent with the *resource's* most recent *binding pre-dispatch advisory schedule;* or

10.1.6.3 in accordance with section 10.1.2, is consistent with the *resource's day-ahead schedule*.

10.1.7 The *IESO* shall not be required to issue a *start-up notice,* or, in the event that the *IESO* does issue a *start-up notice*, shall not be required to satisfy the requirements of section 10.1.6 if:

10.1.7.1 the *security* and *adequacy* of the system would be endangered by implementing the *day-ahead schedule*, *pre-dispatch schedule* or *binding pre-dispatch advisory schedule*;

10.1.7.2 the *day-ahead market calculation engine* or *pre-dispatch calculation engine* has failed, or has produced a *day-ahead schedule*, *pre-dispatch schedule* or *binding pre-dispatch advisory schedule* that is clearly and materially in error;

10.1.7.3 material changes have occurred subsequent to the *IESO's* determination of the *day-ahead schedule, pre-dispatch schedule* or *binding pre-dispatch advisory schedule*, including a failure of an element of a *transmission system* or failure of a *resource* to follow *dispatch instructions*; or

10.1.7.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13.

10.1.8 Notwithstanding sections 10.1.1 and 10.1.4.1, if there is a failure of *IESO* software, hardware or communication systems during the *pre-dispatch process*:

10.1.8.1 the *IESO* shall issue *start-up notices* as soon as reasonably practicable after the hour corresponding to the applicable *pre-dispatch calculation engine* run that is immediately prior to the *resource's* start-up procedures as required by its *lead time*; and

10.1.8.2 the *registered market participant* shall, as soon as reasonably practicable, acknowledge receipt of such *start-up notice* and shall indicate whether it reasonably expects the *resource* to operate in accordance with the *start-up notice*.

10.2 Notice of Decommitment

10.2.1 Subject to section 10.2.6, the *IESO* shall issue a notice of decommitment to a *GOG-eligible resource* no later than 30 minutes after the hour corresponding to the applicable *pre-dispatch calculation engine* run that has not scheduled the *resource* above its *minimum loading point* for the next *dispatch hour.*

10.2.2 The *IESO* may issue a notice of decommitment to a *GOG-eligible resource* at any time, if the *IESO* determines that it is necessary to maintain system *reliability.*

10.2.3 Subject to section 10.2.6, a *registered market participant* for a *GOG-eligible resource* shall acknowledge receipt of a notice of decommitment and shall indicate whether it reasonably expects the *resource* to operate in accordance with the notice of decommitment, no later than 15 minutes prior to the start of the next *dispatch hour*.

10.2.4 If a *registered market participant* indicates that it reasonably expects to operate in accordance with a notice of decommitment in accordance with section 10.2.3, the *registered market participant* shall immediately notify the *IESO* as soon as possible if it expects its *resource* to operate in a manner that, for any reason, differs materially from the notice of decommitment.

10.2.5 The *IESO* shall use reasonable efforts to ensure that the instructions contained in a notice of decommitment issued in accordance with this section 10.2 with respect to each *GOG-eligible resource*, is consistent with the *pre-dispatch schedule*.

10.2.6 The *IESO* shall not be required to issue a notice of decommitment, or, in the event that the *IESO* does issue a notice of decommitment, shall not be required to satisfy the requirements of section 10.2.5 if:

10.2.6.1 the *security* and *adequacy* of the system would be endangered by implementing the *pre-dispatch schedule*;

10.2.6.2 the *pre-dispatch calculation engine* has failed, or has produced a *pre-dispatch schedule* that is clearly and materially in error;

10.2.6.3 material changes have occurred subsequent to determination of the *pre-dispatch schedule*, including a failure of an element of a *transmission system* or failure of a *resource* to follow *dispatch instructions*; or

10.2.6.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13.

10.2.7 Notwithstanding sections 10.2.1 and 10.2.3, if there is a failure of *IESO* software, hardware or communication systems during the *pre-dispatch process*:

10.2.7.1 the *IESO* shall issue notices of decommitment to a *GOG-eligible resource* as soon as reasonably practicable after the hour corresponding to the applicable *pre-dispatch calculation engine* run that has not scheduled the *resource* above its *minimum loading point* for the next *dispatch hour*; and

10.2.7.2 the *registered market participant* shall as soon as reasonably practicable acknowledge receipt of such notice of decommitment and shall indicate whether it reasonably expects the *resource* to operate in accordance with the notice of decommitment.

10.3 Day-Ahead Operational Commitment and Pre-Dispatch Operational Commitment

10.3.1 Without limiting the generality of MR Ch.5 s.1.2.1, the *IESO* may, at any time, cancel a *day-ahead operational commitment* or *a pre-dispatch operational commitment* if the cancellation is necessary to maintain the *reliability* of the *IESO-controlled grid*. The *IESO* shall, as soon as practicable, notify the relevant *market participant* of this cancellation.

10.3.2 If a *registered market participant* for a *GOG-eligible resource* expects that satisfying a *day-ahead operational commitment* or a *pre-dispatch operational commitment* would endanger the safety of any person, cause equipment damage, or violate any *applicable law*, the *registered market participant* shall immediately notify the *IESO* of that expectation, and shall withdraw from the *day-ahead operational commitment* or *pre-dispatch operational commitment*.

10.3.3 If a *registered market participant* for a *GOG-eligible resource* with a *day-ahead operational commitment* or a *pre-dispatch operational commitment* expects, for any reason other than those set out in section 10.3.2, that the *resource* will not satisfy the commitment, the *registered market participant* shall immediately notify the *IESO* of its request to withdraw from the *day-ahead operational commitment* or *pre-dispatch operational commitment*. If, in the *IESO's* judgment, the withdrawal will impair the ability of the *IESO* to maintain the *security* or *adequacy of the electricity system*, the *IESO* may refuse such request.

10.3.4 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource* shall submit an *offer* for any remaining *dispatch hours* of its *minimum generation block run-time* for a *day-ahead operational commitment* or a *pre-dispatch operational commitment* carried over from the previous *dispatch day*.

10.3.5 A *registered market participant* for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource* shall submit an *offer* for any *dispatch hours* prior to or following a *day-ahead operational commitment* or a *pre-dispatch operational commitment* in which the *registered market participant* reasonably expects the *dispatchable generation resource* to be injecting at less than its *minimum loading point* in at least one *dispatch interval*.

11. Generation Resource and Electricity Storage Resource Synchronization Procedures

11.1 Introduction

11.1.1 No *generator* or *electricity storage participant*:

11.1.1.1 may *connect* and synchronize a *generation resource* or an *electricity storage resource* to the *IESO-controlled grid* or de-synchronize and disconnect from the *IESO-controlled grid*; or

11.1.1.2 if it is an *embedded generator* or *embedded electricity storage participant*, may *connect* and synchronize a *resource* associated with an embedded *generation unit* or an *electricity storage unit* to the embedding *facility* or de-synchronize and disconnect from the embedding *facility*,

except as provided in MR Ch.4 and in this section 11.

11.1.2 All *generation facilities* located within the *IESO control area* are subject to the provisions of this section 11 except for:

11.1.2.1 *self-scheduling generation facilities* with name-plate ratings of less than 10 MW;

11.1.2.2 *generators* with *intermittent generation resources*;

11.1.2.3 any *generators* classified as *minor generation facilities* or as *small generation facilities*;

11.1.2.4 *generation facilities* that, for the purposes of the application of the provisions of this section 11, have been designated by the *IESO* as not impairing the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*; and

11.1.2.5 any *generators* exempt from the provisions of the Electricity Act, 1998 by regulation made thereunder.

11.1.3 [Intentionally left blank]

11.1.4 All *electricity storage facilities* located within the *IESO control area* are subject to the provisions of this section 11 except for:

11.1.4.1 *self-scheduling electricity storage facilities* with an *electricity storage facility* size of less than 10 MW;

11.1.4.2 any *electricity storage facilities* classified as *minor electricity storage facilities* or as *small electricity storage facilities*; and

11.1.4.3 *electricity storage facilities* that, for the purposes of the application of the provisions of this section 11, have been designated by the *IESO* as not impairing the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

11.2 Process for Synchronization

Quick Start Resources

11.2.1 A *registered market participant* for a *quick start resource* that receives a *dispatch instruction* and acknowledges receipt of the *dispatch instruction* in accordance with section 7.1.2A may *connect* and synchronize a *generation resource* or *electricity storage resource* to the *IESO-controlled grid* or embedding *facility*, as the case may be.

Non-Quick Start Resources

11.2.2 A *registered market participant* for a *GOG-eligible resource* that receives a *start-up notice* and acknowledges receipt of the *start-up notice* in accordance with section 10.1.4 and that intends to synchronize to the *IESO-controlled grid* or embedding *facility*, as the case may be, shall request the *IESO's* approval for the proposed synchronization plan at least five minutes before the intended synchronization for the *resource*.

11.2.2A Subject to section 11.2.2, a *registered market participant* for a *non-quick start resource* that intends to synchronize to the *IESO-controlled grid* or embedding *facility*, as the case may be, shall request the *IESO's* approval for the proposed synchronization plan at least two hours in advance of the intended synchronization time unless an under-generation advisory notice is in force, in which case the *IESO* may reduce the required notification time to that specified in the advisory notice.

Approval of Synchronization Plan

11.2.3 The *IESO* shall notify the *registered market participant* for a *non-quick start resource* of the *IESO*'s acceptance or rejection of the *non-quick start resource*'s synchronization plans within five minutes of receiving such plans. In the event that the *IESO* does not approve synchronization, the *registered market participant* must revise its *dispatch data* for the *non-quick start resource* in accordance with section 3.

11.2.4 Receipt by the *registered market participant* of the notification of acceptance by the *IESO* under section 11.2.3 allows it to synchronize the *non-quick start resource* to the *IESO-controlled grid* or the embedding *facility*, as the case may be. However, the *IESO* may, at any time, require the de-synchronization of a *non-quick start resource* in the event of over-generation.

11.2.4A If a *registered market participant* for a *non-quick start resource* does not request the *IESO's* approval in advance of synchronization at the appropriate time in accordance with obligations of this section applicable to it or any shorter interval allowed by an under-generation advisory notice, the *IESO* may approve synchronization only if, in the *IESO's* judgement, synchronization will not impair the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

Conditions Attached to Synchronization

11.2.5 The exact time of synchronization shall be subject to directions from the *IESO* and to the terms and conditions specified in the *generator's* or *electricity storage participant's connection agreement* or, in the case of a *resource* associated with an embedded *generation unit* or embedded *electricity storage unit*, its connection agreement, in such form as may be prescribed by the *OEB*, with the *distributor* with whom it is *connected.*

Revisions to Synchronization

11.2.6 Without limiting the obligation to provide notice under section 10.1.5, each *generator* or *electricity storage participant* shall notify the *IESO* of any revisions to its synchronization plans without delay. Upon receipt of such notice, the *IESO* shall re-assess any prior acceptance of a synchronization plan and shall notify the *generator* or *electricity storage participant* accordingly.

11.3 Process for De-synchronization

Quick Start Resources

11.3.1 A *registered market participant* for a *quick start resource* intending to de-synchronize from the *IESO-controlled grid* or embedding *facility*, as the case may be, shall request the *IESO*'s approval five minutes in advance of the intended de-synchronization time.

Non-quick Start Resources

11.3.1A A *registered market participant* for a *GOG-eligible resource* intending to de-synchronize from the *IESO-controlled grid* or embedding *facility*, as the case may be, that receives a notice of decommitment and acknowledges receipt of the notice of decommitment in accordance with section 10.2.3, shall, once it receives *dispatch instructions* below its *minimum loading point*, request the *IESO's* approval to de-synchronize, unless an advisory notice for over-generation is in effect, in which event the *resource* may de-synchronize at will subject to the conditions of the advisory notice.

11.3.2 Subject to 11.3.1A, a *registered market participant* for a *non-quick start resource* intending to de-synchronize from the *IESO-controlled grid* or embedding *facility*, as the case may be, shall request the *IESO's* approval at least one hour in advance of the intended de-synchronization time unless an advisory notice for over-generation is in effect, in which event the *resource* may de-synchronize at will subject to the conditions of the advisory notice.

Approval of De-synchronization

11.3.3 The *IESO* shall approve any such request to de-synchronize unless:

11.3.3.1 the *generation resource* or *electricity storage resource* is operating under the provisions of a *reliability must-run contract* and the *IESO* has directed it to operate;

11.3.3.2 the *IESO* requires the *generation unit* or *electricity storage unit* to remain synchronized to maintain the *security* or *adequacy* of the *electricity system*; or

11.3.3.3 an under-generation advisory notice is in force.

11.3.4 The *IESO* shall notify the *registered market participant* of the *IESO*'s acceptance or rejection of the *generation resource's* or *electricity storage resource's* de-synchronization plans within 5 minutes of receiving such plans.

11.3.4A If a *registered market participant* for a *generation resource* or *electricity storage resource* does not request the *IESO's* approval prior to its planned de-synchronization at the appropriate time in accordance with the obligations of this section applicable to it or any shorter interval allowed by an over-generation advisory notice, the *IESO* may approve de-synchronization only if, in the *IESO*'s judgement, de-synchronization will not impair the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

11.3.5 The exact time of de-synchronization shall be subject to directions from the *IESO* and to the terms and conditions specified in the *generator's* or *electricity storage participant's connection agreement* or, in the case of a *resource* associated with an *embedded generation unit*, or *embedded electricity storage unit*, its connection agreement, in such form as may be prescribed by the *OEB*, with the *distributor* with whom it is *connected.*

11.3.6 Receipt by the *generator* or *electricity storage participant* of notification of acceptance by the *IESO* under section 11.3.4 gives the *generator* or *electricity storage participant* the right to commence shut-down of the *generation resource* or *electricity storage resource*.

11.3.7 Without limiting the obligation to provide notice under section 10.2.4, each *generator* or *electricity storage participant* shall notify the *IESO* of any revisions to its de-synchronization plans without delay. Upon receipt of such notice, the *IESO* shall re-assess any prior acceptance of a de-synchronization plan and shall notify the *generator* or *electricity storage participant* accordingly.

11.4 Reliability

11.4.1 Notwithstanding any other provision in this section 11, the *IESO* may, to maintain the reliable operation of the *IESO-controlled grid*, direct a *generation resource* or an *electricity storage resource* to either de-synchronize from or to not synchronize to the *IESO-controlled grid*.

12. Status Reports, Advisories, and Protocols

12.1 IESO System Status Reports and Advisory Notices

12.1.1 The *IESO* shall *publish*, in addition to the daily assessments specified in MR Ch.5 s.7.3.1.4, system status reports to:

12.1.1.1 to 12.1.1.5 [Intentionally left blank – sections deleted]

12.1.1.6 provide forecasts, with respect to each *dispatch day*, as projected for future *dispatch hours* and as estimated for the current *dispatch hour*, where appropriate, of expected hourly *demand*, *generation capacity*, *electricity storage capacity*, *energy* capability of *generation resources*, exports and imports of *energy*, projected *energy* shortfalls, and *operating reserve* requirements, *published* at the following times:

a. 05:30 EPT on the day prior to the relevant *dispatch day*

b. 09:00 EPT on the day prior to the relevant *dispatch day*;

c. after a successful run of the *day-ahead market calculation engine*, on the day prior to the relevant *dispatch day*;

d. after 20:00 EST, and hourly thereafter, on the day prior to the relevant *dispatch day*; and

e. hourly on the *dispatch day;*

12.1.1.7 provide forecasts of expected transmission capacity with all elements in-service, *published* daily, as soon as practicable; and

12.1.1.8 provide forecasts of expected transmission limits with *outages*, for the *dispatch day* and the two days following the *dispatch day*, *published* twice each hour on the *dispatch day.*

12.1.2 Where the *IESO publishes* an advisory notice, it shall do so in one of the following forms, as further specified in the applicable *market manual*:

12.1.2.1 an alert notice, which shall provide situational awareness and time for advanced preparations;

12.1.2.2 a warning notice, which shall indicate the actions the *IESO* intends to take if the *IESO-administered markets* do not or cannot respond sufficiently to eliminate an identified or potential problem; or

12.1.2.3 an action notice, which shall indicate the actions the *IESO* and *market participants* must take in order to eliminate an identified or potential problem.

12.1.3 The *IESO* shall *publish*, in accordance with the applicable *market manual*, advisory notices in the following circumstances:

12.1.3.1 if a major change in expected *generation capacity, electricity storage capacity* or *transmission capacity* has occurred since the last system status report was issued;

12.1.3.2 if the *IESO* expects over-generation, under-generation or shortfalls in *operating reserve* or *contracted ancillary services*, or an advisory of the total MW of *energy* being directed to submit *bids* or *offers* from the aggregate of *reliability must run resources* under *reliability must run contracts*;

12.1.3.3 if the *IESO* expects an *emergency operating state*, a *high-risk operating state*, or a *conservative operating state*; or

12.1.3.4 if the *IESO* is suspending or resuming operation of all or part of the *IESO-administered markets*.

12.1.3A The *IESO* may *publish* advisory notices in addition to those in 12.1.3, in accordance with the applicable *market manual*, for any other reason where the *IESO* determines that the *publication* of an advisory notice would be in the interest of the *IESO-administered markets*, *market participants*, or the *IESO-controlled grid*.

12.1.4 Where applicable, the corresponding information related to the advisory notices in section 12.1.3 shall be included by the *IESO* in a subsequent *publication* of a scheduled report under section 12.1.1.

12.2 Over-Generation and Under-Generation Advisories

12.2.1 If the *IESO* issues an over-generation advisory notice pursuant to section 12.1.3, the *IESO* shall, unless the *IESO* determines that it is not able to do so for operational or system *security* reasons, and notwithstanding any notification requirements or other conditions specified elsewhere in these *market rules*:

12.2.1.1 solicit and accept additional or revised *bids* to increase *demand* in response to low prices;

12.2.1.2 allow *generation units* or *electricity storage units* or any associated *resources* to de-synchronize from the *IESO-controlled grid* or the embedding *facility*, as the case may be, without penalty, some or all of the *generation units* or *electricity storage units* or any associated *resources* within any *facility* in locations designated by the *IESO*; and/or

12.2.1.3 solicit and accept revised *offers* that will decrease generation or injection of *energy* in response to low prices, in locations designated by the *IESO*.

12.2.2 If the *IESO* issues an under-generation advisory notice pursuant to section 12.1.3, the *IESO* shall, unless the *IESO* determines that it is not able to do so for operational or system *security* reasons, and notwithstanding any notification requirements or other conditions specified elsewhere in these *market rules*:

12.2.2.1 solicit and accept additional or revised *bids* that will decrease *demand* in response to higher prices;

12.2.2.2 allow *generation units* or *electricity storage units* or any associated *resources* to synchronize to the *IESO-controlled grid* or the embedding *facility*, as the case may be, without penalty, some or all of the *generation units* or *electricity storage units* or any associated *resources* within any *facility* in locations designated by the *IESO*; and/or

12.2.2.3 solicit and accept additional or revised *offers* that will increase generation or injections of *energy* in *response* to higher prices, in locations designated by the *IESO*.

12.2.3 If the *IESO* issues an *operating reserve* shortfall advisory notice pursuant to section 12.1.3, the *IESO* shall, within the period specified in the advisory notice, accept additional or revised *offers* for *operating reserve*.

13. Suspension of Market Operations

13.1 Introduction

13.1.1 The *IESO* may, or may be required to, suspend the operation of all or part of the *IESO-administered markets* in accordance with this section 13.

13.1.2 This section 13 sets forth the procedures the *IESO* must follow in:

13.1.2.1 determining whether to declare a suspension of *market operations;*

13.1.2.2 directing the operation of the *IESO-controlled grid* during suspension of *market operations*; and

13.1.2.3 restoring *market operations* once the conditions triggering suspension are eliminated.

13.1.3 This section 13 also sets forth the requirements that *market participants* must meet immediately prior to, during, and immediately after a suspension of *market operations*.

13.2 Market Suspension Events

13.2.1 Subject to section 13.3, the *IESO* may suspend *market operations* if it determines that any of the conditions described in section 13.2.4 exists or is imminent.

13.2.2 As soon as practical the *IESO* shall notify the *IESO Board,* the *OEB* and relevant government authorities of any suspension of *market operations* pursuant to this section 13.

13.2.3 Upon being notified under section 13.2.2, the *IESO Board* may determine whether to continue the suspension or to resume normal *market operations* under such conditions as the *IESO Board* may specify.

13.2.4 The *IESO* may suspend *market operations* in the event of:

13.2.4.1 *market operations* cannot be continued in a normal manner due to a failure in the software, hardware or communication systems that support *market operations*;

13.2.4.2 a major blackout;

13.2.4.2A the *IESO-controlled grid* breaks up into two or more *electrical islands*;

13.2.4.3 an *emergency* situation requiring the *IESO* to evacuate its principal control centre and move to a backup control centre, under conditions and subject to the requirements of MR Ch.5;

13.2.4.4 a declaration of an emergency by the Premier of Ontario or a direction from the *Minister* to the *IESO* or to a *market participant* to implement an *emergency preparedness plan*; or

13.2.4.5 a *market transition*, the commencement of which the *IESO* shall specify in a market advisory notice.

13.2A Market Transition Suspensions

13.2A.1 Where the *IESO* has suspended *market operations* due to a *market transition*, the suspension shall be for the purposes of activating and, if necessary, testing, validating, adjusting, or restoring the software, hardware or communication systems that support normal *market operations*.

13.2A.2 Notwithstanding section 3.1.11, a *registered market participant* that intends for its *dispatchable generation resources*, *dispatchable electricity storage resources*, *dispatchable loads*, or *hourly demand response resources* to be eligible for *dispatch* by the *IESO* in a given *dispatch hour* of:

13.2A.2.1 the *dispatch day* following the day on which the *market transition* commences shall, on the day the *market transition* commences, submit a *bid* or *offer*, as applicable, for *energy* on the *resource* for the applicable *dispatch hour*. The most recent maximum quantity of *energy* included in the *bid* or *offer* submitted on the *resource* prior to

23:50 EST on the day the *market transition* commences shall be deemed to be the *resource's availability declaration envelope* submitted pursuant to section 3.1.11 for the *dispatch day* following the day on which the *market transition* commences; and

13.2A.2.2 any subsequent *dispatch day* until the *IESO* first *publishes day-ahead market* results pursuant to section 4.7.2 shall, on the day prior to the relevant *dispatch day*, submit a *bid* or *offer*, as applicable, for *energy* on the *resource* for the applicable *dispatch hour*. The most recent maximum quantity of *energy* included in the *bid* or *offer* submitted on the *resource* prior to 10:00 EPT on each subsequent day until the *IESO* first *publishes day-ahead market* results pursuant to section 4.7.2 shall be deemed to be the *resource's availability declaration envelope* submitted pursuant to section 3.1.11 for the relevant *dispatch day*.

13.2A.3 Notwithstanding section 4.3.3.2, sections 3.1.12 and 3.1.13 shall continue to apply on the *dispatch day* following the day on which the *market transition* commences and any subsequent *dispatch day* until the *IESO* first *publishes day-ahead market* results even where the *IESO* has declared a failure of the *day-ahead market* pursuant to section 4.3.2.

13.2A.4 For the *dispatch day* following the day on which the *market transition* commences and any subsequent *dispatch day* until the *IESO* first *publishes day-ahead market* results, any *dispatch data* submission or revision restriction in section 3.3 applicable to a *registered market participant* for a *GOG-eligible resource*:

13.2A.4.1 that has received a *day-ahead operational schedule* or *day-ahead operational commitment* shall also apply to a *registered market participant* for a *GOG-eligible resource* that has received a *pre-dispatch operational commitment* or a *reliability* commitment; and

13.2A.4.2 that has not received a *day-ahead operational schedule* or *day-ahead operational commitment* shall also apply to a *registered market participant* for a *GOG-eligible resource* that has not received a *pre-dispatch operational commitment* or a *reliability commitment*.

13.2A.5 Notwithstanding section 3.3.9, any *standing dispatch data* submitted prior to the commencement of the *market transition* shall not apply following the commencement of the *market transition*. A *registered market participant* may submit *standing dispatch data* on the *dispatch day* following the day on which the *market transition* commences, which, if submitted by 06:00 EPT on that *dispatch day*, shall take effect for the following *dispatch day*.

13.2A.6 Where the *IESO* has suspended *market operations* due to a *market transition* and the *IESO* determines pursuant to section 13.2A.7 that a *market transition error* has occurred, the *IESO* may *dispatch* the *IESO-controlled grid* and administer the *IESO-administered markets* in accordance with the *legacy market rules,* which the *IESO* shall *publish*. During any *dispatch hour* subject to such *dispatch* and administration, any *price responsive load* shall for all purposes be deemed a *non-dispatchable load*.

13.2A.7 The *IESO* may determine that a *market transition error* has occurred where it considers that:

13.2A.7.1 the software, hardware, communication systems or business processes that support normal *market operations* have experienced a critical failure;

13.2A.7.2 this failure would prevent the *IESO* from *dispatching* the *IESO-controlled grid* or administering the *IESO-administered markets* in a manner consistent with normal *market operations* or *reliability*; and

13.2A.7.3 the *IESO* is unable to resolve the failure within a reasonable time.

13.2A.8 Where the *IESO* is satisfied with the results of the activation, testing, validation, adjustment or restoration performed in accordance with section 13.2A.1, the *IESO* shall issue a market advisory notice pursuant to section 13.7.1 indicating the time at which the suspension shall end. The time specified in this market advisory notice shall be the *market transition completion*.

13.3 Reasons for Market Suspension

13.3.1 With respect to sections 13.2.4.1, 13.2.4.2, 13.2.4.3 and 13.2.4.4, the *IESO* may suspend *market operations* in response to an event described in those sections only if the *IESO* determines that its ability to operate the *IESO-administered markets* in accordance with these *market rules* has or will become substantially impaired.

13.3.2 The *IESO* shall not suspend *market operations* solely because:

13.3.2.1 the *market price* has reached positive or negative *maximum market clearing price*; or

13.3.2.2 some *load* has been *curtailed*.

13.4 IESO Declaration of Market Suspension

13.4.1 Only a declaration by the *IESO* may suspend *market operations*. If the *IESO* declares a suspension of *market operations*, the *IESO* shall:

13.4.1.1 immediately notify *market participants*; and

13.4.1.2 issue to *market participants* a market suspension notice via such means as the *IESO* determines will ensure timely notification, informing *market participants* of the nature and scope of the suspension and its expected duration, if known.

13.4.2 Any suspension of *market operations* shall commence at the start of the next *dispatch interval* after the *IESO* makes the declaration, unless the *IESO* suspends *market operations* to protect or restore *reliability*, in which case the suspension shall commence at the time the *IESO* makes the declaration.

13.4.3 The *IESO* may not declare a retroactive suspension of *market operations*.

13.5 IESO Responsibilities During Market Suspension

13.5.1 While a suspension of *market operations* is in effect, the *IESO* shall:

13.5.1.1 prescribe and apply procedures for restoring and maintaining *reliable* operation of the *electricity system* and restoring *market operations* as rapidly as practical, consistent with the safety of persons and *facilities*;

13.5.1.2 endeavour to continue use of normal market information, scheduling and pricing procedures to the extent practical;

13.5.1.3 subject to section 13.6, prescribe and apply *administrative prices* in accordance with section 8.4A.6;

13.5.1.4 suspend the *day-ahead market* when a suspension of the *real-time market* is expected to be in effect for future *dispatch days*;

13.5.1.5 provide timely information to *market participants* concerning the reasons for the suspension and efforts by the *IESO* to resume normal *market operations*; and

13.5.1.6 issue directions, through market suspension advisory notices to *market participants*, that will enable the *IESO* to continue *reliable* operations, continue non-suspended *market operations* and resume normal *market operations* as soon as practical.

13.6 Participant Responsibilities and Compensation

13.6.1 If the *IESO* suspends *market operations*, each *market participant* shall:

13.6.1.1 comply with the *IESO's* market suspension advisory notices and any other directions issued by the *IESO*;

13.6.1.2 conduct their operations and interactions with the *IESO* in a manner consistent with such advisory notices and directions, including, where the *IESO* has, pursuant to section 13.2A.6, advised *market participants* that it will *dispatch* the *IESO-controlled grid* and administer the *IESO-administered markets* in accordance with the *legacy market rules*, complying with the *legacy market rules* until the *IESO* advises otherwise; and

13.6.1.3 upon resumption of normal *market operations*, resume normal operations and interactions with the *IESO* pursuant to these *market rules*.

13.6.2 The *IESO* may issue *dispatch instructions* while a suspension of *market operations* is in effect and shall, subject to sections 13.6.3 and 13.6.4, compensate *market participants* for following these *dispatch instructions* based on *administrative prices* established in accordance with section 8.4A.6 rather than on market-determined prices.

13.6.3 Where the *IESO* suspends *market operations* due to a *market transition*, the *IESO* shall, except for *dispatch intervals* subject to compensation in accordance with section 13.6.4, compensate *market participants* for following *dispatch instructions* based on *administrative prices* calculated using the *market prices* determined by the *real-time calculation engine* where the *IESO* considers those *market prices* valid. Where the *IESO* does not consider the *market prices* determined using the *real-time calculation engine* valid, or where such *market prices* are not available, it shall compensate *market participants* for following *dispatch instructions* based on *administrative prices* calculated using one, or a combination of, the following methods to establish *administrative prices* as the *IESO* determines appropriate:

13.6.3.1 the closest preceding *dispatch interval* that has not been administered;

13.6.3.2 the closest subsequent *dispatch interval* that has not been administered;

13.6.3.3 the closest subsequent hourly *market prices* that have not been administered determined by the *day-ahead market calculation engine*; or

13.6.3.4 where the *IESO* gathers sufficient data following the *market transition* to use the methods to establish *administrative prices* set out in section 8.4A.5 based on that data, any or a combination of the methods in that section relying only on data gathered following the commencement of the *market transition*.

13.6.4 Where, pursuant to section 13.2A.6, the *IESO dispatches* the *IESO-controlled grid* and administers the *IESO-administered markets* in accordance with the *legacy market rules*, it shall, during any *dispatch interval* subject to such *dispatch* and administration and any appropriate preceding *dispatch interval* following the commencement of the *market transition*, compensate *market participants* in accordance with the *legacy market rules*.

13.7 Ending and Reporting on Market Suspension

13.7.1 The *IESO* shall monitor the conditions which triggered the suspension of *market operations* and, subject to any decision or direction that the *IESO Board* may have given pursuant to section 13.2.3, shall issue a market advisory notice declaring the end of the suspension:

13.7.1.1 as soon as the *IESO* determines that normal *market operations* are possible and will maintain *reliable* system operations; and

13.7.1.2 indicating the *dispatch hour* for which normal *market operations* are to resume, providing at least one hour advance notice.

The *IESO* may, if circumstances warrant and in order to resume normal *market operations* as soon as possible, issue a market advisory declaring the end of the suspension prior to issuing the notice specified in section 13.2.2.

13.7.2 The *IESO* shall, immediately following the end of the suspension of *market operations*, begin a review of events leading to and occurring during the suspension. The *IESO* may require *market participants* to submit information regarding their operations immediately prior to and during the suspension and to assist the *IESO* in analyzing the suspension.

13.7.3 Within 10 *business days* following the resumption of normal *market operations*, the *IESO Board* shall provide to all *market participants,* the *OEB* and relevant government authorities a preliminary report describing:

13.7.3.1 the circumstances that triggered suspension of *market operations*;

13.7.3.2 the date and time period of the suspension of *market operations;*

13.7.3.3 the steps taken by the *IESO* during the period of suspension to ensure *reliable* operations and remedy the causes of the suspension;

13.7.3.4 the actions of *market participants* during the suspension; and

13.7.3.5 any conclusions or recommendations for avoiding similar suspensions in the future.

13.7.4 The *IESO Board* shall provide a final report containing information in the nature of that described in section 13.7.3 to *market participants* and the public as soon as it is practicable to do so.

13.7.5 If the *IESO Board* determines that one or more corrective measures by *market participants* are warranted to avoid the recurrence of a suspension of *market operations*, the *IESO* may direct the affected *market participants* to implement the corrective measures and the affected *market participants* shall implement the corrective measures as soon as practicable.

13.7.6 A *market participant* directed by the *IESO* to implement corrective measures under section 13.7.5 may apply for compensation from the *IESO* where compliance with the *IESO's* direction results in costs or damages to the *market participant*.

13.7.7 Any disputes regarding the compensation referred to in section 13.7.6 shall be resolved using the dispute resolution process set forth in MR Ch.3 s.2.

14. [Intentionally left blank – section deleted]

15. [Intentionally left blank – section deleted]

16. [Intentionally left blank – section deleted]

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18. Capacity Auctions

18.1 Purpose of Capacity Auctions

18.1.1 The *capacity auctions* will acquire *auction capacity* through a competitive auction.

18.1.2 The *IESO* shall specify and *publish* a target capacity amount to be acquired in each *capacity auction*, as specified in the applicable *market manual.*

18.1A Capacity Auction – Transitional Market Rules

18.1A.1 For the purposes of participation in a *capacity auction, market rules* and *market manuals* that specifically concern *capacity auction* participation, the satisfaction of *capacity obligations,* or the performance of requirements directly related to that participation, shall remain in effect from the date of the *capacity auction* until the end of its associated *capacity auction commitment period,* except as otherwise provided in sections 18.1A.1.1 and 18.1A.3.

18.1A.1.1 Nothing in this section 18.1A shall limit the effectiveness of a *market rule* amendment or *market manual* amendment that expressively excludes the application of sections 18.1A.1 and 18.1A.2.

18.1A.2 Except as otherwise provided in sections 18.1A.1.1 and 18.1A.3, changes to the *market rules* and applicable *market manuals* that specifically concern *capacity auction* participation, the satisfaction of *capacity obligations*, or the performance of requirements directly related to that participation, and which are brought into effect between the date of a given *capacity auction* and the end of its associated *capacity auction commitment period*, shall be applicable to subsequent *capacity auctions* and their associated *capacity auction commitment periods.*

18.1A.3 Nothing in this section 18.1A shall limit the effectiveness of an *urgent rule amendment.*

18.1A.4 The *IESO* shall maintain a *published* archive of *market rules* and applicable *market manuals* in effect on the date of a *capacity auction* for a period of two years following the end of its associated *capacity auction commitment period.*

18.2 Participation in Capacity Auctions

18.2.1 No person may participate in a *capacity auction* nor receive a *capacity obligation* unless that person has:

18.2.1.1 been authorized by the *IESO* as a *capacity auction participant* in accordance with MR Ch.2 s.3 and in accordance with the applicable *market manual*;

18.2.1.2 submitted to the *IESO* a *capacity qualification request*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*; and

18.2.1.3 no less than five *business days* prior to the date on which a *capacity auction* is to be conducted, provided to the *IESO* a *capacity auction deposit,* in one or both of the forms set forth in section 18.4.

18.2.2 The following provisions of the *market rules* shall not apply to a *capacity auction participant* that is authorized by the *IESO* to participate only in a *capacity auction* with an *hourly demand response resource*:

18.2.2.1 MR Ch.4, 5, and 6;

18.2.2.2 Chapter 7 other than this section 18; and

18.2.2.3 MR Ch.8 and 10.

18.2.3 A *capacity auction participant* who obtains a *capacity obligation* shall apply to become authorized by the *IESO* as a *capacity market participant* in accordance with MR Ch.2 s.3.

18.2A Capacity Auction - Capacity Qualification

18.2A.1 For each *obligation period* in a *capacity auction*, the *IESO* shall determine the *unforced capacity* of each *capacity auction resource* where:

18.2A.1.1 the *unforced capacity* of a *capacity auction eligible generation resource*, a *capacity auction eligible storage resource*, or a *capacity dispatchable load resource* is calculated as:

UCAP = ICAP × availability de-rating factor x performance adjustment factor

18.2A.1.2 the *unforced capacity* of a *system-backed capacity auction eligible import resource* is calculated as:

UCAP = ICAP × performance adjustment factor

18.2A.1.3 The *unforced capacity* of a *generator-backed import resource* is calculated as:

UCAP = (exUCAP + esfICAP ×availability de-rating factor) x performance adjustment factor

Where:

a. 'exU*CAP'* is the total equivalent capacity (in MW) for all *generator-backed import contributors* that are *generation units*, as determined by the applicable *control area operator* and provided to the *IESO* in accordance with the applicable *market manual;*

b. 'esfICAP' is the total *ICAP* (in MW)of all *generator-backed import contributors* that are *electricity storage units,* as provided to the *IESO* in accordance with the applicable *market manual.*

18.2A.1.4 the *unforced capacity* of an *hourly demand response resource* is calculated as:

UCAP = ICAP × performance adjustment factor

18.2A.2 No *capacity auction resource* may participate in a *capacity auction*, nor receive a *capacity obligation*, in respect of any *obligation period* in relation to which the *capacity auction resource* has an *unforced capacity* of less than one MW.

18.2A.3 The *IESO s*hall notify each *capacity auction participant* of the *unforced capacity* for each of the *capacity auction participant's capacity auction resources* on the date specified in accordance with section 18.5.4.1A.

18.3 Calculation of Capacity Auction Deposits

18.3.1 Following the determination of *unforced capacity* in accordance with section 18.2A, the *IESO* shall determine for each *capacity auction participant*, a *capacity auction deposit* for a *capacity auction* as specified in the applicable *market manual*.

18.3.2 The *IESO* shall review the *capacity auction deposit* and *capacity prudential support* of a *capacity transferee* upon receipt of a request for a *capacity obligation* transfer in accordance with section 18.9.1. As a result of a transfer request, the *IESO* may increase the *capacity auction deposit* or *capacity prudential support* of a *capacity transferee* and the *IESO* shall notify the *capacity transferee* of any such increase.

18.3.3 Where the amount of a *capacity auction deposit* provided by a *capacity auction participant* exceeds the amount required by the *IESO*, the *IESO* shall return the excess amount to the *capacity auction participant* within five *business days* of such a request from the *capacity auction participant*. Otherwise, that amount shall be held by the *IESO* and shall form part of that *capacity auction participant's capacity auction deposit* for its participation in a subsequent *capacity auction*.

18.4 Capacity Auction Deposits

18.4.1 A *capacity auction deposit* shall be in one or both of the following forms:

18.4.1.1 an irrevocable commercial letter of credit provided by a bank named in a Schedule to the *Bank Act*, (Canada), S.C. 1991, c. 46; or

18.4.1.2 a cash deposit made with the *IESO* by or on behalf of the *capacity auction participant.*

18.4.2 Where all or part of a *capacity auction deposit* is in the form of a standby letter of credit, the following provisions shall apply:

18.4.2.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 1993 Revision, ICE Publication No. 500 or The International Standby Practices 1998;

18.4.2.2 the *IESO* shall be named as beneficiary in the letter of credit, the letter of credit shall be irrevocable and partial draws on the letter of credit shall not be prohibited;

18.4.2.3 the only condition on the ability of the *IESO* to draw on the letter of credit shall be the delivery of a certificate by an officer of the *IESO* that a specified amount is owing by the *capacity auction participant* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate;

18.4.2.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *capacity auction participant* shall arrange for and deliver additional *capacity auction deposits* if the *capacity auction participant* intends to continue to participate in a *capacity auction*. If such additional *capacity auction deposits* are not received by the *IESO* ten (10) *business days* before the expiry of a letter of credit, the *IESO* shall be entitled as of that time to payment of the full face amount of the letter of credit which amount, once drawn by the *IESO*, shall be treated as a *capacity auction deposit* in the form of cash; and

18.4.2.5 by including a letter of credit as part of a *capacity auction deposit*, the *capacity auction participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *capacity auction participant*.

18.4.3 Notwithstanding any other provision of these *market rules*, a person that applies for authorization to participate in the *capacity auction* and that has not applied for authorization to participate, or is not participating, in any other *IESO-administered market* shall not be required to comply with any requirements for authorization other than those set forth in sections 18.2.1.1 to 18.2.1.3.

18.4.4 In the event a *capacity auction participant* has not satisfied the applicable eligibility requirements specified in sections 19.2, 19.3, 19.6, 19.8, 19.9A, or 19.10 prior to the start of the applicable *obligation period* and has not elected to buy-out the *capacity obligation* in accordance with MR Ch.9 s.4.13.9, the *IESO* shall revoke the *capacity obligation* and the *capacity auction participant* shall, at the *IESO's* sole discretion, forfeit its *capacity auction deposit.*

18.5 Capacity Auction Parameters

18.5.1 The *IESO* shall conduct *capacity auctions* at least on an annual basis to acquire *capacity* for a future one-year *capacity auction commitment period*. In each *capacity auction* the *IESO* shall acquire *auction capacity* for each *obligation period* as specified in the applicable *market manual*.

Demand Curve, Zonal Constraints and Pre-Auction Reports

18.5.2 The *IESO* shall, in accordance with the applicable *market manual*, *publish* a pre-auction report in advance of each *capacity auction*, including the following *capacity auction* demand curve reference points:

18.5.2.1 a *target capacity* in accordance with section 18.1.2;

18.5.2.2 a *capacity auction reference price*;

18.5.2.3 a maximum and minimum *capacity auction clearing price*;

18.5.2.4 [Intentionally left blank – section deleted]

18.5.2.5 a maximum auction capacity limit at the maximum *capacity auction clearing price* that a *capacity auction* shall clear; and

18.5.2.6 a maximum auction capacity limit that a *capacity auction* shall clear.

18.5.3 The *IESO* shall define *capacity auction zonal constraints* for each *capacity auction* and the *IESO* shall *publish*, in the pre-auction report, those requirements as specified in the applicable *market manual*.

18.5.4 The *IESO* shall specify and *publish* in the pre-auction report the following timelines associated with a *capacity auction*:

18.5.4.1 the deadline to submit a *capacity qualification request* pursuant to section 18.2.1.2;

18.5.4.1A the date on which the *IESO* shall notify *capacity auction participants* of the *unforced capacity* for each *capacity auction resource*;

18.5.4.2 the deadline for a *capacity auction participant* to submit a *capacity auction deposit* in accordance with section 18.2.1.3;

18.5.4.3 the dates on which a *capacity auction* participant may submit *capacity auction offers* for a *capacity auction*;

18.5.4.4 the period over which the *IESO* shall conduct the *capacity auction*; and

18.5.4.5 the date of *capacity auction* post-auction reporting in accordance with sections 18.8.1 and 18.8.2.

18.5.5 The *IESO* shall define the total *auction capacity* that may be provided by all *system-backed capacity import resources* and *generator-backed capacity import resources* in a *capacity auction* for each obligation period. The *IESO* shall publish, in the pre-auction report, these requirements as specified in the applicable *market manual*.

18.5.6 The *IESO* shall define the total *auction capacity* that may be provided by all *system-backed capacity import resources* and *generator-backed capacity import resources* on each applicable *intertie* in a *capacity auction* for each obligation period. The *IESO* shall publish, in the pre-auction report, these requirements as specified in the applicable *market manual*.

18.6 Capacity Auction Offers

18.6.1 A *capacity auction offer*:

18.6.1.1 may be submitted or revised by the *capacity auction participant* on the dates specified in accordance with section 18.5.4 and the applicable *market manual*;

18.6.1.2 shall only be applicable to the *obligation periods* for which a *capacity auction participant* has submitted a *capacity auction offer*, in accordance with the applicable *market manual*; and

18.6.1.3 shall be time stamped by the *IESO* when received.

18.6.2 A *capacity auction offer* shall only be submitted in respect of a given *capacity auction* if:

18.6.2.1 the *capacity auction participant* complies with the *capacity auction participant* requirements in section 18.2.1; and

18.6.2.2 the *capacity auction participant* has not been disqualified from full or partial participation in the *capacity auction* pursuant to sections 19.4.8, 19.5.4, 19.7.4, 19.9.4 or 19.11.4.

18.6.3 A *capacity auction offer* may include up to twenty *price-quantity* pairs for each *obligation period* and shall comply with the following:

18.6.3.1 the *capacity auction offer* shall be for and applicable over an entire *obligation period* associated with a *capacity auction*;

18.6.3.2 the *capacity auction offer* price in any *price-quantity pair* shall:

- be expressed in dollars and whole cents per MW-day of *auction capacity* to be provided in each hour of the *availability window* throughout the *obligation period* associated with that *capacity auction*;
- be greater than or equal to $0.00/MW-day;
- not exceed the applicable maximum *capacity auction clearing price;* and
- increase as the associated *capacity auction offer* quantity increases.

18.6.3.3 the *capacity auction offer* quantity in any *price-quantity* pair shall be expressed in MW to not more than one decimal place and the total *offered* quantity shall not exceed the *unforced capacity* of the *capacity auction resource*; and

18.6.3.4 the *capacity auction offer* shall indicate whether the *capacity auction participant* is willing to clear a *capacity auction* with the full amount of *auction capacity offered* in a lamination or a partial amount of the *auction capacity offered* in a lamination, in accordance with the applicable *market manual*.

18.7 Capacity Auction Clearing Prices and Quantities

18.7.1 The *IESO* shall determine a *capacity auction* demand curve to be utilized for each *obligation period* based upon the *capacity auction* parameters detailed in the pre-auction report pursuant to section 18.5 and in accordance with the applicable *market manual*.

18.7.2 The *IESO* shall, in each *capacity auction*, determine for each *obligation period* the *capacity auction clearing price* in accordance with the applicable *market manual*.

18.7.3 The *IESO* shall, in each *capacity auction*, determine for each obligation period the *capacity obligation* for each *capacity auction* participant's *capacity auction resource(s)* in accordance with section 18.7.5 and the applicable *market manual*.

18.7.4 The *IESO* shall, for each *capacity auction*, determine for each *obligation period* associated with the *capacity auction*:

18.7.4.1 the *capacity auction clearing prices* for each electrical zone identified in the pre-auction report; and

18.7.4.2 the zonal *capacity obligation* for each *capacity auction participant's capacity auction resource(s)*.

18.7.5 If two or more *capacity auction participants* submit a *capacity auction offer* at the same price, for the last available quantity, the *capacity auction offer* with the earlier time stamp shall be selected as the successful *capacity auction offer*, in accordance with the applicable *market manual.*

18.8 Post-Auction Notification and Publication

18.8.1 The *IESO* shall, as soon as practicable following the conclusion of a *capacity auction*, *publish* the following in accordance with the applicable *market manual*:

18.8.1.1 the *capacity auction* clearing price;

18.8.1.2 the amount of *auction capacity* that has been acquired in each electrical zone; and

18.8.1.3 those *capacity auction* participants who received a *capacity obligation* and all respective *capacity obligations.*

18.8.2 The *IESO* shall, following the conclusion of a *capacity auction*, issue post-auction reports to each *capacity auction participant* by the date specified in accordance with section 18.5.4.5, to detail the *capacity auction offers* that have cleared in the *capacity auction* and the associated *capacity obligations* and *cleared ICAPs* for each *obligation period* in accordance with the applicable *market manual*:

18.8.2.1 the *cleared ICAP* is calculated as:

$$cleared\ ICAP\ =\ cleared\ UCAP\ \times\left(\frac{1}{availability\ de-rating\ factor}\right) \times\left(\frac{1}{performance\ adjustment\ factor}\right)$$

18.8.2.1.1 For the purposes of calculating a *cleared ICAP* where a *capacity auction resource* is not subject to an *availability de-rating factor* as per section 18.2A.1, *an availability de-rating factor* of 1 shall be applied.

18.9 Capacity Obligation Transfers

18.9.1 A *capacity transferor* may, subject to *IESO* approval and in accordance with the applicable *market manual*, request a transfer of all or a portion of its *capacity obligation* to a *capacity transferee* provided that the following criteria are met:

18.9.1.1 the quantity to be transferred does not exceed the difference between the *capacity transferee's unforced capacity* of a *capacity auction resource* for the applicable *obligation period,* and its existing *capacity obligation* of such *capacity auction resource* for the applicable *obligation period*;

18.9.1.2 the *capacity transferor* provides written confirmation to the *IESO* from the *capacity transferee* of its willingness to accept the transfer of a *capacity obligation* from the *capacity transferor*;

18.9.1.3 the *capacity obligation* transfer shall consist of the same attributes (e.g. physical or virtual), as detailed in the applicable *market manual,* as the *capacity transferor's capacity obligation*;

18.9.1.4 the quantity to be transferred is in increments of 0.1MW, and the resulting *capacity obligations* for both the *capacity transferor* and *capacity transferee* following the transfer shall be 0 MW, or greater than or equal to one MW; and

18.9.1.5 [Intentionally left blank – section deleted]

18.9.1.6 [Intentionally left blank – section deleted]

18.9.1.7 [Intentionally left blank – section deleted]

18.9.1.8 *capacity obligation* transfers must not result in the violation of any constraint as defined in the pre-auction report

18.9.1A Where the *capacity obligation* is transferred between electrical zones, the *capacity transferee* shall be settled based upon the *capacity auction clearing price* received by the *capacity transferor* when the *capacity obligation* first cleared the *capacity auction* in accordance with the applicable *market manual*.

18.9.2 For each transfer request that satisfies the criteria in section 18.9.1, the *IESO* shall determine the *capacity transferee's* revised *capacity auction deposit* and/or *capacity prudential support obligation*, as applicable, in accordance with section 18.3.2 and MR Ch.2 s.5B.3.3.

18.9.3 The *capacity transferee* shall provide the *IESO*, within five *business days* of receiving notification from the *IESO* or within such a longer period of time as may be agreed between the *IESO* and the *capacity transferee*, any additional *capacity auction deposit* and/or *capacity prudential support obligation* that may be required as a result of a transfer request.

18.9.4 After the revised *capacity auction deposits* and/or *capacity prudential support obligations* have been satisfied by the *capacity transferee*, the *IESO* shall notify the *capacity transferor* and *capacity transferee* of its approval or rejection, and the *IESO* shall *publish* updated post-auction reports pursuant to section 18.8. If the *IESO* approves the transfer, the *capacity transferor* may request a reassessment of its *capacity auction deposits* and/or *capacity prudential support obligation* to reflect its revised *capacity obligation* and the *IESO* shall remit any excess *capacity auction deposits* and/or *capacity prudential support obligation*.

19. Capacity Market Participants with Capacity Obligations

19.1 Purpose

19.1.1 This section details how a *capacity market participant* must satisfy a *capacity obligation* with a *capacity auction resource*.

19.1.2 *Capacity auction resources* eligible to satisfy a *capacity obligation* are:

19.1.2.1 an *hourly demand response resource*;

19.1.2.2 a *capacity dispatchable load resource*;

19.1.2.3 a *capacity generation resource*;

19.1.2.4 a *system-backed capacity import resource*;

19.1.2.5 a *capacity storage resource*; or

19.1.2.6 a *generator-backed capacity import resource*.

19.2 Eligibility Requirements for Hourly Demand Response Resources

19.2.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with an *hourly demand response resource* provided that the *capacity market participant*:

19.2.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.2.1.2 registers its *facilities* and *demand response contributors* as applicable, to the satisfaction of the *IESO*, in accordance with the applicable *market manual*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.2.1.3 [Intentionally left blank – section deleted]

19.2.1.4 has provided *prudential support* and *capacity prudential support* in accordance with MR Ch.2 s.5.

19.2.2 The *IESO* may refuse the participation of an *hourly demand response resource* in a future *capacity auction* if the *resource's* participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.2.3 The *IESO* may remove or temporarily remove a *capacity market participant's hourly demand response resource* from its participation as a *capacity market participant* if the *resource's* continued participation would negatively impact the *reliable* operation of the *IESO-controlled grid.* A *capacity market participant* that is removed pursuant to this section 19.2.3 shall not receive an availability payment in accordance with section 19.4.1 for the duration of the removal.

19.2.4 The following provisions of the *market rules* shall not apply to a *capacity market participant* that is authorized by the *IESO* to participate only with an *hourly demand response resource* and is not a *wholesale consumer* that is associated with a *non-dispatchable load* or a *price responsive load*:

19.2.4.1 MR Ch.2 s.8;

19.2.4.2 MR Ch.5, other than ss.1.2.1 to 1.2.3, 2.3, 2.4, 5.8 and 5.9;

19.2.4.3 MR Ch.7 s.7; and

19.2.4.4 MR Ch.6, 8, 10.

19.2.5 Subject to section 19.2.6, *load equipment* that is associated with a *non-dispatchable load* may be registered as a *demand response contributor*, provided that the *non-dispatchable load* meets all the applicable eligibility requirements of this section 19.2, and the associated *wholesale consumer* meets all the requirements in the *market rules* that are applicable to a *wholesale consumer* associated with a *non-dispatchable load*.

19.2.6 *Load equipment* that is associated with a *dispatchable load* or *price responsive load* shall not be registered as a demand response contributor.

19.3 Eligibility Requirements for Capacity Dispatchable Load Resources

19.3.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *capacity dispatchable load resource*, provided that the *capacity market participant*:

19.3.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.3.1.2 is authorized as a *wholesale consumer;*

19.3.1.3 registers its *load facilities* as a *dispatchable load* in accordance with the applicable registration requirements. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *resource* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.3.1.4 satisfies the *connection assessment* requirements in accordance with MR Ch.4 s.6, if required by the *IESO* in accordance with the *applicable market manual*;

19.3.1.5 has provided *prudential support* and *capacity prudential support* in accordance with MR Ch.2 s.5.

19.4 Energy Market Participation for Hourly Demand Response Resources

19.4.1 A *capacity market participant* with a *capacity obligation* participating with an *hourly demand response resource* shall receive an availability payment during the *obligation period* in accordance with this section and the applicable *market manual.* Availability payments may be offset by non-performance charges in accordance with section MR Ch.9 s.4.13.

Standby and Activation Notices

19.4.2 If an *hourly demand response resource* has a *day-ahead schedule* or a *pre-dispatch schedule* less than the *resource's* total *bid* quantity, or if the applicable pre-dispatch *locational marginal price* for an *hourly demand response resource* is equal to or greater than the standby notice price threshold, determined by the *IESO,* for at least one hour during the *dispatch day availability window*, the *IESO* shall issue a standby notice to the applicable *capacity market participant* by 07:00 EST in accordance with the applicable *market manual*.

19.4.3 If the *IESO* does not issue a standby notice to a *capacity market participant* by 07:00 EST, the *capacity market participant* shall remove their *bids* for the *hourly demand response resource* as soon as practicable and before 9:00 EST. A capacity *market participant* that does not remove their *bids* for the *hourly demand response resource* before 9:00 EST shall comply with any corresponding activation notices issued by the *IESO* in accordance with section 19.4.5.

19.4.4 Subject to 19.4.4B, the *IESO* shall issue an activation notice to a *capacity market participant* no later than two hours before the activation period, if a standby notice has been issued in accordance with section 19.4.2 or a *capacity market participant* has not removed their *bids* in accordance with section 19.4.3, and the applicable *hourly demand response resource* has, for *the pre-dispatch calculation engine* run three hours before the activation period, a *pre-dispatch schedule* less than the *resource's* total *bid* quantity for at least one hour during the *dispatch day availability window*.

19.4.4A Subject to 19.4.4B, the *IESO* shall use reasonable efforts to ensure that the activation notice issued with respect to each *hourly demand response resource* is consistent with the *pre-dispatch schedule* for the *pre-dispatch calculation engine* run three hours before the activation period for that *resource*.

19.4.4B The *IESO* shall not be required to issue an activation notice, or, in the event that the *IESO* does issue an activation notice, shall not be required to satisfy the requirements of section 19.4.4A if:

19.4.4B.1 the *security* and *adequacy* of the system would be endangered by implementing the *pre-dispatch schedule*;

19.4.4B.2 the *pre-dispatch calculation engine* has failed, or has produced a *pre-dispatch schedule* that is clearly and materially in error;

19.4.4B.3 material changes subsequent to determination of the *pre-dispatch schedule*, such as failure of an element of a *transmission system* or failure of a *resource* to follow *dispatch instructions*, have occurred; or

19.4.4B.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13.

19.4.5 If a *capacity market participant* receives an activation notice pursuant to section 19.4.4, the *capacity market participant* shall comply with the activation notice, unless such a reduction would endanger the safety of any person, damage equipment, or violate any *applicable law*. In such circumstances, the *capacity market participant* shall notify the *IESO* as soon as practicable.

19.4.6 A *capacity market participant* may be subject to non-performance charges, and the *IESO* may take action pursuant to sections 19.2.2 and 19.2.3 if a *capacity market participant* does not comply with an activation notice pursuant to this section 19, in accordance with the applicable *market manual*. The *capacity market participant* may also be subject to compliance actions in accordance with MR Ch.3 s.6.

19.4.7 A *capacity market participant* that expects its *hourly demand response resource* to operate in a manner that differs from the activation notice issued to it in accordance with this section 19 shall notify the *IESO* as soon as possible and in accordance with the applicable *market manual*.

19.4.8 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to reduce its consumption in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Non-performance Events for Hourly Demand Response Resources

19.4.9 In the event of a reduction in the *demand response capacity* of an *hourly demand response resource*, associated with a *capacity obligation* acquired through a *capacity auction*, the *capacity market participant* shall notify the *IESO* as per the procedures and criteria specified in the applicable *market manual*.

19.4.10 A *capacity market participant* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can provide in accordance with section 3.5.9 and due to any non-performance event related to an *hourly demand response resource* in an *obligation period*.

19.4.10A Where a *contributor outage* has occurred and such *contributor outage*:

a. began not more than 14 days prior to the day on which there is an activation; and

b. ends within one hour prior to such activation or within the *activation window* of such activation;

then the *capacity market participant* may *notify* the *IESO* within five *business days* of the activation notice, in accordance with the process and requirements described in the applicable *market manual*.

19.4.10B Where the *IESO* receives a valid *contributor outage* notice pursuant to section 19.4.10A, the *IESO* shall adjust the assessment of the *capacity market participant's* performance as set out in the applicable *market manual.*

Capacity Auction Testing for Hourly Demand Response Resources

19.4.11 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* with a *capacity obligation* to perform a *capacity auction dispatch test* for each *hourly demand response resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period*.

19.4.11A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *hourly demand response resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.4.12 If a *capacity market participant* fails during a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.4.11 or section 19.4.11A, respectively, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual* and MR Ch.9 s.4.13*.* Failure during a *capacity auction dispatch test* or a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with MR Ch.3 s.6.2.

19.4.13 The *IESO* shall provide a *capacity market participant* day-ahead notification of a *capacity auction dispatch test* pursuant to section 19.4.11 and the test activation shall occur within the *availability window* of an *obligation period*.

19.4.14 The *capacity auction dispatch test* shall occur in accordance with the *hourly demand response resource* activation process specified in this section 19.4.

19.4.15 The *hourly demand response resource* shall be entitled to compensation for valid *capacity auction dispatch tests* conducted during a *capacity auction commitment period* pursuant to this section 19.4 and in accordance with the applicable *market manuals*. The *hourly demand response resource* shall not be entitled to compensation for any costs related to any *capacity auction capacity test.*

19.4.16 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines, the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test* or *capacity auction dispatch test*, as the case may be.

19.4.17 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.4.18 Where the notice referred to in section 19.4.17 indicates that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP* and such *capacity market participant* has not filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with MR Ch.9 s.6.8, such *capacity market participant's capacity obligation* for such *hourly demand response resource* shall, effective as of one *business day* following the time period referred to in MR Ch.9 s.6.3.14, be reduced to the amount of capacity that was determined by the *IESO,* in accordance with the applicable *market manual,* to have been provided by the *capacity market participant* during the *capacity auction capacity test*. If such reduction in the *capacity market participant's capacity obligation* for such *hourly demand response resource* results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such *hourly demand response resource* is forfeited effective as of one *business day* following the time period referred to in MR Ch.9 s.6.3.14.

19.4.19 Where the notice referred to in section 19.4.17 indicates that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*, such *capacity market participant* shall be subject to an in-period *cleared UCAP* adjustment charge pursuant to MR Ch.9 s.4.13.8.

19.4.20 After the relevant *capacity market participant* has made payment in full of any *settlement amount* owing pursuant to MR Ch.9 s.4.13.8, in respect of the same *capacity auction capacity test* for which its *capacity obligation* is being reduced pursuant to this section 19.4.16, the *capacity market participant* may request a reassessment of its *capacity prudential support obligation* to reflect its revised *capacity obligation* and the *IESO* shall remit any excess *capacity prudential support*.

Activation of Hourly Demand Response Resources leading up to or during an Emergency Operating State

19.4.21 A *capacity market participant* satisfying a *capacity obligation* using an *hourly demand response resource* shall be entitled to compensation for an activation leading up to or during an *emergency operating state* pursuant to MR Ch.5 s.2.3, and in accordance with the applicable *market manuals*.

19.5 Energy Market Participation for Capacity Dispatchable Load Resources

19.5.1 A *capacity market participant* with a *capacity obligation* participating with a *capacity dispatchable load resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with MR Ch.9 s.4.13*.*

Dispatch of Capacity Dispatchable Load Resources

19.5.2 The *IESO* shall schedule a *capacity dispatchable load resource* in the *real-time market* and issue a *dispatch instruction* in accordance with Chapter 7.

19.5.3 A *capacity dispatchable load resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.5.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to reduce its consumption in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Dispatchable Load Resources

19.5.5 Each *capacity dispatchable load resource* shall comply with the *outage* notification requirements of MR Ch.5.

19.5.6 A *capacity dispatchable load resource* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can consume in accordance with section 3.5.9.

Capacity Auction Testing for Capacity Dispatchable Load Resources

19.5.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period*.

19.5.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity dispatchable load resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.5.8 If a *capacity market participant* fails a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.5.7 or 19.5.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with MR Ch.9 s.4.13*.* Failure during *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with MR Ch.3 s.6.2.

19.5.9 The *IESO* shall provide a *capacity dispatchable load resource* day-ahead notification of a *capacity auction dispatch test* and the test activation shall occur within the *availability window* of an *obligation period*.

19.5.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* for a *capacity dispatchable load resource* specified in this section 19.5.

19.5.11 The *capacity dispatchable load resource* shall not be entitled to compensation for any costs related to any valid *capacity auction dispatch test* or *capacity auction capacity test* conducted during an *obligation period* pursuant to this section 19.5.

19.5.12 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines, the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.5.13 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.6 Eligibility Requirements for Capacity Generation Resources

19.6.1 A *capacity market participant* is eligible to satisfy its capacity obligation as a *capacity generation resource*, provided that the *capacity market participant*:

19.6.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual;*

19.6.1.2 is authorized as a *generator;*

19.6.1.3 registers its *generation facilities* as a *generation resource* in accordance with the applicable registration requirements. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.6.1.4 satisfies the *connection assessment* requirements in accordance with MR Ch.4 s.6, if required by the *IESO* in accordance with the applicable *market manual;*

19.6.1.5 has provided *prudential support* and *capacity prudential support* in accordance with MR Ch.2 s.5.

19.7 Energy Market Participation for Capacity Generation Resources

19.7.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity generation resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with MR Ch.9 s. 4.13.

Dispatch of Resources

19.7.2 The *IESO* shall schedule a *capacity generation resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.7.3 A *capacity generation resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.7.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to inject *energy* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Generation Resources

19.7.5 Each *capacity generation resource* shall comply with the *outage* notification requirements of MR Ch.5.

19.7.6 A *capacity generation resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject in accordance with section 3.5.9.

Capacity Auction Testing for Capacity Generation Resources

19.7.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *capacity generation resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period*.

19.7.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity generation resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business* days prior to the first day of the testing window.

19.7.8 If a *capacity market participant* fails a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.7.7 or 19.7.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with MR Ch.9 s.4.13*.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with MR Ch.3 s.6.2.

19.7.9 The *IESO* shall provide a *capacity generation resource* that is a *non-quick start resource* notification up to one *business day* in advance of a *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.7.9A The *IESO* shall provide a *capacity generation resource* that is a *quick start resource* notification at least one hour in advance of the *dispatch hour* of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.7.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* specified in this section 19.7.

19.7.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.7.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.8 Eligibility Requirements for System-Backed Capacity Import Resources

19.8.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *system-backed capacity import resource* provided that the cap*acity market participant*:

19.8.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.8.1.2 is authorized as a *market participant* eligible to import *energy;*

19.8.1.3 is registered to use the applicable *boundary entity resource* pursuant to section 2.2.7; and

19.8.1.4 has provided *prudential support* and *capacity prudential support* in accordance with MR Ch.2 s.5B.

19.9 Energy Market Participation for System-Backed Capacity Import Resources

19.9.1 A *capacity market participant* satisfying its *capacity obligation* with a *system-backed capacity import resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with MR Ch.9 s.4.13*.*

Dispatch of System-Backed Capacity Import Resources

19.9.2 The *IESO* shall schedule a *system-backed capacity import resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.9.3 A *system-backed capacity import resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.9.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to schedule *energy* with the appropriate *scheduling entity* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for System-Backed Capacity Import Resources

19.9.5 A *system-backed capacity import resource* shall reduce or remove its *offer* to reflect the maximum capacity that it reasonably expects it can provide in accordance with section 3.5.9.

Capacity Auction Testing for System-Backed Capacity Import Resources

19.9.6 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction capacity test* for each *system-backed capacity import resource* up to a maximum of two *capacity auction capacity tests* per *obligation period* to verify that the *cleared ICAP* can be satisfied for a duration specified in the applicable *market manual* by the *system-backed capacity import resource*.

19.9.7 If a *capacity market participant* fails a *capacity auction capacity test* performed pursuant to section 19.9.6, the *capacity market participant* shall be subject to non-performance charges in accordance with MR Ch.9 s.4.13. Failure during a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with MR Ch.3 s.6.2.

19.9.8 The *IESO* shall provide a *system-backed capacity import resource* notification at least two hours in advance of the *dispatch hour* of the *capacity auction capacity test* and the *capacity auction capacity test* shall occur within the *availability window* of an *obligation period*.

19.9.9 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.9.

19.9.10 The *IESO* shall assess, in accordance with the applicable *market manual,* the relevant testing and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.9A Eligibility Requirements for Generator-Backed Capacity Import Resources

19.9A.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *generator-backed capacity import resource* provided that the *capacity market participant*:

19.9A.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.9A.1.2 is authorized as a *market participant* eligible to import *energy* in association with a *boundary entity resource;* and

19.9A.1.3 has provided *prudential support* and *capacity prudential support* in accordance with MR Ch.2 s.5B.

19.9B Energy Market Participation for Generator-Backed Capacity Import Resources

19.9B.1 A *capacity market participant* satisfying its *capacity obligation* with a *generator-backed capacity import resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with MR Ch.9 s. 4.13*.*

Dispatch of Generator-Backed Capacity Import Resources

19.9B.2 The *IESO* shall schedule a *generator-backed capacity import resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.9B.3 A *generator-backed capacity import resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.9B.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to schedule *energy* with the appropriate scheduling entity in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Generator-Backed Capacity Import Resources

19.9B.5 A *generator-backed capacity import resource* shall reduce or remove its *offer* to reflect the maximum capacity that it reasonably expects it can provide in accordance with section 3.5.9*.*

19.9B.6 A *generator-backed capacity import resource* shall comply with the *outage* notification requirements specified in the applicable *market manual.*

Capacity Auction Testing for Generator-Backed Capacity Import Resources

19.9B.7 A *capacity market participant* satisfying its *capacity obligation* with a *generator-backed capacity import resource* must perform a capacity auction capacity test, per obligation period, in accordance with the applicable *market manual*, by scheduling an *energy* import into the *IESO-administered market* for at least one (1) hour that coincides with the timing of its scheduled four hour activation in the neighbouring *control area*, on a date that falls within the first two months of the applicable *obligation period* and by submitting data to the *IESO* to confirm the capability of the *generator-backed capacity import resource* to inject at least its *cleared ICAP* into the *control area* in which it is located for four consecutive hours within the *availability window.*

19.9B.8 A *capacity market participant* that fails to submit data pursuant to section 19.9B.7 in the form specified by the *IESO,* in a timely manner shall be subject to a capacity obligation administration charge pursuant to MR Ch.9 s.4.13.4.

19.9B.9 If a *capacity market participant* fails a *capacity auction capacity test* performed pursuant to section 19.9B.7, the *capacity market participant* shall be subject to non-performance charges in accordance with MR Ch.9 s.4.13*.* Failure during a *capacity auction dispatch test* or a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with MR Ch.3 s.6.2.

19.9B.10 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.9B.

19.9B.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.9B.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.10 Eligibility Requirements for Capacity Storage Resources

19.10.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *capacity storage resource* provided that the *capacity market participant*:

19.10.1.1 demonstrates to the satisfaction of the *IESO* that it can satisfy the *capacity obligation*, as specified in the applicable *market manual. Capacity storage resources* must satisfy *capacity obligations* with injections of *energy* into the *IESO-controlled grid*;

19.10.1.2 is a registered *market participant* authorized as an *electricity storage participant* in accordance with the applicable *market manual;*

19.10.1.3 registers its *electricity storage facilities* as an *electricity storage resource* in accordance with the applicable registration requirements. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.10.1.4 satisfies the *connection assessment* requirements in accordance with MR Ch.4 s.6, if required by the *IESO* in accordance with the applicable *market manual;* and

19.10.1.5 has provided *prudential support* and *capacity prudential support* in accordance with MR Ch.2 s.5.

19.11 Energy Market Participation for Capacity Storage Resources

19.11.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity storage resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with MR Ch.9 s. 4.13.

Dispatch of Capacity Storage Resources

19.11.2 The *IESO* shall schedule a *capacity storage resource* as it would an *electricity storage facility* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.11.3 A *capacity storage resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.11.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to inject *energy* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Storage Resources

19.11.5 Each *capacity storage resource* shall comply with its *outage* notification requirements as outlined in MR Ch.5.

19.11.6 A *capacity storage resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject in accordance with section 3.5.9.

Capacity Auction Testing for Capacity Storage Resources

19.11.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *capacity storage resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period*.

19.11.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity storage resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.11.8 If a *capacity market participant* fails a test performed pursuant to section 19.11.7 or 19.11.7A, the *capacity market participant* shall be subject to non-performance charges in accordance MR Ch.9 s.4.13*.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with MR Ch.3 s.6.2.

19.11.9 The *IESO* shall provide a *capacity storage resource* notification at least one hour in advance of the *dispatch hour* of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.11.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* specified in this section 19.11.

19.11.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.11.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

20. Capacity Exports in the IESO-Administered Markets

20.1 Capacity Export Request and IESO Review

20.1.1 A *market participant* that wishes to export eligible capacity shall submit a *capacity export request* to the *IESO,* in the form, within the timelines and as further prescribed in the applicable *market manual*.

20.1.2 The *IESO* shall approve or deny *capacity export requests* based on the *IESO's* review, as prescribed in the applicable *market manual.*

20.1.3 The *IESO* may, after approving or partially approving a *capacity export request* and prior to the *market participant* committing capacity to an external *control area*, revoke an approval of a *capacity export request* in order to maintain the *reliability* of the *IESO-controlled grid*, or if the *IESO* becomes aware of any event or change in circumstances that may alter the *IESO's* approval of a *capacity export request*.

20.2 Capacity Export Commitment Process

20.2.1 A *market participant* may only commit capacity to an external *control area* in accordance with the time periods, quantities and other terms and conditions of the *IESO's* approval of the *capacity export request*.

20.2.2 A *market participant* that commits its capacity to an external *control area* shall notify the *IESO* of the commitment and any subsequent changes to the commitment in the time and manner prescribed in the applicable *market manual*.

20.3 Called Capacity Exports

20.3.1 The *IESO* shall only accept and schedule a *called capacity export* in accordance with section 20.4 when advised by the external *control area operator* that the applicable external *control area* is anticipating or experiencing an adequacy shortfall, as may be specified in the applicable *capacity export agreement*.

20.3.2 A *market participant* shall notify the *IESO* concerning the details of a *called capacity export* in the time and manner prescribed in the applicable *market manual*.

20.4 Called Capacity Export Scheduling and Dispatch

20.4.1 Export *bids* for *called capacity exports* shall only be submitted by the *registered market participant* for the *resource* that has received approval from the *IESO* to export capacity in accordance with section 20.1.2.

20.4.2 All export *bids* for *called capacity exports* shall be submitted in the form and within the timelines prescribed in the applicable *market manual*.

20.4.3 Notwithstanding any provision of the *market rules* that may require the *IESO* to restrict exports in order to maintain the *adequacy* of the *IESO-controlled grid*, the *IESO* may schedule and *dispatch called capacity exports* in accordance with applicable *capacity export agreements* (the relevant details of which are specified in the applicable *market manual*).

21. Electricity Storage in the IESO-Administered Markets

21.1 Purpose

21.1.1 This section 21 sets out *market rules* intended to facilitate the near-term inclusion of *electricity storage participants* in the *IESO-administered markets* and the connection of *electricity storage resources* to the *electricity system*. A number of the provisions of this section would, based on their subject matter, ordinarily be included under different chapters or sections of the *market rules*. However, these provisions have been gathered together here under a single section for convenience of reference and until such time that *electricity storage participants* and *electricity storage resources* are more fully integrated under these *market rules.*

21.2 Market Registration

21.2.1 An *electricity storage participant* wishing to register an *electricity storage facility* and its associated *self-scheduling electricity storage resources* shall satisfy the applicable requirements in section 2, as further described in the applicable *market manual.* Without limiting the generality of the foregoing, the *electricity storage participant* shall satisfy those requirements set out in MR Ch.4 App.4.24 (IESO Monitoring Requirements: Electricity Storage Facilities) and MR Ch.4 App. 4.25 (Monitoring Requirements: Electricity Storage Performance Standards)".

21.2.2 Subject to the *market rules* governing participation in the *energy markets* and the provision of *ancillary services* to the *IESO,* a *self-scheduling electricity* *storage resource* or its associated *electricity storage units* may only be registered to participate in the *energy market* and to provide *reactive support service*, *voltage control service*, or *regulation* service or combinations of the foregoing, except that it shall not be registered to both participate in the *energy market* and provide *regulation* service.

21.2.3 An *electricity storage participant* wishing to register an *electricity storage facility* and its associated *dispatchable electricity storage resources*, shall satisfy the applicable requirements in section 2 as further described in the applicable *market manual*. Without limiting the generality of the foregoing the *electricity storage participant* shall satisfy those requirements set out in MR Ch.4 App.4.24 (IESO Monitoring Requirements: Electricity Storage Facilities) and MR Ch.4 App.4.25 (Monitoring Requirements: Electricity Storage Performance Standards).

21.2.4 Subject to the *market rules* governing participation in the *energy markets* and the provision of *ancillary services* to the *IESO,* a *dispatchable electricity storage resource* may only be registered to allow that *resource* to participate in the *energy market* or *operating reserve market*, or for its associated *electricity storage units* to provide *reactive support service* or *voltage control service*, or combinations of the foregoing and may participate in the *capacity auction.*

21.3 Provision of Regulation Service

21.3.1 An *electricity storage participant* wishing to provide *regulation* services must register its *electricity storage resource* as further described in the applicable *market manual*.

21.3.2 Notwithstanding section 2.2.9A.1, an *electricity storage participant* may request to register an *electricity storage facility* and its associated *resources* as a *self-scheduling electricity storage facility* if such *electricity storage facility* has an e*lectricity storage capacity* greater than or equal to 10 MW up to 50 MW for the purposes of providing *regulation services* only, provided that the *IESO* determines that there are no adverse impacts on the reliable operation of the *IESO-controlled grid*;

21.3.3 An *electricity storage resource* that is registered to provide *regulation services* may not participate in the *energy market* or the *operating reserve market*.

21.4 Energy Offers and Energy Bids

21.4.1 Notwithstanding section 3.5.1, an *electricity storage participant* may submit both an *offer* to inject *energy* and a *bid* to withdraw *energy* for a *dispatchable electricity storage resource* during the same *dispatch hour*.

21.4.2 For each *dispatch hour* in which an *electricity storage participant* submits both an *energy offer* and *energy bid* for an *electricity storage resource*, the *electricity storage participant* shall not submit a *bid* for that *electricity storage resource* that includes a price that is higher than or equal to the lower of: (i) the lowest price in the *offer* submitted for that *electricity storage resource;* and (ii) the lowest price in that *electricity storage resource's energy offer reference level value*.

21.4.3 An *electricity storage participant* who:

(a) submits a *bid* in the *day-ahead market* contrary to section 21.4.2, is not entitled to the *day-ahead market* make-whole payment *settlement* amount, determined in accordance with MR Ch.9 s.3.4.1, for the relevant *dispatch hours*; and

(b) submits a *bid* in the *real-time market* contrary to section 21.4.2, is not entitled to the *real-time* make-whole payment *settlement* amount determined in accordance with MR Ch.9 s.3.5.1, for the relevant *dispatch hours.*

21.5 Revisions to Dispatch Data

21.5.1 The *IESO* shall approve reduced injections or withdrawal amounts included in revised *dispatch data* from *electricity storage participants* submitted within the *real-time market mandatory window,* where the *electricity storage participant* determines, acting reasonably that its *electricity storage resource* may reach its:

21.5.1.a *lower energy limit* in that *dispatch hour*, and will likely prevent the *electricity storage resource* from injecting *energy* in accordance with its *offer*, or

21.5.1.b *upper energy limit* in that *dispatch hour*, and will likely prevent the *electricity storage resource* from withdrawing *energy* in accordance with its *bid*.

21.6 Operating Reserve

21.6.1 An *electricity storage participant* shall not submit an *offer* to provide *operating reserve* from a *dispatchable electricity storage resource* in any *dispatch hour* when there is a simultaneous *energy bid* and *energy offer* for that *electricity storage resource* in the same *dispatch hour*.

21.6.2 An *electricity storage participant* shall only submit an *offer* to provide *operating reserve* for a *dispatchable electricity storage resource* accompanied by an *offer* to inject *energy* if:

21.6.2.1 The *electricity storage participant* submits an *offer* for the *electricity storage resource* to inject *energy* for the entire *dispatch hour* and has not submitted any *bids* for that *electricity storage resource* to withdraw *energy* for that *dispatch hour*;

21.6.2.2 The *electricity storage participant* does not submit an *offer* to provide *operating reserve* accompanied by a *bid* to withdraw *energy* in the subsequent *dispatch hour*; and

21.6.2.3 the *remaining duration of service* at the time stipulated in the applicable *market manual* is greater than or equal to the period of time stipulated in the applicable *market manual.*

21.6.3 An *electricity storage participant* shall only submit an *offer* to provide *operating reserve* for a *dispatchable electricity storage resource* accompanied by a *bid* to withdraw *energy* if:

21.6.3.1 The *electricity storage participant* submits a *bid* for the *electricity storage resource* to withdraw *energy* for the entire *dispatch hour* and has not submitted any *offers* for that *electricity storage resource* to inject *energy* for that entire *dispatch hour*;

21.6.3.2 The *electricity storage participant* does not submit an *offer* to provide *operating reserve* accompanied by an *offer* to inject *energy* in the subsequent *dispatch hour*; and

21.6.3.3 The *remaining duration of service* at the time stipulated in the applicable *market manual* is greater than or equal to a period of time stipulated in the applicable *market manual.*

21.7 Interpretation

21.7.1 To the extent of any conflict or inconsistency between the provisions of this section 21 and any other provisions of the *market rules*, the provisions of this section 21 shall govern.

21.7.2 With respect to Chapter 7, System Operations and Physical Markets-Appendices, the *IESO* will, acting reasonably and consistently at all times with the scope and intent of the amendments referenced in section 21.1:

21.7.2.a treat electricity storage injecting, or proposing to inject *energy*, as either a *dispatchable generation resource* or *self-scheduling generation resource*; and

21.7.2.b treat electricity storage withdrawing, or proposing to withdraw *energy*, as either a *dispatchable load* or *price responsive load*, in each case, deeming such changes to be made to the applicable provisions of such Appendices or applicable *market manuals* as may be necessary to give full meaning to the foregoing.

21.7.3 For further certainty, the reference in section 21.7.2a to the use of *dispatchable generation resource* or *self-scheduling generation resource* in the interpretation of Chapter 7, System Operations and Physical Markets-Appendices and the applicable *market manuals*, shall not include any features or attributes that pertain primarily to and are distinctive of *intermittent generation resources*, *flexible nuclear generators*, or *variable generators* or.

22. Market Power Mitigation

22.1 Reference Levels - General

22.1.1 The *IESO* shall determine and register *reference levels* for each *dispatchable resource* registered to submit *offers* or *bids* into the *energy market* or *offers* for *operating reserve* into the *operating reserve market*.

22.1.1.1 The *IESO* shall determine a *resource's* initial *reference levels* at the request of the *market participant* that is registered as the owner of the *resource*.

22.1.1.2 The *IESO* shall determine a *resource's reference levels* in accordance with the applicable *market manual*.

22.1.2 No *registered market participant* for a *resource* that meets the requirements in section 22.1.1 shall submit *offers* or *bids* for that *resource* unless the *IESO* has determined and registered *reference levels* for that *resource*.

22.1.3 A *market participant* shall provide to the *IESO* all information and supporting documentation that the *IESO* may reasonably require to determine a *resource*'s *reference levels*, in accordance with the applicable *market manual*.

22.1.4 The *IESO* shall make available to each *market participant* the *reference levels* that are registered and *reference level values* that are calculated for that *market participant's resources,* in accordance with the applicable *market manual*.

22.1.5 The *reference level values* of each *energy offer reference level* shall be consistent with the requirements for *energy offers* in section 3.5.3.

22.1.6 The *reference level values* of each *operating reserve offer reference level* shall be consistent with the requirements for *offers* to provide *operating reserve* in section 3.6.2.

22.1.7 A *dispatchable resource* installed pursuant to the Canadian Nuclear Safety Commission's requirement for nuclear power plants to maintain standby and emergency power systems is exempt from the requirements in, and market power mitigation framework established by, this section 22.

22.2 Reference Levels for Financial Dispatch Data Parameters

22.2.1 The *IESO* shall determine the following *reference levels* for *financial dispatch data parameters,* by month or season if applicable, for each *resource* that meets the requirements in section 22.1.1:

22.2.1.1 *energy offer reference level*;

22.2.1.2 one *speed no-load offer reference level*;

22.2.1.3 one *start-up offer reference level* per *thermal state*; and

22.2.1.4 one *operating reserve offer reference level* for each class of *operating reserve* that the *resource* is registered to provide.

22.2.2 The *IESO* shall determine the *reference levels* in section 22.2.1 based on a *resource*'s *short-run marginal costs,* except as set out in the applicable *market manual.*

22.2.3 Despite section 22.2.2:

22.2.3.1 the *IESO* shall not register an *energy offer reference level* or an *operating reserve offer reference level* that produces *reference level values* that do not monotonically increase in quantity, regardless of a *resource's short-run marginal costs*; and

22.2.3.2 the *IESO* may register a *reference level* that produces *reference level values* below a *resource's short-run marginal costs* at the request of the relevant *market participant*.

22.3 Reference Levels for Non-Financial Dispatch Data Parameters

22.3.1 The *IESO* shall determine the following *reference levels* for *non-financial dispatch data parameters* in accordance with the applicable *market manual*, by month or season if applicable, for each *resource* that meets the requirements in section 22.1.1:

22.3.1.1 *energy ramp rate reference level*;

22.3.1.2 *operating reserve ramp rate reference level*;

22.3.1.3 *lead time reference levels* for each *thermal state*;

22.3.1.4 *minimum loading point reference level*;

22.3.1.5 *minimum generation block run-time reference level*;

22.3.1.6 *minimum generation block down-time reference levels* for each *thermal state*;

22.3.1.7 *maximum number of starts per day reference level*;

22.3.1.8 *ramp hours to minimum loading point reference levels* for each *thermal state*; and

22.3.1.9 minimum and maximum *energy per ramp hour reference levels* for each *thermal state*.

22.3.2 The *IESO* shall determine the *reference levels* in section 22.3.1 based on a *resource's* operating characteristics in *unrestricted competition*, except as may be set out in the applicable *market manual*.

22.3.3 If a *market participant* fails to provide the information or supporting documentation required by the *IESO* pursuant to section 22.1.3, the *IESO* may register the following values for a *reference level* determined pursuant to section 22.3.1:

22.3.3.1 *energy ramp rate reference level*: 0.1 MW/min;

22.3.3.2 *operating reserve ramp rate reference level*: 0.1 MW/min;

22.3.3.3 *lead time reference levels* for each *thermal state*: 24 hours;

22.3.3.4 *minimum loading point reference level*: for a *generation resource*, the *resource*'s registered maximum generator resource active power capability; for a *dispatchable load resource*, the *resource*'s registered maximum load – active power;

22.3.3.5 *minimum generation block run-time reference level*: 24 hours;

22.3.3.6 *minimum generation block down-time reference level* for each *thermal state*: 24 hours;

22.3.3.7 *maximum number of starts per day reference level*: 10,000 starts per day;

22.3.3.8 *ramp hours to minimum loading point reference levels* for each *thermal state*: 12 hours;

22.3.3.9 *minimum energy per ramp hour reference levels* for each *thermal state*: 0 MWh; and

22.3.3.10 *maximum energy per ramp hour reference levels* for each *thermal state*: 1 MWh multiplied by the *resource's minimum loading point reference level*.

22.4 Resources with Multiple Sets of Reference Levels

22.4.1 For each *resource* that is registered as a *pseudo-unit*, the *IESO* shall determine one set of *reference levels* for the combined-cycle mode of operation and one set of *reference levels* for the single-cycle mode of operation, as applicable to that *resource*.

22.4.2 For a *resource* that has registered a primary fuel type of gas, oil, steam, or biomass, and which is not eligible to submit *start-up offers* and *speed-no-load offers* as hourly *dispatch data* into the *day-ahead market* and *real-time market*, the *IESO* shall determine two *energy offer reference levels* for that *resource* in accordance with the applicable *market manual*.

22.4.3 For a *resource* that does not have multiple sets of *reference levels* determined pursuant to section 22.4.1 or 22.4.2 and which has indicated to the *IESO* that it can operate according to two distinct cost profiles, the *IESO* shall determine a set of *reference levels* for each profile in accordance with the applicable *market manual*. Each set of *reference levels* shall include all *reference levels* applicable to the *resource*.

22.4.4 For a *resource* with *reference levels* determined pursuant to section 22.4.3, the *IESO* shall use the set of *reference levels* associated with the profile with the lowest costs, unless the *market participant* requests otherwise pursuant to section 22.5.5 and the *IESO* has accepted the request.

22.4.5 The *IESO* shall determine one *operating reserve offer reference level* to be used when an *electricity storage resource* proposes to inject and a separate *operating reserve offer reference level* for when it proposes to withdraw, in accordance with the applicable *market manual*.

22.5 Changes to Reference Levels

22.5.1 Once the *IESO* has registered a *reference level* for a *resource*, the *IESO* shall not change that *reference level* unless:

22.5.1.1 the *IESO* has modified the *market rules* or the applicable *market manual* such that the *reference level* determined following such modification differs from the registered *reference level*;

22.5.1.2 the *IESO* identifies a need in accordance with section 22.5.2;

22.5.1.3 the *IESO* registered that *reference level* pursuant to section 22.3.3;

22.5.1.4 the *IESO* is required to do so pursuant to section 22.5.3;

22.5.1.5 the *market participant* for the *resource* requests the *IESO* review that *reference level* pursuant to section 22.5.4 and the *IESO* has accepted the request;

22.5.1.6 the *market participant* for the *resource* requests a temporary revision to the fuel cost component of one of the *resource*'s *reference levels* pursuant to section 22.5.5 and the *IESO* has accepted the temporary revision; or

22.5.1.7 more than two years have passed since the *reference level* was established or last updated, whichever is later.

22.5.2 The *IESO* may, at any time, review a *resource's* registered information or the supporting documentation submitted pursuant to section 22.1.3 to verify that the *resource's reference levels* are consistent with the registered information or supporting documentation. If, as a result of such review, the *IESO* determines that the *reference level* needs to be amended to be consistent with the registered information or supporting documentation, the *IESO* shall determine a revised *reference level* on a go-forward basis from a date specified by the *IESO*.

22.5.3 The *IESO* shall include *energy* and *speed no-load costs* in a *resource's start-up offer reference level* for every hour that the *resource's minimum generation block run-time* extends into the next *dispatch day* after HE 24 of the current *dispatch day*, if that *resource* is eligible to submit *start-up offers* and *speed-no-load offers* as hourly *dispatch data* into the *day-ahead market* and *real-time market*.

22.5.4 A *market participant* may, in accordance with the applicable *market manual*, request that the *IESO* review one of its *resources' reference levels* if the *market participant*:

22.5.4.1 believes the *reference level* does not accurately describe the *short-run marginal cost*s or operational characteristics of that *resource*; or

22.5.4.2 reasonably expects the *reference level* will not accurately describe the *short-run marginal costs* or operational characteristics of that *resource*.

22.5.5 A *market participant* may, in accordance with the applicable *market manual*, request a temporary revision to the fuel cost component of a *reference level* for specific *dispatch hours* if the fuel cost component in a *resource*'s *energy offer reference level*, *start-up offer reference level*, or *speed no-load offer reference level* will not reflect the *resource*'*s short-run marginal costs* for fuel in those *dispatch hours.* Such request must include supporting documentation showing that the fuel cost component will not reflect the *resource*'*s short-run marginal costs* for fuel in those *dispatch hours*.

22.5.6 A *market participant* that has more than one set of *reference levels* determined for a *resource* pursuant to section 22.4.3 may request, in accordance with the applicable *market manual*, that the *IESO* temporarily use the set of *reference levels* with the highest costs for specific *dispatch hours* if the *resource* is expected to operate in a manner consistent with those *reference levels* for those *dispatch hours,* and shall submit to the *IESO* documentation to substantiate the need to use those *reference levels* at the time of the request. The form and content of such documentation shall be set by the *IESO* and the *market participant* at the time a *resource's reference levels* are determined and may be amended with the agreement of the *IESO* and the *market participant*.

22.5.7 A *market participant* may make a request pursuant to either, but not both, section 22.5.5 or 22.5.6 for a specific *dispatch hour* or set of *dispatch hours* in the *day-ahead market* or the *real-time market*. A *market participant* may make a request in either or both of the *day-ahead market* and *the real-time market*. A request made pursuant to section 22.5.5 or 22.5.6 must be submitted:

22.5.7.1 for the *day-ahead market*, between the opening of and up to 30 minutes before the close of the *day-ahead market submission window*;

22.5.7.2 for the *real-time market*, no later than 150 minutes before the first *dispatch hour* in the request.

22.5.8 The *IESO* shall temporarily revise the *reference level* for the *dispatch hours* that were the subject of a request made pursuant to section 22.5.5 or 22.5.6 if the request met the applicable deadline specified in section 22.5.7.

22.5.9 The *IESO* may use the *reference level value* in force at the time of a request made pursuant to section 22.5.5 or 22.5.6 despite section 22.5.8 if, upon review, the *IESO* is not satisfied that the supporting documentation submitted demonstrates that the fuel cost component will not reflect the *resource's short-run marginal costs* for fuel in one or more hours of a *dispatch day* or that the *resource* needed to use the set of *reference levels* associated with the profile with the highest costs. The *IESO* may also assess whether a *settlement* charge is required in accordance with MR Ch.9 ss.5.2.1 and 5.3.1.

22.5.10 If the *IESO* is not satisfied that the fuel cost component will not reflect the *resource's short-run marginal costs* for fuel in one or more hours of a *dispatch day* or that the *resource* needed to use the set of *reference levels* associated with the profile with the highest costs then, despite section 22.5.8, the *IESO* may:

22.5.10.1 use the *reference level value* in force at the time of a request;

22.5.10.2 assess whether a *settlement* charge is required in accordance with MR Ch.9 ss.5.2.1 and 5.3.1;

22.5.10.3 reject subsequent requests for the *resource* made outside of 8:00 to 16:00 EPT on *business days* for 20 *business* days following the *dispatch day* that was the subject of the initial request without reviewing such subsequent requests; and

22.5.10.4 reject subsequent requests for the *resource* that the *IESO* has not reviewed before:

22.5.10.4.1 the close of the *day-ahead market submission window*, for the *day-ahead market;* or

22.5.10.4.2 no later than 130 minutes before the requested *dispatch hour*, for the *real-time market*.

22.5.11 For a request made pursuant to section 22.5.6 that has been accepted by the *IESO*, the *IESO* may require that the *market participant* provide additional supporting documentation showing that the set of *reference levels* associated with the profile with the highest costs represented the relevant *resource*'s *short-run marginal costs* during the requested *dispatch hour*s within two *business days* after the *dispatch day* for which use of those *reference levels* was requested. The form and content of such documentation shall be set by the *IESO* and the *market participant* at the time the *resource's reference levels* are determined and may be amended with the agreement of the *IESO* and the *market participant*. If the *market participant* fails to provide the documentation within the specified time or if the *IESO* is not satisfied that the documentation provided shows that those *reference levels* represented the *resource's short-run marginal costs* during the requested *dispatch hours*, the *IESO* shall assess whether a *settlement* charge is required in accordance with MR Ch.9 ss. 5.2.1 and 5.3.1.

22.5.12 The requirement in section 22.8.1 to communicate a *preliminary view* to the relevant *market participant* prior to registering a *reference level* shall not apply to a *reference level* registered pursuant to sections 22.5.1.4 or 22.5.1.6.

22.6 Reference Quantities

22.6.1 The *IESO* shall determine and register *reference quantities* for each *dispatchable resource* registered to submit *offers* into the *energy* or *operating reserve* markets.

22.6.1.1 The *IESO* shall determine a *resource*'s initial *reference quantities* at the request of the *market participant* that is registered as the owner of the *resource*.

22.6.1.2 The *IESO* shall determine a *resource's reference quantities* in accordance with the applicable *market manual*.

22.6.2 No *registered market participant* for a *resource* that meets the requirements in section 22.6.1 shall submit *offers* or *bids* for that *resource* unless the *IESO* has determined and registered *reference quantities* for that *resource*.

22.6.3 A *market participant* shall provide to the *IESO* all information and supporting documentation that the *IESO* may reasonably require to determine a *resource*'s *reference quantities*, in accordance with the applicable *market manual*.

22.6.4 The *IESO* shall make available to each *market participant* the *reference quantities* and *reference quantity values* registered for that *market participant's resources* in accordance with the applicable *market manual*.

22.6.5 A *market participant* may request that the *IESO* modify a *reference quantity* for a *resource* registered under that *market participant*, if the *market participant* believes that the *IESO's* methodology for calculating that *reference quantity* will over-estimate the quantity of *energy* or *operating reserve* that the *resource* can provide. Any request to do so must be accompanied by additional data and supporting documentation, as set out in the applicable *market manual*.

22.6.6 If the *IESO* is satisfied that the modified methodology used pursuant to section 22.6.5 more accurately describes the specific operational characteristics of the *resource*, then the *IESO* shall use such modified methodology to determine the *reference quantities* for that *resource*.

22.6.7 If a *market participant* fails to provide the information or supporting documentation required by the *IESO* pursuant to section 22.6.3, the *IESO* may register as the *resource*'s *reference quantity*:

22.6.7.1 the maximum quantity of *operating reserve* that the *resource* is registered to *offer*, if the *resource* is a *dispatchable load* or an *electricity storage resource* that is withdrawing *energy*, or

22.6.7.2 the sum of the maximum active power capability of all *generation units* or *electricity storage units* associated with the *resource*, for all *resources* other than those described in 22.6.7.1.

22.7 Changes to Reference Quantities

22.7.1 Once the *IESO* has registered a *reference quantity* for a *resource*, the *IESO* shall not change that *reference quantity* unless:

22.7.1.1 the *IESO* has modified the *market rules or* the applicable *market manual* such the *reference quantity* determined following such modification differs from the registered *reference quantity*;

22.7.1.2 the *IESO* identifies a need in accordance with section 22.7.2;

22.7.1.3 the *market participant* for the *resource* notifies the *IESO* of a change to the *resource's* operational characteristics in accordance with section 22.5.4 or section 22.7.3 and the *IESO* has accepted the change; or

22.7.1.4 more than two years have passed since the *reference quantity* was established or last updated, whichever is later.

22.7.2 The *IESO* may, at any time, review the supporting documentation submitted pursuant to section 22.6.3 to verify that the *reference quantity* determined is consistent with the supporting documentation. If, as a result of such review, the *IESO* determines that the *reference quantity* needs to be amended to be consistent with the supporting documentation, the *IESO* shall update that *reference quantity* on a go-forward basis from a date specified by the *IESO*.

22.7.3 A *market participant* may request that the *IESO* review one of its *resources' reference quantities* if the *market participant*:

22.7.3.1 believes the *reference quantity* does not accurately describe the operational characteristics of that *resource*; or

22.7.3.2 reasonably expects the *reference quantity* will not accurately describe the operational characteristics of that *resource*.

22.8 Independent Review

22.8.1 Prior to registering a *reference level* or *reference quantity* for a *resource*, the *IESO* shall communicate a *preliminary view* to the relevant *market participant*.

22.8.1.1 The *IESO* shall register the *reference levels* and *reference quantities* contained in the *preliminary view* on the 11th *business day* after the date of the *preliminary view*, unless the *market participant*:

i. makes a request pursuant to section 22.8.2;

ii. requests that the *IESO* delay registration until a date specified by the *market participant* and the *IESO* has approved such request; or

iii. requests that the *IESO* register the *reference levels* and *reference quantities* in the *preliminary view* at an earlier date, in which case the *IESO* shall register the *reference levels* and *reference quantities* in *the preliminary view* no later than the 11th *business day* after the date of the *preliminary view*.

22.8.1.2 A *market participant* shall not make a request pursuant to section 22.8.2 if the *IESO* has registered the *reference levels* and *reference quantities* contained in the *preliminary view* pursuant to section 22.8.1.1.

22.8.2 A *market participant* may request that the *IESO* engage an expert independent of the *IESO* and the *market participant* to determine a value upon which the *IESO* and *market participant* disagree and which the *IESO* relied upon for the purpose of determining its *preliminary view* of a *reference level* or *reference quantity*. The *IESO* shall not register a *reference level* or *reference quantity* that is the subject of an expert determination except in accordance with this section 22.8.

22.8.3 The *IESO* shall request proposals to conduct a determination following a request made pursuant to section 22.8.2 or as required by section 22.8.11.2, as specified in the applicable *market manual*. If no responses to the request for proposals are received, the *IESO* shall register the applicable *reference levels* and *reference quantities* communicated in the *preliminary view.* A *market participant* may request a determination no more frequently than once every 60 days until such time as the *IESO* receives a response to the request for proposals, despite any time to do so specified in the applicable *market manual*.

22.8.4 The *IESO* shall provide the *market participant* with an estimate of the cost of the determination, as specified in the applicable *market manual*. If the *market participant* has not notified the *IESO* that it accepts the cost estimate and wishes to proceed with the determination within five *business days* of the *IESO's* notification, the *IESO* shall terminate the determination and register the applicable *reference levels* and *reference quantities* in the *preliminary view*.

22.8.5 The *IESO* shall, in accordance with and as further prescribed in the applicable *market manual*, provide an expert engaged pursuant to this section 22.8 with the following:

22.8.5.1 a statement of the values that are in dispute between the *IESO* and *market participant* and which the expert is required to determine;

22.8.5.2 the relevant *market rules*, *market manuals* and other documents setting out the values and supporting documents and information required to be submitted by *market participants* for the purpose of the *IESO's* determination of *reference levels* or *reference quantities*;

22.8.5.3 the documents and information relevant to the expert's determination of the disputed values, as prescribed by the applicable *market manual*; and

22.8.5.4 other relevant documents and information as may be agreed upon by the *IESO* and the *market participant*, including any documents or information that may be requested by the expert.

22.8.6 The *IESO* shall provide the *market participant* with a copy of the expert's determination following receipt thereof.

22.8.7 The *IESO* shall, subject to the *IESO*'s and *market participant*'s rights and obligations under sections 22.8.8, 22.8.10, and 22.8.13, register a *reference level* or *reference quantity* that is consistent with the expert's determination and the *market rules*, in accordance with the applicable *market manual*. If an expert has determined multiple values, the *IESO* rejecting a value pursuant to section 22.8.10 shall not affect the requirement in this section 22.8.7 that the *IESO* register *reference levels* or *reference quantities* consistent with the values that were not rejected.

22.8.8 The *IESO* or *market participant* may request that the expert correct any typographical error, error of calculation or similar error in the expert's determination of any values, or request that the expert reconsider and vary the expert's determination of any values on the grounds that:

22.8.8.1 the expert did not determine certain values that the expert was requested to determine; or

22.8.8.2 the expert did not provide reasons, or adequate reasons, for his or her determination of certain values.

22.8.9 A request made pursuant to section 22.8.8 shall be made in accordance with the applicable *market manual*.

22.8.10 The *IESO* shall, within 15 *business day*s of receiving the expert's determination, or within 10 *business days* of receiving the expert's further determination following a request made pursuant to section 22.8.8, if applicable, reject the expert's determination of any value if:

22.8.10.1 the expert's determination of that value contains a manifest error that materially affected the expert's determination of such value; or

22.8.10.2 the expert's determination of that value, if accepted and implemented by the *IESO* for the purpose of calculating and registering the applicable *reference level* or *reference quantity*, would require the *IESO* to breach the *market rules*.

22.8.11 If the *IESO* rejects any values pursuant to section 22.8.10, the *IESO* shall:

22.8.11.1 notify the relevant *market participant* within 15 *business days* of receiving a determination that it has rejected a determination and specify the reason for the rejection; and

22.8.11.2 within 10 *business days* of its rejection, take steps pursuant to sections 22.8.3 to 22.8.5 to procure a new expert to determine the rejected values. The *IESO* shall not be required to procure a new expert if it registers *reference levels* or *reference quantities* pursuant to sections 22.8.12 or 22.8.13. A *market participant* disputing the *IESO's* rejection shall not stay the requirement that the *IESO* procure a new expert.

22.8.12 A *market participant* that has requested a determination pursuant to section 22.8.2 may request that the *IESO* discontinue the process with respect to a *reference level* or *reference quantity* at any time prior to receiving the expert's determination. In such cases, the *IESO* shall register the relevant *reference level* or *reference quantity* in the *preliminary view.*

22.8.13 Despite sections 22.8.7 and 22.8.10, the *IESO* and a *market participant* may, at any time, agree to discontinue the determination process and register the *reference levels* or *reference quantities* that the *market participant* originally requested.

22.8.14 The *IESO* may apply a *settlement* charge to the *market participant* equal to the amount charged to the *IESO* by the expert for a review conducted pursuant to section 22.8.2. The costs to the *IESO* of a review conducted pursuant to section 22.8.11.2 shall be recovered from *market participants* pursuant to MR Ch.9 s.4.14.12(j).

22.9 Market Control Entities

22.9.1 The obligations in this section 22.9 apply to a *market participant* that is registered with the *IESO* as:

22.9.1.1 the owner of a:

22.9.1.1.1 *generation resource*;

22.9.1.1.2 *dispatchable load*;

22.9.1.1.3 *load resource* participating as a *price-responsive load*; or

22.9.1.1.4 *electricity storage resource*;

22.9.1.2 an *energy trader*; or

22.9.1.3 a *virtual trader*,

and a reference to a *market participant* in sections 22.9.2 and section 22.9.3 includes a person who has filed an *application for authorization to participate* and indicated its intent to register as: (i) the owner of a *resource* type set out in section 22.9.1.1.1, 22.9.1.1.2, or 22.9.1.1.4; (ii) the owner of a *load resource* that will participate as a *price responsive load;* (iii) an *energy trader*, or (iv) a *virtual trader*.

22.9.2 A *market participant* shall disclose to the *IESO* the name, address, relationship to the *market participant*, and, if applicable, jurisdiction of formation, of each person or entity that meets any of the following criteria:

22.9.2.1 a person or entity that ultimately beneficially owns, directly or indirectly, whether through one or more subsidiaries or otherwise, voting securities carrying more than 10 per cent of the voting rights attached to all voting securities of the *market participant*;

22.9.2.2 a person or entity that is ultimately able to elect or appoint, directly or indirectly, whether through one or more subsidiaries or otherwise, at least 10 per cent of the directors of the *market participant*, other than ex officio directors;

22.9.2.3 a person or entity that is a partner in or of the *market participant*;

22.9.2.4 a person or entity that has a substantial beneficial interest in the *market participant* or that serves as a trustee in the *market participant*, if the *market participant* is a trust;

22.9.2.5 a person or entity that is an *affiliate* of the *market participant*, excluding *affiliates* of the *market participant* that are controlled by the *market participant;*

22.9.2.6 a person or entity that ultimately holds, directly or indirectly, whether through one or more subsidiaries or otherwise, an interest in the *market participant* that entitles the entity or individual to receive more than 10 per cent of the profits of the *market participant,* if the *market participant* is an entity other than a corporation; or

22.9.2.7 a person or entity that has any form of agreement with the *market participant* whereby: (i) the *market participant* confers the right or ability to determine a *resource's energy offers* and *bids* or *offers* for *operating reserve* to that person or entity or the ability to follow the *dispatch* instructions given to the *resource*; and (ii) that person or entity is entitled to receive more than 10 per cent of the amounts paid to the *market participant* in respect of all *energy* and *operating reserve* transacted through the *energy* and *operating reserve markets* for a *resource*.

22.9.3 A *market participant* shall designate one of the persons or entities disclosed pursuant to section 22.9.2 as the *market control entity for physical withholding* for each *dispatchable generation resource*, *dispatchable electricity storage resource* and *dispatchable load resource* for which the *market participant* is registered with the *IESO* as the owner, in accordance with sections 22.9.3-22.9.7.

22.9.3.1 A *market participant* shall designate *market control entities* and the *market control entity for physical withholding* for a *resource* in accordance with the applicable *market manual*.

22.9.4 A *market participant* shall designate a *market control entity* as the *market control entity for physical withholding* for a *resource* if the *market participant* has any form of agreement with that *market control entity* whereby: (i) the *market* *participant* confers the right or ability to determine the *resource's energy offers* and *bids* or *offers* for *operating reserve* to that *market control entity*; and (ii) that *market control entity* is entitled to receive more than 50 per cent of the amounts paid to the *market participant* in respect of all *energy* and *operating reserve* transacted through the *energy* and *operating reserve* markets by the *resource*.

22.9.5 If none of the *market participant's market control entities* meets the criteria in section 22.9.4, the *market participant* shall designate a *market control entity* as the *market control entity for physical withholding* for a *resource* as follows:

22.9.5.1 If the *market participant* is a corporation with share capital, then the *market participant* shall designate as the *resource's market control entity for physical withholding* the person or entity that ultimately holds, directly or indirectly, whether through one or more subsidiaries or otherwise, otherwise than by way of security only, by or for the benefit of that person or entity securities of the *market participant* that are attached to more than 50% of the votes that may be cast to elect directors of the *market participant* and the votes attached to those securities are sufficient, if exercised, to elect a majority of the directors of the *market participant*.

22.9.5.2 If the *market participant* is a corporation without share capital, then the *market participant* shall designate as the *resource*'s *market control entity for physical withholding* the person or entity that ultimately, directly or indirectly, whether through one or more subsidiaries or otherwise, is able to elect or appoint a majority of the directors of the *market participant*, other than ex officio directors.

22.9.5.3 If the *market participant* is an entity other than a corporation, then the *market participant* shall designate as the *resource's market control entity for physical withholding* the person or entity that ultimately holds, directly or indirectly, whether through one or more subsidiaries or otherwise, an interest in the *market participant* that entitles that person or entity to receive more than 50 per cent of the profits of the *market participant*.

22.9.6 If none of the *market participant's market control entities* meets the criteria in sections 22.9.4 to 22.9.5 and the *market participant* is any type of partnership, then the *market participant* shall designate as the *resource's market control entity for physical withholding* the partner that is entitled to the greatest share of the profits of the *market participant*.

22.9.7 If none of the *market participant's market control entities* meets the criteria in sections 22.9.4 to 22.9.6 then the *market participant* shall designate itself as the *resource's market control entity for physical withholding*.

22.10 Designation of Constrained Areas

22.10.1 Potential Constrained Areas

22.10.1.1 The *IESO* may designate an area as a *potential constrained area* following or in advance of relevant configuration changes on the *IESO-controlled grid,* in accordance with the applicable *market manual*.

22.10.1.2 The *IESO* shall assess *potential constrained area* designations on at least an annual basis.

22.10.2 Narrow Constrained Areas

22.10.2.1 The *IESO* shall *publish* a list of *narrow constrained areas*, along with each of the *resources* and the transmission constraints within each *narrow constrained area*, at least once per year, in accordance with the applicable *market manual*.

22.10.2.2 The *IESO* shall designate a *potential constrained area* as a *narrow constrained area* if during an *IESO*-determined study period, the *potential constrained area* was import constrained in more than 4% of the hours in the previous 365 days in either the *day-ahead market* or the *real-time market*, as further specified in the applicable *market manual*.

22.10.2.3 The *IESO* may update the list of *resources* or the name of any system element in a *narrow constrained area* in accordance with the applicable *market manual*.

22.10.2.4 Designations made pursuant to section 22.10.2.1 and changes *published* under section 22.10.2.3 shall come into effect in accordance with the applicable *market manual*.

22.10.3 Dynamic Constrained Areas

22.10.3.1 The *IESO* shall designate a *potential constrained area* as a *dynamic constrained area* if the *potential constrained area:* (i) is not currently designated as a *narrow constrained area*; and (ii) was import constrained in more than 15% of the previous 120 hours in either the *day-ahead market* or the *real-time market*, as further specified in the applicable *market manual.* The designation shall come into effect no sooner than four hours following the criteria above being met.

22.10.3.2 The *dynamic constrained area* designation shall remain in effect until: (i) 120 *dispatch hours* have passed since the start of the *dispatch hour* in which the designation came into effect; and (ii) the *potential constrained area* was import constrained in fewer than 15% of the previous 120 hours in both the *day-ahead market* and the *real-time market* from the start of the current hour.

22.10.3.3 The *IESO* shall assess a *dynamic constrained area* designation every day prior to the *dispatch day* for the *day-ahead market* and every hour for the *real-time market*.

22.10.3.4 The *IESO* shall *publish* a list of *dynamic constrained area*s, along with each of the *resources* and the transmission constraints within each *dynamic constrained area*.

22.11 Global Market Power Reference Intertie Zones

22.11.1 The *IESO* may designate an *intertie zone* as a *global market power reference intertie zone* if:

22.11.1.1 the *intertie* associated with that *intertie zone* connects Ontario directly to another wholesale electricity market; and

22.11.1.2 the *intertie zone* is able to provide effective competitive discipline for *market participant* behaviour.

22.11.2 The *IESO* shall designate an *intertie zone* as a *global market power reference intertie zone* in accordance with the applicable *market manual*.

22.11.3 The *IESO* shall *publish* the *intertie zones* designated as *global market power reference intertie zones* following a change to an *intertie zone's* designation status. A change to an *intertie zone's* designation status shall take effect no earlier than five *business days* following *publication*.

22.12 Uncompetitive Intertie Zones

22.12.1 The *IESO* shall designate an *intertie zone* as uncompetitive if at least one of the following conditions is true for that *intertie zone*:

22.12.1.1 a single *market participant* received at least ninety percent of the *day-ahead market* scheduled *energy* withdrawals or injections over *boundary entity resources* connected to that *intertie zone* scheduled in the previous calendar quarter; or

22.12.1.2 the *IESO* reasonably determines that effective competition in that *intertie zone* is or is expected to be restricted.

22.12.2 The *IESO* shall designate an *intertie zone* as uncompetitive in accordance with the applicable *market manual*.

22.12.3 The *IESO* may remove the designation of an *intertie zone* as uncompetitive if the *intertie zone* no longer meets any of the criteria specified in section 22.12.1.

22.12.4 The *IESO* shall *publish* the *intertie zones* designated as uncompetitive following a change to an *intertie zone's* designation status. A change to an *intertie zone's* designation status shall take effect no earlier than two days following *publication*.

22.12.5 The *IESO* shall review the *intertie zones* designated as uncompetitive:

22.12.5.1 within the first five *business days* of each calendar quarter to determine whether either of the conditions in section 22.12.1 has been met; and

22.12.5.2 when a new *intertie zone* is added to the *IESO-administered market*.

22.12.6 The *IESO* may review the *intertie zones* designated as uncompetitive when a material change in market trade, structure, or regulation of external markets has occurred in the neighbouring *control area*.

22.13 Ex-Ante Validation of Non-Financial Dispatch Data Parameters

22.13.1 The *IESO* shall validate a *dispatchable resource's non-financial dispatch data parameters* against its corresponding *reference level values* at the time the *registered market participant* for a *resource* submits a *non-financial dispatch data parameter* by evaluating whether the *resource's* submitted *non-financial dispatch data parameter* exceeds the corresponding *reference level value*. A submitted *non-financial dispatch data parameter* shall be rejected if it violates any of the following:

22.13.1.1 *minimum generation block run-time* is greater than the minimum of:

22.13.1.1.1 100% above the *reference level value*; or

22.13.1.1.2 three hours above the *reference level value*;

22.13.1.2 *minimum generation block down-time* is greater than the minimum of:

22.13.1.2.1 100% above the *reference level value* for the hot *thermal state*; or

22.13.1.2.2 three hours above the *reference level value* for the hot *thermal state*;

22.13.1.3 *minimum generation block down-time* is less than:

22.13.1.3.1 50% of the *reference level value* for the warm *thermal state*; or

22.13.1.3.2 the *reference level* value minus three hours for the warm *thermal state*;

22.13.1.4 *minimum generation block down-time* is less than:

22.13.1.4.1 50% of the *reference level value* for the cold *thermal state*; or

22.13.1.4.2 the *reference level* value minus three hours for the cold *thermal state*;

22.13.1.5 *minimum loading point* is greater than 100% above the *reference level value*;

22.13.1.6 *energy* ramp rate *offered* is less than 50% of the *reference level value*;

22.13.1.7 *operating reserve* ramp rate *offered* is less than 50% of the *reference level value*;

22.13.1.8 *lead time* is greater than the minimum of:

22.13.1.8.1 100% above the *reference level value* for any *thermal state;* or

22.13.1.8.2 three hours above the *reference level value* for any *thermal state*;

22.13.1.9 the summed *lead time* of all *thermal states* is greater than six hours above the summed *reference level values* of all *thermal states*;

22.13.1.10 *ramp hours to minimum loading point* is greater than the minimum of:

22.13.1.10.1 100% above the *reference level value* for any *thermal state*; or

22.13.1.10.2 three hours above the *reference level value* for any *thermal state*;

22.13.1.11 *energy per ramp hour* is greater than:

22.13.1.11.1 50% above the upper bound *reference level value* for any *thermal state*; or

22.13.1.11.2 50% below the lower bound *reference level value* for any *thermal state*; or

22.13.1.12 *maximum number of starts per day* is 50% less than the *reference level value* or less than one.

22.14 Ex-Ante Mitigation of Economic Withholding

22.14.1 The *IESO* shall, for *dispatchable resources*, apply a conduct test and impact test to assess *economic withholding* of *energy* and *operating reserve* in any *dispatch hour* using *day-ahead market* and *real-time market reference levels* in the processes to determine *day-ahead schedules* and *pre-dispatch schedules*, respectively, as set out in Appendix 7.5 and Appendix 7.5A of the *market rules*.

22.14.2 If the application of a conduct test applied further to this section 22.14 would result in an *energy offer* that exceeds (i) 20 *price-quantity pairs*, for a *resource* that is not a *pseudo-unit*, or (ii) the number of *price-quantity pairs* specified in section 3.5.5.6, for a *resource* that is a *pseudo-unit*, the *IESO* shall:

(i) for conduct tests applicable to *price-quantity pairs* that are above the *price-quantity pair* that includes the *resource*'s *minimum loading point,* delete the *price-quantity pairs* in order from the highest price to the lowest price, except maintaining the *price-quantity pair* with the highest price, until the number of *price-quantity pairs* is equal to the maximum number of *price-quantity pairs* permitted; and

(ii) for conduct tests applicable to *price-quantity pairs* that are up to and including the *price-quantity pair* that includes the *resource*'s *minimum loading point*, replace all *price-quantity pairs* with one *price-quantity pair* where the price is equal to the highest price *price-quantity pair* of the relevant *reference level* and the quantity is equal to the submitted *minimum loading point*.

22.15 Ex-Post Mitigation of Physical Withholding

22.15.1 The *IESO* may apply the conduct tests and impact tests specified in this section 22.15, and as further specified in the applicable *market manual,* to assess *physical withholding* of *energy* and *operating reserve*.

22.15.2 The *IESO* may assess a *dispatchable resource* for *physical withholding* pursuant to this section 22.15 and may cease an assessment of *physical withholding* at any time.

22.15.3 When comparing an *offer* to the relevant *reference quantity value* pursuant to section 22.15.4, 22.15.5, 22.15.11, or 22.15.13, the *IESO* shall use the highest MW quantity value from that *offer*.

Conditions – Energy

22.15.4 The *IESO* may test an *energy offer* submitted by the *registered market participant* for a *resource* to assess *physical withholding* of *energy* if the *resource*:

22.15.4.1 had a *day-ahead market* or a *real-time market locational marginal price* for *energy* greater than $25/MWh and can supply at least 10 MW of *energy* based on that *resource's* maximum resource active power capability; or

22.15.4.2 had a *day-ahead market* or a *real-time market locational marginal price* for *energy* greater than $25/MWh and the *market control entity for physical withholding* for that *resource* was designated as the *market control entity for physical withholding* for *resources* that can supply at least 10 MW of *energy* in aggregate based on those *resources'* maximum resource active power capabilities,

and the *resource* met at least one of the following conditions in the *day-ahead market calculation engine* or the hour-ahead run of the *pre-dispatch calculation engine*:

22.15.4.3 the *energy offer* was below the *resource's reference quantity value* and the *resource* was part of a *narrow constrained area* where at least one of the transmission constraints that defines that *narrow constrained area* was binding;

22.15.4.4 the *energy offer* was below the *resource's reference quantity value* and the *resource* was part of a *dynamic constrained area* where at least one of the transmission constraints that defines that *dynamic constrained area* was binding;

22.15.4.5 the *energy offer* was below the *resource's reference quantity value* and the *resource* had a positive congestion component greater than $25/MWh; or

22.15.4.6 the *energy offer* was below the *resource's reference quantity value* and the *resource* could have met incremental load within Ontario when the conditions for testing for global market power for *energy* price impact set out in Appendix 7.5 and Appendix 7.5A were met.

Conduct Test – Energy

22.15.5 The *IESO* may apply a conduct test for *physical withholding* to an *energy offer* of the *registered market participant* for a *resource* that met the requirements set out in section 22.15.4. An *energy offer* shall fail the conduct test for *physical withholding* if:

22.15.5.1 that *resource* met the conditions in section 22.15.4.3 or 22.15.4.4 and:

22.15.5.1.1 the *registered market participant* for that *resource* submitted an *energy offer* less than its *reference quantity value* by greater than the lesser of 2% or 5 MW; or

22.15.5.1.2 that *resource* and every other *resource*: (i) that shares a *market control entity for physical withholding* that met the same condition in section 22.15.4.3 or 22.15.4.4, but (ii) that did not meet the condition in section 22.15.5.1.1, submitted *energy offers* that were, in the aggregate, greater than 5 MW less than those *resources'* aggregate *reference quantity values*; or

22.15.5.2 that *resource* met the condition in section 22.15.4.5 or 22.15.4.6 and:

22.15.5.2.1 the *registered market participant* for that *resource* submitted an *energy offer* less than its *reference quantity value* by greater than the lesser of 10% or 100 MW; or

22.15.5.2.2 that *resource* and every other *resource* (i) that shares a *market control entity for physical withholding* that met the same condition in section 22.15.4.5 or 22.15.4.6, but (ii) that did not meet the condition in section 22.15.5.2.1, submitted *energy offers* that were, in the aggregate, less than those *resources'* aggregate *reference quantity values* by greater than the lesser of 5% or 200 MW.

22.15.6 A *registered market participant* for a *resource* that did not submit an *energy offer* for a *dispatch hour* in the *day-ahead market* or *real-time market* shall be deemed to have submitted an *energy offer* of 0 MW in that market for the purposes of the conduct test set out in this section.

22.15.7 If a *resource* met more than one of the conditions in sections 22.15.4.3 to 22.15.4.6, the *IESO* shall apply the conduct test for *physical withholding* with the most restrictive of the conduct thresholds set out in section 22.15.5.

Impact Test – Energy

22.15.8 The *IESO* may apply an impact test for *physical withholding* to the *energy offers* of the *registered market participant* for a *resource* that had an *energy offer* fail any of the conduct tests in section 22.15.5. An *energy offer* shall fail the impact test if:

22.15.8.1 the *resource* met the condition in section 22.15.4.3 and the *resource's simulated as-offered energy locational marginal price* is greater than the *resource's simulated reference quantity energy locational marginal price* by greater than the lesser of 50% or $25/MWh;

22.15.8.2 the *resource* met the condition in section 22.15.4.4 and the *resource's simulated as-offered energy locational marginal price* is greater than the *resource's simulated reference quantity energy locational marginal price* by greater than the lesser of 50% or $25/MWh;

22.15.8.3 the *resource* met the condition in section 22.15.4.5 and the *resource's simulated as-offered energy locational marginal price* is greater than the *resource's simulated reference quantity energy locational marginal price* by greater than the lesser of 100% or $50/MWh; or

22.15.8.4 the *resource* met the condition in section 22.15.4.6 and the *resource's simulated as-offered energy locational marginal price* is greater than the *resource's simulated reference quantity energy locational marginal price* by greater than the lesser of 100% or $50/MWh.

22.15.9 The *IESO* shall calculate a *resource*'s *simulated as-offered energy locational marginal price* using the same inputs as those used by the relevant calculation engine to calculate that *resource*'s *energy locational marginal price*.

22.15.10 The *IESO* shall calculate a *resource*'s *simulated reference quantity energy locational marginal price* by using the same inputs as those used by the relevant calculation engine to calculate the *resource's simulated as-offered energy locational marginal price* and the applicable *reference quantities* and *reference levels*.

Conditions – Operating Reserve

22.15.11 The *IESO* may test an *offer* for *operating reserve* of the *registered market participant* for a *resource* for *physical withholding* of *operating reserve* if the *resource*:

22.15.11.1 had a *day-ahead market* or a *real-time market locational marginal price* for the *offered* class of *operating reserve* greater than $5/MW and can supply at least 10 MW of *operating reserve* based on that *resource's* maximum resource active power capability or its maximum load active power; or

22.15.11.2 had a *day-ahead market* or a *real-time market locational marginal price* for the *offered* class of *operating reserve* greater than $5/MW and the *market control entity for physical withholding* for the *resource* was designated as the *market control entity for physical withholding* for *resources* that can supply at least 10 MW of *operating reserve* in aggregate based on those *resources'* maximum resource active power capabilities or its maximum load active power,

and the *resource* met at least one of the following conditions in the *day-ahead market calculation engine* or the hour-ahead run of the *pre-dispatch calculation engine*:

22.15.11.3 the *offer* for *operating reserve* was below the *resource's reference quantity value* and the *operating reserve locational marginal price* for the *offered* class of *operating reserve* for the *resource* was greater than $15/MW; or

22.15.11.4 the *offer* for *operating reserve* was below the *resource's reference quantity value* and the *resource* was located in a reserve area where the value of a minimum constraint for a class of *operating reserve* that the *resource* is eligible to *offer* was greater than 0 MW.

Conduct Test – Operating Reserve

22.15.12 The *IESO* may apply a conduct test for *physical withholding* to the *offers* for *operating reserve* of the *registered market participant* for a *resource* that meet the requirements set out in section 22.15.11. An *offer* for *operating reserve* shall fail the conduct test for *physical withholding* if:

22.15.12.1 that *resource* met the conditions in section 22.15.11.3, and:

22.15.12.1.1 the *registered market participant* for that *resource* submitted an *offer* for *operating reserve* less than its *operating reserve reference quantity* by greater than the lesser of 10% or 100 MW; or

22.15.12.1.2 that *resource* and every other *resource* (i) that shares a *market control entity for physical withholding* that met the same condition in section 22.15.11.3, but (ii) that did not meet the condition in section 22.15.12.1.1, submitted *offers* for *operating reserve* that were, in the aggregate, less than those *resources'* aggregate *reference quantity values* by greater than the lesser of 5% or 200 MW; or

22.15.12.2 that *resource* met the conditions in section 22.15.11.4 and:

22.15.12.2.1 the *registered market participant* for that *resource* submitted an *offer* for *operating reserve* less than the applicable *reference quantity* by greater than the lesser of 2% or 5 MW; or

22.15.12.2.2 that *resource* and every other *resource*: (i) that shares a *market control entity for physical withholding* that met the same condition in section 22.15.11.4, but (ii) that did not meet the conditions in section 22.15.12.2.1, submitted *offers* for *operating reserve* that were, in the aggregate, lower than 5 MW less than those *resources'* aggregate *reference quantity values*.

22.15.13 Despite section 22.15.3, a *registered market participant* for a *resource* that does not submit an *offer* for *operating reserve* of a class that it is eligible to *offer* for a *dispatch hour* in the *day-ahead market* or *real-time market* shall be deemed to have submitted an *offer* for *operating reserve* of 0 MW for that class in that market for the purposes of the conduct test set out in this section.

22.15.14 If a *resource* meets more than one of the conditions in sections 22.15.11.1 and 22.15.11.2, the *IESO* shall apply the conduct test for *physical withholding* using the most restrictive conduct thresholds set out in section 22.15.12.

Impact Test – Operating Reserve

22.15.15 The *IESO* may apply an impact test for *physical withholding* to a *resource* that had an *offer* for *operating reserve* fail any of the conduct tests applied pursuant to section 22.15.12. An *offer* for the *offered* class of *operating reserve* shall fail the impact test if:

22.15.15.1 the *resource* met the condition in section 22.15.11.3 and the *resource's simulated as-offered operating reserve locational marginal price* the *offered* class of *operating reserve* is greater than the *resource's simulated reference quantity operating reserve locational marginal price* by greater than the lesser of 50% or $25/MW; or

22.15.15.2 the *resource* met the condition in section 22.15.11.4 and the *resource's simulated as-offered operating reserve locational marginal price* for the *offered* class of *operating reserve* is greater than the *resource's simulated reference quantity operating reserve locational marginal price*.

22.15.16 The *IESO* shall calculate a *resource*'s *simulated as-offered operating reserve locational marginal price* using the same inputs as those used by the relevant calculation engine to calculate that *resource*'s *operating reserve locational marginal price*.

22.15.17 The *IESO* shall calculate a *resource*'s *simulated reference quantity operating reserve locational marginal price* by using the same inputs as those used by the relevant calculation engine to calculate the *resource's simulated as-offered operating reserve locational marginal price* and the applicable *reference quantities* and *reference levels*.

Physical Withholding - Procedural Steps and Timelines

22.15.18 If an *energy offer* or *offer* for *operating reserve* fails an impact test for *physical withholding* applied pursuant to section 22.15.8 or 22.15.15, the *IESO* shall issue a first notice of *physical withholding* to the relevant *market participant* communicating a finding of an *instance of physical withholding*.

22.15.18.1 Notices issued pursuant to this section shall be issued no later than 180 days following the *dispatch day* for which the *offer* was submitted.

22.15.19 The *IESO* shall notify the *market participant* if the *IESO* ceases its assessment of *physical withholding* following issuance of the first notice of *physical withholding.*

22.15.20 Up to 45 days after the date of the notice specified in section 22.15.18, the *market participant* may submit to the *IESO* a request that the *IESO* determine an *alternative reference quantity value* for the relevant *resource* during the *dispatch day* in which the *offer* was submitted that failed the impact test for *physical withholding* applied pursuant to section 22.15.8 or 22.15.15.

22.15.20.1 Requests submitted pursuant to this section must include documentation to support any *resource*-specific considerations that were not accounted for in the *reference quantities* in use during the *instance of physical withholding.*

22.15.21 The *IESO* shall review the submitted supporting documentation and if upon such review the *IESO* determines that it demonstrates that a *resource* was able to supply a quantity of *energy* or *operating reserve* different than the *resource's reference quantity values* during the *instance of physical withholding*, the *IESO* shall determine an *alternative reference quantity value* for the *resource* and repeat the conduct test applied pursuant to section 22.15.5 or 22.15.12 and impact test applied pursuant to section 22.15.8 or 22.15.15, as applicable, using the *alternative reference quantity value* in the place of the applicable *reference quantity value.*

22.15.22 If the conduct test and impact test repeated pursuant to section 22.15.21 are not failed when the *alternative reference quantity value* is used, the *IESO* shall discontinue the assessment and notify the *market participant* within 90 days of receiving the supporting documentation.

22.15.23 The *IESO* shall issue a second notice of *physical withholding* to the relevant *market participant* within 90 days of the day the *IESO* received supporting documentation pursuant to section 22.15.20 if:

22.15.23.1 the conduct test and impact test repeated pursuant to section 22.15.21 are failed; or

22.15.23.2 upon review of the supporting documentation, the *IESO* determines that the supporting documentation does not demonstrate that a *resource* was able to supply a quantity of *energy* or *operating reserve* different than the *resource's reference quantity values* during the *instance of physical withholding*.

22.15.24 If a *market participant* does not request that the *IESO* determine an *alternative reference quantity value* in accordance with section 22.15.20 or notifies the *IESO* that it will not make such a request, the *IESO* shall issue a second notice of *physical withholding* within 90 days of the time period in section 22.15.20 elapsing or receipt of such notice, as the case may be.

22.15.25 If the *registered market participant* for a *resource* has submitted an *offer* that fails an impact test repeated pursuant to section 22.15.21, the *IESO* shall issue a second notice of *physical withholding* to the *market participant* for the *resource* within 90 days of the time period in section 22.15.20 elapsing.

22.15.25.1 A second notice of *physical withholding* shall set out the *settlement* charge relating to the *instance of physical withholding* specified in the notice and, if applicable, additional information regarding the conduct test and impact test. The *settlement* charge applied shall be determined in accordance with the applicable *market manual*.

22.16 Intertie Reference Levels

22.16.1 The *IESO* shall determine daily *day-ahead market* and *real-time market intertie reference levels* for each *dispatch day* for each *market participant* for each *boundary entity resource* on which the *market participant* may submit *offers* or *bids*.

22.16.1.1 The *IESO* shall determine one *intertie reference level* for each class of *operating reserve* a *market participant* is registered to *offer* on a *boundary entity resource*.

22.16.1.2 The *IESO* shall determine the *intertie reference levels* in section 22.16.1 using the information available on the day that is 14 days following the relevant *dispatch day.*

22.16.2 For a *market participant* that has *intertie reference levels* determined pursuant to section 22.16.1, the *IESO* shall determine one set of *intertie reference levels* for the period from 7:00 to 23:00 EPT on *business days* and one set of *intertie reference levels* for all other times. The *IESO* shall consider only the *dispatch hours* within each period when determining *intertie reference levels* for that period.

Energy Offers

22.16.3 When determining *day-ahead market energy offer intertie reference levels* for a *market participant* for a *boundary entity resource*, the *IESO* shall consider all the *dispatch hours* in the 90 days prior to the *dispatch day* when:

22.16.3.1 the *market participant* had at least 1 MW in at least 1 *dispatch hour* scheduled at the *boundary entity resource* in the *day-ahead schedule,* excluding any *dispatch hours* where the *IESO* manually set the schedule for the *market participant* for that *boundary entity resource*;

22.16.3.2 the positive congestion component of the *intertie border price* in the *day-ahead market* was less than or equal to $25/MWh for *energy*; and

22.16.3.3 the *market participant's energy offer* for the *boundary entity resource* was priced below or equal to the *intertie border price*.

22.16.4 If a *market participant* did not have an *energy offer* that met the conditions in section 22.16.3 scheduled in the *day-ahead schedule* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *day-ahead market energy offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the *intertie border price* for *energy* from the *day-ahead market* for that *dispatch hour* in that *dispatch day*.

22.16.5 If a *market participant* had an *energy offer* that met the conditions in section 22.16.3 scheduled in the *day-ahead schedule* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *day-ahead market energy offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the unweighted average of the highest price *offer* lamination that was scheduled contained in all *energy offers* submitted by that *market participant* for that *boundary entity resource* that met the conditions in section 22.16.3.

22.16.6 When determining *real-time market energy offer intertie reference levels* for a *market participant* for a *boundary entity resource*, the *IESO* shall consider all the *dispatch hours* in the 90 days prior to the *dispatch day* when:

22.16.6.1 the *market participant* had at least 1 MW in at least 1 *dispatch hour* scheduled at the *boundary entity resource* in the hour-ahead run of the *pre-dispatch calculation engine,* excluding any *dispatch hours* where the *IESO* manually set the schedule for the *market participant* for that *boundary entity resource;*

22.16.6.2 the positive congestion component of the *intertie border price* in the *real-time market* was less than or equal to $25/MWh for *energy*; and

22.16.6.3 the *market participant's energy offer* for the *boundary entity resource* was priced below or equal to the *intertie border price*.

22.16.7 If a *market participant* did not have an *energy offer* that met the conditions in section 22.16.6 scheduled in the hour-ahead run of the *pre-dispatch calculation engine* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *real-time market energy offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the *intertie border price* for *energy* from the *real-time market* for that *dispatch hour* in that *dispatch day*.

22.16.8 If a *market participant* had an *energy offer* that met the conditions in section 22.16.6 scheduled in the hour-ahead run of the *pre-dispatch calculation engine* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *real-time market energy offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the unweighted average of the highest price *offer* lamination that was scheduled contained in all *energy offers* submitted by that *market participant* for that *boundary entity resource* that met the conditions in section 22.16.6.

Energy Bids

22.16.9 When determining *day-ahead market energy bid intertie reference levels* for a *market participant* for a *boundary entity resource*, the *IESO* shall consider all the *dispatch hours* in the 90 days prior to the *dispatch day* when:

22.16.9.1 the *market participant* had at least 1 MW in at least 1 *dispatch hour* scheduled at the *boundary entity resource* in the *day-ahead schedule,* excluding any *dispatch hours* where the *IESO* manually set the schedule for the *market participant* for that *boundary entity resource*;

22.16.9.2 the positive congestion component of the *intertie border price* in the *day-ahead market* was less than or equal to $25/MWh for *energy*; and

22.16.9.3 the *market participant's energy bid* for the *boundary entity resource* was priced above the *intertie border price*.

22.16.10 If a *market participant* did not have an *energy bid* that met the conditions in section 22.16.9 scheduled in the *day-ahead schedule* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *day-ahead market energy bid intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the *intertie border price* for *energy* from the *day-ahead market* for that *dispatch hour* in that *dispatch day*.

22.16.11 If a *market participant* had an *energy bid* that met the conditions in section 22.16.9 scheduled in the *day-ahead schedule* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *day-ahead market energy bid intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the unweighted average of the highest price *bid* lamination that was scheduled contained in all *energy bids* submitted by that *market participant* for that *boundary entity resource* that met the conditions in section 22.16.9.

22.16.12 When determining *real-time market energy bid intertie reference levels* for a *market participant* for a *boundary entity resource*, the *IESO* shall consider all the *dispatch hours* in the 90 days prior to the *dispatch day* when:

22.16.12.1 the *market participant* had at least 1 MW in at least 1 *dispatch hour* scheduled at the *boundary entity resource* in the hour-ahead run of the *pre-dispatch calculation engine,* excluding any *dispatch hours* where the *IESO* manually set the schedule for the *market participant* for that *boundary entity resource*;

22.16.12.2 the positive congestion component of the *intertie border price* in the *real-time market* was less than or equal to $25/MWh for *energy*; and

22.16.12.3 the *market participant's energy bid* for the *boundary entity resource* was priced above the *intertie border price*.

22.16.13 If a *market participant* did not have an *energy bid* that met the conditions in section 22.16.12 scheduled in the hour-ahead run of the *pre-dispatch calculation engine* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *real-time market energy bid intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the *intertie border price* for *energy* from the *real-time market* for that *dispatch hour* in that *dispatch day*.

22.16.14 If a *market participant* had an *energy bid* that met the conditions in section 22.16.12 scheduled in the hour-ahead run of the *pre-dispatch calculation engine* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *real-time market energy bid intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the unweighted average of the highest price *bid* lamination that was scheduled contained in all *energy bids* submitted by that *market participant* for that *boundary entity resource* that met the conditions in section 22.16.12.

Operating Reserve

22.16.15 When determining a *day-ahead market operating reserve offer intertie reference level* for a class of *operating reserve* for a *market participant* for a *boundary entity resource*, the *IESO* shall consider all the *dispatch hours* in the 90 days prior to the *dispatch day* when:

22.16.15.1 the *market participant* had at least 1 MW of that class of *operating reserve* scheduled in at least 1 *dispatch hour* scheduled at the *boundary entity resource* in the *day-ahead schedule,* excluding any *dispatch hours* where the *IESO* manually set the schedule for the *market participant* for that *boundary entity resource*;

22.16.15.2 the positive congestion component of the *intertie border price* in the *day-ahead market* was less than or equal to $25/MW for that class of *operating reserve;* and

22.16.15.3 the *market participant's offer* for *operating reserve* for the *boundary entity resource* was priced below or equal to the *intertie border price* for that class of *operating reserve*.

22.16.16 If a *market participant* did not have an *offer* for *operating reserve* that met the conditions in section 22.16.15 scheduled in the *day-ahead schedule* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *day-ahead market operating reserve offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* for a particular class of *operating reserve* shall be the *intertie border price* for that class of *operating reserve* in the *day-ahead market* for that *dispatch hour* in that *dispatch day*.

22.16.17 If a *market participant* had an *offer* for *operating reserve* that met the conditions in section 22.16.15 scheduled in the *day-ahead schedule* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *day-ahead market operating reserve offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* for that class of *operating reserve* shall be the unweighted average of the highest price *offer* lamination that was scheduled contained in all *offers* for that class of *operating reserve* submitted by that *market participant* for that *boundary entity resource* that met the conditions in section 22.16.15.

22.16.18 When determining a *real-time market operating reserve offer intertie reference level* for a class of *operating reserve* for a *market participant* for a *boundary entity resource*, the *IESO* shall consider all the *dispatch hours* in the 90 days prior to the *dispatch day* when:

22.16.18.1 the *market participant* had at least 1 MW of that class of *operating reserve* scheduled in at least 1 *dispatch hour* scheduled at the *boundary entity resource* in the hour-ahead run of the *pre-dispatch calculation engine,* excluding any *dispatch hours* where the *IESO* manually set the schedule for the *market participant* for that *boundary entity resource*;

22.16.18.2 the positive congestion component of the *intertie border price* in the *real-time market* was less than or equal to $25/MW for that class of *operating reserve;* and

22.16.18.3 the *market participant*'s *offer* for *operating reserve* for the *boundary entity resource* was priced below or equal to the *intertie border price* for that class of *operating reserve*.

22.16.19 If a *market participant* did not have an *offer* for *operating reserve* that met the conditions in section 22.16.18 scheduled in the hour-ahead run of the *pre-dispatch calculation engine* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *real-time market operating reserve offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* for a particular class of *operating reserve* shall be the *intertie border price* for that class of *operating reserve* in the *real-time market* for that *dispatch hour* in that *dispatch day*.

22.16.20 If a *market participant* had an *offer* for *operating reserve* that met the conditions in section 22.16.18 scheduled in the hour-ahead run of the *pre-dispatch calculation engine* for at least one *dispatch hour* in 15 of the 90 days prior to a *dispatch day*, then its *real-time market operating reserve offer intertie reference level* for a *boundary entity resource* for a particular *dispatch hour* on a particular *dispatch day* shall be the unweighted average of the highest price *offer* lamination that was scheduled contained in all *offers* for that class of *operating* *reserve* submitted by that *market participant* for that *boundary entity resource* that met the conditions in section 22.16.18.

22.17 Intertie Economic Withholding on an Uncompetitive Intertie Zone

22.17.1 The *IESO* may apply the conduct tests and impact tests specified in this section 22.17 in accordance with the applicable *market manual* to assess *intertie economic withholding.*

22.17.1.1 The *IESO* shall not assess the export transactions of an *energy trader* for *intertie economic withholding* under this section 22.17 if that *energy trader* has not disclosed a *market control entity* that has been designated as the *market control entity for physical withholding* for a *dispatchable resource* that is authorized to supply *energy* or *operating reserve*.

22.17.2 The *IESO* may cease the assessment of *intertie economic withholding* at any time.

Conduct Test – Energy

22.17.3 The *IESO* may apply a conduct test for *intertie economic withholding* to an *energy offer* or *energy bid* submitted by a *registered market participant* for a *boundary entity resource* in an *uncompetitive intertie zone* if: (i) that *energy offer* or *energy bid* was scheduled; and (ii) there is a positive congestion component on the *intertie border price* for *energy* greater than $25/MWh in the *day-ahead market* or greater than $25/MWh in the *real-time market*, as applicable.

22.17.4 An *energy offer* or *energy bid* shall fail the conduct test applied pursuant to section 22.17.3 if the *offer* or *bid* is greater than the lesser of:

22.17.4.1 the sum of: (i) the *boundary entity resource's* applicable *intertie reference level* and (ii) the absolute value of the *boundary entity resource's* applicable *reference level* multiplied by 300%; or

22.17.4.2 the sum of: (i) the *boundary entity resource's* applicable *reference level* and (ii) $100/MWh.

22.17.5 A *price-quantity pair* in an *energy offer* or *energy bid* submitted by a *registered market participant* for a *boundary entity resource* that has a price component less than or equal to $25/MWh shall be deemed not to have failed a conduct test applied pursuant to section 22.17.3.

Impact Test – Energy

22.17.6 The *IESO* may apply an impact test for *intertie economic withholding* in an uncompetitive *intertie zone* to any *boundary entity resource* that fails the conduct test applied pursuant to section 22.17.3.

22.17.7 An *energy offer* or *energy bid* submitted by a *registered market participant* for a *boundary entity resource* shall fail the impact test if the *boundary entity resource's simulated as-offered energy locational marginal price* is the lesser of greater than 100% or $50/MWh above the *simulated intertie reference level energy locational marginal price* in the *day-ahead market* or the lesser of greater than 100% or $50/MW above the *simulated intertie reference level energy locational marginal price* in the *real-time market*, as applicable.

22.17.8 The *IESO* shall calculate the *simulated intertie reference level energy locational marginal price* using the same inputs as those used by the relevant calculation engine to calculate the *energy locational marginal price* for the uncompetitive *intertie zone* and replacing each *energy offer* or *energy bid* that failed the conduct test applied pursuant to section 22.17.3 with the applicable *intertie reference level* for *energy* for the *boundary entity resource* in the *dispatch day* being assessed.

Conduct Test – Operating Reserve

22.17.9 The *IESO* may apply a conduct test for *intertie economic withholding* to an *offer* for *operating reserve* submitted by a *registered market participant* for a *boundary entity resource* in an *uncompetitive intertie zone* if: (i) that *offer* for *operating reserve* was scheduled; and (ii) the *operating reserve locational marginal price* for a class of *operating reserve* in that *uncompetitive intertie zone* is greater than $15/MWh in the *day-ahead market* or greater than $15/MW in the *real-time market*, as applicable.

22.17.10 An *offer* for *operating reserve* submitted by a *registered market participant* for *a boundary entity resource* shall fail the conduct test applied pursuant to section 22.17.9 if the *offer* is greater than the lesser of 50% or $25/MWh above the *boundary entity resource's intertie reference level* in the *day-ahead market* or greater than the lesser of 50% or $25/MW above the *boundary entity resource's intertie reference level* in the *real-time market*.

22.17.11 A *price-quantity pair* in an *offer* for *operating reserve* submitted by a *registered market participant* for a *boundary entity resource* that has a price component less than or equal to $5/MWh in the *day-ahead market* or $5/MW in the *real-time market* shall be deemed not to have failed the conduct test applied pursuant to section 22.17.9.

Impact Test – Operating Reserve

22.17.12 The *IESO* may apply an impact test for *intertie economic withholding* in an uncompetitive *intertie zone* to any *boundary entity resource* that fails the conduct test applied pursuant to section 22.17.9.

22.17.13 A *boundary entity resource's offer* for *operating reserve* shall fail the impact test if its *simulated as-offered operating reserve locational marginal price* is greater than the lesser of 50% or $25/MWh above the *simulated intertie reference level operating reserve locational marginal price* in the *day-ahead market* or greater than the lesser of 50% or $25/MW above the *simulated intertie reference level operating reserve locational marginal price* in the *real-time market*.

22.17.14 The *IESO* shall calculate the *simulated intertie reference level operating reserve locational marginal price* using the same inputs as those used by the relevant calculation engine to calculate the *operating reserve locational marginal price* for the *uncompetitive intertie zone* and replacing each *offer* for *operating reserve* that failed the conduct test applied pursuant to section 22.17.10 with the applicable *operating reserve offer intertie reference level* for the *boundary entity resource* in the *dispatch day* being assessed.

22.18 Mitigation for Make-Whole Payment Impact in Uncompetitive Intertie Zones

22.18.1 The *IESO* may apply the conduct tests and impact tests specified in this section 22.18 in accordance with the applicable *market manual* to assess mitigation for make-whole payment impact on an uncompetitive *intertie zone.*

22.18.2 The *IESO* may cease the assessment of mitigation for make-whole payment impact at any time.

Conditions

22.18.3 The *IESO* may assess mitigation for make-whole payment impact on an uncompetitive *intertie zone* for a *boundary entity resource* if:

22.18.3.1 the *boundary entity resource* was tested for an *energy* price impact pursuant to section 22.17.6;

22.18.3.2 the *boundary entity resource* was tested for an *operating reserve* price impact pursuant to section 22.17.12; or

22.18.3.3 the *boundary entity resource* was scheduled to provide *operating reserve* on an uncompetitive *intertie zone* and received a make-whole payment greater than $10,000 for a *dispatch hour*.

Conduct Test

22.18.4 The *IESO* may apply a conduct test for *intertie economic withholding* to an *energy offer* or *offer* for *operating reserve* submitted by a *registered market participant* for a *boundary entity resource* that met any of the conditions in section 22.18.3. The *energy offer* or *offer* for *operating reserve* shall fail the conduct test if:

22.18.4.1 the *energy offer* was greater than the lesser of 300% or $100/MWh above the *boundary entity resource*'s *intertie reference level* in the *day-ahead market* or greater than the lesser of 300% or $100/MW above the *boundary entity resource*'s *intertie reference level* in the *real-time market*; or

22.18.4.2 the *offer* for *operating reserve* was greater than the lesser of 50% or $25/MWh above the *boundary entity resource*'s *intertie reference level* in the *day-ahead market* or greater than the lesser of 50% or $25/MW above the *boundary entity resource*'s *intertie reference level* in the *real-time market*.

Impact Test

22.18.5 The *IESO* may apply an impact test for *intertie economic withholding* to an *energy offer* or *offer* for *operating reserve* submitted by a *registered market participant* for a *boundary entity resource* that that fails the conduct test applied pursuant to section 22.18.4.

22.18.5.1 The *energy offer* or *offer* for *operating reserve* shall fail the impact test for a *dispatch hour* if the *boundary entity resource's* make-whole payment for that *dispatch hour* is greater than 10% higher than the make-whole payment would have been based on the *boundary entity resource's* relevant *intertie reference levels* for *offer* parameters that failed the conduct test.

22.19 Intertie Economic Withholding – Procedural Steps and Timelines

22.19.1 If an *energy offer, energy bid,* or *offer* for *operating reserve* fails an impact test applied pursuant to section 22.17.6, 22.17.12 or 22.18.5, the *IESO* shall issue a first notice of *economic withholding* to the relevant *market participant* communicating a finding of an *instance of intertie economic withholding*.

22.19.1.1 Notices issued pursuant to this section shall be issued no later than 180 days following the *dispatch day* for which the *offer* or *bid* was submitted.

22.19.2 The *IESO* shall notify the *market participant* if the *IESO* ceases its assessment of *intertie economic withholding* following issuance of the first notice of *intertie economic withholding*.

22.19.3 Up to 45 days after the date of the notice specified in section 22.19.1, the *market participant* may submit to the *IESO* a request that the *IESO* determine an *alternative intertie reference level value* for the relevant *boundary entity resource* during the *dispatch day* in which the *offer* or *bid* was submitted.

22.19.3.1 Requests submitted pursuant to this section must include documentation to support any *resource*-specific considerations that were not accounted for in the *intertie reference levels* in use during the *instance of intertie economic withholding*.

22.19.4 The *IESO* shall review the submitted supporting documentation and if upon such review the *IESO* determines it demonstrates that the *intertie reference level* did not account for all a *market participant's short-run marginal costs*, for *offers*, or *short-run marginal benefits*, for *bids*, the *IESO* shall determine an *alternative intertie reference level value* for the *boundary entity resource* that accounts for all the *short-run marginal costs* or *short-run marginal benefits*, as the case may be, and repeat the conduct test applied pursuant to section 22.17.3, 22.17.9, or 22.18.4 and impact test applied pursuant to section 22.17.6, 22.17.12, or 22.18.5 using the *alternative intertie reference level value* in the place of the applicable *intertie reference level value.*

22.19.5 If the conduct test and impact test repeated pursuant to section 22.19.4 are not failed when the *alternative intertie reference level value* is used, the *IESO* shall discontinue the assessment and notify the *market participant* within 90 days of receiving the supporting documentation.

22.19.6 The *IESO* shall issue a second notice of *intertie economic withholding* to the relevant *market participant* within 90 days of the day the *IESO* received supporting documentation pursuant to section 22.19.3 if:

22.19.6.1 the conduct test and impact test for *intertie economic withholding* repeated pursuant to section 22.19.4 are failed; or

22.19.6.2 upon review of the supporting documentation, the *IESO* determines that the supporting documentation does not demonstrate that the relevant *intertie reference level* did not account for all of a *market participant's short-run marginal costs*, for *offers*, or *short-run marginal benefits*, for *bids*.

22.19.7 If a *market participant* does not request that the *IESO* determine an *alternative intertie reference level value* in accordance with section 22.19.3 or notifies the

IESO that it will not make such a request, the *IESO* shall issue a second notice of *intertie economic withholding* within 90 days of the time period in section 22.19.3 elapsing or receipt of such notice, as the case may be.

22.19.8 If a *registered market participant* for a *boundary entity resource* has submitted an *offer* or *bid* that fails an impact test applied pursuant to section 22.17.6, 22.17.12, or 22.18.5, the *IESO* shall apply a *settlement* charge to the relevant *market participant* in respect of each *instance of intertie economic withholding*.

22.19.8.1 A second notice of *intertie economic withholding* shall set out the *settlement* charge relating to the *instance of intertie economic withholding* specified in the notice and, if applicable, additional information regarding the conduct test and impact test. The *settlement* charge applied shall be determined in accordance with the applicable *market manual*.

RUL-18

Renewed Market Rules

Chapter 0.7

System Operations and Physical Markets - Appendices

Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

Appendix 7.1 – Energy Offer, Schedule or Forecast Information

1.1 Energy Offers/Schedules/Forecasts from Generation Resources

1.1.1 In order for a *generation resource* to provide *energy*, its *registered market participant* shall submit an *offer,* schedule or forecast, as applicable that includes, at a minimum, the information specified in this section 1.1.

1.1.2 *Resource* name.

1.1.3 *Registered market participant*.

1.1.4 *Dispatch day* and *dispatch hour(s)* for which *offer*, schedule or forecast applies.

1.1.5 For a *dispatchable generation resource*, two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*.

1.1.6 For a *dispatchable generation resource*, one to five sets of ramp quantity and its corresponding ramp up and ramp down values for each *dispatch hour* applicable to the entire range of the *resources* output contained in the *offer*.

1.1.7 Is this a standing *offer*, schedule or forecast? Yes/No. If Yes, Date To: ________
For which day(s) of the week? ____________________

1.1.8 For a *dispatchable generation resource* other than *a quick-start resource* or a nuclear *generation resource*:

1.1.8.1 a *minimum loading point*;

1.1.8.2 a *minimum generation block run-time*;

1.1.8.3 a *minimum generation block down-time* for each *thermal state*;

1.1.8.4 a *lead time* for each *thermal state*; and

1.1.8.5 ramp up energy to *minimum loading point* for each *thermal state*.

1.2 Energy Offers from Imports

1.2.1 In order for a *boundary entity resource* to provide *energy* from an import, its *registered market participant* shall submit an *offer* that includes, at a minimum, the information specified in this section 1.2.

1.2.2 Unique *boundary entity* identifier (*interconnection* and *boundary entity resource*).

1.2.3 *Registered market participant*.

1.2.4 *Dispatch day* and *dispatch hour(s)* for which *offer* applies.

1.2.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*.

1.2.6 Is this a standing *offer*? – Yes/No. If Yes, Date To: _____ For which day(s) of the week? ___________

1.2.7 Source *control area* (determined by selecting appropriate *boundary entity resource*).

1.2.8 e-Tag identification.

1.2.9 Notwithstanding MR Ch.7 s.3.3, e-Tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.9.1 all *resources* shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates;

1.2.9.2 each *registered market participant* shall submit its e-Tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*; and

1.2.9.3 interchange scheduling defaults specified by the relevant *standards authority* shall be used unless otherwise approved by the *IESO*. Transactions shall be one hour in duration, in accordance with agreements between *control areas* along the path. Transactions shall ramp in/out over the hour and shall respect a ten-minute ramp period.

1.2.10 Capacity transaction parameter, if applicable.

1.3 Energy Offers for Virtual Zonal Resources

1.3.1 In order for a *virtual zonal resource* to participate in the *day-ahead market*, its *registered market participant* shall submit an *offer*, that includes, at a minimum, the information specified in this section 1.3.

1.3.2 *Virtual trader*.

1.3.3 *Virtual transaction* type indicating an *offer*.

1.3.4 *Virtual zonal resource*.

1.3.5 *Dispatch day* and *dispatch hour(s)* for which the *offer* applies.

1.3.6 For a *virtual zonal resource*, two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*.

Appendix 7.2 – Energy Bid Information

1.1 Energy Bids from Load Resources

1.1.1 In order for a *dispatchable load* to provide *energy* or when other *load resources* are submitting *bids*, its *registered market participant* shall submit a *bid* that includes, at a minimum, the information specified in this section 1.1.

1.1.2 *Resource* name.

1.1.3 *Registered market participant*.

1.1.4 *Dispatch day* and *dispatch hour(s)* for which *bid* applies.

1.1.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

1.1.6 For *load resources*, excluding *price responsive loads*, one to five ramp sets of ramp quantity and its corresponding ramp up and ramp down values for each *dispatch hour* applicable to the entire range of *load* contained in the *bid*.

1.1.7 Is this a standing *bid*? Yes/No. If Yes, Date To:__________ For which day(s) of the week? ____________________

1.2 Energy Bids from Exports

1.2.1 In order for a *boundary entity resource* to provide *energy* from an export, its *registered market participant* shall submit an *bid* that includes, at a minimum, the information specified in this section 1.2.

1.2.2 Unique boundary entity identifier (interconnection and boundary entity resource).

1.2.3 *Registered market participant* name.

1.2.4 *Dispatch day* and *dispatch hour(s)* for which *bid* applies.

1.2.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

1.2.6 Is this a standing *bid*? – Yes/No. If Yes, Date To: _________ For which day(s) of the week? _______

1.2.7 Sink *control area* (determined by selecting appropriate *boundary entity resource*).

1.2.8 e-Tag identification.

1.2.9 Notwithstanding MR Ch.7 s.3.3, e-Tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.9.1 all *resources* shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates;

1.2.9.2 each *registered market participant* shall submit its e-Tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*; and

1.2.9.3 interchange scheduling defaults specified by the relevant *standards authority* shall be used unless otherwise approved by the *IESO*. Transactions shall be one hour in duration, in accordance with agreements between *control areas* along the path. Transactions shall ramp in/out over the hour and shall respect a ten-minute ramp period.

1.2.10 Capacity transaction parameter (if applicable)

1.3 Energy Bids for Virtual Zonal Resources

1.3.1 In order for a *virtual zonal resource* participate in the *day-ahead market*, its *registered market participant* shall submit a *bid*, that includes, at a minimum, the information specified in this section 1.3.

1.3.2 *Virtual trader*.

1.3.3 *Virtual transaction* type indicating a *bid.*

1.3.4 *Virtual zonal resource*.

1.3.5 *Dispatch day* and *dispatch hour(s)* for which the *bid* applies.

1.3.6 For a *virtual zonal resource*, two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

Appendix 7.3 – Operating Reserve Offer Information

1.1 Operating Reserve Offers from Generation Resources

1.1.1 In order for a *generation resource* to provide *operating reserve*, its *registered market participant* shall submit an *offer* that includes, at a minimum, the information specified in this section 1.1.

1.1.2 *Resource* name.

1.1.3 *Registered market participant*.

1.1.4 *Dispatch day* and *dispatch hour(s)* for which *offer* applies.

1.1.5 *Operating reserve* class.

1.1.6 *Reserve loading point*

1.1.7 Two to five *price-quantity pairs* for all classes of *operating reserve* being offered in each *dispatch hour*, the final of which represents the maximum quantity of the *offer*.

1.1.8 One ramp rate applicable for all classes of *operating reserve* being offered in accordance with MR Ch.7 s.3.5.8.

1.1.9 Is this a standing *offer*? Yes/No. If Yes, Date To: __________ For which day(s) of the week? __________

1.2 Operating Reserve Offers from Imports

1.2.1 In order for a *boundary entity resource* to provide *operating reserve* from an import, its *registered market participant* shall submit an *offer* that includes, at a minimum, the information specified in this section 1.2.

1.2.2 Unique *boundary entity* identifier (*interconnection* and *boundary entity resource*).

1.2.3 *Registered market participant*.

1.2.4 *Dispatch day* and *dispatch hour(s)* for which *offer* applies.

1.2.5 *Operating reserve* class.

1.2.6 Two to five *price-quantity pairs* for each *dispatch hour* for each class of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.2.7 Is this a standing *offer*? – Yes/No. If Yes, Date To: _____ For which day(s) of the week?______

1.2.8 Source *control area* (determined by selecting appropriate *boundary entity resource*).

1.2.9 e-Tag identification.

1.2.10 Notwithstanding MR Ch.7 s.3.3, e-Tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.10.1 all *resources* shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates; and

1.2.10.2 each *registered market participant* shall submit its e-Tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*.

1.3 Operating Reserve Offers from Dispatchable Loads

1.3.1 In order for a *dispatchable load* to provide *operating reserve*, its *registered market participant* shall submit an *offer* that includes, at a minimum, the information specified in this section 1.3.

1.3.2 *Resource* name.

1.3.3 *Registered market participant*.

1.3.4 *Dispatch day* and *dispatch hour(s)* for which *offer* applies.

1.3.5 *Operating reserve* class.

1.3.6 Two to five *price-quantity pairs* for each *dispatch hour* for each class of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.3.7 One ramping rate applicable for all classes of *operating reserve* being offered.

1.3.8 Is this a standing *offer*? Yes/No. If Yes, Date To: _______ For which day(s) of the week? __________

1.4 Operating Reserve Offers from Exports

1.4.1 In order for a *boundary entity resource* to provide *operating reserve* from an export, its *registered market participant* shall submit an *offer* that includes, at a minimum, the information specified in this section 1.4.

1.4.2 Unique *boundary entity* identifier (interconnection and *boundary entity resource*).

1.4.3 *Registered market participant*.

1.4.4 *Dispatch day* and *dispatch hour(s)* for which *offer* applies.

1.4.5 *Operating reserve* class.

1.4.6 Two to five *price-quantity pairs* for each *dispatch hour* for each class of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.4.7 Is this a standing *offer* – Yes/No. If Yes, Date To: _________ For which day(s) of the week? _____

1.4.8 Sink *control area* (determined by selecting appropriate *boundary entity resource*).

1.4.9 e-Tag identification.

1.4.10 Notwithstanding MR Ch.7 s.3.3, e-Tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.4.10.1 all *resources* shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates; and

1.4.10.2 each *registered market participant* shall submit its e-Tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*.

Appendix 7.4 – Transmission Information Required for Scheduling and Dispatching

1.1 Transmission Information Required for Scheduling and Dispatching

1.1.1 Full *connection-related reliability information* and *transmission system* data is required to be provided and updated to the *IESO* in accordance with MR Ch.7 s.2.2.5 and MR Ch.4 App.4.16.

1.1.2 Advance *outage* information is required to be provided to the *IESO* in terms of MR Ch.5.

1.1.3 The following information is required to be advised to the *IESO* for scheduling and *dispatch* purposes:

1.1.3.1 any change to the maximum thermal rating of any transmission branch as advised by the *IESO* to be included in the *DAM calculation engine, pre-dispatch calculation engine* and *real-time calculation engine*; and

1.1.3.2 any change to the proposed *outage* plan as advised to and approved by the *IESO*.

Appendix 7.5 – The Day-Ahead Market Calculation Engine Process

1.1 Purpose

1.1.1 This appendix describes the process used by the *day-ahead market calculation engine* to determine commitments, schedules and prices for the *day-ahead market*.

2 Day-Ahead Market Calculation Engine

2.1 Passes of the Day-Ahead Market Calculation Engine

2.1.1 The *day-ahead market calculation engine* shall execute three passes to produce day-ahead schedules, commitments and *locational marginal prices*.

2.1.1.1 Pass 1, the Market Commitment and Market Power Mitigation Pass in accordance with section 7;

2.1.1.2 Pass 2, the Reliability Scheduling and Commitment Pass in accordance with section 17; and

2.1.1.3 Pass 3, the DAM Scheduling and Pricing Pass, in accordance with section 19.

3 Information Used by the Day-Ahead Market Calculation Engine

3.1.1 The *day-ahead market calculation engine* shall use the information in section 3A.1 of Chapter 7.

4 Sets, Indices and Parameters Used in the Day-Ahead Market Calculation Engine

4.1 Fundamental Sets and Indices

4.1.1 A designates the set of all *intertie zones*;

4.1.2 B designates the set of buses identifying all *dispatchable* and non-*dispatchable resources* within Ontario;

4.1.3 $B^{PRL} \subseteq B$ designates the set of buses identifying *price responsive loads*;

4.1.4 $B^{DL} \subseteq B$ designates the set of buses identifying *dispatchable loads*;

4.1.5 $B^{HDR} \subseteq B$ designates the set of buses identifying *hourly demand response resources*;

4.1.6 $B^{NDG} \subseteq B$ designates the set of buses identifying *non-dispatchable generation resources*;

4.1.7 $B^{DG} \subseteq B$ designates the set of buses identifying *dispatchable generation resources*;

4.1.8 $B^{NQS} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable non-quick start resources*;

4.1.9 $B^{PSU} \subseteq B^{NQS}$ designates the subset of buses identifying *pseudo-units*;

4.1.10 $B^{VG} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable variable generation resources*;

4.1.11 $B^{ELR} \subseteq B^{DG}$ designates the subset of buses identifying *energy limited resources*;

4.1.12 $B^{HE} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources*;

4.1.13 $B^{HE}_s \subseteq B^{HE}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

4.1.14 $\wp(B^{HE})$ designates the set of all subsets of the set B^{HE};

4.1.15 $B_{up}^{HE} \subseteq \wp(B^{HE})$ designates the set of buses identifying all upstream *dispatchable* hydroelectric *generation resources* with a registered *forebay* that are linked via *time lag* and *MWh ratio dispatch data* with downstream *dispatchable* hydroelectric *generation resources* with a registered *forebay*;

4.1.16 $B_{dn}^{HE} \subseteq \wp(B^{HE})$ designates the set of buses identifying all downstream *dispatchable* hydroelectric *generation resources* with a registered *forebay* that are linked via *time lag* and *MWh ratio dispatch data* with upstream *dispatchable* hydroelectric *generation resources* with a registered *forebay*;

4.1.17 $B_r^{REG} \subseteq B$ designates the set of internal buses in *operating reserve* region $r \in ORREG$;

4.1.18 $B_p^{ST} \subseteq B^{PSU}$ designates the subset of buses identifying *pseudo-units* with a share of steam turbine *resource* $p \in PST$;

4.1.19 $B^{NO10DF} \subseteq B^{PSU}$ designates the subset of buses identifying *pseudo-units* that cannot provide *ten-minute operating reserve* from the duct firing region;

4.1.20 C designates the set of contingencies that shall be considered in the *security* assessment function;

4.1.21 D designates the set of buses outside Ontario, corresponding to imports and exports at *intertie zones*;

4.1.22 $D^{GMPRef} \subseteq D$ designates the set of *global market power reference intertie zones*, and *boundary entity resources* for those *interties*;

4.1.23 $D_r^{REG} \subseteq D$ designates the set of *intertie zone* buses identifying *boundary entity resources* in *operating reserve* region $r \in ORREG$;

4.1.24 $DX \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids*;

4.1.25 $DI \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers*;

4.1.26 $D_a \subseteq D$ designates the set of all buses identifying *boundary entity resources* in *intertie zone* $a \in A$;

4.1.27 $DX_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids* in *intertie zone* $a \in A$;

4.1.28 $DI_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers* in *intertie zone* $a \in A$;

4.1.29 $DX_h^{EM} \subseteq DX$ designates the *intertie zone* buses corresponding to *emergency energy* export transactions for hour $h \in \{1,..,24\}$;

4.1.30 $DX_h^{INP} \subseteq DX$ designates the *intertie zone* buses corresponding to inadvertent *energy* payback export transactions for hour $h \in \{1,..,24\}$;

4.1.31 $DI_h^{EM} \subseteq DI$ designates the *intertie zone* buses corresponding to *emergency energy* import transactions for hour $h \in \{1,..,24\}$;

4.1.32 $DI_h^{EMNS} \subseteq DI_h^{EM}$ designates the *intertie zone* buses corresponding to *emergency energy* import transactions that do not support *emergency energy* export transactions in hour $h \in \{1,..,24\}$;

4.1.33 $DI_h^{INP} \subseteq DI$ designates the *intertie zone* buses corresponding to inadvertent *energy* payback import transactions for hour $h \in \{1,..,24\}$;

4.1.34 F designates the set of *facilities* and groups of *facilities* for which transmission constraints may be identified;

4.1.35 $F_h \subseteq F$ designates the set of *facilities* whose pre-contingency limit was violated in hour h as determined by a preceding *security* assessment function iteration;

4.1.36 $F_{h,c} \subseteq F$ designates the set of *facilities* whose post-contingency limit for contingency c is violated in hour h as determined by a preceding *security* assessment function iteration;

4.1.37 $J_{h,b}^{E}$ designates the set of *bid* laminations for *energy* at $b \in B \cup DX \cup VB$ for hour $h \in \{1,..,24\}$;

4.1.38 $J_{h,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for hour $h \in \{1,..,24\}$;

4.1.39 $J_{h,b}^{10S}$ designates the set of *reference level value* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.40 $J_{h,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B \cup DX$ for hour $h \in \{1, . . ,24\}$;

4.1.41 $J_{h,b}^{10N}$ designates the set of *reference level value* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.42 $J_{h,b}^{30R}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at bus $b \in B \cup DX$ for hour $h \in \{1, . . ,24\}$;

4.1.43 $J_{h,b}^{\prime 30R}$ designates the set of *reference level value* laminations for *thirty-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.44 $K_{h,b}^{E}$ designates the set of *offer* laminations for *energy* at bus $b \in B \cup DI \cup VO$ for hour $h \in \{1, . . ,24\}$;

4.1.45 $K_{h,b}^{\prime E}$ designates the set of *reference level value* laminations for *energy* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.46 $K_{h,b}^{DF} \subseteq K_{h,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the duct firing region of a *pseudo-unit* at bus $b \in B^{PSU}$ in hour $h \in \{1, . . ,24\}$;

4.1.47 $K_{h,b}^{DR} \subseteq K_{h,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the *dispatchable* region of a *pseudo-unit* at bus $b \in B^{PSU}$ in hour $h \in \{1, . . ,24\}$;

4.1.48 $K_{h,b}^{LTMLP}$ designates the set of *offer* laminations for *energy* quantities up to the *minimum loading point* for a *non-quick start resource* at bus $b \in B^{NQS}$ in hour $h \in \{1, . . ,24\}$;

4.1.49 $K_{h,b}^{\prime LTMLP}$ designates the set of *reference level value* laminations for *energy* quantities up to the *minimum loading point reference level* for a *non-quick start resource* at bus $b \in B^{NQS}$ in hour $h \in \{1, . . ,24\}$;

4.1.50 $K_{h,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.51 $K_{h,b}^{\prime 10S}$ designates the set of *reference level value* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.52 $K_{h,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B \cup DI$ for hour $h \in \{1, . . ,24\}$;

4.1.53 $K_{h,b}^{\prime 10N}$ designates the set of *reference level value* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.54 $K_{h,b}^{30R}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at bus $b \in B \cup DI$ for hour $h \in \{1, . . ,24\}$;

4.1.55 $K^{30R}_{h,b}$ designates the set of *reference level value* laminations for *thirty-minute operating reserve* at bus $b \in B$ for hour $h \in \{1, . . ,24\}$;

4.1.56 L designates the set of buses where the *locational marginal prices* represent prices for *delivery points* associated with *non-dispatchable generation resources* and *dispatchable generation resources*, *dispatchable loads*, *hourly demand response resources*, *price responsive loads* and *non-dispatchable loads*;

4.1.57 $L^{NDL}_{y} \subseteq L$ designates the buses contributing to the zonal price for *non-dispatchable load* zone $y \in Y$;

4.1.58 $L^{VIRT}_{m} \subseteq L$ designates the buses contributing to the *virtual zonal price* for *virtual transaction zone* $m \in M$;

4.1.59 M designates the set of *virtual transaction zones*;

4.1.60 NCA designates the set of *narrow constrained areas*;

4.1.61 DCA designates the set of *dynamic constrained areas*;

4.1.62 BCA designates the set of broad constrained areas;

4.1.63 PST designates the set of steam turbine *resources offered* as part of a *pseudo-unit*;

4.1.64 SHE designates the set indexing the sets of *dispatchable* hydroelectric *generation resources* with a *maximum daily energy limit* or a *minimum daily energy limit* or both for a registered *forebay*;

4.1.65 V designates the set of *offers* and *bids* for *energy* corresponding to *virtual transactions*;

4.1.66 $VB \subseteq V$ designates the set of *bids* for *energy* corresponding to *virtual transactions*;

4.1.67 $VO \subseteq V$ designates the set of *offers* for *energy* corresponding to *virtual transactions;*

4.1.68 $V_m \subseteq V$ designates the set of *offers* and *bids* for *energy* corresponding to *virtual transactions* at *virtual transaction zone* $m \in M$;

4.1.69 $VB_m \subseteq V_m$ designates the set of *bids* for *energy* corresponding to *virtual transactions* at *virtual transaction zone* $m \in M$;

4.1.70 $VO_m \subseteq V_m$ designates the set of *offers* for *energy* corresponding to *virtual transactions* at *virtual transaction zone* $m \in M$;

4.1.71 *Y* designates the *non-dispatchable load* zones in Ontario; and

4.1.72 Z_{Sch} designates the set of all *intertie* limit constraints.

4.2 Market Participant Data Parameters

4.2.1 With respect to a *non-dispatchable generation resource* identified by bus $b \in B^{NDG}$:

4.2.1.1 $QNDG_{h,b,k}$ designates the maximum incremental quantity of *energy* that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^E_{h,b}$; and

4.2.1.2 $PNDG_{h,b,k}$ designates the price for the maximum incremental quantity of *energy* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^E_{h,b}$.

4.2.2 With respect to a *dispatchable generation resource* identified by bus $b \in B^{DG}$:

4.2.2.1 $MinQDG_b$ designates the *minimum loading point*;

4.2.2.2 $QDG_{h,b,k}$ designates the maximum incremental quantity of *energy* above the *minimum loading point* that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^E_{h,b}$;

4.2.2.3 $PDG_{h,b,k}$ designates the price for the maximum incremental quantity of *energy* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^E_{h,b}$;

4.2.2.4 $Q10SDG_{h,b,k}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10S}_{h,b}$;

4.2.2.5 $P10SDG_{h,b,k}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10S}_{h,b}$;

4.2.2.6 $Q10NDG_{h,b,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10N}_{h,b}$;

4.2.2.7 $P10NDG_{h,b,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{10N}$;

4.2.2.8 $Q30RDG_{h,b,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{30R}$;

4.2.2.9 $P30RDG_{h,b,k}$ designates the price of the maximum incremental quantity of *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{30R}$;

4.2.2.10 $ORRDG_b$ designates the maximum *operating reserve* ramp rate in MW per minute;

4.2.2.11 $NumRRDG_{h,b}$ designates the number of ramp rates provided in hour $\mathrm{h} \in \{1,..,24\}$;

4.2.2.12 $RmpRngMaxDG_{h,b,w}$ for $w \in \{1,..,NumRRDG_{h,b}\}$ designates the w$^{\text{th}}$ ramp rate break point in hour $\mathrm{h} \in \{1,..,24\}$;

4.2.2.13 $URRDG_{h,b,w}$ for $w \in \{1,..,NumRRDG_{h,b}\}$ designates the ramp rate in MW per minute at which the *resource* can increase the amount of *energy* it supplies in hour $\mathrm{h} \in \{1,..,24\}$ while operating in the range between $RmpRngMaxDG_{h,b,w-1}$ and $RmpRngMaxDG_{h,b,w}$, where $RmpRngMaxDG_{h,b,0}$ shall be equal to zero;

4.2.2.14 $DRRDG_{h,b,w}$ for $w \in \{1,..,NumRRDG_{i,b}\}$ designates the ramp rate in MW per minute at which the *resource* can decrease the amount of *energy* it supplies in hour $\mathrm{h} \in \{1,..,24\}$ while operating in the range between $RmpRngMaxDG_{h,b,w-1}$ and $RmpRngMaxDG_{h,b,w}$, where $RmpRngMaxDG_{h,b,0}$ shall be equal to zero;

4.2.2.15 $RLP30R_{h,b}$ designates the *reserve loading point* for *thirty-minute operating reserve* in hour $\mathrm{h} \in \{1,..,24\}$; and

4.2.2.16 $RLP10S_{h,b}$ designates the *reserve loading point* for synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$.

4.2.3 With respect to a *dispatchable non-quick start resource* identified by bus $b \in B^{NQS}$:

4.2.3.1 $SUDG_{h,b}$ designates the *start-up offer* in hour $h \in \{1,..,24\}$;

4.2.3.2 $SNL_{h,b}$ designates the *speed no-load offer* in hour $h \in \{1,..,24\}$;

4.2.3.3 $\mathrm{MGBRTDG_b}$ designates the *minimum generation block run-time*;

4.2.3.4 $\mathrm{MGBDTDG_b}$ designates the *minimum generation block down-time*;

4.2.3.5 $\mathrm{MaxStartsDG_b}$ designates the *maximum number of starts per day*;

4.2.3.6 $\mathrm{RampHrs_b}$ designates the *ramp hours to minimum loading point*;

4.2.3.7 $\mathrm{RampE_{b,w}}$ designates the *ramp up energy to minimum loading point* for $\mathrm{w} \in \{1,..,\mathrm{RampHrs_b}\}$;

4.2.3.8 $QLTMLP_{h,b,k}$ designates the maximum incremental quantity of *energy* up to the *minimum loading point* that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{LTMLP}$;

4.2.3.9 $PLTMLP_{h,b,k}$ designates the price for the maximum incremental quantity of *energy* up to the *minimum loading point* that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{LTMLP}$; and

4.2.3.10 $MGODG_{h,b}$ designates the minimum generation cost to operate at *minimum loading point* in hour $h \in \{1,..,24\}$. This parameter is calculated as follows:

$$MGODG_{h,b} = SNL_{h,b} + \sum_{k \in K_{h,b}^{LTMLP}} PLTMLP_{h,b,k} \cdot QLTMLP_{h,b,k}$$

4.2.4 With respect to an *energy limited resource* identified by bus $b \in B^{ELR}$:

4.2.4.1 $MaxDEL_b$ designates the *maximum daily energy limit* for a single *resource* with or without out a registered *forebay.*

4.2.5 With respect to a *dispatchable* hydroelectric *generation resource* identified by bus $b \in B^{HE}$:

4.2.5.1 $MinHMR_{h,b}$ designates the *hourly must-run* value for the *resource* in hour $h \in \{1,..,24\}$;

4.2.5.2 $MinHO_{h,b}$ designates the *minimum hourly output* for the *resource* in hour $h \in \{1,..,24\}$;

4.2.5.3 $MinDEL_b$ designates the *minimum daily energy limit* for a single *resource* with or without a registered *forebay*;

4.2.5.4 $MaxStartsHE_b$ designates the *maximum number of starts per day* for the *resource*;

4.2.5.5 $StartMW_{b,i}$ for $i \in \{1, .., NStartMW_b\}$ designates the *start indication value* for measuring *maximum number of starts per day*; a start is counted between hours h and $(h + 1)$ if the schedule increases from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$; and

4.2.5.6 $(ForL_{b,i}, ForU_{b,i})$ for $i \in \{1,.., NFor_b\}$ designate the lower and upper limits of the *forbidden regions* and indicate that the *resource* cannot be scheduled between $ForL_{b,i}$ and $ForU_{b,i}$ for all $i \in \{1,..,NFor_b\}$.

4.2.6 With respect to multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay:*

4.2.6.1 $MaxSDEL_s$ designates the *maximum daily energy limit* shared by all *dispatchable* hydroelectric *generation resources* in set $s \in SHE$; and

4.2.6.2 $MinSDEL_s$ designates the *minimum daily energy limit* shared by all *dispatchable* hydroelectric *generation resources* in set $s \in SHE$.

4.2.7 With respect to a *dispatchable* hydroelectric *generation resource* for which a MWh ratio was respected

4.2.7.1 $LNK \subseteq B_{up}^{HE} \times B_{dn}^{HE}$ designates the set of linked *dispatchable* hydroelectric *generation resources*, where LNK is a set with elements of the form (b_1, b_2) and $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$;

4.2.7.2 $Lag_{b_1,b_2} \in \{0, .., 23\}$ designates the *time lag* in hours between upstream *dispatchable* hydroelectric *generation resources* $b_1 \in B_{up}^{HE}$ and downstream *dispatchable* hydroelectric *generation resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK$; and

4.2.7.3 $MWhRatio_{b_1,b_2}$ designates the *MWh ratio* between upstream *dispatchable* hydroelectric *generation resources* $b_1 \in B_{up}^{HE}$ and downstream *dispatchable* hydroelectric *generation resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK$.

4.2.8 With respect to a *pseudo-unit* identified by bus $b \in B^{PSU}$:

4.2.8.1 $STShareMLP_b$ designates the steam turbine *resource's* share of the *minimum loading point* region;

4.2.8.2 $STShareDR_b$ designates the steam turbine *resource's* share of the *dispatchable* region;

4.2.8.3 $RampCT_{b,w}$ designates the quantity of *energy* injected w hours before the *pseudo-unit* reaches its *minimum loading point* that is attributed to the combustion turbine *resource* for $w \in \{1, .., RampHrs_b\}$; and

4.2.8.4 $RampST_{b,w}$ designates the quantity of *energy* injected w hours before the *pseudo-unit* reaches its *minimum loading point* that is attributed to the steam turbine *resource* for $w \in \{1, .., RampHrs_b\}$.

4.2.9 With respect to a *dispatchable load* identified by bus $b \in B^{DL}$:

4.2.9.1 $QDL_{h,b,j}$ designates the maximum incremental quantity of *energy* that may be scheduled in hour $h \in \{1, .., 24\}$ in association with *bid* lamination $j \in J^{E}_{h,b}$;

4.2.9.2 $PDL_{h,b,j}$ designates the price for the maximum incremental quantity of *energy* in hour $h \in \{1, .., 24\}$ in association with *bid* lamination $j \in J^{E}_{h,b}$;

4.2.9.3 $Q10SDL_{h,b,j}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* that may be scheduled in hour $h \in \{1, .., 24\}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$;

4.2.9.4 $P10SDL_{h,b,j}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in hour $h \in \{1, .., 24\}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$;

4.2.9.5 $Q10NDL_{h,b,j}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled in hour $h \in \{1, .., 24\}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$;

4.2.9.6 $P10NDL_{h,b,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1, .., 24\}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$;

4.2.9.7 $Q30RDL_{h,b,j}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled in hour $h \in \{1, .., 24\}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$;

4.2.9.8 $P30RDL_{h,b,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in hour $h \in \{1, .., 24\}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$;

4.2.9.9 $ORRDL_b$ designates the *operating reserve* ramp rate in MW per minute for reductions in load consumption;

4.2.9.10 $NumRRDL_{h,b}$ designates the number of ramp rates provided in hour $h \in \{1,..,24\}$;

4.2.9.11 $RmpRngMaxDL_{h,b,w}$ for $w \in \{1,..,NumRRDL_{h,b}\}$ designates the w[th] ramp rate break point in hour h ∈ {1, . . ,24};

4.2.9.12 $URRDL_{h,b,w}$ for $w \in \{1,..,NumRRDL_{h,b}\}$ designates the ramp rate in MW per minute at which the *dispatchable load* can increase its amount of *energy* consumption in hour h ∈ {1, . . ,24} while operating in the range between $RmpRngMaxDL_{h,b,w-1}$ and $RmpRngMaxDL_{h,b,w}$, where $RmpRngMaxDL_{h,b,0}$ shall be equal to zero;

4.2.9.13 $DRRDL_{h,b,w}$ for $w \in \{1,..,NumRRDL_{h,b}\}$ designates the ramp rate in MW per minute at which the *dispatchable load* can decrease its amount of *energy* consumption in hour $h \in \{1,..,24\}$ while operating in the range between $RmpRngMaxDL_{h,b,w-1}$ and $RmpRngMaxDL_{h,b,w}$, where $RmpRngMaxDL_{h,b,0}$ shall be equal to zero; and

4.2.9.14 $QDLFIRM_{h,b}$ designates the quantity of *energy* that is *bid* at the *maximum market clearing price* in hour $h \in \{1,..,24\}$.

4.2.10 With respect to an *hourly demand response resource* identified by bus $b \in B^{HDR}$:

4.2.10.1 $QHDR_{h,b,j}$ designates the maximum incremental quantity of reduction in *energy* consumption that may be scheduled in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$;

4.2.10.2 $PHDR_{h,b,j}$ designates the price for the maximum incremental quantity of reduction in *energy* consumption for hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$;

4.2.10.3 $URRHDR_b$ designates the maximum rate in MW per minute at which the *hourly demand response resource* can decrease its amount of *energy* consumption; and

4.2.10.4 $DRRHDR_b$ designates the maximum rate in MW per minute at which the *hourly demand response resource* can increase its amount of *energy* consumption.

4.2.11 With respect to a *price responsive load* identified by bus $b \in B^{PRL}$:

4.2.11.1 $QPRL_{h,b,j}$ designates the maximum incremental quantity of *energy* that may be scheduled in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$;

4.2.11.2 $PPRL_{h,b,j}$ designates the price for the maximum incremental quantity of *energy* in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$; and

4.2.11.3 $QPRLFIRM_{h,b}$ designates the quantity of *energy* that is *bid* at $MMCP$ in hour $h \in \{1,..,24\}$.

4.2.12 With respect to a *virtual transaction:*

4.2.12.1 $QVB_{h,v,j}$ designates the maximum incremental quantity of *energy* that may be scheduled in hour $h \in \{1,..,24\}$ from a *virtual zonal resource* $v \in VB$ in association with *bid* lamination $j \in J^E_{h,v}$;

4.2.12.2 $PVB_{h,v,j}$ designates the price for the maximum incremental quantity of *energy* in hour $h \in \{1,..,24\}$ from a *virtual zonal resource* $v \in VB$ in association with *bid* lamination $j \in J^E_{h,v}$;

4.2.12.3 $QVO_{h,v,k}$ designates the maximum incremental quantity of *energy* that may be scheduled in hour $h \in \{1,..,24\}$ from a *virtual zonal resource* $v \in VO$ in association with *offer* lamination $k \in K^E_{h,v}$; and

4.2.12.4 $PVO_{h,v,k}$ designates the price for the maximum incremental quantity of *energy* in hour $h \in \{1,..,24\}$ from a *virtual zonal resource* $v \in VO$ in association with *offer* lamination $k \in K^E_{h,v}$.

4.2.13 With respect to a *boundary entity resource* import from *intertie zone* bus $d \in DI$, where the *locational marginal price* represents the price for the *intertie metering point*:

4.2.13.1 $QIG_{h,d,k}$ designates the maximum incremental quantity of *energy* that may be scheduled to import in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^E_{h,d}$;

4.2.13.2 $PIG_{h,d,k}$ designates the price for the maximum incremental quantity of *energy* that may be scheduled to import in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^E_{h,d}$;

4.2.13.3 $Q10NIG_{h,d,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{10N}$;

4.2.13.4 $P10NIG_{h,d,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{10N}$;

4.2.13.5 $Q30RIG_{h,d,k}$ designates the the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{30R}$; and

4.2.13.6 $P30RIG_{h,d,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{30R}$.

4.2.14 With respect to a *boundary entity resource* export to *intertie zone* bus $d \in DX$, where the *locational marginal price* represents the price for the *intertie metering point*:

4.2.14.1 $QXL_{h,d,j}$ designates the maximum incremental quantity of *energy* that may be scheduled to export in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J_{h,d}^{E}$;

4.2.14.2 $PXL_{h,d,j}$ designates the price for the maximum incremental quantity of *energy* that may be scheduled to export in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J_{h,d}^{E}$;

4.2.14.3 $Q10NXL_{h,d,j}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{10N}$;

4.2.14.4 $P10NXL_{h,d,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1, . . ,24\}$ in association with *offer* lamination $\mathrm{j} \in \mathrm{J}_{\mathrm{h,d}}^{\mathrm{10N}}$;

4.2.14.5 $Q30RXL_{h,d,j}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{30R}$; and

4.2.14.6 $P30RXL_{h,d,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{30R}$.

4.2.15 With respect to a *linked wheeling through transaction*:

4.2.15.1 $L_h \subseteq DX \times DI$ designates the set of linked *boundary entity resource* import and export buses corresponding to *linked wheeling through transactions,* where L_h is a set with elements of the form (dx, di) and $dx \in DX$ and $di \in DI$.

4.3 IESO Data Parameters

4.3.1 Variable Generation Forecast

4.3.1.1 $FG_{h,b}$ designates the *IESO*'s centralized *variable generation* forecast for a *variable generation resource* identified by bus $b \in B^{VG}$ in hour $h \in \{1,..,24\}$.

4.3.2 Variable Generation Tie-Breaking

4.3.2.1 $NumVG$ designates the number of *variable generation resources* in the daily *dispatch* order; and

4.3.2.2 $TBM_b \in \{1, . . . , NumVG\}$ designates the tie-breaking modifier for the *variable generation resource* at bus $b \in B^{VG}$.

4.3.3 Operating Reserve Requirements

4.3.3.1 $TOT10S_h$ designates the synchronized *ten-minute operating reserve* requirement;

4.3.3.2 $TOT10R_h$ designates the total *ten-minute operating reserve* requirement;

4.3.3.3 $TOT30R_h$ designates the *thirty-minute operating reserve* requirement;

4.3.3.4 $ORREG$ designates the set of regions for which regional *operating reserve* limits have been defined;

4.3.3.5 $REGMin10R_{h,r}$ designates the minimum requirement for total *ten-minute operating reserve* in region $r \in ORREG$ in hour $h \in \{1, . . ,24\}$;

4.3.3.6 $REGMin30R_{h,r}$ designates the minimum requirement for *thirty-minute operating reserve* in region $r \in ORREG$ in hour $h \in \{1, . . ,24\}$;

4.3.3.7 $REGMax10R_{h,r}$ designates the maximum amount of total *ten-minute operating reserve* that may be scheduled in region $r \in ORREG$ in hour $h \in \{1, . . ,24\}$; and

4.3.3.8 $REGMax30R_{h,r}$ designates the maximum amount of *thirty-minute operating reserve* that may be scheduled in region $r \in ORREG$ in hour $h \in \{1,..,24\}$.

4.3.4 Intertie Limits

4.3.4.1 $EnCoeff_{a,z}$ designates the coefficient for calculating the contribution of scheduled *energy* flows and *operating reserve* inflows for *intertie zone* $a \in A$, which is part of *intertie* limit constraint $z \in Z_{Sch}$. A coefficient of $+1$ shall describe flows into Ontario while a coefficient of -1 shall describe flows out of Ontario;

4.3.4.2 $MaxExtSch_{h,z}$ designates the maximum flow limit for *intertie* flow constraint $z \in Z_{Sch}$in hour $h \in \{1,..,24\}$;

4.3.4.3 $ExtDSC_h$ designates the net interchange scheduling limit for when the net flows over all *interties* from hour $(h-1)$ to hour h decrease; and

4.3.4.4 $ExtUSC_h$ designates the net interchange scheduling limit for when the net flows over all *interties* from hour $(h-1)$ to hour h increase.

4.3.5 Resource Minimum and Maximum Constraints

4.3.5.1 Where applicable the minimum or maximum output of a *dispatchable generation resource* or a *non-dispatchtable generation resource* and minimum or maximum consumption of a *dispatchable load* may be limited due to *reliability* constraints, applicable *contracted ancillary services*, *outages,* derates, and other constraints, such that:

4.3.5.1.1 $MinDL_{h,b}$ designates the most restrictive minimum consumption limit for the *dispatchable load* in hour h at bus $b \in B^{DL}$;

4.3.5.1.2 $MaxDL_{h,b}$ designates the most restrictive maximum consumption limit for the *dispatchable load* in hour h at bus $b \in B^{DL}$;

4.3.5.1.3 $MinNDG_{h,b}$ designates the most restrictive minimum output limit for the *non-dispatchable generation resource* in hour h at bus $b \in B^{NDG}$;

4.3.5.1.4 $MaxNDG_{h,b}$ designates the most restrictive maximum output limit for the *non-dispatchable generation resource* in hour h at bus $b \in B^{NDG}$;

4.3.5.1.5 $MinDG_{h,b}$ designates the most restrictive minimum output limit for the *dispatchable generation resource* in hour h at bus $b \in B^{DG}$;

4.3.5.1.6 $MaxDG_{h,b}$ designates the most restrictive maximum output limit for the *dispatchable generation resource* in hour h at bus $b \in B^{DG}$;

4.3.5.1.7 $MaxMLP_{h,b}$ designates the maximum output limit in hour h for the *minimum loading point* region of a *pseudo-unit* at bus $b \in B^{PSU}$;

4.3.5.1.8 $MaxDR_{h,b}$ designates the maximum output limit in hour h for the *dispatchable* region of a *pseudo-unit* at bus $b \in B^{PSU}$; and

4.3.5.1.9 $MaxDF_{h,b}$ designates the maximum output limit in hour h for the duct firing region of a *pseudo-unit* at bus $b \in B^{PSU}$.

4.3.6 Constraint Violation Penalties

4.3.6.1 $(PLdViolSch_{h,i}, QLdViolSch_{h,i})$ for $i \in \{1, .., N_{LdViol_h}\}$ designate the price-quantity segments of the penalty curve for under generation used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.2 $(PLdViolPrc_{h,i}, QLdViolPrc_{h,i})$ for $i \in \{1, .., N_{LdViol_h}\}$ designate the price-quantity segments of the penalty curve for under generation used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.3 $(PGenViolSch_{h,i}, QGenViolSch_{h,i})$ for $i \in \{1, .., N_{GenViol_h}\}$ designate the price-quantity segments of the penalty curve for over generation used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.4 $(PGenViolPrc_{h,i}, QGenViolPrc_{h,i})$ for $i \in \{1, .., N_{GenViol_h}\}$ designate the price-quantity segments of the penalty curve for over generation used by the As-Offered Pricing algorithm in section 9, Reference Level

Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.5 $(P10SViolSch_{h,i}, Q10SViolSch_{h,i})$ for $i \in \{1, . . , N_{10SViol_h}\}$ designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.6 $(P10SViolPrc_{h,i}, Q10SViolPrc_{h,i})$ for $i \in \{1, . . , N_{10SViol_h}\}$ designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.7 $(P10RViolSch_{h,i}, Q10RViolSch_{h,i})$ for $i \in \{1, . . , N_{10RViol_h}\}$ designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.8 $(P10RViolPrc_{h,i}, Q10RViolPrc_{h,i})$ for $i \in \{1, . . , N_{10RViol_h}\}$ designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.9 $(P30RViolSch_{h,i}, Q30RViolSch_{h,i})$ for $i \in \{1, . . , N_{30RViol_h}\}$ designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.10 $(P30RViolPrc_{h,i}, Q30RViolPrc_{h,i})$ for $i \in \{1, . . , N_{30RViol_h}\}$ designate the price-quantity segments of the penalty curve for the total *thirty-*

minute operating reserve requirement and, when applicable, the flexibility *operating reserve* requirement used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.11 $(PREG10RViolSch_{h,i}, QREG10RViolSch_{h,i})$ for $i \in \{1,..,N_{REG10RViol_h}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.12 $(PREG10RViolPrc_{h,i}, QREG10RViolPrc_{h,i})$ for $i \in \{1,..,N_{REG10RViol_h}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.13 $(PREG30RViolSch_{h,i}, QREG30RViolSch_{h,i})$ for $i \in \{1,..,N_{REG30RViol_h}\}$ designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.14 $(PREG30RViolPrc_{h,i}, QREG30RViolPrc_{h,i})$ for $i \in \{1,..,N_{REG30RViol_h}\}$ designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.15 $(PXREG10RViolSch_{h,i}, QXREG10RViolSch_{h,i})$ for $i \in \{1,..,N_{XREG10RViol_h}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.16 $(PXREG10RViolPrc_{h,i}, QXREG10RViolPrc_{h,i})$ for $i \in \{1,..,N_{XREG10RViol_h}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.17 $(PXREG30RViolSch_{h,i}, QXREG30RViolSch_{h,i})$ for $i \in \{1,..,N_{XREG30RViol_h}\}$ designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.18 $(PXREG30RViolPrc_{h,i}, QXREG30RViolPrc_{h,i})$ for $i \in \{1,..,N_{XREG30RViol_h}\}$ designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.19 $(PPreITLViolSch_{f,h,i}, QPreITLViolSch_{f,h,i})$ for $i \in \{1,..,N_{PreITLViol_{f,h}}\}$ designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.20 $(PPreITLViolPrc_{f,h,i}, QPreITLViolPrc_{f,h,i})$ for $i \in \{1,..,N_{PreITLViol_{f,h}}\}$ designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.21 $(PITLViolSch_{c,f,h,i}, QITLViolSch_{c,f,h,i})$ for $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$ designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used by As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.22 $(PITLViolPrc_{c,f,h,i}, QITLViolPrc_{c,f,h,i})$ for $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$ designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.23 $(PPreXTLViolSch_{z,h,i}, QPreXTLViolSch_{z,h,i})$ for $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ designate the price-quantity segments of the penalty curve for exceeding the flow limit specified by $z \in Z_{Sch}$ used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.24 $(PPreXTLViolPrc_{z,h,i}, QPreXTLViolPrc_{z,h,i})$ for $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ designate the price-quantity segments of the penalty curve for exceeding the flow limit specified by $z \in Z_{Sch}$ used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.25 $(PNIUViolSch_{h,i}, QNIUViolSch_{h,i})$ for $i \in \{1,..,N_{NIUViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange increase constraint between hours $(h-1)$ and h used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.26 $(PNIUViolPrc_{h,i}, QNIUViolPrc_{h,i})$ for $i \in \{1,..,N_{NIUViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange increase constraint between hours $(h-1)$ and h used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.27 $(PNIDViolSch_{h,i}, QNIDViolSch_{h,i})$ for $i \in \{1,..,N_{NIDViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange decrease constraint between hours $(h-1)$ and h used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.28 $(PNIDViolPrc_{h,i}, QNIDViolPrc_{h,i})$ for $i \in \{1, .., N_{NIDViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange decrease constraint between hours $(h-1)$ and h used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.29 $(PMaxDelViolSch_{h,i}, QMaxDelViolSch_{h,i})$ for $i \in \{1, .., N_{MaxDelViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding a *resource*'s *maximum daily energy limit* used by As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.30 $(PMaxDelViolPrc_{h,i}, QMaxDelViolPrc_{h,i})$ for $i \in \{1, .., N_{MaxDelViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding a *resource*'s *maximum daily energy limit* used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.31 $(PMinDelViolSch_{h,i}, QMinDelViolSch_{h,i})$ for $i \in \{1, .., N_{MinDelViol_h}\}$ designate the price-quantity segments of the penalty curve for under-scheduling a *resource*'s *minimum daily energy limit* used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.32 $(PMinDelViolPrc_{h,i}, QMinDelViolPrc_{h,i})$ for $i \in \{1, .., N_{MinDelViol_h}\}$ designate the price-quantity segments of the penalty curve for under-scheduling a *resource*'s *minimum daily energy limit* used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.33 $(PSMaxDelViolSch_{h,i}, QSMaxDelViolSch_{h,i})$ for $i \in \{1, .., N_{SMaxDelViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding a shared *maximum daily energy limit* used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.34 $(PSMaxDelViolPrc_{h,i}, QSMaxDelViolPrc_{h,i})$ for $i \in \{1,..,N_{MaxDelViol_h}\}$ designate the price-quantity segments of the penalty curve for exceeding a shared *maximum daily energy limit* used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.35 $(PSMinDelViolSch_{h,i}, QSMinDelViolSch_{h,i})$ for $i \in \{1,..,N_{SMinDelViol_h}\}$ designate the price-quantity segments of the penalty curve for under-scheduling a shared *minimum daily energy limit* used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.36 $(PSMinDelViolPrc_{h,i}, QSMinDelViolPrc_{h,i})$ for $i \in \{1,..,N_{SMinDelViol_h}\}$ designate the price-quantity segments of the penalty curve for under-scheduling a shared *minimum daily energy limit* used by the As-Offered Pricing algorithm in section 9, Reference Level Pricing algorithm in section 13, Mitigated Pricing algorithm in section 16, and DAM Pricing algorithm in section 21;

4.3.6.37 $(POGenLnkViolSch_{h,i}, QOGenLnkViolSch_{h,i})$ for $i \in \{1,..,N_{OGenLnkViol_h}\}$ designate the price-quantity segments of the penalty curve for over generation on a downstream *resource* used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20;

4.3.6.38 $(PUGenLnkViolSch_{h,i}, QUGenLnkViolSch_{h,i})$ for $i \in \{1,..,N_{UGenLnkViol_h}\}$ designate the price-quantity segments of the penalty curve for under generation on a downstream *resource* used by the As-Offered Scheduling algorithm in section 8, Reference Level Scheduling algorithm in section 12, Mitigated Scheduling algorithm in section 15, Reliability Scheduling algorithm in section 18, and DAM Scheduling algorithm in section 20; and

4.3.6.39 $NISLPen$ designates the net interchange scheduling limit constraint violation penalty price for *locational marginal pricing*.

4.3.7 Price Bounds

4.3.7.1 $EngyPrcCeil$ designates and is equal to the *maximum market clearing price* for *energy*;

4.3.7.2 $EngyPrcFlr$ designates and is equal to the *settlement floor price*;

4.3.7.3 $ORPrcCeil$ designates and is equal to the *maximum operating reserve price* for all classes of *operating reserve*; and

4.3.7.4 $ORPrcFlr$ designates the minimum price for all classes of *operating reserve* and is equal to $0.

4.3.8 Ex-ante Market Power Mitigation

4.3.8.1 $BCACondThresh$ designates the threshold for the congestion component of a *resource's locational marginal price* for *energy* and is equal to $25/MWh;

4.3.8.2 $IBPThresh$ designates the *intertie border price* threshold for *energy* and is equal to $100/MWh;

4.3.8.3 $ORGCondThresh$ designates the global market power condition threshold for a *resource's locational marginal price* for *operating reserve* and is equal to $15/MW;

4.3.8.4 $PDGRef_{h,b,k'}$ designates the *reference level value* for *energy* lamination $k' \in K'^{E}_{h,b}$ for the *resource* at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;

4.3.8.5 $P10SDGRef_{h,b,k'}$ designates the *reference level value* for synchronized *ten-minute operating reserve* lamination $k' \in K'^{10S}_{h,b}$ for the *resource* at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;

4.3.8.6 $P10NDGRef_{h,b,k'}$ designates the *reference level value* for non-synchronized *ten-minute operating reserve* lamination $k' \in K'^{10N}_{h,b}$ for the *resource* at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;

4.3.8.7 $P30RDGRef_{h,b,k'}$ designates the *reference level value* for *thirty-minute operating reserve* lamination $k' \in K'^{30R}_{h,b}$ for the *resource* at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;

4.3.8.8 $P10SDLRef_{h,b,j'}$ designates the *reference level value* for synchronized *ten-minute operating reserve* lamination $j' \in J'^{10S}_{h,b}$ for the *resource* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$;

4.3.8.9 $P10NDLRef_{h,b,j'}$ designates the *reference level value* for non-synchronized *ten-minute operating reserve* lamination $j' \in J'^{10N}_{h,b}$ for the *resource* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$;

4.3.8.10 $P30RDLRef_{h,b,j'}$ designates the *reference level value* for *thirty-minute operating reserve* lamination $j' \in J_{h,b}^{30R}$ for the *resource* at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$

4.3.8.11 $SUDGRef_{h,b}$ designates the *reference level value* for the *start-up offer* for the *resource* at bus $b \in B^{NQS}$ in hour $h \in \{1,..,24\}$;

4.3.8.12 $SNLRef_{h,b}$ designates the *reference level value* for the *speed no-load offer* for the *resource* at bus $b \in B^{NQS}$ in hour $h \in \{1,..,24\}$;

4.3.8.13 $PLTMLPRef_{h,b,k'}$ designates the *reference level value* for the *energy* up to the *minimum loading point reference level* lamination $k' \in K_{h,b}^{'LTMLP}$ of the *offer* for the *resource* at bus $\mathrm{b} \in \mathrm{B}^{\mathrm{DG}}$ in hour $h \in \{1,..,24\}$;

4.3.8.14 $CTEnThresh1^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 50%;

4.3.8.15 $CTEnThresh2^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $25/MWh;

4.3.8.16 $CTSUThresh^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 25%;

4.3.8.17 $CTSNLThresh^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 25%;

4.3.8.18 $CTEnThresh1^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 50%;

4.3.8.19 $CTEnThresh2^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $25/MWh;

4.3.8.20 $CTSUThresh^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 25%;

4.3.8.21 $CTSNLThresh^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 25%;

4.3.8.22 $CTEnThresh1^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 300%;

4.3.8.23 $CTEnThresh2^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $100/MWh;

4.3.8.24 $CTSUThresh^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 100%;

4.3.8.25 $CTSNLThresh^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 100%;

4.3.8.26 $CTEnThresh1^{GMP}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 300%;

4.3.8.27 $CTEnThresh2^{GMP}$ designates the global market power conduct threshold for a *resource* as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $100 MW/h;

4.3.8.28 $CTSUThresh^{GMP}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 100%;

4.3.8.29 $CTSNLThresh^{GMP}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 100%;

4.3.8.30 $CTORThresh1^{ORL}$ designates the local market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to 10%;

4.3.8.31 $CTORThresh2^{ORL}$ designates the local market power conduct threshold for a *resource* as a $/MW increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to $25/MW;

4.3.8.32 $CTEnThresh1^{ORL}$ designates the local market power conduct threshold for *energy* to *minimum loading point* for a *resource* as a percent increase above the *reference level value* of the *offer* for *energy* up to the *minimum loading point* for the *resource* and is equal to 10%;

4.3.8.33 $CTEnThresh2^{ORL}$ designates the local market power conduct threshold for *energy* to *minimum loading point* conduct threshold for a *resource* as a $/MW increase above the *reference level value* of the *energy* for *energy* up to the *minimum loading point* for the *resource* and is equal to $25/MW;

4.3.8.34 $CTSUThresh^{ORL}$ designates the local market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 10%;

4.3.8.35 $CTSNLThresh^{ORL}$ designates the local market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 10%;

4.3.8.36 $CTORThresh1^{ORG}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to 50%;

4.3.8.37 $CTORThresh2^{ORG}$ designates the global market power conduct threshold for a *resource* as a $/MW increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to $25/MW;

4.3.8.38 $CTEnThresh1^{ORG}$ designates the global market power conduct threshold for *energy* to *minimum loading point* for a *resource* as a percent increase above the *reference level value* of the *offer* for *energy* up to the *minimum loading point* for the *resource* and is equal to 50%;

4.3.8.39 $CTEnThresh2^{ORG}$ designates the global market power conduct threshold for *energy* to *minimum loading point* for a *resource* as a $/MW increase above the *reference level value* of the *offer* for *energy* up to the *minimum loading point* for the *resource* and is equal to $25/MW;

4.3.8.40 $CTSUThresh^{ORG}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 25%;

4.3.8.41 $CTSNLThresh^{ORG}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 25%;

4.3.8.42 $CTEnMinOffer$ designates the minimum price for the *offer* lamination for *energy* to be included in the Conduct Test. *Offer* laminations for *energy* below this value are excluded from the Conduct Test and is equal to $25/MWh;

4.3.8.43 $CTORMinOffer$ designates the minimum price for the *offer* lamination for *operating reserve* to be included in the Conduct Test. *Offer* laminations for *operating reserve* below this value are excluded from the Conduct Test and is equal to $5/MW;

4.3.8.44 $ITThresh1^{NCA}$ designates the price impact threshold for a *resource* in a *narrow constrained area* as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 50%;

4.3.8.45 $ITThresh2^{NCA}$ designates the price impact threshold for a *resource* in a *narrow constrained area* as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to $25/MWh;

4.3.8.46 $ITThresh1^{DCA}$ designates the price impact threshold for a *resource* in a *dynamic constrained area* as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 50%;

4.3.8.47 $ITThresh2^{DCA}$ designates the price impact threshold for a *resource* in a *dynamic constrained area* as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy* *locational marginal price* output from section 13 and is equal to $25/MWh;

4.3.8.48 $ITThresh1^{BCA}$ designates the price impact threshold for a *resource* in a broad constrained area as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 100%;

4.3.8.49 $ITThresh2^{BCA}$ designates the price impact threshold for a *resource* in a broad constrained area as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to$50/MWh;

4.3.8.50 $ITThresh1^{GMP}$ designates the global market power price impact threshold for a *resource* as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 100%;

4.3.8.51 $ITThresh2^{GMP}$ designates the global market power price impact threshold for a *resource* as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to $50/MWh;

4.3.8.52 $ITThresh1^{ORG}$ designates the global market power price impact threshold for a *resource* as a percent increase in the *operating reserve locational marginal price* output from section 9 above the *operating reserve locational marginal price* output from section 13 and is equal to 50%; and

4.3.8.53 $ITThresh2^{ORG}$ designates the global market power price impact threshold for a *resource* as a $/MW increase in the *operating reserve locational marginal price* output from section 9 above the *operating reserve locational marginal price* output from section 13 and is equal to $25/MW.

4.3.9 Weighting Factors for Zonal Prices

4.3.9.1 $WF_{h,m,b}^{VIRT}$ designates the weighting factor for bus $b \in L_m^{VIRT}$ used to calculate the price for *virtual transaction zone* $m \in M$ for hour $h \in \{1,..,24\}$;

4.3.9.2 $WF^{NDL}_{h,y,b}$ designates the weighting factor for bus $b \in L^{NDL}_{y}$ used to calculate the price for *non-dispatchable load* zone $y \in Y$ for hour $h \in \{1, .., 24\}$; and

4.3.9.3 The weighting factors in section 4.3.9.1 and section 4.3.9.2 shall be obtained by renormalizing the load distribution factors so that for a given hour the sum of weighting factors for a *non-dispatchable load* zone or for a *virtual transaction zone* is one.

4.4 Other Data Parameters

4.4.1 Non-Dispatchable Demand Forecast

4.4.1.1 AFL_h designates the average province-wide *non-dispatchable demand* forecast for hour $h \in \{1, .., 24\}$ calculated by the *security* assessment function; and

4.4.1.2 PFL_h designates the peak province-wide non-*dispatchable demand* forecast for hour $h \in \{1, .., 24\}$ calculated by the *security* assessment function.

4.4.2 Variable Generation

4.4.2.1 $AFG_{h,b}$ designates the alternative forecast for a *variable generation resource* identified by bus $b \in B^{VG}$ in hour $h \in \{1, .., 24\}$, which is either the *registered market participant*-submitted forecast or the *IESO*'s centralized forecast.

4.4.3 Internal Transmission Constraints

4.4.3.1 $PreConSF_{h,f,b}$ designates the pre-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during hour h under pre-contingency conditions;

4.4.3.2 $VPreConSF_{h,f,m}$ designates the pre-contingency sensitivity factor for *virtual transaction zone* $m \in M$ indicating the effect of scheduled *energy* at m to flows on *facility* $f \in F_h$ in hour h under pre-contingency conditions. It shall be determined as the weighted average of the pre-contingency sensitivity factors for *non-dispatchable loads*, *dispatchable loads*, *hourly demand response resources*, and *price responsive loads* within the *virtual transaction zone* using the weighting factors $WF^{VIRT}_{h,m,b}$ for *virtual transactions*;

4.4.3.3 $AdjNormMaxFlow_{h,f}$ designates the limit corresponding to the maximum flow allowed on *facility* f in hour h under pre-contingency conditions;

4.4.3.4 $SF_{h,c,f,b}$ designates the post-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during hour h under post-contingency conditions for contingency c;

4.4.3.5 $VSF_{h,c,f,m}$ designates the post-contingency sensitivity factor for *virtual transaction zone* $m \in M$ indicating the effect of scheduled *energy* at m to flows on *facility* $f \in F_{h,c}$ in hour h under post-contingency conditions for contingency c. It shall be determined as the weighted average of the post-contingency sensitivity factors for *non-dispatchable loads*, *dispatchable loads*, *hourly demand response resources*, and *price responsive loads* within the *virtual transaction zone* using the weighting factors $WF^{VIRT}_{h,m,b}$ for *virtual transactions*; and

4.4.3.6 $AdjEmMaxFlow_{h,c,f}$ designates the limit corresponding to the maximum flow allowed on *facility* f in hour h under post-contingency conditions for contingency c.

4.4.4 Transmission Losses

4.4.4.1 $LossAdj_h$ designates any adjustment needed for hour $h \in \{1,..,24\}$ to correct for any discrepancy between Ontario total system losses calculated using a base case power flow from the *security* assessment function and linearized losses that would be calculated using the marginal loss factors.

4.4.4.2 $MglLoss_{h,b}$ designates the marginal loss factor and represent the marginal impact on transmission losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at *resource* bus $b \in B \cup D$ in hour $h \in \{1,..,24\}$; and

4.4.4.3 $VMglLoss_{h,m}$ designates the marginal loss factor for *virtual transaction zone* $m \in M$ in hour $h \in \{1,..,24\}$. It shall be determined as the weighted average of the marginal loss factors for *non-dispatchable loads*, *dispatchable loads*, *hourly demand response resources*, and *price responsive loads* within the *virtual transaction zone* using the weighting factors $WF^{VIRT}_{h,m,b}$ for *virtual transactions*.

5 Initialization

5.1 Purpose

5.1.1 The initialization processes set out in this section 5 shall occur prior to the execution of the *day-ahead market calculation engine* described in section 2.1.1 above.

5.2 Reference Bus

5.2.1 The *IESO* shall use Richview Transformer Station as the *day-ahead market calculation engine's* default *reference bus* for the calculation of *locational marginal prices.*

5.2.2 If the default *reference bus* is out of service, another in-service bus shall be selected.

5.3 Islanding Conditions

5.3.1 In the event of a network split, the *day-ahead market calculation engine* shall:

5.3.1.1 only evaluate *resources* that are within the *main island*;

5.3.1.2 use only forecasts of *demand* forecast areas in the *main island*; and

5.3.1.3 use a bus within the *main island* in place of the *reference bus* if the *reference bus* does not fall within the *main island*.

5.4 Variable Generation Tie-Breaking

5.4.1 For each hour $h \in \{1,..,24\}$, each *variable generation resource* bus $b \in B^{VG}$ and each *offer* lamination $k \in K_{h,b}^{E}$, the *offer* price $PDG_{h,b,k}$ shall be modified to $PDG_{h,b,k} - (\frac{TBM_b}{NumVG})\rho$, where ρ is a small nominal value of order 10^{-4}.

5.5 Pseudo-Unit Constraints

5.5.1 Constraints for *pseudo-units* corresponding to minimum and maximum constraints on physical *resources* shall be determined in accordance with section 22.

5.6 Initial Scheduling Assumptions

5.6.1 Initial Schedules

5.6.1.1 The following parameters designate the initial *energy* schedules used for hour 0 in the optimization of the next *dispatch day* and shall be based on the hour ending 24 schedules of the most recent execution of the *pre-dispatch calculation engine* prior to the execution of the *day-ahead market calculation engine*:

5.6.1.1.1 $SDL_{0,b,j}$, which designates the amount of *energy* that a *dispatchable load* is scheduled to consume at bus $b \in B^{DL}$;

5.6.1.1.2 $SHDR_{0,b,j}$, which designates the amount of *energy* an *hourly demand response resource* is scheduled to reduce consumption at bus $b \in B^{HDR}$;

5.6.1.1.3 $SXL_{0,d,j}$, which designates the amount of *energy* a *boundary entity resource* is scheduled to export at bus $d \in DX$;

5.6.1.1.4 $SDG_{0,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$;

5.6.1.1.5 $SCT_{0,b}$, which designates the schedule of the combustion turbine *resource* associated with the *pseudo-unit* at bus $b \in B^{PSU}$;

5.6.1.1.6 $SST_{0,p}$, which designates the schedule of steam turbine *resource* $p \in PST$;

5.6.1.1.7 $SIG_{0,d,k}$, which designates the amount of *energy* that a *boundary entity resource is* scheduled to import from *intertie zone* bus $d \in DI$;

5.6.1.2 The initial schedules for *non-quick start resources* shall be determined to align with the commitment status logic described in section 5.6.2.

5.6.2 The following parameters designate the initial commitment status and number of hours in operation used for hour 0 in the optimization of the next *dispatch day*:

5.6.2.1 $ODG_{0,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{NQS}$ has been scheduled at or above its *minimum loading point*;

5.6.2.2 $InitOperHrs_b$, which designates the number of consecutive hours at the end of previous day for which the *resource* at bus $b \in B^{NQS}$ was scheduled to operate at or above its *minimum loading point*. For *resources* with $ODG_{0,b} = 0$, $InitOperHrs_b$ shall be set to zero.

5.6.3 Initial Net Interchange Schedule

5.6.3.1 The initial net *interchange schedule* value shall be the difference between all imports to Ontario and all exports from Ontario in the last hour of the previous day. By default, this value will be based on the most recent schedules from the *pre-dispatch calculation engine*.

6 Security Assessment Function

6.1 Interaction between the Security Assessment Function and Optimization Functions

6.1.1 The scheduling and pricing algorithms of the *day-ahead market calculation engine* shall perform multiple iterations of the optimization functions and the *security* assessment function to check for violations of monitored thermal limits and operating *security limits* using the schedules produced by the optimization functions.

6.1.2 As multiple iterations are performed, the transmission constraints produced by the *security* assessment function shall be used by the optimization functions.

6.1.3 All three passes of the *day-ahead market calculation engine* shall use the *security* assessment function.

6.1.4 The *security* assessment function shall use the physical *resource* representation of *combined cycle plants* that are registered as *pseudo-units*.

6.2 Inputs into the Security Assessment Function

6.2.1 The *security* assessment function shall use the following inputs:

6.2.1.1 the *IESO* average and peak *demand* forecasts; and

6.2.1.2 applicable *IESO-controlled grid* information pursuant to section 3A.1 of Chapter 7.

6.2.2 The *security* assessment function shall also use the following outputs of the optimization functions in Pass 1 and Pass 3:

6.2.2.1 the schedules for *dispatchable loads*, *hourly demand response resources*, and *price responsive loads*;

6.2.2.2 the schedules for *non-dispatchable generation resources* and *dispatchable generation resources*;

6.2.2.3 the schedules for *boundary entity resources* at each *intertie zone*; and

6.2.2.4 the net schedules for *virtual transactions* for each *virtual transaction zone*.

6.2.3 The *security* assessment function shall also use the following outputs of the optimization functions in Pass 2:

6.2.3.1 the schedules for *dispatchable loads* and *hourly demand response resources*;

6.2.3.2 the schedules for *non-dispatchable generation resources* and *dispatchable generation resources*; and

6.2.3.3 the schedules for *boundary entity resources* at each *intertie zone*.

6.3 Security Assessment Function Processing

6.3.1 In Pass 1 and Pass 3 of the *day-ahead market calculation engine*, the *security* assessment function shall determine the average province-wide non-*dispatchable demand* forecast for hour h, AFL_h, as follows:

6.3.1.1 determine forecast MW quantities for all *load resources* and losses using the *IESO* average *demand* forecasts for *demand* forecast areas, load distribution factors, the total of the *bid* quantities submitted for virtual *hourly demand response resources* and physical *hourly demand response resources*; and

6.3.1.2 determine AFL_h by adding the forecast MW quantities determined for each *non-dispatchable load,* including forecast MW losses in the *demand* forecast areas.

6.3.2 In Pass 2 of the *day-ahead market calculation engine*, the *security* assessment function shall determine the peak province-wide non-*dispatchable demand* forecast for hour h, PFL_h, as follows:

6.3.2.1 determine forecast MW quantities for all *load resources* and losses using the *IESO* peak *demand* forecasts for *demand* forecast areas, load distribution factors, the total of the *bid* quantities submitted for virtual *hourly demand response resources* and physical *hourly demand response resources*; and

6.3.2.2 determine PFL_h by adding the forecast MW quantities determined for each *non-dispatchable load*, each *price responsive load,* and each *dispatchable load* with no *bid* for *energy,* including forecast MW losses in the *demand* forecast areas.

6.3.3 In Passes 1 and 3 of the *day-ahead market calculation engine*, the security assessment function shall distribute the net schedules for *virtual transactions* in each *virtual transaction zone* to *non-dispatchable loads*, *dispatchable loads*, *hourly demand response resources*, and *price responsive loads* within the *virtual transaction zone* using the weighting factors ($\mathrm{WF}_{\mathrm{h,m,b}}^{\mathrm{VIRT}}$) for *virtual transactions*. In the security assessment function, the total MW quantity allocated to:

6.3.3.1 a *dispatchable load*, an *hourly demand response resource* or a *price responsive load* shall be equal to the schedule determined by the optimization functions plus the amount allocated in the distribution of the net schedules for *virtual transactions*; and

6.3.3.2 a *non-dispatchable load* shall be equal to its forecast MW quantity plus the amount allocated in the distribution of the net schedules for *virtual transactions*.

6.3.4 The *security* assessment function shall perform the following calculations and analyses:

6.3.4.1 A base case solution function shall prepare a power flow solution for each hour. The base case solution function shall select the power system model state applicable to the forecast of conditions for the hour and input schedules.

6.3.4.2 The base case solution function shall use an AC power flow analysis. If the AC power flow analysis fails to converge, the base case solution function shall use a non-linear DC power flow analysis. If the non-linear DC power flow analysis fails to converge, the base case solution function shall use a linear DC power flow analysis.

6.3.4.3 If the AC or non-linear DC power flow analysis converges, continuous thermal limits for all monitored equipment and operating *security limits* shall be monitored to check for pre-contingency limit violations.

6.3.4.4 Violated pre-contingency limits shall be linearized using pre-contingency sensitivity factors and incorporated as constraints for use by the optimization functions.

6.3.4.5 If the linear DC power flow analysis is used, the pre-contingency *security* assessment may develop linear constraints to facilitate the convergence of the AC or non-linear DC power flow analysis in the subsequent iterations.

6.3.4.6 A linear power flow analysis shall be used to simulate contingencies, calculate post-contingency flows and check all monitored equipment for limited-time thermal limit violations.

6.3.4.7 Violated post-contingency limits shall be linearized using post-contingency sensitivity factors and incorporated as constraints for use by the optimization functions.

6.3.4.8 The base case solution shall be used to calculate Ontario *transmission system* losses, marginal loss factors and loss adjustment for each hour. The impact of losses on branches between the *resource* bus and the *resource connection point* to the *IESO-controlled grid* and losses on branches outside Ontario shall be excluded when determining marginal loss factors.

6.3.4.9 The As-Offered Scheduling, Reference Level Scheduling, Mitigated Scheduling, Reliability Scheduling and DAM Scheduling algorithms described in sections 8, 12, 15, 18 and 20, respectively, shall use the marginal loss factors for each hour calculated by the *security* assessment function.

6.3.4.10 The As-Offered Pricing, Reference Level Pricing, Mitigated Pricing, and DAM Pricing algorithms described in sections 9, 13, 16 and 21, respectively, shall use the marginal loss factors used in the last iteration of the optimization function in the corresponding scheduling algorithm.

6.4 Outputs from the Security Assessment Function

6.4.1 The outputs of the *security* assessment function used in the optimization functions include the following:

6.4.1.1 a set of linearized constraints for all violated pre-contingency and post-contingency limits for each hour. The sensitivities and limits associated with the constraints shall be those provided by the most recent *security* assessment function iteration;

6.4.1.2 pre-contingency and post-contingency sensitivity factors for each hour;

6.4.1.3 the marginal loss factors as described in sections 6.3.4.8-6.3.4.10; and

6.4.1.4 loss adjustment quantity for each hour.

7 Pass 1: Market Commitment and Market Power Mitigation Pass

7.1.1 Pass 1 shall use *market participant* and *IESO* inputs and *resource* and system constraints to determine a set of *resource* schedules and commitments. Pass 1 shall consist of the following algorithms and tests:

- the As-Offered Scheduling algorithm described in section 8;
- the As-Offered Pricing algorithm described in section 9;
- the Constrained Area Conditions Test described in section 10;
- the Conduct Test described in section 11;
- the Reference Level Scheduling algorithm described in section 12;
- the Reference Level Pricing algorithm described in section 13;
- the Price Impact Test described in section 14;
- the Mitigated Scheduling algorithm described in section 15; and
- the Mitigated Pricing algorithm described in section 16.

8 As-Offered Scheduling

8.1 Purpose

8.1.1 The As-Offered Scheduling algorithm shall perform a *security*-constrained unit commitment and economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants* to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day*.

8.2 Information, Sets, Indices and Parameters

8.2.1 Information, sets, indices and parameters used by the As-Offered Scheduling algorithm are described in sections 3 and 4.

8.3 Variables and Objective Function

8.3.1 The As-Offered Scheduling algorithm shall solve for the following variables:

8.3.1.1 $SPRL_{h,b,j}$, which designates the amount of *energy* that a *price responsive load* is scheduled to consume at bus $b \in B^{PRL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$;

8.3.1.2 $SDL_{h,b,j}$, which designates the amount of *energy* that a *dispatchable load* is scheduled to consume at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$;

8.3.1.3 $S10SDL_{h,b,j}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10S}_{h,b}$;

8.3.1.4 $S10NDL_{h,b,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10N}_{h,b}$;

8.3.1.5 $S30RDL_{h,b,j}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{30R}_{h,b}$;

8.3.1.6 $SHDR_{h,b,j}$, which designates the amount of *energy* reduction scheduled for an *hourly demand response resource* at bus $b \in B^{HDR}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$;

8.3.1.7 $SVB_{h,v,j}$, which designates the amount of *energy* a *virtual zonal resource* $v \in VB$ is scheduled to withdraw in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,v}$;

8.3.1.8 $SXL_{h,d,j}$, which designates the amount of *energy* a *boundary entity resource* is scheduled to export at bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,d}$;

8.3.1.9 $S10NXL_{h,d,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* scheduled that a *boundary entity resource* is scheduled to provide at bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10N}_{h,d}$;

8.3.1.10 $S30RXL_{h,d,j}$, which designates the amount of *thirty-minute operating reserve* scheduled that a *boundary entity resource* is scheduled to provide at bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{30R}_{h,d}$;

8.3.1.11 $SNDG_{h,b,k}$, which designates the amount of *energy* that a *non-dispatchable generation resource* is scheduled to provide at bus $b \in B^{NDG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,b}$;

8.3.1.12 $SDG_{h,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDG_b$ at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,b}$;

8.3.1.13 $ODG_{h,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ has been scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$;

8.3.1.14 $IDG_{h,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ has been scheduled to reach its *minimum loading point* in hour $h \in \{1,..,24\}$;

8.3.1.15 $S10SDG_{h,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$;

8.3.1.16 $S10NDG_{h,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$;

8.3.1.17 $S30RDG_{h,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,b}$;

8.3.1.18 $SCT_{h,b}$, which designates the schedule of the combustion turbine *resource* associated with the *pseudo-unit* at bus $b \in B^{PSU}$ in hour $h \in \{1, . . , 24\}$;

8.3.1.19 $SST_{h,p}$, which designates the schedule of steam turbine *resource* $p \in PST$ in hour $h \in \{1, . . , 24\}$;

8.3.1.20 $O10R_{h,b}$, which designates whether the *pseudo-unit* at bus $b \in B^{NO10DF}$ has been scheduled for *ten-minute operating reserve* in hour $h \in \{1, . . , 24\}$;

8.3.1.21 $OHO_{h,b}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1, . . , 24\}$;

8.3.1.22 $OFR_{h,b,i}$ for $i \in \{1, . . , NFor_b\}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or below $ForL_{b,i}$, or, at or above $ForU_{b,i}$ in hour $h \in \{1, . . , 24\}$;

8.3.1.23 $IHE_{h,b,i}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ registered a start between hours $(h - 1)$ and $h \in \{1, . . , 24\}$ as a result of its schedule increasing from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$ for $i \in \{1, . . , NStartMW_b\}$;

8.3.1.24 $SVO_{h,v,k}$, which designates the amount of *energy* a *virtual zonal resource* $v \in VO$ is scheduled to inject in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{E}_{h,v}$;

8.3.1.25 $SIG_{h,d,k}$, which designates the amount of *energy* that a *boundary entity resource is* scheduled to import from *intertie zone* bus $d \in DI$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{E}_{h,d}$;

8.3.1.26 $S10NIG_{h,d,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *boundary entity resource* is scheduled to provide from *intertie zone* bus $d \in DI$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{10N}_{h,d}$;

8.3.1.27 $S30RIG_{h,d,k}$, which designates the amount of *thirty-minute operating reserve* that a *boundary entity resource* is scheduled to provide from *intertie zone* bus $d \in DI$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{30R}_{h,d}$;

8.3.1.28 TB_h, which designates any adjustment to the objective function to facilitate pro-rata tie-breaking in hour $h \in \{1,..,24\}$, as described in section 8.3.2.1; and

8.3.1.29 $ViolCost_h$, which designates the cost incurred in order to avoid having the schedules violate constraints for hour $h \in \{1,..,24\}$, as described in section 8.3.2.3.

8.3.2 The objective function for the As-Offered Scheduling algorithm shall maximize gains from trade by maximizing the following expression:

$$\sum_{h=1,..,24} \begin{pmatrix} ObjPRL_h + ObjDL_h - ObjHDR_h + ObjVB_h + ObjXL_h - ObjNDG_h \\ - ObjDG_h - ObjVO_h - ObjIG_h - TB_h - ViolCost_h \end{pmatrix}$$

Where

$$ObjPRL_h = \sum_{b \in B^{PRL}} \left(\sum_{j \in J^E_{h,b}} SPRL_{h,b,j} \cdot PPRL_{h,b,j} \right)$$

$$ObjDL_h = \sum_{b \in B^{DL}} \begin{pmatrix} \sum_{j \in J^E_{h,b}} SDL_{h,b,j} \cdot PDL_{h,b,j} - \sum_{j \in J^{10S}_{h,b}} S10SDL_{h,b,j} \cdot P10SDL_{h,b,j} - \\ \sum_{j \in J^{10N}_{h,b}} S10NDL_{h,b,j} \cdot P10NDL_{h,b,j} - \sum_{j \in J^{30R}_{h,b}} S30RDL_{h,b,j} \cdot P30RDL_{h,b,j} \end{pmatrix}$$

$$ObjHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J^E_{h,b}} SHDR_{h,b,j} \cdot PHDR_{h,b,j} \right)$$

$$ObjVB_h = \sum_{v \in VB} \left(\sum_{j \in J^E_{h,v}} SVB_{h,v,j} \cdot PVB_{h,v,j} \right)$$

$$ObjXL_h = \sum_{d \in DX} \begin{pmatrix} \sum_{j \in J^E_{h,d}} SXL_{h,d,j} \cdot PXL_{h,d,j} - \sum_{j \in J^{10N}_{h,d}} S10NXL_{h,d,j} \cdot P10NXL_{h,d,j} \\ - \sum_{j \in J^{30R}_{h,d}} S30RXL_{h,d,j} \cdot P30RXL_{h,d,j} \end{pmatrix}$$

$$ObjNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K^E_{h,b}} SNDG_{h,b,k} \cdot PNDG_{h,b,k} \right)$$

$$ObjDG_h = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \cdot PDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \cdot P10SDG_{h,b,k} + \\ \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \cdot P10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \cdot P30RDG_{h,b,k} \end{array} \right) + \sum_{b \in B^{NQS}} \left(ODG_{h,b} \cdot MGODG_{h,b} + IDG_{h,b} \cdot SUDG_{h,b} \right)$$

$$ObjVO_h = \sum_{v \in VO} \left(\sum_{k \in K_{h,v}^{E}} SVO_{h,v,k} \cdot PVO_{h,v,k} \right)$$

$$ObjIG_h = \sum_{d \in DI} \left(\begin{array}{c} \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \cdot PIG_{h,d,k} + \sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \cdot P10NIG_{h,d,k} \\ + \sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \cdot P30RIG_{h,d,k} \end{array} \right)$$

8.3.2.1 The tie-breaking term (TB_h) shall sum a term for each *bid* or *offer* lamination. For each lamination, this term shall be the product of a small penalty cost and the quantity of the lamination scheduled. The penalty cost shall be calculated by multiplying a base penalty cost of $TBPen$ by the amount of the lamination scheduled and then dividing by the maximum amount that could have been scheduled. That is:

$$TB_h = TBPRL_h + TBDL_h + TBHDR_h + TBVB_h + TBXL_h + TBNDG_h + TBDG_h + TBVO_h + TBIG_h$$

Where:

$$TBPRL_h = \sum_{b \in B^{PRL}} \left(\sum_{j \in J_{h,b}^{E}} \frac{\left(SPRL_{h,b,j}\right)^2 \cdot TBPen}{QPRL_{h,b,j}} \right);$$

$$TBDL_h = \sum_{b \in B^{DL}} \left(\begin{array}{c} \sum_{j \in J_{h,b}^{E}} \left(\frac{\left(SDL_{h,b,j}\right)^2 \cdot TBPen}{QDL_{h,b,j}} \right) + \sum_{j \in J_{h,b}^{10S}} \left(\frac{\left(S10SDL_{h,b,j}\right)^2 \cdot TBPen}{Q10SDL_{h,b,j}} \right) + \\ \sum_{j \in J_{h,b}^{10N}} \left(\frac{\left(S10NDL_{h,b,j}\right)^2 \cdot TBPen}{Q10NDL_{h,b,j}} \right) + \sum_{j \in J_{h,b}^{30R}} \left(\frac{\left(S30RDL_{h,b,j}\right)^2 \cdot TBPen}{Q30RDL_{h,b,j}} \right) \end{array} \right);$$

$$TBHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J_{h,b}^{E}} \frac{\left(SHDR_{h,b,j}\right)^2 \cdot TBPen}{QHDR_{h,b,j}} \right);$$

$$TBVB_h = \sum_{v \in VB} \left(\sum_{j \in J_{h,v}^{E}} \frac{\left(SVB_{h,v,j}\right)^2 \cdot TBPen}{QVB_{h,v,j}} \right);$$

$$TBXL_h = \sum_{d \in \mathrm{DX}} \left(\begin{array}{c} \sum_{j \in J_{h,d}^{E}} \left(\frac{\left(SXL_{h,d,j}\right)^2 \cdot TBPen}{QXL_{h,d,j}} \right) + \sum_{j \in J_{h,d}^{10N}} \left(\frac{\left(S10NXL_{h,d,j}\right)^2 \cdot TBPen}{Q10NXL_{h,d,j}} \right) \\ + \sum_{j \in J_{h,d}^{30R}} \left(\frac{\left(S30RXL_{h,d,j}\right)^2 \cdot TBPen}{Q30RXL_{h,d,j}} \right) \end{array} \right);$$

$$TBNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{h,b}^{E}} \left(\frac{\left(SNDG_{h,b,k}\right)^2 \cdot TBPen}{QNDG_{h,b,k}} \right) \right);$$

$$TBDG_h = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{E}} \left(\frac{\left(SDG_{h,b,k}\right)^2 \cdot TBPen}{QDG_{h,b,k}} \right) + \sum_{k \in K_{h,b}^{10S}} \left(\frac{\left(S10SDG_{h,b,k}\right)^2 \cdot TBPen}{Q10SD_{h,b,k}} \right) + \\ \sum_{k \in K_{h,b}^{10N}} \left(\frac{\left(S10NDG_{h,b,k}\right)^2 \cdot TBPen}{Q10NDG_{h,b,k}} \right) + \sum_{k \in K_{h,b}^{30R}} \left(\frac{\left(S30RDG_{h,b,k}\right)^2 \cdot TBPen}{Q30RDG_{h,b,k}} \right) \end{array} \right);$$

$$TBVO_h = \sum_{v \in VO} \left(\sum_{k \in K_{h,v}^{E}} \frac{\left(SVO_{h,v,k}\right)^2 \cdot TBPen}{QVO_{h,v,k}} \right);$$

and

$$TBIG_h = \sum_{d \in \mathrm{DI}} \left(\sum_{k \in K^{E}_{h,d}} \left(\frac{\left(SIG_{h,d,k}\right)^2 \cdot TBPen}{QIG_{h,d,k}} \right) + \sum_{k \in K^{10N}_{h,d}} \left(\frac{\left(S10NIG_{h,d,k}\right)^2 \cdot TBPen}{Q10NIG_{h,d,k}} \right) + \sum_{k \in K^{30R}_{h,d}} \left(\frac{\left(S30RIG_{h,d,k}\right)^2 \cdot TBPen}{Q30RIG_{h,d,k}} \right) \right).$$

8.3.2.2 $ViolCost_h$ shall be calculated for hour $h \in \{1,..,24\}$ using the following variables:

8.3.2.2.1 $SLdViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{LdViol_h}\}$ of the penalty curve for the *energy* balance constraint allowing under-generation;

8.3.2.2.2 $SGenViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{GenViol_h}\}$ of the penalty curve for the *energy* balance constraint allowing over-generation;

8.3.2.2.3 $S10SViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{10SViol_h}\}$ of the penalty curve for the synchronized *ten-minute operating reserve* requirement;

8.3.2.2.4 $S10RViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{10RViol_h}\}$ of the penalty curve for the total *ten-minute operating reserve* requirement;

8.3.2.2.5 $S30RViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,.., N_{30RViol_h}\}$ of the penalty curve for the *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement;

8.3.2.2.6 $SREG10RViol_{r,h,i}$, which designates the violation variable associated with segment $i \in \{1,.., N_{REG10RViol_h}\}$ of the penalty curve for violating the area total *ten-minute* *operating reserve* minimum requirement in region $r \in ORREG$;

8.3.2.2.7 $SREG30RViol_{r,h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{REG30RViol_h}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* minimum requirement in region $r \in ORREG$;

8.3.2.2.8 $SXREG10RViol_{r,h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{XREG10RViol_h}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* maximum restriction in region $r \in ORREG$;

8.3.2.2.9 $SXREG30RViol_{r,h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{XREG30RViol_h}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* maximum restriction in region $r \in ORREG$;

8.3.2.2.10 $SPreITLViol_{f,h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{PreITLViol_{f,h}}\}$ of the penalty curve for violating the pre-contingency transmission limit for *facility* $f \in F$;

8.3.2.2.11 $SITLViol_{c,f,h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$ of the penalty curve for violating the post-contingency transmission limit for *facility* $f \in F$ and contingency $c \in C$;

8.3.2.2.12 $SPreXTLViol_{z,h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ of the penalty curve for violating the import/export limit associated with *intertie* limit constraint $z \in Z_{Sch}$;

8.3.2.2.13 $SNIUViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{NIUViol_h}\}$ of the penalty curve for exceeding the net interchange increase limit between hours $(h-1)$ and h;

8.3.2.2.14 $SNIDViol_{h,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{NIDViol_h}\}$ of the penalty curve for exceeding the net interchange decrease limit between hours $(h-1)$ and h;

8.3.2.2.15 $SMaxDelViol_{h,b,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{MaxDelViol_h}\}$ of the penalty curve for exceeding the *maximum daily energy limit* constraint for a *resource* at bus $b \in B^{ELR}$;

8.3.2.2.16 $SMinDelViol_{h,b,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{MinDelViol_h}\}$ of the penalty curve for violating the *minimum daily energy limit* constraint for a *resource* at bus $b \in B^{HE}$;

8.3.2.2.17 $SSMaxDelViol_{h,s,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{SMaxDelViol_h}\}$ of the penalty curve for exceeding the shared *maximum daily energy limit* constraint for *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

8.3.2.2.18 $SSMinDelViol_{h,s,i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{SMinDelViol_h}\}$ of the penalty curve for violating the shared *minimum daily energy limit* constraint for *dispathable* hydroelectric *generation resources* in set $s \in SHE$;

8.3.2.2.19 $SOGenLnkViol_{h,(b_1,b_2),i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{OGenLnkViol_h}\}$ of the penalty curve for violating the linked *dispatchable* hydroelectric *generation resources* constraint by over-generating the downstream *resource*, for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$; and

8.3.2.2.20 $SUGenLnkViol_{h,(b_1,b_2),i}$, which designates the violation variable associated with segment $i \in \{1,..,N_{UGenLnkViol_h}\}$ of the penalty curve for violating the linked *dispatchable* hydroelectric *generation resources* constraint by under-generating the downstream *resource*, for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$.

8.3.2.3 $ViolCost_h$ shall be calculated as follows:

$$
\begin{aligned}
ViolCost_h = & \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \cdot PLdViolSch_{h,i} \\
& - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} \cdot PGenViolSch_{h,i} \\
& + \sum_{i=1..N_{10SViol_h}} S10SViol_{h,i} \cdot P10SViolSch_{h,i} \\
& + \sum_{i=1..N_{10RViol_h}} S10RViol_{h,i} \cdot P10RViolSch_{h,i} \\
& + \sum_{i=1..N_{30RViol_h}} S30RViol_{h,i} \cdot P30RViolSch_{h,i} \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG10RViol_h}} SREG10RViol_{r,h,i} \cdot PREG10RViolSch_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG30RViol_h}} SREG30RViol_{r,h,i} \cdot PREG30RViolSch_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG10RViol_h}} SXREG10RViol_{r,h,i} \cdot PXREG10RViolSch_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG30RViol_h}} SXREG30RViol_{r,h,i} \cdot PXREG30RViolSch_{h,i} \right) \\
& + \sum_{f \in F_h} \left(\sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} \cdot PPreITLViolSch_{f,h,i} \right) \\
& + \sum_{c \in C} \sum_{f \in F_{h,c}} \left(\sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \right.
\end{aligned}
$$

$$
\begin{aligned}
& \cdot PITLViolSch_{c,f,h,i}\Bigg) \\
& + \sum_{z \in Z_{Sch}} \left(\sum_{i=1..N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} \right. \\
& \left. \cdot PPreXTLViolSch_{z,h,i} \right) \\
& + \sum_{i=1..N_{NIUViol_h}} SNIUViol_{h,i} \cdot PNIUViolSch_{h,i} \\
& + \sum_{i=1..N_{NIDViol_h}} SNIDViol_{h,i} \cdot PNIDViolSch_{h,i} \\
& + \sum_{b \in B^{ELR}} \left(\sum_{i=1..N_{MaxDelViol_h}} SMaxDelViol_{h,b,i} \right. \\
& \left. \cdot PMaxDelViolSch_{h,i} \right) \\
& + \sum_{b \in B^{HE}} \left(\sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i} \cdot PMinDelViolSch_{h,i} \right) \\
& + \sum_{s \in \mathrm{SHE}} \left(\sum_{i=1..N_{SMaxDelViol_h}} SSMaxDelViol_{h,s,i} \cdot PSMaxDelViolSch_{h,i} \right) \\
& + \sum_{s \in \mathrm{SHE}} \left(\sum_{i=1..N_{SMinDelViol_h}} SSMinDelViol_{h,s,i} \cdot PSMinDelViolSch_{h,i} \right) \\
& + \sum_{(b_1,b_2) \in LNK} \left(\sum_{i=1..N_{OGenLnkViol_h}} SOGenLnkViol_{h,(b_1,b_2),i} \right. \\
& \left. \cdot POGenLnkViolSch_{h,i} \right) \\
& + \sum_{(b_1,b_2) \in LNK} \left(\sum_{i=1..N_{UGenLnkViol_h}} SUGenLnkViol_{h,(b_1,b_2),i} \right. \\
& \left. \cdot PUGenLnkViolSch_{h,i} \right).
\end{aligned}
$$

8.4 Constraints

8.4.1 The constraints described in sections 8.5, 8.6 and 8.7 apply to the optimization function in the As-Offered Scheduling algorithm.

8.5 Dispatch Data Constraints Applying to Individual Hours

8.5.1 Scheduling Variable Bounds

8.5.1.1 A Boolean variable, $ODG_{h,b}$, shall indicate whether the *resource* at bus $b \in B^{DG}$ is committed in hour $h \in \{1,..,24\}$. A value of zero shall indicate that a *resource* is not committed, while a value of one shall indicate that it is committed. Therefore:

8.5.1.1.1 $ODG_{h,b} \in \{0,1\}$ for all hours $h \in \{1, . . , 24\}$ and all buses $b \in B^{DG}$.

8.5.1.2 *Reliability must-run resources* shall be considered committed for all must-run hours.

8.5.1.3 *Resources* providing *regulation* are considered committed for all the hours that they are regulating.

8.5.1.4 *Dispatchable generation resources* that have *minimum loading points*, *start-up offers*, *speed no-load offers*, *minimum generation block run-times* and *minimum generation block down-times* equal to zero shall be considered committed for all hours.

8.5.1.5 If the *dispatchable generation resource* at bus $b \in B^{DG}$ is considered committed according to the requirements in sections 8.5.1.2, 8.5.1.3, and 8.5.1.4 in hour $h \in \{1,..,24\}$, then:

$$ODG_{h,b} = 1.$$

8.5.1.6 No schedule shall be negative, nor shall any schedule exceed the quantity *offered* for the respective *energy* and *operating reserve* market. Therefore:

$$0 \le SPRL_{h,b,j} \le QPRL_{h,b,j} \quad \text{for all } b \in B^{PRL}, j \in J^{E}_{h,b};$$

$$0 \le SDL_{h,b,j} \le QDL_{h,b,j} \quad \text{for all } b \in B^{DL}, j \in J^{E}_{h,b};$$

$$0 \le S10SDL_{h,b,j} \le Q10SDL_{h,b,j} \quad \text{for all } b \in B^{DL}, j \in J^{10S}_{h,b};$$

$$0 \le S10NDL_{h,b,j} \le Q10NDL_{h,b,j} \quad \text{for all } b \in B^{DL}, j \in J^{10N}_{h,b};$$

$0 \leq S30RDL_{h,b,j} \leq Q30RDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{30R}_{h,b}$;

$0 \leq SHDR_{h,b,j} \leq QHDR_{h,b,j}$ for all $b \in B^{HDR}$, $j \in J^{E}_{h,b}$;

$0 \leq SVB_{h,v,j} \leq QVB_{h,v,j}$ for all $v \in VB$, $j \in J^{E}_{h,v}$;

$0 \leq SXL_{h,d,j} \leq QXL_{h,d,j}$ for all $d \in DX$, $j \in J^{E}_{h,d}$;

$0 \leq S10NXL_{h,d,j} \leq Q10NXL_{h,d,j}$ for all $d \in DX$, $j \in J^{10N}_{h,d}$;

$0 \leq S30RXL_{h,d,j} \leq Q30RXL_{h,d,j}$ for all $d \in DX$, $j \in J^{30R}_{h,d}$;

$0 \leq SNDG_{h,b,k} \leq QNDG_{h,b,k}$ for all $b \in B^{NDG}$, $k \in K^{E}_{h,b}$;

$0 \leq SVO_{h,v,k} \leq QVO_{h,v,k}$ for all $v \in VO$, $k \in K^{E}_{h,v}$;

$0 \leq SIG_{h,d,k} \leq QIG_{h,d,k}$ for all $d \in DI$, $k \in K^{E}_{h,d}$;

$0 \leq S10NIG_{h,d,k} \leq Q10NIG_{h,d,k}$ for all $d \in DI$, $k \in K^{10N}_{h,d}$; and

$0 \leq S30RIG_{h,d,k} \leq Q30RIG_{h,d,k}$ for all $d \in DI$, $k \in K^{30R}_{h,d}$

for all hours $h \in \{1, . . . , 24\}$.

8.5.1.7 *Generation resources* may be scheduled for *energy* and/or *operating reserve* only if $ODG_{h,b} = 1$. Therefore, for all hours $h \in \{1, . . , 24\}$:

$0 \leq SDG_{h,b,k} \leq ODG_{h,b} \cdot QDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{E}_{h,b}$;

$0 \leq S10SDG_{h,b,k} \leq ODG_{h,b} \cdot Q10SDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{10S}_{h,b}$;

$0 \leq S10NDG_{h,b,k} \leq ODG_{h,b} \cdot Q10NDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{10N}_{h,b}$; and

$0 \leq S30RDG_{h,b,k} \leq ODG_{h,b} \cdot Q30RDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{30R}_{h,b}$.

8.5.2 Resource Minimums and Maximums for Energy

8.5.2.1 The non-*dispatchable* portion of *price responsive loads* shall always be scheduled. For all hours $h \in \{1, . . ,24\}$ and all buses $b \in B^{PRL}$:

$$\sum_{j \in J^{E}_{h,b}} SPRL_{h,b,j} \geq QPRLFIRM_{h,b}.$$

8.5.2.2 A constraint shall limit schedules for *dispatchable loads* within their minimum and maximum consumption for an hour. For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$MinDL_{h,b} \leq \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} \leq MaxDL_{h,b}.$$

8.5.2.3 The non-*dispatchable* portion of *dispatchable loads* shall always be scheduled. For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} \geq QDLFIRM_{h,b}.$$

8.5.2.4 A constraint shall limit schedules for *non-dispatchable generation resources* within their minimum and maximum output for an hour. For all hours $h \in \{1, . . . , 24\}$ and all buses $b \in B^{NDG}$:

$$MinNDG_{h,b} \leq \sum_{k \in K_{h,b}^{E}} SNDG_{h,b,k} \leq MaxNDG_{h,b}.$$

8.5.2.5 A constraint shall limit schedules for *dispatchable generation resources* within their minimum and maximum output for an hour. For a *dispatchable variable generation resource,* the maximum schedule shall be limited by its forecast. That is:

For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$,

$$AdjMaxDG_{h,b} = \begin{cases} \min\left(MaxDG_{h,b}, AFG_{h,b}\right) & if\ b\ \in B^{VG} \\ MaxDG_{h,b} & otherwise \end{cases}$$

and

$$AdjMinDG_{h,b} = min(MinDG_{h,b}, AdjMaxDG_{h,b}).$$

For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{h,b} \leq MinQDG_{b} \cdot ODG_{h,b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq AdjMaxDG_{h,b}.$$

8.5.2.6 If the commitment status, $ODG_{h,b}$, of a *dispatchable generation resource* is equal to 1 and if this status is inconsistent with the adjusted minimum and maximum constraints, $MinQDG_b > AdjMaxDG_{h,b}$, then $ODG_{h,b}$ shall be changed to a value between 0 and 1.

8.5.2.7 If the total *offered* quantity does not exceed the minimum constraint for the *resource*, $MinQDG_b + \sum_{k\in K^E_{h,b}} QDG_{h,b,k} < AdjMinDG_{h,b}$, then the *resource* shall receive a schedule of zero.

8.5.3 Off-Market Transactions

8.5.3.1 For all hours $h \in \{1,..,24\}$ and all *intertie zone* buses corresponding to an inadvertent *energy* payback export transaction $d \in DX^{INP}_h$:

$$\sum_{j\in J^E_{h,d}} SXL_{h,d,j} = \sum_{j\in J^E_{h,d}} QXL_{h,d,j}.$$

8.5.3.2 For all hours $h \in \{1, . . , 24\}$ and all *intertie zone* buses corresponding to an inadvertent *energy* payback import transaction $d \in DI^{INP}_h$:

$$\sum_{k\in K^E_{h,d}} SIG_{h,d,k} = \sum_{k\in K^E_{h,d}} QIG_{h,d,k}.$$

8.5.3.3 For all hours $h \in \{1, . . , 24\}$ and all *intertie zone* buses corresponding to an *emergency energy* export $d \in DX^{EM}_h$:

$$\sum_{j\in J^E_{h,d}} SXL_{h,d,j} = \sum_{j\in J^E_{h,d}} QXL_{h,d,j}.$$

8.5.3.4 For all hours $h \in \{1, . . , 24\}$ and all *intertie zone* buses corresponding to *emergency energy* import $d \in DI^{EM}_h$:

$$\sum_{k\in K^E_{h,d}} SIG_{h,d,k} = \sum_{k\in K^E_{h,d}} QIG_{h,d,k}.$$

8.5.4 Operating Reserve Requirements

8.5.4.1 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled from a *dispatchable load* shall not exceed:

8.5.4.1.1 the *dispatchable load's* ramp capability over 30 minutes;

8.5.4.1.2 the total scheduled load less the non-*dispatchable* portion; and

8.5.4.1.3 the remaining portion of its capacity that is *dispatchable* after considering minimum load consumption constraints.

These restrictions shall be enforced by the following constraints for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq 30 \cdot ORRDL_b;$$

$$\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} - QDLFIRM_{h,b};$$

and

$$\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} - MinDL_{h,b}$$

8.5.4.2 The amount of both synchronized and non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide shall not exceed the amount by which the *dispatchable load* can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This restriction shall be enforced by the following constraint for all hours $h \in \{1, . . . , 24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \leq 10 \cdot ORRDL_b$$

8.5.4.3 The total non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled for an hour shall not exceed total scheduled exports. This restriction shall be enforced by the following constraint for all hours $h \in \{1, . . . , 24\}$ and all *intertie zone* export buses $d \in DX$:

$$\sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} + \sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \leq \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j}$$

8.5.4.4 The total *operating reserve* scheduled from a committed *dispatchable generation resource* shall not exceed that *resource*'s: (i) ramp capability over 30 minutes; (ii) remaining capacity; and (iii) unscheduled capacity. These restrictions shall be enforced by the following constraints for all hours $h \in \{1, . . . , 24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq 30 \cdot ORRDG_b;$$

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \sum_{k \in K_{h,b}^{E}} (QDG_{h,b,k} - SDG_{h,b,k});$$

and

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq AdjMaxDG_{h,b} - \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} - MinQDG_b$$

8.5.4.5 The amount of both synchronized and non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall not exceed the amount by which the *resource* can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This restriction shall be enforced by the following constraint for all hours $h \in \{1, . . . , 24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \leq 10 \cdot ORRDG_b$$

8.5.4.6 The amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* may be scheduled to provide shall be limited by its *reserve loading point* for synchronized *ten-minute operating reserve*. This restriction shall be enforced by the following constraint for all hours $h \in \{1, . . . , 24\}$ and all buses $b \in B^{DG}$ with $RLP10S_{h,b} > 0$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \leq \left(MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \right) \cdot \left(\frac{1}{RLP10S_{h,b}} \right) \cdot \left(min \left\{ 10 \cdot ORRDG_b, \sum_{k \in K_{h,b}^{10S}} Q10SDG_{h,b,k} \right\} \right)$$

8.5.4.7 The amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be limited by its *reserve loading point* for *thirty-minute operating reserve*. This restriction shall be enforced by the following constraint for all hours $h \in \{1, . . . , 24\}$ and all buses $b \in B^{DG}$ with $RLP30R_{h,b} > 0$:

$$\sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \left(MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \right) \cdot \left(\frac{1}{RLP30R_{h,b}} \right) \cdot \left(min \left\{ 30 \cdot ORRDG_b, \sum_{k \in K_{h,b}^{30R}} Q30RDG_{h,b,k} \right\} \right)$$

8.5.4.8 The total non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled for an hour shall not exceed the remaining maximum import *offers* minus scheduled *energy* imports. This restriction shall be enforced by the following constraint for all hours $h \in \{1, . . , 24\}$ and all *intertie zone* import buses $d \in DI$:

$$\sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} + \sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \leq \sum_{k \in K_{h,d}^{E}} (QIG_{h,d,k} - SIG_{h,d,k})$$

8.5.5 Pseudo-Units

8.5.5.1 A constraint shall be required to calculate physical *generation resource* schedules from *pseudo-unit* schedules using the steam turbine *resource* shares in the operating regions of the *pseudo-unit* determined in section 22. For all hours $h \in \{1, . . , 24\}$ and *pseudo-unit* buses $b \in B^{PSU}$:

$$SCT_{h,b} = (1 - STShareMLP_b) \cdot MinQDG_b \cdot ODG_{h,b} + (1 - STShareDR_b) \cdot \left(\sum_{k \in K_{h,b}^{DR}} SDG_{h,b,k} \right),$$

and for all hours $h \in \{1, . . , 24\}$ and steam turbine *resources* $p \in PST$:

$$SST_{h,p} = \sum_{b \in B_p^{ST}} \left(\begin{array}{c} STShareMLP_b \cdot MinQDG_b \cdot ODG_{h,b} + \\ STShareDR_b \cdot \left(\sum_{k \in K_{h,b}^{DR}} SDG_{h,b,k} \right) + \sum_{k \in K_{h,b}^{DF}} SDG_{h,b,k} \end{array} \right)$$

8.5.5.2 Maximum constraints shall be enforced on the operating region to which they apply for both *energy* and *operating reserve* schedules. For all hours $h \in \{1, . . , 24\}$ and *pseudo-unit* buses $b \in B^{PSU}$:

$$MinQDG_b \cdot ODG_{h,b} \leq MaxMLP_{h,b},$$

$$\sum_{k \in K_{h,b}^{DR}} SDG_{h,b,k} \leq MaxDR_{h,b},$$

$$\sum_{k \in K_{h,b}^{DF}} SDG_{h,b,k} \leq MaxDF_{h,b},$$

and

$$\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq MaxDR_{h,b} + MaxDF_{h,b}$$

8.5.5.3 For a *pseudo-unit* that cannot provide *ten-minute operating reserve* from its duct firing region, constraints shall limit the *pseudo-unit* from being scheduled in its duct firing region whenever the *pseudo-unit* is scheduled for *ten-minute operating reserve.* For all hours $h \in \{1, . . . , 24\}$ and *pseudo-unit* buses $b \in B^{NO10DF}$:

$$O10R_{h,b} \in \{0,1\}$$

$$\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \leq MaxDR_{h,b} + (1 - O10R_{h,b}) \cdot MaxDF_{h,b}$$

and

8.5.5.4 For all hours $h \in \{1, . . . , 24\}$, *pseudo-unit* buses $b \in B^{NO10DF}$, and laminations $k \in K_{h,b}^{10S}$:

$$S10SDG_{h,b,k} \leq O10R_{h,b} \cdot Q10SDG_{h,b,k}$$

8.5.5.5 For all hours $h \in \{1, . . . , 24\}$, *pseudo-unit* buses $b \in B^{NO10DF}$, and laminations $k \in K_{h,b}^{10N}$:

$$S10NDG_{h,b,k} \leq O10R_{h,b} \cdot Q10NDG_{h,b,k}$$

8.5.5.6 For the purposes of the *energy* balance constraint in section 8.7.1 and the transmission constraints in section 8.7.3, the combustion turbine *resource's* schedule for the *pseudo-unit* at bus $b \in B^{PSU}$ in hour $h \in \{1, . . , 24\}$ shall be equal to:

8.5.5.6.1 $\mathrm{SCT_{h,b}}$ if the *pseudo-unit* is scheduled at or above *minimum loading point*,

8.5.5.6.2 $RampCT_{b,w}$ if the *pseudo-unit* is scheduled to reach *minimum loading point* in hour $(h + w)$ for $w \in \{1,..,\mathrm{RampHrs_b}\}$, or

8.5.5.6.3 0 otherwise.

8.5.5.7 For the purposes of the *energy* balance constraint in section 8.7.1 and the transmission constraints in section 8.7.3, the steam turbine *resource's* schedule for $p \in PST$ shall be equal to $SST_{h,p}$ plus any contribution from *pseudo-unit* $b \in B_p^{ST}$ ramping to *minimum loading point* as given by $RampST_{b,w}$ for a *pseudo-unit* scheduled to reach *minimum loading point* in hour $(h + w)$ for $w \in \{1, . . , RampHrs_b\}$.

8.5.6 Dispatchable Hydroelectric Generation Resources

8.5.6.1 A *dispatchable* hydroelectric *generation resource* shall be scheduled to at least its *hourly must run* quantity. For all hours $h \in \{1, . . , 24\}$ and *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq MinHMR_{h,b}$$

8.5.6.2 A *dispatchable* hydroelectri*c generation resource* shall either be scheduled to 0 or to at least its *minimum hourly output*. For all hours $h \in \{1, . . . , 24\}$ and all *dispatchable* hydroelectri*c generation resource* buses $b \in B^{HE}$

$$OHO_{h,b} \in \{0,1\}\,;$$

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq MinHO_{h,b} \cdot OHO_{h,b};$$

and for all $k \in K_{h,b}^E$:

$$0 \leq SDG_{h,b,k} \leq OHO_{h,b} \cdot QDG_{h,b,k}$$

8.5.6.3 A *dispatchable* hydroelectric *generation resource* shall not be scheduled within its *forbidden regions*. For all hours $h \in \{1, .., 24\}$, all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ and all $i \in \{1, .., NFor_b\}$:

$$OFR_{h,b,i} \in \{0,1\};$$

$$\begin{aligned} ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} &\leq OFR_{h,b,i} \cdot ForL_{b,i} + (1 - OFR_{h,b,i}) \\ &\cdot \left(MinQDG_b + \sum_{k \in K_{h,b}^E} QDG_{h,b,k} \right); \end{aligned}$$

and

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq (1 - OFR_{h,b,i}) \cdot ForU_{b,i}$$

8.5.7 Linked Wheeling Through Transactions

8.5.7.1 The amount of scheduled export *energy* must be equal to the amount of scheduled import *energy* for *linked wheeling through transactions*. For all hours $h \in \{1, .., 24\}$ and all linked *boundary entity resource* buses $(dx, di) \in L_h$:

$$\sum_{j \in J_{h,dx}^E} SXL_{h,dx,j} = \sum_{k \in K_{h,di}^E} SIG_{h,di,k}$$

8.6 Dispatch Data Inter-Hour/Multi-Hour Constraints

8.6.1 Energy Ramping

8.6.1.1 For *disptachable loads*, the constraints in section 8.6.1.5 and section 8.6.2.1 use $URRDL_b$ to represent a ramp up rate selected from $URRDL_{h,b,w}$ and use $DRRDL_b$ to represent a ramp down rate selected from $DRRDL_{h,b,w}$.

8.6.1.2 For *disptachable generation resources*, the constraints in section 8.6.1.7 and section 8.6.2.2 use $URRDG_b$ to represent a ramp up rate selected from $URRDG_{h,b,w}$ and use $DRRDG_b$ to represent a ramp down rate selected from $DRRDG_{h,b,w}$.

8.6.1.3 The *day-ahead market calculation engine* shall respect the ramping restrictions determined by the up to five *offered* MW quantity, ramp up rate and ramp down rate value sets.

8.6.1.4 In all ramping constraints, the schedules for hour 0 are obtained from the initial scheduling assumptions in section 5.6. For all hours $h \in \{1,..,24\}$ the ramping rates in all ramping constraints must be adjusted to allow the applicable *resource* to:

8.6.1.4.1 ramp down from its lower limit in hour $(h-1)$ to its upper limit in hour h; and

8.6.1.4.2 ramp up from its upper limit in hour $(h-1)$ to its lower limit in hour h.

8.6.1.5 *Energy* schedules for *dispatchable loads* cannot vary by more than an hour's ramping capability for the applicable *resource*. This constraint shall be enforced by the following for all hours $h \in \{1,..,24\}$ and buses $b \in B^{DL}$:

$$\sum_{j \in J^E_{h-1,b}} SDL_{h-1,b,j} - 60 \cdot DRRDL_b \leq \sum_{j \in J^E_{h,b}} SDL_{h,b,j} \leq \sum_{j \in J^E_{h-1,b}} SDL_{h-1,b,j} + 60 \cdot URRDL_b$$

8.6.1.6 *Energy* schedules for *hourly demand response resources* cannot vary by more than an hour's ramping capability for the applicable *resource*. This constraint shall be enforced by the following for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{HDR}$:

$$\sum_{j \in J^E_{h-1,b}} (QHDR_{h-1,b,j} - SHDR_{h-1,b,j}) - 60 \cdot URRHDR_b \leq \sum_{j \in J^E_{h,b}} (QHDR_{h,b,j} - SHDR_{h,b,j}) \leq \sum_{j \in J^E_{h-1,b}} (QHDR_{h-1,b,j} - SHDR_{h-1,b,j}) + 60 \cdot DRRHDR_b$$

8.6.1.7 *Energy* schedules for a *dispatchable generation resource* cannot vary by more than an hour's ramping capability for the applicable *resource.* For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

8.6.1.7.1 For the first hour a *resource* reaches its *minimum loading point*, where $ODG_{h,b} = 1$, $ODG_{h\text{-}1,b} = 0$, the following constraint shall be applied:

$$0 \leq \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq 30 \cdot URRDG_b$$

8.6.1.7.2 If the *resource* stays on at or above *minimum loading point* and $ODG_{h,b} = 1,\ ODG_{h\text{-}1,b} = 1$, the following constraint shall be applied:

$$\sum_{k \in K^E_{h-1,b}} SDG_{h-1,b,k} - 60 \cdot DRRDG_b \leq \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq \sum_{k \in K^E_{h-1,b}} SDG_{h-1,b,k} + 60 \cdot URRDG_b$$

8.6.1.7.3 For the last hour the *resource* is scheduled at or above *minimum loading point* before being scheduled off, where $ODG_{h,b} = 1,\ ODG_{h+1,b} = 0$, the following constraint shall be applied:

$$0 \leq \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq 30 \cdot DRRDG_b$$

8.6.1.8 The constraints in sections 8.6.1.6.1 and 8.6.1.6.3 do not apply to a *quick start resource*.

8.6.1.9 For hours where *non-quick start resources* are ramping up to *minimum loading point*, *energy* shall be scheduled using the submitted *ramp up energy to minimum loading point*.

8.6.2 Operating Reserve Ramping

8.6.2.1 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* from *dispatchable loads* shall not exceed their ramp capability to decrease load consumption and for all hours $h \in \{1, .., 24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J^{10S}_{h,b}} S10SDL_{h,b,j} + \sum_{j \in J^{10N}_{h,b}} S10NDL_{h,b,j} + \sum_{j \in J^{30R}_{h,b}} S30RDL_{h,b,j} \leq \sum_{j \in J^E_{h,b}} SDL_{h,b,j} - \sum_{j \in J^E_{h-1,b}} SDL_{h-1,b,j} + 60 \cdot DRRDL_b$$

8.6.2.2 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* from a committed *dispatchable generation resource* shall not exceed its ramp capability to increase generation and for all hours $h \in \{1, . . , 24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \sum_{k \in K_{h-1,b}^{E}} SDG_{h-1,b,k} - \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + 60.URRDG_b;$$

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq [(h-n) \cdot 60 + 30] \cdot URRDG_b \cdot ODG_{h,b}$$

where n is the hour of the last start before or in hour h; and

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq [(m-h) \cdot 60 + 30] \cdot DRRDG_b \cdot ODG_{h,b}$$

where m is the hour of the last shutdown in or after hour h.

8.6.3 Non-Quick Start Resources

8.6.3.1 Schedules for *non-quick start resources* shall not violate such *resources' minimum generation block run-times*, *minimum generation block down-times* and *maximum number of starts per day*.

8.6.3.2 A *resource*'s previous day's schedule shall be evaluated to determine any remaining *minimum generation block run-time* constraints to enforce and determine the commitment status of the *resource* in hour 0. If $0 < InitOperHrs_b < MGBRTDG_b$, then the *resource* at bus $b \in B^{NQS}$ has yet to complete its *minimum generation block run-time*, and:

$$ODG_{1,b}, ODG_{2,b}, \ldots, ODG_{\min(24, MGBRTDG_b - InitOperHrs_b),b} = 1$$

8.6.3.3 If $ODG_{h\text{-}1,b} = 0$, $ODG_{h,b} = 1$, and $MGBRTDG_b > 1$ for hour $h \in \{1, . . , 24\}$, then the *resource* at bus $b \in B^{NQS}$ has been scheduled to start up during hour h and shall be scheduled to remain in operation until it has completed its *minimum generation block run-time* or to the end of the day. Therefore:

$$ODG_{h+1,b}, ODG_{h+2,b}, \dots, ODG_{min(24,h\,+\,MGBRTDG_b-1),b} = 1$$

8.6.3.4 If $ODG_{h\text{-}1,b} = 1$, $ODG_{h,b} = 0$, and $MGBDTDG_b > 1$ for hour $h \in \{1, . . , 24\}$, then the *resource* at bus $b \in B^{NQS}$ has been scheduled to shut down during hour h and shall be scheduled to remain off until it has completed its *minimum generation block down-time* or to the end of the day. Therefore:

$$ODG_{h+1,b}, ODG_{h+2,b}, \dots, ODG_{min(24,h\,+\,MGBDTDG_b-1),b} = 0$$

8.6.3.5 *The day-ahead market calculation engine* shall not consider *start-up offers* for *non-quick start resources* to be scheduled in the first hour of the day if the *resource* is expected to be scheduled as a result of an operational constraint.

8.6.3.6 A Boolean variable, $IDG_{h,b}$ indicates that the *non-quick start resource* at bus $b \in B^{NQS}$ is scheduled to reach its *minimum loading point* in hour $h \in \{1, . . , 24\}$ after being scheduled below its *minimum loading point* in the preceding hour. A value of zero shall indicate that a *resource* is not scheduled to reach its *minimum loading point*, while a value of one indicates that it is scheduled to reach its *minimum loading point.* For all hours $h \in \{1, . . , 24\}$ and all buses $b \in B^{NQS}$:

$$IDG_{h,b} = \begin{cases} 1 & if\ ODG_{h-1,b} = 0\ and\ ODG_{h,b} = 1 \\ 0 & otherwise. \end{cases}$$

8.6.3.7 A *non-quick start resource* shall not be scheduled more than its *maximum number of starts per day*. For all buses $b \in B^{NQS}$:

$$\sum_{h=1..24} IDG_{h,b} \leq MaxStartsDG_b$$

8.6.4 Energy Limited Resources

8.6.4.1 An *energy limited resource* shall not be scheduled to provide:

8.6.4.1.1 more *energy* than the *maximum daily energy limit* specified for such *resource*; or

8.6.4.1.2 *energy* in amounts that would preclude such *resource* from providing *operating reserve* when activated, for all buses $b \in B^{ELR}$ where an *energy limited resource* is located and all hours $H \in \{1,..,24\}$:

$$\sum_{h=1..H}\left(ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k}\right) + 10ORConv\left(\sum_{k \in K^{10S}_{H,b}} S10SDG_{H,b,k} + \sum_{k \in K^{10N}_{H,b}} S10NDG_{H,b,k}\right) + 30ORConv\left(\sum_{k \in K^{30R}_{H,b}} S30RDG_{H,b,k}\right) - \sum_{i=1..N_{MaxDelViol_H}} SMaxDelViol_{H,b,i} \leq MaxDEL_b$$

where the factors $10ORConv$ and $30ORConv$ are applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* for *energy limited resources* to convert MW into MWh. Violation variables for over-scheduling a *resource's maximum daily energy limit* may be used to allow the *day-ahead market calculation engine* to find a solution.

8.6.5 Dispatchable Hydroelectric Generation Resources

8.6.5.1 *Dispatchable* hydroelectric *generation resources* shall be scheduled for at least their *minimum daily energy limit*. Violation variables for under-scheduling a *resource's minimum daily energy limit* may be used to allow the *day-ahead market calculation engine* to find a solution. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$\sum_{h=1..24}\left(ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} + \sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i}\right) \geq MinDEL_b$$

8.6.5.2 A Boolean variable, $IHE_{h,b,i}$ shall indicate that a start for the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ was counted in hour $h \in \{1, . . 24\}$ as a result of the *resource* schedule increasing from below its i-th *start indication value* to at or above its i-th *start indication value* for $i \in \{1, . . , NStartMW_b\}$. A value of zero shall indicate that a start was not counted, while a value of one indicates that a start was counted.

Therefore, for all hours $h \in \{1, . . , 24\}$, buses $b \in B^{HE}$ and $start\ indication\ values\ i \in \{1, . . , NStartMW_b\}$:

$$IHE_{h,b,i} = \begin{cases} 1 \quad if \left(ODG_{h-1,b} \cdot MinQDG_b + \sum_{k \in K^E_{h-1,b}} SDG_{h-1,b,k} < StartMW_{b,i}\right) \\ \qquad and \left(ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \geq StartMW_{b,i}\right) \\ 0 \quad otherwise. \end{cases}$$

8.6.5.3 *Dispatchable* hydroelectric *generation resources* shall not be scheduled to be started more times than permitted by their *maximum number of starts per day.* The following constraint shall apply for all buses $b \in B^{HE}$:

$$\sum_{h=1..24}\left(\sum_{i=1..NStartMW_b} IHE_{h,b,i}\right) \leq MaxStartsHE_b$$

8.6.5.4 The schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall not exceed shared *maximum daily energy limits*. Violation variables for over-scheduling the *maximam daily energy limit* may be used to allow the *day-ahead* *market calculation engine* to find a solution. For all sets $s \in SHE$ and all hours $H \in \{1,..,24\}$:

$$\sum_{h=1..H}\left(\sum_{b\,\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\right)\right)$$
$$+\sum_{b\,\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}}S10SDG_{H,b,k}\right.\right.$$
$$\left.+\sum_{k\in K_{H,b}^{10N}}S10NDG_{H,b,k}\right)$$
$$\left.\left.+\,30ORConv\left(\sum_{k\in K_{H,b}^{30R}}S30RDG_{H,b,k}\right)\right)\right)$$
$$-\sum_{i=1..N_{SMaxDelViol_H}}SSMaxDelViol_{H,s,i}$$
$$\leq MaxSDEL_s$$

where the factors $10ORConv$ and $30ORConv$ shall be applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* to convert MW into MWh.

8.6.5.5 Schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall respect shared *minimum daily energy limits*. Violation variables for under-scheduling the *minimum daily energy limit* may be used to allow the *day-ahead market calculation engine* to find a solution. For all sets $s \in SHE$:

$$\sum_{h=1..24}\left(\sum_{b\,\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\right)\right.$$
$$\left.+\sum_{i=1..N_{SMinDelViol_h}}SSMinDelViol_{h,s,i}\right)$$
$$\geq MinSDEL_s$$

8.6.5.6 For linked *dispatchable* hydroelectric *generation resources* with a registered *forebay*, *energy* scheduled at the upstream *resources* in one hour shall result in a proportional amount of *energy* being scheduled at the linked downstream *resources* in the hour determined by the *time lag*.

8.6.5.7 For all linked *dispatchable* hydroelectric *generation resources* between upstream *resources* $b_1 \in B_{up}^{HE}$ and downstream *resources* $b_2 \in B_{dn}^{HE}$ for $(b_1, b_2) \in LNK$ and hours $h \in \{1, \ldots, 24\}$ such that $h + Lag_{b_1,b_2} \leq 24$:

$$\sum_{b_2 \in B_{dn}^{HE}} \left(ODG_{h+Lag_{b_1,b_2},b_2} \cdot MinQDG_{b_2} + \sum_{k \in K^E_{b_2,h+Lag_{b_1,b_2}}} SDG_{k,h+Lag_{b_1,b_2},b_2} \right) - \sum_{i=1..N_{OGenLnkViol_{h+Lag_{b_1,b_2}}}} SOGenLnkViol_{h+Lag_{b_1,b_2},(b_1,b_2),i} + \sum_{i=1..N_{UGenLnkViol_{h+Lag_{b_1,b_2}}}} SUGenLnkViol_{h+Lag_{b_1,b_2},(b_1,b_2),i} = MWhRatio_{b_1,b_2} \cdot \sum_{b_1 \in B_{up}^{HE}} \left(ODG_{h,b_1} \cdot MinQDG_{b_1} + \sum_{k \in K^E_{b_1,h}} SDG_{k,h,b_1} \right)$$

8.7 Constraints for Reliability Requirements

8.7.1 Energy Balance

8.7.1.1 The total amount of *energy* withdrawals scheduled at load bus $b \in B$ in hour $h \in \{1, \ldots, 24\}$, $With_{h,b}$ shall be:

$$With_{h,b} = \begin{cases} \sum_{j \in J^E_{h,b}} SPRL_{h,b,j} & if\ b \in B^{PRL} \\ \sum_{j \in J^E_{h,b}} SDL_{h,b,j} & if\ b \in B^{DL} \\ \sum_{j \in J^E_{h,b}} (QHDR_{h,b,j} - SHDR_{h,b,j}) & if\ b \in B^{HDR} \end{cases}$$

8.7.1.2 The net *energy* withdrawal for *virtual transaction zone* $m \in M$ in hour $h \in \{1, \ldots, 24\}$, $VWith_{h,m}$, as all *bids* scheduled from *virtual* *transactions* for *energy* less all *offers* scheduled from *virtual transaction* for *energy* shall be:

$$VWith_{h,m} = \left(\sum_{v \in VB_m} \sum_{j \in J^E_{h,v}} SVB_{h,v,j} \right) - \left(\sum_{v \in VO_m} \sum_{k \in K^E_{h,v}} SVO_{h,v,k} \right)$$

8.7.1.3 The total amount of export *energy* scheduled at *intertie zone* bus $d \in DX$ in hour $h \in \{1, . . . , 24\}$, $With_{h,d}$, as the exports from Ontario to the *intertie zone* bus shall be:

$$With_{h,d} = \sum_{j \in J^E_{h,d}} SXL_{h,d,j}$$

8.7.1.4 The total amount of injections scheduled at internal bus $b \in B$ in hour $h \in \{1, . . . , 24\}$, $Inj_{h,b}$, shall be:

$$Inj_{h,b} = OfferInj_{h,b} + RampInj_{h,b}$$

where

$$OfferInj_{h,b} = \begin{cases} \sum_{k \in K^E_{h,b}} SNDG_{h,b,k} & if\ b \in B^{NDG} \\ ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} & if\ b \in B^{DG} \end{cases}$$

and

$$RampInj_{h,b} = \begin{cases} \sum_{w=1..min(RampHrs_b, 24-h)} RampE_{b,w} \cdot IDG_{h+w,b} & if\ b \in B^{NQS} \\ 0 & otherwise \end{cases}$$

8.7.1.5 The total amount of import *energy* scheduled at *intertie zone* bus $d \in DI$ in hour $h \in \{1, . . . , 24\}$, $Inj_{h,d}$, as the imports into Ontario from that *intertie zone* bus shall be:

$$Inj_{h,d} = \sum_{k \in K^E_{h,d}} SIG_{h,d,k}$$

8.7.1.6 Injections and withdrawals at each bus shall be multiplied by one plus the marginal loss factor calculated by the *security* assessment function to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the *demand* constraint violation shall be subtracted from the total load or generation for the *day-ahead market calculation engine* to produce a solution. For hour $h \in \{1, . . . , 24\}$, the *energy* balance shall be:

$$\begin{aligned} AFL_h + \sum_{b \in B^{PRL} \cup B^{DL} \cup B^{HDR}} (1 + MglLoss_{h,b}) \cdot With_{h,b} \\ + \sum_{m \in M} (1 + VMglLoss_{h,m}) \cdot VWith_{h,m} \\ + \sum_{d \in DX} (1 + MglLoss_{h,d}) \cdot With_{h,d} \\ - \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \\ = \sum_{b \in B^{NDG} \cup B^{DG}} (1 + MglLoss_{h,b}) \cdot Inj_{h,b} \\ + \sum_{d \in DI} (1 + MglLoss_{h,d}) \cdot Inj_{h,d} \\ - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} + LossAdj_h \end{aligned}$$

8.7.2 Operating Reserve Requirements

8.7.2.1 *Operating reserve* shall be scheduled to meet system-wide requirements for synchronized *ten-minute operating reserve*, total *ten-minute operating reserve,* and *thirty-minute operating reserve* while respecting all applicable regional minimum requirements and regional maximum restrictions for *operating reserve*.

8.7.2.2 Constraint violation penalty curves shall be used to impose a penalty cost for not meeting the *IESO*'s system-wide *operating reserve* requirements, not meeting a regional minimum requirement, or not adhering to a regional maximum restriction. Full *operating reserve* requirements shall be scheduled unless the cost of doing so would be higher than the applicable penalty cost.

For each hour $h \in \{1, . . 24\}$:

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \right) + \sum_{i=1..N_{10SViol_h}} S10SViol_{h,i} \geq TOT10S_h;$$

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \right) + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \right) + \sum_{d \in DX} \left(\sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \right) + \sum_{d \in DI} \left(\sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \right) + \sum_{i=1..N_{10RViol_h}} S10RViol_{h,i} \geq TOT10R_h;$$

and

$$\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)+\sum_{d\in DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)+\sum_{d\in DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,j}\right)+\sum_{d\in DX}\left(\sum_{j\in J_{h,d}^{30R}} S30RXL_{h,d,j}\right)$$
$$+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k}\right)+\sum_{d\in DI}\left(\sum_{k\in K_{h,d}^{30R}} S30RIG_{h,d,k}\right)$$
$$+\sum_{i=1..N_{30RViol_h}} S30RViol_{h,i} \geq TOT30R_h$$

8.7.2.3 The following constraints shall be applied for each hour $h \in \{1, . . 24\}$ and each region $r \in ORREG$:

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$+\sum_{i=1..N_{REG10RViol_h}} SREG10RViol_{r,h,i} \geq REGMin10R_{h,r};$$

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$-\sum_{i=1..N_{XREG10RViol_h}} SXREG10RViol_{r,h,i}$$
$$\leq\ REGMax10R_{h,r};$$

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \right)$$
$$+ \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \right)$$
$$+ \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \right)$$
$$+ \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \right)$$
$$+ \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \right)$$
$$+ \sum_{i=1..N_{REG30RViol_h}} SREG30RViol_{r,h,i} \geq REGMin30R_{h,r};$$

and

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{30R}} S30RXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{30R}} S30RIG_{h,d,k}\right)$$
$$-\sum_{i=1..N_{XREG30RViol_h}} SXREG30RViol_{r,h,i}$$
$$\leq REGMax30R_{h,r}.$$

8.7.3 IESO Internal Transmission Limits

8.7.3.1 A set of *energy* schedules shall be produced that do not violate any *security limits* in the pre-contingency state and the post-contingency state subject to the remainder of this section 8.7.3. The total amount of *energy* scheduled to be injected and withdrawn at each bus used by the *energy* balance constraint in section 8.7.1.6, shall be used to produce these schedules.

8.7.3.2 Pre-contigency, $SPreITLViol_{f,h,i}$, and post-contingency, $SITLViol_{c,f,h,i}$, transmission limit violation variables shall allow the *day-ahead market calculation engine* to find a solution.

8.7.3.3 For all hours $h \in \{1, . . , 24\}$ and *facilities* $f \in F_h$, the linearized constraints for violated pre-contingency limits obtained from the *security* assesment function shall take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG}} PreConSF_{h,f,b} \cdot Inj_{h,b} - \sum_{b \in B^{PRL} \cup B^{DL} \cup B^{HDR}} PreConSF_{h,f,b} \cdot With_{h,b} - \sum_{m \in M} VPreConSF_{h,f,m} \cdot VWith_{h,m} + \sum_{d \in DI} PreConSF_{h,f,d} \cdot Inj_{h,d} - \sum_{d \in DX} PreConSF_{h,f,d} \cdot With_{h,d} - \sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} \leq AdjNormMaxFlow_{h,f}$$

8.7.3.4 For all hours $h \in \{1, . . , 24\}$, contingencies $c \in C$, and *facilities* $f \in F_{h,c}$, the linearized constraints for violated post-contingency limits obtained from the *security* assesment function shall take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG}} SF_{h,c,f,b} \cdot Inj_{h,b} - \sum_{b \in B^{PRL} \cup B^{DL} \cup B^{HDR}} SF_{h,c,f,b} \cdot With_{h,b} - \sum_{m \in M} VSF_{h,c,f,m} \cdot VWith_{h,m} + \sum_{d \in DI} SF_{h,c,f,d} \cdot Inj_{h,d} - \sum_{d \in DX} SF_{h,c,f,d} \cdot With_{h,d} - \sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \leq AdjEmMaxFlow_{h,c,f}$$

8.7.4 Intertie Limits

8.7.4.1 A set of *energy* and *operating reserve* schedules shall be produced that respect any *security limits* associated with *interties* between

Ontario and *intertie zones*. For all hours $h \in \{1, . . . , 24\}$ and all constraints $z \in Z_{Sch}$:

$$\sum_{a \in A:\, EnCoeff_{a,z} \neq 0} \left[\begin{array}{c} EnCoeff_{a,z} \left(\sum_{d \in DI_a} \sum_{k \in K^{E}_{h,d}} SIG_{h,d,k} - \sum_{d \in DX_a} \sum_{j \in J^{E}_{h,d}} SXL_{h,d,j} \right) \\ +0.5 \cdot (EnCoeff_{a,z} + 1) \left(\begin{array}{c} \sum_{d \in DI_a} \left(\sum_{k \in K^{10N}_{h,d}} S10NIG_{h,d,k} + \sum_{k \in K^{30R}_{h,d}} S30RIG_{h,d,k} \right) + \\ \sum_{d \in DX_a} \left(\sum_{j \in J^{10N}_{h,d}} S10NXL_{h,d,j} + \sum_{j \in J^{30R}_{h,d}} S30RXL_{h,d,j} \right) \end{array} \right) \end{array} \right]$$

$$- \sum_{i=1..N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} \leq MaxExtSch_{h,z}$$

where for out-of-service *intertie zones*, the *intertie* limits shall be set to zero and all *boundary entity resources* shall receive a zero schedule for *energy* and *operating reserve*.

8.7.4.2 Changes in the hour-to-hour net *energy* schedule over all *intertie zones* shall not exceed the net interchange scheduling limit. The net import schedule shall be summed over all *intertie zones* for a given hour to obtain the net *interchange schedule* for the hour as follows:

8.7.4.2.1 It shall not exceed the net *interchange schedule* for the previous hour plus the net interchange scheduling limit;

8.7.4.2.2 It shall not be less than the net *interchange schedule* for the previous hour minus the net interchange scheduling limit; and

8.7.4.3 Violation variables may be used for both the up and down ramp limits to allow the *day-ahead market calculation engine* to find a solution and for all hours $h \in \{1, .., 24\}$:

$$\sum_{d \in DI} \sum_{k \in K^E_{h-1,d}} SIG_{h-1,d,k} - \sum_{d \in DX} \sum_{j \in J^E_{h-1,d}} SXL_{h-1,d,j} - ExtDSC_h - \sum_{i=1..N_{NIDViol_h}} SNIDViol_{h,i} \le \sum_{d \in DI} \sum_{k \in K^E_{h,d}} SIG_{h,d,k} - \sum_{d \in DX} \sum_{j \in J^E_{h,d}} SXL_{h,d,j} \le \sum_{d \in DI} \sum_{k \in K^E_{h-1,d}} SIG_{h-1,d,k} - \sum_{d \in DX} \sum_{j \in J^E_{h-1,d}} SXL_{h-1,d,j} + ExtUSC_h + \sum_{i=1..N_{NIUViol_h}} SNIUViol_{h,i}$$

8.7.5 Penalty Price Variable Bounds

8.7.5.1 Penalty price variables shall be restricted to the ranges determined by the constraint violation penalty curves for the As-Offered Scheduling algorithm and for all hours $h \in \{1, . . , 24\}$:

$0 \leq SLdViol_{h,i} \leq QLdViolSch_{h,i}$ for all $i \in \{1, . . , N_{LdViol_h}\}$;

$0 \leq SGenViol_{h,i} \leq QGenViolSch_{h,i}$ for all $i \in \{1, . . , N_{GenViol_h}\}$;

$0 \leq S10SViol_{h,i} \leq Q10SViolSch_{h,i}$ for all $i \in \{1, . . , N_{10SViol_h}\}$;

$0 \leq S10RViol_{h,i} \leq Q10RViolSch_{h,i}$ for all $i \in \{1, . . , N_{10RViol_h}\}$;

$0 \leq S30RViol_{h,i} \leq Q30RViolSch_{h,i}$ for all $i \in \{1, . . , N_{30RViol_h}\}$;

$0 \leq SREG10RViol_{r,h,i} \leq QREG10RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . , N_{REG10RViol_h}\}$;

$0 \leq SREG30RViol_{r,h,i} \leq QREG30RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . , N_{REG30RViol_h}\}$;

$0 \leq SXREG10RViol_{r,h,i} \leq QXREG10RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . , N_{XREG10RViol_h}\}$;

$0 \leq SXREG30RViol_{r,h,i} \leq QXREG30RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . , N_{XREG30RViol_h}\}$;

$0 \leq SPreITLViol_{f,h,i} \leq QPreITLViolSch_{f,h,i}$ for all $f \in F_h$, $i \in \{1, . . , N_{PreITLViol_{f,h}}\}$;

$0 \leq SITLViol_{c,f,h,i} \leq QITLViolSch_{c,f,h,i}$ for all $c \in C, f \in F_{h,c}$, $i \in \{1, \ldots, N_{ITLViol_{c,f,h}}\}$;

$0 \leq SPreXTLViol_{z,h,i} \leq QPreXTLViolSch_{z,h,i}$ for all $z \in Z_{Sch}$, $i \in \{1, \ldots, N_{PreXTLViol_{z,h}}\}$;

$0 \leq SNIUViol_{h,i} \leq QNIUViolSch_{h,i}$ for all $i \in \{1, \ldots, N_{NIUViol_h}\}$;

$0 \leq SNIDViol_{h,i} \leq QNIDViolSch_{h,i}$ for all $i \in \{1, \ldots, N_{NIDViol_h}\}$;

$0 \leq SMaxDelViol_{h,b,i} \leq QMaxDelViolSch_{h,i}$ for all $b \in B^{ELR}$, $i \in \{1, \ldots, N_{MaxDelViol_h}\}$;

$0 \leq SMinDelViol_{h,b,i} \leq QMinDelViolSch_{h,i}$ for all $b \in B^{HE}$, $i \in \{1, \ldots, N_{MinDelViol_h}\}$;

$0 \leq SSMaxDelViol_{h,s,i} \leq QSMaxDelViolSch_{h,i}$ for all $s \in SHE$, $i \in \{1, \ldots, N_{SMaxDelViol_h}\}$;

$0 \leq SSMinDelViol_{h,s,i} \leq QSMinDelViolSch_{h,i}$ for all $s \in SHE$, $i \in \{1, \ldots, N_{SMinDelViol_h}\}$;

$0 \leq SOGenLnkViol_{h,(b_1,b_2),i} \leq QOGenLnkViol_{h,i}$ for all $(b_1, b_2) \in LNK$, $i \in \{1, \ldots, N_{OGenLnkViol_h}\}$; and

$0 \leq SUGenLnkViol_{h,(b_1,b_2),i} \leq QUGenLnkViol_{h,i}$ for all $(b_1, b_2) \in LNK$, $i \in \{1, \ldots, N_{UGenLnkViol_h}\}$

8.8 Outputs

8.8.1 Outputs for the As-Offered Scheduling algorithm include *resource* schedules and commitments.

9 As-Offered Pricing

9.1 Purpose

9.1.1 The As-Offered Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants,* including *resource* schedules and commitments produced by the As-Offered Scheduling algorithm, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day*.

9.2 Information, Sets, Indices and Parameters

9.2.1 Information sets, indices and parameters used by the As-Offered Pricing algorithm are described in sections 3 and 4. In addition, the following *resource* schedules and commitments from the As-Offered Scheduling algorithm in section 8 shall be used by the As-Offered Pricing algorithm:

9.2.1.1 $SDG^{AOS}_{h,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDG_b$ at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . . , 24\}$ in association with lamination $k \in K^{E}_{h,b}$;

9.2.1.2 $ODG^{AOS}_{h,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1, . . . , 24\}$;

9.2.1.3 $S10SDG^{AOS}_{h,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . . , 24\}$ in association with lamination $k \in K^{10S}_{h,b}$;

9.2.1.4 $S10NDG^{AOS}_{h,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . . , 24\}$ in association with lamination $k \in K^{10N}_{h,b}$;

9.2.1.5 $S30RDG^{AOS}_{h,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . . , 24\}$ in association with lamination $k \in K^{30R}_{h,b}$; and

9.2.1.6 $OHO^{AOS}_{h,b}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1, . . . , 24\}$.

9.3 Variables and Objective Function

9.3.1 The *day-ahead market calculation engine* shall solve for the same variables as in the As-Offered Scheduling algorithm, section 8.3.1, with the following exceptions:

9.3.1.1 $IDG_{h,b}$ for bus $b \in B^{DG}$ and hour $h \in \{1, . . , 24\}$ shall not appear in the formulation;

9.3.1.2 $ODG_{h,b}$ for bus $b \in B^{DG}$ and hour $h \in \{1, . . , 24\}$ shall be fixed to a constant value;

9.3.1.3 $OHO_{h,b}$ for bus $b \in B^{HE}$ and hour $h \in \{1, . . , 24\}$ shall be fixed to a constant value;

9.3.1.4 $IHE_{h,b,i}$ for bus $b \in B^{HE}$, hour $h \in \{1, . . , 24\}$ and *start indication value* $i \in \{1, . . , NStartMW_b\}$ shall not appear in the formulation;

9.3.1.5 $SOGenLnkViol_{h,(b_1,b_2),i}$ for $(b_1, b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$, hour $h \in \{1, . . . , 24\}$ and $i \in \{1, . . . , N_{OGenLnkViol_h}\}$ shall not appear in the formulation; and

9.3.1.6 $SUGenLnkViol_{h,(b_1,b_2),i}$ for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$, hour $h \in \{1, . . . , 24\}$ and $i \in \{1, . . . , N_{UGenLnkViol_h}\}$ shall not appear in the formulation.

9.3.2 The objective function for the As-Offered Pricing algorithm shall maximize gains from trade by maximizing the following expression:

$$\sum_{h=1,..,24} \begin{pmatrix} ObjPRL_h + ObjDL_h - ObjHDR_h + ObjVB_h + ObjXL_h - ObjNDG_h \\ - ObjDG_h - ObjVO_h - ObjIG_h - TB_h - ViolCost_h \end{pmatrix}$$

where:

$$ObjPRL_h = \sum_{b \in B^{PRL}} \left(\sum_{j \in J_{h,b}^{E}} SPRL_{h,b,j} \cdot PPRL_{h,b,j} \right)$$

$$ObjDL_h = \sum_{b \in B^{DL}} \left(\begin{array}{c} \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} \cdot PDL_{h,b,j} - \sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \cdot P10SDL_{h,b,j} - \\ \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \cdot P10NDL_{h,b,j} - \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \cdot P30RDL_{h,b,j} \end{array} \right)$$

$$ObjHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J_{h,b}^{E}} SHDR_{h,b,j} \cdot PHDR_{h,b,j} \right)$$

$$ObjVB_h = \sum_{v \in VB} \left(\sum_{j \in J_{h,v}^{E}} SVB_{h,v,j} \cdot PVB_{h,v,j} \right)$$

$$ObjXL_h = \sum_{d \in DX} \left(\begin{array}{c} \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \cdot PXL_{h,d,j} - \sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \cdot P10NXL_{h,d,j} \\ - \sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \cdot P30RXL_{h,d,j} \end{array} \right)$$

$$ObjNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{h,b}^{E}} SNDG_{h,b,k} \cdot PNDG_{h,b,k} \right)$$

$$ObjDG_h = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \cdot PDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \cdot P10SDG_{h,b,k} + \\ \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \cdot P10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \cdot P30RDG_{h,b,k} \end{array} \right)$$

$$ObjVO_h = \sum_{v \in VO} \left(\sum_{k \in K_{h,v}^{E}} SVO_{h,v,k} \cdot PVO_{h,v,k} \right)$$

$$ObjIG_h = \sum_{d \in DI} \left(\sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \cdot PIG_{h,d,k} + \sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \cdot P10NIG_{h,d,k} + \sum_{k \in K_{h,d}^{30R}} S30IG_{h,d,k} \cdot P30RIG_{h,d,k} \right)$$

9.3.2.1 The tie-breaking term (TB_h) shall be the same term described in section 8.3.2.1.

9.3.2.2 $ViolCost_h$ shall be calculated as follows:

$$\begin{aligned} ViolCost_h = & \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \cdot PLdViolPrc_{h,i} \\ & - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} \cdot PGenViolPrc_{h,i} \\ & + \sum_{i=1..N_{10SViol_h}} S10SViol_{h,i} \cdot P10SViolPrc_{h,i} \\ & + \sum_{i=1..N_{10RViol_h}} S10RViol_{h,i} \cdot P10RViolPrc_{h,i} \\ & + \sum_{i=1..N_{30RViol_h}} S30RViol_{h,i} \cdot P30RViolPrc_{h,i} \\ & + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG10RViol_h}} SREG10RViol_{r,h,i} \cdot PREG10RViolPrc_{h,i} \right) \end{aligned}$$

$$+ \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG30RViol_h}} SREG30RViol_{r,h,i} \cdot PREG30RViolPrc_{h,i} \right)$$

$$+ \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG10RViol_h}} SXREG10RViol_{r,h,i} \cdot PXREG10RViolPrc_{h,i} \right)$$

$$+ \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG30RViol_h}} SXREG30RViol_{r,h,i} \cdot PXREG30RViolPrc_{h,i} \right)$$

$$+ \sum_{f \in F_h} \left(\sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} \cdot PPreITLViolPrc_{f,h,i} \right)$$

$$+ \sum_{c \in C} \sum_{f \in F_{h,c}} \left(\sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \cdot PITLViolPrc_{c,f,h,i} \right)$$

$$+ \sum_{z \in Z_{Sch}} \left(\sum_{i=1..N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} \cdot PPreXTLViolPrc_{z,h,i} \right)$$

$$+ \sum_{i=1..N_{NIUViol_h}} SNIUViol_{h,i} \cdot PNIUViolPrc_{h,i}$$

$$+ \sum_{i=1..N_{NIDViol_h}} SNIDViol_{h,i} \cdot PNIDViolPrc_{h,i}.$$

$$+ \sum_{b \in B^{ELR}} \left(\sum_{i=1..N_{MaxDelViol_h}} SMaxDelViol_{h,b,i} \cdot PMaxDelViolPrc_{h,i} \right)$$

$$+ \sum_{b \in B^{HE}} \left(\sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i} \cdot PMinDelViolPrc_{h,i} \right)$$

$$+ \sum_{s \in \mathrm{SHE}} \left(\sum_{i=1..N_{SMaxDelViol_h}} SSMaxDelViol_{h,s,i} \cdot PSMaxDelViolPrc_{h,i} \right)$$

$$+ \sum_{s \in \mathrm{SHE}} \left(\sum_{i=1..N_{SMinDelViol_h}} SSMinDelViol_{h,s,i} \cdot PSMinDelViolPrc_{h,i} \right)$$

9.4 Constraints

9.4.1 The constraints described in sections 9.5, 9.6, 9.7 and 9.8 apply to the optimization function in the As-Offered Pricing algorithm.

9.5 Dispatch Data Constraints Applying to Individual Hours

9.5.1 Scheduling Variable Bounds

9.5.1.1 No schedule shall be negative, nor shall any schedule exceed the quantity respectively *offered* for *energy* and *operating reserve*. For all hours $h \in \{1, . . , 24\}$:

$0 \leq SPRL_{h,b,j} \leq QPRL_{h,b,j}$ for all $b \in B^{PRL}, j \in J^{E}_{h,b}$;

$0 \leq SDL_{h,b,j} \leq QDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{E}_{h,b}$;

$0 \leq S10SDL_{h,b,j} \leq Q10SDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{10S}_{h,b}$;

$0 \leq S10NDL_{h,b,j} \leq Q10NDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{10N}_{h,b}$;

$0 \leq S30RDL_{h,b,j} \leq Q30RDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{30R}_{h,b}$;

$0 \leq SHDR_{h,b,j} \leq QHDR_{h,b,j}$ for all $b \in B^{HDR}, j \in J^{E}_{h,b}$;

$0 \leq SVB_{h,v,j} \leq QVB_{h,v,j}$ for all $v \in VB, j \in J^{E}_{h,v}$;

$0 \leq SXL_{h,d,j} \leq QXL_{h,d,j}$ for all $d \in DX, j \in J^{E}_{h,d}$;

$0 \leq S10NXL_{h,d,j} \leq Q10NXL_{h,d,j}$ for all $d \in DX, j \in J^{10N}_{h,d}$;

$0 \leq S30RXL_{h,d,j} \leq Q30RXL_{h,d,j}$ for all $d \in DX, j \in J^{30R}_{h,d}$;

$0 \leq SNDG_{h,b,k} \leq QNDG_{h,b,k}$ for all $b \in B^{NDG}, k \in K^{E}_{h,b}$;

$0 \leq SVO_{h,v,k} \leq QVO_{h,v,k}$ for all $v \in VO, k \in K^{E}_{h,v}$;

$0 \leq SIG_{h,d,k} \leq QIG_{h,d,k}$ for all $d \in DI, k \in K^{E}_{h,d}$;

$0 \leq S10NIG_{h,d,k} \leq Q10NIG_{h,d,k}$ for all $d \in DI, k \in K^{10N}_{h,d}$; and

$0 \leq S30RIG_{h,d,k} \leq Q30RIG_{h,d,k}$ for all $d \in DI, k \in K^{30R}_{h,d}$

9.5.1.2 A *dispatchable generation resource* can be scheduled for *energy* and *operating reserve* only if its commitment status variable is equal to 1. For all hours $h \in \{1, . . , 24\}$:

$0 \leq SDG_{h,b,k} \leq ODG_{h,b} \cdot QDG_{h,b,k}$ for all $b \in B^{DG}, \ k \in K^{E}_{h,b}$;

$0 \leq S10SDG_{h,b,k} \leq ODG_{h,b} \cdot Q10SDG_{h,b,k}$ for all $b \in B^{DG}, \ k \in K^{10S}_{h,b}$;

$0 \leq S10NDG_{h,b,k} \leq ODG_{h,b} \cdot Q10NDG_{h,b,k}$ for all $b \in B^{DG}, \ k \in K^{10N}_{h,b}$; and

$0 \leq S30RDG_{h,b,k} \leq ODG_{h,b} \cdot Q30RDG_{h,b,k}$ for all $b \in B^{DG}, \ k \in K^{30R}_{h,b}$

where:

$ODG_{h,b}$ is a fixed constant in the above constraints as per section 9.8.1.

9.5.2 Resource Minimums and Maximums

9.5.2.1 The constraints in section 8.5.2 shall apply in the As-Offered Pricing algorithm.

9.5.3 Off-Market Transactions

9.5.3.1 The constraints in section 8.5.3.1 and 8.5.3.2 shall apply in the As-Offered Pricing algorithm.

9.5.3.2 In the case of *emergency energy* transactions, subject to section 9.5.3.3, the constraints in sections 8.5.3.3 and 8.5.3.4 shall apply in As-Offered Pricing algorithm.

9.5.3.3 For all hours h ∈ {1, . . , 24} and all *intertie zone* buses scheduled to import *emergency energy* that does not support an export $d \in DI_h^{EMNS}$:

$$\sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} = 0.$$

9.5.4 Operating Reserve Requirements

9.5.4.1 The constraints in section 8.5.4 shall apply in the As-Offered Pricing algorithm.

9.5.5 Pseudo-Units

9.5.5.1 The constraints in section 8.5.5 shall apply in the As-Offered Pricing algorithm.

9.5.6 Dispatchable Hydroelectric Generation Resources

9.5.6.1 The constraints in section 8.5.6 shall apply in the As-Offered Pricing algorithm, with the following exceptions:

9.5.6.1.1 *offer* laminations for *energy* corresponding to the *hourly must-run* amount shall be ineligible to set prices;

9.5.6.1.2 *minimum hourly output* constraints shall be replaced by the constraints in section 9.8; and

9.5.6.1.3 a *dispatchable* hydroelectric *generation resource's* schedule shall respect its *forbidden regions* and may only set prices within the operating range determined by the adjacent *forbidden regions* between which the *resource* was scheduled.

9.5.7 Linked Wheeling Through Transactions

9.5.7.1 The constraints in section 8.5.7 shall apply in the As-Offered Pricing algorithm.

9.6 Dispatch Data Inter-Hour/Multi-Hour Constraints

9.6.1 Energy Ramping

9.6.1.1 The constraints in section 8.6.1 shall apply in the As-Offered Pricing algorithm.

9.6.2 Operating Reserve Ramping

9.6.2.1 The constraints in section 8.6.2 shall apply in the As-Offered Pricing algorithm.

9.6.3 Energy Limited Resources

9.6.3.1 The constraints in section 8.6.4 shall apply to *energy limited resources*. If the *maximum daily energy limit* is binding, then the constraints in section 9.8 shall apply.

9.6.4 Dispatchable Hydroelectric Generation Resources

9.6.4.1 A *dispatchable* hydroelectric *generation resource* shall be scheduled for *energy* to at least its *minimum daily energy limit*. Violation variables for scheduling a *resource* below its *minimum daily energy limit* may be used to allow the *day-ahead market calculation engine* to find a solution. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$\sum_{h=1..24} \left(ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} + \sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i} \right) \geq MinDEL_b$$

9.6.4.2 The constraints in section 9.8.3.3 shall apply to a *dispatchable* hydroelectric *generation resource* with a binding *minimum daily energy limit* in the As-Offered Scheduling algorithm in section 8.

9.6.4.3 The schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall respect shared *maximum daily energy limits*. Violation variables for scheduling *resources* above the *maximum daily energy limit* may be used to allow the *day-ahead market calculation engine* to find a solution. For all sets $s \in SHE$ and all hours $H \in \{1, . . ,24\}$:

$$\sum_{h=1..H}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\right)\right)$$
$$+\sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}}S10SDG_{H,b,k}\right.\right.$$
$$\left.+\sum_{k\in K_{H,b}^{10N}}S10NDG_{H,b,k}\right)$$
$$\left.+30ORConv\left(\sum_{k\in K_{H,b}^{30R}}S30RDG_{H,b,k}\right)\right)$$
$$-\sum_{i=1..N_{SMaxDelViol_H}}SSMaxDelViol_{H,s,i}$$
$$\leq MaxSDEL_s$$

where the factors $10ORConv$ and $30ORConv$ shall be applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* for *energy limited resources* to convert MW into MWh.

9.6.4.4 The schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall not violate shared *minimum daily energy limits*. Violation variables for scheduling *resources* below the *minimum daily energy limit* may be used to allow the *day-ahead market calculation engine* to find a solution. For all sets $s \in SHE$:

$$\sum_{h=1..24}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\right)+\sum_{i=1..N_{SSMinDelViol_h}}SSMinDelViol_{h,s,i}\right)\geq MinSDEL_s$$

9.7 Constraints for Reliability Requirements

9.7.1 Energy Balance

9.7.1.1 The constraint in section 8.7.1 shall apply in the As-Offered Pricing algorithm, except the marginal loss factors used in the *energy* balance constraint in the As-Offered Pricing algorithm shall be fixed to the marginal loss factors used in the last optimization function iteration of the As-Offered Scheduling algorithm.

9.7.2 Operating Reserve Requirements

9.7.2.1 The constraints in section 8.7.2 shall apply in the As-Offered Pricing algorithm.

9.7.3 IESO Internal Transmission Limits

9.7.3.1 The constraints in section 8.7.3 shall apply in the As-Offered Pricing algorithm, except the sensitivities and limits considered shall be those provided by the most recent *security* assessment function iteration of the As-Offered Pricing algorithm.

9.7.4 Intertie Limits

9.7.4.1 The constraints in section 8.7.4 shall apply in the As-Offered Pricing algorithm.

9.7.5 Penalty Price Variable Bounds

9.7.5.1 The following constraints shall restrict the penalty price variables to the ranges determined by the constraint violation penalty curves for the pricing algorithm. For all $h \in \{1, . . , 24\}$:

$0 \leq SLdViol_{h,i} \leq QLdViolPrc_{h,i}$ for all i $\in \{1, . . . , N_{LdViol_h}\}$;

$0 \leq SGenViol_{h,i} \leq QGenViolPrc_{h,i}$ for all $i \in \{1, . . , N_{GenViol_h}\}$;

$0 \leq S10SViol_{h,i} \leq Q10SViolPrc_{h,i}$ for all $i \in \{1, . . . , N_{10SViol_h}\}$;

$0 \leq S10RViol_{h,i} \leq Q10RViolPrc_{h,i}$ for all $i \in \{1, . . . , N_{10RViol_h}\}$;

$0 \leq S30RViol_{h,i} \leq Q30RViolPrc_{h,i}$ for all $i \in \{1, . . . , N_{30RViol_h}\}$;

$0 \leq SREG10RViol_{r,h,i} \leq QREG10RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . . , N_{REG10RViol_h}\}$;

$0 \leq SREG30RViol_{r,h,i} \leq QREG30RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . . , N_{REG30RViol_h}\}$;

$0 \leq SXREG10RViol_{r,h,i} \leq QXREG10RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . . , N_{XREG10RViol_h}\}$;

$0 \leq SXREG30RViol_{r,h,i} \leq QXREG30RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1, . . . , N_{XREG30RViol_h}\}$;

$0 \leq SPreITLViol_{f,h,i} \leq QPreITLViolPrc_{f,h,i}$ for all $f \in F_h$, $i \in \{1, . . . , N_{PreITLViol_{f\,h}}\}$;

$0 \leq SITLViol_{c,f,h,i} \leq QITLViolPrc_{c,f,h,i}$ for all $c \in C$, $f \in F_{h,c}$, $i \in \{1, . . . , N_{ITLViol_{c,f,h}}\}$;

$0 \leq SPreXTLViol_{z,h,i} \leq QPreXTLViolPrc_{z,h,i}$ for all $z \in Z_{Sch}$, $i \in \{1, . . . , N_{PreXTLViol_{z,h}}\}$;

$0 \leq SNIUViol_{h,i} \leq QNIUViolPrc_{h,i}$ for all $i \in \{1, . . . , N_{NIUViol_h}\}$;

$0 \leq SNIDViol_{h,i} \leq QNIDViolPrc_{h,i}$ for all $i \in \{1, . . . , N_{NIDViol_h}\}$;

$0 \leq SMaxDelViol_{h,b,i} \leq QMaxDelViolPrc_{h,i}$ for all $b \in B^{ELR}$, $i \in \{1, . . . , N_{MaxDelViol_h}\}$;

$0 \leq SMinDelViol_{h,b,i} \leq QMinDelViolPrc_{h,i}$ for all $b \in B^{HE}$, i $\in \{1, . . . , N_{MinDelViol_h}\}$;

$0 \leq SSMaxDelViol_{h,s,i} \leq QSMaxDelViolPrc_{h,i}$ for all s $\in$ SHE, $i \in \{1, . . . , N_{SMaxDelViol_h}\}$; and

$0 \leq SSMinDelViol_{h,s,i} \leq QSMinDelViolPrc_{h,i}$ for all s $\in$ SHE $i \in \{1, . . . , N_{SMinDelViol_h}\}$.

9.8 Constraints to Ensure the Price Setting Eligibility Reflect Offer/Bid Laminations

9.8.1 Commitment Status Variables

9.8.1.1 Commitment decisions shall be fixed to the commitment statuses of *resources* calculated by the As-Offered Scheduling algorithm in section 8. For all hours $h \in \{1, . . , 24\}$ and all buses $b \in B^{DG}$:

$$ODG_{h,b} = ODG_{h,b}^{AOS}$$

9.8.2 Energy Limited Resources

9.8.2.1 For an *energy limited resource* with a *maximum daily energy limit* that was binding in the As-Offered Scheduling algorithm in section 8, the schedules calculated in the As-Offered Scheduling algorithm shall determine the price-setting eligibility of the *resource's energy* and *operating reserve offer* laminations. In each hour, *energy* or *operating reserve* laminations up to the total amount of *energy* and *operating reserve* scheduled in the As-Offered Scheduling algorithm shall be eligible to set prices. For bus $b \in B^{ELR}$, if there exists an hour $H \in \{1, . . ,24\}$ such that:

$$\sum_{h=1..H} \left(ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS} \right) + 10ORConv \left(\sum_{k \in K_{H,b}^{10S}} S10SDG_{H,b,k}^{AOS} + \sum_{k \in K_{H,b}^{10N}} S10NDG_{H,b,k}^{AOS} \right) + 30ORConv \left(\sum_{k \in K_{H,b}^{30R}} S30RDG_{H,b,k}^{AOS} \right) = MaxDEL_{b},$$

then the *maximum daily energy limit* constraint shall be considered binding in the As-Offered Scheduling algorithm. In such circumstances, the following constraints must hold for bus $b \in B^{ELR}$ for all hours $h \in \{1, . . , 24\}$:

$$\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS} + \epsilon$$

$$\sum_{k\in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k} \le MaxDEL_b - \sum_{\tau=1}^{h-1} \sum_{k\in K_{h,b}^{E}} SDG_{\tau,b,k}^{AOS}$$

where ϵ is a small positive constant.

9.8.3 Dispatchable Hydroelectric Generation Resources

9.8.3.1 If a *dispatchable* hydroelectric *generation resource* is scheduled to provide *energy* at or above its *minimum hourly output* in the As-Offered Scheduling algorithm in section 8, such *resource* shall also be scheduled at or above its *minimum hourly output* in the As-Offered Pricing algorithm. The *energy offer* laminations corresponding to the *minimum hourly output* amount shall be ineligible to set prices. If a *dispatchable* hydroelectric *generation resource* with a *minimum hourly output* amount receives a zero schedule in the As-Offered Scheduling algorithm, the *resource* shall also receive a zero schedule in the As-Offered Pricing algorithm and shall be ineligible to set prices in the *energy market*. For all hours $h \in \{1, . . , 24\}$ and *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k\in K_{h,b}^{E}} SDG_{h,b,k} \ge MinHO_{h,b} \cdot OHO_{h,b}^{AOS}$$

and for all $k \in K_{h,b}^{E}$:

$$0 \le SDG_{h,b,k} \le OHO_{h,b}^{AOS} \cdot QDG_{h,b,k}$$

9.8.3.2 For a *dispatchable* hydroelectric *generation resource* with a limited number of starts, such *resource* shall be scheduled such that it is limited to set prices within an operating range consistent with the number of starts utilized by the *resource's* schedule determined by the As-Offered Scheduling algorithm in section 8. The *resource's* schedule shall be between the same *start indication value*s as determined in the As-Offered Scheduling algorithm. For all hydroelectric buses $b \in B^{HE}$ and all hours $h \in \{1, . . . , 24\}$:

If $0 \leq ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k}^{AOS} < StartMW_{b,1}$,

then

$$0 \leq ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \leq StartMW_{b,1} - 0.1$$

If $StartMW_{b,i} \leq ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k}^{AOS} < StartMW_{b,i+1}$ for $i \in \{1, . . , (NStartMW_b - 1)\}$,

then

$$StartMW_{b,i} \leq ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \leq StartMW_{b,i+1} - 0.1$$

If $ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k}^{AOS} \geq StartMW_{b,NStartMW_b}$,

then

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq StartMW_{b,NStartMW_b}$$

9.8.3.3 For a *dispatchable* hydroelectric *generation resource* with a *minimum daily energy limit* that was binding in the As-Offered Scheduling algorithm in section 8, the *energy* schedules calculated in the As-Offered Scheduling algorithm shall be ineligible to set prices. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ such that $MinDEL_b > 0$ and

$$\sum_{h=1..24} \left(ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k}^{AOS} \right) \leq MinDEL_b$$

the following constraints shall apply for all hours $h \in \{1, . . , 24\}$ and offer laminations $k \in K_{h,b}^E$:

$$SDG_{h,b,k} \geq SDG_{h,b,k}^{AOS}$$

9.8.3.4 For a *dispatchable* hydroelectric *generation resource* with a shared *minimum daily energy limit* that was binding in the As-Offered Scheduling algorithm in section 8, the *energy* schedules calculated for all *resources* in the set $s \in SHE$ in the As-Offered Scheduling algorithm shall be ineligible to set prices. Thus, for all sets $s \in SHE$ such that:

$$\sum_{h=1..24}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}^{AOS}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}^{AOS}\right)\right)\leq MinSDEL_s$$

the following constraints shall apply for all hours $h \in \{1, . . . , 24\}$:

$$\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\right)\geq\sum_{b\in B_s^{HE}}\left(ODG_{h,b}^{AOS}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}^{AOS}\right)$$

9.8.3.5 For a *dispatchable* hydroelectric *generation resource* with a binding *maximum daily energy limit* in the As-Offered Scheduling algorithm in section 8, the schedules calculated in the As-Offered Scheduling algorithm shall determine the price-setting eligibility of the *resource's energy* and *operating reserve offer* laminations as described in section 9.8.2.

9.8.3.6 For a *dispatchable* hydroelectric *generation resource* with with a shared *maximum daily energy limit* that was binding in the As-Offered Scheduling algorithm in section 8, the schedules calculated in the As-Offered Scheduling algorithm shall determine the price-setting eligibility of the *resource's offer* laminations for *energy* and *operating reserve*. In each hour, the sum of *energy* schedules calculated in As-Offered Scheduling algorithm for all *resources* in each set $s \in SHE$

will be eligible to set prices. For each set $s \in SHE$, if there exists $H \in \{1,..,24\}$ such that:

$$\sum_{h=1..H}\left(\sum_{b\ \in B_s^{HE}}\left(ODG_{h,b}^{AOS}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}^{AOS}\right)\right)$$
$$+\sum_{b\ \in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}}S10SDG_{H,b,k}^{AOS}\right.\right.$$
$$\left.+\sum_{k\in K_{H,b}^{10N}}S10NDG_{H,b,k}^{AOS}\right)$$
$$\left.+30ORConv\left(\sum_{k\in K_{H,b}^{30R}}S30RDG_{H,b,k}^{AOS}\right)\right)$$
$$=MaxSDEL_s$$

then the *maximum daily energy limit* constraint shall be considered binding in the As-Offered Scheduling algorithm in section 8. In such circumstances, the following constraints shall apply for hours $h \in \{1,...,24\}$:

$$\sum_{b\in B_s^{HE}}\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\ \leq\sum_{b\in B_s^{HE}}\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}^{AOS}+\epsilon,$$

$$\sum_{b\in B_s^{HE}}\left(\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}+\sum_{k\in K_{h,b}^{10S}}S10SDG_{h,b,k}+\sum_{k\in K_{h,b}^{10N}}S10NDG_{h,b,k}\right.$$
$$\left.+\sum_{k\in K_{h,b}^{30R}}S30RDG_{h,b,k}\right)$$
$$\leq MaxSDEL_s-\sum_{b\in B_s^{HE}}\sum_{\tau=2}^{h-1}\sum_{k\in K_{h,b}^{E}}SDG_{\tau,b,k}^{AOS}.$$

where ϵ is a small positive constant.

9.8.3.7 For a *dispatchable* hydroelectric *generation resource* for which a *MWh ratio* was respected in the As-Offered Scheduling algorithm in section 8, such *resource* shall be scheduled between its As-Offered Scheduling algorithm schedule plus or minus a tolerance Δ specified by the *IESO*. The *resource* schedule shall continue to be limited by its *offer* quantity bounds, in section 9.5.1, and any applicable *resource* minimum or maximum constraints, in section 9.5.2. For all hours $h \in \{1, . . , 24\}$ and *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ such $b \in \{b_1, b_2\}$ where $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$ for some $(b_1, b_2) \in LNK$ with $h + Lag_{b_1, b_2} \leq 24$:

$$max\left(0\,, ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG^{AOS}_{h,b,k} - \Delta\,, AdjMinDG_{h,b}\right)$$
$$\leq ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k}$$
$$\leq min\left(\begin{matrix} MinQDG_b + \sum_{k \in K^E_{h,b}} QDG_{h,b,k}\,, \quad ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG^{AOS}_{h,b,k} + \Delta\,, \\ AdjMaxDG_{h,b} \end{matrix}\right)$$

9.9 Outputs

9.9.1 Outputs for the As-Offered Pricing algorithm include the following:

9.9.1.1 shadow prices;

9.9.1.2 *locational marginal prices* and their components; and

9.9.1.3 sensitivity factors.

10 Constrained Area Conditions Test

10.1 Purpose

10.1.1 The Constrained Area Conditions Test shall:

10.1.1.1 identify when and where competition is restricted; and

10.1.1.2 determine which *resources* shall have their *financial dispatch data parameters* be subject to the Conduct Test in section 11 and the thresholds above the *reference levels* that shall be used in the Conduct Test.

10.2 Information, Sets, Indices and Parameters

10.2.1 The sets and parameters associated with *narrow constrained areas* and *dynamic constrained areas* shall be identified in accordance with Appendix 7.8 and used by the Constrained Area Conditions Test.

10.2.2 Information, sets, indices and parameters for the Constrained Area Conditions Test are described in sections 3 and 4. In addition, the following prices produced by the As-Offered Pricing algorithm shall be used by the Constrained Area Conditions Test:

10.2.2.1 $LMP_{h,b}^{AOP}$, which designates the *locational marginal price* for bus $b \in B$ in hour $h \in \{1, .., 24\}$;

10.2.2.2 $PCong_{h,b}^{AOP}$, which designates the congestion component of the *locational marginal price* for bus $b \in B$ in hour $h \in \{1, .., 24\}$;

10.2.2.3 $ExtLMP_{h,d}^{AOP}$, which designates the *locational marginal price* for *intertie zone* bus $d \in D$ in hour $h \in \{1, .., 24\}$;

10.2.2.4 $PExtCong_{h,d}^{AOP}$, which designates the *intertie* congestion component of the *locational marginal price* for *intertie zone* bus $d \in D$ in hour $h \in \{1, .., 24\}$;

10.2.2.5 $PIntCong_{h,d}^{AOP}$, which designates the internal congestion component of the *locational marginal price* for *intertie zone* bus $d \in D$ in hour $h \in \{1, .., 24\}$;

10.2.2.6 $IntLMP_{h,d}^{AOP}$, which designates the *intertie border price* for *intertie zone* bus $d \in D$ in hour $h \in \{1, .., 24\}$;

10.2.2.7 $SPNormT_{h,f}^{AOP}$, which designates the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour $h \in \{1, .., 24\}$;

10.2.2.8 $SPEmT_{h,c,f}^{AOP}$, which designates the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h;

10.2.2.9 $SPNIUExtBwdT_h^{AOP}$, which designates the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h-1)$ and hour h;

10.2.2.10 $L30RP_{h,b}^{AOP}$, which designates the *locational marginal price* for *thirty-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$;

10.2.2.11 $L10NP_{h,b}^{AOP}$, which designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$; and

10.2.2.12 $L10SP_{h,b}^{AOP}$, which designates the *locational marginal price* for synchronized *ten-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$.

10.3 Variables

10.3.1 The *day-ahead market calculation engine* shall use the constrained area conditions in sections 10.4 and 10.5 to identify the *resources* that are part of the following data sets:

10.3.1.1 $BCond_h^{NCA}$, which designates the *resources* in a *narrow constrained area* that must be checked for local market power for *energy* in hour $h \in \{1,..,24\}$;

10.3.1.2 $BCond_h^{DCA}$, which designates the *resources* in a *dynamic constrained area* that must be checked for local market power for *energy* in hour $h \in \{1,..,24\}$;

10.3.1.3 $BCond_h^{BCA}$, which designates the *resources* in a broad constrained area that must be checked for local market power for *energy* in hour $h \in \{1,..,24\}$;

10.3.1.4 $BCond_h^{GMP}$, which designates the *resources* that must be checked for global market power for *energy* in hour $h \in \{1,..,24\}$;

10.3.1.5 $BCond_h^{10S}$, which designates the *resources* that must be checked for local market power for synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$;

10.3.1.6 $BCond_h^{10N}$, which designates the *resources* that must be checked for local market power for non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$;

10.3.1.7 $BCond_h^{30R}$, which designates the *resources* that must be checked for local market power for *thirty-minute operating reserve* in hour $h \in \{1, . . , 24\}$;

10.3.1.8 $BCond_h^{GMP10S}$, which designates the *resources* that must be checked for global market power for synchronized *ten-minute operating reserve* in hour $h \in \{1, . . , 24\}$;

10.3.1.9 $BCond_h^{GMP10N}$, which designates the *resources* that must be checked for global market power for non-synchronized *ten-minute operating reserve* in hour $h \in \{1, . . , 24\}$; and

10.3.1.10 $BCond_h^{GMP30R}$, which designates the *resources* that must be checked for global market power for *thirty minute operating reserve* in hour $h \in \{1, . . , 24\}$.

10.4 Constrained Area Conditions Test for Local Market Power (Energy)

10.4.1 Constrained Area Conditions Test for Narrow Constrained Areas and Dynamic Constrained Areas

10.4.1.1 If at least one transmission constraint for a *narrow constrained area* or *dynamic constrained area* is binding in the As-Offered Pricing algorithm, then all *resources* identified within the *narrow constrained area* or *dynamic constrained area* area shall undergo the applicable Conduct Test in section 11 and:

10.4.1.1.1 For each $n \in NCA$ and hour $h \in \{1, . . . , 24\}$: For each transmission *facility* that transmits flow into n, $f \in F_n^{NCA}$, check if $SPNormT_{h,f}^{AOP} \neq 0$ or $SPEmT_{h,c,f}^{AOP} \neq 0$ for the inbound flow limit, the *day-ahead market calculation engine* will place n in the set $NCA_h{}'$ and assign the *resources* in n to the set $BCond_h^{NCA}$; and

10.4.1.1.2 For each $d \in DCA$ and hour $h \in \{1, . . . , 24\}$: For each transmission *facility* that transmits flow into d, $f \in F_d^{DCA}$, check if $SPNormT_{h,f}^{AOP} \neq 0$ or $SPEmT_{h,c,f}^{AOP} \neq 0$ for the inbound flow limit, *the day-ahead market calculation engine* will place d in the set $DCA_h{}'$ and assign the *resources* in d to the set $BCond_h^{DCA}$.

10.4.1.2 Each *narrow constrained area* and *dynamic constrained area* that meets the criteria in section 10.4.1.1 shall be assigned to one of the following subsets, as appropriate:

10.4.1.2.1 $NCA_h{}'$ designates the *narrow constrained areas* that qualify for market power mitigation for *energy* in hour $h \in \{1, . . , 24\}$; and

10.4.1.2.2 $DCA_h{}'$ designates the *dynamic constrained areas* that qualify for market power mitigation for *energy* in hour $\mathrm{h} \in \{1,..,24\}$.

10.4.2 Constrained Area Conditions Test for Broad Constrained Areas

10.4.2.1 If the congestion component of the *locational marginal price* for a *resource* is greater than $BCACondThresh$, and the *resource* is not part of a *narrow constrained area* or *dynamic constrained area* that has a binding transmission constraint, then the *resource* shall be tested for Conduct Test under the broad constrained area thresholds. For each hour $h \in \{1, . . , 24\}$ and bus $b \in B^{DG}$ such that $b \notin BCond_h^{NCA} \cup BCond_h^{DCA}$, if $PCong_{h,b}^{AOP} > BCACondThresh$, *the day-ahead market calculation engine* will place *resource* b in the set $BCond_h^{BCA}$.

10.5 Constrained Area Conditions Test for Global Market Power (Energy)

10.5.1 The *day-ahead market calculation engine* shall test *resources* that can meet incremental load within Ontario for global market power, subject to 10.5.2, if:

10.5.1.1 the *intertie border prices* at the *global market power reference intertie zones* are greater than the specified threshold value, indicated in hour $h \in \{1, . . , 24\}$ by $IntLMP_{h,d}^{AOP} > IBPThresh$ for *bids* and *offers*, $d \in D^{GMPRef}$, corresponding to the *boundary entity resource* bus for the *global market power reference intertie zone*; and

10.5.1.2 at least one of the following conditions is met:

10.5.1.2.1 import congestion, represented by a negative *intertie* congestion component, is present on all of the *global market power reference interties*, indicated in hour $h \in \{1, . . , 24\}$ by: $PExtCong_{h,d}^{AOP} < 0$ for *bids* and *offers*, $d \in D^{GMPRef}$, corresponding to the *boundary entity resource* bus for the *global market power reference intertie zone*; or

10.5.1.2.2 the net interchange schedule limit is binding for imports, represented by a non-zero net interchange schedule limit shadow price for incremental imports, indicated in hour $h \in \{1, . . , 24\}$ by: $SPNIUExtBwdT_h^{AOP} \neq 0$.

10.5.2 If the conditions in sections 10.5.1 are met, then the *day-ahead market calculation engine* shall test *resources* that can meet incremental load within Ontario for global market power, for each hour $h \in \{1, . . , 24\}$, place all $b \in B^{DG}$ in the set $BCond_h^{GMP}$, unless they are excluded because of one of the following two conditions:

10.5.2.1 the *resources* in any zone have congestion components at least $1/MWh below the internal congestion component at all of the *global market power reference intertie zones:*

10.5.2.1.1 if $PCong_{h,b}^{AOP} < PIntCong_{h,d}^{AOP} - \$1/\text{MWh}$ where $d \in D^{GMPRef}$ is true for all *global market power reference intertie zones*; or

10.5.2.2 the *resources* can not meet the incremental load because of a binding transmission constraint:

10.5.2.2.1 if *resources* can not meet incremental load because of any binding transmission *facility* where $SPNormT_{h,f}^{AOP} \neq 0 \;\; or$ $SPEmT_{h,c,f}^{AOP} \neq 0$.

10.6 Constrained Area Conditions Test for Local Market Power (Operating Reserve)

10.6.1 Subject to section 10.6.1.3 for a regional minimum requirement of greater than zero for a specific class of *operating reserve*, then all *resources* within the region with *offers* for classes of *operating reserve* that can satisfy the requirements of the specific class of *operating reserve* shall be tested for local market power:

10.6.1.1 A *resource* shall not qualify for local market power mitigation test for *operating reserve* if the *resource* is located in a region with a binding maximum constraint and for each *resource* $b \in B^{DG} \cup B^{DL}$ and hour $h \in \{1, . . , 24\}$:

10.6.1.2 subject to section 10.6.1.3, if b is in a region with a non-zero minimum requirement, then b is subject to the Conduct Test and is placed in the set $BCond_h^{10S}$, $BCond_h^{10N}$, or $BCond_h^{30R}$; and

10.6.1.3 if b is in a region with a binding maximum restriction constraint, then b is exempt from the Conduct Test.

10.7 Constrained Area Conditions Test for Global Market Power (Operating Reserve)

10.7.1 A *resource* shall be subject to global market power mitigation testing for *operating reserve* if its *offers* for a class of *operating reserve* where the *locational marginal price* for that class of *operating reserve* is greater than $ORGCondThresh$.

10.7.2 Subject to section 10.7.3, if the condition in section 10.7.1 has been met for a class of *operating reserve*, then all *resources* with *offers* for classes of *operating reserve* that can satisfy the requirements of that class of *operating reserve* shall be tested and for each $b \in B^{DG} \cup B^{DL}$ and hour $h \in \{1, .., 24\}$:

10.7.2.1 if $\mathrm{L10SP}_{t,b}^{\mathrm{PDP}} > \mathrm{ORGCondThresh}$, the *day-ahead market calculation engine* shall add *resource* b to $\mathrm{BCond}_{t}^{\mathrm{GMP10S}}$;

10.7.2.2 if $\mathrm{L10NP}_{t,b}^{\mathrm{PDP}} > \mathrm{ORGCondThresh}$, the *day-ahead market calculation engine* shall add *resource* b to $\mathrm{BCond}_{t}^{\mathrm{GMP10N}}$; and

10.7.2.3 if $\mathrm{L30RP}_{t,b}^{\mathrm{PDP}} > \mathrm{ORGCondThresh}$, the *day-ahead market calculation engine* shall add *resource* b to $BCond_{t}^{GMP30R}$.

10.7.3 If b is in a region with a binding maximum constraint, then b shall be exempt from the Conduct Test.

10.7.3.1 If a *resource* is located in a region with a binding regional maximum constraint, then the *resource* shall not qualify for global market power mitigation testing for *operating reserve*.

10.8 Outputs

10.8.1 Outputs of the Constrained Area Conditions Test include the list of *resources* that will be subject to the Conduct Test in section 11 and the thresholds that will be used in the Conduct Test for those *resources*.

11 Conduct Test

11.1 Purpose

11.1.1 The Conduct Test shall verify whether the *financial dispatch data parameter* values submitted by *registered market participants* for *resources* identified in section 10.8.1 are within the applicable threshold level of the corresponding *reference level values* for those *resources*.

11.2 Information, Sets, Indices and Parameters

11.2.1 Information, sets, indices and parameters used by the Conduct Test in section 11 are described in section 3. In addition, the list of *resources* produced pursuant to section 10.8.1 shall also be used by the Conduct Test.

11.3 Variables

11.3.1 The *day-ahead market calculation engine* shall apply the Conduct Test set out in sections 11.4 and 11.5 to the *resources* identified by the Constrained Area Conditions Test in accordance with section 10.8, to identify the following data sets:

11.3.1.1 The sets of *resources* that failed the Conduct Test for at least one *financial dispatch data parameter*, where:

11.3.1.1.1 BCT_h^{NCA} designates the *resources* in a *narrow constrained area* that failed the Conduct Test for at least one *financial dispatch data parameter* in hour $h \in \{1,..,24\}$;

11.3.1.1.2 BCT_h^{DCA} designates the *resources* in a *dynamic constrained area* that failed the Conduct Test for at least one *financial dispatch data parameter* in hour $h \in \{1,..,24\}$;

11.3.1.1.3 BCT_h^{BCA} designates the *resources* in a broad constrained area that failed the Conduct Test for at least one *financial dispatch data parameter* in hour $h \in \{1,..,24\}$;

11.3.1.1.4 BCT_h^{GMP} designates the *resources* that failed the global market power for *energy* Conduct Test for at least one *financial dispatch data parameter* in hour $h \in \{1,..,24\}$;

11.3.1.1.5 BCT_h^{ORL} designates the *resources* that failed the local market power for *operating reserve* Conduct Test for at least one *financial dispatch data parameter* in hour $h \in \{1, .., 24\}$; and

11.3.1.1.6 BCT_h^{ORG} designates the *resources* that failed the global market power Conduct Test for *operating reserve* for at least one *financial dispatch data parameter* in hour $h \in \{1,..,24\}$;

11.3.1.2 The following *financial dispatch data parameters* for all hours $h \in \{1, .., 24\}$:

11.3.1.2.1 $PARAME_{h,b}$ designates the set of *dispatch data* parameters that failed the *energy* Conduct Test at bus $b \in BCT_h^{NCA} \cup BCT_h^{DCA} \cup BCT_h^{BCA} \cup BCT_h^{GMP}$ in hour h, and may include the following *dispatch data* parameters:

11.3.1.2.1.1 $EnergyOffer_k$ designates the non-zero quantity of *energy* above the *minimum loading point* in association with *offer* lamination $k \in K_{h,b}^{E}$ failed the Conduct Test;

11.3.1.2.2 For all hours prior to and including the last hour where conditions are met for the *energy* Conduct Test:

11.3.1.2.2.1 $EnergyToMLP_k$ designates the non-zero quantity of *energy* up to the *minimum loading point* in association with *offer* lamination $k \in K_{h,b}^{LTMLP}$ failed the Conduct Test;

11.3.1.2.2.2 $SUOffer$ designates the *start-up offer* failed the Conduct Test; and

11.3.1.2.2.3 $SNLOffer$ designates the *speed no-load offer* failed the Conduct Test;

11.3.1.2.3 $PARAMOR_{h,b}$ designates the set of *dispatch data* parameters that failed the *operating reserve* Conduct Test at bus $b \in BCT_h^{ORL} \cup BCT_h^{ORG}$ in hour h, and may include the following *dispatch data* parameters:

11.3.1.2.3.1 $OR10SOffer_k$ designates the non-zero quantity of synchronized *ten-minute operating reserve* in association with *offer* lamination $k \in K_{h,b}^{10S}$ failed the Conduct Test;

11.3.1.2.3.2 $OR10NOffer_k$ designates the non-zero quantity of non-synchronized *ten-minute operating reserve* in association with *offer* lamination $k \in K^{10N}_{h,b}$ failed the Conduct Test;

11.3.1.2.3.3 $OR30ROffer_k$ designates the non-zero quantity of *thirty-minute operating reserve* in association with *offer* lamination $k \in K^{30R}_{h,b}$ failed the Conduct Test; and

11.3.1.2.4 For all hours prior to and including the last hour where conditions are met for the *operating reserve* Conduct Test:

11.3.1.2.4.1 $SUOffer$ designates the *start-up offer* failed the Conduct Test;

11.3.1.2.4.2 $SNLOffer$ designates the *speed no-load offer* failed the Conduct Test; and

11.3.1.2.4.3 $EnergyToMLP_k$ designates the non-zero quantity of *energy* up to the *minimum loading point* in association with *offer* lamination $k \in K^{E}_{h,b}$ failed the Conduct Test.

11.4 Conduct Test for Energy

11.4.1 The *day-ahead market calculation engine* shall perform the Conduct Test for *energy* for *resources* in a *narrow constrained area* that were identified pursuant to section 10.8.1 as follows, subject to sections 11.4.2 and 11.4.3. For each hour $h \in \{1,..,24\}$ and $b \in BCond^{NCA}_h$, the *day-ahead market calculation engine* shall:

11.4.1.1 Evaluate *offers* for *energy* above the *minimum loading point*: For all $k \in K^{E}_{h,b}$, if $PDG_{h,b,k} > CTEnMinOffer$ and $PDG_{h,b,k} > min(PDGRef_{h,b,k'} + (abs(PDGRef_{h,b,k'})*CTEnThresh1^{NCA}), PDGRef_{h,b,k'} + CTEnThresh2^{NCA})$, where $k' \in K'^{E}_{h,b}$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT^{NCA}_h and add $EnergyOffer_k$ to $PARAME_{h,b}$;

11.4.1.2 Evaluate *offers* for *energy* for the range of production up to the *minimum loading point*: For all hours prior to and including the hour that qualified to be tested under the Constrained Area Conditions Test, for all $k \in K^{LTMLP}_{h,b}$, if $PLTMLP_{h,b,k} > CTEnMinOffer$ and

$PLTMLP_{h,b,k} > min(PLTMLPRef_{h,b,k'} + (abs(PLTMLPRef_{h,b,k'}) * CTEnThresh1^{NCA}), PLTMLPRef_{h,b,k'} + CTEnThresh2^{NCA})$, where $k' \in K^{E}_{h,b}$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{NCA} and add $EnergyToMLP_k$ to $PARAME_{h,b}$ and $PARAMOR_{h,b}$;

11.4.1.3 Evaluate *start-up offers*: For all hours prior to and including the hour where conditions are met for the Constrained Area Conditions Test in section 10 , if $SUDG_{h,b} > SUDGRef_{h,b} + (abs(SUDGRef_{h,b}) * CTSUThresh^{NCA})$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{NCA} and add $SUOffer$ to $PARAME_{h,b}$ and $PARAMOR_{h,b}$; and

11.4.1.4 Evaluate *speed no-load offers*: For all hours prior to and including the hour that meets the conditions test, if $SNL_{h,b} > SNLRef_{h,b} + (abs(SNLRef_{h,b}) * CTSNLThresh^{NCA})$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{NCA} and add $SNLOffer$ to $PARAME_{h,b}$ and $PARAMOR_{h,b}$.

11.4.2 For *resources* identified pursuant to section 10.8.1 in a *dynamic constrained area* or broad constrained area, the *day-ahead market calculation engine* shall use the steps in section 11.4.1 , using *resources* in $BCond_h^{DCA}$ or $BCond_h^{BCA}$, as the case may be, in place of $BCond_h^{NCA}$ and using the applicable Conduct Test thresholds $CTEnThresh1^{DCA}$, $CTEnThresh2^{DCA}$, $CTEnThresh1^{BCA}$, $CTEnThresh2^{BCA}$, $CTSUThresh^{DCA}$, $CTSUThresh^{BCA}$, $CTSNLThresh^{DCA}$, $CTSNLThresh^{BCA}$. If any of the *financial dispatch data parameters* of a *resource* fail the Conduct Test, the *resource* shall be assigned to subset BCT_h^{DCA} or BCT_h^{BCA}, as the case may be.

11.4.3 For *resources* identified pursuant to section 10.8.1 that were selected for global market power mitigation testing for *energy,* the *day-ahead market calculation engine* shall use the steps in section 11.4.1, using *resources* in $BCond_h^{GMP}$ in place of $BCond_h^{NCA}$ and the applicable global market power Conduct Test thresholds $CTEnThresh1^{GMP}$, $CTEnThresh2^{GMP}$, $CTSUThresh^{GMP}$, $CTSNLThresh^{GMP}$. If any of the applicable *financial dispatch data parameters* of a *resource* fails the Conduct Test, the *resource* shall be assigned to subset BCT_h^{GMP}.

11.4.4 If a *resource* is assigned to more than one of the sets, $BCond_h^{NCA}$, $\mathrm{BCond}_\mathrm{h}^{\mathrm{DCA}}$, $BCond_h^{BCA}$, and $BCond_h^{GMP}$, only the Conduct Test with the most restrictive threshold levels shall be performed for that *resource*.

11.5 Conduct Test for Operating Reserve

11.5.1 The *day-ahead market calculation engine* shall perform the Conduct Test for local market power for *operating reserve* for *resources* that were identified pursuant to section 10.8.1, as follows, subject to 11.5.3. For each hour $h \in \{1,..,24\}$ and $b \in BCond_h^{10S} \cup BCond_h^{10N} \cup BCond_h^{30R}$, the *day-ahead market calculation engine* shall:

11.5.1.1 Evaluate *offers* for *operating* reserve as follows:

11.5.1.1.1 for all $k \in K_{h,b}^{10S}$ if $P10SDG_{h,b,k} > CTORMinOffer$ and $P10SDG_{h,b,k} > min(P10SDGRef_{h,b,k`} + (abs(P10SDGRef_{h,b,k`}) * CTORThresh1^{ORL}), P10SDGRef_{h,b,k`} + CTORThresh2^{ORL})$, where $k' \in K_{h,b}^{'10S}$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $OR10SOffer_k$ to $PARAMOR_{h,b}$;

11.5.1.1.2 for all $k \in K_{h,b}^{10N}$ if $P10NDG_{h,b,k} > CTORMinOffer$ and $P10NDG_{h,b,k} > min(P10NDGRef_{h,b,k`} + (abs(P10NDGRef_{h,b,k`}) * CTORThresh1^{ORL}), P10NDGRef_{h,b,k`} + CTORThresh2^{ORL})$, where $k' \in K_{h,b}^{'10N}$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $OR10NOffer_k$ to $PARAMOR_{h,b}$; and

11.5.1.1.3 for all $k \in K_{h,b}^{30R}$ if $P30RDG_{h,b,k} > CTORMinOffer$ and $P30RDG_{h,b,k} > min(P30RDGRef_{h,b,k`} + (abs(P30RDGRef_{h,b,k`}) * CTORThresh1^{ORL}), P30RDGRef_{h,b,k`} + CTORThresh2^{ORL})$, where $k' \in K_{h,b}^{'30R}$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $OR30ROffer_k$ to $PARAMOR_{h,b}$;

11.5.1.1.4 for all $j \in J_{h,b}^{10S}$ if $P10SDL_{h,b,j} > CTORMinOffer$ and $P10SDL_{h,b,j} > min(P10SDLRef_{h,b,j`} + (abs(P10SDLRef_{h,b,j`}) * CTORThresh1^{ORL}), P10SDLRef_{h,b,j`} + CTORThresh2^{ORL})$, where $j' \in J_{h,b}^{'10S}$, then the Conduct Test was failed for the *dispatchable load* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $OR10SOffer_k$ to $PARAMOR_{h,b}$;

11.5.1.1.5 for all $j \in J_{h,b}^{10N}$ if $P10NDL_{h,b,j}$ > *CTORMinOffer* and $P10NDL_{h,b,j} > min(P10NDLRef_{h,b,j`} + (abs(P10NDLRef_{h,b,j`}) * CTORThresh1^{ORL}), P10NDLRef_{h,b,j`} + CTORThresh2^{ORL})$, where $j' \in J_{h,b}^{\prime 10N}$, then the Conduct Test was failed for the *dispatchable load* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $OR10NOffer_k$ to $PARAMOR_{h,b}$; and

11.5.1.1.6 for all $j \in J_{h,b}^{30R}$ if $P30RDL_{h,b,j}$ > *CTORMinOffer* and $P30RDL_{h,b,j} > min(P30RDLRef_{h,b,j`} + (abs(P30RDLRef_{h,b,j`}) * CTORThresh1^{ORL}), P30RDLRef_{h,b,j`} + CTORThresh2^{ORL})$, where $j' \in J_{h,b}^{\prime 30R}$, then the Conduct Test was failed for the *dispatchable load* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $OR30ROffer_k$ to $PARAMOR_{h,b}$;

11.5.1.2 Evaluate *start-up offers*: For all hours prior to and including the hour that meets the Constrainted Area Conditions Test, if $SUDG_{h,b} > SUDGRef_{h,b} + (abs(SUDGRef_{h,b}) * CTSUThresh^{ORL})$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add *SUOffer* to $PARAMOR_{h,b}$ and $PARAME_{h,b}$;

11.5.1.3 Evaluate *speed no-load offers*: For all hours prior to and including the hour that meets the conditions test, if $SNL_{h,b} > SNLRef_{h,b} + (abs(SNLRef_{h,b}) * CTSNLThresh^{ORL})$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add *SNLOffer* to $PARAMOR_{h,b}$ and $PARAME_{h,b}$; and

11.5.1.4 Evaluate *offers* for *energy* for the range of production up to the *minimum loading point*: For all hours prior to and including the hour that meets the conditions test, for all $k \in K_{h,b}^{LTMLP}$, if $PLTMLP_{h,b,k} > CTEnMinOffer$ and $PLTMLP_{h,b,k} > min(PLTMLPRef_{h,b,k`} + (abs(PLTMLPRef_{h,b,k`}) * CTEnThresh1^{ORL}), PLTMLPRef_{h,b,k`} + CTEnThresh2^{ORL})$, where $k' \in$

$K'^{E}_{h,b}$, then the Conduct Test was failed for the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_h^{ORL} and add $EnergyToMLP_k$ to $PARAMOR_{h,b}$ and $PARAME_{h,b}$.

11.5.2 The *day-ahead market calculation engine* shall perform the Conduct Test for global market power for *operating reserve* for *resources* that were identified pursuant to section 10.8.1. The *day-ahead market calculation engine* shall use the steps set out in section 11.5.1 using *resources* in $BCond_h^{GMP10S}$, $BCond_h^{GMP10N}$, and $BCond_h^{GMP30R}$ in place of $BCond_h^{10S}$, $BCond_h^{10N}$, and $BCond_h^{30R}$, respectively, and the applicable Conduct Test thresholds $CTORThresh1^{ORG}$, $CTORThresh2^{ORG}$, $CTSUThresh^{ORG}$, $CTSNLThresh^{ORG}$, $CTEnThresh1^{ORG}$, $CTEnThresh2^{ORG}$. The *resources* shall be assigned to the subset BCT_h^{ORG}.

11.5.3 If a *resource* is assigned to more than one of $BCond_h^{GMP10S}$, $BCond_h^{GMP10N}$, and $BCond_h^{GMP30R}$, only the Conduct Test with the most restrictive threshold levels shall be performed for that *resource*.

11.6 Outputs

11.6.1 Subject to section 11.6.2, the outputs of the Conduct Test shall include the following for each hour $h \in \{1, . . , 24\}$:

11.6.1.1 The set of *resources* that failed the Conduct Test for at least one *financial dispatch data parameter* by condition type;

11.6.1.2 The *financial dispatch data parameters* that failed the Conduct Test for the *resource* at bus b; and

11.6.1.3 A revised set of *financial dispatch data parameters* for *resources* that failed a Conduct Test with *dispatch data* parameters that failed the Conduct Test replaced with *reference level values*. For *offers* for *energy* and *operating reserve* with multiple laminations:

11.6.1.3.1 if the *offer* lamination for *energy* that corresponds to the *minimum loading point* fails the Conduct Test, the *day-ahead market calculation engine* shall replace all *offer* laminations for *energy* up to the *minimum loading point*;

11.6.1.3.2 if one or more *offer* laminations for *energy* above the *minimum loading point* fails the Conduct Test, the *day-ahead market calculation engine* shall replace all *offer* laminations for *energy* up to and above the *minimum loading point*; and

11.6.1.3.3 if one or more *offer* laminations for *operating reserve* fails the Conduct Test, the *day-ahead market calculation engine* shall replace all *offer* laminations for *operating reserve*.

11.6.2 The *day-ahead market calculation engine* shall not replace the *financial dispatch data parameter* for a *resource* with that *resource's* applicable *reference level value* if the *financial dispatch data parameter* is less than the corresponding *reference level value*.

12 Reference Level Scheduling

12.1 Purpose

12.1.1 The *day-ahead market calculation engine* shall perform the Reference Level Scheduling algorithm where at least one *financial dispatch data parameter* for a *resource* failed the Conduct Test in section 11.

12.1.2 The Reference Level Scheduling algorithm shall perform a *security*-constrained unit commitment and economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants,* including *reference level value* for *resources* subject to section 12.2.2, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day*.

12.2 Information, Sets, Indices and Parameters

12.2.1 Information, sets, indices and parameters used by the Reference Level Scheduling algorithm are described in section 3 and 4. In addition, the list of *resources* that failed the Conduct Test from section 11.6.1.1 and a revised set of *financial dispatch data parameters* from section 11.6.1.3, for those *resources* shall be used by the Reference Level Scheduling algorithm.

12.2.2 The Reference Level Scheduling algorithm shall use the *reference level value* that corresponds to any *financial dispatch data parameter* submitted for a *resource* that failed the Conduct Test.

12.3 Variables and Objective Function

12.3.1 The *day-ahead market calculation engine* shall solve for the variables listed in section 8.3.1.

12.3.2 The objective function for the Reference Level Scheduling algorithm shall be the same as the objective function in section 8.3.2, subject to section 12.4.

12.4 Constraints

12.4.1 The constraints in sections 8.4 through 8.7 apply in the Reference Level Scheduling algorithm, except that the sensitivities and limits considered for *IESO* internal transmission limits shall be those provided by the most recent *security* assessment function iteration of the Reference Level Scheduling algorithm.

12.5 Outputs

12.5.1 Outputs of the Reference Level Scheduling algorithm include *resource* schedules and commitments.

13 Reference Level Pricing

13.1 Purpose

13.1.1 The *day-ahead market calculation engine* shall perform the Reference Level Pricing algorithm whenever the Reference Level Scheduling algorithm has been performed.

13.1.2 The Reference Level Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants, reference level values* for *resources* subject to section 13.2.2, and *resource* schedules and commitments produced by the Reference Level Scheduling algorithm, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day.*

13.2 Information, Sets, Indices and Parameters

13.2.1 Information, sets, indices and parameters used by the Reference Level Pricing algorithm are described in sections 3 and 4. In addition, the following *resource* schedule and commitments from the Reference Level Scheduling algorithm shall be used by the Reference Level Pricing algorithm:

13.2.1.1 $SDG^{RLS}_{h,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDG_b$ at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,b}$;

13.2.1.2 $ODG_{h,b}^{RLS}$ designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1, . . , 24\}$;

13.2.1.3 $S10SDG_{h,b,k}^{RLS}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K_{h,b}^{10S}$;

13.2.1.4 $S10NDG_{h,b,k}^{RLS}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K_{h,b}^{10N}$;

13.2.1.5 $S30RDG_{h,b,k}^{RLS}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K_{h,b}^{30R}$; and

13.2.1.6 $OHO_{h,b}^{RLS}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1, . . , 24\}$.

13.2.2 The Reference Level Pricing algorithm shall use a *resource's reference level value* for any *financial dispatch data parameters* submitted by *registered market participants* that failed the Conduct Test.

13.3 Variables and Objective Function

13.3.1 The *day-ahead market calculation engine* shall solve for the variables set out in section 9.3.1.

13.3.2 The objective function used in the Reference Level Pricing algorithm shall be the same as the objective function set out in section 9.3.2, subject to section 13.4.

13.4 Constraints

13.4.1 The constraints that apply in the Reference Level Pricing algorithm shall be the same as the constraints in sections 9.4 through 9.8, with the following exceptions:

13.4.1.1 the marginal loss factors used in the *energy* balance constraint in section 9.7.1 shall be fixed to the marginal loss factors used in the last optimization function iteration of the Reference Level Scheduling alogorithm;

13.4.1.2 the sensitivities and limits in section 9.7.3 shall be replaced with the most recent *security* assessment function iteration of the Reference Level Pricing algorithm; and

13.4.1.3 for the constraints in section 9.8, the outputs from the As-Offered Scheduling algorithm shall be replaced with the outputs from the Reference Level Scheduling algorithm as follows:

13.4.1.3.1 $SDG_{h,b,k}^{AOS}$ shall be replaced by $SDG_{h,b,k}^{RLS}$ for all $h \in \{1, . . . , 24\}, b \in B^{ELR} \cup B^{HE}, k \in K_{h,b}^{E}$;

13.4.1.3.2 $ODG_{h,b}^{AOS}$ shall be replaced by $ODG_{h,b}^{RLS}$ for all $h \in \{1, . . . , 24\}, b \in B^{DG}$;

13.4.1.3.3 $S10SDG_{h,b,k}^{AOS}$ shall be replaced by $S10SDG_{h,b,k}^{RLS}$ for all $h \in \{1, . . . , 24\}, b \in B^{ELR} \cup B^{HE}, k \in K_{h,b}^{10S}$;

13.4.1.3.4 $S10NDG_{h,b,k}^{AOS}$ shall be replaced by $S10NDG_{h,b,k}^{RLS}$ for all $h \in \{1, . . . , 24\}, b \in B^{ELR} \cup B^{HE}, k \in K_{h,b}^{10N}$;

13.4.1.3.5 $S30RDG_{h,b,k}^{AOS}$ shall be replaced by $S30RDG_{h,b,k}^{RLS}$ for all $h \in \{1, . . . , 24\}, b \in B^{ELR} \cup B^{HE}, k \in K_{h,b}^{30R}$; and

13.4.1.3.6 $OHO_{h,b}^{AOS}$ shall be replaced by $OHO_{h,b}^{RLS}$ for all $h \in \{1, . . . , 24\}, b \in B^{HE}$.

13.5 Outputs

13.5.1 Outputs of the Reference Level Pricing algorithm include the following:

13.5.1.1 shadow prices; and

13.5.1.2 *locational marginal prices* and their components.

14 Price Impact Test

14.1 Purpose

14.1.1 The *day-ahead market calculation engine* shall perform the Price Impact Test whenever at least one *financial dispatch data parameter* for a *resource* failed the Conduct Test.

14.1.2 The Price Impact Test shall:

14.1.2.1 compare the *locational marginal prices* for *energy* or *operating reserve* produced by the As-Offered Pricing algorithm with those produced by the Reference Level Pricing algorithm; and

14.1.2.2 consider the corresponding *offer* parameters to have failed the Price Impact Test if the difference in price in section 14.1.2.1 is greater than the applicable impact threshold in section 4.3.8.

14.2 Information, Sets, Indices and Parameters

14.2.1 Information, sets, indices and parameters for the Price Impact Test are described in sections 3 and 4. In addition, the following *locational marginal prices* from the As-Offered Pricing algorithm and the Reference Level Pricing algorithm shall be used by the Price Impact Test:

14.2.1.1 $LMP_{h,b}^{AOP}$, which designates the *locational marginal price* for *energy* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the As-Offered Pricing algorithm;

14.2.1.2 $L30RP_{h,b}^{AOP}$, which designates the *locational marginal price* for *thirty-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the As-Offered Pricing algorithm;

14.2.1.3 $L10NP_{h,b}^{AOP}$, which designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the As-Offered Pricing algorithm;

14.2.1.4 $L10SP_{h,b}^{AOP}$, which designates the *locational marginal price* for synchronized *ten-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the As-Offered Pricing algorithm;

14.2.1.5 $LMP_{h,b}^{RLP}$, which designates the *locational marginal price* for *energy* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the Reference Level Pricing algorithm;

14.2.1.6 $L30RP_{h,b}^{RLP}$, which designates the *locational marginal price* for *thirty-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the Reference Level Pricing algorithm;

14.2.1.7 $L10NP_{h,b}^{RLP}$, which designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the Reference Level Pricing algorithm; and

14.2.1.8 $L10SP_{h,b}^{RLP}$, which designates the *locational marginal price* for synchronized *ten-minute operating reserve* at bus $b \in B$ in hour $h \in \{1,..,24\}$ from the Reference Level Pricing algorithm.

14.3 Variables

14.3.1 The *day-ahead market calculation engine* shall apply the Price Impact Test as set out in sections 14.4 and 14.5 for the *resources* identified in accordance with section 10.3.1, to identify:

14.3.1.1 A set of *resources* that failed the Price Impact Test for each condition for all hours $h \in \{1,..,24\}$, where:

14.3.1.1.1 BIT_h^{NCA} designates the *resources* in a *narrow constrained area* that failed the Price Impact Test for the *locational marginal price* for *energy*;

14.3.1.1.2 BIT_h^{DCA} designates the *resources* in a *dynamic constrained area* that failed the Price Impact Test for the *locational marginal price* for *energy*;

14.3.1.1.3 BIT_h^{BCA} designates the *resources* in a broad constrained area that failed the Price Impact Test for the *locational marginal price* for *energy*;

14.3.1.1.4 BIT_h^{GMP} designates the *resources* that failed the global market power (*energy*) Price Impact Test for the *locational marginal price* for *energy*;

14.3.1.1.5 BIT_h^{ORL} designates the *resources* that failed the local market power (*operating reserve*) Price Impact Test for at least one type of *locational marginal price* for *operating reserve*;

14.3.1.1.6 BIT_h^{ORG} designates the *resources* that failed the global market power (*operating reserve*) Price Impact Test for at least one type of *locational marginal price* for *operating reserve*; and

14.3.1.1.7 $LMPIT_{h,b}$ designates the *locational marginal price* that failed the Price Impact Test for bus $b \in BIT_h^{NCA} \cup BIT_h^{DCA} \cup BIT_h^{BCA} \cup BIT_h^{GMP} \cup BIT_h^{ORL} \cup BIT_h^{ORG}$ in hour h; and

14.3.1.2 *Locational marginal prices* for *energy* and *operating reserve* for each *resource* at bus $b \in B^{DG} \cup B^{DL}$ that failed the Price Impact Test, where:

14.3.1.2.1 $EnergyLMP$ designates that the *locational marginal price* for *energy* failed the Price Impact Test;

14.3.1.2.2 $OR10SLMP$ designates that the *locational marginal price* for synchronized *ten-minute operating reserve* failed the Price Impact Test;

14.3.1.2.3 $OR10NLMP$ designates that the *locational marginal price* for non-synchronized *ten-minute operating reserve* failed the Price Impact Test; and

14.3.1.2.4 $OR30RLMP$ designates that the *locational marginal price* for *thirty-minute operating reserve* failed the Price Impact Test.

14.4 Price Impact Test for Energy

14.4.1 The *day-ahead market calculation engine* shall perform the Price Impact Test for *resources* that were identified in the corresponding Conduct Test for *energy* in section 11.6.1.1, as follows:

14.4.1.1 For local market power for *energy*:

14.4.1.1.1 For each hour $h \in \{1, \ldots, 24\}$ and $b \in BCT_h^{NCA}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} + (abs(LMP_{h,b}^{RLP}) * ITThresh1^{NCA}), LMP_{h,b}^{RLP} + ITThresh2^{NCA})$, the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{NCA} and add $EnergyLMP$ to $LMPIT_{h,b}$;

14.4.1.1.2 For each hour $h \in \{1, \ldots, 24\}$ and $b \in BCT_h^{DCA}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} + (abs(LMP_{h,b}^{RLP}) * ITThresh1^{DCA}), LMP_{h,b}^{RLP} + ITThresh2^{DCA})$, the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{DCA} and add $EnergyLMP$ to $LMPIT_{h,b}$; and

14.4.1.1.3 For each hour $h \in \{1, . . , 24\}$ and $b \in BCT_h^{BCA}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} + (abs(LMP_{h,b}^{RLP}) * ITThresh1^{BCA}), LMP_{h,b}^{RLP} + ITThresh2^{BCA})$, the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{BCA} and add $EnergyLMP$ to $LMPIT_{h,b}$.

14.4.1.2 For global market power for *energy*:

14.4.1.2.1 For each hour $h \in \{1, . . , 24\}$ and $b \in BCT_h^{GMP}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} + (abs(LMP_{h,b}^{RLP}) * ITThresh1^{GMP}), LMP_{h,b}^{RLP} + ITThresh2^{GMP})$, the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{GMP} and add $EnergyLMP$ to $LMPIT_{h,b}$.

14.5 Price Impact Test for Operating Reserve

14.5.1 The *day-ahead market calculation engine* shall perform the Price Impact Test for *resources* that were identified in the corresponding Conduct Test for *operating reserve* in section 11.6.1.1, as follows:

14.5.1.1 For local market power for *operating reserve*, for each hour $h \in \{1, . . , 24\}$ and $b \in BCT_h^{ORL}$:

14.5.1.1.1 If $L30RP_{h,b}^{AOP} > L30RP_{h,b}^{RLP}$, then the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{ORL} and add $OR30RLMP$ to $LMPIT_{h,b}$;

14.5.1.1.2 If $L10NP_{h,b}^{AOP} > L10NP_{h,b}^{RLP}$, then the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{ORL} and add $OR10NLMP$ to $LMPIT_{h,b}$; and

14.5.1.1.3 If $L10SP_{h,b}^{AOP} > L10SP_{h,b}^{RLP}$, then the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{ORL} and add $OR10SLMP$ to $LMPIT_{h,b}$.

14.5.1.2 For global market power for *operating reserve*, for each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{ORG}$:

14.5.1.2.1 If $L30RP_{h,b}^{AOP} > min(L30RP_{h,b}^{RLP} + (abs(L30RP_{h,b}^{RLP}) * ITThresh1^{ORG}), L30RP_{h,b}^{RLP} + ITThresh2^{ORG})$, then the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{ORG} and add $OR30RLMP$ to $LMPIT_{h,b}$;

14.5.1.2.2 If $L10NP_{h,b}^{AOP} > min(L10NP_{h,b}^{RLP} + (abs(L10NP_{h,b}^{RLP}) * ITThresh1^{ORG}), L10NP_{h,b}^{RLP} + ITThresh2^{ORG})$, then the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BIT_h^{ORG} and add $OR10NLMP$ to $LMPIT_{h,b}$; and

14.5.1.2.3 If $L10SP_{h,b}^{AOP} > min(L10SP_{h,b}^{RLP} + (abs(L10SP_{h,b}^{RLP}) * ITThresh1^{ORG}), L10SP_{h,b}^{RLP} + ITThresh2^{ORG})$, then the Price Impact Test was failed by the *resource* at bus b and the *day-ahead market calculation engine* shall assign the *resource* BIT_h^{ORG} and add $OR10SLMP$ to $LMPIT_{h,b}$.

14.6 Revised Financial Dispatch Data Parameter Determination

14.6.1.1 A *resource* that fails the Price Impact Test shall have its *financial dispatch data parameters* revised as follows:

14.6.1.1 If the *resource* has failed a Price Impact Test for *energy* and is in BIT_h^{NCA}, BIT_h^{DCA}, BIT_h^{BCA}, or BIT_h^{GMP}, the *dispatch data* parameters in $PARAME_{h,b}$ shall be used to determine the *dispatch data* parameters that shall be replaced.

14.6.1.2 If the *resource* has failed a Price Impact Test for *operating reserve* and is in BIT_h^{ORL} or BIT_h^{ORG}, the *dispatch data* parameters in $PARAMOR_{h,b}$ shall be used to determine the *dispatch data* parameters that shall be replaced.

14.6.1.3 If a *non-quick-start resource* has failed a Price Impact Test in any hour, the *commitment cost parameters* that failed the corresponding Conduct Test shall be replaced with the *resource's* applicable *reference level value* for that hour. For any hours prior, any *commitment cost parameters* for that *resource* that failed the Conduct Test shall be replaced with the *resource's* applicable *reference level values* in those hours. This is expressed as:

14.6.1.3.1 For each hour $h \in \{1, . . , 24\}$ and all $b \in B^{NQS}$ such that $b \in BIT_h^{NCA} \cup BIT_h^{DCA} \cup BIT_h^{BCA} \cup BIT_h^{GMP}$, for hours prior to and including the hour that failed the Price Impact Test, $H \in \{1, . . , h\}$, if $b \in BCT_H^{NCA} \cup BCT_H^{DCA} \cup BCT_H^{BCA} \cup BCT_H^{GMP}$ and $PARAME_{H,b}$ contains any of the *commitment cost parameters* $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, these parameters shall be replaced with *reference levels*.

14.6.1.4 Section 14.6.1.3 shall apply to the tests for local market power and global market power for *operating reserve*, except $PARAMOR_{H,b}$ shall be checked in place of $PARAME_{H,b}$.

14.6.1.5 If a *resource* is in a *narrow constrained area* or a *dynamic constrained area* and has failed a Price Impact Test, each *resource* in the same *narrow constrained area* or *dynamic constrained area* that also failed the corresponding Conduct Test shall have its *offer* data replaced with its applicable *reference level value* for that hour. For each hour $h \in \{1, . . , 24\}$:

14.6.1.5.1 if BIT_h^{NCA} includes one or more *resource* in a *narrow constrained area*, n, each *resource* $\mathrm{b} \in \mathrm{BCT}_h^{NCA}$ for the *narrow constrained area*, n, shall have the parameters in $PARAME_{h,b}$ replaced with its *reference level values*; and

14.6.1.5.2 if BIT_h^{DCA} includes one or more *resources* in a *dynamic constrained area*, d, each *resource* $b \in BCT_h^{DCA}$ for *dynamic constrained area*, d, shall have the parameters in $\mathrm{PARAME}_{\mathrm{h,b}}$ replaced with its *reference level values*.

14.6.1.6 If a *non-quick-start resource* in a *narrow constrained area* or a *dynamic constrained area* has failed a Price Impact Test, each *non-quick start resource* in the *narrow constrained area* or *dynamic constrained area* that also failed the corresponding Conduct Test shall have its *commitment cost parameters* replaced with its applicable *reference level value* for that hour. For any hours prior, if a *non-quick-start resource* in that *narrow constrained area* or *dynamic constrained area* has a *commitment cost parameter* that failed the Conduct Test, that *commitment cost parameter* shall be replaced with the *resource's* applicable *reference level value* in those hours. This is expressed as:

14.6.1.6.1 For all hours up to the hour in which a *resource* failed the Price Impact Test for a *narrow constrained area*, for all $b \in BCT_h^{NCA}$, if $PARAME_{h,b}$ contains any of the *commitment cost parameters* $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with *reference level values*.

14.6.1.6.2 For all hours up to the hour in which a *resource* failed the Price Impact Test for a *dynamic constrained area*, for all $b \in BCT_h^{DCA}$, if $PARAME_{h,b}$ contains any of the *commitment cost parameters* $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with *reference level values*.

14.6.1.7 If a *resource* fails the local market power for *operating reserve* Price Impact Test, all *resources* in the same *operating reserve* region with a non-zero *operating reserve* minimum requirement that failed the corresponding Conduct Test for at least one parameter shall have the parameter that failed the Conduct Test replaced with the *resource's* applicable *reference level value* for that hour. This is expressed as:

14.6.1.7.1 For each hour $h \in \{1, .., 24\}$, if BIT_h^{ORL} includes one or more *resources* in *operating reserve* region, r, all *resources*, $b \in BIT_h^{ORL}$ for *operating reserve* region, r, shall have the parameters in $PARAMOR_{h,b}$ replaced with *reference level values*.

14.6.1.8 If a *non-quick start resource* fails the local market power for *operating reserve* Price Impact Test in any hour, the *commitment cost parameters* for all *non-quick start resources* in the same *operating reserve* region with a non-zero *operating reserve* minimum requirement that failed the corresponding Conduct Test shall be replaced with the *resource's* applicable *reference level value* for that hour. For any hours prior, any *commitment cost parameters* of *non-quick start resources* that failed the Conduct Test shall be replaced with the *resource's* applicable *reference level value* in those hours. This is expressed as:

14.6.1.8.1 For all hours up to the hour in which a *resource* failed the Price Impact Test for r, for all $b \in BCT_h^{ORL}$, if $PARAME_{h,b}$ contains any of the *commitment cost parameters* $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with *reference level values*.

14.7 Outputs

14.7.1 The *day-ahead market calculation engine* shall prepare the following outputs for each hour $h \in \{1, . . , 24\}$:

14.7.1.1 The set of *resources* that failed the Price Impact Test, by condition, in accordance to sections 14.4 and 14.5;

14.7.1.2 The *locational marginal prices* for *energy* and *operating reserve* that failed the Price Impact Test for each *resource* at bus b in accordince to sections 14.4 and 14.5; and

14.7.1.3 A revised set of *offer* data for *resources* that failed the Price Impact Test, replacing *offer* data that failed the Conduct Test with the applicable *reference level values*, in accordance with section 14.6.

14.7.2 The *day-ahead market calculation engine* shall not replace *financial dispatch data parameters* for a *resource* with that *resource's* applicable *reference level value* if the *dispatch data* is less than the *reference level value*.

15 Mitigated Scheduling

15.1 Purpose

15.1.1 The *day-ahead market calculation engine* shall perform the Mitigated Scheduling algorithm if at least one *resource* failed the Price Impact Test in section 14.

15.1.2 The Mitigated Scheduling algorithm shall perform a *security*-constrained unit commitment and economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants,* including *resource reference level values* subject to section 15.2.2, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day.*

15.1 Information, Sets, Indices and Parameters

15.2.1 Information, sets, indices and parameters used by the Mitigated Scheduling algorithm are described in section 3 and 4. In addition, the Mitigated Scheduling algorithm shall use the list of *resources* that failed the Price Impact Test and a revised set of *financial dispatch data parameters* for those *resources*.

15.2.2 For *resources* identified in section 14.7.1, the Mitigated Scheduling algorithm shall use *reference level value* for any *financial dispatch data parameters* that failed the Conduct Test.

15.3 Variables, Objective Function and Constraints

15.3.1 The *day-ahead market calculation engine* shall solve for the variables set out in section 8.3.1.

15.3.2 The objective function for the Mitigated Scheduling algorithm shall be the same as the objective function in section 8.3.2, subject to the constraints in sections 8.4 through 8.7. The sensitivities and limits used in section 8.7.3 shall be replaced with those provided by the most recent *security* assessment function iteration in the Mitigated Scheduling algorithm.

15.4 Outputs

15.4.1 Outputs of the Mitigated Scheduling algorithm include *resource* schedules and commitments.

16 Mitigated Pricing

16.1 Purpose

16.1.1 The *day-ahead market calculation engine* shall perform the Mitigated Pricing algorithm if the *day-ahead market calculation engine* performs the Mitigated Scheduling algorithm.

16.1.2 The Mitigated Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants, resource reference level value* subject to section 16.2.2, and *resource* schedules and commitments produced by the Mitigated Scheduling algorithm, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day.*

16.2 Information, Sets, Indices and Parameters

16.2.1 Information, sets, indices and parameters used by the Mitigated Pricing algorithm are described in sections 3 and 4. In addition, the following *resource* schedules and commitments from the Mitigated Scheduling algorithm shall be used by the Mitigated Pricing algorithm:

16.2.1.1 $SDG^{MS}_{h,b,k}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDG_b$ at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{E}_{h,b}$;

16.2.1.2 $ODG^{MS}_{h,b}$ designates whether a *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1, . . , 24\}$;

16.2.1.3 $S10SDG^{MS}_{h,b,k}$ designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{10S}_{h,b}$;

16.2.1.4 $S10NDG^{MS}_{h,b,k}$ designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{10N}_{h,b}$;

16.2.1.5 $S30RDG^{MS}_{h,b,k}$ designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{30R}_{h,b}$; and

16.2.1.6 $OHO^{MS}_{h,b}$ designates whether a *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1, . . , 24\}$.

16.2.2 For each *resource* identified in section 14.7.1, the Mitigated Pricing algorithm shall use such *resource's reference level value* for any *financial dispatch data parameters* that failed the Conduct Test.

16.3 Variables and Objective Function

16.3.1 The *day-ahead market calculation engine* shall solve for the variables listed in section 9.3.1.

16.3.2 The objective function for the Mitigated Pricing algorithm shall be the same as the objective function in section 9.3.2, subject to section 16.4.

16.4 Constraints

16.4.1 The constraints that apply in the Mitigated Pricing algorithm shall be the same as the constraints in sections 9.4 through 9.8, with the following exceptions:

16.4.1.1 The marginal loss factors used in the *energy* balance constraint in section 9.7.1 shall be fixed to the marginal loss factors used in the last iteration of the optimization function in the Mitigated Scheduling algorithm.

16.4.1.2 The sensitivities and limits used in section 9.7.3 shall be replaced with those provided by the most recent *security* assessment function iteration in the Mitigated Pricing algorithm.

16.4.1.3 For the constraints in section 9.8, the outputs from the As-Offered Scheduling algorithm shall be replaced with the outputs from the Mitigated Scheduling algorithm as follows:

16.4.1.3.1 $SDG_{h,b,k}^{AOS}$ shall be replaced by $SDG_{h,b,k}^{MS}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{h,b}^{E}$;

16.4.1.3.2 $ODG_{h,b}^{AOS}$ shall be replaced by $ODG_{h,b}^{MS}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{DG}$;

16.4.1.3.3 $S10SDG_{h,b,k}^{AOS}$ shall be replaced by $S10SDG_{h,b,k}^{MS}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{h,b}^{10S}$;

16.4.1.3.4 $S10NDG_{h,b,k}^{AOS}$ shall be replaced by $S10NDG_{h,b,k}^{MS}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{h,b}^{10N}$;

16.4.1.3.5 $S30RDG_{h,b,k}^{AOS}$ shall be replaced by $S30RDG_{h,b,k}^{MS}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{h,b}^{30R}$; and

16.4.1.3.6 $OHO_{h,b}^{AOS}$ shall be replaced by $OHO_{h,b}^{MS}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{HE}$.

16.5 Outputs

16.5.1 Outputs of the Mitigated Pricing algorithm include the following:

16.5.1.1 Shadow prices; and

16.5.1.2 *Locational marginal prices* and their components.

17 Pass 2: Reliability Scheduling and Commitment

17.1 Purpose

17.1.1 Pass 2 shall use *market participant* and *IESO* inputs along with *resource* and system constraints to determine a set of *resource* schedules and commitments. Pass 2 shall consist of the Reliability Scheduling algorithm described in section 18.

18 Reliabilty Scheduling

18.1 Purpose

18.1.1 The Reliability Scheduling algorithm shall use *dispatch data* submitted by *registered market participants* and perform a *security*-constrained unit commitment and economic *dispatch* to meet the *IESO's* peak province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next day to minimize the cost of additional commitments.

18.2 Information, Sets, Indices and Parameters

18.2.1 Information sets, indices and parameters used by the Reliability Scheduling algorithm are described in sections 3 and 4. The Reliability Scheduling algorithm shall also use the following:

18.2.1.1 *resource* schedules, commitments, and *locational marginal prices* from Pass 1, where:

18.2.1.1.1 $SXL^1_{h,d,j}$ designates the amount of *energy* that a *boundary entity resource* is scheduled to export at *intertie zone* bus $d \in DX$ in hour $h \in \{1, . . , 24\}$ in association with lamination $j \in J^E_{h,d}$;

18.2.1.1.2 $SDG^1_{h,b,k}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDG_b$ at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^E_{h,b}$;

18.2.1.1.3 $ODG^1_{h,b}$ designates whether a *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1, . . , 24\}$;

18.2.1.1.4 $S10SDG^1_{h,b,k}$ designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{10S}_{h,b}$;

18.2.1.1.5 $S10NDG^1_{h,b,k}$ designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{10N}_{h,b}$;

18.2.1.1.6 $S30RDG^1_{h,b,k}$ designates the amount of *thirty-minute operating reserve* that a qualified *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^{30R}_{h,b}$;

18.2.1.1.7 $SIG^1_{h,d,k}$ designates the amount of *energy* that a *boundary entity resource* is scheduled to import at *intertie zone* bus $d \in DI$ in hour $h \in \{1, . . , 24\}$ in association with lamination $k \in K^E_{h,d}$; and

18.2.1.1.8 $LMP^1_{h,b}$ designates the *locational marginal price* in hour $h \in \{1, . . , 24\}$ at bus $b \in B^{ELR} \cup B^{HE}$; and

18.2.1.2 the buses identifying either single *energy limited resources* or multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay*, and the subset of *resources* with a binding *maximum daily energy limit* constraint from Pass 1:

18.2.1.2.1 $\mathrm{B^{LIM} = B^{ELR} \cup \{B^{HE}_s \text{ for all } s \in SHE\}}$ designates the set of buses identifying either *energy limited resources* or *dispatchable* hydroelectric *generation resources* sharing a *maximum daily energy limit*; and

18.2.1.2.2 $B^{BND} \subseteq B^{LIM}$ designates the subset of buses identifying either *energy limited resources*, or *dispatchable* hydroelectric *generation resources* sharing a *maximum* *daily energy limit*, with a binding *maximum daily energy limit* constraint from Pass 1, where:

a *maximum daily energy limit* shall be considered binding if the criteria in sections 9.8.2 and 9.8.3.6 are met using $ODG^1_{h,b}$, $SDG^1_{h,b,k}$, $S10SDG^1_{h,b,k}$, $S10NDG^1_{h,b,k}$ and $S30RDG^1_{h,b,k}$.

18.2.2 The Reliability Scheduling algorithm shall use *reference level value* for any *financial dispatch data parameters* that failed the Conduct Test associated with *resources* identified in section 14.7.

18.2.3 *Dispatchable loads*, *non-dispatchable generation resources*, and the *energy* offered above *minimum loading point* for *dispatchable generation resources* shall be evaluated in the Reliability Scheduling algorithm as follows:

18.2.3.1 $PRucDL_{h,b,j}$ designates the *energy* price for incremental *energy* consumption in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *bid* lamination $j \in J^E_{h,b}$, where:

$$PRucDL_{h,b,j} = min(n, PDL_{h,b,j});$$

18.2.3.2 $PRuc10SDL_{h,b,j}$ designates the price of being scheduled to provide synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$, where:

$$PRuc10SDL_{h,b,j} = min(n, P10SDL_{h,b,j});$$

18.2.3.3 $PRuc10NDL_{h,b,j}$ designates the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$, where:

$$PRuc10NDL_{h,b,j} = min(n, P10NDL_{h,b,j});$$

18.2.3.4 $PRuc30RDL_{h,b,j}$ designates the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$, where:

$$PRuc30RDL_{h,b,j} = min(n, P30RDL_{h,b,j});$$

18.2.3.5 $PRucNDG_{h,b,k}$ designates the *energy* price for incremental generation in hour $h \in \{1,..,24\}$ at *non-dispatchable generation resource* bus $b \in B^{NDG}$ in association with *offer* lamination $k \in K^E_{h,b}$, where:

$$PRucNDG_{h,b,k} = min(n, PNDG_{h,b,k});$$

18.2.3.6 $PRucDG_{h,b,k}$ designates the *energy* price for incremental generation in hour $h \in \{1,..,24\}$ at *dispatchable generation resource* bus $b \in B^{DG}$ in association with *offer* lamination $k \in K_{h,b}^{E}$, where:

$$PRucDG_{h,b,k} = min(n, PDG_{h,b,k});$$

18.2.3.7 $PRuc10SDG_{h,b,k}$ designates the price of being scheduled to provide synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable generation resource* bus $b \in B^{DG}$ in association with *offer* lamination $k \in K_{h,b}^{10S}$, where:

$$PRuc10SDG_{h,b,k} = min(n, P10SDG_{h,b,k});$$

18.2.3.8 $PRuc10NDG_{h,b,k}$ designates the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable generation resource* bus $b \in B^{DG}$ in association with *offer* lamination $k \in K_{h,b}^{10N}$, where:

$$PRuc10NDG_{h,b,k} = min(n, P10NDG_{h,b,k});$$

18.2.3.9 $PRuc30RDG_{h,b,k}$ designates the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable* generation bus $b \in B^{DG}$ in association with *offer* lamination $k \in K_{h,b}^{30R}$, where:

$$PRuc30RDG_{h,b,k} = min(n, P30RDG_{h,b,k});$$

where:

n = $0.10/MWh;

18.2.4 For the set of *resources* identified in the buses in section 18.2.1.2, incremental quantities of *energy* at or above *minimum loading point* shall be evaluated in the Reliability Scheduling algorithm as follows:

18.2.4.1 $Q1DG_{h,b,k}$ designates an incremental quantity of *energy* that a *resource* may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 scheduled portion of the lamination, where:

$$Q1DG_{h,b,k} = SDG_{h,b,k}^{1};$$

18.2.4.2 $P1DG_{h,b,k}$ designates the price for the incremental quantity of *energy* that a *resource* may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 scheduled portion of the lamination, where:

$$P1DG_{h,b,k} = min\left(PDG_{h,b,k}, -LMP_{h,b}^{1}\right);$$

18.2.4.3 $Q2DG_{h,b,k}$ designates an incremental quantity of *energy* that a *resource* may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 unscheduled portion of the lamination, where:

$$Q2DG_{h,b,k} = QDG_{h,b,k} - SDG_{h,b,k}^{1};$$ and

18.2.4.4 $P2DG_{h,b,k}$ designates the price for the incremental quantity of *energy* that a *resource* may be scheduled to provide in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 unscheduled portion of the lamination, where:

$$P2DG_{h,b,k} = \begin{cases} max(n, PDG_{h,b,k} - LMP_{h,b}^{1}) & if\ b \in B^{BND} \\ min(n, PDG_{h,b,k}) & otherwise \end{cases}.$$

18.3 Variable and Objective Function

18.3.1 The *day-ahead market calculation engine* shall solve for the variables listed in section 8.3.1.

18.3.2 The objective function for the Reliability Scheduling algorithm shall be the same as the objective function in section 8.3.2, with the following exceptions:

18.3.2.1 The *day-ahead market calculation engine* shall remove the variables for *price responsive loads* ($SPRL_{h,b,j}$), *virtual transaction bids* ($PVB_{h,v,j}$, $QVB_{h,v,j}$), and *virtual transaction offers* ($PVO_{h,v,k}$, $QVO_{h,v,k}$) from the objective function;

18.3.2.2 The *day-ahead market calculation engine* shall add the following variables to the objective function:

18.3.2.2.1 $S1DG_{h,b,k}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{LIM}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}^{E}$ corresponding to the Pass 1 scheduled portion of the lamination; and

18.3.2.2.2 $S2DG_{h,b,k}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{LIM}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}^{E}$ corresponding to the Pass 1 unscheduled portion of the lamination;

18.3.2.3 The objective function coefficients for *dispatchable loads*, *non-dispatchable generation resources* and *dispatchable generation resources* shall be modified to reflect the price of incremental *energy* from such *resources* as specified in section 18.2.3; and

18.3.2.4 The objective function coefficients for single *energy limited resources* and multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall be modified to reflect the pricing of the Pass 1 scheduled and unscheduled portions as specified in section 18.2.4.

18.3.3 The objective function for the Reliability Scheduling algorithm shall minimize the cost of additional commitments by maximizing the following expression:

$$\sum_{h=1,..,24} \begin{pmatrix} ObjDL_h - ObjHDR_h + ObjXL_h - ObjNDG_h \\ - ObjDG_h - ObjIG_h - TB_h - ViolCost_h \end{pmatrix}$$

where:

$$ObjDL_h = \sum_{b \in B^{DL}} \begin{pmatrix} \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} \cdot PRucDL_{h,b,j} - \sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \cdot PRuc10SDL_{h,b,j} - \\ \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \cdot PRuc10NDL_{h,b,j} - \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \cdot PRuc30RDL_{h,b,j} \end{pmatrix}$$

$$ObjHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J_{h,b}^{E}} SHDR_{h,b,j} \cdot PHDR_{h,b,j} \right)$$

$$ObjXL_h = \sum_{d \in DX} \begin{pmatrix} \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \cdot PXL_{h,d,j} - \sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \cdot P10NXL_{h,d,j} \\ - \sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \cdot P30RXL_{h,d,j} \end{pmatrix}$$

$$ObjNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{h,b}^{E}} SNDG_{h,b,k} \cdot PRucNDG_{h,b,k} \right)$$

$$
\begin{aligned}
&ObjDG_h \\
&= \sum_{b \in B^{DG},\ b \notin B^{LIM}} \left(\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \cdot PRucDG_{h,b,k} \right) \\
&+ \sum_{b \in B^{LIM}} \left(\sum_{k \in K_{h,b}^{E}} \left(S1DG_{h,b,k} \cdot P1DG_{h,b,k} + S2DG_{h,b,k} \cdot P2DG_{h,b,k} \right) \right) \\
&+ \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \cdot PRuc10SDG_{h,b,k}\ + \\ \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \cdot PRuc10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \cdot PRuc30RDG_{h,b,k} \end{array} \right) \\
&+ \sum_{b \in B^{NQS}} \left(ODG_{h,b} \cdot MGODG_{h,b}\ +\ IDG_{h,b} \cdot SUDG_{h,b} \right)
\end{aligned}
$$

$$
ObjIG_h\ = \sum_{d \in DI} \left(\begin{array}{c} \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \cdot PIG_{h,d,k}\ +\ \sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \cdot P10NIG_{h,d,k} \\ +\ \sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \cdot P30RIG_{h,d,k} \end{array} \right)
$$

18.3.3.1 The tie-breaking (TB_h) and the violation cost ($ViolCost_h$) terms used shall be the ones defined in sections 8.3.1 and 8.3.2.

18.4 Constraints

18.4.1 The Reliability Scheduling algorithm optimization shall apply the constraints described in sections 18.5 through 18.7 and 18.8.

18.5 Dispatch Data Constraints Applying to Individual Hours

18.5.1 Scheduling Variable Bounds and Commitment Status Variables

18.5.1.1 The constraints shall be the same as in section 8.5.1 with the following exceptions:

18.5.1.1.1 the constraints applying to *price responsive loads* in section 8.5.1.6 shall be removed; and

18.5.1.1.2 the constraints applying to *virtual transaction bids* and *offers* in section 8.5.1.6 shall be removed.

18.5.2 Resource Minimums and Maximums

18.5.2.1 The constraints in section 8.5.2 shall apply for *dispatchable loads*, *non-dispatchable generation resources* and inadvertent payback transactions.

18.5.2.2 The constraints in section 8.5.2 shall apply for *dispatchable generation resources*, except the alternative forecast ($AFG_{h,b}$) is replaced with the *IESO*'s centralized forecast ($FG_{h,b}$). That is:

$$AdjMaxDG_{h,b} = \begin{cases} min(MaxDG_{h,b}, FG_{h,b}) & if\ b \in B^{VG} \\ MaxDG_{h,b} & otherwise \end{cases}$$

and

$$AdjMinDG_{h,b} = min(MinDG_{h,b}, AdjMaxDG_{h,b})$$

Then, for all hours $h \in \{1, \ldots, 24\}$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{h,b} \leq MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq AdjMaxDG_{h,b}$$

18.5.3 Operating Reserve Requirements

18.5.3.1 The constraints in section 8.5.4 shall apply for *operating reserve* requirements.

18.5.4 Pseudo-Units

18.5.4.1 The constraints in section 8.5.5 shall apply for *pseudo-units*.

18.5.5 Dispatchable Hydroelectric Generation Resources

18.5.5.1 The constraints in section 8.5.6 shall apply for *dispatchable* hydroelectric *generation resources*.

18.5.6 Linked Wheeling Through Transactions

18.5.6.1 The constraints in section 8.5.7 shall apply for *linked wheeling through transactions*.

18.6 Dispatch Data Inter-Hour/Multi-Hour Constraints

18.6.1 Energy Ramping

18.6.1.1 The constraints in section 8.6.1 shall apply for *energy* ramping.

18.6.2 Operating Reserve Ramping

18.6.2.1 The constraints in section 8.6.2 shall apply for *operating reserve* ramping.

18.6.3 Non-Quick-start Resources

18.6.3.1 The constraints in section 8.6.3 shall apply for *non-quick start resources*.

18.6.4 Energy Limited Resources

18.6.4.1 The constraints in section 8.6.4 shall apply for *energy limited resources*.

18.6.5 Dispatchable Hydroelectric Generation Resources

18.6.5.1 The constraints in section 8.6.5 shall apply for *dispatchable* hydroelectric *generation resources*.

18.7 Constraints for Reliability Requirements

18.7.1 Energy Balance

18.7.1.1 The constraint in section 8.7.1 shall apply in the Reliability Scheduling algorithm, with the following exceptions:

18.7.1.1.1 *price responsive loads* shall be removed from the total amount of scheduled *energy* withdrawals, $With_{h,b}$, in section 8.7.1.1;

18.7.1.1.2 the net withdrawal for *virtual transaction zones,* $VWith_{h,m}$, in sections 8.7.1.2 and 8.7.1.6 shall be removed; and

18.7.1.1.3 the Reliability Scheduling algorithm shall use the *IESO's* peak province-wide non-*dispatchable demand* forecast (PFL_h), in place of the *IESO's* average province-wide non-*dispatchable demand* forecast (AFL_h).

18.7.1.2 The total amount of *energy* withdrawals scheduled at load bus $b \in B$ in hour $h \in \{1,..,24\}$, $With_{h,b}$, shall be:

$$With_{h,b} = \begin{cases} \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} & if\ b \in B^{DL} \\ \sum_{j \in J_{h,b}^{E}} (QHDR_{h,b,j} - SHDR_{h,b,j}) & if\ b \in B^{HDR} \end{cases}$$

18.7.1.3 The total amount of *energy* withdrawals scheduled at *intertie zone* bus $d \in DX$ in hour $h \in \{1,..,24\}$, $With_{h,d}$, shall be:

$$With_{h,d} = \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j}$$

18.7.1.4 The total amount of *energy* injections scheduled at internal bus $b \in B$ in hour $h \in \{1,..,24\}$, $Inj_{h,b}$, shall be:

$$Inj_{h,b} = OfferInj_{h,b} + RampInj_{h,b}$$

where:

$$OfferInj_{h,b} = \begin{cases} \sum_{k \in K_{h,b}^{E}} SNDG_{h,b,k} & if\ b \in B^{NDG} \\ ODG_{h,b} \cdot MinQDG_{b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} & if\ b \in B^{DG} \end{cases}$$

and

$$RampInj_{h,b} = \begin{cases} \sum_{w=1..min(RampHrs_{b},24-h)} RampE_{b,w} \cdot IDG_{h+w,b} & if\ b \in B^{NQS} \\ 0 & otherwise \end{cases}$$

18.7.1.5 The total amount of *energy* injections scheduled at *intertie zone* bus $d \in DI$ in hour $h \in \{1,..,24\}$, $Inj_{h,d}$, shall be:

$$Inj_{h,d} = \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k}.$$

18.7.1.6 *Energy* injections and withdrawals at each bus shall be multiplied by one plus the marginal loss factor from the *security* assessment function to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted *energy* injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the *demand* constraint violation shall be subtracted from the total load or generation to allow the *day-ahead market calculation engine* to produce a solution. For hour $h \in \{1,..,24\}$:

$$\begin{aligned} PFL_h + \sum_{b \in B^{DL} \cup B^{HDR}} (1 + MglLoss_{h,b}) \cdot With_{h,b} \\ + \sum_{d \in DX} (1 + MglLoss_{h,d}) \cdot With_{h,d} \\ - \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \\ = \sum_{b \in B^{NDG} \cup B^{DG}} \left(1 + MglLoss_{h,b}\right) \cdot Inj_{h,b} \\ + \sum_{d \in DI} \left(1 + MglLoss_{h,d}\right) \cdot Inj_{h,d} \\ - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} + LossAdj_h. \end{aligned}$$

18.7.2 Operating Reserve Requirements

18.7.2.1 The constraints in section 8.7.2 shall apply for *operating reserve*.

18.7.3 IESO Internal Transmission Limits

18.7.3.1 The constraints in section 8.7.3 shall apply for *IESO* internal transmission limits. The sensitivities and limits applied shall be provided by the most recent *security* assessment function iteration of the Reliability Scheduling algorithm, with the following exceptions:

18.7.3.2 The terms for *price responsive loads* in sections 8.7.3.3 and 8.7.3.4 shall be removed; and

18.7.3.3 The terms for *bids* and *offers* for *virtual transactions* in sections 8.7.3.3 and 8.7.3.4 shall be removed.

18.7.4 Intertie Limits

18.7.4.1 The constraints in section 8.7.4 shall apply for *intertie* limits.

18.7.5 Penalty Price Variable Bounds

18.7.5.1 The constraints in section 8.7.5 shall apply for penalty price variable bounds.

18.8 Constraints to Respect Pass 1 Decisions

18.8.1 The Reliability Scheduling algorithm shall not schedule *energy* import schedules for *boundary entity resources* below those import schedules determined in Pass 1. For all hours $h \in \{1,..,24\}$ and *intertie zone* buses $d \in DI$ that are not part of a *linked wheeling through transaction*:

$$\sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \geq \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k}^{1}$$

18.8.2 The Reliability Scheduling algorithm shall not schedule *energy* export schedules for *boundary entity resources* above those export schedules determined in Pass 1. For all hours $h \in \{1,..,24\}$ and *intertie zone* buses $d \in DX$ that are not part of a *linked wheeling through transaction*:

$$\sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \leq \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j}^{1}$$

18.8.3 The Reliability Scheduling algorithm shall not de-commit *dispatchable generation resources* committed in Pass 1. For all hours $h \in \{1,..,24\}$ and buses $b \in B^{DG}$:

$$ODG_{h,b} \geq ODG_{h,b}^{1}$$

18.8.4 For single *energy limited resources* and multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay*, the Reliability Scheduling algorithm shall ensure the schedule for each *offer* lamination is equal to the schedules corresponding to the Pass 1 scheduled and unscheduled portions. For all buses $b \in B^{LIM}$, hours $h \in \{1, . . , 24\}$ and *offer* laminations $k \in K^{E}_{h,b}$:

$$SDG_{h,b,k} = S1DG_{h,b,k} + S2DG_{h,b,k}$$

18.8.5 The *generation resource* schedules for the Pass 1 scheduled and unscheduled portions of the lamination shall respect the incremental quantity of *energy* beyond the *minimum loading point* that may be scheduled. For all buses $b \in B^{LIM}$, hours $h \in \{1, . . , 24\}$ and *offer* laminations $k \in K^{E}_{h,b}$:

$$0 \leq S1DG_{h,b,k} \leq Q1DG_{h,b,k}$$

and

$$0 \leq S2DG_{h,b,k} \leq Q2DG_{h,b,k}$$

18.9 Outputs

18.9.1 Outputs of the Reliability Scheduling algorithm shall include *resource* schedules and commitments.

19 Pass 3: DAM Scheduling and Pricing

19.1 Purpose

19.1.1 Pass 3 shall use *market participant* and *IESO* inputs along with *resource* and system constraints to determine a set of *resource* schedules, commitments, and shadow prices, as well as a set of schedules and *locational marginal prices* that shall be used for *settlement*. Pass 3 consists of the DAM Scheduling algorithm described in section 20 and the DAM Pricing algorithm described in section 21.

20 DAM Scheduling

20.1 Purpose

20.1.1 The DAM Scheduling algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants, reference level values* for *resources* subject to section 20.2.2, and *resource* schedules and commitments from the Reliability Scheduling algorithm, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day.*

20.2 Information, Sets, Indices and Parameters

20.2.1 Information, sets, indices and parameters for the DAM Scheduling algorithm are described in sections 3 and 4. In addition, the following *resource* schedules and commitments from Pass 2 shall be used by the DAM Scheduling algorithm:

20.2.1.1 $SXL^2_{h,d,j}$, which designates the amount of *energy* that a *boundary entity resource* is scheduled to export at *intertie zone* bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,d}$;

20.2.1.2 $ODG^2_{h,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$; and

20.2.1.3 $SIG^2_{h,d,k}$, which designates the amount of *energy* that a *boundary entity resource* is scheduled to import at *intertie zone* bus $d \in DI$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,d}$.

20.2.2 The DAM Scheduling algorithm shall use *reference level value* for any *financial dispatch data parameters* that failed the Conduct Test associated with *resources* identified in section 14.7.

20.3 Variables and Objective Function

20.3.1 The *day-ahead market calculation engine* shall solve for the variables set out in section 8.3.1.

20.3.2 The objective function for the DAM Scheduling algorithm shall be the same as the objective function in section 8.3.2, with the following exceptions:

20.3.2.1 the variables for unit commitment decisions ($ODG_{h,b}$) shall be fixed within the optimization function; and

20.3.2.2 the *start-up offer* ($SUDG_{h,b}$) and the *offer* price to operate at *minimum loading point* ($MGODG_{h,b}$) shall be removed from the objective function.

20.3.3 The optimization function in the DAM Scheduling algorithm shall be subject to the constraints described in section 20.4.

20.4 Constraints

20.4.1 The DAM Scheduling algorithm optimization function shall apply the constraints described in sections 20.5– 20.8.

20.5 Dispatch Data Constraints Applying to Individual Hours

20.5.1 The constraints in section 8.5 shall apply in the DAM Scheduling algorithm.

20.6 Dispatch Data Inter-Hour/Multi-Hour Constraints

20.6.1 The constraints in section 8.6 shall apply in the DAM Scheduling algorithm, with the exception that the constraints for *non-quick start resources* in section 8.6.3 shall be removed.

20.7 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

20.7.1 The constraints are the same as in section 8.7. The sensitivities and limits used in section 8.7.3 are those provided by the most recent *security* assessment function iteration of the DAM Scheduling algorithm.

20.8 Constraints to Respect Pass 2 Decisions

20.8.1 The DAM Scheduling algorithm shall not decrease import schedules from the values produced in Pass 2 and may schedule additional imports of *energy* in Pass 3. For all hours $h \in \{1,..,24\}$ and *intertie zone* buses $d \in DI$ that are not part of a *linked wheeling through transaction*:

$$\sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \geq \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k}^{2}$$

20.8.2 The DAM Scheduling algorithm shall not increase export schedules in Pass 3 from the values produced in Pass 2. For all hours $h \in \{1,..,24\}$ and *intertie zone* buses $d \in DX$ that are not part of a *linked wheeling through transaction*:

$$\sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \leq \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j}^{2}$$

20.8.3 The DAM Scheduling algorithm shall not change commitments statuses in Pass 3 for *resources* as determined in Pass 2. For all hours $h \in \{1, .., 24\}$ and buses $b \in B^{DG}$:

$$ODG_{h,b} = ODG_{h,b}^{2}$$

20.9 Outputs

20.9.1 Outputs for the DAM Scheduling algorithm shall include *resource* schedules and commitments.

21 DAM Pricing

21.1 Purpose

21.1.1 The DAM Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants, reference level values* for *resources* subject to section 21.2.2, and *resource* schedules and commitments produced by the DAM Scheduling algorithm, to meet the *IESO's* average province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the next *dispatch day.*

21.2 Information, Sets, Indices and Parameters

21.2.1 Information, sets, indices and parameters for the DAM Pricing algorithm are described in sections 3 and 4. In addition, DAM Pricing algorithm shall use the following *resource* schedules and commitments from the DAM Scheduling algorithm in section 20:

21.2.1.1 $SDG_{h,b,k}^{3}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDG_b$ at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1, .., 24\}$ in association with lamination $k \in K_{h,b}^{E}$.;;

21.2.1.2 $ODG_{h,b}^{3}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum* *loading point* in hour $h \in \{1,..,24\}$. Note that $ODG^3_{h,b} = ODG^2_{h,b}$ for all hours $h \in \{1,..,24\}$ and buses $b \in B^{DG}$;

21.2.1.3 $S10SDG^3_{h,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$;

21.2.1.4 $S10NDG^3_{h,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$;

21.2.1.5 $S30RDG^3_{h,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,b}$; and

21.2.1.6 $OHO^3_{h,b}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

21.2.2 The *resource* schedules from Pass 2:

21.2.2.1 $SXL^2_{h,d,j}$, which designates the amount of *energy* that a *boundary entity resource* is scheduled to export at bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,d}$; and

21.2.2.2 $SIG^2_{h,d,k}$, which designates the amount of *energy* that a *boundary entity resource* is scheduled to import at bus $d \in DI$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,d}$.

21.2.2.3 The DAM Pricing algorithm shall use *reference level values* for any *financial dispatch data parameters* that failed the Conduct Test associated with *resources* identified in section 14.7.

21.3 Variables and Objective Function

21.3.1 The DAM Pricing algorithm shall solve for the variables listed in section 9.3.1.

21.3.2 The objective function for the DAM Pricing algorithm shall be the same as the objective function in section 9.3.2, subject to section 21.4.

21.4 Constraints

21.4.1 The constraints in sections 9.4 through 9.8 shall apply in the DAM Pricing algorithm, with the following exceptions:

21.4.1.1 The marginal loss factors used in the *energy* balance constraint in section 9.7.1 shall be fixed to the marginal loss factors used in the last optimization function iteration of the DAM Scheduling alogorithm in section 20.

21.4.1.2 The sensitivities and limits used in section 9.7.3 shall be provided by the most recent *security* assessment function iteration of the DAM Pricing algorithm.

21.4.1.3 For the constraints in section 9.8, the outputs from the As-Offered Scheduling algorithm in section 8 shall be replaced with the outputs from the DAM Scheduling algorithm in section 20, as follows:

21.4.1.3.1 $SDG^{AOS}_{h,b,k}$ shall be replaced by $SDG^{3}_{h,b,k}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{E}_{h,b}$;

21.4.1.3.2 $ODG^{AOS}_{h,b}$ shall be replaced by $ODG^{3}_{h,b}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{DG}$;

21.4.1.3.3 $S10SDG^{AOS}_{h,b,k}$ shall be replaced by $S10SDG^{3}_{h,b,k}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10S}_{h,b}$;

21.4.1.3.4 $S10NDG^{AOS}_{h,b,k}$ shall be replaced by $S10NDG^{3}_{h,b,k}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10N}_{h,b}$;

21.4.1.3.5 $S30RDG^{AOS}_{h,b,k}$ shall be replaced by $S30RDG^{3}_{h,b,k}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{30R}_{h,b}$; and

21.4.1.3.6 $OHO^{AOS}_{h,b}$ shall be replaced by $OHO^{3}_{h,b}$ for all $h \in \{1, . . . , 24\}$, $b \in B^{HE}$.

21.4.1.4 The constraints imposed for *boundary entity resource* schedules in section 20.8 shall apply to *boundary entity resource* schedules in the DAM Pricing algorithm, with a tolerance Δ specified by the *IESO* and:

21.4.1.4.1 For all hours $h \in \{1, . . , 24\}$ and *boundary entity resource* import buses $d \in DI$ that are not part of a *linked wheeling through transaction*:

$$\sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \geq \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k}^{2} - \Delta$$

21.4.1.4.2 For all hours $h \in \{1, .., 24\}$ and *boundary entity resource* export buses $d \in DX$ that are not part of a *linked wheeling through transaction*:

$$\sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \leq \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j}^{2} + \Delta$$

21.5 Outputs

21.5.1 Outputs of the DAM Pricing algorithm include shadow prices and *locational marginal prices* for *energy* and *operating reserve*.

22 Pseudo-Unit Modelling

22.1 Pseudo-Unit Model Parameters

22.1.1 The *day-ahead market calculation engine* shall use the following registration and daily *dispatch data* to determine the underlying relationship between a *pseudo-unit* and the associated physical *resources* for a *combined cycle plant* with K combustion turbine *resources* and one steam turbine *resource*:

22.1.1.1 $CMCR_k$ designates the registered *maximum continuous rating* of combustion turbine $k \in \{1, .., K\}$ in MW;

22.1.1.2 $CMLP_k$ designates the *minimum loading point* of combustion turbine *resource* $k \in \{1, .., K\}$ in MW;

22.1.1.3 $SMCR$ designates the registered *maximum continuous rating* of the steam turbine *resource* in MW;

22.1.1.4 $SMLP$ designates the *minimum loading point* of the steam turbine *resource* in MW for a 1x1 configuration;

22.1.1.5 SDF designates the amount of duct firing capacity available on the steam turbine *resource* in MW;

22.1.1.6 $STPortion_k$ designates the percentage of the steam turbine *resource* capacity attributed to *pseudo-unit* $k \in \{1,..,K\}$; and

22.1.1.7 $CSCM_k \in \{0,1\}$ designates whether *pseudo-unit* $k \in \{1,..,K\}$ is flagged to operate in single cycle mode for the day.

22.1.2 The *day-ahead market calculation engine* shall calculate the following model parameters for each *pseudo-unit* $k \in \{1,..K\}$:

22.1.2.1 $MMCR_k$ designates the *maximum continuous rating* of *pseudo-unit* k and is calculated as follows:

$$CMCR_k + SMCR \cdot STPortion_k \cdot (1 - CSCM_k)$$

22.1.2.2 $MMLP_k$ designates the *minimum loading point* of *pseudo-unit* k and is calculated as follows:

$$CMLP_k + SMLP \cdot (1 - CSCM_k)$$

22.1.2.3 MDF_k designates the duct firing capacity of *pseudo-unit* k and is calculated as follows:

$$SDF \cdot STPortion_k \cdot (1 - CSCM_k)$$

22.1.2.4 MDR_k designates the *dispatchable* capacity of *pseudo-unit* k and is calculated as follows:

$$MMCR_k - MMLP_k - MDF_k$$

22.1.3 The *day-ahead market calculation engine* shall define three operating regions of *pseudo-unit* $k \in \{1,..K\}$, as follows:

22.1.3.1 The *minimum loading point* region shall be the capacity between 0 and $MMLP_k$;

22.1.3.2 The *dispatchable* region shall be the capacity between $MMLP_k$ and $MMLP_k + MDR_k$; and

22.1.3.3 The duct firing region shall be the capacity between $MMLP_k + MDR_k$ and $MMCR_k$.

22.1.4 The *day-ahead market calculation engine* shall calculate the associated combustion turbine *resource* and steam turbine *resource* shares for the three operating regions of *pseudo-unit* $k \in \{1,..K\}$, as follows:

22.1.4.1 For the *minimum loading point* region:

22.1.4.1.1 Steam turbine *resource* share:

$$STShareMLP_k = \frac{SMLP \cdot (1 - CSCM_k)}{MMLP_k};$$

and

22.1.4.1.2 Combustion turbine *resource* share:

$$CTShareMLP_k = \frac{CMLP_k}{MMLP_k};$$

22.1.4.2 For the *dispatchable* region:

22.1.4.2.1 Steam turbine *resource* share:

$$STShareDR_k = \frac{(1 - CSCM_k)(SMCR \cdot STPortion_k - SMLP - SDF_k \cdot STPortion_k)}{MDR_k};$$

and

22.1.4.2.2 Combustion turbine *resource* share:

$$CTShareDR_k = \frac{CMCR_k - CMLP_k}{MDR_k};$$ and

22.1.4.3 For the duct firing region:

22.1.4.3.1 Steam turbine *resource* share shall be equal to 1; and

22.1.4.3.2 Combustion turbine *resource* share shall be equal to 0.

22.2 Application of Physical Resource Deratings to the Pseudo-Unit Model

22.2.1 The *day-ahead market calculation engine* shall apply deratings submitted by *market participants* to the applicable *dispatchable* capacity and duct firing capacity parameters for a *pseudo-unit*, where:

22.2.1.1 $CTCap_{h,k}$ designates the capacity of combustion turbine *resource* $k \in \{1,..,K\}$ in hour h as determined by submitted deratings;

22.2.1.2 $STCap_h$ designates the capacity of the steam turbine *resource* in hour h as determined by submitted deratings; and

22.2.1.3 $TotalQ_{h,k}$ designates the total *offered* quantity of *energy* for *pseudo-unit* $k \in \{1,..,K\}$ in hour h.

22.2.2 The *day-ahead market calculation engine* shall solve for the following operating region parameters for hour $h \in [1,..,24\}$ for each *pseudo-unit* $k \in \{1,..,K\}$:

22.2.2.1 $MLP_{h,k}$ designates the *minimum loading point* of *pseudo-unit* k in hour h;

22.2.2.2 $DR_{h,k}$ designates the *dispatchable* region capacity of *pseudo-unit* k in hour h; and

22.2.2.3 $DF_{h,k}$ designates the duct firing region capacity of *pseudo-unit* k in hour h.

22.2.3 Pre-processing of De-rates

22.2.3.1 The *day-ahead market calculation engine* shall perform the following pre-processing steps to determine the available operating regions for a *pseudo-unit* based on the combustion turbine *resource* and steam turbine *resource* share and the application of the *pseudo-unit* deratings. For *pseudo-unit* $k \in \{1,..,K\}$ for hour $h \in \{1,..,24\}$:

22.2.3.1.1 Step 1: Calculate the amount of *offered energy* attributed to each combustion turbine *resource* ($CTAmt_{h,k}$) and steam turbine *resource* portion ($STAmt_{h,k}$):

If $TotalQ_{h,k} < MMLP_k$ then:

$CTAmt_{h,k} = 0$; and

$STAmt_{h,k} = 0$.

Otherwise:

$CTAmtMLP = MMLP_k \cdot CTShareMLP_k$; and

$STAmtMLP = MMLP_k \cdot STShareMLP_k$.

If $TotalQ_{h,k} > MMLP_k + MDR_k$, then:

$CTAmtDR = MDR_k \cdot CTShareDR_k$;

$STAmtDR = MDR_k \cdot STShareDR_k$; and

$STAmtDF = (1 - CSCM_k) \cdot (TotalQ_{h,k} - MMLP_k - MDR_k)$.

Otherwise:

$CTAmtDR = (TotalQ_{h,k} - MMLP_k) \cdot CTShareDR_k$;

$STAmtDR = (TotalQ_{h,k} - MMLP_k) \cdot STShareDR_k$;

$STAmtDF = 0$;

$CTAmt_{h,k} = CTAmtMLP + CTAmtDR$; and

$STAmt_{h,k} = STAmtMLP + STAmtDR + STAmtDF$.

22.2.3.1.2 Step 2: Allocate the steam turbine *resource* capacity to each *pseudo-unit*:

$$PRSTCap_{h,k} = \left(\frac{STAmt_{h,k}}{\sum_{w \in \{1,..,K\}} STAmt_{h,w}} \right) \cdot STCap_h$$

22.2.3.1.3 Step 3: Determine if the *pseudo-unit* is available:

If $CTAmt_{h.k} < CMLP_k$, then the *pseudo-unit* is unavailable.

If $STAmt_{h,k} < SMLP \cdot (1 - CSCM_k)$, then the *pseudo-unit* is unavailable.

If $CTCap_{h,k} < CMLP_k$, then the *pseudo-unit* is unavailable.

If $PRSTCap_{h,k} < SMLP \cdot (1 - CSCM_k)$, then the *pseudo-unit* is unavailable.

22.2.3.1.4 Step 4: Initialize the operating region parameters for hour $h \in \{1, . . , 24\}$ to the model parameter values:

Set $MLP_{h,k} = MMLP_k$.

Set $DR_{h,k} = MDR_k$.

Set $DF_{h,k} = MDF_k$.

22.2.3.1.5 Step 5: Apply the derating on the combustion turbine *resource* to the *dispatchable* region:

Calculate P so that $CMLP_k + P \cdot CTShareDR_k \cdot MDR_k = CTCap_{h,k}$; and

Set $DR_{h,k} = min(DR_{h,k}, P \cdot MDR_k)$.

22.2.3.1.6 Step 6: Apply the derating on the steam turbine *resource* to the duct firing and *dispatchable* regions for *pseudo-units* not operating in *single cycle mode*:

Calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTCap_{h,k}$.

If $R \leq 1$, set $DF_{h,k} = 0$, and $DR_{h,k} = min(DR_{h,k}, \ R \cdot MDR_k)$.

If $R > 1$, set $DF_{h,k} = min(DF_{h,k}, PRSTCap_{h,k} - SMLP - STShareDR_k \cdot MDR_k)$.

22.2.4 Available Energy Laminations

22.2.4.1 The *day-ahead market calculation engine* shall determine the *offer* quantity laminations that may be scheduled for *energy* and *operating reserve* in each operating region for hour $h \in \{1, . . , 24\}$ for each *pseudo-unit* $k \in \{1, . . , K\}$, subject to section 22.2.4.2, where:

22.2.4.1.1 $QMLP_{h,k}$ designates the total quantity that may be scheduled in the *minimum loading point* region;

22.2.4.1.2 $QDR_{h,k}$ designates the total quantity that may be scheduled in the *dispatchable* region; and

22.2.4.1.3 $QDF_{h,k}$ designates the total quantity that may be scheduled in the duct firing region.

22.2.4.2 The available *offered* quantity laminations shall be subject to the following conditions:

$$0 \leq QMLP_{h,k} \leq MLP_{h,k};$$

$$0 \leq QDR_{h,k} \leq DR_{h,k};$$

$$0 \leq QDF_{h,k} \leq DF_{h,k};$$

if $QMLP_{h,k} < MLP_{h,k}$, then the *pseudo-unit* is unavailable and $QDR_{h,k} = QDF_{h,k} = 0$; and

if $QDR_{h,k} < DR_{t,k}$, then $QDF_{h,k} = 0$.

22.3 Convert Physical Resource Constraints to Pseudo-Unit Constraints

22.3.1 The *day-ahead market calculation engine* shall convert physical *resource* constraints to *pseudo-unit* constraints, where:

22.3.1.1 $PSUMin^{q}_{h,k}$ designates the minimum limitation on *pseudo-unit* k determined by translating constraint q. When constraint q does not provide a minimum limitation on *pseudo-unit* k, then $PSUMin^{q}_{h,k}$ shall be set equal to 0;

22.3.1.2 $PSUMax^{q}_{h,k}$ designates the maximum limitation on *pseudo-unit* k determined by translating constraint q. When constraint q does not provide a maximum limitation on *pseudo-unit* k, then $PSUMax^{q}_{h,k}$ shall be set equal to $MLP_{h,k}+DR_{h,k}+DF_{h,k}$; and

22.3.1.3 $CTCmtd_{h,k}\in\{0,1\}$ designates whether combustion turbine *resource* $k \in \{1,..K\}$ is considered committed in hour $h \in \{1,...,24\}$.

22.3.2 The *day-ahead market calculation engine* shall calculate the minimum and maximum limitations, subject to section 22.3.3.1, as follows:

22.3.2.1 Minimum limitation: $MinDG_{h,k} = max_{q\in\{1,..Q\}} PSUMin^{q}_{h,k}$; and

22.3.2.2 Maximum limitation: $MaxDG_{h,k} = min_{q\in\{1,..Q\}} PSUMax^{q}_{h,k}$.

where Q designates the number of constraints impacting a *combined cycle plant* that have been provided to the *day-ahead market calculation engine*.

22.3.3 Pseudo-unit Minimum and Maximum Constraints

22.3.3.1 *Pseudo-unit* minimum and maximum constraints shall be calculated as follows:

22.3.3.1.1 $PSUMin_{h,k} = PMin$, where $PMin$ shall be a minimum constraint provided on *pseudo-unit* $k \in \{1,...,K\}$ for hour $h \in \{1,...,24\}$; and

22.3.3.1.2 $PSUMax_{h,k} = PMax$, where $PMax$ shall be a maximum constraint provided on *pseudo-unit* $k \in \{1,...,K\}$ for hour $h \in \{1,...,24\}$.

22.3.4 Combustion Turbine Resource Minimum and Maximum Constraints

22.3.4.1 If a *pseudo-unit* is not flagged to operate in *single cycle mode*, then the combustion turbine *resource* minimum constraint shall be converted to a *pseudo-unit* constraint as follows:

If $CTMin < MLP_{h,k} \cdot CTShareMLP_k$, then set

$$STMinMLP = CTMin \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right); \text{ and}$$

$$STMinDR = 0$$

Otherwise, if $CTMin \geq MLP_{h,k} \cdot CTShareMLP_k$, then set

$$STMinMLP = MLP_{h,k} \cdot STShareMLP_k \text{ ; and}$$

$$STMinDR = \left(CTMin - MLP_{h,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right)$$

$$PSUMin_{h,k} = CTMin + STMinMLP + STMinDR$$

22.3.4.2 If a *pseudo-unit* is flagged to operate in *single cycle mode*, then the combustion turbine *resource* minimum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PSUMin_{h,k} = CTMin$$

22.3.4.3 If a *pseudo-unit* is not flagged to operate in *single cycle mode*, then the combustion turbine *resource* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

If $CTMax < MLP_{h,k} \cdot CTShareMLP_k$, then $PSUMax_{h,k} = 0$

Otherwise, calculate the effect of the constraint on the steam turbine within the *minimum loading point* and *dispatchable* regions:

:

$$STMaxMLP = MLP_{h,k} \cdot STShareMLP_k$$

$$STMaxDR = \left(CTMax - MLP_{h,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right)$$

$$PSUMax_{h,k} = CTMax + STMaxMLP + STMaxDR$$

22.3.4.4 If a *pseudo-unit* is flagged to operate in *single cycle mode*, then the combustion turbine *resource* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PSUMax_{h,k}=CTMax$$

22.3.5 Steam Turbine Resource Minimum and Maximum Constraints

22.3.5.1 The *day-ahead market calculation engine* shall convert a steam turbine *resource* minimum constraint to a *pseudo-unit* constraint as follows:

22.3.5.1.1 Step 1: Identify $A \subseteq \{1,..,K\}$, which shall indicate the set of *pseudo-units* to which the constraint may be allocated where *pseudo-unit* $k \in \{1,..,K\}$ is placed in set A if and only if $CSCM_k=0$ and $CTCmtd_{h,k}=1$. If the set A is empty, then no further steps are required, otherwise proceed to Step 2.

22.3.5.1.2 Step 2: Determine the steam turbine *resource* portion of the capacity of *pseudo-unit* $k \in A$:

$$STCap_k = QMLP_{h,k} \cdot STShareMLP_k + QDR_{h,k} \cdot STShareDR_k + QDF_{h,k}$$

22.3.5.1.3 Step 3: Allocate the $STMin$ constraint to each *pseudo-unit* $k \in A$, where $STMin$ constraint shall be allocated equally to each *pseudo-unit* $k \in A$ and $STPMin_k$ is limited by $STCap_k$.

22.3.5.1.4 Step 4: The steam turbine *resource* portion minimum constraint shall be converted to a *pseudo-unit* constraint, where for each *pseudo-unit* $k \in A$:

If $STPMin_k < MLP_{h,k} \cdot STShareMLP_k$, then set

$$CTMinMLP_k = \mathrm{STPMin_k} \cdot \left(\frac{\mathrm{CTShareMLP_k}}{\mathrm{STShareMLP_k}}\right);\text{ and}$$

$$CTMinDR_k = 0$$

Otherwise, if $STPMin_k \geq MLP_{h,k} \cdot STShareMLP_k$, then set

$$CTMinMLP_k = MLP_{h,k} \cdot CTShareMLP_k; \text{ and}$$

$$CTMinDR_k = \left(STPMin_k - MLP_{h,k} \cdot STShareMLP_k\right) \cdot \left(\frac{CTShareDR_k}{STShareDR_k}\right)$$

Therefore:

$$PSUMin_{h,k} = STPMin_k + CTMinMLP_k + CTMinDR_k$$

22.3.5.2 If *pseudo-units* with sufficient steam turbine *resource* capacity are not committed, then the *day-ahead market calculation engine* shall not convert the entire quantity of the steam turbine *resource* minimum constraint to *pseudo-unit* constraints.

22.3.5.3 The steam turbine *resource* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PRSTMax_{h,k} = \left(\frac{STAmt_{h,k}}{\sum_{w \in \{1,..,K\}} STAmt_{h,w}}\right) \cdot STMax$$

If the prorated steam turbine maximum constraint limits the steam turbine portion to below its *minimum loading point*, then

$$PSUMax_{h,k} = 0$$

Otherwise, calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTMax_{h,k}$

If $R \leq 1$, set $PSUMax_{h,k} = MLP_{h,k} + min(DR_{h,k}, R \cdot MDR_k)$

If $R > 1$, set $PSUMax_{h,k} = MLP_{h,k} + DR_{h,k} + PRSTMax_{h,k} - SMLP - STShareDR_k \cdot MDR_k$

22.3.5.4 If the steam turbine *resource* minimum and maximum constraints are equal but do not convert to equal *pseudo-unit* minimum and maximum constraints, then the steam turbine *resource* minimum constraint conversion in section 22.3.5.1 shall be used to determine equal *pseudo-unit* minimum and maximum constraints.

22.4 Conversion of Pseudo-Unit Schedules to Physical Resource Schedules

22.4.1 For a *combined cycle plant* with K combustion turbine *resources* and one steam turbine *resource*, the *day-ahead market calculation engine* shall compute the following *energy* and *operating reserve* schedules for hours $h \in \{1, . . , 24\}$:

22.4.1.1 $CTE_{h,k}$ designates the *energy* schedule for combustion turbine *resource* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.2 $STPE_{h,k}$ designates the *energy* schedule for the steam turbine *resource* portion of *pseudo-unit* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.3 STE_h designates the *energy* schedule for the steam turbine *resource*;

22.4.1.4 $CT10S_{h,k}$ designates the synchronized *ten-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.5 $STP10S_{h,k}$ designates the synchronized *ten-minute operating reserve* schedule for the steam turbine *resource* portion of *pseudo-unit* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.6 $ST10S_h$ designates the synchronized *ten-minute operating reserve* schedule for the steam turbine *resource*;

22.4.1.7 $CT10N_{h,k}$ designates the non-synchronized *ten-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.8 $STP10N_{h,k}$ designates the non-synchronized *ten-minute operating reserve* schedule for the steam turbine *resource* portion of *pseudo-unit* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.9 $ST10N_h$ designates the non-synchronized *ten-minute operating reserve* schedule for the steam turbine *resource*;

22.4.1.10 $CT30R_{h,k}$ designates the *thirty-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1, . . , \mathrm{K}\}$;

22.4.1.11 $STP30R_{h,k}$ designates the *thirty-minute operating reserve* schedule for the steam turbine *resource* portion of *pseudo-unit* $k \in \{1, . . , \mathrm{K}\}$; and

22.4.1.12 $ST30R_h$ designates the *thirty-minute operating reserve* schedule for the steam turbine *resource*.

22.4.2 The *day-ahead market calculation engine* shall determine the following *energy* and *operating reserve* schedules for *pseudo-unit* $k \in \{1, .. ,K\}$ in hour $h \in \{1, .. , 24\}$:

22.4.2.1 $SE_{h,k}$ designates the total amount of *energy* scheduled and $SE_{h,k} = SEMLP_{h,k} + SEDR_{h,k} + SEDF_{h,k}$ where:

22.4.2.1.1 $SEMLP_{h,k}$ designates the portion of the schedule corresponding to the *minimum loading point* region, where $0 \leq SEMLP_{h,k} \leq QMLP_{h,k}$;

22.4.2.1.2 $SEDR_{h,k}$ designates the portion of the schedule corresponding to the *dispatchable* region, where $0 \leq SEDR_{h,k} \leq QDR_{h,k}$ and $SEDR_{h,k} > 0$ only if $SEMLP_{h,k} = QMLP_{h,k}$; and

22.4.2.1.3 $SEDF_{h,k}$ designates the portion of the schedule corresponding to the duct firing region, where $0 \leq SEDF_{h,k} \leq QDF_{h,k}$ and $SEDF_{h,k} > 0$ only if $SEDR_{h,k} = QDR_{h,k}$;

22.4.2.2 $S10S_{h,k}$ designates the total amount of synchronized *ten-minute operating reserve* scheduled;

22.4.2.3 $S10N_{h,k}$ designates the total amount of non-synchronized *ten-minute operating reserve* scheduled. If the *pseudo-unit* cannot provide *operating reserve* from its duct firing region then $0 \leq SE_{h,k} + S10S_{h,k} + S10N_{h,k} \leq QMLP_{h,k} + QDR_{h,k}$; and

22.4.2.4 $\mathrm{S30R_{h,k}}$ designates the total amount of *thirty-minute operating reserve* scheduled, where $0 \leq SE_{h,k} + S10S_{h,k} + S10N_{h,k} + S30R_{h,k} \leq QMLP_{h,k} + QDR_{h,k} + QDF_{h,k}$.

22.4.3 The *day-ahead market calculation engine* shall convert *pseudo-unit* schedules to physical *generation resource* schedules for *energy* and *operating reserve*, as follows:

22.4.3.1 If $SE_{h,k} \geq MLP_{h,k}$, then:

$CTE_{h,k} = SEMLP_{h,k} \cdot CTShareMLP_k + SEDR_{h,k} \cdot CTShareDR_k$;

$STPE_{h,k} = SEMLP_{h,k} \cdot STShareMLP_k + SEDR_{h,k} \cdot STShareDR_k + SEDF_{h,k}$;

$RoomDR_{h,k} = QDR_{h,k} - SEDR_{h,k}$;

$10SDR_{h,k} = min(RoomDR_{h,k}, S10S_{h,k})$;

$10NDR_{h,k} = min(RoomDR_{h,k} - 10SDR_{h,k}, S10N_{h,k})$;

$30RDR_{h,k} = min(RoomDR_{h,k} - 10SDR_{h,k} - 10NDR_{h,k}, S30R_{h,k})$;

$CT10S_{h,k} = 10SDR_{h,k} \cdot CTShareDR_k$;

$STP10S_{h,k} = 10SDR_{h,k} \cdot STShareDR_k + (S10S_{h,k} - 10SDR_{h,k})$;

$CT10N_{h,k} = 10NDR_{h,k} \cdot CTShareDR_k$;

$STP10N_{h,k} = 10NDR_{h,k} \cdot STShareDR_k + (S10N_{h,k} - 10NDR_{h,k})$;

$CT30R_{h,k} = 30RDR_{h,k} \cdot CTShareDR_k$; and

$STP30R_{h,k} = 30RDR_{h,k} \cdot STShareDR_k + (S30R_{h,k} - 30RDR_{h,k})$.

22.4.3.2 If $SE_{h,k} < MLP_{h,k}$ and is ramping to *minimum loading point*, then the conversion shall be determined by the *ramp up energy to minimum loading point*.

22.4.3.3 The steam turbine *resources* portion schedules from section 22.4.3.1 shall be summed to obtain the steam turbine *resource* schedule as follows:

$STE_h = \sum_{k=1,..,K} STPE_{h,k}$;

$ST10S_h = \sum_{k=1,..,K} STP10S_{h,k}$;

$ST10N_h = \sum_{k=1,..,K} STP10N_{h,k}$; and

$ST30R_h = \sum_{k=1,..,K} STP30R_{h,k}$.

23 Pricing Formulas

23.1 Purpose

23.1.1 The *day-ahead market calculation engine* shall calculate *locational marginal prices* using shadow prices, constraint sensitivities and marginal loss factors.

23.2 Sets, Indices and Parameters

23.2.1 The sets, indices and parameters used to calculate *locational marginal prices* are described in section 4. In addition, the following shadow prices from Passes 1 and 3 shall be used:

23.2.1.1 $SPEmT^{p}_{h,c,f}$ designates the Pass p shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h;

23.2.1.2 $SPExtT^{p}_{h,z}$ designates the Pass p shadow price for the import or export limit constraint $z \in Z_{Sch}$ in hour h;

23.2.1.3 SPL^{p}_{h} designates the Pass p shadow price for the *energy* balance constraint in hour h;

23.2.1.4 $SPNIUExtBwdT^{p}_{h}$ designates the Pass p shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h-1)$ and hour h;

23.2.1.5 $SPNIDExtBwdT^{p}_{h}$ designates the Pass p shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour $(h-1)$ and hour h;

23.2.1.6 $SPNIUExtFwdT^{p}_{h}$ designates the Pass p shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour h and hour $(h+1)$;

23.2.1.7 $SPNIDExtFwdT^{p}_{h}$ designates the Pass p shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour h and hour $(h+1)$;

23.2.1.8 $SPNormT^{p}_{h,f}$ designates the Pass p shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour h;

23.2.1.9 $SP10S^{p}_{h}$ designates the Pass p shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in hour h;

23.2.1.10 $SP10R^{p}_{h}$ designates the Pass p shadow price for the total *ten-minute operating reserve* requirement constraint in hour h;

23.2.1.11 $SP30R^{p}_{h}$ designates the Pass p shadow price for the total *thirty-minute operating reserve* requirement constraint in hour h;

23.2.1.12 $SPREGMin10R^{p}_{h,r}$ designates the Pass p shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h;

23.2.1.13 $SPREGMin30R^{p}_{h,r}$ designates the Pass p shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h;

23.2.1.14 $SPREGMax10R^{p}_{h,r}$ designates the Pass p shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h; and

23.2.1.15 $SPREGMax30R^{p}_{h,r}$ designates the Pass p shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

23.3 Locational Marginal Prices for Energy

23.3.1 Energy Locational Marginal Prices for Delivery Points

23.3.1.1 The *day-ahead market calculation engine* shall calculate a *locational marginal price* and components for *energy* for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for every bus $b \in L$ where a non-*dispatchable* or *dispatchable generation resource*, a *dispatchable load*, a *price responsive load*, an *hourly demand response resource*, or a *non-dispatchable load* is sited and:

23.3.1.1.1 $LMP^{p}_{h,b}$ designates the Pass p hour h *locational marginal price* for *energy*;

23.3.1.1.2 $PRef^{p}_{h}$ designates the Pass p hour h energy locational marginal price for energy at the reference bus;

23.3.1.1.3 $PLoss^{p}_{h,b}$ designates the Pass p hour h loss component; and

23.3.1.1.4 $PCong^{p}_{h,b}$ designates the Pass p hour h congestion component.

23.3.1.2 The *day-ahead market calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* at the *reference bus*, a loss component and a congestion component for Pass $p \in \{1,3\}$ at bus $b \in L$ in hour $h \in \{1,..,24\}$, as follows:

$$InitLMP_{h,b}^{p} = InitPRef_{h}^{p} + InitPLoss_{h,b}^{p} + InitPCong_{h,b}^{p}$$

where

$$InitPRef_{h}^{p} = SPL_{h}^{p};$$

$$InitPLoss_{h,b}^{p} = MglLoss_{h,b}^{p} \cdot SPL_{h}^{p};$$

and

$$InitPCong_{h,b}^{p} = \sum_{f \in F_h} PreConSF_{h,f,b} \cdot SPNormT_{h,f}^{p} + \sum_{c \in C} \sum_{f \in F_{h,c}} SF_{h,c,f,b} \cdot SPEmT_{h,c,f}^{p}$$

23.3.1.3 If the initial *locational marginal price* for *energy* at the *reference bus* ($InitPRef_{h}^{p}$) is not within the *settlement* bounds ($EngyPrcFlr, EngyPrcCeil$), then the *day-ahead market calculation engine* shall modify the *locational marginal price* for *energy* at the *reference bus* as follows:

If $InitPRef_{h}^{p} > EngyPrcCeil$, $PRef_{h}^{p} = EngyPrcCeil$

If $InitPRef_{h}^{p} < EngyPrcFlr$, $PRef_{h}^{p} = EngyPrcFlr$

Otherwise, $PRef_{h}^{p} = InitPRef_{h}^{p}$

23.3.1.4 If the initial *locational marginal price* for *energy* ($InitLMP_{h,b}^{p}$) is not within the *settlement* bounds ($EngyPrcFlr, EngyPrcCeil$), then the *day-ahead market calculation engine* shall modify the *locational marginal price* for *energy* as follows:

If $InitLMP_{h,b}^{p} > EngyPrcCeil$, $LMP_{h,b}^{p} = EngyPrcCeil$

If $InitLMP_{h,b}^{p} < EngyPrcFlr$, $LMP_{h,b}^{p} = EngyPrcFlr$

Otherwise, $LMP_{h,b}^{p} = InitLMP_{h,b}^{p}$

23.3.1.5 The *day-ahead market calculation engine* shall modify the loss component as follows:

If $PRef_{h}^{p} \neq InitPRef_{h}^{p}$, then $PLoss_{h,b}^{p} = MglLoss_{h,b}^{p} \cdot PRef_{h}^{p}$

Otherwise, $PLoss^{p}_{h,b} = InitPLoss^{p}_{h,b}$

23.3.1.6 The *day-ahead market calculation engine* shall modify the congestion component as follows:

If $LMP^{p}_{h,b} - PRef^{p}_{h} - PLoss^{p}_{h,b}$ and $InitPCong^{p}_{h,b}$ have the same mathematical sign, then $PCong^{p}_{h,b} = LMP^{p}_{h,b} - PRef^{p}_{h} - PLoss^{p}_{h,b}$

Otherwise, $PCong^{p}_{h,b} = 0$ and $PLoss^{p}_{h,b} = LMP^{p}_{h,b} - PRef^{p}_{h}$

23.3.2 Energy Locational Marginal Prices for Intertie Metering Points

23.3.2.1 The *day-ahead market calculation engine* shall calculate a *locational marginal price* and components for *energy* for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for *intertie zone* bus $d \in D$, where:

23.3.2.1.1 $\mathrm{ExtLMP}^{\mathrm{p}}_{\mathrm{h,d}}$ designates the Pass p hour h *locational marginal price* for *energy*;

23.3.2.1.2 $IntLMP^{p}_{h,d}$ designates the Pass p hour h *intertie border price* for *energy*;

23.3.2.1.3 $ICP^{p}_{h,d}$ designates the Pass p hour h *intertie congestion price*;

23.3.2.1.4 $PRef^{p}_{h}$ designates the Pass p hour h *locational marginal price* for *energy* at the reference bus;

23.3.2.1.5 $PLoss^{p}_{h,d}$ designates the Pass p hour h loss component;

23.3.2.1.6 $PIntCong^{p}_{h,d}$ designates the Pass p hour h internal congestion component for *energy*;

23.3.2.1.7 $PExtCong^{p}_{h,d}$ designates the Pass p hour h external congestion component for the *intertie congestion price*; and

23.3.2.1.8 $PNISL^{p}_{h,d}$ designates the Pass p hour h net interchange scheduling limit congestion component for the *intertie congestion price*.

23.3.2.2 The *day-ahead market calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* for the *reference bus*, a loss component and a congestion component for *energy* for Pass p at *intertie zone* bus $d \in D_a$ in *intertie zone* $\mathrm{a} \in \mathrm{A}$ in hour $\mathrm{h} \in \{1,..,24\}$, subject to section 23.3.2.8 and 23.3.2.9, as follows:

$$InitExtLMP_{h,d}^{p} = InitIntLMP_{h,d}^{p} + InitICP_{h,d}^{p}$$

where

$$InitPRef_{h}^{p} = SPL_{h}^{p} ;$$

$$InitPLoss_{h,d}^{p} = MglLoss_{h,d}^{p} \cdot SPL_{h}^{p} ;$$

$$InitPIntCong_{h,d}^{p} = \sum_{f \in F_h} PreConSF_{h,f,d} \cdot SPNormT_{h,f}^{p} + \sum_{c \in C} \sum_{f \in F_{h,c}} SF_{h,c,f,d} \cdot SPEmT_{h,c,f}^{p} ;$$

$$InitIntLMP_{h,d}^{p} = InitPRef_{h}^{p} + InitPLoss_{h,d}^{p} + InitPIntCong_{h,d}^{p};$$

$$InitICP_{h,d}^{p} = InitPExtCong_{h,d}^{p} + InitPNISL_{h,d}^{p};$$

$$InitPExtCong_{h,d}^{p} = \sum_{z \in Z_{sch}} EnCoeff_{a,z} \cdot SPExtT_{h,z}^{p} ;$$

and

$$InitPNISL_{h,d}^{p} = SPNIUExtBwdT_{h}^{p} - SPNIUExtFwdT_{h}^{p} - SPNIDExtBwdT_{h}^{p} + SPNIDExtFwdT_{h}^{p}$$

23.3.2.3 If the initial *locational marginal price* for *energy* ($InitExtLMP_{h,d}^{p}$) is not within the *settlement* bounds ($EngyPrcFlr, EngyPrcCeil$), then the *day-ahead market calculation engine* shall modify the *intertie border price* for *energy*, and its components, as follows:

23.3.2.3.1 The initial *locational marginal price* for the *reference bus* ($InitPRef_{h}^{p}$) shall be modified per section 23.3.1.3;

23.3.2.3.2 The initial *intertie border price* ($InitIntLMP_{h,d}^{p}$) shall be modified per section 23.3.1.4, where $InitLMP_{h,b}^{p} = InitIntLMP_{h,d}^{p}$;

23.3.2.3.3 The initial loss component ($InitPLoss_{h,b}^{p}$) shall be modified per section 23.3.1.5; and

23.3.2.3.4 The initial congestion component ($InitPCong_{h,b}^{p}$) shall be modified per section 23.3.1.6.

23.3.2.4 If the initial *locational marginal price* for *energy* ($InitExtLMP_{h,d}^{p}$) is not within the *settlement bounds* ($EngyPrcFlr, EngyPrcCeil$), then the *day-ahead market calculation engine* shall modify the *locational marginal price* for *energy*, as follows:

If $InitExtLMP_{h,d}^{p} > EngyPrcCeil$, set $ExtLMP_{h,d}^{p} = EngyPrcCeil$

If $InitExtLMP_{h,d}^{p} < EngyPrcFlr$, set $ExtLMP_{h,d}^{p} = EngyPrcFlr$

Otherwise, set $ExtLMP_{h,d}^{p} = InitExtLMP_{h,d}^{p}$

23.3.2.5 If the modified *locational marginal price* for *energy* ($ExtLMP_{h,d}^{p}$) is equal to the *intertie border price* for *energy* ($IntLMP_{h,d}^{p}$), then the *day-ahead market calculation engine* shall modify the external congestion component for the *intertie congestion price* and net interchange scheduling limit congestion components for the *intertie congestion price*, as follows:

If $ExtLMP_{h,d}^{p} = IntLMP_{h,d}^{p}$, set $PExtCong_{h,d}^{p} = 0$ and $PNISL_{h,d}^{p} = 0$

23.3.2.6 If the modified *locational marginal price* for *energy* ($ExtLMP_{h,d}^{p}$) is not equal to the *intertie border price* for *energy* ($IntLMP_{h,d}^{p}$), then the *day-ahead market calculation engine* shall modify the external congestion component for the *intertie congestion price* and net interchange scheduling limit congestion components for the *intertie congestion price*, as follows:

If $ExtLMP_{h,d}^{p} \neq IntLMP_{h,d}^{p}$, set

$$PNISL_{h,d}^{p} = (ExtLMP_{h,d}^{p} - IntLMP_{h,d}^{p}) \cdot \left(\frac{InitPNISL_{h,d}^{p}}{InitPNISL_{h,d}^{p} + InitPExtCong_{h,d}^{p}}\right)$$

If $PNISL_{h,d}^{p} > NISLPen$, $PNISL_{h,d}^{p} = NISLPen$

If $PNISL_{h,d}^{p} < (-1) \cdot NISLPen$, $PNISL_{h,d}^{p} = (-1) \cdot NISLPen$

Then $PExtCong_{h,d}^{p} = ExtLMP_{h,d}^{p} - IntLMP_{h,d}^{p} - PNISL_{h,d}^{p}$

23.3.2.7 The *day-ahead market calculation engine* shall calculate the *intertie congestion price* as follows:

$$ICP_{h,d}^{p} = PExtCong_{h,d}^{p} + PNISL_{h,d}^{p}$$

23.3.2.8 The *locational marginal price* for *energy* calculated by the *day-ahead market calculation engine* shall be the same for all *boundary entity resource* buses at the same *intertie zone*. *Intertie* transactions associated with the same *boundary entity resource* bus, but specified as occurring at different *intertie zones*, subject to phase shifter operation, shall be modelled as flowing across independent paths. Pricing of these transactions shall utilize shadow prices associated with the internal transmission constraints, *intertie* limits and transmission losses applicable to the path associated to the relevant *intertie zone*.

23.3.2.9 When an *intertie zone* is out-of-service, the *intertie* limits for that *intertie zone* will be set to zero and all import and export *boundary entity resources* for that *intertie zone* will receive a zero schedule and the *locational marginal price* for *energy* shall be set to the *intertie border price* for *energy*.

23.3.3 Zonal Prices for Energy

23.3.3.1 The *day-ahead market calculation engine* shall calculate the zonal price for *energy* and its components for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for each *virtual transaction zone* $m \in M$, as follows:

$$VZonalP_{h,m}^{p} = PRef_{h}^{p} + VZonalPLoss_{h,m}^{p} + VZonalPCong_{h,m}^{p}$$

where

$$VZonalPLoss_{h,m}^{p} = \sum_{b \in L_{m}^{VIRT}} WF_{h,m,b}^{VIRT} \cdot PLoss_{h,b}^{p}$$

and

$$VZonalPCong_{h,m}^{p} = \sum_{b \in L_{m}^{VIRT}} WF_{h,m,b}^{VIRT} \cdot PCong_{h,b}^{p}$$

23.3.3.2 The *day-ahead market calculation engine* shall calculate the zonal price for *energy* and its components for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for *non-dispatchable load* zone, $y \in Y$ as follows:

$$ZonalP_{h,y}^{p} = PRef_{h}^{p} + ZonalPLoss_{h,y}^{p} + ZonalPCong_{h,y}^{p}$$

where

$$ZonalPLoss_{h,y}^{p} = \sum_{b \in L_{y}^{NDL}} WF_{h,y,b}^{NDL} \cdot PLoss_{h,b}^{p}$$

and

$$ZonalPCong_{h,y}^{p} = \sum_{b \in L_{y}^{NDL}} WF_{h,y,b}^{NDL} \cdot PCong_{h,b}^{p}$$

23.3.3.3 The *day-ahead market Ontario zonal price* is calculated per section 23.3.3.2 where the *non-dispatchable load* zone is comprised of all *non-dispatchable loads* within Ontario.

23.3.4 Pseudo-Unit Pricing

23.3.4.1 The *day-ahead market calculation engine* shall calculate a *locational marginal price* and components for *energy* for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for every *pseudo-unit* $k \in \{1,..,K\}$ where:

23.3.4.1.1 $CTMglLoss_{h,k}^{p}$ designates the marginal loss factor for the combustion turbine *resource* identified by *pseudo-unit* k for hour *h* in Pass *p*;

23.3.4.1.2 $STMglLoss_{h,k}^{p}$ designates the marginal loss factor for the steam turbine *resource* identified by *pseudo-unit* k for hour *h* in Pass *p*;

23.3.4.1.3 $CTPreConSF_{h,f,k}$ designates the pre-contingency sensitivity factor for the combustion turbine *resource* identified by *pseudo-unit* k on *facility f* during hour *h* under pre-contingency conditions;

23.3.4.1.4 $STPreConSF_{h,f,k}$ designates the pre-contingency sensitivity factor for the steam turbine *resource* identified by *pseudo-unit* k on *facility f* during hour *h* under pre-contingency conditions;

23.3.4.1.5 $CTSF_{h,c,f,k}$ designates the post-contingency sensitivity factor for the combustion turbine *resource* identified by *pseudo-unit* k on *facility f* during hour *h* under post-contigency conditions for contingency *c*; and

23.3.4.1.6 $STSF_{h,c,f,k}$ designates the post-contingency sensitivity factor for the steam turbine *resource* identified by *pseudo-unit* k on *facility f* during hour *h* under post-contingency conditions for contingency *c*.

23.3.4.2 The *day-ahead market calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* at the *reference bus*, a loss component and a congestion component for Pass $p \in \{1,3\}$ for every *pseudo-unit* $k \in \{1,..,K\}$ in hour $h \in \{1,...,24\}$, as follows:

$$InitLMP_{h,k}^{p} = InitPRef_{h}^{p} + InitPLoss_{h,k}^{p} + InitPCong_{h,k}^{p}$$

where

$$InitPRef_{h}^{p} = SPL_{h}^{p};$$

$$InitPLoss_{h,k}^{p} = MglLoss_{h,k}^{p} \cdot SPL_{h}^{p};$$

and

$$InitPCong_{h,k}^{p} = \sum_{f \in F_h} PreConSF_{h,f,k} \cdot SPNormT_{h,f}^{p} + \sum_{c \in C} \sum_{f \in F_{h,c}} SF_{h,c,f,k} \cdot SPEmT_{h,c,f}^{p}$$

23.3.4.3 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its Minimum Loading Point range or not scheduled at all, its marginal loss and sensitivity factors shall be:

$$MglLoss^{p}_{h,k} = CTShareMLP_k \cdot CTMglLoss^{p}_{h,k} + STShareMLP_k \cdot STMglLoss^{p}_{h,k}$$

$$PreConSF_{h,f,k} = CTShareMLP_k \cdot CTPreConSF_{h,f,k} + STShareMLP_k \cdot STPreConSF_{h,f,k}$$

$$SF_{h,c,f,k} = CTShareMLP_k \cdot CTSF_{h,c,f,k} + STShareMLP_k \cdot STSF_{h,c,f,k}$$

23.3.4.4 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its *dispatchable* region, its marginal loss and sensitivity factors shall be:

$$MglLoss^{p}_{h,k} = CTShareDR_k \cdot CTMglLoss^{p}_{h,k} + STShareDR_k \cdot STMglLoss^{p}_{h,k}$$

$$PreConSF_{h,f,k} = CTShareDR_k \cdot CTPreConSF_{h,f,k} + STShareDR_k \cdot STPreConSF_{h,f,k}$$

$$SF_{h,c,f,k} = CTShareDR_k \cdot CTSF_{h,c,f,k} + STShareDR_k \cdot STSF_{h,c,f,k}$$

23.3.4.5 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its duct firing region, its marginal loss and sensitivity factors shall be:

$$MglLoss^{p}_{h,k} = STMglLoss^{p}_{h,k}$$

$$PreConSF_{h,f,k} = STPreConSF_{h,f,k}$$

$$SF_{h,c,f,k} = STSF_{h,c,f,k}$$

23.4 Locational Marginal Prices for Operating Reserve

23.4.1 Operating Reserve Locational Marginal Prices for Delivery Points

23.4.1.1 The *day-ahead market calculation engine* shall calculate a *locational marginal price* and components for *operating reserve* for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for a *delivery point* associated with the *dispatchable generation resource* and *dispatchable load* at bus $b \in B$, where:

23.4.1.1.1 $L30RP_{h,b}^{p}$ designates the Pass p hour h *locational marignal price* for *thirty-minute operating reserve*;

23.4.1.1.2 $P30RRef_{h}^{p}$ designates the Pass p hour h *locational marignal price* for *thirty-minute operating reserve* at the *reference bus*;

23.4.1.1.3 $P30RCong_{h,b}^{p}$ designates the Pass p hour h congestion component for *thirty-minute operating reserve*;

23.4.1.1.4 $L10NP_{h,b}^{p}$ designates the Pass p hour h *locational marignal price* for non-synchronized *ten-minute operating reserve*;

23.4.1.1.5 $\mathrm{P10NRef_{h}^{p}}$ designates the Pass p hour h *locational marignal price* for non-synchronized *ten-minute operating reserve* at the *reference bus*;

23.4.1.1.6 $P10NCong_{h,b}^{p}$ designates the Pass p hour h congestion component for non-synchronized *ten-minute operating reserve*;

23.4.1.1.7 $L10SP_{h,b}^{p}$ designates the Pass p hour h *locational marignal price* for synchronized *ten-minute operating reserve*;

23.4.1.1.8 $P10SRef_{h}^{p}$ designates the Pass p hour h *locational marignal price* for synchronized *ten-minute operating reserve* at the *reference bus*;

23.4.1.1.9 $P10SCong_{h,b}^{p}$ designates the Pass p hour h congestion component for synchronized *ten-minute operating reserve*; and

23.4.1.1.10 $ORREG_b \subseteq ORREG$ designates the subset of $ORREG$ consisting of regions that include bus b.

23.4.1.2 The *day-ahead market calculation engine* shall calculate an initial *locational marginal price*, a *locational marginal price* at the *reference bus*, and congestion components for Pass p for a *delivery point* associated with the *dispatchable generation resource* and *dispatchable load* at bus $b \in B$ in hour $h \in \{1,..,24\}$, for each class of *operating reserve*, as follows:

$$InitL30RP_{h,b}^{p} = InitP30RRef_{h}^{p} + InitP30RCong_{h,b}^{p}$$

where

$$InitP30RRef_{h}^{p} = SP30R_{h}^{p}$$

and

$$InitP30RCong_{h,b}^{p} = \sum_{r \in ORREG_b} SPREGMin30R_{h,r}^{p} + \sum_{r \in ORREG_b} SPREGMax30R_{h,r}^{p}$$

$$InitL10NP_{h,b}^{p} = InitP10NRef_{h}^{p} + InitP10NCong_{h,b}^{p}$$

where

$$InitP10NRef_{h}^{p} = SP10R_{h}^{p} + SP30R_{h}^{p}$$

and

$$InitP10NCong_{h,b}^{p} = \sum_{r \in ORREG_b} \left(SPREGMin10R_{h,r}^{p} + SPREGMin30R_{h,r}^{p}\right) + \sum_{r \in ORREG_b} \left(SPREGMax10R_{h,r}^{p} + SPREGMax30R_{h,r}^{p}\right)$$

$$InitL10SP_{h,b}^{p} = InitP10SRef_{h}^{p} + InitP10SCong_{h,b}^{p}$$

where

$$InitP10SRef_{h}^{p} = SP10S_{h}^{p} + SP10R_{h}^{p} + SP30R_{h}^{p}$$

and

$$InitP10SCong_{h,b}^{p} = \sum_{r \in ORREG_b} \left(SPREGMin10R_{h,r}^{p} + SPREGMin30R_{h,r}^{p}\right) + \sum_{r \in ORREG_b} \left(SPREGMax10R_{h,r}^{p} + SPREGMax30R_{h,r}^{p}\right)$$

23.4.1.3 If the initial *locational marginal price* at the *reference bus* ($InitP30RRef_h^p, InitP10NRef_h^p, or\ InitP10SRef_h^p$) is not within the *settlement* bounds ($ORPrcFlr, ORPrcCeil$), then the *day-ahead market calculation engine* shall modify the initial *locational marginal prices* at the *reference bus* for each class of *operating reserve* as follows:

If $InitP30RRef_h^p\ >\ ORPrcCeil\ , P30RRef_h^p\ = ORPrcCeil$;

If $InitP30RRef_h^p < ORPrcFlr, P30RRef_h^p = ORPrcFlr$; Otherwise, $P30RRef_h^p = InitP30RRef_h^p$.

If $InitP10NRef_h^p\ >\ ORPrcCeil\ , P10NRef_h^p\ =\ ORPrcCeil$;

If $InitP10NRef_h^p\ <\ ORPrcFlr, P10NRef_h^p\ =\ ORPrcFlr$; Otherwise, $P10NRef_h^p = InitP10NRef_h^p$.

If $InitP10SRef_h^p\ >\ ORPrcCeil\ , P10SRef_h^p\ =\ ORPrcCeil$;

If $InitP10SRef_h^p\ <\ ORPrcFlr, P10SRef_h^p\ =\ ORPrcFlr$; Otherwise, $P10SRef_h^p = InitP10SRef_h^p$

23.4.1.4 If the initial *locational marginal price* ($InitL30RP_{h,b}^p, InitL10NP_{h,b}^p, or\ InitL10SP_{h,b}^p$) is not within the *settlement* bounds ($ORPrcFlr, ORPrcCeil$), then the *day-ahead market calculation engine* shall modify the initial *locational marginal price* for each class of *operating reserve* as follows:

If $InitL30RP_{h,b}^p\ >\ ORPrcCeil\ , L30RP_{h,b}^p\ =\ ORPrcCeil$;

If $InitL30RP_{h,b}^p\ <\ ORPrcFlr, L30RP_{h,b}^p = ORPrcFlr$; Otherwise, $L30RP_{h,b}^p = InitL30RP_{h,b}^p$.

If $InitL10NP_{h,b}^p\ >\ ORPrcCeil\ , L10NP_{h,b}^p\ =\ ORPrcCeil$;

If $InitL10NP_{h,b}^p\ <\ ORPrcFlr, L10NP_{h,b}^p\ =\ ORPrcFlr$; Otherwise, $L10NP_{h,b}^p = InitL10NP_{h,b}^p$.

If $InitL10SP_{h,b}^p\ >\ ORPrcCeil\ , L10SP_{h,b}^p\ =\ ORPrcCeil$;

If $InitL10SP_{h,b}^p\ <\ ORPrcFlr, L10SP_{h,b}^p\ =\ ORPrcFlr$; Otherwise, $L10SP_{h,b}^p\ =\ InitL10SP_{h,b}^p$

23.4.1.5 If the initial *locational marginal price* ($InitL30RP_{h,b}^p, InitL10NP_{h,b}^p, or\ InitL10SP_{h,b}^p$) is not within the *settlement* bounds ($ORPrcFlr, ORPrcCeil$), then the *day-ahead market calculation engine* shall modify the congestion component for each class of *operating reserve*, as follows:

Set $P30RCong_{h,b}^{p} = L30RP_{h,b}^{p} - P30RRef_{h}^{p}$;

Set $P10NCong_{h,b}^{p} = L10NP_{h,b}^{p} - P10NRef_{h}^{p}$; and

Set $P10SCong_{h,b}^{p} = L10SP_{h,b}^{p} - P10SRef_{h}^{p}$.

23.4.2 Operating Reserve Locational Marginal Prices for Intertie Metering Points

23.4.2.1 The *day-ahead market calculation engine* shall calculate a *locational marginal price* and components for *operating reserve* for each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$ for *intertie zone* bus $d \in D$, where:

23.4.2.1.1 $ExtL30RP_{h,d}^{p}$ designates the Pass p hour h *locational marginal price* for *thirty-minute operating reserve*;

23.4.2.1.2 $P30RRef_{h}^{p}$ designates the Pass p hour h *locational marginal price* for *thirty-minute operating reserve* at the *reference bus*;

23.4.2.1.3 $P30RIntCong_{h,d}^{p}$ designates the Pass p hour h internal congestion component for *thirty-minute operating reserve*;

23.4.2.1.4 $P30RExtCong_{h,d}^{p}$ designates the Pass p hour h *intertie* congestion component for *thirty-minute operating reserve*;

23.4.2.1.5 $ExtL10NP_{h,d}^{p}$ designates the Pass p hour h non-synchronized *ten-minute operating reserve* price;

23.4.2.1.6 $P10NRef_{h}^{p}$ designates the Pass p hour h *locational marginal price* for non-synchronized *ten-minute operating reserve* at the *reference bus*;

23.4.2.1.7 $P10NIntCong_{h,d}^{p}$ designates the Pass p hour h internal congestion component for non-synchronized *ten-minute operating reserve*;

23.4.2.1.8 $P10NExtCong_{h,d}^{p}$ designates the Pass p hour h *intertie* congestion component for non-synchronized *ten-minute operating reserve*; and

23.4.2.1.9 $ORREG_d \subseteq ORREG$ designates the subset of $ORREG$ consisting of regions that include bus d.

23.4.2.2 The *day-ahead market calculation engine* shall calculate an initial *locational marginal price*, a *locational marginal price* at the *reference bus*, an internal congestion component and an *intertie* congestion component for Pass p at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in hour $h \in \{1, .., 24\}$, for each class of *operating reserve*, subject to sections 23.4.2.5 and 23.4.2.6, as follows:

$$InitExtL30RP_{h,d}^{p} = InitP30RRef_{h}^{p} + InitP30RIntCong_{h,d}^{p} + InitP30RExtCong_{h,d}^{p}$$

where

$$InitP30RRef_{h}^{p} = SP30R_{h}^{p};$$

$$InitP30RIntCong_{h,d}^{p} = \sum_{r \in ORREG_d} SPREGMin30R_{h,r}^{p} + \sum_{r \in ORREG_d} SPREGMax30R_{h,r}^{p};$$

and

$$InitP30RExtCong_{h,d}^{p} = \sum_{z \in Z_{Sch}} 0.5 \cdot (EnCoeff_{a,z} + 1) \cdot SPExtT_{h,z}^{p}$$

$$InitExtL10NP_{h,d}^{p} = InitP10NRef_{h}^{p} + InitP10NIntCong_{h,d}^{p} + InitP10NExtCong_{h,d}^{p}$$

where

$$InitP10NRef_{h}^{p} = SP10R_{h}^{p} + SP30R_{h}^{p};$$

$$InitP10NIntCong_{h,d}^{p} = \sum_{r \in ORREG_d} \left(SPREGMin10R_{h,r}^{p} + SPREGMin30R_{h,r}^{p}\right) + \sum_{r \in ORREG_d} \left(SPREGMax10R_{h,r}^{p} + SPREGMax30R_{h,r}^{p}\right)$$

and

$$InitP10NExtCong_{h,d}^{p} = \sum_{z \in Z_{Sch}} 0.5 \cdot \left(EnCoeff_{a,z} + 1\right) \cdot SPExtT_{h,z}^{p}$$

23.4.2.3 If the initial *locational marginal price* ($InitExtL30RP_{h,b}^{p}$) is not within the *settlement* bounds ($ORPrcFlr, ORPrcCeil$), then the *day-ahead market calculation engine* shall modify the initial *locational marginal price*, the *locational marginal price* at the *reference bus*, and the external congestion component for *thirty-minute operating reserve* as follows:

$$IntL30R = InitP30RRef_{h}^{p} + InitP30RIntCong_{h,d}^{p}$$

If $InitP30RRef_{h}^{p} > ORPrcCeil$, $P30RRef_{h}^{p} = ORPrcCeil$;

If $InitP30RRef_{h}^{p} < ORPrcFlr$, $P30RRef_{h}^{p} = ORPrcFlr$;
Otherwise, $P30RRef_{h}^{p} = InitP30RRef_{h}^{p}$;

Set $P30RIntCong_{h,d}^{p} = ExtL30RP_{h,d}^{p} - P30RRef_{h}^{p}$

If $InitExtL30RP_{h,b}^{p} > ORPrcCeil$, $ExtL30RP_{h,b}^{p} = ORPrcCeil$;

If $InitExtL30RP_{h,b}^{p} < ORPrcFlr$, $ExtL30RP_{h,b}^{p} = ORPrcFlr$;
Otherwise, $ExtL30RP_{h,b}^{p} = InitExtL30RP_{h,b}^{p}$; and

Set $P30RExtCong_{h,d}^{p} = ExtL30RP_{h,b}^{p} - P30RRef_{h}^{p} - P30RIntCong_{h,d}^{p}$

23.4.2.4 If the initial *locational marginal price* ($InitExtL10NP_{h,b}^{p}$) is not within the *settlement* bounds ($ORPrcFlr, ORPrcCeil$), then the *day-ahead market calculation engine* shall modify the initial *locational marginal price*, the *locational marginal price* at the reference bus, and the external congestion component for *ten-minute operating reserve* as follows:

$$IntL10N = InitP10NRef_{h}^{p} + InitP10NIntCong_{h,d}^{p}$$

If $InitP10NRef_{h}^{p} > ORPrcCeil$, $P10NRef_{h}^{p} = ORPrcCeil$;

If $InitP10NRef_{h}^{p} < ORPrcFlr, P10NRef_{h}^{p} = ORPrcFlr$;
Otherwise, $P10NRef_{h}^{p} = InitP10NRef_{h}^{p}$;

Set $P10NCong_{h,b}^{p} = L10NP_{h,b}^{p} - P10NRef_{h}^{p}$

If $InitExtL10NP_{h,b}^{p} > ORPrcCeil$, $ExtL10NP_{h,b}^{p} = ORPrcCeil$;

If $InitExtL10NP_{h,b}^{p} < ORPrcFlr, ExtL10NP_{h,b}^{p} = ORPrcFlr$;
Otherwise, $ExtL10NP_{h,b}^{p} = InitExtL10NP_{h,b}^{p}$; and

Set $P10NExtCong_{h,d}^{p} = ExtL10NP_{h,b}^{p} - P10NRef_{h}^{p} - P10NIntCong_{h,d}^{p}$

23.4.2.5 The *locational marginal price* calculated by the *day-ahead market calculation engine* shall be the same for all *boundary entity resource* buses at the same *intertie zone*. Reserve imports associated with the same *boundary entity resource* bus, but specified as occurring at a different *intertie zone*, subject to phase shifter operation, shall be modelled as flowing across independent paths. Pricing of these reserve imports shall utilize shadow prices associated with *intertie* limits and regional minimum and maximum *operating reserve* requirements applicable to the path associated to the relevant *intertie zone*.

23.4.2.6 When an *intertie zone* is out-of-service, the *intertie* limits for that *intertie zone* will be set to zero and all *boundary entity resources* for that *intertie zone* will receive a zero schedule for *energy and operating reserve* and the *intertie operating reserve* prices shall be set equal to the *locational marginal price* for the *reference bus* for that class of *operating reserve* plus the applicable shadow prices associated with regional minimum and maximum *operating reserve* requirements.

23.5 Pricing for Islanded Nodes

23.5.1 For *non-quick start resources* that are not connected to the *main island*, the *day-ahead market calculation engine* may use the following reconnection logic where enabled by the *IESO* in the order set out below to calculate the *locational marginal prices* for *energy*:

23.5.1.1 Determine the connection paths over open switches that connect the *non-quick start resource* to the *main island*;

23.5.1.2 Determine the priority rating for each connection path identified based on a weighted sum of the base voltage over all open switches used by the reconnection path and the MW ratings of the newly connected branches; and

23.5.1.3 Select the reconnection path with the highest priority rating, breaking ties arbitrarily.

23.5.2 For all (i) *resources* other than those specified in section 23.5.1 not connected to the *main island*; (ii) *non-quick start resources* where a price was not able to be determined in accordance with section 23.5.1; the *day-ahead market calculation engine* shall use the following logic in the order set out below to calculate *locational marginal prices*, using a node-level and *facility*-level substitution list determined by the *IESO*:

23.5.2.1 Use the *locational marginal price* for *energy* at a node in the node-level substitution list where defined and enabled by the *IESO*, provided such node is connected to the *main island*;

23.5.2.2 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes at the same voltage level within the same *facility* that are connected to the *main island*;

23.5.2.3 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes within the same *facility* that are connected to the *main island*;

23.5.2.4 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes from another *facility* that is connected to the *main island*, as determined by the *facility*-level substitution list where defined and enabled by the *IESO*; and

23.5.2.5 If a price is unable to be determined in accordance with sections 23.5.2.1 through 23.5.2.4, use the *locational marginal price* for *energy* for the *reference bus*.

Appendix 7.5A – The Pre-Dispatch Calculation Engine Process

1.1 Purpose

1.1.1 This appendix describes the process used by the *pre-dispatch calculation engine* to determine commitments, schedules, and prices for the pre-dispatch look-ahead period.

2 Pre-Dispatch Calculation Engine

2.1 Pre-Dispatch Look-Ahead Period

2.1.1 The pre-dispatch look-ahead period is the time horizon considered in the multi-hour optimization. The pre-dispatch look-ahead period changes depending on when the *pre-dispatch calculation engine* runs:

2.1.1.1 for the *pre-dispatch calculation engine* runs from 00:00 EST to 19:00 EST in the current *dispatch day*, the pre-dispatch look-ahead period consists of the remaining hours of the current *dispatch day*; and

2.1.1.2 for the *pre-dispatch calculation engine* runs from 20:00 EST to 23:00 EST in the current *dispatch day*, the pre-dispatch look-ahead period consists of the remaining hours of the current *dispatch day* in addition to all hours in the next *dispatch day*.

2.2 Pre-Dispatch Calculation Engine Pass

2.2.1 The *pre-dispatch calculation engine* shall execute one pass, Pass 1, the Pre-Dispatch Scheduling Process Pass, in accordance with section 7, to produce *pre-dispatch schedules*, commitments and *locational 2arginal prices*:

3 Information Used by the Pre-Dispatch Calculation Engine

3.1.1 The *pre-dispatch calculation engine* shall use the information in section 3A.1 of Chapter 7.

4 Sets, Indices and Paramaters Used in the Pre-Dispatch Calculation Engine

4.1 Fundamental Sets and Indices

4.1.1 A designates the set of all *intertie zones*;

4.1.2 B designates the set of buses identifying all *dispatchable* and non-*dispatchable resources* within Ontario;

4.1.3 $B^{DG} \subseteq B$ designates the set of buses identifying *dispatchable generation resources*;

4.1.4 $B^{DL} \subseteq B$ designates the set of buses identifying *dispatchable loads*;

4.1.5 $B^{ELR} \subseteq B^{DG}$ designates the subset of buses identifying *energy limited resources*;

4.1.6 $B^{HDR} \subseteq B$ designates the set of buses identifying *hourly demand response resources*;

4.1.7 $B^{HE} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources*;

4.1.8 $\wp(B^{HE})$ designates the set of all subsets of the set B^{HE};

4.1.9 $B^{HE}_{up} \subseteq \wp(B^{HE})$ designates the set of buses identifying all upstream *dispatchable* hydroelectric *generation resources* with a registered *forebay* that are linked via *time lag* and *MWh ratio dispatch data* with downstream *dispatchable* hydroelectric *generation resources* with a registered *forebay*;

4.1.10 $B_{dn}^{HE} \subseteq \wp(B^{HE})$ designates the set of buses identifying all downstream *dispatchable* hydroelectric *generation resources* with a registered *forebay* that are linked via *time lag* and *MWh ratio dispatch data* with upstream *dispatchable* hydroelectric *generation resources* with a registered *forebay*;

4.1.11 $B_s^{HE} \subseteq B^{HE}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

4.1.12 $B^{NDG} \subseteq B$ designates the set of buses identifying *non-dispatchable generation resources*;

4.1.13 $B^{NO10DF} \subseteq B^{PSU}$ designates the subset of buses identifying *pseudo-units* that cannot provide *ten-minute operating reserve* from the duct firing region;

4.1.14 $B^{NQS} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable non-quick start resources*;

4.1.15 $B^{PSU} \subseteq B^{NQS}$ designates the subset of buses identifying *pseudo-units*;

4.1.16 $B_r^{REG} \subseteq B$ designates the set of internal buses in *operating reserve* region $r \in ORREG$;

4.1.17 $B_p^{ST} \subseteq B^{PSU}$ designates the subset of buses identifying *pseudo-units* with a share of steam turbine *resource* $p \in PST$;

4.1.18 $B^{VG} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable variable generation resources*;

4.1.19 C designates the set of contingencies that shall be considered in the *security* assessment function;

4.1.20 D designates the set of buses outside Ontario corresponding to imports and exports at *intertie zones*;

4.1.21 *DAYS* designates the set of days in the look-ahead period. If the look-ahead period spans one day, then *DAYS* = {tod}. If the look-ahead period spans two days, then *DAYS* = {tod, tom};

4.1.22 $D_r^{REG} \subseteq D$ designates the set of *intertie zone* buses identifying *boundary entity resources* in *operating reserve* region $r \in ORREG$;

4.1.23 $DX \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids*;

4.1.24 $DI \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers*;

4.1.25 $D_a \subseteq D$ designates the set of all buses identifying *boundary entity resources* in *intertie zone* $a \in A$;

4.1.26 $DI_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers* in *intertie zone* $a \in A$;

4.1.27 $DI_t^{CAPEX} \subseteq DI$ designates the *intertie zone* source buses identifying import *offers* flagged as capacity imports in time-step $t \in \{4,..,n_{LAP}\}$;

4.1.28 $DI_t^{EM} \subseteq DI$ designates the *intertie zone* buses corresponding to *emergency energy* import transactions for time-step $t \in TS$;

4.1.29 $DI_t^{EMNS} \subseteq DI_t^{EM}$ designates the *intertie zone* buses corresponding to *emergency energy* import transactions that do not support *emergency energy* export transactions in time-step $t \in TS$;

4.1.30 $DI_t^{INP} \subseteq DI$ designates the *intertie zone* buses corresponding to inadvertent *energy* payback import transactions for time-step $t \in TS$;

4.1.31 $DX_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids* in *intertie zone* $a \in A$;

4.1.32 $DX_t^{CAPEX} \subseteq DX$ designates the *intertie zone* sink buses identifying export *bids* flagged as *capacity exports* in time-step t;

4.1.33 $DX_t^{INP} \subseteq DX$ designates the *intertie zone* buses corresponding to inadvertent *energy* payback export transactions for time-step $t \in TS$;

4.1.34 $DX_t^{EM} \subseteq DX$ designates the *intertie zone* buses corresponding to *emergency energy* export transactions for time-step $t \in TS$;

4.1.35 F designates the set of *facilities* and groups of *facilities* for which transmission constraints may be identified;

4.1.36 $F_t \subseteq F$ designates the set of *facilities* whose pre-contingency limit was violated in time step t as determined by a preceding *security* assessment function iteration;

4.1.37 $F_{t,c} \subseteq F$ designates the set of *facilities* whose post-contingency limit for contingency c is violated in time step t as determined by a preceding *security* assessment function iteration;

4.1.38 $J_{t,b}^{E}$ designates the set of *bid* laminations for energy at bus $b \in B \cup DX$ for time-step $t \in TS$;

4.1.39 $J_{t,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.40 $J'^{10S}_{t,b}$ designates the set of *reference level value* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.41 $J_{t,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B \cup DX$ for time-step $t \in TS$;

4.1.42 $J'^{10N}_{t,b}$ designates the set of *reference level value* laminations for non-synchronized *ten-minute operating reserve* at bus $\mathrm{b} \in \mathrm{B}$ for time-step $t \in TS$;

4.1.43 $J_{t,b}^{30R}$ designates the set of *offer* laminations for *thirty-minute operating reserve offer* at bus $b \in B \cup DX$ for time-step $t \in TS$;

4.1.44 $J'^{30R}_{t,b}$ designates the set of *reference level value* laminations for *thirty-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.45 $K_{t,b}^{DF} \subseteq K_{t,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the duct firing region of a *pseudo-unit* at bus $b \in B^{PSU}$ for time-step $t \in TS$;

4.1.46 $K_{t,b}^{DR} \subseteq K_{t,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the *dispatchable* region of a *pseudo-unit* at bus $b \in B^{PSU}$ for time-step $t \in TS$;

4.1.47 $K_{t,b}^{E}$ designates the set of *offer* laminations for *energy* at bus $b \in B \cup DI$ for time-step $t \in TS$;

4.1.48 $K'^{E}_{t,b}$ designates the set of *reference level value* laminations for *energy* at bus $b \in B$ for time-step $t \in TS$;

4.1.49 $K^{LTMLP}_{t,b}$ designates the set of *offer* laminations for *energy* quantities up to the *minimum loading point* for a *non-quick start resource* at bus $b \in B^{NQS}$ for time-step $t \in TS$;

4.1.50 $K'^{LTMLP}_{t,b}$ designates the set of *reference level value* laminations for *energy* quantities up to the *minimum loading point reference level* for a *non-quick start resource* at bus $\mathrm{b} \in B^{NQS}$ for time-step $t \in TS$;

4.1.51 $K^{10S}_{t,b}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.52 $K'^{10S}_{t,b}$ designates the set of *reference level value* laminations for synchronized *ten-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.53 $K^{10N}_{t,b}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B \cup DI$ for time-step $t \in TS$;

4.1.54 $K'^{10N}_{t,b}$ designates the set of *reference level value* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.55 $K^{30R}_{t,b}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at bus $b \in B \cup DI$ for time-step $t \in TS$;

4.1.56 $K'^{30R}_{t,b}$ designates the set of *reference level value* laminations for *thirty-minute operating reserve* at bus $b \in B$ for time-step $t \in TS$;

4.1.57 L designates the set of buses where the *locational marginal prices* represent prices for *delivery points* associated with *non-dispatchable generation resources* and *dispatchable generation resources*, *dispatchable loads*, *hourly demand response resources*, *price responsive loads* and *non-dispatchable loads*;

4.1.58 $L^{NDL}_{y} \subseteq L$, designates the buses contributing to the zonal price for *non-dispatchable load* zone $y \in Y$;

4.1.59 $L^{VIRT}_{m} \subseteq L$, designates the buses contributing to the *virtual zonal price* for *virtual transaction zone* $m \in M$;

4.1.60 M designates the set of *virtual transaction zones*;

4.1.61 NCA designates the set of *narrow constrained areas*;

4.1.62 DCA designates the set of *dynamic constrained areas*;

4.1.63 BCA designates the set of broad constrained areas;

4.1.64 PST designates the set of steam turbine *resources offered* as part of a *pseudo-unit*;

4.1.65 SHE designates the set indexing the sets of *dispatchable* hydroelectric *generation resources* with a *maximum daily energy limit* or a *minimum daily energy limit* or both for a registered *forebay*;

4.1.66 $THERM = \{COLD, WARM, HOT\}$ designates the set of *thermal states* for *non-quick start resources*;

4.1.67 $TS = \{2,..,n_{LAP}\}$ designates the set of all time-steps in the look-ahead period that are included in the *pre-dispatch calculation engine* optimization, where n_{LAP} designates the number of time-steps in the look-ahead period;

4.1.68 $TS_{tod} \subseteq TS$ designates the time-steps in the look-ahead period that are part of the current *dispatch day;*

4.1.69 $TS_{tom} \subseteq TS$ designates the time-steps in the look-ahead period that are part of the next *dispatch day*;

4.1.70 $TSC_b \subseteq TS$ designates the set of time-steps representing the first hour of a *day-ahead operational commitment* for the *resource* at bus $b \in B$;

4.1.71 $t_{tom} \in TS_{tom}$ designates the first time-step of the next *dispatch day*;

4.1.72 Y designates the *non-dispatchable load* zones in Ontario; and

4.1.73 Z_{Sch} designates the set of all *intertie* limit constraints.

4.2 Market Participant Data Parameters

4.2.1 With respect to a *non-dispatchable generation resource* identified by bus $\mathrm{b} \in \mathrm{B}^{\mathrm{NDG}}$:

4.2.1.1 $QNDG_{t,b,k}$ designates the maximum incremental quantity of *energy* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K^{E}_{t,b}$; and

4.2.1.2 $PNDG_{t,b,k}$ designates the price for the maximum incremental quantity of *energy* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{E}_{t,b}$.

4.2.2 With respect to a *dispatchable generation resource* identified by bus $b \in B^{DG}$:

4.2.2.1 $MinQDG_{q,b}$ designates the *minimum loading point* for day $\mathrm{q} \in \mathrm{DAYS}$;

4.2.2.2 $QDG_{t,b,k}$ designates the maximum incremental quantity of *energy* above the *minimum loading point* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K^{E}_{t,b}$;

4.2.2.3 $PDG_{t,b,k}$ designates the price for the maximum incremental quantity of *energy* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{E}_{t,b}$;

4.2.2.4 $Q10SDG_{t,b,k}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{10S}_{t,b}$;

4.2.2.5 $P10SDG_{t,b,k}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{10S}_{t,b}$;

4.2.2.6 $Q10NDG_{t,b,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{10N}_{t,b}$;

4.2.2.7 $P10NDG_{t,b,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{10N}_{t,b}$;

4.2.2.8 $Q30RDG_{t,b,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,b}^{30R}$;

4.2.2.9 $P30RDG_{t,b,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,b}^{30R}$;

4.2.2.10 $ORRDG_b$ designates the maximum *operating reserve* ramp rate in MW per minute;

4.2.2.11 $NumRRDG_{t,b}$ designates the number of ramp rates provided in time-step $t \in TS$;

4.2.2.12 $RmpRngMaxDG_{t,b,w}$ for $w \in \{1,..,NumRRDG_{t,b}\}$ designates the w^th ramp rate break point in time-step $t \in TS$;

4.2.2.13 $URRDG_{t,b,w}$ for $w \in \{1,..,NumRRDG_{t,b}\}$ designates the ramp rate in MW per minute at which the *resource* can increase the amount of *energy* it supplies in time-step $t \in TS$ while operating in the range between $RmpRngMaxDG_{t,b,w\text{-}1}$ and $RmpRngMaxDG_{t,b,w}$, where $RmpRngMaxDG_{t,b,0}$ shall be equal to zero;

4.2.2.14 $DRRDG_{t,b,w}$ for $w \in \{1,..,NumRRDG_{t,b}\}$ designates the ramp rate in MW per minute at which the *resource* can decrease the amount of *energy* it supplies in time-step $t \in TS$ while operating in the range between $RmpRngMaxDG_{t,b,w\text{-}1}$ and $RmpRngMaxDG_{t,b,w}$, where $RmpRngMaxDG_{t,b,0}$ shall be equal to zero;

4.2.2.15 $RLP30R_{t,b}$ designates the *reserve loading point* for *thirty-minute operating reserve* in time-step $t \in TS$; and

4.2.2.16 $RLP10S_{t,b}$ designates the *reserve loading point* for synchronized *ten-minute operating reserve* in time-step $t \in TS$.

4.2.3 With respect to a *dispatchable non-quick start resource* identified by bus $b \in B^{NQS}$:

4.2.3.1 $LT_{q,b}^{m}$ designates the *lead time* in *dispatch day* $q \in DAYS$ for *thermal state* $m \in THERM$;

4.2.3.2 $MGODG_{t,b}$ designates the minimum generation cost to operate at *minimum loading point* in time-step $t \in TS$. This parameter is calculated as follows:

$$MGODG_{t,b} = SNL_{t,b} + \sum_{k \in K_{t,b}^{LTMLP}} PLTMLP_{t,b,k} \cdot QLTMLP_{t,b,k}.$$

4.2.3.3 $MGBRTDG_{q,b}$ designates the *minimum generation block run-time* within *dispatch day* $q \in DAYS$;

4.2.3.4 $MaxStartsDG_{q,b}$ designates the *maximum number of starts per day* within *dispatch day* $q \in DAYS$;

4.2.3.5 $MGBDTDG_{q,b}^{HOT}$ designates the *minimum generation block down-time* for a hot *thermal state* within *dispatch day* $q \in DAYS$;

4.2.3.6 $MGBDTDG_{q,b}^{WARM}$ designates the *minimum generation block down-time* for a warm *thermal state* in *dispatch day* $q \in DAYS$;

4.2.3.7 $MGBDTDG_{q,b}^{COLD}$ designates the *minimum generation block down-time* for a cold *thermal state* in *dispatch day* $q \in DAYS$;

4.2.3.8 $PLTMLP_{t,b,k}$ designates the price for the maximum incremental quantity of *energy* up to the *minimum loading point* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,b}^{LTMLP}$;

4.2.3.9 $QLTMLP_{t,b,k}$ designates the maximum incremental quantity of *energy* up to the *minimum loading point* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,b}^{LTMLP}$;

4.2.3.10 $RampE_{q,b,w}^{m}$ designates the *ramp up energy to minimum loading point* in *dispatch day* $q \in DAYS$ for $w \in \{1,..,RampHrs_{q,b}^{m}\}$ and *thermal state* $m \in THERM$;

4.2.3.11 $RampHrs_{q,b}^{m}$ designates the *ramp hours to minimum loading point* in *dispatch day* $q \in DAYS$ for *thermal state* $m \in THERM$;

4.2.3.12 $SNL_{t,b}$ designates the *speed no-load offer* in time-step $t \in TS$;

4.2.3.13 $SUDG^{m}_{t,b}$ designates the *start-up offer* in time-step $t \in TS$ for *thermal state* $m \in THERM$;

4.2.3.14 $SUDG^{DAM}_{t,b}$ designates the *start-up offer* used to evaluate the *day-ahead operational commitment* starting in time-step $t \in TSC_b$;

4.2.3.15 $SUAdjDG^{m}_{t,b}$ designates the *start-up offer* that the optimization function will evaluate in time-step $t \in TS$ under *thermal state m*.

4.2.4 With respect to an *energy limited resource* identified by bus $b \in B^{ELR}$:

4.2.4.1 $MaxDEL_{q,b}$ designates the *maximum daily energy limit* for a single *resource* with or without a registered *forebay* within *dispatch day* $q \in DAYS$.

4.2.5 With respect to a *dispatchable* hydroelectric *generation resource* identified by bus $b \in B^{HE}$:

4.2.5.1 $MinHMR_{t,b}$ designates the *hourly must-run* value in time-step $t \in TS$;

4.2.5.2 $MinHO_{t,b}$ designates the *minimum hourly output* in time-step $t \in TS$;

4.2.5.3 $MinDEL_{q,b}$ designates the *minimum daily energy limit* for a single *resource* with of without a registered *forebay* within *dispatch day* $q \in DAYS$.;

4.2.5.4 $MaxStartsHE_{q,b}$ designates the *maximum number of starts per day* within *dispatch day* $q \in DAYS$;

4.2.5.5 $StartMW_{b,i}$ for $i \in \{1,..,NStartMW_b\}$ designates the *start indication value* for measuring *maximum number of starts per day*; a start is counted between time-step t and $(t+1)$ if the schedule increases from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$; and

4.2.5.6 $(ForL_{q,b,i},\ ForU_{q,b,i})$ for $i \in \{1,..,NFor_{q,b}\}$ designates the lower and upper limits of the *forbidden regions* and indicate that the *resource* cannot be scheduled between $ForL_{q,b,i}$ and $ForU_{q,b,i}$ for all $i \in \{1,..,NFor_{q,b}\}$ within *dispatch day* $q \in DAYS.$

4.2.6 With respect to multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay*:

4.2.6.1 $MaxSDEL_{q,s}$ designates the *maximum daily energy limit* shared by all *dispatchable* hydroelectric *generation resources* in set $s \in SHE$ for *dispatch day* $q \in DAYS$; and

4.2.6.2 $MinSDEL_{q,s}$ designates the *minimum daily energy limit* shared by all *dispatchable* hydroelectric *generation resources* in set $s \in SHE$ within *dispatch day* $q \in DAYS$.

4.2.7 With respect to a *dispatchable* hydroelectric *generation resource* for which a *MWh ratio* was respected:

4.2.7.1 $LNK_q \subseteq B_{up}^{HE} \times B_{dn}^{HE}$ designates the set of linked *dispatchable* hydroelectric *generation resources* for *dispatch day* $q \in DAYS$, where LNK_q designates a set with elements of the form (b_1, b_2) where $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$;

4.2.7.2 $Lag_{q,b_1,b_2} \in \{0,..,23\}$ designates the *time lag* in hours between upstream *dispatchable* hydroelectric *generation resources* $b_1 \in B_{up}^{HE}$ and downstream *dispatchable* hydroelectric *generation resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK_q$ for *dispatch day* $q \in DAYS$; and

4.2.7.3 $\mathrm{MWhRatio}_{q,b_1,b_2}$ designates the MWh ratio between upstream *dispatchable* hydroelectric *generation resources* $b_1 \in B_{up}^{HE}$ and downstream *dispatchable* hydroelectric *generation resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK_q$ for dispatch day $q \in DAYS$.

4.2.8 With respect to a *pseudo-unit* identified by bus $b \in B^{PSU}$:

4.2.8.1 $STShareMLP_b$ designates the steam turbine *resource's* share of the *minimum loading point* region;

4.2.8.2 $STShareDR_b$ designates the steam turbine *resource's* share of the *dispatchable* region;

4.2.8.3 $RampCT_{q,b,w}^m$ designates the quantity of *energy* injected w hours before the *pseudo-unit* reaches its *minimum loading point* in *dispatch day* $q \in DAYS$ and *thermal state* $m \in THERM$ that is attributed to the combustion turbine *resource* for $w \in \{1,..,RampHrs_{q,b}^m\}$; and

4.2.8.4 $RampST_{q,b,w}^m$ designates the quantity of *energy* injected w hours before the *pseudo-unit* reaches its *minimum loading point* in *dispatch* *day* $q \in DAYS$ for *thermal state* $m \in THERM$ that is attributed to the steam turbine *resource* for $w \in \{1,..,RampHrs_{q,b}^{m}\}$.

4.2.9 With respect to a *dispatchable load* identified by bus $b \in B^{DL}$:

4.2.9.1 $QDL_{t,b,j}$ designates the maximum incremental quantity of *energy* that may be scheduled in time-step $t \in TS$ in association with *bid* lamination $j \in J_{t,b}^{E}$;

4.2.9.2 $PDL_{t,b,j}$ designates the price for the maximum incremental quantity of *energy* in time-step $t \in TS$ in association with *bid* lamination $j \in J_{t,b}^{E}$;

4.2.9.3 $Q10SDL_{t,b,j}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,b}^{10S}$;

4.2.9.4 $P10SDL_{t,b,j}$ designates the price for the maximum incremental quanitity of synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,b}^{10S}$;

4.2.9.5 $Q10NDL_{t,b,j}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,b}^{10N}$;

4.2.9.6 $P10NDL_{t,b,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,b}^{10N}$;

4.2.9.7 $Q30RDL_{t,b,j}$ designates the maximum increamental quantity of *thirty-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,b}^{30R}$;

4.2.9.8 $P30RDL_{t,b,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,b}^{30R}$;

4.2.9.9 $ORRDL_{b}$ designates the *operating reserve* ramp rate in MW per minute for reductions in load consumption;

4.2.9.10 $NumRRDL_{t,b}$ designates the number of ramp rates provided in time-step $t \in TS$;

4.2.9.11 $RmpRngMaxDL_{t,b,w}$ for $w \in \{1,..,NumRRDL_{t,b}\}$ designates the w[th] ramp rate break point in time-step $t \in TS$;

4.2.9.12 $URRDL_{t,b,w}$ for $w \in \{1,..,NumRRDL_{t,b}\}$ designates the ramp rate in MW per minute at which the *dispatchable load* can increase its amount of *energy* consumption in time-step $t \in TS$ while operating in the range between $RmpRngMaxDL_{t,b,w-1}$ and $RmpRngMaxDL_{t,b,w}$, where $RmpRngMaxDL_{t,b,0}$ shall be equal to zero;

4.2.9.13 $DRRDL_{t,b,w}$ for $w \in \{1,..,NumRRDL_{t,b}\}$ designates the ramp rate in MW per minute at which the *dispatchable load* can decrease its amount of *energy* consumption in time-step $t \in TS$ while operating in the range between $RmpRngMaxDL_{t,b,w-1}$ and $RmpRngMaxDL_{t,b,w}$, where $RmpRngMaxDL_{t,b,0}$ shall be equal to zero; and

4.2.9.14 $QDLFIRM_{t,b}$ designates the quantity of *energy* that is *bid* at the *maximum market clearing pric*e in time-step $t \in TS$.

4.2.10 With respect to an *hourly demand response resource* identified by bus $b \in B^{HDR}$:

4.2.10.1 $QHDR_{t,b,j}$ designates an maximum incremental quantity of reduction in *energy* consumption that may be scheduled in time-step $t \in TS$ in association with *bid* lamination $j \in J^{E}_{t,b}$;

4.2.10.2 $PHDR_{t,b,j}$ designates the price for the maximum incremental quantity of reduction in *energy* consumption for time-step $t \in TS$ in association with *bid* lamination $j \in J^{E}_{t,b}$;

4.2.10.3 $URRHDR_{b}$ designates the maximum rate in MW per minute at which the *hourly demand response resource* can decrease its amount of *energy* consumption; and

4.2.10.4 $DRRHDR_{b}$ designates the maximum rate in MW per minute at which the *hourly demand response resource* can increase its amount of *energy* consumption.

4.2.11 With respect to a *boundary entity resource* import from *intertie zone* bus $d \in DI$, where the *locational marginal price* represents the price for the *intertie metering point*:

4.2.11.1 $QIG_{t,d,k}$ designates the maximum incremental quantity of *energy* that may be scheduled to import in time-step $t \in TS$ in association with *offer* lamination $k \in K^{E}_{t,d}$;

4.2.11.2 $PIG_{t,d,k}$ designates the price for the maximum incremental quantity of *energy* may be scheduled to import in time-step $t \in TS$ in association with *offer* lamination $k \in K^{E}_{t,d}$;

4.2.11.3 $Q10NIG_{t,d,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K^{10N}_{t,d}$;

4.2.11.4 $P10NIG_{t,d,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{10N}_{t,d}$;

4.2.11.5 $Q30RIG_{t,d,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* quantity that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K^{30R}_{t,d}$; and

4.2.11.6 $P30RIG_{t,d,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K^{30R}_{t,d}$.

4.2.12 With respect to a *boundary entity resource* export to *intertie zone* sink bus $d \in DX$, where the *locational marginal price* represents the price for the *intertie metering point*:

4.2.12.1 $QXL_{t,d,j}$ designates the maximum incremental quantity of *energy* that may be scheduled to export in time-step $t \in TS$ in association with *bid* lamination $j \in J^{E}_{t,d}$;

4.2.12.2 $PXL_{t,d,j}$ designates the price for the maximum incremental quantity of *energy* that may be scheduled to export in time-step $t \in TS$ in association with *bid* lamination $j \in J^{E}_{t,d}$;

4.2.12.3 $Q10NXL_{t,d,j}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled to provide in time-step $t \in TS$ in association with *offer* lamination $j \in J^{10N}_{t,d}$;

4.2.12.4 $P10NXL_{t,d,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{10N}$;

4.2.12.5 $Q30RXL_{t,d,j}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled to provide in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{30R}$; and

4.2.12.6 $P30RXL_{t,d,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{30R}$.

4.2.13 With respect to a *linked wheeling through transaction*:

4.2.13.1 $L_t \subseteq DX \times DI$ designates the set of linked *boundary entity resource* import and export buses corresponding to *linked wheeling through transactions*, where L_t is a set with elements of the form (dx, di) where $dx \in DX$ and $di \in DI$.

4.3 IESO Data Parameters

4.3.1 Variable Generation Forecast

4.3.1.1 $FG_{t,b}$ designates the *IESO's* centralized *variable generation* forecast for a *variable generation resource* identified by bus $b \in B^{VG}$ in time-step $t \in TS$.

4.3.2 Variable Generation Tie-Breaking

4.3.2.1 $NumVG_t$ designates the number of *variable generation resources* in the daily *dispatch* order for time-step $t \in TS$; and

4.3.2.2 $TBM_{t,b} \in \{1,..,NumVG_t\}$ designates the tie-breaking modifier for the *variable generation resource* at bus $b \in B^{VG}$ for time-step $t \in TS$.

4.3.3 Intertie Curtailments

4.3.3.1 $ICMaxXL_{t,d}$ designates the maximum limit on the quantity of *energy* scheduled for export to *intertie zone* sink bus $d \in DX$ and time-step $t \in TS$ as the result of an *intertie* curtailment;

4.3.3.2 $ICMinXL_{t,d}$ designates the minimum limit on the quantity of *energy* scheduled for export to *intertie zone* sink bus $d \in DX$ and time-step $t \in TS$ as the result of an *intertie* curtailment;

4.3.3.3 $ICMaxIG_{t,d}$ designates the maximum limit on the quantity of *energy* scheduled for import from *intertie zone* source bus $d \in DI$ and time-step $t \in TS$ as the result of an *intertie* curtailment;

4.3.3.4 $ICMax10NIG_{t,d}$ designates the maximum limit on the quantity of non-synchronized *ten-minute operating reserve* scheduled for import from *intertie zone* source bus $d \in DI$ and time-step $t \in TS$ as the result of an *intertie* curtailment;

4.3.3.5 $ICMax30RIG_{t,d}$ designates the maximum limit on the quantity of *thirty-minute operating reserve* scheduled for import from *intertie zone* source bus $d \in DI$ and time-step $t \in TS$ as the result of an *intertie* curtailment;

4.3.3.6 $ICMinIG_{t,d}$ designates the minimum limit on the quantity of *energy* scheduled for import from *intertie zone* source bus $d \in DI$ and time-step $t \in TS$ as the result of an *intertie* curtailment;

4.3.3.7 $ICMin10NIG_{t,d}$ designates the minimum limit on the quantity of non-synchronized *ten-minute operating reserve* scheduled for import from *intertie zone* source bus $d \in DI$ and time-step $t \in TS$ as the result of an *intertie* curtailment; and

4.3.3.8 $ICMin30RIG_{t,d}$ designates the minimum limit on the quantity of *thirty-minute operating reserve* scheduled for import from *intertie zone* source bus $d \in DI$ and time-step $t \in TS$ as the result of an *intertie* curtailment.

4.3.4 Operating Reserve Requirements

4.3.4.1 $TOT10S_t$ designates the synchronized *ten-minute operating reserve* requirement;

4.3.4.2 $TOT10R_t$ designates the total *ten-minute operating reserve* requirement;

4.3.4.3 $TOT30R_t$ designates the *thirty-minute operating reserve* requirement;

4.3.4.4 $ORREG$ designates the set of regions for which regional *operating reserve* limits have been defined;

4.3.4.5 $REGMin10R_{t,r}$ designates the minimum requirement for total *ten-minute operating reserve* in region $r \in ORREG$ in time-step $t \in TS$;

4.3.4.6 $REGMin30R_{t,r}$ designates the minimum requirement for *thirty-minute operating reserve* in region $r \in ORREG$ in time-step $t \in TS$;

4.3.4.7 $REGMax10R_{t,r}$ designates the maximum amount of total *ten-minute operating reserve* that may be scheduled in region $r \in ORREG$ in time-step $t \in TS$; and

4.3.4.8 $REGMax30R_{t,r}$ designates the maximum amount of *thirty-minute operating reserve* that may be scheduled in region $r \in ORREG$ in time-step $t \in TS$.

4.3.5 Intertie Limits

4.3.5.1 $EnCoeff_{a,z}$ designates the coefficient for calculating the contribution of scheduled *energy* flows and *operating reserve* inflows for *intertie* zone $a \in A$, which is part of *intertie* limit constraint $z \in Z_{Sch}$. A coefficient of $+1$ shall describe flows into Ontario while a coefficient of -1 shall describe flows out of Ontario;

4.3.5.2 $MaxExtSch_{t,z}$ designates the maximum flow limit for *intertie* flow constraint $z \in Z_{Sch}$in time-step $t \in TS$;

4.3.5.3 $ExtDSC_t$ designates the net interchange scheduling limit for when the net flows over all *interties* from time-step $(t-1)$ to time-step t decrease; and

4.3.5.4 $ExtUSC_t$ designates the net interchange scheduling limit for when the net flows over all *interties* from time-step $(t-1)$ to time-step t increase.

4.3.6 Resource Minimum and Maximum Constraints

4.3.6.1 Where applicable the minimum or maximum output of a *dispatchable generation resource* or a *non-dispatchable generation resource*, minimum or maximum consumption of a *dispatchable load*, and minimum and maximum reduction of an *hourly demand response resource* may be limited due to *reliability* constraints, applicable *contracted ancillary services*, *day-ahead operational commitments,* previous *pre-dispatch operational commitments*, *outages*, derates, activation/non-activation of *hourly demand response resources* and other constraints, such that:

4.3.6.1.1 $MinDL_{t,b}$ designates the most restrictive minimum consumption limit for the *dispatchable load* at bus $b \in B^{DL}$;

4.3.6.1.2 $MaxDL_{t,b}$ designates the most restrictive maximum consumption limit for the *dispatchable load* at bus $b \in B^{DL}$;

4.3.6.1.3 $MinNDG_{t,b}$ designates the most restrictive minimum output limit for the *non-dispatchable generation resource* at bus $b \in B^{NDG}$;

4.3.6.1.4 $MaxNDG_{t,b}$ designates the most restrictive maximum output limit for the *non-dispatchable generation resource* at bus $b \in B^{NDG}$;

4.3.6.1.5 $MinDG_{t,b}$ designates the most restrictive minimum output limit for the *dispatchable generation resource* at bus $b \in B^{DG}$;

4.3.6.1.6 $MaxDG_{t,b}$ designates the most restrictive maximum output limit for the *dispatchable generation resource* at bus $b \in B^{DG}$;

4.3.6.1.7 $MaxMLP_{t,b}$ designates the maximum output limit in time-step t for the *minimum loading point* region of a *pseudo-unit* at bus $b \in B^{PSU}$;

4.3.6.1.8 $MaxDR_{t,b}$ designates the maximum output limit in time-step t for the *dispatchable* region of a *pseudo-unit* at bus $b \in B^{PSU}$;

4.3.6.1.9 $MaxDF_{t,b}$ designates the maximum output limit in time-step t for the duct firing region of a *pseudo-unit* at bus $b \in B^{PSU}$;

4.3.6.1.10 $MinHDR_{t,b}$ designates the minimum load reduction level that may be scheduled for the *hourly demand response resource* at bus $b \in B^{HDR}$; and

4.3.6.1.11 $MaxHDR_{t,b}$ designates the maximum load reduction level that may be scheduled for the *hourly demand response resource* at bus $b \in B^{HDR}$.

4.3.7 Constraint violation penalties for time step $t \in TS$:

4.3.7.1 $(PLdViolSch_{st,i}, QLdViolSch_{t,i})$ for $i \in \{1,..,N_{LdViol_t}\}$ designates the price-quantity segments of the penalty curve for under generation used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.2 $(PLdViolPrc_{t,i}, QLdViolPrc_{t,i})$ for $i \in \{1,..,N_{LdViol_t}\}$ designates the price-quantity segments of the penalty curve for under generation used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.3 $(PGenViolSch_{t,i}, QGenViolSch_{t,i})$ for $i \in \{1,..,N_{GenViol_t}\}$ designates the price-quantity segments of the penalty curve for over generation used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.4 $(PGenViolPrc_{t,i}, QGenViolPrc_{t,i})$ for $i \in \{1,..,N_{GenViol_t}\}$ designates the price-quantity segments of the penalty curve for over generation used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.5 $(P10SViolSch_{t,i}, Q10SViolSch_{t,i})$ for $i \in \{1,..,N_{10SViol_t}\}$ designates the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.6 $(P10SViolPrc_{t,i}, Q10SViolPrc_{t,i})$ for $i \in \{1,..,N_{10SViol_t}\}$ designates the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.7 $(P10RViolSch_{t,i}, Q10RViolSch_{t,i})$ for $i \in \{1,..,N_{10RViol_t}\}$ designates the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.8 $(P10RViolPrc_{t,i}, Q10RViolPrc_{t,i})$ for $i \in \{1,..,N_{10RViol_t}\}$ designates the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.9 $(P30RViolSch_{t,i}, Q30RViolSch_{t,i})$ for $i \in \{1,..,N_{30RViol_t}\}$ designates the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.10 $(P30RViolPrc_{t,i}, Q30RViolPrc_{t,i})$ for $i \in \{1,..,N_{30RViol_t}\}$ designates the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.11 $(PREG10RViolSch_{t,i}, QREG10RViolSch_{t,i})$ for $i \in \{1,..,N_{REG10RViol_t}\}$ designates the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.12 $(PREG10RViolPrc_{t,i}, QREG10RViolPrc_{t,i})$ for $i \in \{1,..,N_{REG10RViol_t}\}$ designates the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.13 $(PREG30RViolSch_{t,i}, QREG30RViolSch_{t,i})$ for $i \in \{1,..,N_{REG30RViol_t}\}$ designates the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.14 $(PREG30RViolPrc_{t,i}, QREG30RViolPrc_{t,i})$ for $i \in \{1,..,N_{REG30RViol_t}\}$ designates the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.15 $(PXREG10RViolSch_{t,i}, QXREG10RViolSch_{t,i})$ for $i \in \{1,..,N_{XREG10RViol_t}\}$ designates the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.16 $(PXREG10RViolPrc_{t,i}, QXREG10RViolPrc_{t,i})$ for $i \in \{1,..,N_{XREG10RViol_t}\}$ designates the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.17 $(PXREG30RViolSch_{t,i}, QXREG30RViolSch_{t,i})$ for $i \in \{1,..,N_{XREG30RViol_t}\}$ designates the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.18 $(PXREG30RViolPrc_{t,i}, QXREG30RViolPrc_{t,i})$ for $i \in \{1,..,N_{XREG30RViol_t}\}$ designates the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.19 $(PPreITLViolSch_{f,t,i}, QPreITLViolSch_{f,t,i})$ for $i \in \{1,..,N_{PreITLViol_{f,t}}\}$ designates the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.20 $(PPreITLViolPrc_{f,t,i}, QPreITLViolPrc_{f,t,i})$ for $i \in \{1,..,N_{PreITLViol_{f,t}}\}$ designates the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.21 $(PITLViolSch_{c,f,t,i}, QITLViolSch_{c,f,t,i})$ for $i \in \{1,..,N_{ITLViol_{c,f,t}}\}$ designates the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.22 $(PITLViolPrc_{c,f,t,i}, QITLViolPrc_{c,f,t,i})$ for $i \in \{1,..,N_{ITLViol_{c,f,t}}\}$ designates the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.23 $(PPreXTLViolSch_{z,t,i}, QPreXTLViolSch_{z,t,i})$ for $i \in \{1,..,N_{PreXTLViol_{z,t}}\}$ designates the price-quantity segments of the penalty curve for exceeding the flow limit specified by $z \in Z_{Sch}$ used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.24 $(PPreXTLViolPrc_{z,t,i}, QPreXTLViolPrc_{z,t,i})$ for $i \in \{1,..,N_{PreXTLViol_{z,t}}\}$ designates the price-quantity segments of the penalty curve for exceeding the flow limit specified by $z \in Z_{Sch}$ used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.25 $(PNIUViolSch_{t,i}, QNIUViolSch_{t,i})$ for $i \in \{1,..,N_{NIUViol_t}\}$ designates the price-quantity segments of the penalty curve for exceeding the time-step t net interchange increase constraint between time-steps $(t\text{-}1)$ and t used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.26 $(PNIUViolPrc_{t,i}, QNIUViolPrc_{t,i})$ for $i \in \{1,..,N_{NIUViol_t}\}$ designates the price-quantity segments of the penalty curve for exceeding the time-step t net interchange increase constraint between time-steps $(t\text{-}1)$ and t used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.27 $(PNIDViolSch_{t,i}, QNIDViolSch_{t,i})$ for $i \in \{1,..,N_{NIDViol_t}\}$ designates the price-quantity segments of the penalty curve for exceeding the time-step t net interchange decrease constraint between time-steps $(t\text{-}1)$ and t used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.28 $(PNIDViolPrc_{t,i}, QNIDViolPrc_{t,i})$ for $i \in \{1,..,N_{NIDViol_t}\}$ designates the price-quantity segments of the penalty curve for exceeding the time-step t net interchange decrease constraint between time-steps $(t\text{-}1)$ and t used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.29 $(PMaxDelViolSch_{t,i}, QMaxDelViolSch_{t,i})$ for $i \in \{1,..,N_{MaxDelViol_t}\}$ designates the price-quantity segments of the penalty curve for exceeding a *resource's maximum daily energy limit* used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.30 $(PMaxDelViolPrc_{t,i}, QMaxDelViolPrc_{t,i})$ for $i \in \{1,..,N_{MaxDelViol_t}\}$ designates the price-quantity segments of the penalty curve for exceeding a *resource's maximum daily energy limit* used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.31 $(PMinDelViolSch_{t,i}, QMinDelViolSch_{t,i})$ for $i \in \{1,..,N_{MinDelViol_t}\}$ designates the price-quantity segments of the penalty curve for under-scheduling a *resource's minimum daily energy limit* used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.32 $(PMinDelViolPrc_{t,i}, QMinDelViolPrc_{t,i})$ for $i \in \{1,..,N_{MinDelViol_t}\}$ designates the price-quantity segments of the penalty curve for under-scheduling a *resource's minimum daily energy limit* used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.33 $(PSMaxDelViolSch_{t,i}, QSMaxDelViolSch_{t,i})$ for $i \in \{1,..,N_{SMaxDelViol_t}\}$ designate the price-quantity segments of the penalty curve for exceeding a shared *maximum daily energy limit* used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.34 $(PSMaxDelViolPrc_{t,i}, QSMaxDelViolPrc_{t,i})$ for $i \in \{1,..,N_{MaxDelViol_t}\}$ designate the price-quantity segments of the penalty curve for exceeding a shared *maximum daily energy limit* used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.35 $(PSMinDelViolSch_{t,i}, QSMinDelViolSch_{t,i})$ for $i \in \{1,..,N_{SMinDelViol_t}\}$ designate the price-quantity segments of the penalty curve for under-scheduling a shared *minimum daily energy limit* used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.36 $(PSMinDelViolPrc_{t,i}, QSMinDelViolPrc_{t,i})$ for $i \in \{1,..,N_{SMinDelViol_t}\}$ designate the price-quantity segments of the penalty curve for under-scheduling a shared *minimum daily energy limit* used by the Pre-Dispatch Pricing algorithm in section 9 and Reference Level Pricing algorithm in section 13;

4.3.7.37 $(POGenLnkViolSch_{t,i}, QOGenLnkViolSch_{t,i})$ for $i \in \{1,..,N_{OGenLnkViol_t}\}$ designate the price-quantity segments of the penalty curve for over generation on a downstream *resource* used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12;

4.3.7.38 $(PUGenLnkViolSch_{t,i}, QUGenLnkViolSch_{t,i})$ for $i \in \{1,..,N_{UGenLnkViol_t}\}$ designate the price-quantity segments of the penalty curve for under generation on a downstream *resource* used by the Pre-Dispatch Scheduling algorithm in section 8 and the Reference Level Scheduling algorithm in section 12; and

4.3.7.39 $NISLPen$ designates the net interchange scheduling limit constraint violation penalty price for *locational marginal pricing*.

4.3.8 Price Bounds

4.3.8.1 $EngyPrcCeil$ designates and is equal to the *maximum market clearing price* for *energy*;

4.3.8.2 $EngyPrcFlr$ designates and is equal to the *settlement floor price* for *energy*;

4.3.8.3 $ORPrcCeil$ designates and is equal to the *maximum operating reserve price* for all classes of *operating reserve*; and

4.3.8.4 $ORPrcFlr$ designates the minimum price for all classes of *operating reserve* and is equal to $0.

4.3.9 Ex-Ante Market Power Mitigation

4.3.9.1 $BCACondThresh$ designates the threshold for the congestion component of a *resource's locational marginal price* for *energy*, above which the *resource* will meet the broad constrained area condition, and is equal to $25/MWh;

4.3.9.2 $IBPThresh$ designates the *intertie border price* threshold for *energy* and is equal to $100/MWh;

4.3.9.3 $ORGCondThresh$ designates the global market power condition threshold for a *resource's locational marginal price* for *operating reserve* and is equal to $15/MW;

4.3.9.4 $PDGRef_{t,b,k'}$ designates the *reference level value* for *energy* lamination $k' \in K'^{E}_{t,b}$ for the *resource* at bus $b \in B^{DG}$ in time-step $t \in TS$;

4.3.9.5 $P10SDGRef_{t,b,k'}$ designates the *reference level value* for synchronized *ten-minute operating reserve* lamination $k' \in K'^{10S}_{t,b}$ for the *resource* at bus $b \in B^{DG}$ in time-step $t \in TS$;

4.3.9.6 $P10NDGRef_{t,b,k'}$ designates the *reference level value* for non-synchronized *ten-minute operating reserve* lamination $k' \in K'^{10N}_{t,b}$ for the *resource* at bus $b \in B^{DG}$ in time-step $t \in TS$;

4.3.9.7 $P30RDGRef_{t,b,k'}$ designates the *reference level value* for *thirty-minute operating reserve* lamination $k' \in K'^{30R}_{t,b}$ for the *resource* at bus $b \in B^{DG}$ in time-step $t \in TS$;

4.3.9.8 $P10SDLRef_{t,b,j'}$ designates the *reference level value* for synchronized *ten-minute operating reserve* lamination $j' \in J'^{10S}_{t,b}$ for the *resource* at bus $b \in B^{DL}$ in time-step $t \in TS$;

4.3.9.9 $P10NDLRef_{t,b,j'}$ designates the *reference level value* for non-synchronized *ten-minute operating reserve* lamination $j' \in J'^{10N}_{t,b}$ for the *resource* at bus $b \in B^{DL}$ in time-step $t \in TS$;

4.3.9.10 $P30RDLRef_{t,b,j'}$ designates the *reference level value* for *thirty-minute operating reserve* lamination $j' \in J'^{30R}_{t,b}$ for the *resource* at bus $b \in B^{DG}$ in time-step $t \in z$

4.3.9.11 $SUDGRef_{t,b}$ designates the *reference level value* for the *start-up offer* for the *resource* at bus $b \in B^{NQS}$ in time-step $t \in TS$;

4.3.9.12 $SNLRef_{t,b}$ designates the *reference level value* for the *speed no-load offer* for the *resource* at bus $b \in B^{NQS}$ in time-step $t \in TS$;

4.3.9.12 $PLTMLPRef_{t,b,k'}$ designates the *reference level value* for the *energy* up to the *minimum loading point reference level* lamination $k' \in K'^{LTMLP}_{h,b}$ of the *offer* for the *resource* at bus $b \in B^{DG}$ in time-step $t \in TS$;

4.3.9.14 $CTEnThresh1^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 50%;

4.3.9.15 $CTEnThresh2^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $25/MWh;

4.3.9.16 $CTSUThresh^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 25%;

4.3.9.17 $CTSNLThresh^{NCA}$ designates the conduct threshold for a *resource* in a *narrow constrained area* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 25%;

4.3.9.18 $CTEnThresh1^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 50%;

4.3.9.19 $CTEnThresh2^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $25/MWh;

4.3.9.20 $CTSUThresh^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 25%;

4.3.9.21 $CTSNLThresh^{DCA}$ designates the conduct threshold for a *resource* in a *dynamic constrained area* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 25%;

4.3.9.22 $CTEnThresh1^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 300%;

4.3.9.23 $CTEnThresh2^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $100/MWh;

4.3.9.24 $CTSUThresh^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 100%;

4.3.9.25 $CTSNLThresh^{BCA}$ designates the conduct threshold for a *resource* in a broad constrained area as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 100%;

4.3.9.26 $CTEnThresh1^{GMP}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *energy offer* for the *resource* and is equal to 300%;

4.3.9.27 $CTEnThresh2^{GMP}$ designates the global market power conduct threshold for a *resource* as a $/MWh increase above the *reference level value* of the *energy offer* for the *resource* and is equal to $100 MW/h;

4.3.9.28 $CTSUThresh^{GMP}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 100%;

4.3.9.29 $CTSNLThresh^{GMP}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 100%;

4.3.9.30 $CTORThresh1^{ORL}$ designates the local market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to 10%;

4.3.9.31 $CTORThresh2^{ORL}$ designates the local market power conduct threshold for a *resource* as a $/MW increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to $25/MW;

4.3.9.32 $CTEnThresh1^{ORL}$ designates the local marker power conduct thershold for *energy* to *minimum loading point* for a *resource* as a percent increase above the *reference level value* of the *offer* for *energy* up to the *minimum loading point* for the *resource* and is equal to 10%;

4.3.9.33 $CTEnThresh2^{ORL}$ designates the local maket power conduct threshold for *energy* to *minimum loading point* conduct threshold for a *resource* as a $/MW increase above the *reference level value* of the *energy* for *energy* up to the *minimum loading point* for the *resource* and is equal to $25/MW;

4.3.9.34 $CTSUThresh^{ORL}$ designates the local market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 10%;

4.3.9.35 $CTSNLThresh^{ORL}$ designates the local market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 10%;

4.3.9.36 $CTORThresh1^{ORG}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to 50%;

4.3.9.37 $CTORThresh2^{ORG}$ designates the global market power conduct threshold for a *resource* as a $/MW increase above the *reference level value* of the *operating reserve offer* for the *resource* and is equal to $25/MW;

4.3.9.38 $CTEnThresh1^{ORG}$ designates the global market power conduct thershold for *energy* to *minimum loading point* for a *resource* as a percent increase above the *reference level value* of the *offer* for *energy* up to the *minimum loading point* for the *resource* and is equal to 50%;

4.3.9.39 $CTEnThresh2^{ORG}$ designates the global market power conduct thershold for *energy* to *minimum loading point* for a *resource* as a

$/MW increase above the *reference level value* of the *offer* for *energy* up to the *minimum loading point* for the *resource* and is equal to $25/MW;

4.3.9.40 $CTSUThresh^{ORG}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *start-up offer* for the *resource* and is equal to 25%;

4.3.9.41 $CTSNLThresh^{ORG}$ designates the global market power conduct threshold for a *resource* as a percent increase above the *reference level value* of the *speed no-load offer* for the *resource* and is equal to 25%;

4.3.9.42 $CTEnMinOffer$ designates the minimum price for the *offer* lamination for *energy* to be included in the Conduct Test. *Offer* laminations for *energy* below this value are excluded from the Conduct Test and is equal to $25/MWh;

4.3.9.43 $CTORMinOffer$ designates the minimum price for the *offer* lamination for *operating reserve* to be included in the Conduct Test. *Offer* laminations for *operating reserve* below this value are excluded from the Conduct Test and is equal to $5/MW;

4.3.9.44 $ITThresh1^{NCA}$ designates the price impact threshold for a *resource* in a *narrow constrained area* as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 50%;

4.3.9.45 $ITThresh2^{NCA}$ designates the price impact threshold for a *resource* in a *narrow constrained area* as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to $25/MWh;

4.3.9.46 $ITThresh1^{DCA}$ designates the price impact threshold for a *resource* in a *dynamic constrained area* as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 50%;

4.3.9.47 $ITThresh2^{DCA}$ designates the price impact threshold for a *resource* in a *dynamic constrained area* as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy* *locational marginal price* output from section 13 and is equal to $25/MWh;

4.3.9.48 $ITThresh1^{BCA}$ designates the price impact threshold for a *resource* in a broad constrained area as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 100%;

4.3.9.49 $ITThresh2^{BCA}$ designates the price impact threshold for a *resource* in a broad constrained area as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to$50/MWh;

4.3.9.50 $ITThresh1^{GMP}$ designates the global market power price impact threshold for a *resource* as a percent increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to 100%;

4.3.9.51 $ITThresh2^{GMP}$ designates the global market power price impact threshold for a *resource* as a $/MWh increase in the *energy locational marginal price* output from section 9 above the *energy locational marginal price* output from section 13 and is equal to $50/MWh;

4.3.9.52 $ITThresh1^{ORG}$ designates the global market power price impact threshold for a *resource* as a percent increase in the *operating reserve locational marginal price* output from section 9 above the *operating reserve locational marginal price* output from section 13 and is equal to 50%; and

4.3.9.53 $ITThresh2^{ORG}$ designates the global market power price impact threshold for a *resource* as a $/MW increase in the *operating reserve locational marginal price* output from section 9 above the *operating reserve locational marginal price* output from section 13 and is equal to $25/MW.

4.3.10 Weighting Factors for Zonal Prices

4.3.10.1 $WF_{t,m,b}^{VIRT}$ designates the weighting factor for bus $b \in L_m^{VIRT}$ used to calculate the price for *virtual transaction zone* $m \in M$ for time-step $t \in TS$ and is equal to the weighting factor used in the *day-ahead market* for the applicable hour;

4.3.10.2 $WF_{h,y,b}^{NDL}$ designates the weighting factor for bus $b \in L_y^{NDL}$ used to calculate the price for *non-dispatchable load* zone $y \in Y$ for time-step $t \in TS$. The weighting factors shall be obtained by renormalizing the load distribution factors so that for a given time-step the sum of weighting factors for a *non-dispatchable load* zone is equal to one.

4.3.11 Day-Ahead Market Scheduled Intertie Transactions

4.3.11.1 $SIGT_{t,d}^{DAM}$ designates the *day-ahead market* scheduled quantity of import *energy* for *intertie zone* source bus $d \in DI$ in time-step $t \in \{4,..,n_{LAP}\}$;

4.3.11.2 $S10NIGT_{t,d}^{DAM}$ designates the *day-ahead market* scheduled quantity of non-synchronized *ten-minute operating reserve* for *intertie zone* source bus $d \in DI$ in time-step $t \in \{4,..,n_{LAP}\}$;

4.3.11.3 $S30RIGT_{t,d}^{DAM}$ designates the *day-ahead market* scheduled quantity of *thirty-minute operating reserve* for *intertie zone* source bus $d \in DI$ in time-step $t \in \{4,..,\mathrm{n_{LAP}}\}$;

4.3.11.4 $SXLT_{t,d}^{DAM}$ designates the *day-ahead market* scheduled quantity of export *energy* for *intertie zone* sink bus $d \in DX$ in time-step $t \in \{4,..,n_{LAP}\}$;

4.3.11.5 $S10NXLT_{t,d}^{DAM}$ designates the *day-ahead market* scheduled quantity of non-synchronized *ten-minute operating reserve* for *intertie zone* sink bus $d \in DX$ in time-step $t \in \{4,..,n_{LAP}\}$; and

4.3.11.6 $\mathrm{S30RXLT_{t,d}^{DAM}}$ designates the *day-ahead market* scheduled quantity of *thirty-minute operating reserve* for *intertie zone* sink bus $d \in DX$ in time-step $t \in \{4,..,\mathrm{n_{LAP}}\}$.

4.3.12 Import Offers Without a Day-Ahead Market Schedule

4.3.12.1 $SIGT_{t,d}^{EXTRA}$ designates the extra quantity of *energy* for import from *intertie zone* source bus $d \in DI$ in time-step $t \in \{4,..,n_{LAP}\}$ that may be considered for the purpose of *reliability*;

4.3.12.2 $S10NIGT_{t,d}^{EXTRA}$ designates the extra quantity of non-synchronized *ten-minute operating reserve* for import from *intertie zone* source bus $d \in DI$ in time-step $t \in \{4,..,n_{LAP}\}$ that may be considered for the purpose of *reliability*; and

4.3.12.3 $S30RIGT_{t,d}^{EXTRA}$ designates the extra quantity of *thirty-minute operating reserve* for import from *intertie zone* source bus $d \in DI$ in time-step $t \in \{4,..,n_{LAP}\}$ that may be considered for the purpose of *reliability*.

4.4 Other Data Parameters

4.4.1 Non-Dispatchable Demand Forecast

4.4.1.1 FL_t designates the total province-wide non-*dispatchable demand* forecast for time-step $t \in TS$ calculated by the *security* assessment function.

4.4.2 Internal Transmission Constraints

4.4.2.1 $PreConSF_{t,f,b}$ designates the pre-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during time-step t under pre-contingency conditions;

4.4.2.2 $AdjNormMaxFlow_{t,f}$ designates the limit corresponding to the maximum flow allowed on *facility* f in time-step t under pre-contingency conditions;

4.4.2.3 $SF_{t,c,f,b}$ designates the post-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during time-step t under post-contingency conditions for contingency c; and

4.4.2.4 $AdjEmMaxFlow_{t,c,f}$ designates the limit corresponding to the maximum flow allowed on *facility* f in time-step t under post-contingency conditions for contingency c.

4.4.3 Transmission Losses

4.4.3.1 $MglLoss_{t,b}$ designates the marginal loss factor and represents the marginal impact on transmission losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at *resource* bus $b \in B \cup D$ in time-step $t \in TS$; and

4.4.3.2 $LossAdj_t$ designates any adjustment needed for time-step $t \in TS$ to correct for any discrepancy between Ontario total system losses calculated using a base case power flow from the *security* assessment function and linearized losses that would be calculated using the marginal loss factors.

5 Initialization

5.1 Purpose

5.1.1 The initialization processes set out in this section 5 shall occur prior to the execution of the *pre-dispatch calculation engine* described in section 2.2.1 above.

5.2 Reference Bus

5.2.1 The *IESO* shall use Richview Transformer Station as the *pre-dispatch calculation engine's* default *reference bus* for the calculation of *locational marginal prices.*

5.2.2 If the default *reference bus* is out of service, another in-service bus shall be selected.

5.3 Islanding Conditions

5.3.1 In the event of a network split, the *pre-dispatch calculation engine* shall:

5.3.1.1 only evaluate *resources* that are within the *main island*;

5.3.1.2 use only forecasts of *demand* forecast areas in the *main island*; and

5.3.1.3 use a bus within the *main island* in place of the *reference bus* if the *reference bus* does not fall within the *main island*.

5.4 Variable Generation Tie-Breaking

5.4.1 For each time-step $t \in TS$, each *variable generation resource* bus $b \in B^{VG}$ and each *offer* lamination $k \in K^{E}_{t,b}$, the *offer* price $PDG_{t,b,k}$ shall be modified to $PDG_{t,b,k} - \left(\frac{TBM_{t,b}}{NumVG_t}\right) \rho$, where ρ is a small nominal value of order 10^{-4}.

5.5 Pseudo-Unit Constraints

5.5.1 Constraints for *pseudo-units* corresponding to minimum and maximum constraints on physical *resources* shall be determined in accordance with section 15.

5.6 Dispatch Data Across Two Dispatch Days

5.6.1 If the pre-dispatch look-ahead period spans two *dispatch days*, then the *pre-dispatch calculation engine* shall set the parameters below as follows:

5.6.1.1 $LNKC$, which designates the linked *dispatchable* hydroelectric *generation resources* and is defined by:

$$LNKC = \begin{cases} LNK_{tod} & if\ DAYS = \{tod\} \\ LNK_{tom} & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.2 $LagC_{b_1,b_2}$, which designates the *time lag* between *dispatchable* hydroelectric *generation resources* $(b_1,b_2) \in LNKC$ and is defined by:

$$LagC_{b_1,b_2} = \begin{cases} Lag_{tod,b_1,b_2} & if\ DAYS = \{tod\} \\ Lag_{tom,b_1,b_2} & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.3 $MWhRatioC_{b_1,b_2}$, which designates the *MWh ratio* for *dispatchable* hydroelectric *generation resources* $(b_1,b_2) \in LNKC$ and is defined by:

$$MWhRatioC_{b_1,b_2} = \begin{cases} MWhRatio_{tod,b_1,b_2} & if\ DAYS = \{tod\} \\ MWhRatio_{tom,b_1,b_2} & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.4 $MinQDGC_b$, which designates the *minimum loading point* for *dispatchable generation resource* $b \in B^{DG}$ and, subject to section 5.6.2, is defined by:

$$MinQDGC_b = \begin{cases} MinQDG_{tod,b} & if\ DAYS = \{tod\} \\ MinQDG_{tom,b} & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.5 $MGBRTDGC_b$, which designates the *minimum generation block run-time* for *non-quick start resource* $b \in B^{NQS}$ and, subject to section 5.6.2, is defined by:

$$MGBRTDGC_b = \begin{cases} MGBRTDG_{tod,b} & if\ DAYS = \{tod\} \\ MGBRTDG_{tom,b} & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.6 $MGBDTDGC_b^m$, which designates the *minimum generation block down-time* for *non-quick start resource* $b \in B^{NQS}$ for *thermal state* $m \in THERM$ and is defined by:

$$MGBDTDGC_b^m = \begin{cases} MGBDTDG_{tod,b}^m & if\ DAYS = \{tod\} \\ MGBDTDG_{tom,b}^m & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.7 LTC_b^m, which designates the *lead time* for *non-quick start resource* $b \in B^{NQS}$ for *thermal state* $m \in THERM$ and is defined by

$$LTC_b^m = \begin{cases} LT_{tod,b}^m & if\ DAYS = \{tod\} \\ LT_{tom,b}^m & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.8 $RampHrsC_b^m$, which designates the *ramp hours to minimum loading point* for a *non-quick start resource* $b \in B^{NQS}$ for *thermal state* $m \in THERM$ and is defined by:

$$RampHrsC_b^m = \begin{cases} RampHrs_{tod,b}^m & if\ DAYS = \{tod\} \\ RampHrs_{tom,b}^m & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.9 $RampEC_{b,w}^m$ for $w \in \{1,..,RampHrsC_b^m\}$, which designates the *ramp up energy to minimum loading point* for a *non-quick start resource* $b \in B^{NQS}$ for *thermal state* $m \in THERM$ and is defined by:

$$RampEC_{b,w}^m = \begin{cases} RampE_{tod,b,w}^m & if\ DAYS = \{tod\} \\ RampE_{tom,b,w}^m & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.10 $RampCTC_{b,w}^m$ for $w \in \{1,..,RampHrsC_b^m\}$, which designates the *ramp up energy to minimum loading point* for the combustion turbine *resource* associated with the *pseudo-unit* at bus $b \in B^{PSU}$ for *thermal state* $m \in THERM$ and is defined by:

$$RampCTC_{b,w}^m = \begin{cases} RampCT_{tod,b,w}^m & if\ DAYS = \{tod\} \\ RampCT_{tom,b,w}^m & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.1.11 $RampSTC^{m}_{b,w}$ for $w \in \{1,..,RampHrsC^{m}_{b}\}$, which designates the *ramp up energy to minimum loading point* for the steam turbine *resource's* portion of the *pseudo-unit* at bus $b \in B^{PSU}$ for *thermal state* $m \in THERM$ and is defined by:

$$RampSTC^{m}_{b,w} = \begin{cases} RampST^{m}_{tod,b,w} & if\ DAYS = \{tod\} \\ RampST^{m}_{tom,b,w} & if\ DAYS = \{tod, tom\} \end{cases}.$$

5.6.2 If a *non-quick start resource* receives a commitment prior to the 20:00 EST *pre-dispatch calculation engine* run but that commitment is not yet complete, then:

5.6.2.1 $MinQDG_{tod,b}$ and $MGBRTDG_{tod,b}$ shall continue to be applied until the commitment is complete; and

5.6.2.2 $MinQDG_{tom,b}$ and $MGBRTDG_{tom,b}$ shall be applied for any new commitments made in the 20:00 EST *pre-dispatch calculation engine run* or later.

5.6.3 For all other daily *dispatch data*, except the *single cycle mode* flag determined in section 15.5, the current day value shall be used for all *dispatch hours* in the current *dispatch day* and the next day value shall be used for all *dispatch hours* in the next *dispatch day*.

5.7 Start-Up Offers for Non-Quick Start Resource Advancements

5.7.1 The *pre-dispatch calculation engine* shall use *start-up offers* for *non-quick start resources* with a *day-ahead operational commitment* as follows:

5.7.1.1 If the time-step t in the set of hours preceding the start-up time $t_{DAM} \in TSC_b$ of a *day-ahead operational commitment* in day $q \in DAYS$ are such that $t \in \{max(t_{DAM}\text{-}(MGBRTDG_{q,b} + MGBDTDG^{HOT}_{q,b}), 2),...,t_{DAM}\}$, then:

If $SUDG^{m}_{t,b} \geq SUDG^{DAM}_{t,b}$, then set $SUAdjDG^{m}_{t,b} = SUDG^{m}_{t,b}$

If $SUDG^{m}_{t,b} < SUDG^{DAM}_{t,b}$, then set $SUAdjDG^{m}_{t,b} = SUDG^{DAM}_{t,b}$

5.7.1.2 If the time-step t in the set of hours preceding the start-up time $t_{DAM} \in TSC_b$ of a *day-ahead operational commitment* in day $q \in DAYS$ are *offer*such that $t \notin \{max(t_{DAM}\text{-}(MGBRTDG_{q,b} + MGBDTDG^{HOT}_{q,b}), 2),...,t_{DAM}\}$, then:

$$SUAdjDG_{t,b}^{m} = SUDG_{t,b}^{m}$$

5.8 Non-Quick Start Resource First Time-Step Available to Start

5.8.1 The *pre-dispatch calculation engine* shall determine the first time-step a *non-quick start resource* can be scheduled to its *minimum loading point* as follows:

5.8.1.1 For a *non-quick start resource* at bus $b \in B^{NQS}$ that has not been scheduled at or above its *minimum loading point* for $InitDownHrs_b$ hours:

5.8.1.1.1 If $0 \leq \mathrm{InitDownHrs_b} + \mathrm{t} - 1 \leq \mathrm{MGBDTDGC_b^{HOT}}$, then the *resource* cannot be scheduled to reach *minimum loading point* in time-step $\mathrm{t} \in \mathrm{TS}$;

5.8.1.1.2 If $\mathrm{InitDownHrs_b} + \mathrm{LTC_b^{HOT}} + 1 \leq \mathrm{MGBDTDGC_b^{WARM}}$, then a *lead time* of $\mathrm{LTC_b^{HOT}}$ will be applied and the *resource* can be scheduled to its *minimum loading point* in time-step $\mathrm{t} \in \mathrm{TS}$ only if $\mathrm{t} \geq \mathrm{LTC_b^{HOT}} + 2$;

5.8.1.1.3 If $\mathrm{InitDownHrs_b} + \mathrm{LTC_b^{WARM}} + 1 \leq \mathrm{MGBDTDGC_b^{COLD}}$, then a *lead time* of $\mathrm{LTC_b^{WARM}}$ will be applied and the *resource* can be scheduled to its *minimum loading point* in time-step $\mathrm{t} \in \mathrm{TS}$ only if $\mathrm{t} \geq \mathrm{LTC_b^{WARM}} + 2$; and

5.8.1.1.4 If a *lead time* of LTC_b^{COLD} will be applied and the *resource* can be scheduled to its *minimum loading point* in time-step $t \in TS$ only if $t \geq LTC_b^{COLD} + 2$.

5.9 Initial Scheduling Assumptions

5.9.1 Initial Schedules

5.9.1.1 The following parameters designate the initial *energy* schedules used for time-step 1 of the pre-dispatch look-ahead period and shall be based on the values determined by the *IESO's energy* management system for internal *resources* and the most recent *interchange schedules* for time-step 1 for *boundary entity resources*:

5.9.1.1.1 $SDL_{1,b,j}$ designates the amount of *energy* that a *dispatchable load* is scheduled to consume at bus $b \in B^{DL}$;

5.9.1.1.2 $SHDR_{1,b,j}$ designates the amount of *energy* an *hourly demand response resource* is scheduled to reduce consumption at bus $b \in B^{HDR}$;

5.9.1.1.3 $SXL_{1,d,j}$ designates the amount of *energy* a *bounday entity resource* is scheduled to export at bus $d \in DX$;

5.9.1.1.4 $SDG_{1,b,k}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$;

5.9.1.1.5 $SCT_{1,b}$ designates the schedule of the combustion turbine *resource* associated with the *pseudo-unit* at bus $b \in B^{PSU}$;

5.9.1.1.6 $SST_{1,p}$ designates the schedule of the steam turbine *resource* $p \in PST$;

5.9.1.1.7 $SIG_{1,d,k}$ designates the amount of *energy* that a *boundary entity resource* is scheduled to import from *intertie zone* source bus $d \in DI$;

5.9.1.2 The initial schedules for *non-quick start resources* shall be determined to align with the commitment status logic described in section 5.9.2.

5.9.2 The following parameters designate initial commitment status, number of hours in operation and number of hours down for time-step 1 of the pre-dispatch look-ahead period:

5.9.2.1 $ODG_{1,b}$ designates whether the *dispatchable generation resource* at bus $b \in B^{NQS}$ has been scheduled at or above its *minimum loading point* in time-step 1, where $ODG_{1,b}$ shall be set to $ODG_{2,b}$ from the previous *pre-dispatch calculation engine run* unless the *real-time calculation engine* has kept such *resource* at or above its *minimum loading point* to respect a *reliability* constraint. In such cases, $ODG_{1,b}$ shall be determined by the *real-time calculation engine* advisory schedule;

5.9.2.2 $InitOperHrs_b$ designates the number of consecutive hours at the end of time-step 1 for which the *resource* at bus $b \in B^{NQS}$ has been, and is anticipated to be, operating at or above its *minimum loading point*. For *resources* with $ODG_{1,b} = 0$, $InitOperHrs_b$ shall be set to zero; and

5.9.2.3 $InitDownHrs_b$ designates the number of consecutive hours at the end of time-step 1 for which the *resource* at bus $b \in B^{NQS}$ has not been, and is not anticipated to be, operating at or above its *minimum loading point*. For *resources* with $ODG_{1,b} = 1$, $InitDownHrs_b$ shall be set to zero.

5.9.3 Initial Net Interchange Schedule

5.9.3.1 The initial net *interchange schedule* value shall be the difference between all imports to Ontario and all exports from Ontario for time-step 1. By default, this value will be based on fixed schedules for imports and exports from the *real-time calculation engine*.

5.9.4 Number of Starts for Non-Quick Start Resources

5.9.4.1 $NumStarts_b$ designates the number of starts the *resource* at bus $b \in B^{NQS}$ has incurred in the current *dispatch* day, plus any anticipated starts in time-step 1.

5.9.5 Number of Starts for Hydroelectric Resources

5.9.5.1 $NumStartsHE_b$ designates the number of starts the *resource* at bus $b \in B^{HE}$ has incurred in the current *dispatch day*, plus any anticipated starts in time-step 1.

5.9.6 Cumulative Energy Production for Energy Limited Resources and Dispatchable Hydroelectric Resources

5.9.6.1 $EngyUsed_b$ designates the *energy* already provided by the *resource* at bus $b \in B^{ELR} \cup B^{HE}$ in the current *dispatch day*, plus the *energy* scheduled in time-step 1; and

5.9.6.2 $EngyUsedSHE_s$ designates the *energy* already provided in the current *dispatch day* by all *resources* sharing a *maximum daily energy limit* or *minimum daily energy limit* in set $s \in SHE$ plus the *energy* scheduled in time-step 1.

5.9.7 Past Hourly Production for Linked Hydroelectric Resources

5.9.7.1 For linked hydroelectric *resources*, the past hourly *energy* production of upstream *resources* shall be used to schedule downstream *resources* for time-steps in the pre-dispatch look-ahead period within the *time lag*. These past hourly production schedules shall be equal to the output determined by the *IESO's energy* management system based on real-time telemetry less any production scheduled as part of an *operating reserve* activation. For all linked hydroelectric *resources* $(b_1,b_2) \in LNKC$ and all time-steps $t \in TS$ such that $t \leq LagC_{b_1,b_2}$, $PastMWh_{t,b_1}$ designates the total *energy* produced by *resource* b_1 exactly $LagC_{b_1,b_2}$ hours prior to time-step t.

5.9.7.2 The schedules of downstream *resources* linked to time-step 1 upstream *resource* schedules shall be pre-determined based on the average value of the upstream *resource* advisory schedules from the last *real-time calculation engine* run that successfully completed before the *pre-dispatch calculation engine* run commenced. If the advisory schedule reflects an *operating reserve* activation for an upstream *resource*, then the schedule determined by the *real-time calculation engine* run prior to the *operating reserve* activation shall be used. For all linked hydroelectric *resources* $(b_1,b_2) \in LNKC$ and all time-steps $t \in TS$ such that $t = LagC_{b_1,b_2}+1$, $PastMWh_{t,b_1}$ designates the total *energy* determined for *resource* b_1 for time-step 1 to be used for scheduling downstream *resources* in time-step t.

6 Security Assessment Function in the Pre-Dispatch Calculation Engine

6.1 Interaction between the Security Assessment Function and Optimization Functions

6.1.1 The scheduling and pricing algorithms of the *pre-dispatch calculation engine* shall perform multiple iterations of the optimization functions and the *security* assessment function to check for violations of monitored thermal limits and operating *security limits* using the schedules produced by the optimization functions.

6.1.2 As multiple iterations are performed, the transmission constraints produced by the *security* assessment function shall be used by the optimization functions.

6.1.3 The *security* assessment function shall use the physical *resource* representation of *combined cycle plant* that are registered as *pseudo-units*.

6.2 Inputs into the Security Assessment Function

6.2.1 The *security* assessment function shall use the following inputs:

6.2.1.1 the *IESO demand* forecasts; and

6.2.1.2 applicable *IESO-controlled grid* information pursuant to section 3A.1 of Chapter 7.

6.2.2 The *security* assessment function shall also use the following outputs of the optimization functions:

6.2.2.1 the schedules for *dispatchable loads* and *hourly demand response resources*;

6.2.2.2 the schedules for *non-dispatchable generation resources* and *dispatchable generation resources*; and

6.2.2.3 the schedules for *boundary entity resources* at each *intertie zone*.

6.3 Security Assessment Function Processing

6.3.1 The *security* assessment function shall determine the province-wide non-*dispatchable demand* forecast for time-step t, FL_t, as follows:

6.3.1.1 determine forecast MW quantities for all *load resources* and losses using the *IESO demand* forecasts for *demand* forecast areas, load distribution factors, and the total of the *bid* quantities submitted for virtual *hourly demand response resources* and physical *hourly demand response resources*; and

6.3.1.2 determine FL_t by adding the forecast MW quantities determined for each *non-dispatchable load*, each *price responsive load*, and each *dispatchable load* with no *bid*, including forecast MW losses in the *demand* forecast areas.

6.3.2 The *security* assessment function shall perform the following calculations and analyses:

6.3.2.1 A base case solution function shall prepare a power flow solution for each time-step. The base case solution function shall select the power system model state applicable to the forecast of conditions for the time-step and input schedules.

6.3.2.2 The base case solution function shall use an AC power flow analysis. If the AC power flow analysis fails to converge, the base case solution function shall use a non-linear DC power flow analysis. If the non-linear DC power flow analysis fails to converge, the base case solution function shall use a linear DC power flow analysis.

6.3.2.3 If the AC or non-linear DC power flow analysis converges, continuous thermal limits for all monitored equipment and operating *security limits* shall be monitored to check for pre-contingency limit violations.

6.3.2.4 Violated pre-contingency limits shall be linearized using pre-contingency sensitivity factors and incorporated as constraints for use by the optimization functions.

6.3.2.5 If the linear DC power flow analysis is used, the pre-contingency *security* assessment may develop linear constraints to facilitate the convergence of the AC or non-linear DC power flow analysisin the subsequent iterations.

6.3.2.6 A linear power flow analysis shall be used to simulate contingencies, calculate post-contingency flows and check all monitored equipment for limited-time thermal limit violations.

6.3.2.7 Violated post-contingency limits shall be linearized using post-contingency sensitivity factors and incorporated as constraints for use by the optimization functions.

6.3.2.8 The base case solution shall be used to calculate Ontario *transmission system* losses, marginal loss factors and loss adjustment for each time-step. The impact of losses on branches between the *resource* bus and the *resource connection point* to the *IESO-controlled grid* and losses on branches outside Ontario shall be excluded when determining marginal loss factors.

6.3.2.9 The Pre-Dispatch Scheduling and the Reference Level Scheduling algorithms described in sections 8 and 12, respectively, shall use the marginal loss factors for each time step calculated by the *security* assessment function.

6.3.2.10 The Pre-Dispatch Pricing and Reference Level Pricing algoritms described in sections 9 and 13, respectively, shall use the marginal loss factors used in the last iteration of the optimization function in the corresponding scheduling algorithm.

6.4 Outputs from the Security Assessment Function

6.4.1 The outputs of the *security* assessment function used in the optimization functions include the following:

6.4.1.1 a set of linearized constraints for all violated pre-contingency and post-contingency limits for each time-step. The sensitivities and limits associated with the constraints shall be those provided by the most recent *security* assessment function iteration;

6.4.12 pre-contingency and post-contingency sensitivity factors for each time step;

6.4.1.3 the marginal loss factors as described in sections 6.3.2.8 - 6.3.2.10; and

6.4.1.4 loss adjustment quantity for each time-step.

7 Pass 1: Pre-Dispatch Scheduling Process

7.1.1 Pass 1 shall use *market participant* and *IESO* inputs and *resource* and system constraints to determine a set of *resource* schedules, commitments and *locational marginal prices*. Pass 1 shall consist of the following algorithms and tests:

- the Pre-Dispatch Scheduling algorithm described in section 8;
- the Pre-Dispatch Pricing algorithm described in section 9;
- the Constrained Area Conditions Test described in section 10;
- the Conduct Test described in section 11;
- the Reference Level Scheduling algorithm described in section 12;
- the Reference Level Pricing algorithm described in section 13; and
- the Price Impact Test described in section 14.

8 Pre-Dispatch Scheduling

8.1 Purpose

8.1.1 The Pre-Dispatch Scheduling algorithm shall perform a *security*-constrained unit commitment and economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants,* subject to section 14.7.1.3, to meet the *IESO's* province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the pre-dispatch look-ahead period.

8.2 Information, Sets, Indices and Parameters

8.2.1 Information, sets, indices and parameters used by the Pre-Dispatch Scheduling algorithm are described in sections 3 and 4.

8.3 Variables and Objective Function

8.3.1 The Pre-Dispatch Scheduling algorithm shall solve for the following variables:

8.3.1.1 $SDL_{t,b,j}$, which designates the amount of *energy* that a *dispatchable load* is scheduled to consume at bus $b \in B^{DL}$ in time-step $t \in TS$ in association with lamination $j \in J^{E}_{t,b}$;

8.3.1.2 $S10SDL_{t,b,j}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in time-step $t \in TS$ in association with lamination $j \in J^{10S}_{t,b}$;

8.3.1.3 $S10NDL_{t,b,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in time-step $t \in TS$ in association with lamination $j \in J^{10N}_{t,b}$;

8.3.1.4 $S30RDL_{t,b,j}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in time-step $t \in TS$ in association with lamination $j \in J^{30R}_{t,b}$;

8.3.1.5 $SHDR_{t,b,j}$, which designates the amount of *energy* reduction scheduled for an *hourly demand response resource* at bus $b \in B^{HDR}$ in time-step $t \in TS$ in association with lamination $j \in J^{E}_{t,b}$;

8.3.1.6 $SXL_{t,d,j}$, which designates the amount of *energy* a *boundary entity resource* is scheduled to export at bus $d \in DX$ in time-step $t \in TS$ in association with lamination $j \in J^{E}_{t,d}$;

8.3.1.7 $S10NXL_{t,d,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *boundary entity resource* is scheduled to provide at bus $d \in DX$ in time-step $t \in TS$ in association with lamination $j \in J^{10N}_{t,d}$;

8.3.1.8 $S30RXL_{t,d,j}$, which designates the amount of *thirty-minute operating reserve* that a *boundary entity resource* is scheduled to provide bus $d \in DX$ in time-step $t \in TS$ in association with lamination $j \in J^{30R}_{t,d}$;

8.3.1.9 $SNDG_{t,b,k}$, which designates the amount of *energy* that a *non-dispatchable generation resource* is scheduled to provide at bus $b \in B^{NDG}$ in time-step $t \in TS$ in association with lamination $k \in K^{E}_{t,b}$;

8.3.1.10 $SDG_{t,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDGC_b$ at bus $b \in B^{DG}$ in time-step $t \in TS$ in association with lamination $k \in K^{E}_{t,b}$;

8.3.1.11 $ODG_{t,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ has been scheduled at or above its *minimum loading point* in time-step $t \in TS$;

8.3.1.12 $IDG_{t,b}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ has been scheduled to reach its *minimum loading point* in time-step $t \in TS$;

8.3.1.13 $S10SDG_{t,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in time-step $t \in TS$ in association with lamination $k \in K^{10S}_{t,b}$;

8.3.1.14 $S10NDG_{t,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in time-step $t \in TS$ in association with lamination $k \in K^{10N}_{t,b}$;

8.3.1.15 $S30RDG_{t,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in time-step $t \in TS$ in association with lamination $k \in K^{30R}_{t,b}$;

8.3.1.16 $SCT_{t,b}$, which designates the schedule of the combustion turbine *resource* associated with the *pseudo-unit* at bus $b \in B^{PSU}$ in time-step $t \in TS$;

8.3.1.17 $SST_{t,p}$, which designates the schedule of steam turbine *resource* $p \in PST$ in time-step $t \in TS$;

8.3.1.18 $O10R_{t,b}$, which designates whether the *pseudo-unit* at bus $b \in B^{NO10DF}$ has been scheduled for *ten-minute operating reserve* in time-step $t \in TS$;

8.3.1.19 $OHO_{t,b}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{t,b}$ in time-step $t \in TS$;

8.3.1.20 $OFR_{t,b,i}$ for $i \in \{1,..,NFor_{q,b}\}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or below $ForL_{q,b,i}$, or, at or above $ForU_{q,b,i}$ in time-step $t \in TS$;

8.3.1.21 $IHE_{t,b,i}$, which designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ registered a start between time-step $(t-1)$ and t as a result of its schedule increasing from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$ for $i \in \{1,..,NStartMW_b\}$;

8.3.1.22 $SIG_{t,d,k}$, which designates the amount of *energy* that a *boundary entity resource* is scheduled to import from *intertie zone* source bus $d \in DI$ in time-step $t \in TS$ in association with lamination $k \in K^{E}_{t,d}$;

8.3.1.23 $S10NIG_{t,d,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *boundary entity resource* is scheduled to provide from *intertie zone* source bus $d \in DI$ in time-step $t \in TS$ in association with lamination $k \in K^{10N}_{t,d}$;

8.3.1.24 $S30RIG_{t,d,k}$, which designates the amount of *thirty-minute operating reserve* that a *boundary entity resource* is scheduled to provide from *intertie zone* source bus $d \in DI$ in time-step $t \in TS$ in association with lamination $k \in K^{30R}_{t,d}$;

8.3.1.25 TB_t , which designates any adjustment to the objective function to facilitate pro-rata tie-breaking in time-step $t \in TS$, as described in section 8.3.2.1; and

8.3.1.26 $ViolCost_t$, which designates the cost incurred in order to avoid having the schedules violate constraints in time-step $t \in TS$, as described in section 8.3.2.3.

8.3.2 The objective function for the Pre-Dispatch Scheduling algorithm shall maximize gains from trade by maximizing the following expression:

$$\sum_{t \in TS}\begin{pmatrix} ObjDL_t - ObjHDR_t + ObjXL_t - ObjNDG_t \\ - ObjDG_t - ObjIG_t - TB_t - ViolCost_t \end{pmatrix}$$

where:

$$ObjDL_t = \sum_{b \in B^{DL}}\begin{pmatrix} \sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} \cdot PDL_{t,b,j} - \sum_{j \in J^{10S}_{t,b}} S10SDL_{t,b,j} \cdot P10SDL_{t,b,j} - \\ \sum_{j \in J^{10N}_{t,b}} S10NDL_{t,b,j} \cdot P10NDL_{t,b,j} - \sum_{j \in J^{30R}_{t,b}} S30RDL_{t,b,j} \cdot P30RDL_{t,b,j} \end{pmatrix};$$

$$ObjHDR_t = \sum_{b \in B^{HDR}}\left(\sum_{j \in J^{E}_{t,b}} SHDR_{t,b,j} \cdot PHDR_{t,b,j}\right);$$

$$ObjXL_t = \sum_{d \in DX}\begin{pmatrix} \sum_{j \in J^{E}_{t,d}} SXL_{t,d,j} \cdot PXL_{t,d,j} - \sum_{j \in J^{10N}_{t,d}} S10NXL_{t,d,j} \cdot P10NXL_{t,d,j} \\ - \sum_{j \in J^{30R}_{t,d}} S30RXL_{t,d,j} \cdot P30RXL_{t,d,j} \end{pmatrix};$$

$$ObjNDG_t = \sum_{b \in B^{NDG}}\left(\sum_{k \in K^{E}_{t,b}} SNDG_{t,b,k} \cdot PNDG_{t,b,k}\right);$$

$$ObjDG_t = \sum_{b \in B^{DG}}\begin{pmatrix} \sum_{k \in K^{E}_{t,b}} SDG_{t,b,k} \cdot PDG_{t,b,k} + \sum_{k \in K^{10S}_{t,b}} S10SDG_{t,b,k} \cdot P10SDG_{t,b,k} + \\ \sum_{k \in K^{10N}_{t,b}} S10NDG_{t,b,k} \cdot P10NDG_{t,b,k} + \sum_{k \in K^{30R}_{t,b}} S30RDG_{t,b,k} \cdot P30RDG_{t,b,k} \end{pmatrix} + \sum_{b \in B^{NQS}}\left(ODG_{t,b} \cdot MGODG_{t,b} + IDG_{t,b} \cdot SUAdjDG^{T_{t,b}}_{t,b}\right);$$

and

$$ObjIG_t = \sum_{d \in DI}\begin{pmatrix} \sum_{k \in K^{E}_{t,d}} SIG_{t,d,k} \cdot PIG_{t,d,k} + \sum_{k \in K^{10N}_{t,d}} S10NIG_{t,d,k} \cdot P10NIG_{t,d,k} \\ + \sum_{k \in K^{30R}_{t,d}} S30RIG_{t,d,k} \cdot P30RIG_{t,d,k} \end{pmatrix}.$$

8.3.2.1 The tie-breaking term TB_t shall sum a term for each *bid* or *offer* lamination. For each lamination, this term shall be the product of a small penalty cost and the quantity of the lamination scheduled. The penalty cost shall be calculated by multiplying a base penalty cost of $TBPen$ by the amount of the lamination scheduled and then dividing by the maximum amount that could have been scheduled. That is:

$$TB_t = TBDL_t + TBHDR_t + TBXL_t + TBNDG_t + TBDG_t + TBIG_t$$

Where

$$TBDL_t = \sum_{b \in B^{DL}} \left(\begin{array}{l} \sum_{j \in J^{E}_{t,b}} \left(\frac{(SDL_{t,b,j})^2 \cdot TBPen}{QDL_{t,b,j}} \right) + \sum_{j \in J^{10S}_{t,b}} \left(\frac{(S10SDL_{t,b,j})^2 \cdot TBPen}{Q10SDL_{t,b,j}} \right) + \\ \sum_{j \in J^{10N}_{t,b}} \left(\frac{(S10NDL_{t,b,j})^2 \cdot TBPen}{Q10NDL_{t,b,j}} \right) + \sum_{j \in J^{30R}_{t,b}} \left(\frac{(S30RDL_{t,b,j})^2 \cdot TBPen}{Q30RDL_{t,b,j}} \right) \end{array} \right);$$

$$TBHDR_t = \sum_{b \in B^{HDR}} \left(\sum_{j \in J^{E}_{t,b}} \frac{(SHDR_{t,b,j})^2 \cdot TBPen}{QHDR_{t,b,j}} \right);$$

$$TBXL_t = \sum_{d \in DX} \left(\begin{array}{l} \sum_{j \in J^{E}_{t,d}} \left(\frac{(SXL_{t,d,j})^2 \cdot TBPen}{QXL_{t,d,j}} \right) + \sum_{j \in J^{10N}_{t,d}} \left(\frac{(S10NXL_{t,d,j})^2 \cdot TBPen}{Q10NXL_{t,d,j}} \right) \\ + \sum_{j \in J^{30R}_{t,d}} \left(\frac{(S30RXL_{t,d,j})^2 \cdot TBPen}{Q30RXL_{t,d,j}} \right) \end{array} \right);$$

$$TBNDG_t = \sum_{b \in B^{NDG}} \left(\sum_{k \in K^{E}_{t,b}} \left(\frac{(SNDG_{t,b,k})^2 \cdot TBPen}{QNDG_{t,b,k}} \right) \right);$$

$$TBDG_t = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{t,b}^{E}} \left(\frac{\left(SDG_{t,b,k}\right)^2 \cdot TBPen}{QDG_{t,b,k}} \right) + \sum_{k \in K_{t,b}^{10S}} \left(\frac{\left(S10SDG_{t,b,k}\right)^2 \cdot TBPen}{Q10SDG_{t,b,k}} \right) + \\ \sum_{k \in K_{t,b}^{10N}} \left(\frac{\left(S10NDG_{t,b,k}\right)^2 \cdot TBPen}{Q10NDG_{t,b,k}} \right) + \sum_{k \in K_{t,b}^{30R}} \left(\frac{\left(S30RDG_{t,b,k}\right)^2 \cdot TBPen}{Q30RDG_{t,b,k}} \right) \end{array} \right);$$

and

$$TBIG_t = \sum_{d \in DI} \left(\begin{array}{c} \sum_{k \in K_{t,d}^{E}} \left(\frac{\left(SIG_{t,d,k}\right)^2 \cdot TBPen}{QIG_{t,d,k}} \right) + \sum_{k \in K_{t,d}^{10N}} \left(\frac{\left(S10NIG_{t,d,k}\right)^2 \cdot TBPen}{Q10NIG_{t,d,k}} \right) \\ + \sum_{k \in K_{t,d}^{30R}} \left(\frac{\left(S30RIG_{t,d,k}\right)^2 \cdot TBPen}{Q30RIG_{t,d,k}} \right) \end{array} \right).$$

8.3.2.2 $ViolCost_t$ shall be calculated for time-step $t \in TS$ using the following variables:

8.3.2.2.1 $SLdViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{LdViol_t}\}$ of the penalty curve for the *energy* balance constraint allowing under-generation;

8.3.2.2.2 $SGenViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{GenViol_t}\}$ of the penalty curve for the *energy* balance constraint allowing over-generation;

8.3.2.2.3 $S10SViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{10SViol_t}\}$ of the penalty curve for the synchronized *ten-minute operating reserve* requirement;

8.3.2.2.4 $S10RViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{10RViol_t}\}$ of the penalty curve for the total *ten-minute operating reserve* requirement;

8.3.2.2.5 $S30RViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{30RViol_t}\}$ of the penalty curve for the *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement;

8.3.2.2.6 $SREG10RViol_{r,t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{REG10RViol_t}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* minimum requirement in region $r \in ORREG$;

8.3.2.2.7 $SREG30RViol_{r,t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{REG30RViol_t}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* minimum requirement in region $r \in ORREG$;

8.3.2.2.8 $SXREG10RViol_{r,t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{XREG10RViol_t}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* maximum restriction in region $r \in ORREG$;

8.3.2.2.9 $SXREG30RViol_{r,t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{XREG30RViol_t}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* maximum restriction in region $r \in ORREG$;

8.3.2.2.10 $SPreITLViol_{f,t,i}$, which designates the violation variable affiliated with segment $I \in \{1,..,N_{PreITLViol_{f,t}}\}$ of the penalty curve for violating the pre-contingency transmission limit for *facility* $f \in F$;

8.3.2.2.11 $SITLViol_{c,f,t,i}$, which designates the violation variable affiliated with segment $I \in \{1,..,N_{ITLViol_{c,f,t}}\}$ of the penalty curve for violating the post-contingency transmission limit for *facility* $f \in F$ and contingency $c \in C$;

8.3.2.2.12 $SPreXTLViol_{z,t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{PreXTLViol_{z,t}}\}$ of the penalty curve for violating the import/export limit affiliated with *intertie* limit constraint $z \in Z_{Sch}$;

8.3.2.2.13 $SNIUViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{NIUViol_t}\}$ of the penalty curve for exceeding the net interchange increase limit between time-steps $(t\text{-}1)$ and t;

8.3.2.2.14 $SNIDViol_{t,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{NIDViol_t}\}$ of the penalty curve for exceeding the net interchange decrease limit between time-steps $(t\text{-}1)$ and t;

8.3.2.2.15 $SMaxDelViol_{t,b,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{MaxDelViol_t}\}$ of the penalty curve for exceeding the *maximum daily energy limit* constraint for a *resource* at bus $b \in B^{ELR}$;

8.3.2.2.16 $SMinDelViol_{t,b,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{MinDelViol_t}\}$ of the penalty curve for violating the *minimum daily energy limit* constraint for a *resource* at bus $b \in B^{HE}$;

8.3.2.2.17 $SSMaxDelViol_{t,s,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{SMaxDelViol_t}\}$ of the penalty curve for exceeding the shared *maximum daily energy limit* constraint for *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

8.3.2.2.18 $SSMinDelViol_{t,s,i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{SMinDelViol_t}\}$ of the penalty curve for violating the shared *minimum daily energy limit* constraint for *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

8.3.2.2.19 $SOGenLnkViol_{t,(b_1,b_2),i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{OGenLnkViol_t}\}$ of the penalty curve for violating the linked *dispatchable* hydroelectric *generation resources* constraint by over-generating the downstream *resource*, for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$; and

8.3.2.2.20 $SUGenLnkViol_{t,(b_1,b_2),i}$, which designates the violation variable affiliated with segment $i \in \{1,..,N_{UGenLnkViol_t}\}$ of the penalty curve for violating the linked *dispatchable* hydroelectric *generation resources* constraint by under-generating the downstream *resource*, for $(b_1,b_2) \in LNK$ such that $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$.

8.3.2.3 $ViolCost_t$ shall be calculated as follows:

$$
\begin{aligned}
ViolCost_t = & \\
& \sum_{i=1..N_{LdViol_t}} SLdViol_{t,i} \cdot PLdViolSch_{t,i} \text{ -} \\
& \sum_{i=1..N_{GenViol_t}} SGenViol_{t,i} \cdot PGenViolSch_{t,i} + \sum_{i=1..N_{10SViol_t}} S10SViol_{t,i} \cdot P10SViolSch_{t,i} + \\
& \sum_{i=1..N_{10RViol_t}} S10RViol_{t,i} \cdot P10RViolSch_{t,i} + \sum_{i=1..N_{30RViol_t}} S30RViol_{t,i} \cdot P30RViolSch_{t,i} + \\
& \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG10RViol_t}} SREG10RViol_{r,t,i} \cdot PREG10RViolSch_{t,i} \right) + \\
& \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG30RViol_t}} SREG30RViol_{r,t,i} \cdot PREG30RViolSch_{t,i} \right) + \\
& \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG10RViol_t}} SXREG10RViol_{r,t,i} \cdot PXREG10RViolSch_{t,i} \right) + \\
& \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG30RViol_t}} SXREG30RViol_{r,t,i} \cdot PXREG30RViolSch_{t,i} \right) \\
& \text{.....}
\end{aligned}
$$

$$+\sum_{f\in F_t}\left(\sum_{i=1..N_{PreITLViol_{f,t}}} SPreITLViol_{f,t,i}\cdot PPreITLViolSch_{f,t,i}\right)$$

$$+\sum_{c\in C}\sum_{f\in F_{t,c}}\left(\sum_{i=1..N_{ITLViol_{c,f,t}}} SITLViol_{c,f,t,i}\cdot PITLViolSch_{c,f,t,i}\right)$$

$$+\sum_{z\in Z_{Sch}}\left(\sum_{i=1..N_{PreXTLViol_{z,t}}} SPreXTLViol_{z,t,i}\cdot PPreXTLViolSch_{z,t,i}\right)$$

$$+\sum_{i=1..N_{NIUViol_t}} SNIUViol_{t,i}\cdot PNIUViolSch_{t,i} + \sum_{i=1..N_{NIDViol_t}} SNIDViol_{t,i}\cdot PNIDViolSch_{t,i}$$

$$+\sum_{b\in B^{ELR}}\left(\sum_{i=1..N_{MaxDelViol_t}} SMaxDelViol_{t,b,i}\cdot PMaxDelViolSch_{t,b,i}\right)$$

$$+\sum_{b\in B^{HE}}\left(\sum_{i=1..N_{MinDelViol_t}} SMinDelViol_{t,b,i}\cdot PMinDelViolSch_{t,b,i}\right)$$

$$+\sum_{s\in SHE}\left(\sum_{i=1..N_{SMaxDelViol_t}} SSMaxDelViol_{t,s,i}\cdot PSMaxDelViolSch_{t,s,i}\right)$$

$$+\sum_{s\in SHE}\left(\sum_{i=1..N_{SMinDelViol_t}} SSMinDelViol_{t,s,i}\cdot PSMinDelViolSch_{t,s,i}\right)$$

$$+\sum_{(b_1,b_2)\in LNK}\left(\sum_{i=1..N_t} SOGenLnkViol_{t,(b_1,b_2),i}\cdot POGenLnkViolSch_{t,i}\right) /$$

$$+\sum_{(b_1,b_2)\in LNK}\left(\sum_{i=1..N_t} SUGenLnkViol_{t,(b_1,b_2),i}\cdot PUGenLnkViolSch_{t,i}\right).$$

8.4 Constraints

8.4.1 The constraints described in sections 8.5 – 8.7 apply to the optimization function in the Pre-Dispatch Scheduling algorithm.

8.5 Dispatch Data Constraints Applying to Individual Hours

8.5.1 Scheduling Variable Bounds

8.5.1.1 A Boolean variable $ODG_{t,b}$ indicates whether the *resource* at bus $b \in B^{DG}$ is committed in time-step $t \in TS$. A value of zero indicates that a *resource* is not committed, while a value of one indicates that it is committed. Therefore:

$ODG_{t,b} \in \{0,1\}$ for all time-steps $t \in TS$ and all buses $b \in B^{DG}$.

8.5.1.2 *Reliability must-run resources* are considered committed for all must-run hours.

8.5.1.3 *Resources* providing *regulation* are considered committed for all the hours that they are regulating.

8.5.1.4 *Dispatchable generation resources* that have *minimum loading points*, *start-up offers*, *speed no-load offers*, *minimum generation block run-times* and *minimum generation block down-times* equal to zero shall be considered committed for all hours.

8.5.1.5 If the *dispatchable generation resource* at bus $b \in B^{DG}$ is considered committed according to the requirements in sections 8.5.1.2, 8.5.1.3, and 8.5.1.4 in time-step $t \in TS$ then:

$$\mathrm{ODG}_{\mathrm{t,b}} = 1$$

8.5.1.6 No schedule shall be negative, nor shall any schedule exceed the quantity *offered* for the respective *energy* and *operating reserve* market. Therefore:

$0 \leq SDL_{t,b,j} \leq QDL_{t,b,j}$ for all $b \in B^{DL}$, $j \in J^{E}_{t,b}$;

$0 \leq S10SDL_{t,b,j} \leq Q10SDL_{t,b,j}$ for all $b \in B^{DL}$, $j \in J^{10S}_{t,b}$;

$0 \leq S10NDL_{t,b,j} \leq Q10NDL_{t,b,j}$ for all $b \in B^{DL}$, $j \in J^{10N}_{t,b}$;

$0 \leq S30RDL_{t,b,j} \leq Q30RDL_{t,b,j}$ for all $b \in B^{DL}$, $j \in J^{30R}_{t,b}$;

$0 \leq SHDR_{t,b,j} \leq QHDR_{t,b,j}$ for all $b \in B^{HDR}$, $j \in J^{E}_{t,b}$;

$0 \leq SXL_{t,d,j} \leq QXL_{t,d,j}$ for all $d \in DX$, $j \in J^{E}_{t,d}$;

$0 \leq S10NXL_{t,d,j} \leq Q10NXL_{t,d,j}$ for all $d \in DX$, $j \in J^{10N}_{t,d}$;

$0 \leq S30RXL_{t,d,j} \leq Q30RXL_{t,d,j}$ for all $d \in DX$, $j \in J^{30R}_{t,d}$;

$0 \leq SNDG_{t,b,k} \leq QNDG_{t,b,k}$ for all $b \in B^{NDG}$, $k \in K^{E}_{t,b}$;

$0 \leq SIG_{t,d,k} \leq QIG_{t,d,k}$ for all $d \in DI$, $k \in K^{E}_{t,d}$;

$0 \leq S10NIG_{t,d,k} \leq Q10NIG_{t,d,k}$ for all $d \in DI$, $k \in K^{10N}_{t,d}$; and

$0 \leq S30RIG_{t,d,k} \leq Q30RIG_{t,d,k}$ for all $d \in DI$, $k \in K^{30R}_{t,d}$

for all time-steps $t \in TS$.

8.5.1.7 *Generation resources* may be scheduled for *energy* and/or *operating reserve* only if their commitment status is equal to 1. Therefore, for all time-steps $t \in TS$:

$0 \leq SDG_{t,b,k} \leq ODG_{t,b} \cdot QDG_{t,b,k}$ for all $b \in B^{DG}$, $k \in K^{E}_{t,b}$;

$0 \leq S10SDG_{t,b,k} \leq ODG_{t,b} \cdot Q10SDG_{t,b,k}$ for all $b \in B^{DG}$, $k \in K^{10S}_{t,b}$;

$0 \leq S10NDG_{t,b,k} \leq ODG_{t,b} \cdot Q10NDG_{t,b,k}$ for all $b \in B^{DG}$, $k \in K^{10N}_{t,b}$;

and

$0 \leq S30RDG_{t,b,k} \leq ODG_{t,b} \cdot Q30RDG_{t,b,k}$ for all $b \in B^{DG}$, $k \in K^{30R}_{t,b}$.

8.5.2 Resource Minimums and Maximums for Energy

8.5.2.1 A constraint shall limit schedules for *dispatchable loads* within their minimum and maximum consumption for a time-step. For all time-steps $t \in TS$ and all buses $b \in B^{DL}$:

$$MinDL_{t,b} \leq \sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} \leq MaxDL_{t,b}.$$

8.5.2.2 The non-*dispatchable* portion of a *dispatchable load* shall always be scheduled. For all time-steps $t \in TS$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} \geq QDLFIRM_{t,b}.$$

8.5.2.3 A constraint shall limit schedules for *non-dispatchable generation resources* within their minimum and maximum output for a time-step. For all time-steps $t \in TS$ and all buses $b \in B^{NDG}$:

$$MinNDG_{t,b} \leq \sum_{k \in K^{E}_{t,b}} SNDG_{t,b,k} \leq MaxNDG_{t,b}.$$

8.5.2.4 A constraint shall limit schedules for *dispatchable generation resources* within their minimum and maximum output for a time-step.For a *dispatchable variable generation resource*, the maximum schedule shall be limited by its forecast. That is:

For all time-steps $t \in TS$ and all buses $b \in B^{DG}$:

$$AdjMaxDG_{t,b} = \begin{cases} Min(MaxDG_{t,b}, FG_{t,b}) & if\, b \in B^{VG} \\ MaxDG_{t,b} & \text{otherwise} \end{cases}$$

and

$$AdjMinDG_{t,b} = Min(MinDG_{t,b}, AdjMaxDG_{t,b}).$$

For all time-steps $t \in TS$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{t,b} \leq MinQDGC_{b} \cdot ODG_{t,b} + \sum_{k \in K^{E}_{t,b}} SDG_{t,b,k} \leq AdjMaxDG_{t,b}.$$

8.5.2.5 If the commitment status, $ODG_{t,b}$, of a *dispatchable generation resource* is equal to 1 and if this status is inconsistent with the adjusted minimum and maximum constraints, $MinQDGC_b > AdjMaxDG_{t,b}$, then the commitment status value, $ODG_{t,b}$, shall be changed to a value between 0 and 1.

8.5.2.6 If the total *offered* quantity does not exceed the minimum, $MinQDGC_b + \sum_{k \in K_{t,b}^E} QDG_{t,b,k} < AdjMinDG_{t,b}$, then the *resource* shall receive a schedule of zero.

8.5.2.7 Minimum and maximum limits placed on *hourly demand response resource* schedules for the purposes of reflecting activation/non-activation decisions shall be respected. For all time-steps $t \in TS$ and all buses $b \in B^{HDR}$:

$$MinHDR_{t,b} \leq \sum_{j \in J_{t,b}^E} SHDR_{t,b,j} \leq MaxHDR_{t,b}.$$

8.5.3 Off-Market Transactions

8.5.3.1 For all time-steps $t \in TS$ and all *intertie zone* buses corresponding to an inadvertent *energy* payback export transaction $d \in DX_t^{INP}$:

$$\sum_{j \in J_{t,d}^E} SXL_{t,d,j} = \sum_{j \in J_{t,d}^E} QXL_{t,d,j}.$$

8.5.3.2 For all time-steps $t \in TS$ and all *intertie zone* buses corresponding to an inadvertent *energy* payback import transaction $d \in DI_t^{INP}$:

$$\sum_{k \in K_{t,d}^E} SIG_{t,d,k} = \sum_{k \in K_{t,d}^E} QIG_{t,d,k}.$$

8.5.3.3 For all time-steps $t \in TS$ and all *intertie zone* buses corresponding to an *emergency energy* export $d \in DX_t^{EM}$:

$$\sum_{j \in J_{t,d}^E} SXL_{t,d,j} = \sum_{j \in J_{t,d}^E} QXL_{t,d,j}.$$

8.5.3.4 For all time-steps $t \in TS$ and all *intertie zone* buses corresponding to *emergency energy* import $d \in DI_t^{EM}$:

$$\sum_{k \in K_{t,d}^E} SIG_{t,d,k} = \sum_{k \in K_{t,d}^E} QIG_{t,d,k}.$$

8.5.4 Intertie Minimum and Maximum Constraints

8.5.4.1 A constraint shall limit export schedules beyond the first two forecast hours of the pre-dispatch look-ahead period to the corresponding *day-ahead market* schedules for export transactions, subject to Chapter 7, section 5.2.2. For time-step $t \in \{4,..,n_{LAP}\}$ and *intertie zone* sink bus $\mathrm{d} \in \mathrm{DX}$ such that $d \notin DX_t^{CAPEX} \cup DX_t^{EM} \cup DX_t^{INP}$:

$$\sum_{j \in J_{t,d}^E} SXL_{t,d,j} \leq SXLT_{t,d}^{DAM};$$

$$\sum_{j \in J_{t,d}^{10N}} S10NXL_{t,d,j} \leq S10NXLT_{t,d}^{DAM};$$

and

$$\sum_{j \in J_{t,d}^{30R}} S30RXL_{t,d,j} \leq S30RXLT_{t,d}^{DAM}.$$

8.5.4.2 Import *offers* with no *day-ahead market* schedule may be evaluated beyond the first two forecast hours of the look-ahead period for the purpose of *reliability*.

8.5.4.3 A constraint shall limit import schedules beyond the first two forecast hours of the pre-dispatch look-ahead period to the corresponding *day-ahead market* schedules for import transactions plus any additional *offered* quantities permitted for *reliability* reasons, with the exception of transactions flagged as capacity imports or off-market transactions, subject to Chapter 7, section 5.2.2. For time-step $t \in \{4,..,n_{LAP}\}$ and *intertie zone* source bus $d \in DI$ such that $d \notin DI_t^{CAPEX} \cup DI_t^{EM} \cup DI_t^{INP}$:

$$\sum_{k\in K_{t,d}^{E}} SIG_{t,d,k} \leq SIGT_{t,d}^{DAM} + SIGT_{t,d}^{EXTRA};$$

$$\sum_{k\in K_{t,d}^{10N}} S10NIG_{t,d,k} \leq S10NIGT_{t,d}^{DAM} + S10NIGT_{t,d}^{EXTRA};$$

and

$$\sum_{k\in K_{t,d}^{30R}} S30RIG_{t,d,k} \leq S30RIGT_{t,d}^{DAM} + S30RIGT_{t,d}^{EXTRA}.$$

8.5.4.4 A constraint shall limit *intertie* schedules as a result of *intertie* curtailments. For *intertie zone* sink bus $d \in DX$ and time-step $t \in TS$:

$$ICMinXL_{t,d} \leq \sum_{j\in J_{t,d}^{E}} SXL_{t,d,j} \leq ICMaxXL_{t,d}.$$

8.5.4.4.1 For *intertie zone* source bus $d \in DI$ and time-step $t \in TS$:

$$ICMinIG_{t,d} \leq \sum_{k\in K_{t,d}^{E}} SIG_{t,d,k} \leq ICMaxIG_{t,d};$$

$$ICMin10NIG_{t,d} \leq \sum_{k\in K_{t,d}^{10N}} S10NIG_{t,d,k} \leq ICMax10NIG_{t,d};$$

and

$$ICMin30RIG_{t,d} \leq \sum_{k\in K_{t,d}^{30R}} S30RIG_{t,d,k} \leq ICMax30RIG_{t,d}.$$

8.5.5 Operating Reserve Requirements

8.5.5.1 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled from a *dispatchable load* shall not exceed:

8.5.5.1.1 the *dispatchable load's* ramp capability over 30 minutes;

8.5.5.1.2 the total scheduled load less the non-*dispatchable* portion; and

8.5.5.1.3 the remaining portion of its capacity that is *dispatchable* after considering minimum load consumption constraints.

8.5.5.1.4 These restrictions shall be enforced by the following constraints for all time-steps $t \in TS$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J^{10S}_{t,b}} S10SDL_{t,b,j} + \sum_{j \in J^{10N}_{t,b}} S10NDL_{t,b,j} + \sum_{j \in J^{30R}_{t,b}} S30RDL_{t,b,j} \leq 30 \cdot ORRDL_b;$$

$$\sum_{j \in J^{10S}_{t,b}} S10SDL_{t,b,j} + \sum_{j \in J^{10N}_{t,b}} S10NDL_{t,b,j} + \sum_{j \in J^{30R}_{t,b}} S30RDL_{t,b,j} \leq \sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} - QDLFIRM_{t,b};$$

and

$$\sum_{j \in J^{10S}_{t,b}} S10SDL_{t,b,j} + \sum_{j \in J^{10N}_{t,b}} S10NDL_{t,b,j} + \sum_{j \in J^{30R}_{t,b}} S30RDL_{t,b,j} \leq \sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} - MinDL_{t,b}.$$

8.5.5.2 The amount of both synchronized and non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide shall not exceed the amount by which the *dispatchable load* can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This restriction shall be enforced by the following constraint for all time-steps $t \in TS$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J^{10S}_{t,b}} S10SDL_{t,b,j} + \sum_{j \in J^{10N}_{t,b}} S10NDL_{t,b,j} \leq 10 \cdot ORRDL_b.$$

8.5.5.3 The total non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled for an hour shall not exceed total scheduled exports. This restriction shall be enforced by the following constraint for all all time-steps $t \in TS$ and all *intertie zone* sink buses $d \in DX$:

$$\sum_{j\in J_{t,d}^{10N}} S10NXL_{t,d,j} + \sum_{j\in J_{t,d}^{30R}} S30RXL_{t,d,j} \leq \sum_{j\in J_{t,d}^{E}} SXL_{t,d,j}.$$

8.5.5.4 The total *operating reserve* scheduled from a committed *dispatchable generation resource* shall not exceed that *resource*'s: (i) ramp capability over 30 minutes; (ii) remaining capacity; and (iii) unscheduled capacity. These restrictions shall be enforced by the following constraints for all time-steps $t \in TS$ and all buses $b \in B^{DG}$:

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} \leq 30 \cdot ORRDG_b;$$

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} \leq \sum_{k\in K_{t,b}^{E}} (QDG_{t,b,k} - SDG_{t,b,k});$$

and

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} \leq AdjMaxDG_{t,b} - \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} - MinQDGC_b.$$

8.5.5.5 The amount of both synchronized and non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall not exceed the amount by which the *resource* can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This restriction shall be enforced by the following constraint for all time-steps $t \in TS$ and all buses $b \in B^{DG}$:

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} \leq 10 \cdot ORRDG_b.$$

8.5.5.6 The amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be limited by its *reserve loading point for* synchronized *ten-minute operating reserve*. This restriction shall be enforced by the following constraint for all time-steps $t \in TS$ and all buses $b \in B^{DG}$ with $RLP10S_{t,b} > 0$:

$$\sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} \leq \left(MinQDGC_b \cdot ODG_{t,b} + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} \right) \cdot \left(\frac{1}{RLP10S_{t,b}} \right) \cdot \left(min \left\{ 10 \cdot ORRDG_b, \sum_{k \in K_{t,b}^{10S}} Q10SDG_{t,b,k} \right\} \right).$$

8.5.5.7 The amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be limited by its *reserve loading point* for *thirty-minute operating reserve*. This restriction shall be enforced by the following constraint for all all time-steps $t \in TS$ and all buses $b \in B^{DG}$ with $RLP30R_{t,b} > 0$:

$$\sum_{k \in K_{t,b}^{30R}} S30RDG_{t,b,k} \leq \left(MinQDGC_b \cdot ODG_{t,b} + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} \right) \cdot \left(\frac{1}{RLP30R_{t,b}} \right) \cdot \left(min \left\{ 30 \cdot ORRDG_b, \sum_{k \in K_{t,b}^{30R}} Q30RDG_{t,b,k} \right\} \right).$$

8.5.5.8 The total non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled for an hour shall not exceed the remaining maximum import *offers* minus scheduled *energy* imports. This restriction shall be enforced by the following constraint for all time-steps $t \in TS$ and all *intertie zone* source buses $d \in DI$:

$$\sum_{k \in K_{t,d}^{10N}} S10NIG_{t,d,k} + \sum_{k \in K_{t,d}^{30R}} S30RIG_{t,d,k} \leq \sum_{k \in K_{t,d}^{E}} (QIG_{t,d,k} - SIG_{t,d,k}).$$

8.5.6 Pseudo-Units

8.5.6.1 A constraint shall be required to calculate physical *generation resource* schedules from *pseudo-unit* schedules using the steam turbine *resource's* shares in the operating regions of the *pseudo-unit* determined in section 15. For all time-steps $t \in TS$ and *pseudo-unit* buses $b \in B^{PSU}$:

$$SCT_{t,b} = (1 - STShareMLP_b) \cdot MinQDGC_b \cdot ODG_{t,b} + (1 - STShareDR_b) \cdot \left(\sum_{k \in K_{t,b}^{DR}} SDG_{t,b,k} \right),$$

and for all time-steps $t \in TS$ and steam turbine *resources* $p \in PST$:

$$SST_{t,p} = \sum_{b \in B_p^{ST}} \left(\begin{array}{c} STShareMLP_b \cdot MinQDGC_b \cdot ODG_{t,b} + \\ STShareDR_b \cdot \left(\sum_{k \in K_{t,b}^{DR}} SDG_{t,b,k} \right) + \sum_{k \in K_{t,b}^{DF}} SDG_{t,b,k} \end{array} \right).$$

8.5.6.2 Maximum constraints shall be enforced on the operating region to which they apply for both *energy* and *operating reserve* schedules. For all time-steps $t \in TS$ and *pseudo-unit* buses $b \in B^{PSU}$:

$$MinQDGC_b \cdot ODG_{t,b} \leq MaxMLP_{t,b},$$

$$\sum_{k \in K_{t,b}^{DR}} SDG_{t,b,k} \leq MaxDR_{t,b},$$

$$\sum_{k \in K_{t,b}^{DF}} SDG_{t,b,k} \leq MaxDF_{t,b},$$

and

$$\sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k \in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k \in K_{t,b}^{30R}} S30RDG_{t,b,k} \leq MaxDR_{t,b} + MaxDF_{t,b}.$$

8.5.6.3 For a *pseudo-unit* that cannot provide *ten-minute operating reserve* from its duct firing region, constraints shall limit the *pseudo-unit* from being scheduled in its duct firing region whenever the *pseudo-unit* is scheduled for *ten-minute operating reserve.* For all all time-steps $t \in TS$ and *pseudo-unit* buses $b \in B^{NO10DF}$:

$$O10R_{t,b} \in \{0,1\},$$

and

$$\sum_{k \in K^{E}_{t,b}} SDG_{t,b,k} + \sum_{k \in K^{10S}_{t,b}} S10SDG_{t,b,k} + \sum_{k \in K^{10N}_{t,b}} S10NDG_{t,b,k} \leq MaxDR_{t,b} + (1 - O10R_{t,b}) \cdot MaxDF_{t,b}$$

8.5.6.3.1 For all time-steps $t \in TS$, *pseudo-unit* buses $b \in B^{NO10DF}$, and laminations $k \in K^{10S}_{t,b}$:

$$S10SDG_{t,b,k} \leq O10R_{t,b} \cdot Q10SDG_{t,b,k}.$$

8.5.6.3.2 For all time-steps $t \in TS$, *pseudo-unit* buses $b \in B^{NO10DF}$, and laminations $k \in K^{10N}_{t,b}$:

$$S10NDG_{t,b,k} \leq O10R_{t,b} \cdot Q10NDG_{t,b,k}.$$

8.5.6.4 For the purposes of the *energy* balance constraint in section 8.7.1 and the transmission constraints in section 8.7.3, the combustion turbine *resource's* schedule for the *pseudo-unit* at bus $b \in B^{PSU}$ in in time-step $t \in TS$ will be equal to:

8.5.6.4.1 $SCT_{t,b}$ if the *pseudo-unit* is scheduled at or above *minimum loading point*;

8.5.6.4.2 $RampCTC^{m}_{b,w}$ if the *pseudo-unit* is scheduled to reach *minimum loading point* in *thermal state* $m \in THERM$ in time-step $t + w$ for $w \in \{1,\ldots,RampHrsC^{m}_{b}\}$; or

8.5.6.4.3 0 otherwise.

8.5.6.5 For the purposes of the *energy* balance constraint in section 8.7.1 and the transmission constraints in section 8.7.3, the steam turbine *resource's* schedule for $p \in PST$ shall be equal to $SST_{h,p}$ plus any contribution from *pseudo-unit* $b \in B^{ST}_{p}$ ramping to *minimum loading point* as given by $RampSTC^{m}_{b,w}$ for a *pseudo-unit* scheduled to reach *minimum loading point* in *thermal state* $m \in THERM$ in time-step $(t + w)$ for $w \in \{1,\ldots,RampHrsC^{m}_{b}\}$.

8.5.7 Dispatchable Hydroelectric Generation Resources

8.5.7.1 A *dispatchable* hydroelectric *generation resource* shall be scheduled to at least its *hourly must-run* quantity. For all time-steps $t \in TS$ and *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \geq MinHMR_{t,b}.$$

8.5.7.2 A *dispatchable* hydroelectric *generation resource* shall either be scheduled to 0 or to at least its *minimum hourly output*. For all time-steps $t \in TS$ and all hydroelectric *generation resource* buses $b \in B^{HE}$:

$$OHO_{t,b} \in \{0,1\};$$

$$ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \geq MinHO_{t,b} \cdot OHO_{t,b};$$

and for all $k \in K_{t,b}^E$:

$$0 \leq SDG_{t,b,k} \leq OHO_{t,b} \cdot QDG_{t,b,k}.$$

8.5.7.3 A *dispatchable* hydroelectric *generation resource* shall not be scheduled within its *forbidden regions*. For *dispatch days* $q \in DAYS$, all time-steps $t \in TS$ in *dispatch day* q, all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ and all $i \in \{1,..,NFor_{q,b}\}$:

$$OFR_{t,b,i} \in \{0,1\};$$

$$\begin{aligned} ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \\ \leq OFR_{t,b,i} \cdot ForL_{q,b,i} + (1 - OFR_{t,b,i}) \\ \cdot \left(MinQDGC_b + \sum_{k \in K_{t,b}^E} QDG_{t,b,k} \right); \end{aligned}$$

and

$$ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \geq (1 - OFR_{t,b,i}) \cdot ForU_{q,b,i}.$$

8.5.8 Linked Wheeling Through Transactions

8.5.8.1 The amount of scheduled export *energy* must be equal to the amount of scheduled import *energy* for *linked wheeling through transactions*. For all time-steps $t \in TS$ and all linked *boundary entity resource* buses $(dx, di) \in L_t$:

$$\sum_{j \in J^E_{t,dx}} SXL_{t,dx,j} = \sum_{k \in K^E_{t,di}} SIG_{t,di,k}.$$

8.6 Dispatch Data Inter-Hour/Multi-Hour Constraints

8.6.1 Energy Ramping

8.6.1.1 For *disptachable loads*, the constraints in section 8.6.1.5 and section 8.6.2.1 use $URRDL_b$ to represent a ramp up rate selected from $URRDL_{t,b,w}$ and uses $DRRDL_b$ to represent a ramp down rate selected from $DRRDL_{t,b,w}$.

8.6.1.2 For *disptachable generation resources*, the constraints in section 8.6.1.7 and section 8.6.2.2 use $URRDG_b$ to represent a ramp up rate selected from $URRDG_{t,b,w}$ and uses $DRRDG_b$ to represent a ramp down rate selected from $DRRDG_{t,b,w}$.

8.6.1.3 The *pre-dispatch calculation engine* shall respect the ramping restrictions determined by the up to five *offered* MW quantity, ramp up rate and ramp down rate value sets.

8.6.1.4 In all ramping constraints, the schedules for time-step 1 are obtained from the initial scheduling assumptions in section 5.9. For all time-steps $t \in TS$ the ramping rates in all ramping constraints shall be adjusted to allow the applicable *resource* to:

8.6.1.4.1 ramp down from its lower limit in time-step $(t-1)$ to its upper limit in time-step t; and

8.6.1.4.2 ramp up from its upper limit in time-step $(t-1)$ to its lower limit in time-step t.

8.6.1.5 *Energy* schedules for *dispatchable loads* cannot vary by more than an hour's ramping capability for the applicable *resource*. This constraint shall be enforced by the following for all time-steps $t \in TS$ and buses $b \in B^{DL}$:

$$\sum_{j \in J^{E}_{t-1,b}} SDL_{t-1,b,j} - 60 \cdot DRRDL_b \leq \sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} \leq \sum_{j \in J^{E}_{t-1,b}} SDL_{t-1,b,j} + 60 \cdot URRDL_b.$$

8.6.1.6 *Energy* schedules for *hourly demand response resources* cannot vary by more than an hour's ramping capability for the applicable *resource*. This constraint shall be enforced by the following for all time-steps $t \in TS$ and all buses $b \in B^{HDR}$:

$$\sum_{j \in J^{E}_{t-1,b}} (QHDR_{t-1,b,j} - SHDR_{t-1,b,j}) - 60 \cdot URRHDR_b \leq \sum_{j \in J^{E}_{t,b}} (QHDR_{t,b,j} - SHDR_{t,b,j}) \leq \sum_{j \in J^{E}_{t-1,b}} (QHDR_{t-1,b,j} - SHDR_{t-1,b,j}) + 60 \cdot DRRHDR_b.$$

8.6.1.7 *Energy* schedules for a *dispatchable generation resource* that is committed cannot vary by more than an hour's ramping capability for the applicable *resource*. For all time-steps $t \in TS$ and all buses $b \in B^{DG}$:

8.6.1.7.1 For the first hour a *resource* reaches its *minimum loading point*, where $ODG_{t,b} = 1$, $ODG_{t\text{-}1,b} = 0$, the following constraint shall be applied:

$$0 \leq \sum_{k \in K^{E}_{t,b}} SDG_{t,b,k} \leq 30 \cdot URRDG_b$$

8.6.1.7.2 If the *resource* stays on at or above *minimum loading point* and $ODG_{t,b} = 1$, $ODG_{t\text{-}1,b} = 1$, the following constraint shall be applied:

$$\sum_{k\in K^E_{t-1,b}} SDG_{t-1,b,k} - 60\cdot DRRDG_b \leq \sum_{k\in K^E_{t,b}} SDG_{t,b,k} \leq \sum_{k\in K^E_{t-1,b}} SDG_{t-1,b,k} + 60\cdot URRDG_b$$

8.6.1.7.3 For the last hour the *resource* is scheduled at or above *minimum loading point* before being scheduled off, where $ODG_{t,b} = 1$, $ODG_{t+1,b} = 0$, the following constraint shall be applied:

$$0 \leq \sum_{k\in K^E_{t,b}} SDG_{t,b,k} \leq 30\cdot DRRDG_b$$

8.6.1.8 The first and third constraint in section 8.6.1.6 do not apply to a *quick start resource*.

8.6.1.9 For time-steps where *non-quick start resources* are ramping up to *minimum loading point*, *energy* shall be scheduled for these *resources* using the submitted *ramp up energy to minimum loading point*.

8.6.2 Operating Reserve Ramping

8.6.2.1 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* from *dispatchable loads* shall not exceed the their ramp capability to decrease load consumption and for all time-steps $t\in TS$ and all buses $b\in B^{DL}$:

$$\sum_{j\in J^{10S}_{t,b}} S10SDL_{t,b,j} + \sum_{j\in J^{10N}_{t,b}} S10NDL_{t,b,j} + \sum_{j\in J^{30R}_{t,b}} S30RDL_{t,b,j} \leq \sum_{j\in J^E_{t,b}} SDL_{t,b,j} - \sum_{j\in J^E_{t-1,b}} SDL_{t-1,b,j} + 60\cdot DRRDL_b.$$

8.6.2.2 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* from a committed *dispatchable generation resource* shall not exceed its ramp capability to increase generation and for all time-steps $t\in TS$ and all buses $b\in B^{DG}$:

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} \leq \sum_{k\in K_{t-1,b}^{E}} SDG_{t-1,b,k} - \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} + 60 \cdot URRDG_b;$$

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} + \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} \leq [(t-n)\cdot 60 + 30]\cdot URRDG_b \cdot ODG_{t,b}$$

where n is the time − step of the last start before or in time − step t; and

$$\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{h,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} + \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} \leq [(m-t)\cdot 60 + 30]\cdot DRRDG_b \cdot ODG_{t,b}$$

where m is the time-step of the last shutdown in or after time-step t.

8.6.3 Non-Quick Start Resources

8.6.3.1 Schedules for a *non-quick start resource* shall not violate such *resource's minimum generation block run-times*, *minimum generation block down-times* and *maximum number of starts per day*.

8.6.3.2 In the first forecast hour of the pre-dispatch look-ahead period, a *resource's* current hours on shall determine any remaining *minimum generation block run-time* to enforce. If $0 < InitOperHrs_b < MGBRTDG_{tod,b}$, then the *resource* at bus $b \in B^{NQS}$ has yet to complete its *minimum generation block run-time*, and:

$$ODG_{2,b}, ODG_{3,b}, \ldots, ODG_{\min(n_{LAP}, MGBRTDG_{tod,b} - InitOperHrs_b + 1),b} = 1.$$

8.6.3.3 In the first forecast hour of the pre-dispatch look-ahead period (i.e. time-step 2), the number of hours a *resource* has been down shall determine any remaining *minimum generation block down-time* to enforce and shall respect the *minimum generation block down-time* for a hot *thermal state*. If $0 < InitDownHrs_b < MGBDTDG^{HOT}_{tod,b}$, then the *resource* at bus $b \in B^{NQS}$ has yet to complete its *minimum generation block down-time*, and:

$$ODG_{2,b}, ODG_{3,b}, \ldots, ODG_{min(n_{LAP}, MGBDTDG^{HOT}_{tod,b} - InitDownHrs_b + 1),b} = 0.$$

8.6.3.4 If $ODG_{t\text{-}1,b} = 0$ and $ODG_{t,b} = 1$ for time-step $t \in TS$, then the *resource* at bus $b \in B^{NQS}$ has been scheduled to start up during time-step t and shall be scheduled to remain in operation until it has completed its *minimum generation block run-time* or to the end of the pre-dispatch look-ahead period. Therefore:

$$ODG_{t+1,b}, ODG_{t+2,b}, \ldots, ODG_{min(n_{LAP}, t + MGBRTDGC_b - 1),b} = 1.$$

8.6.3.5 If $ODG_{t\text{-}1,b} = 1$ and $ODG_{t,b} = 0$ for time-step $t \in TS$, then the *resource* at bus $b \in B^{NQS}$ has been scheduled to shut down during time-step t and shall be scheduled to remain off until it has completed its hot *minimum generation block down-time* or to the end of the pre-dispatch look-ahead period. Therefore:

$$ODG_{t+1,b}, ODG_{t+2,b}, \ldots, ODG_{min(n_{LAP}, t + MGBDTDGC^{HOT}_b - 1),b} = 0.$$

8.6.3.6 A Boolean variable $IDG_{t,b}$ indicates that the *non-quick start resource* at bus $b \in B^{NQS}$ is scheduled to reach its *minimum loading point* in time-step $t \in TS$ after being scheduled below its *minimum loading point* in the preceding time-step. A value of zero indicates that a *resource* is not scheduled to reach its *minimum loading point*, while a value of one indicates that it is scheduled to reach its *minimum loading point*. Therefore, for all time-steps $t \in TS$ and all buses $b \in B^{NQS}$:

$$IDG_{t,b} = \begin{cases} 1 & if\ ODG_{t-1,b} = 0\ and\ ODG_{t,b} = 1 \\ 0 & otherwise. \end{cases}$$

8.6.3.7 A *non-quick start resource* shall not be scheduled more than its *maximum number of starts per day*. For all buses $b \in B^{NQS}$:

$$\sum_{t \in TS_{tod}} IDG_{t,b} \leq MaxStartsDG_{tod,b} - NumStarts_{tod,b}.$$

8.6.3.7.1 and if the pre-dispatch look-ahead period spans two *dispatch days* then:

$$\sum_{t \in TS_{tom}} IDG_{t,b} \leq MaxStartsDG_{tom,b}.$$

8.6.3.8 For a *non-quick start resource* at bus $b \in B^{NQS}$ that has been offline $InitDownHrs_b$ hours, and for future *minimum loading point* time-step $t \in \{2,....,n_{LAP}\}$, the *pre-dispatch calcluation engine* shall assign a *start-up offer* and ramp *energy* to *minimum loading point* profile as follows:

8.6.3.8.1 If $0 \leq InitDownHrs_b + t - 1 \leq MGBDTDGC_b^{HOT}$, then the *resource* cannot be scheduled in time-step *t*;

8.6.3.8.2 If $MGBDTDGC_b^{HOT} < InitDownHrs_b + t - 1 \leq MGBDTDGC_b^{WARM}$, then the *resource* will be assigned a "HOT" *thermal state* for time-step t and the *start-up offer* $SUDG_{t,b}^{HOT}$ shall apply. The *ramp up energy to minimum loading point* profile shall be $\mathrm{RampEC}_{\mathrm{b,w}}^{\mathrm{HOT}}$ for $w \in \{1,..,RampHrsC_b^m\}$;

8.6.3.8.3 If $MGBDTDGC_b^{WARM} < InitDownHrs_b + t - 1 \leq MGBDTDGC_b^{COLD}$, then the *resource* will be assigned a "WARM" *thermal state* for time-step t and the *start-up offer* $SUDG_{t,b}^{WARM}$ shall apply. The *ramp up energy to minimum loading point* profile shall be $RampEC_{b,w}^{WARM}$ for $w \in \{1,..,RampHrsC_b^m\}$; and

8.6.3.8.4 If $MGBDTDGC_b^{COLD} < InitDownHrs_b + t - 1$ then the *resource* will be assigned a "COLD" *thermal state* for time-step t and the *start-up offer* $SUDG_{t,b}^{COLD}$ shall apply. The *ramp up energy to minimum loading point* profile shall be $RampEC_{b,w}^{COLD}$ for $w \in \{1,..,RampHrsC_b^m\}$.

8.6.3.9 For a *non-quick start resource* at bus $b \in B^{NQS}$ that is in-service as determined by its initial condition, the *pre-dispatch calculation engine* shall assign a *start-up offer* and *ramp up energy to minimum loading point* profile associated with the future *thermal state* as specified in section 8.6.3.8.

8.6.4 Energy Limited Resources

8.6.4.1 An *energy limited resource* shall not be scheduled to provide:

8.6.4.1.1 more *energy* than the *maximum daily energy limit* specified for such *resource*; or

8.6.4.1.2 *energy* in amounts that would preclude such *resource* from providing *operating reserve* when activated;

8.6.4.1.3 for all buses $b \in B^{ELR}$ where an *energy limited resource* is located and all time-steps $T \in TS_{tod}$:

$$\sum_{t=2..T}\left(ODG_{t,b}\cdot MinQDGC_b + \sum_{k\in K^{E}_{t,b}} SDG_{t,b,k}\right) + 10ORConv\left(\sum_{k\in K^{10S}_{T,b}} S10SDG_{T,b,k} + \sum_{k\in K^{10N}_{T,b}} S10NDG_{T,b,k}\right) + 30ORConv\left(\sum_{k\in K^{30R}_{T,b}} S30RDG_{T,b,k}\right) - \sum_{i=1..N_{MaxDelViol_T}} SMaxDelViol_{T,b,i} \le MaxDEL_{tod,b} - EngyUsed_b.$$

8.6.4.2 If the pre-dispatch look-ahead period spans two *dispatch days*, the constraints in section 8.6.4.1 shall apply to an *energy limited resource* for each *dispatch day*, and shall consider the amount of *energy* already provided by the *resource* for the current *dispatch day*. Therefore, for all buses $b \in B^{ELR}$ where an *energy limited resource* is located and all time-steps $T \in TS_{tom}$:

$$\sum_{t=t_{tom}..T}\left(ODG_{t,b}\cdot MinQDGC_b+\sum_{k\in K^E_{t,b}}SDG_{t,b,k}\right)$$
$$+10ORConv\left(\sum_{k\in K^{10S}_{T,b}}S10SDG_{T,b,k}+\sum_{k\in K^{10N}_{T,b}}S10NDG_{T,b,k}\right)$$
$$+30ORConv\left(\sum_{k\in K^{30R}_{T,b}}S30RDG_{T,b,k}\right)$$
$$-\sum_{i=1..N_{MaxDelViol_T}}SMaxDelViol_{T,b,i}\le MaxDEL_{tom,b}.$$

where the factors $10\ ORConv$ and $30\ ORConv$ are applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* for *energy limited resources* to convert MW into MWh. Violation variables for over-scheduling a *resource's maximum daily energy limit* may be used to allow the *pre-dispatch calculation engine* to find a solution.

8.6.5 Dispatchable Hydroelectric Generation Resources

8.6.5.1 *Dispatchable* hydroelectric *generation resources* shall be scheduled for at least their *minimum daily energy limit*. If the pre-dispatch look-ahead period spans two *dispatch days*, the constraint shall be applied for both days. Violation variables for under-scheduling a *resource's minimum daily energy limit* may be used to allow the *pre-dispatch calculation engine* to find a solution. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$\sum_{t\in TS_{tod}}\left(ODG_{t,b}\cdot MinQDGC_b+\sum_{k\in K^E_{t,b}}SDG_{t,b,k}\right.$$
$$\left.+\sum_{i=1..N_{MinDelViol_t}}SMinDelViol_{t,b,i}\right)\ge MinDEL_{tod,b}-EngyUsed_b.$$

8.6.5.1.1 and if the pre-dispatch look-ahead period spans two *dispatch days*, for all hydroelectric *resource* buses $b \in B^{HE}$:

$$\sum_{t \in TS_{tom}} \left(ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} + \sum_{i=1..N_{MinDelViol_t}} SMinDelViol_{t,b,i} \right) \geq MinDEL_{tom,b}.$$

8.6.5.2 A Boolean variable $IHE_{t,b,i}$ indicates that a start for the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ was counted in time-step $t \in TS$ as a result of the *resource* schedule increasing from below its i-th *start indication value* to at or above its i-th start indication for $i \in \{1,.., NStartMW_b\}$. A value of zero indicates that a start was not counted, while a value of one indicates that a start was counted. Therefore, for all time-steps $t \in TS$, buses $b \in B^{HE}$ and *start indication values* $i \in \{1,..,NStartMW_b\}$:

$$IHE_{t,b,i} = \begin{cases} 1 \quad if \left(ODG_{t-1,b} \cdot MinQDGC_b + \sum_{k \in K_{t-1,b}^E} SDG_{t-1,b,k} < StartMW_{b,i} \right) \\ \qquad and \left(ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \geq StartMW_{b,i} \right) \\ 0 \quad otherwise. \end{cases}$$

8.6.5.3 *Dispatchable* hydroelectric *generation resources* shall not be scheduled to be started more times than permitted by their *maximum number of starts per day.* If the pre-dispatch look-ahead period spans two *dispatch days*, this constraint shall be applied for both days. The following constraint shall apply for all buses $b \in B^{HE}$:

$$\sum_{t \in TS_{tod}} \left(\sum_{i=1..NStartMW_b} IHE_{t,b,i} \right) \leq MaxStartsHE_{tod,b} - NumStartsHE_b.$$

8.6.5.3.1 and if the pre-dispatch look-ahead period spans two *dispatch days*, for buses $b \in B^{HE}$:

$$\sum_{t \in TS_{tom}} \left(\sum_{i=1..NStartMW_b} IHE_{t,b,i} \right) \leq MaxStartsHE_{tom,b}.$$

8.6.5.4 The schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall not exceed shared *maximum daily energy limits*. If the pre-dispatch look-ahead period spans two *dispatch days*, the constraint shall be applied for both days, where the constraint for today shall consider the amount of *energy* already provided by *resources* with a registered *forebay*. Violation variables for over-scheduling the *maximum daily energy limit* may be used to allow the *pre-dispatch calculation engine* to find a solution. For all sets $s \in SHE$ and all time-steps $T \in TS_{tod}$:

$$\sum_{t=2..T} \left(\sum_{b \in B_s^{HE}} \left(ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} \right) \right)$$
$$+ \sum_{b \in B_s^{HE}} \left(10ORConv \left(\sum_{k \in K_{T,b}^{10S}} S10SDG_{T,b,k} + \sum_{k \in K_{T,b}^{10N}} S10NDG_{T,b,k} \right) \right.$$
$$\left. + 30ORConv \left(\sum_{k \in K_{T,b}^{30R}} S30RDG_{T,b,k} \right) \right)$$
$$- \sum_{i=1..N_{SMaxDelViol_T}} SSMaxDelViol_{T,s,i} \leq MaxSDEL_{tod,s} - EngyUsedSHE_s$$

8.6.5.4.1 and if the look-ahead period spans two *dispatch days*, then for all sets $s \in SHE$ and all time-steps $T \in TS_{tom}$:

$$\sum_{t=t_{tom}..T}\left(\sum_{b\in B_s^{HE}}\left(ODG_{t,b}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^{E}}SDG_{t,b,k}\right)\right)$$
$$+\sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{T,b}^{10S}}S10SDG_{T,b,k}+\sum_{k\in K_{T,b}^{10N}}S10NDG_{T,b,k}\right)\right.$$
$$\left.\left.+30ORConv\left(\sum_{k\in K_{T,b}^{30R}}S30RDG_{T,b,k}\right)\right)\right)$$
$$-\sum_{i=1..N_{SMaxDelViol_T}}SSMaxDelViol_{T,s,i}\le MaxSDEL_{tom,s}$$

where the factors $10\ ORConv$ and $30\ ORConv$ shall be applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* to convert MW into MWh.

8.6.5.5 Schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall respect shared *minimum daily energy limits*. If the pre-dispatch look-ahead period spans two *dispatch days*, the constraint shall be applied for both days, where the constraint for today shall consider the amount of *energy* already provided by *resources* with a registered *forebay*. Violation variables for under-scheduling the *minimum daily energy limit* may be used to allow the *pre-dispatch calculation engine* to find a solution. For all sets $s\in SHE$:

$$\sum_{t\in TS_{tod}}\left(\sum_{b\in B_s^{HE}}\left(ODG_{t,b}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^{E}}SDG_{t,b,k}\right)\right.$$
$$\left.+\sum_{i=1..N_{SMinDelViol_t}}SSMinDelViol_{t,s,i}\right)\ge MinSDEL_{tod,s}-EngyUsedSHE_s$$

8.6.5.5.1 and if the pre-dispatch look-ahead period spans two *dispatch days*, then for all sets $s\in SHE$:

$$\sum_{t \in TS_{tom}} \left(\sum_{b \in B_S^{HE}} \left(ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \right) + \sum_{i=1..N_{SMinDelViol_t}} SSMinDelViol_{t,s,i} \right) \geq MinSDEL_{tom,s}.$$

8.6.5.6 For linked *dispatchable* hydroelectric *generation resources* with a registered *forebay*, *energy* scheduled at the upstream *resource* in one time-step shall result in a proportional amount of *energy* being scheduled at the linked downstream *resource* in the time-step determined by the *time lag*.

8.6.5.7 For linked *dispatchable* hydroelectric *generation resources*, time-steps in which the upstream *resources* schedule is not determined in the *pre-dispatch calculation engine* optimization, the constraint shall link either the historical or time-step 1 anticipated production for the upstream *resources* to the schedule for the downstream *resources*.

8.6.5.8 For all linked *dispatchable* hydroelectric *generation resources* between upstream *resources* $b_1 \in B_{up}^{HE}$ and downstream *resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNKC$ and all time-steps $t \in TS$ such that $t \leq LagC_{b_1,b_2}+1$:

$$\begin{aligned} &\sum_{b_2 \in B_{dn}^{HE}} \left(ODG_{t,b_2} \cdot MinQDGC_{b_2} + \sum_{k \in K_{t,b_2}^E} SDG_{t,b_2,k} \right) \\ &\quad - \sum_{i=1..N_{OGenLnkViol_t}} SOGenLnkViol_{t,(b_1,b_2),i} \\ &\quad + \sum_{i=1..N_{UGenLnkViol_t}} SUGenLnkViol_{t,(b_1,b_2),i} \\ &\quad = MWhRatioC_{b_1,b_2} \cdot PastMWh_{t,b_1}. \end{aligned}$$

8.6.5.9 For linked *dispatchable* hydroelectric *generation resources*, time-steps in which both the upstream and downstream *resource* schedules are determined in the *pre-dispatch calculation engine* optimization, the constraint will link the scheduling variables for both the upstream and downstream *resources*.

8.6.5.10 For all linked *dispatchable* hydroelectric *generation resources* between upstream *resources* $b_1 \in B_{up}^{HE}$ and downstream *resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNKC$ and time-steps $t \in TS$ such that $t + LagC_{b_1,b_2} \leq n_{LAP}$:

$$\sum_{b_2 \in B_{dn}^{HE}} \left(ODG_{t+LagC_{b_1,b_2},b_2} \cdot MinQDGC_{b_2} + \sum_{k \in K_{t+LagC_{b_1,b_2},b_2}^{E}} SDG_{t+LagC_{b_1,b_2},b_2,k} \right)$$
$$- \sum_{i=1..N_{OGenLnkViol_{t+Lag_{b_1,b_2}}}} SOGenLnkViol_{t+Lag_{b_1,b_2},(b_1,b_2),i}$$
$$+ \sum_{i=1..N_{UGenLnkViol_{t+Lag_{b_1,b_2}}}} SUGenLnkViol_{t+Lag_{b_1,b_2},(b_1,b_2),i}$$
$$= MWhRatioC_{b_1,b_2} \cdot \sum_{b_1 \in B_{up}^{HE}} \left(ODG_{t,b_1} \cdot MinQDGC_{b_1} + \sum_{k \in K_{t,b_1}^{E}} SDG_{t,b_1,k} \right)$$

8.7 Constraints for Reliability Requirements

8.7.1 Energy Balance

8.7.1.1 The total amount of *energy* withdrawals scheduled at load bus $b \in B$ in time-step $t \in TS$, $With_{t,b}$ shall be represented by:

$$With_{t,b} = \begin{cases} \sum_{j \in J_{t,b}^{E}} SDL_{t,b,j} & if\ b \in B^{DL} \\ \sum_{j \in J_{t,b}^{E}} (QHDR_{t,b,j} - SHDR_{t,b,j}) & if\ b \in B^{HDR} \end{cases}.$$

8.7.1.2 The total amount of export *energy* scheduled at *intertie zone* bus $d \in DX$ in time-step $t \in TS$, $With_{t,d}$, as the exports from Ontario to the *intertie zone* bus shall be represented by:

$$With_{t,d} = \sum_{j \in J^{E}_{t,d}} SXL_{t,d,j}.$$

8.7.1.3 The total amount of injections scheduled at internal bus $b \in B$ in time-step $t \in TS$, $Inj_{t,b}$, shall be represented by:

$$Inj_{t,b} = OfferInj_{t,b} + RampInj_{t,b}$$

where:

$$OfferInj_{t,b} = \begin{cases} \sum_{k \in K^{E}_{t,b}} SNDG_{t,b,k} & if\ b \in B^{NDG} \\ ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K^{E}_{t,b}} SDG_{t,b,k} & if\ b \in B^{DG} \end{cases}$$

and

$$RampInj_{t,b} = \begin{cases} \sum_{w=1..min(RampHrsC^{m}_{b}, n_{LAP}-t)} RampEC^{m}_{b,w} \cdot IDG_{t+w,b} & if\ b \in B^{NQS} \\ 0 & otherwise \end{cases}.$$

8.7.1.4 The total amount of import *energy* scheduled at *intertie zone* bus $d \in DI$ in time-step $t \in TS$, $Inj_{t,d}$, as the imports into Ontario from that *intertie zone* bus shall be represented by:

$$Inj_{t,d} = \sum_{k \in K^{E}_{t,d}} SIG_{t,d,k}.$$

8.7.1.5 Injections and withdrawals at each bus shall be multiplied by one plus the marginal loss factor calculated by the *security* assessment function to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the *demand* constraint violation shall be subtracted from the total load or generation for the *pre-dispatch* *calculation engine* to produce a solution. For time-step $t \in TS$, the *energy* balance shall be:

$$\begin{aligned} FL_t + \sum_{b \in B^{DL} \cup B^{HDR}} (1 + MglLoss_{t,b}) \cdot With_{t,b} \\ + \sum_{d \in DX} (1 + MglLoss_{t,d}) \cdot With_{t,d} - \sum_{i=1..N_{LdViol_t}} SLdViol_{t,i} \\ = \sum_{b \in B^{NDG} \cup B^{DG}} (1 + MglLoss_{t,b}) \cdot Inj_{t,b} \\ + \sum_{d \in DI} (1 + MglLoss_{t,d}) \cdot Inj_{t,d} - \sum_{i=1..N_{GenViol_t}} SGenViol_{t,i} \\ + LossAdj_t. \end{aligned}$$

8.7.2 Operating Reserve Requirements

8.7.2.1 *Operating reserve* shall be scheduled to meet system-wide requirements for synchronized *ten-minute operating reserve*, total *ten-minute operating reserve,* and *thirty-minute operating reserve* while respecting all applicable regional minimum requirements and regional maximum restrictions for *operating reserve*.

8.7.2.2 Constraint violation penalty curves may be used to impose a penalty cost for not meeting the *IESO*'s system-wide *operating reserve* requirements, not meeting a regional minimum requirement, or not adhering to a regional maximum restriction. Full *operating reserve* requirements shall be scheduled unless the cost of doing so would be higher than the applicable penalty cost. For each time-step $t \in TS$:

$$\begin{aligned} \sum_{b \in B^{DL}} \left(\sum_{j \in J_{t,b}^{10S}} S10SDL_{t,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} \right) + \sum_{i=1..N_{10SViol_t}} S10SViol_{t,i} \\ \geq TOT10S_t; \end{aligned}$$

$$\sum_{b\in B^{DL}}\left(\sum_{j\in J_{t,b}^{10S}} S10SDL_{t,b,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k}\right)$$
$$+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{t,b}^{10N}} S10NDL_{t,b,j}\right)+\sum_{d\in DX}\left(\sum_{j\in J_{t,d}^{10N}} S10NXL_{t,d,j}\right)$$
$$+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k}\right)+\sum_{d\in DI}\left(\sum_{k\in K_{t,d}^{10N}} S10NIG_{t,d,k}\right)$$
$$+\sum_{i=1..N_{10RViol_t}} S10RViol_{t,i} \geq TOT10R_t;$$

and

$$\sum_{b\in B^{DL}}\left(\sum_{j\in J_{t,b}^{10S}} S10SDL_{t,b,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k}\right)+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{t,b}^{10N}} S10NDL_{t,b,j}\right)$$
$$+\sum_{d\in DX}\left(\sum_{j\in J_{t,d}^{10N}} S10NXL_{t,d,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k}\right)$$
$$+\sum_{d\in DI}\left(\sum_{k\in K_{t,d}^{10N}} S10NIG_{t,d,k}\right)+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{t,b}^{30R}} S30RDL_{t,b,j}\right)$$
$$+\sum_{d\in DX}\left(\sum_{j\in J_{t,d}^{30R}} S30RXL_{t,d,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k}\right)$$
$$+\sum_{d\in DI}\left(\sum_{k\in K_{t,d}^{30R}} S30RIG_{t,d,k}\right)+\sum_{i=1..N_{30RViol_t}} S30RViol_{t,i} \geq TOT30R_t.$$

8.7.2.3 The following constraints shall be applied for each time-step $t \in TS$ and each region $r \in ORREG$:

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10S}} S10SDL_{t,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10N}} S10NDL_{t,b,j} \right) + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{t,d}^{10N}} S10NXL_{t,d,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10N}} S10NDG_{t,b,k} \right) + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{t,d}^{10N}} S10NIG_{t,d,k} \right) + \sum_{i=1..N_{REG10RViol_t}} SREG10RViol_{r,t,i} \geq REGMin10R_{t,r};$$

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10S}} S10SDL_{t,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10N}} S10NDL_{t,b,j} \right) + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{t,d}^{10N}} S10NXL_{t,d,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10N}} S10NDG_{t,b,k} \right) + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{t,d}^{10N}} S10NIG_{t,d,k} \right) - \sum_{i=1..N_{XREG10RViol_t}} SXREG10RViol_{r,t,i} \leq REGMax10R_{t,r};$$

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10S}} S10SDL_{t,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10N}} S10NDL_{t,b,j} \right) + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{t,d}^{10N}} S10NXL_{t,d,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10N}} S10NDG_{t,b,k} \right) + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{t,d}^{10N}} S10NIG_{t,d,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{30R}} S30RDL_{t,b,j} \right) + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{t,d}^{30R}} S30RXL_{t,d,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{30R}} S30RDG_{t,b,k} \right) + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{t,d}^{30R}} S30RIG_{t,d,k} \right) + \sum_{i=1..N_{REG30RViol_t}} SREG30RViol_{r,t,i} \geq REGMin30R_{t,r};$$

and

$$
\begin{aligned}
&+ \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10N}} S10NDL_{t,b,j} \right) \\
&\quad + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{t,d}^{10N}} S10NXL_{t,d,j} \right) \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{10S}} S10SDL_{t,b,j} \right) \\
&\quad + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10S}} S10SDG_{t,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{10N}} S10NDG_{t,b,k} \right) \\
&\quad + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{t,d}^{10N}} S10NIG_{t,d,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{t,b}^{30R}} S30RDL_{t,b,k} \right) \\
&\quad + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{t,d}^{30R}} S30RXL_{t,d,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{t,b}^{30R}} S30RDG_{t,b,k} \right) \\
&\quad + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{t,d}^{30R}} S30RIG_{t,d,k} \right) - \sum_{i=1..N_{XREG30RViol_t}} SXREG30RViol_{r,t,i} \\
&\quad \leq REGMax30R_{t,r}.
\end{aligned}
$$

8.7.3 IESO Internal Transmission Limits

8.7.3.1 The Pre-Dispatch Scheduling algorithm shall produce a set of *energy* schedules that do not violate any *security limits* in the pre-contingency state and the post-contingency state subject to the remainder of this section 8.7.3. The total amount of *energy* scheduled to be injected and withdrawn at each bus used by the *energy* balance constraint in section 8.7.1.5, shall be used to produce these schedules.

8.7.3.2 Pre-contigency, $SPreITLViol_{f,t,i}$, and post-contingency, $SITLViol_{c,f,t,i}$, transmission limit violation variables shall allow the *pre-dispatch calculation engine* to find a solution.

8.7.3.3 For all time-steps $t \in TS$ and *facilities* $f \in F_t$, the linearized constraints for violated pre-contingency limits obtained from the *security* assesment function shall take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG}} PreConSF_{t,f,b} \cdot Inj_{t,b} - \sum_{b \in B^{DL} \cup B^{HDR}} PreConSF_{t,f,b} \cdot With_{t,b} + \sum_{d \in DI} PreConSF_{t,f,d} \cdot Inj_{t,d} - \sum_{d \in DX} PreConSF_{t,f,d} \cdot With_{t,d} - \sum_{i=1..N_{PreITLViol_{f,t}}} SPreITLViol_{f,t,i} \leq AdjNormMaxFlow_{t,f}.$$

8.7.3.4 For all time-steps $t \in TS$, contingencies $c \in C$, and *facilities* $f \in F_{t,c}$, the linearized constraints for violated post-contingency limits obtained from the *security* assesment function shall take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG}} SF_{t,c,f,b} \cdot Inj_{t,b} - \sum_{b \in B^{DL} \cup B^{HDR}} SF_{t,c,f,b} \cdot With_{t,b} + \sum_{d \in DI} SF_{t,c,f,d} \cdot Inj_{t,d} - \sum_{d \in DX} SF_{t,c,f,d} \cdot With_{t,d} - \sum_{i=1..N_{ITLViol_{c,f,t}}} SITLViol_{c,f,t,i} \leq AdjEmMaxFlow_{t,c,f}.$$

8.7.4 Intertie Limits

8.7.4.1 The Pre-Dispatch Scheduling algorithm shall produce a set of *energy* and *operating reserve* schedules that respect any *security limits* associated with *interties* between Ontario and *intertie zones*. For all time-steps $t \in TS$ and all constraints $z \in Z_{Sch}$:

$$\sum_{a\in A:\, EnCoeff_{a,z}\neq 0}\left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d\in DI_a}\sum_{k\in K_{t,d}^{E}} SIG_{t,d,k}-\sum_{d\in DX_a}\sum_{j\in J_{t,d}^{E}} SXL_{t,d,j}\right)\\ +0.5\cdot\left(EnCoeff_{a,z}+1\right)\left(\begin{array}{l}\sum_{d\in DI_a}\left(\sum_{k\in K_{t,d}^{10N}} S10NIG_{t,d,k}+\sum_{k\in K_{t,d}^{30R}} S30RIG_{t,d,k}\right)+\\ \sum_{d\in DX_a}\left(\sum_{j\in J_{t,d}^{10N}} S10NXL_{t,d,j}+\sum_{j\in J_{t,d}^{30R}} S30RXL_{t,d,j}\right)\end{array}\right)\end{array}\right]$$

$$-\sum_{i=1..N_{PreConXTLViol_{z,t}}} SPreXTLViol_{z,t,i}\leq MaxExtSch_{t,z}.$$

where for out-of-service *intertie zones*, the *intertie* limits shall be set to zero and all *boundary entity resources* shall receive a zero schedule for *energy* and *operating reserve*.

8.7.4.2 Changes in the hour-to-hour net *energy* schedule over all *interties* shall not exceed the net interchange scheduling limit. The net import schedule shall be summed over all *intertie zones* for a given time-step to obtain the net *interchange schedule* for the time-step, and shall not:

8.7.4.2.1 exceed the net *interchange schedule* for the previous time-step plus the net interchange scheduling limit; and

8.7.4.2.2 be less than the net *interchange schedule* for the previous time-step minus the net interchange scheduling limit.

8.7.4.3 Violation variables shall be provided for both the up and down ramp limits to allow the *pre-dispatch calculation engine* to find a solution and for all time-steps $t\in TS$:

$$\sum_{d\in DI}\sum_{k\in K_{t-1,d}^{E}} SIG_{t-1,d,k} - \sum_{d\in DX}\sum_{j\in J_{t-1,d}^{E}} SXL_{t-1,d,j} - ExtDSC_t - \sum_{i=1..N_{NIDViol_t}} SNIDViol_{t,i}$$
$$\leq \sum_{d\in DI}\sum_{k\in K_{t,d}^{E}} SIG_{t,d,k} - \sum_{d\in DX}\sum_{j\in J_{t,d}^{E}} SXL_{t,d,j}$$
$$\leq \sum_{d\in DI}\sum_{k\in K_{t-1,d}^{E}} SIG_{t-1,d,k} - \sum_{d\in DX}\sum_{j\in J_{t-1,d}^{E}} SXL_{t-1,d,j} + ExtUSC_t$$
$$+ \sum_{i=1..N_{NIUViol_t}} SNIUViol_{t,i}.$$

8.7.5 Penalty Price Variable Bounds

8.7.5.1 Penalty price variables shall be restricted to the ranges determined by the constraint violation penalty curves for the Pre-Dispatch Scheduling algorithm and for time-steps $t \in TS$:

$0 \leq SLdViol_{t,i} \leq QLdViolSch_{t,i}$ for all $i \in \{1,..,N_{LdViol_t}\}$;

$0 \leq SGenViol_{t,i} \leq QGenViolSch_{t,i}$ for all $i \in \{1,..,N_{GenViol_t}\}$;

$0 \leq S10SViol_{t,i} \leq Q10SViolSch_{t,i}$ for all $i \in \{1,..,N_{10SViol_t}\}$;

$0 \leq S10RViol_{t,i} \leq Q10RViolSch_{t,i}$ for all i $\in \{1,..,N_{10RViol_t}\}$;

$0 \leq S30RViol_{t,i} \leq Q30RViolSch_{t,i}$ for all $i \in \{1,..,N_{30RViol_t}\}$;

$0 \leq SREG10RViol_{r,t,i} \leq QREG10RViolSch_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG10RViol_t}\}$;

$0 \leq SREG30RViol_{r,t,i} \leq QREG30RViolSch_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG30RViol_t}\}$;

$0 \leq SXREG10RViol_{r,t,i} \leq QXREG10RViolSch_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG10RViol_t}\}$;

$0 \leq SXREG30RViol_{r,t,i} \leq QXREG30RViolSch_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG30RViol_t}\}$;

$0 \leq SPreITLViol_{f,t,i} \leq QPreITLViolSch_{f,t,i}$ for all $f \in F_t$, $i \in \{1,..,N_{PreITLViol_{f,t}}\}$;

$0 \leq SITLViol_{c,f,t,i} \leq QITLViolSch_{c,f,t,i}$ for all $c \in C$, $f \in F_{t,c}$, $i \in \{1,..,N_{ITLViol_{c,f,t}}\}$;

$0 \leq SPreXTLViol_{z,t,i} \leq QPreXTLViolSch_{z,t,i}$ for all $z \in Z_{Sch}$, $i \in \{1,..,N_{PreXTLViol_{z,t}}\}$;

$0 \leq SNIUViol_{t,i} \leq QNIUViolSch_{t,i}$ for all $i \in \{1,..,N_{NIUViol_t}\}$;

$0 \leq SNIDViol_{t,i} \leq QNIDViolSch_{t,i}$ for all $i \in \{1,..,N_{NIDViol_t}\}$;

$0 \leq SMaxDelViol_{t,b,i} \leq QMaxDelViolSch_{t,b,i}$ for all $b \in B^{ELR}$, $i \in \{1,..,N_{MaxDelViol_t}\}$;

$0 \leq SMinDelViol_{t,b,i} \leq QMinDelViolSch_{t,b,i}$ for all $b \in B^{HE}$, $i \in \{1,..,N_{MinDelViol_t}\}$;

$0 \leq SSMaxDelViol_{t,s,i} \leq QSMaxDelViolSch_{t,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMaxDelViol_t}\}$;

$0 \leq SSMinDelViol_{t,s,i} \leq QSMinDelViolSch_{t,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMinDelViol_t}\}$;

$0 \leq SOGenLnkViol_{t,(b_1,b_2),i} \leq QOGenLnkViol_{t,(b_1,b_2),i}$ for all $(b_1,b_2) \in LNK$, $i \in \{1,..,N_{OGenLnkViol_t}\}$; and

$0 \leq SUGenLnkViol_{t,(b_1,b_2),i} \leq QUGenLnkViol_{t,(b_1,b_2),i}$ for all $(b_1,b_2) \in LNK$, $i \in \{1,..,N_{UGenLnkViol_t}\}$.

8.8 Outputs

8.8.1 Outputs for the Pre-Dispatch Scheduling algorithm include *resource* schedules and commitments.

9 Pre-Dispatch Pricing

9.1 Purpose

9.1.1 The Pre-Dispatch Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants*, subject to section 14.7.1.3, and *resource* schedules and commitments produced by the Pre-Dispatch Scheduling algorithm to meet the *IESO's* province-wide non-dispatchable *demand* forecast and IESO-specified *operating reserve* requirements for each hour of the pre-dispatch look-ahead period.

9.2 Information, Sets, Indices and Parameters

9.2.1 Information, sets, indices and parameters used by the Pre-Dispatch Pricing algorithm are described in section 3. In addition, the following *resource* schedules and commitments determined by the Pre-Dispatch Scheduling algorithm shall be used by the Pre-Dispatch Pricing algorithm:

9.2.1.1 $SDG_{t,b,k}^{PDS}$ designates the amount of *energy* that the *dispatchable generation resource* is scheduled to provide above $MinQDGC_b$ at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{E}$;

9.2.1.2 $ODG_{t,b}^{PDS}$ designates whether the *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in time-step $t \in TS$;

9.2.1.3 $S10SDG_{t,b,k}^{PDS}$ designates the amount of synchronized *ten-minute operating reserve* that the *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{10S}$;

9.2.1.4 $S10NDG_{t,b,k}^{PDS}$ designates the amount of non-synchronized *ten-minute operating reserve* that the *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{10N}$;

9.2.1.5 $S30RDG^{PDS}_{t,b,k}$ designates the amount of *thirty-minute operating reserve* that the *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K^{30R}_{t,b}$; and

9.2.1.6 $OHO^{PDS}_{t,b}$ designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{t,b}$ in time-step $t \in TS$.

9.3 Variables and Objective Function

9.3.1 The Pre-Dispatch Pricing algorithm shall solve for the same variables as in the Pre-Dispatch Scheduling algorithm, section 8.3.1, with the following exceptions:

9.3.1.1 $IDG_{t,b}$ for bus $b \in B^{DG}$ and time-step $t \in TS$ shall not appear in the formulation;

9.3.1.2 $ODG_{t,b}$ for bus $b \in B^{DG}$ and time-step $t \in TS$ will be fixed to a constant value, as determined by the Pre-Dispatch Scheduling algorithm;

9.3.1.3 $OHO_{t,b}$ for bus $b \in B^{HE}$ and time-step $t \in TS$ will be fixed to a constant value, as determined by the Pre-Dispatch Scheduling algorithm;

9.3.1.4 $IHE_{t,b,i}$ for $b \in B^{HE}$, time-step $t \in TS$ and *start indication value* $i \in \{1,..,NStartMW_b\}$ shall not appear in the formulation;

9.3.1.5 $SOGenLnkViol_{t,(b_1,b_2),i}$ for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$, time-step $t \in TS$ and $i \in \{1,..,N_{OGenLnkViol_t}\}$ shall not appear in the formulation; and

9.3.1.6 $SUGenLnkViol_{t,(b_1,b_2),i}$ for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$, time-step $t \in TS$ and $i \in \{1,..,N_{UGenLnkViol_t}\}$ shall not appear in the formulation.

9.3.2 The objective function for the Pre-Dispatch Pricing algorithm shall maximize gains from trade by maximizing the following expression:

$$\sum_{t \in TS} \begin{pmatrix} ObjDL_t - ObjHDR_t + ObjXL_t - ObjNDG_t \\ - ObjDG_t - ObjIG_t - TB_t - ViolCost_t \end{pmatrix}$$

where:

$$ObjDL_t = \sum_{b \in B^{DL}} \begin{pmatrix} \sum_{j \in J^{E}_{t,b}} SDL_{t,b,j} \cdot PDL_{t,b,j} - \sum_{j \in J^{10S}_{t,b}} S10SDL_{t,b,j} \cdot P10SDL_{t,b,j} - \\ \sum_{j \in J^{10N}_{t,b}} S10NDL_{t,b,j} \cdot P10NDL_{t,b,j} - \sum_{j \in J^{30R}_{t,b}} S30RDL_{t,b,j} \cdot P30RDL_{t,b,j} \end{pmatrix};$$

$$ObjHDR_t = \sum_{b \in B^{HDR}} \left(\sum_{j \in J^{E}_{t,b}} SHDR_{t,b,j} \cdot PHDR_{t,b,j} \right);$$

$$ObjXL_t = \sum_{d \in DX} \begin{pmatrix} \sum_{j \in J^{E}_{t,d}} SXL_{t,d,j} \cdot PXL_{t,d,j} - \sum_{j \in J^{10N}_{t,d}} S10NXL_{t,d,j} \cdot P10NXL_{t,d,j} \\ - \sum_{j \in J^{30R}_{t,d}} S30RXL_{t,d,j} \cdot P30RXL_{t,d,j} \end{pmatrix};$$

$$ObjNDG_t = \sum_{b \in B^{NDG}} \left(\sum_{k \in K^{E}_{t,b}} SNDG_{t,b,k} \cdot PNDG_{t,b,k} \right);$$

$$ObjDG_t = \sum_{b \in B^{DG}} \begin{pmatrix} \sum_{k \in K^{E}_{t,b}} SDG_{t,b,k} \cdot PDG_{t,b,k} + \sum_{k \in K^{10S}_{t,b}} S10SDG_{t,b,k} \cdot P10SDG_{t,b,k} + \\ \sum_{k \in K^{10N}_{t,b}} S10NDG_{t,b,k} \cdot P10NDG_{t,b,k} + \sum_{k \in K^{30R}_{t,b}} S30RDG_{t,b,k} \cdot P30RDG_{t,b,k} \end{pmatrix};$$

$$ObjIG_t = \sum_{d \in DI} \begin{pmatrix} \sum_{k \in K^{E}_{t,d}} SIG_{t,d,k} \cdot PIG_{t,d,k} + \sum_{k \in K^{10N}_{t,d}} S10NIG_{t,d,k} \cdot P10NIG_{t,d,k} \\ + \sum_{k \in K^{30R}_{t,d}} S30RIG_{t,d,k} \cdot P30RIG_{t,d,k} \end{pmatrix}.$$

9.3.2.1 The tie-breaking term, TB_t, shall be the same term described in section 8.3.2.1.

9.3.2.2 $ViolCost_t$ shall be calculated as follows:

$$\begin{aligned} ViolCost_t = & \sum_{i=1..N_{LdViol_t}} SLdViol_{t,i} \cdot PLdViolPrc_{t,i} \\ & - \sum_{i=1..N_{GenViol_t}} SGenViol_{t,i} \cdot PGenViolPrc_{t,i} \\ & + \sum_{i=1..N_{10SViol_t}} S10SViol_{t,i} \cdot P10SViolPrc_{t,i} \\ & + \sum_{i=1..N_{10RViol_t}} S10RViol_{t,i} \cdot P10RViolPrc_{t,i} \\ & + \sum_{i=1..N_{30RViol_t}} S30RViol_{t,i} \cdot P30RViolPrc_{t,i} \\ & + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG10RViol_t}} SREG10RViol_{r,t,i} \cdot PREG10RViolPrc_{t,i} \right) \\ & + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG30RViol_t}} SREG30RViol_{r,t,i} \cdot PREG30RViolPrc_{t,i} \right) \\ & + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG10RViol_t}} SXREG10RViol_{r,t,i} \cdot PXREG10RViolPrc_{t,i} \right) \end{aligned}$$

$$+\sum_{r\in ORREG}\left(\sum_{i=1..N_{XREG30RViol_t}} SXREG30RViol_{r,t,i}\cdot PXREG30RViolPrc_{t,i}\right)$$

$$+\sum_{f\in F_t}\left(\sum_{i=1..N_{PreITLViol_{f,t}}} SPreITLViol_{f,t,i}\cdot PPreITLViolPrc_{f,t,i}\right)$$

$$+\sum_{c\in C}\sum_{f\in F_{t,c}}\left(\sum_{i=1..N_{ITLViol_{c,f,t}}} SITLViol_{c,f,t,i}\cdot PITLViolPrc_{c,f,t,i}\right)$$

$$+\sum_{z\in Z_{Sch}}\left(\sum_{i=1..N_{PreXTLViol_t}} SPreXTLViol_{z,t,i}\cdot PPreXTLViolPrc_{z,t,i}\right)$$

$$+\sum_{i=1..N_{NIUViol_t}} SNIUViol_{t,i}\cdot PNIUViolPrc_{t,i}$$

$$+\sum_{i=1..N_{NIDViol_t}} SNIDViol_{t,i}\cdot PNIDViolPrc_{t,i}$$

$$+\sum_{b\in B^{ELR}}\left(\sum_{i=1..N_{MaxDelViol_t}} SMaxDelViol_{t,b,i}\cdot PMaxDelViolPrc_{t,b,i}\right)$$

$$+\sum_{b\in B^{HE}}\left(\sum_{i=1..N_{MinDelViol_t}} SMinDelViol_{t,b,i}\cdot PMinDelViolPrc_{t,b,i}\right)$$

$$+\sum_{s\in \mathrm{SHE}}\left(\sum_{i=1..N_{SMaxDelViol_t}} SSMaxDelViol_{t,s,i}\cdot PSMaxDelViolPrc_{t,s,i}\right)$$

$$+\sum_{s\in \mathrm{SHE}}\left(\sum_{i=1..N_{SMinDelViol_t}} SSMinDelViol_{t,s,i}\cdot PSMinDelViolPrc_{t,s,i}\right)$$

9.3.2.3 The objective function of the Pre-Dispatch Pricing algorithm in section 9.3.2 shall be subject to the constraints described in sections 9.4 - 9.8.

9.4 Constraints

9.4.1 The constraints described in sections 9.5, 9.6, 9.7 and 9.8 apply to the optimization function in the Pre-Dispatch Pricing algorithm.

9.5 Dispatch Data Constraints Applying to Individual Hours

9.5.1 Scheduling Variable Bounds

9.5.1.1 *Energy* and *operating reserve* schedules shall not be negative and shall not exceed the quantity respectively offered for *energy* and *operating reserve*. For all time-steps $t \in TS$:

$$0 \leq SDL_{t,b,j} \leq QDL_{t,b,j} \qquad \text{for all } b \in B^{DL}, j \in J^{E}_{t,b};$$

$$0 \leq S10SDL_{t,b,j} \leq Q10SDL_{t,b,j} \qquad \text{for all } b \in B^{DL}, j \in J^{10S}_{t,b};$$

$$0 \leq S10NDL_{t,b,j} \leq Q10NDL_{t,b,j} \qquad \text{for all } b \in B^{DL}, j \in J^{10N}_{t,b};$$

$$0 \leq S30RDL_{t,b,j} \leq Q30RDL_{t,b,j} \qquad \text{for all } b \in B^{DL}, j \in J^{30R}_{t,b};$$

$$0 \leq SHDR_{t,b,j} \leq QHDR_{t,b,j} \qquad \text{for all } b \in B^{HDR}, j \in J^{E}_{t,b};$$

$$0 \leq SXL_{t,d,j} \leq QXL_{t,d,j} \qquad \text{for all } d \in DX, j \in J^{E}_{t,d};$$

$$0 \leq S10NXL_{t,d,j} \leq Q10NXL_{t,d,j} \qquad \text{for all } d \in DX, j \in J^{10N}_{t,d};$$

$$0 \leq S30RXL_{t,d,j} \leq Q30RXL_{t,d,j} \qquad \text{for all } d \in DX, j \in J^{30R}_{t,d};$$

$$0 \leq SNDG_{t,b,k} \leq QNDG_{t,b,k} \qquad \text{for all } b \in B^{NDG}, k \in K^{E}_{t,b};$$

$$0 \leq SIG_{t,d,k} \leq QIG_{t,d,k} \qquad \text{for all } d \in DI, k \in K^{E}_{t,d};$$

$$0 \leq S10NIG_{t,d,k} \leq Q10NIG_{t,d,k} \qquad \text{for all } d \in DI, k \in K^{10N}_{t,d}; \text{ and}$$

$$0 \leq S30RIG_{t,d,k} \leq Q30RIG_{t,d,k} \qquad \text{for all } d \in DI, k \in K^{30R}_{t,d}.$$

9.5.1.2 A *dispatchable generation resource* may be scheduled for *energy* and *operating reserve* only if its commitment status variable, as determined by the Pre-Dispatch Scheduling algorithm, is equal to 1. For all time-steps $t \in TS$:

$$0 \leq SDG_{t,b,k} \leq ODG_{t,b}^{PDS} \cdot QDG_{t,b,k} \qquad \text{for all } b \in B^{DG},\ k \in K_{t,b}^{E};$$

$$0 \leq S10SDG_{t,b,k} \leq ODG_{t,b}^{PDS} \cdot Q10SDG_{t,b,k} \qquad \text{for all } b \in B^{DG},\ k \in K_{t,b}^{10S};$$

$$0 \leq S10NDG_{t,b,k} \leq ODG_{t,b}^{PDS} \cdot Q10NDG_{t,b,k} \qquad \text{for all } b \in B^{DG},\ k \in K_{t,b}^{10N}; \text{and}$$

$$0 \leq S30RDG_{t,b,k} \leq ODG_{t,b}^{PDS} \cdot Q30RDG_{t,b,k} \qquad \text{for all } b \in B^{DG},\ k \in K_{t,b}^{30R}.$$

where

$ODG_{t,b}^{PDS}$ is a fixed constant in the above constraints, per section 9.8.1.1.

9.5.2 Resource Minimums and Maximums

9.5.2.1 The constraints in section 8.5.2 shall apply in the Pre-Dispatch Pricing algorithm.

9.5.3 Off-Market Transactions

9.5.3.1 The constraints in sections 8.5.3.1 and 8.5.3.2 for inadvertent payback transactions shall apply in the Pre-Dispatch Pricing algorithm.

9.5.3.2 In the case of *emergency energy* transactions, subject to section 9.5.3.3, the constraints in sections 8.5.3.3 and 8.5.3.4 shall apply in the Pre-Dispatch Pricing algorithm.

9.5.3.3 For all time-steps $t \in TS$ and all *boundary entity resources* scheduled to import *emergency energy* that does not support an export $d \in DI_t^{EMNS}$:

$$\sum_{k \in K_{t,d}^{E}} SIG_{t,d,k} = 0.$$

9.5.4 Intertie Minimum and Maximum Constraints

9.5.4.1 The constraints in section 8.5.4 shall apply in the Pre-Dispatch Pricing algorithm as well.

9.5.5 Operating Reserve Scheduling

9.5.5.1 The constraints in section 8.5.5 shall apply in the Pre-Dispatch Pricing algorithm as well.

9.5.6 Pseudo-Units

9.5.6.1 The constraints in section 8.5.6 shall apply in the Pre-Dispatch Pricing algorithm as well.

9.5.7 Dispatchable Hydroelectric Generation Resources

9.5.7.1 The constraints in section 8.5.7 shall apply in the Pre-Dispatch Pricing algorithm as well, with the following exceptions:

9.5.7.1.1 *energy offer* laminations corresponding to the *hourly must-run* amount shall be ineligible to set prices;

9.5.7.1.2 *minimum hourly output* constraints shall be replaced by the constraints in section 9.8; and

9.5.7.1.3 a *dispatchable* hydroelectric *generation resource's* schedule shall respect its *forbidden regions* and may only set prices within the operating range determined by the adjacent *forbidden regions* between which the *resource* was scheduled.

9.5.8 Linked Wheeling Through Transactions

9.5.8.1 The constraints in section 8.5.8 shall apply in the Pre-Dispatch Pricing algorithm as well.

9.6 Dispatch Data Inter-Hour/Multi-Hour Constraints

9.6.1 Energy Ramping

9.6.1.1 The constraints in section 8.6.1 shall apply in the Pre-Dispatch Pricing algorithm as well.

9.6.2 Operating Reserve Ramping

9.6.2.1 The constraints in section 8.6.2 shall apply in the Pre-Dispatch Pricing algorithm as well.

9.6.3 Energy Limited Resources

9.6.3.1 The constraints in section 8.6.4 shall apply to *energy limited resources*. If a *resource*'s *maximum daily energy limit* is binding, then the constraints in section 9.8 shall also apply.

9.6.4 Dispatchable Hydroelectric Generation Resources

9.6.4.1 A *dispatchable* hydroelectric *generation resource* shall be scheduled for *energy* to at least its *minimum daily energy limit*. Violation variables for under-scheduling a *resource's minimum daily energy limit* shall be provided to allow the *pre-dispatch calculation engine* to find a solution. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$\sum_{t \in TS_{tod}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{i=1..N_{MinDelViol_t}} SMinDelViol_{t,b,i} \right) \geq MinDEL_{tod,b} - EngyUsed_b.$$

9.6.4.1.1 If the pre-dispatch look-ahead period spans two *dispatch days*, for all hydroelectric *resource* buses $b \in B^{HE}$:

$$\sum_{t \in TS_{tom}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{i=1..N_{MinDelViol_t}} SMinDelViol_{t,b,i} \right) \geq MinDEL_{tom,b}.$$

9.6.4.2 The constraints in section 9.8.3.3 shall apply to a *dispatchable* hydroelectric *generation resource* with a binding *minimum daily energy limit* in the Pre-Dispatch Scheduling algorithm.

9.6.4.3 The schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall respect shared *maximum daily energy limits*. Violation variables for scheduling *resources* above the *maximum daily energy limit* may be used to allow the *pre-*

dispatch calculation engine to find a solution. For all sets $s \in SHE$ and all time-steps $T \in TS_{tod}$:

$$\sum_{t=2..T}\left(\sum_{b\,\in B_s^{HE}}\left(ODG_{t,b}^{PDS}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^{E}}SDG_{t,b,k}\right)\right)$$
$$+\sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{T,b}^{10S}}S10SDG_{T,b,k}+\sum_{k\in K_{T,b}^{10N}}S10NDG_{T,b,k}\right)\right.$$
$$\left.\left.+30ORConv\left(\sum_{k\in K_{T,b}^{30R}}S30RDG_{T,b,k}\right)\right)\right)$$
$$-\sum_{i=1..N_{SMaxDelViol_T}}SSMaxDelViol_{T,s,i}\le MaxSDEL_{tod,s}-EngyUsedSHE_s.$$

9.6.4.3.1 If the look-ahead period spans two *dispatch days*, then for all sets $s \in SHE$ and all time-steps $T \in TS_{tom}$:

$$\sum_{t=t_{tom}..T}\left(\sum_{b\,\in B_s^{HE}}\left(ODG_{t,b}^{PDS}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^{E}}SDG_{t,b,k}\right)\right)$$
$$+\sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{T,b}^{10S}}S10SDG_{T,b,k}+\sum_{k\in K_{T,b}^{10N}}S10NDG_{T,b,k}\right)\right.$$
$$\left.\left.+30ORConv\left(\sum_{k\in K_{T,b}^{30R}}S30RDG_{T,b,k}\right)\right)\right)$$
$$-\sum_{i=1..N_{SMaxDelViol_T}}SSMaxDelViol_{T,s,i}\le MaxSDEL_{tom,s}$$

where the factors $10\ ORConv$ and $30\ ORConv$ shall be applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* to convert MW into MWh.

9.6.4.4 The schedules for multiple *dispatchable* hydroelectric *generation resources* with a registered *forebay* shall not violate shared *minimum* *daily energy limits*. Violation variables for scheduling *resources* below the *minimum daily energy limit* may be used to allow the *pre-dispatch calculation engine* to find a solution. For all sets $s \in SHE_{tod}$ and all time-steps $t \in TS_{tod}$:

$$\sum_{t \in TS_{tod}} \left(\sum_{b \in B_s^{HE}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} \right) + \sum_{i=1..N_{SMinDelViol_t}} SSMinDelViol_{t,s,i} \right) \geq MinSDEL_{tod,s} - EngyUsedSHE_s.$$

9.6.4.4.1 If the look-ahead period spans two *dispatch days*, then for all sets $s \in SHE$ and all time-steps $t \in TS_{tom}$:

$$\sum_{t \in TS_{tom}} \left(\sum_{b \in B_s^{HE}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} \right) + \sum_{i=1..N_{SMinDelViol_t}} SSMinDelViol_{t,s,i} \right) \geq MinSDEL_{tom,s}.$$

9.7 Constraints for Reliability Requirements

9.7.1 Energy Balance

9.7.1.1 The constraint in section 8.7.1 shall also apply in the Pre-Dispatch Pricing algorithm, except the marginal loss factors used in the *energy* balance constraint in the Pre-Dispatch Pricing algorithm shall be fixed to the marginal loss factors used in the last optimization function iteration of the Pre-Dispatch Scheduling algorithm.

9.7.2 Operating Reserve Requirements

9.7.2.1 The constraints in section 8.7.2 shall also apply in the Pre-Dispatch Pricing algorithm.

9.7.3 IESO Internal Transmission Limits

9.7.3.1 The constraints in section 8.7.3 shall also apply in the Pre-Dispatch Pricing algorithm, except the sensitivities and limits considered shall be those provided by the most recent *security* assessment function iteration of the Pre-Dispatch Pricing algorithm.

9.7.4 Intertie Limits

9.7.4.1 The constraints in section 8.7.4 shall also apply in the Pre-Dispatch Pricing algorithm.

9.7.5 Penalty Price Variable Bounds

9.7.5.1 The following constraints shall restrict the penalty price variables to the ranges determined by the constraint violation penalty curves for the pricing algorithm. For all time-steps $t \in TS$:

$0 \leq SLdViol_{t,i} \leq QLdViolPrc_{t,i}$ for all $i \in \{1,..,N_{LdViol_t}\}$;

$0 \leq SGenViol_{t,i} \leq QGenViolPrc_{t,i}$ for all $i \in \{1,..,N_{GenViol_t}\}$;

$0 \leq S10SViol_{t,i} \leq Q10SViolPrc_{t,i}$ for all $i \in \{1,..,N_{10SViol_t}\}$;

$0 \leq S10RViol_{t,i} \leq Q10RViolPrc_{t,i}$ for all $i \in \{1,..,N_{10RPrc_t}\}$;

$0 \leq S30RViol_{t,i} \leq Q30RViolPrc_{t,i}$ for all $i \in \{1,..,N_{30RPrc_t}\}$;

$0 \leq SREG10RViol_{r,t,i} \leq QREG10RViolPrc_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG10RPrc_t}\}$;

$0 \leq SREG30RViol_{r,t,i} \leq QREG30RViolPrc_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG30RPrc_t}\}$;

$0 \leq SXREG10RViol_{r,t,i} \leq QXREG10RViolPrc_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG10RPrc_t}\}$;

$0 \leq SXREG30RViol_{r,t,i} \leq QXREG30RViolPrc_{t,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG30RPrc_t}\}$;

$0 \leq SPreITLViol_{f,t,i} \leq QPreITLViolPrc_{f,t,i}$ for all $f \in F_t$, $i \in \{1,..,N_{PreITLPrc_{f,t}}\}$;

$0 \leq SITLViol_{f,c,t,i} \leq QITLViolPrc_{f,c,t,i}$ for all $c \in C$, $f \in F_{c,t}$, $i \in \{1,..,N_{PITLPrc_{c,f,t}}\}$;

$0 \leq SPreXTLViol_{z,t,i} \leq QPreXTLViolPrc_{z,t,i}$ for all $z \in Z_{Sch}$, $i \in \{1,..,N_{PreXTLPrc_{z,t}}\}$;

$0 \leq SNIUViol_{t,i} \leq QNIUViolPrc_{t,i}$ for all $i \in \{1,..,N_{NIUPrc_t}\}$;

$0 \leq SNIDViol_{t,i} \leq QNIDViolPrc_{t,i}$ for all $i \in \{1,..,N_{NIDPrc_t}\}$;

$0 \leq SMaxDelViol_{t,b,i} \leq QMaxDelViolPrc_{t,b,i}$ for all $b \in B^{ELR}$, $i \in \{1,..,N_{MaxDelViol_t}\}$;

$0 \leq SMinDelViol_{t,b,i} \leq QMinDelViolPrc_{t,b,i}$ for all $b \in B^{HE}$, $i \in \{1,..,N_{MinDelViol_t}\}$;

$0 \leq SSMaxDelViol_{t,s,i} \leq QSMaxDelViolPrc_{t,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMaxDelViol_t}\}$; and

$0 \leq SSMinDelViol_{t,s,i} \leq QSMinDelViolPrc_{t,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMinDelViol_t}\}$.

9.8 Constraints to Ensure the Price Setting Eligibility of Offer/Bid Laminations

9.8.1 Commitment Status Variables

9.8.1.1 Commitment decisions shall be fixed to the commitment statuses of *resources* calculated by the Pre-Dispatch Scheduling algorithm in section 8. For all time-steps $t \in TS$ and all buses $b \in B^{DG}$:

$$ODG_{t,b} = ODG_{t,b}^{PDS}.$$

9.8.2 Energy Limited Resources

9.8.2.1 For an *energy limited resource* with a *maximum daily energy limit* that was binding in the Pre-Dispatch Scheduling algorithm, the schedules calculated by the Pre-Dispatch Scheduling algorithm shall determine the price-setting eligibility of the *resource's energy* and *operating reserve offer* laminations. In each time-step, *energy* or *operating reserve* laminations up to the total amount of *energy* and *operating reserve* scheduled in the Pre-Dispatch Scheduling algorithm shall be eligible to set prices. For bus $b \in B^{ELR}$, if there exists a time-step $T \in TS_{tod}$ such that:

$$\sum_{t=2..T}\left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k}^{PDS}\right) + 10ORConv\left(\sum_{k \in K_{T,b}^{10S}} S10SDG_{T,b,k}^{PDS} + \sum_{k \in K_{T,b}^{10N}} S10NDG_{T,b,k}^{PDS}\right) + 30ORConv\left(\sum_{k \in K_{T,b}^{30R}} S30RDG_{T,b,k}^{PDS}\right) = MaxDEL_{tod,b} - EngyUsed_b$$

9.8.2.1.1 then the *maximum daily energy limit* constraint shall be considered binding in the Pre-Dispatch Scheduling algorithm. In such circumstances, the following constraints must hold for bus $b \in B^{ELR}$ for all time-steps $t \in TS_{tod}$:

$$\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} \le \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} + \epsilon,$$

$$\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} \le MaxDEL_{tod,b} - EngyUsed_b - \sum_{\tau=2}^{t-1} \sum_{k\in K_{t,b}^{E}} SDG_{\tau,b,k}^{PDS}.$$

where ϵ is a small positive constant.

9.8.2.2 If the pre-dispatch look-ahead period spans two *dispatch days*, then for bus $b \in B^{ELR}$, if there exists a time-step $T \in TS_{tom}$ such that:

$$\sum_{t=t_{tom}..T} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} \right) + 10ORConv \left(\sum_{k\in K_{T,b}^{10S}} S10SDG_{T,b,k}^{PDS} + \sum_{k\in K_{T,b}^{10N}} S10NDG_{T,b,k}^{PDS} \right) + 30ORConv \left(\sum_{k\in K_{T,b}^{30R}} S30RDG_{T,b,k}^{PDS} \right) = MaxDEL_{tom,b}$$

9.8.2.2.1 then the *maximum daily energy limit* constraint is considered to be binding for the next *dispatch day* in Pre-Dispatch Scheduling algorithm. In such circumstances, the following constraints must hold for bus $b \in B^{ELR}$ for all time-steps $t \in TS_{tom}$:

$$\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} \le \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} + \epsilon,$$

$$\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k} \le MaxDEL_{tom,b} - \sum_{\tau=tom}^{t-1} \sum_{k\in K_{t,b}^{E}} SDG_{\tau,b,k}^{PDS}.$$

where ϵ is a small positive constant.

9.8.3 Dispatchable Hydroelectric Generation Resources

9.8.3.1 If a *dispatchable* hydroelectric *generation resource* is scheduled to provide *energy* at or above its *minimum hourly output* in the Pre-Dispatch Scheduling algorithm, such *resource* shall also be scheduled at or above its *minimum hourly output* in the Pre-Dispatch Pricing algorithm. The *energy offer* laminations corresponding to the *minimum hourly output* amount shall be ineligible to set prices. If a *dispatchable* hydroelectric *generation resource* with a *minimum hourly output* amount receives a zero schedule in the Pre-Dispatch Scheduling algorithm, the *resource* shall also receive a zero schedule in the Pre-Dispatch Pricing algorithm and shall be ineligible to set prices in the *energy* market. For all time-steps $t \in TS$ and *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$:

$$ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \geq MinHO_{t,b} \cdot OHO_{t,b}^{PDS}$$

and for all $k \in K_{t,b}^E$:

$$0 \leq SDG_{t,b,k} \leq OHO_{t,b}^{PDS} \cdot QDG_{t,b,k}.$$

9.8.3.2 For a *dispatchable* hydroelectric *generation resource* with a limited number of starts, such *resource* shall be scheduled such that it is limited to set prices within an operating range consistent with the number of starts utilized by the *resource's* schedule determined by the Pre-Dispatch Scheduling algorithm. The *resource's* schedule shall be between the same *start indication values* as determined in the Pre-Dispatch Scheduling algorithm. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ and all time-steps $t \in TS$:

If $0 \leq ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k}^{PDS} < StartMW_{b,1}$,

then

$$0 \leq ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \leq StartMW_{b,1} - 0.1$$

If $StartMW_{b,i} \leq ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k}^{PDS} < StartMW_{b,i+1}$ for $i \in \{1,..,(NStartMW_b\text{-}1)\}$,

then

$$StartMW_{b,i} \leq ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \leq StartMW_{b,i+1} - 0.1$$

If $ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k}^{PDS} \geq StartMW_{b,NStartMW_b}$,

then

$$ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k} \geq StartMW_{b,NStartMW_b}.$$

9.8.3.3 For a *dispatchable* hydroelectric *generation resource* with a *minimum daily energy limit* that was binding in the Pre-Dispatch Scheduling algorithm, the *offer* laminations corresponding to the *energy* schedules calculated in the Pre-Dispatch Scheduling algorithm shall be ineligible to set prices. For all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ such that $MinDEL_{tod,b} > 0$ and

$$\sum_{t \in TS_{tod}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^E} SDG_{t,b,k}^{PDS} \right) \leq MinDEL_{tod,b} - EngyUsed_b,$$

9.8.3.3.1 the following constraints must hold for all time-steps $t \in TS_{tod}$ and *offer* laminations $k \in K_{t,b}^E$:

$$SDG_{t,b,k} \geq SDG_{t,b,k}^{PDS}.$$

9.8.3.3.2 If the pre-dispatch look-ahead period spans two *dispatch days*, for all *dispatchable* hydroelectric *generation resource* buses $b \in B^{HE}$ such that $MinDEL_{tom,b} > 0$ and

$$\sum_{t \in TS_{tom}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} \right) \leq MinDEL_{tom,b},$$

9.8.3.3.3 the following constraints must hold for all time-steps $t \in TS_{tom}$ and *offer* laminations $k \in K_{t,b}^{E}$:

$$SDG_{t,b,k} \geq SDG_{t,b,k}^{PDS}.$$

9.8.3.4 For a *dispatchable* hydroelectric *generation resource* with a shared *minimum daily energy limit* that was binding in the Pre-Dispatch Scheduling algorithm, the *offer* laminations corresponding to the *energy* schedules calculated for all *resources* in the set $s \in SHE$ in the Pre-Dispatch Scheduling algorithm shall be ineligible to set prices. Thus, for each set $s \in SHE$:

$$\sum_{t \in TS_{tod}} \left(\sum_{b \in B_s^{HE}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} \right) \right) \leq MinSDEL_{tod,s} - EngyUsedSHE_s,$$

9.8.3.4.1 the following constraints must hold for all time-steps $t \in TS_{tod}$ ∈ :

$$\sum_{b \in B_s^{HE}} \left(ODG_{t,b} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k} \right) \geq \sum_{b \in B_s^{HE}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} \right).$$

9.8.3.4.2 If the pre-dispatch look-ahead period spans two *dispatch days*, then for each set $s \in SHE$:

$$\sum_{t \in TS_{tom}} \left(\sum_{b \in B_s^{HE}} \left(ODG_{t,b}^{PDS} \cdot MinQDGC_b + \sum_{k \in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} \right) \right) \leq MinSDEL_{tom,s}$$

9.8.3.4.3 the following constraints must hold for all time-steps $t \in TS_{tom}$:

$$\sum_{b\in B_s^{HE}}\left(ODG_{t,b}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^E}SDG_{t,b,k}\right)\geq\sum_{b\in B_s^{HE}}\left(ODG_{t,b}^{PDS}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^E}SDG_{t,b,k}^{PDS}\right).$$

9.8.3.5 For a *dispatchable* hydroelectric *generation resource* with a binding *maximum daily energy limit* in the Pre-Dispatch Scheduling algorithm, the schedules calculated in the Pre-Dispatch Scheduling algorithm shall determine the price-setting eligibility of the *resource's energy* and *operating reserve offer* laminations as described in section 9.8.2.

9.8.3.6 For a *dispatchable* hydroelectric *generation resource* with a shared *maximum daily energy limit* that was binding in the Pre-Dispatch Scheduling algorithm, in each hour, the *offer* laminations up to the sum of *energy* and *operating reserve* schedules calculated in Pre-Dispatch Scheduling algorithm for all *resources* in each set $s\in SHE$ will be eligible to set prices. For each set $s\in SHE$, if there exists $T\in TS_{tod}$ such that:

$$\sum_{t=2..T}\left(\sum_{b\in B_s^{HE}}\left(ODG_{t,b}^{PDS}\cdot MinQDGC_b+\sum_{k\in K_{t,b}^E}SDG_{t,b,k}^{PDS}\right)\right)+\sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{T,b}^{10S}}S10SDG_{T,b,k}^{PDS}+\sum_{k\in K_{T,b}^{10N}}S10NDG_{T,b,k}^{PDS}\right)+30ORConv\left(\sum_{k\in K_{T,b}^{30R}}S30RDG_{T,b,k}^{PDS}\right)\right)=MaxSDEL_{tod,s}-EngyUsedSHE_s.$$

9.8.3.6.1 then the *maximum daily energy limit* constraint is considered to be binding for the current *dispatch day* in the Pre-Dispatch Scheduling algorithm. In such circumstances, the following constraints shall apply for all time-steps $t\in TS_{tod}$:

$$\sum_{b\in B_s^{HE}}\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} \leq \sum_{b\in B_s^{HE}}\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} + \epsilon,$$

$$\sum_{b\in B_s^{HE}}\left(\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k}\right)$$
$$\leq MaxSDEL_{tod,s} - EngyUsedSHE_s - \sum_{b\in B_s^{HE}}\sum_{\tau=2}^{t-1}\sum_{k\in K_{t,b}^{E}} SDG_{\tau,b,k}^{PDS}.$$

where ϵ is a small positive constant.

9.8.3.6.2 If the pre-dispatch look-ahead period spans two *dispatch days*, if there exists a time-step $T \in TS_{tom}$ such that:

$$\sum_{t=t_{tom}..T}\left(\sum_{b\in B_s^{HE}}\left(ODG_{t,b}^{PDS}\cdot MinQDGC_b + \sum_{k\in K_{t,b}^{E}} SDG_{t,b,k}^{PDS}\right)\right)$$
$$+\sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{T,b}^{10S}} S10SDG_{T,b,k}^{PDS} + \sum_{k\in K_{T,b}^{10N}} S10NDG_{T,b,k}^{PDS}\right)\right.$$
$$\left.+\,30ORConv\left(\sum_{k\in K_{T,b}^{30R}} S30RDG_{T,b,k}^{PDS}\right)\right) = MaxSDEL_{tom,s},$$

9.8.3.6.3 then the *maximum daily energy limit* constraint is considered to be binding for the next *dispatch day* in the Pre-Dispatch Scheduling algorithm. In such circumstances, the following constraints shall apply for all time-steps $t \in TS_{tom}$:

$$\sum_{b\in B_s^{HE}}\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} \leq \sum_{b\in B_s^{HE}}\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k}^{PDS} + \epsilon,$$

$$\sum_{b\in B_s^{HE}}\left(\sum_{k\in K_{t,b}^{E}} SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10S}} S10SDG_{t,b,k} + \sum_{k\in K_{t,b}^{10N}} S10NDG_{t,b,k} + \sum_{k\in K_{t,b}^{30R}} S30RDG_{t,b,k}\right)$$
$$\leq MaxSDEL_{tom,s} - \sum_{b\in B_s^{HE}}\sum_{\tau=tom}^{t-1}\sum_{k\in K_{t,b}^{E}} SDG_{\tau,b,k}^{PDS}.$$

where ϵ is a small positive constant.

9.8.3.7 For a *dispatchable* hydroelectric *generation resource* for which a *MWh ratio* was respected in the Pre-Dispatch Scheduling algorithm, such *resource* shall be scheduled between its Pre-Dispatch Scheduling algorithm schedule plus or minus a tolerance Δ specified by the *IESO*. The *resource* schedule shall be limited by its *offer* quantity bounds, in section 9.5.1, and any applicable *resource* minimum or maximum constraints, in section 9.5.2. For all linked downstream *dispatchable* hydroelectric *generation resources* b_2 such that $(b_1,b_2) \in LNKC$ where $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$ and all time-steps $t \in TS$:

$$ODG_{t,b_2}^{PDS}\cdot MinQDGC_{b_2} + \sum_{k\in K_{t,b_2}^{E}} SDG_{t,b_2,k}^{PDS} - \Delta \leq ODG_{t,b_2}^{PDS}\cdot MinQDGC_{b_2} + \sum_{k\in K_{t,b_2}^{E}} SDG_{t,b_2,k}$$
$$\leq ODG_{t,b_2}^{PDS}\cdot MinQDGC_{b_2} + \sum_{k\in K_{t,b_2}^{E}} SDG_{t,b_2,k}^{PDS} + \Delta.$$

9.8.3.7.1 For all linked *dispatchable* hydroelectric *generation resources* b_1 such that $(b_1,b_2) \in LNKC$ where $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$ and all time-steps $t \in TS$ such that $t + LagC_{b_1,b_2} \leq n_{LAP}$:

$$ODG_{t,b_1}^{PDS}\cdot MinQDGC_{b_1} + \sum_{k\in K_{t,b_1}^{E}} SDG_{t,b_1,k}^{PDS} - \Delta \leq ODG_{t,b_1}^{PDS}\cdot MinQDGC_{b_1} + \sum_{k\in K_{t,b_1}^{E}} SDG_{t,b_1,k}$$
$$\leq ODG_{t,b_1}^{PDS}\cdot MinQDGC_{b_1} + \sum_{k\in K_{t,b_1}^{E}} SDG_{t,b_1,k}^{PDS} + \Delta.$$

9.9 Outputs

9.9.1 Outputs for the Pre-Dispatch Pricing algorithm include the following:

9.9.1.1 shadow prices;

9.9.1.2 *locational marginal prices* and their components; and

9.9.1.3 sensitivity factors.

10 Constrained Area Conditions Test

10.1 Purpose

10.1.1 The Constrained Area Conditions Test shall:

10.1.1.1 identify when and where competition is restricted; and

10.1.1.2 determine which *resources* shall have their *financial dispatch data parameters* be subject to the Conduct Test in section 11 and the thresholds above the *reference levels* that shall be used in the Conduct Test.

10.2 Information, Sets, Indices and Parameters

10.2.1 The *narrow constrained areas* and *dynamic constrained areas* and the information published therein in accordance with section 22 of Chapter 7 shall be inputs for the Constrained Area Conditions Test.

10.2.2 Information, sets, indices and parameters for the Constrained Area Conditions Test are described in sections 3 and 4. In addition, the following prices produced by the Pre-Dispatch Pricing algorithm shall be used by the Constrained Area Conditions Test:

10.2.2.1 $LMP_{t,b}^{PDP}$, which designates the *locational marginal price* for bus $b \in B$ in time-step $t \in TS$;

10.2.2.2 $PCong_{t,b}^{PDP}$, which designates the congestion component of the *locational marginal price* for bus $b \in B$ in time-step $t \in TS$;

10.2.2.3 $\mathrm{ExtLMP}_{t,d}^{PDP}$, which designates the locational marginal price for intertie bus $d \in D$ in time-step $t \in TS$;

10.2.2.4 $PExtCong_{t,d}^{PDP}$, which designates the *interti*e congestion component of the *locational marginal price* for *intertie* bus $d \in D$ in time-step $t \in TS$;

10.2.2.5 $PIntCong_{t,d}^{PDP}$, which designates the internal congestion component of the *locational marginal price* for *intertie* bus $d \in D$ in time-step $t \in TS$;

10.2.2.6 $IntLMP_{t,d}^{PDP}$, which designates the *intertie border price* for *intertie* bus $d \in D$ in time-step $t \in TS$;

10.2.2.7 $SPNormT_{t,f}^{PDP}$, which designates the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in time-step $t \in TS$;

10.2.2.8 $SPEmT_{h,c,f}^{PDP}$, which designates the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in time-step $t \in TS$;

10.2.2.9 $SPNIUExtBwdT_t^{PDP}$, which designates the shadow price for the net *interchange schedule* limit constraint limiting increases in net imports between time-step $(t - 1)$ and time-step t;

10.2.2.10 $L30RP_{t,b}^{PDP}$, which designates the *locational marginal price* for *thirty-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$;

10.2.2.11 $L10NP_{t,b}^{PDP}$, which designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$; and

10.2.2.12 $L10SP_{t,b}^{PDP}$, which designates the *locational marginal price* for synchronized *ten-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$.

10.3 Variables

10.3.1 The *pre-dispatch calculation engi*ne shall use the constrained area conditions tests in sections 10.4 and 10.5 to identify the *resources* that are part of the following data sets:

10.3.1.1 $BCond_t^{NCA}$, which designates the *resources* in a *narrow constrained area* that must be checked for local market power for *energy* in time-step $t \in TS$;

10.3.1.2 $BCond_t^{DCA}$, which designates the *resources* in a *dynamic constrained area* that must be checked for local market power for *energy* in time-step $t \in TS$;

10.3.1.3 $BCond_t^{BCA}$, which designates the *resources* in a broad constrained area to be checked for local market power for *energy* in time-step $t \in TS$;

10.3.1.4 $BCond_t^{GMP}$, which designates the *resources* to be checked for global market power for *energy* in time-step $t \in TS$;

10.3.1.5 $BCond_t^{10S}$, which designates that *resources* to be checked for local market power for synchronized *ten-minute operating reserve* in time-step $t \in TS$;

10.3.1.6 $BCond_t^{10N}$, which designates that *resources* to be checked for local market power for non-synchronized *ten-minute operating reserve* in time-step $t \in TS$;

10.3.1.7 $BCond_t^{30R}$, which designates that *resources* to be checked for local market power for *thirty-minute operating reserve* in time-step $t \in TS$;

10.3.1.8 $BCond_t^{GMP10S}$, which designates that *resources* to be checked for global market power for synchronized *ten-minute operating reserve* in time-step $t \in TS$;

10.3.1.9 $BCond_t^{GMP10N}$, which designates that *resources* to be checked for global market power for non-synchronized *ten-minute operating reserve* in time-step $t \in TS$; and

10.3.1.10 $BCond_t^{GMP30R}$, which designates that *resources* to be checked for global market power for *thirty-minute operating reserve* in time-step $t \in TS$.

10.4 Constrained Area Conditions Test for Local Market Power (Energy)

10.4.1 Constrained Area Conditions Test for *narrow constrained areas* and *dynamic constrained area*

10.4.1.1 If at least one transmission constraint for a *narrow constrained area* or *dynamic constrained area* is binding in the Pre-Dispatch Pricing algorithm, then all *resources* identified within the *narrow constrained area* or *dynamic constrained area* shall undergo the applicable Conduct Test in section 11 and:

10.4.1.1.1 For each $n \in NCA$ and time-step $t \in TS$: For each transmission *facility* that transmits flow into n, $f \in F_n^{NCA}$, if $SPNormT_{t,f}^{PDP} \neq 0$ or $SPEmT_{t,c,f}^{PDP} \neq 0$ for the inbound flow limit, the *pre-dispatch calculation engine* will place n in the set NCA_t' and assign the *resources* in n to the set $BCond_t^{NCA}$; and

10.4.1.1.2 For each $d \in DCA$ and time-step $t \in TS$: For each transmission *facility* that transmits flow into d, $f \in F_d^{DCA}$, if $SPNormT_{t,f}^{PDP} \neq 0$ or $SPEmT_{t,c,f}^{PDP} \neq 0$ for the inbound flow limit, the *pre-dispatch calculation engine* will place d in the set DCA_t' and assign the *resources* in n to the set $BCond_t^{DCA}$.

10.4.1.2 Each *narrow constrained area* and *dynamic constrained area* that meets the criteria in section 10.4.1.1 shall be assigned to one of the following subsets, as appropriate:

10.4.1.2.1 NCA_t', which designates the *narrow constrained areas* that qualify for market power mitigation for *energy* in time-step $t \in TS$; and

10.4.1.2.2 DCA_t', which designates the *dynamic constrained areas* that qualify for market power mitigation for *energy* in time-step $t \in TS$.

10.4.2 Constrained Area Conditions Test for the Broad Constrained Area

10.4.2.1 If the congestion component of the *locational marginal price* of a *resource* is greater than $BCACondThresh$ and the *resource* is not part of a *narrow constrained area* or *dynamic constrained area* that has a binding transmission constraint, then the *resource* shall be tested using the broad constrained area thresholds. For each time-step $t \in TS$ and bus $b \in B^{DG}$ such that $b \notin BCond_t^{NCA} \cup BCond_t^{DCA}$, if $PCong_{t,b}^{PDP} > BCACondThresh$, the *pre-dispatch calculation engine* will then place *resource* b in the set $BCond_t^{BCA}$.

10.5 Constrained Area Conditions Test for Global Market Power (Energy)

10.5.1 The *pre-dispatch calculation engine* shall test *resources* that can meet incremental load within Ontario for global market power, subject to section 10.5.2, if:

10.5.1.1 the *intertie border prices* at the *global market power reference intertie zones* are greater than the $IBPThresh$ threshold value, indicated in time-step $t \in TS$ by:

10.5.1.1.1 $IntLMP_{t,d}^{PDP} > IBPThresh$ for *bids* and *offers*, $d \in D^{GMPRef}$, corresponding to the *boundary entity resource* bus for the *global market power reference intertie zones*; and

10.5.1.2 at least one of the following conditions is met:

10.5.1.2.1 import congestion, represented by a negative *intertie* congestion component, is present on all of the *global market power reference intertie zones*, indicated in time-steps $t = \{2,3\}$ by:

10.5.1.2.1.1 $PExtCong_{t,d}^{PDP} < 0$ for *bids* and *offers*, $d \in D^{GMPRef}$, corresponding to the *boundary entity resource* bus for the *global market power reference intertie zone*; or

10.5.1.2.1.2 the net *interchange schedule* limit is binding for imports, represented by a non-zero net *interchange schedule* limit shadow price for incremental imports, indicated in time-steps $t = \{2,3\}$ by:

$SPNIUExtBwdT_t^{PDP} \neq 0$

10.5.2 If the conditions in sections 10.5.1 are met, then the *pre-dispatch calculation engine* shall test *resources* that can meet incremental load within Ontario for global market power, for each time-step $t \in TS$, place all $b \in B^{DG}$ in the set $BCond_t^{GMP}$, unless they are excluded because one of the following two conditions:

10.5.2.1 the *resources* in any zone have congestion components at least \$1/MWh below the internal congestion component at all of the *global market power reference intertie zones*:

10.5.2.1.1 if $PCong_{t,b}^{PDP} < PIntCong_{t,d}^{PDP} - \$1/\mathrm{MWh}$ where $\mathrm{d} \in \mathrm{D}^{\mathrm{GMPRef}}$ is true for all *global market power reference intertie zones*, or

10.5.2.2 the *resources* cannot meet the incremental load because of a binding transmission constraint:

10.5.2.2.1 if *resources* cannot meet incremental load because of any binding transmission *facility* where $SPNormT_{t,f}^{PDP} \neq 0 \ or \ SPEmT_{t,c,f}^{PDP} \neq 0$.

10.6 Constrained Area Conditions Test for Local Market Power (Operating Reserve)

10.6.1 Subject to section 10.6.2, for a regional minimum requirement of greater than zero for a specific class of *operating reserve*, then all *resources* within the region with *offers* for classes of *operating reserve* that can satisfy the requirements of the specific class of *operating reserve* shall be tested for local market power:

10.6.1.1 if b is in a region with a non-zero minimum requirement, then b is subject to the Conduct Test and is placed in the set $BCond_t^{10S}$, $BCond_t^{10N}$,or $BCond_t^{30R}$

10.6.2 A *resource* shall not qualify for local market power mitigation testing for *operating reserve* if the *resource* is located in a region with a binding maximum constraint and for each *resource* $b \in B^{DG} \cup B^{DL}$ and time-step $t \in TS$:

10.6.2.1 if b is in a region with a binding maximum restriction constraint, then b is exempt from the Conduct Test.

10.7 Constrained Area Conditions Test for Global Market Power (Operating Reserve)

10.7.1 A *resource* shall be subject to global market power mitigation testing for *operating reserve* if its offers for a class of *operating reserve* where the *locational marginal price* for that class of *operating reserve* is greater than $ORGCondThresh$.

10.7.2 Subject to section 10.7.3, if the condition in section 10.7.1 has been met for a class of *operating reserve*, then all *resources* with offers for classes of *operating reserve* that can satisfy the requirements of that class of *operating reserve* shall be tested and for each $b \in B^{DG} \cup B^{DL}$ and time-step $t \in TS$:

10.7.2.1 if $L10SP_{t,b}^{PDP} > ORGCondThresh$, the *pre-dispatch calculation engine* shall add *resource b* to $BCond_t^{GMP10S}$;

10.7.2.2 if $L10NP_{t,b}^{PDP} > ORGCondThresh$, the *pre-dispatch calculation engine* shall add *resource b* to $BCond_t^{GMP10N}$; and

10.7.2.2 if $L30RP_{t,b}^{PDP} > ORGCondThresh$, the *pre-dispatch calculation engine* shall add *resource b* to $BCond_t^{GMP30R}$.

10.7.3 If a *resource* is located in a region with a binding regional maximum constraint, then the *resource* shall not qualify for global market power mitigation testing for *operating reserve*:

10.7.3.1 if b is in a region with a binding maximum constraint, then b shall be exempt from the Conduct Test.

10.8 Outputs

10.8.1 Outputs of the Constrained Area Conditions Test include the list of *resources* that will be subject to the Conduct Test in section 11 and the thresholds that will be used in the Conduct Test for those *resources*.

11 Conduct Test

11.1 Purpose

11.1.1 The Conduct Test shall verify whether the *financial dispatch data parameter* values submitted by *registered market participants* for *resources* identified in section 10.8.1 are within the applicable threshold level of the *reference level values* for those *resources*.

11.2 Information, Sets, Indices and Parameters

11.2.1 Information, sets, indices and parameters for the Conduct Test are described in sections 3 and 4. In addition, the list of *resources* produced pursuant to section 10.8.1 shall be used by the Conduct Test.

11.3 Variables

11.3.1 The *pre-dispatch calculation engine* shall apply the Conduct Test set out in sections 11.4 and 11.5 to the *resources* identified by the Constrained Area Conditions Test in accordance with section 10.8, to identify the following data sets:

11.3.1.1 The sets of *resources* that failed the Conduct Test for at least one *financial dispatch data parameter*, where:

11.3.1.1.1 BCT_t^{NCA} designates the *resources* in a *narrow constrained area* that failed the Conduct Test for at least one *financial dispatch data parameter* in time-step $t \in TS$;

11.3.1.1.2 BCT_t^{DCA} designates the *resources* in a *dynamic constrained area* that failed the Conduct Test for at least one *financial dispatch data parameter* in time-step $t \in TS$;

11.3.1.1.3 BCT_t^{BCA} designates the *resources* in a broad constrained area that failed the Conduct Test for at least one *financial dispatch data parameter* in time-step $t \in TS$;

11.3.1.1.4 BCT_t^{GMP} designates the *resources* that failed the global market power for *energy* Conduct Test for at least one *financial dispatch data parameter* in time-step $t \in TS$;

11.3.1.1.5 BCT_t^{ORL} designates the *resources* that failed the local market power for *operating reserve* Conduct Test for at least one *dispatch data* parameter in time-step $t \in TS$; and

11.3.1.1.6 BCT_t^{ORG} designates the *resources* that failed the global market power Conduct Test for *operating reserve* for at least one *financial dispatch data parameter* in time-step $t \in TS$.

11.3.1.2 The following *financial dispatch data parameters* for all time-steps $t \in TS$:

11.3.1.2.1 $PARAME_{t,b}$, which designates the set of *dispatch data* parameters that failed the *energy* Conduct Test at bus $b \in \{BCT_t^{NCA} \cup BCT_t^{DCA} \cup BCT_t^{BCA} \cup BCT_t^{GMP}\}$ in time-step *t*, and may include the following *financial dispatch data parameters*:

11.3.1.2.1.1 $EnergyOffer_k$, which designates a non-zero quantity of *energy* above the *minimum loading point* in association with *offer* lamination $k \in K_{t,b}^{E}$ failed the Conduct Test;

11.3.1.2.2 For all hours prior to and including the last hour where conditions are met for the *energy* Conduct Test:

11.3.1.2.2.1 $EnergyToMLP_k$, which designates the non-zero quantity of *energy* up to the *minimum loading point* in association with *offer* lamination $k \in K_{t,b}^{LTMLP}$ failed the Conduct Test;

11.3.1.2.2.2 $SUOffer$, which designates the *start-up offer* failed the Conduct Test; and

11.3.1.2.2.3 $SNLOffer$, which designates the *speed no-load offer* failed the Conduct Test.

11.3.1.2.3 $PARAMOR_{t,b}$ designates the set of *financial dispatch data parameter* that failed the *operating reserve* Conduct Test for bus $b \in \{BCT_t^{ORL} \cup BCT_t^{ORG}\}$ in time-step t, and may include the following *financial dispatch data parameter*:

11.3.1.2.3.1 $OR10SOffer_k$, which designates the non-zero quantity of synchronized *ten-minute operating reserve* in association with *offer* lamination $k \in K_{t,b}^{10S}$ failed the Conduct Test;

11.3.1.2.3.2 $OR10NOffer_k$, which designates the non-zero quantity of non-synchronized *ten-minute operating reserve* in associciation with *offer* lamination $k \in K_{t,b}^{10N}$ failed the Conduct Test; and

11.3.1.2.3.3 $OR30ROffer_k$, which designates the non-zero quantity of *thirty-minute operating reserve* in association with *offer* lamination $k \in K_{t,b}^{30R}$ failed the Conduct Test;

11.3.1.2.4 For all hours prior to and including the last hour where conditions are met for the *operating reserve* Conduct Test:

11.3.1.2.4.1 $SUOffer$, which designates the *start-up offer* failed the Conduct Test;

11.3.1.2.4.2 $SNLOffer$, which designates the *speed no-load offer* failed the Conduct Test; and

11.3.1.2.4.3 $EnergyToMLP_k$, which designates the non-zero quantity of up to the *minimum loading point* in association with *offer* lamination $k \in K_{t,b}^{E}$ failed the Conduct Test.

11.4 Conduct Test for Energy

11.4.1 The *pre-dispatch calculation engine* shall perform the Conduct Test for *energy* for *resources* in a *narrow constrained area* that were identified pursuant to section 10.8.1 as follows, subject to sections 11.4.2 and 11.4.3. For each time-step $t \in TS$ and $b \in BCond_t^{NCA}$, the *pre-dispatch calculation engine* shall:

11.4.1.1 Evaluate *energy offers* above *minimum loading point*: For all $k \in K_{t,b}^{E}$, if $PDG_{t,b,k} > min\ (PDGRef_{t,b,k`} + (abs(PDGRef_{t,b,k`}) *$

$CTEnThresh1^{NCA}$), $PDGRef_{t,b,k`} + CTEnThresh2^{NCA}$) , where $k' \in K'^{E}_{t,b}$, then the Conduct Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{NCA} and add $EnergyOffer_k$ to $PARAME_{t,b}$;

11.4.1.2 Evaluate *offers* for *energy* for the range of production up to *minimum loading point*: For all time-steps prior to and including the last time-step where conditions are met for the Constrained Area Conditions Test, for all $k \in K_{t,b}^{LTMLP}$, if $PLTMLP_{t,b,k} > CTEnMinOffer$ and $PLTMLP_{t,b,k} > min$ ($PLTMLPRef_{t,b,k`}$ + ($abs(PLTMLPRef_{t,b,k`}) * CTEnThresh1^{NCA}$), $PLTMLPRef_{t,b,k`} + CTEnThresh2^{NCA}$, where $k' \in K'^{E}_{t,b}$, then the Conduct Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{NCA} and add $EnergyToMLP_k$ to $PARAME_{t,b}$ and $PARAMOR_{t,b}$;

11.4.1.3 Evaluate *start-up offers*: For all time-steps prior to and including the last time-step t where conditions are met for the Constrained Area Conditions Test in section 10, if $SUDG_{t,b} > SUDGRef_{t,b} + (abs(SUDGRef_{t,b}) * CTSUThresh^{NCA})$, then the Conduct Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{NCA} and add $SUOffer$ to $PARAME_{t,b}$ and $PARAMOR_{t,b}$; and

11.4.1.4 Evaluate *speed no-load offers*: For all time-steps prior to and including the last time-step where conditions are met for the Constrained Area Conditions Test, if $SNL_{t,b} > SNLRef_{t,b} + (abs(SNLRef_{t,b}) * CTSNLThresh^{NCA})$, then the Conduct Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{NCA} and add $SNLOffer$ to $PARAME_{t,b}$ and $PARAMOR_{t,b}$.

11.4.2 For *resources* identified pursuant to section 10.8.1 in a *dynamic constrained area* or broad constrained area, the *pre-dispatch calculation engine* shall use the steps in section 11.4.1, using *resources* in $BCond_t^{DCA}$ or $BCond_t^{BCA}$, as the case may be, in place of $BCond_t^{NCA}$ and using the applicable Conduct Test thresholds $CTEnThresh1^{DCA}$, $CTEnThresh2^{DCA}$, $CTEnThresh1^{BCA}$, $CTEnThresh2^{BCA}$, $CTSUThresh^{DCA}$, $CTSUThresh^{BCA}$, $CTSNLThresh^{DCA}$, $CTSNLThresh^{BCA}$. If any of the *financial dispatch data parameters* of *a resource* fail the Conduct Test, the *resource* shall be assigned to subset BCT_h^{DCA} or BCT_h^{BCA}, as the case may be.

11.4.3 For *resources* identified pursuant to section 10.8.1 that were selected for global market power mitigation testing for *energy*, the *pre-dispatch calculation engine* shall use the steps in section 11.4.1, using *resources* in $BCond_t^{GMP}$ in place of $BCond_t^{NCA}$ and the applicable global market power Conduct Test thresholds $CTEnThresh1^{GMP}$, $CTEnThresh2^{GMP}$, $CTSUThresh^{GMP}$, $CTSNLThresh^{GMP}$. If any of the applicable *financial dispatch data parameters* of a *resource* fails the Conduct Test, the *resource* shall be assigned to subset BCT_h^{GMP}.

11.4.4 If a *resource* is assigned to more than one of the sets, $BCond_t^{NCA}$, $BCond_t^{DCA}$, $BCond_t^{BCA}$, and $BCond_t^{GMP}$, only the Conduct Test with the most restrictive threshold levels shall be performed for that *resource*.

11.5 Conduct Test for Operating Reserve

11.5.1 The *pre-dispatch calculation engine* shall perform the Conduct Test for local market power for *operating reserve* for *resources* that were identified pursuant to section 10.8.1, as follows, subject to 11.5.3. For each time-step $t \in TS$ and $b \in BCond_t^{10S} \cup BCond_t^{10N} \cup BCond_t^{30R}$, the *pre-dispatch calculation engine* shall:

11.5.1.1 Evaluate *offers* for *operating reserve* as follows:

11.5.1.1.1 for all $k \in K_{t,b}^{10S}$ such that $P10SDG_{t,b,k} > CTORMinOffer$ and $P10SDG_{t,b,k} >$ $min\,(P10SDGRef_{t,b,k`} + (abs(P10SDGRef_{t,b,k`}) * CTORThresh1^{ORL}), P10SDGRef_{t,b,k`} + CTORThresh2^{ORL})$, where $k' \in K_{h,b}^{'10S}$, then the Conduct Test was failed for the *resource* at bus b and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $OR10SOffer_k$ to $PARAMOR_{t,b}$;

11.5.1.1.2 for all $k \in K_{t,b}^{10N}$ such that $P10NDG_{t,b,k} > CTORMinOffer$ and $P10NDG_{t,b,k} > min\,(P10NDGRef_{t,b,k`} + (abs(P10NDGRef_{t,b,k`}) * CTORThresh1^{ORL}), P10NDGRef_{t,b,k`} + CTORThresh2^{ORL})$, where $k' \in K_{h,b}^{'10N}$, then the Conduct Test was failed for the *resource* at bus b and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $OR10NOffer_k$ to $PARAMOR_{t,b}$;

11.5.1.1.3 for all $k \in K_{t,b}^{30R}$ such that $P30RDG_{t,b,k} > CTORMinOffer$ and $P30RDG_{t,b,k} > min\,(P30RDGRef_{t,b,k`} + (abs(P30RDGRef_{t,b,k`}) * CTORThresh1^{ORL}), P30RDGRef_{t,b,k`} + CTORThresh2^{ORL})$, where $k' \in K_{h,b}^{'30R}$, then the Conduct Test was failed for the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $OR30ROffer_k$ to $PARAMOR_{t,b}$;

11.5.1.1.4 for all $j \in J_{t,b}^{10S}$ if $P10SDL_{t,b,j} > CTORMinOffer$ and $P10SDL_{t,b,j} > min(P10SDLRef_{t,b,j`} + (abs(P10SDLRef_{t,b,j`}) * CTORThresh1^{ORL}), P10SDLRef_{t,b,j`} + CTORThresh2^{ORL})$, where $j' \in J_{t,b}^{'10S}$, then the Conduct Test was failed for the *dispatchable load* at bus *b* and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $OR10SOffer_k$ to $PARAMOR_{t,b}$;

11.5.1.1.5 for all $j \in J_{t,b}^{10N}$ if $P10NDL_{t,b,j} > CTORMinOffer$ and $P10NDL_{t,b,j} > min(P10NDLRef_{t,b,j`} + (abs(P10NDLRef_{t,b,j`}) * CTORThresh1^{ORL}), P10NDLRef_{t,b,j`} + CTORThresh2^{ORL})$, where $j' \in J_{t,b}^{'10N}$, then the Conduct Test was failed for the *dispatchable load* at bus *b* and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $OR10NOffer_k$ to $PARAMOR_{t,b}$; and

11.5.1.1.6 for all $j \in J_{t,b}^{30R}$ if $P30RDL_{t,b,j} > CTORMinOffer$ and $P30RDL_{t,b,j} > min(P30RDLRef_{t,b,j`} + (abs(P30RDLRef_{t,b,j`}) * CTORThresh1^{ORL}), P30RDLRef_{t,b,j`} + CTORThresh2^{ORL})$, where $j' \in J_{t,b}^{'30R}$, then the Conduct Test was failed for the *dispatchable load* at bus b and the *day-ahead market calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $OR30ROffer_k$ to $PARAMOR_{t,b}$;

11.5.1.2 Evaluate *start-up offers*: For all time-steps prior to and including the last time-step where conditions are met for the Constrainted Area Conditions Test, if $SUDG_{t,b} > SUDGRef_{t,b} + (abs(SUDGRef_{t,b}) * CTSUThresh^{ORL})$, then the Conduct Test failed for the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $SUOffer$ to $PARAMOR_{t,b}$ and $PARAME_{t,b}$;

11.5.1.3 Evaluate *speed no-load offers*: For all time-steps prior to and including the last time-step where conditions are met for the Constrainted Area Conditions Test, if $SNL_{t,b} > SNLRef_{t,b} + (abs(SNLRef_{t,b}) * CTSNLThresh^{ORL})$, then the Conduct Test was failed for the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $SNLOffer$ to $PARAMOR_{t,b}$ and $PARAME_{t,b}$; and

11.5.1.4 Evaluate *offers* for *energy* for the range of production up to the *minimum loading point*: For all time-steps prior to and including the last time-step where conditions are met for the Constrainted Area Conditions Test, for all $k \in K_{t,b}^{LTMLP}$, if $PLTMLP_{t,b,k} > min\ (PLTMLPRef_{t,b,k`} + (abs(PLTMLPRef_{t,b,k`}) * CTEnThresh1^{ORL}), PLTMLPRef_{t,b,k`} + CTEnThresh2^{ORL})$, where $k' \in K'^{E}_{t,b}$, then the Conduct Test was failed for the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BCT_t^{ORL} and add $EnergyToMLP_k$ to $PARAMOR_{t,b}$ and $PARAME_{t,b}$.

11.5.2 The *pre-dispatch calculation engine* shall perform the Conduct Test for global market power for *operating reserve* for *resources* that were identified pursuant to section 10.8.1. The *pre-dispatch calculation engine* shall use the steps set out in section 11.5.1 using *resources* in $BCond_t^{GMP10S}$, $BCond_t^{GMP10N}$, and $BCond_t^{GMP30R}$ in place of $BCond_t^{10S}$, $BCond_t^{10N}$, and $BCond_t^{30R}$, respectively, and the applicable Conduct Test thresholds ($CTORThresh1^{ORG}$, $CTORThresh2^{ORG}$, $CTSUThresh^{ORG}$, $CTSNLThresh^{ORG}$, $CTEnThresh1^{ORG}$, $CTEnThresh2^{ORG}$). The *resources* shall be assigned to the subset BCT_h^{ORG}.

11.5.3 If a *resource* is assigned to more than one of $BCond_t^{GMP10S}$, $BCond_t^{GMP10N}$, and $BCond_t^{GMP30R}$, only the Conduct Test with the most restrictive threshold levels shall be performed for that *resource*.

11.6 Outputs

11.6.1 Subject to section 11.6.2, the outputs of the Conduct Test shall include the following for each time-step $t \in TS$:

11.6.1.1 The set of *resources* that failed the Conduct Test for at least one *financial dispatch data parameter* by condition type;

11.6.1.2 The *financial dispatch data parameters* that failed the Conduct Test for the *resource* at bus b; and

11.6.1.3 A revised set of *financial dispatch data parameters* replaced with *reference level values* for *resources* that:

11.6.1.3.1 has one or more *financial dispatch data parameters* that failed a Conduct Test for the current *pre-dispatch calculation engine* run; and

11.6.1.3.2 has one or more *financial dispatch data parameter*s that failed both the Conduct Test and failed the Price Impact Test in previous *pre-dispatch calculation engine* runs.

11.6.1.4 For *offers* for *energy* and *operating reserve* with multiple laminations:

11.6.1.4.1 if the *offer* lamination for *energy* that corresponds to the *minimum loading point* fails the Conduct Test, the *pre-dispatch calculation engine* shall replace all *offer* laminations for *energy* up to the *minimum loading point*;

11.6.1.4.2 if one or more offer laminations for *energy* above the *minimum loading point* fails the Conduct Test, the *pre-dispatch calculation engine* shall replace all *offer* laminations for *energy* up to and above the *minimum loading point*; and

11.6.1.4.3 if one or more *offer* laminations for *operating reserve* fails the Conduct Test, the *pre-dispatch calculation engine* shall replace all *offer* laminations for *operating reserve.*

11.6.1.5 For a *non-quick start resource* whose *start-up offer* failed the Conduct Test, identified in section 11.6.1.1, the *pre-dispatch calculation engine* shall use the *start-up offer reference level value* to evaluate any advancements pursuant to section 5.7.

11.6.2 The *pre-dispatch calculation engine* shall not replace the *financial dispatch data parameter* for a *resource* with that *resource's* applicable *reference level value* if the *financial dispatch data parameter* is less than the corresponding *reference level value*.

12 Reference Level Scheduling

12.1 Purpose

12.1.1 The *pre-dispatch calculation engine* shall perform the Reference Level Scheduling algorithm where at least one *financial dispatch data parameter* for a *resource* failed the Conduct Test in section 11.

12.1.2 The Reference Level Scheduling algorithm shall perform a *security*-constrained unit commitment and economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants*, including *reference level value* for *resources* subject to 14.7.1.3 and 12.2.2, to meet the *IESO's* province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the pre-dispatch look-ahead period.

12.2 Information, Sets, Indices and Parameters

12.2.1 Information, sets, indices and parameters used by the Reference Level Scheduling algorithm are described in section 3 and section 4. In addition, the list of *resources* that failed the Conduct Test from section 11.6.1.1 and a revised set of *financial dispatch data parameters* from section 11.6.1.3, for those *resources* shall be used by the Reference Level Scheduling algorithm

12.2.2 The Reference Level Scheduling algorithm shall use the *reference level value* that corresponds to any *financial dispatch data parameter* submitted for a *resource* that failed the Conduct Test.

12.3 Variables and Objective Function

12.3.1 The *pre-dispatch calculation engine* shall solve for the variables listed in section 8.3.1.

12.3.2 The objective function for the Reference Level Scheduling algorithm shall be the same as the objective function in section 8.3.2, subject to section 12.4.

12.4 Constraints

12.4.1 The constraints in sections 8.4 through 8.7 apply in the Reference Level Scheduling algorithm, except that the sensitivities and limits considered for IESO internal transmission limits shall be those provided by the most recent *security* assessment function iteration of the Reference Level Scheduling algorithm.

12.5 Outputs

12.5.1 Outputs of the Reference Level Scheduling algorithm include *resource* schedules and commitments.

13 Reference Level Pricing

13.1 Purpose

13.1.1 The *pre-dispatch calculation engine* shall perform the Reference Level Pricing algorithm whenever the Reference Level Scheduling algorithm has been performed.

13.1.2 The Reference Level Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants*, *reference level value* for r*esources* subject to 14.7.1.3 and 13.2.2, and *resource* schedules and commitments produced by the Reference Level Scheduling algorithm, to meet the *IESO's* province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each hour of the pre-dispatch look-ahead period.

13.2 Information, Sets, Indices and Parameters

13.2.1 Information, sets, indices and parameters used by the Reference Level Pricing algorithm are described in sections 3 and 4. In addition, the following *resource* schedule and commitments from the Reference Level Scheduling algorithm shall be used by the Reference Level Pricing algorithm:

13.2.1.1 $SDG_{t,b,k}^{RLS}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide above $MinQDGC_b$ at bus

$b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{E}$;

13.2.1.2 $ODG_{t,b}^{RLS}$, which designates whether a *dispatchable generation resource* at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in time-step $t \in TS$;

13.2.1.3 $S10SDG_{t,b,k}^{RLS}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{10S}$;

13.2.1.4 $S10NDG_{t,b,k}^{RLS}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable* generation *resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{10N}$;

13.2.1.5 $S30RDG_{t,b,k}^{RLS}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable* generation *resource* is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in time-step $t \in TS$ in association with lamination $k \in K_{t,b}^{30R}$; and

13.2.1.6 $OHO_{t,b}^{RLS}$, which designates whether the *dispatchable* hydroelectric *generation resource* at but $b \in B^{HE}$ has been scheduled at or above $MinHO_{t,b}$ in time-step $t \in TS$.

13.2.2 The Reference Level Pricing algorithm shall use *a resource's reference level value* for any *financial dispatch data parameters* submitted by *registered market participants* that failed the Conduct Test in Section 11.

13.3 Variables and Objective Function

13.3.1 The *pre-dispatch calculation engine* shall solve for the variables set out in section 9.3.1.

13.3.2 The objective function used in the Reference Level Pricing algorithm shall be the same as the objective function set out in section 9.3.2, subject to section 13.4.

13.4 Constraints

13.4.1 The constraints that apply in the Reference Level Pricing algorithm shall be the same as the constraints in sections 9.4 through 9.8, with the following exceptions:

13.4.1.1 the marginal loss factors used in the *energy* balance constraint in section 9.7.1 shall be fixed to the marginal loss factors used in the last optimization function iteration of the Reference Level Scheduling alogorithm;

13.4.1.2 the sensitivities and limits in section 9.7.3 shall be replaced with the most recent *security* assessment function iteration of the Reference Level Pricing algorithm; and

13.4.1.3 for the constraints in section 9.8, the outputs from the Pre-Dispatch Scheduling algorithm shall be replaced with the outputs from the Reference Level Scheduling algorithm as follows:

13.4.1.3.1 $SDG_{t,b,k}^{PDS}$ shall be replaced by $SDG_{t,b,k}^{RLS}$ for all $t \in TS$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{t,d}^{E}$;

13.4.1.3.2 $ODG_{t,b}^{PDS}$ shall be replaced by $ODG_{t,b}^{RLS}$ for all $t \in TS$, $b \in B^{DG}$;

13.4.1.3.3 $IDG_{t,b}^{PDS}$ shall be replaced by $IDG_{t,b}^{RLS}$ for all $t \in TS$, $b \in B^{DG}$;

13.4.1.3.4 $\mathrm{S10SDG}_{t,b,k}^{PDS}$ shall be replaced by $\mathrm{S10SDG}_{t,b,k}^{RLS}$ for all $t \in TS$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{t,b}^{10S}$;

13.4.1.3.5 $\mathrm{S10NDG}_{t,b,k}^{PDS}$ shall be replaced by $\mathrm{S10NDG}_{t,b,k}^{RLS}$ for all $t \in TS$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{t,b}^{10N}$;

13.4.1.3.6 $S30RDG_{t,b,k}^{PDS}$ shall be replaced by $S30RDG_{t,b,k}^{RLS}$ for all $t \in TS$, $b \in B^{ELR} \cup B^{HE}$, $k \in K_{t,b}^{30R}$; and

13.4.1.3.7 $OHO_{t,b}^{PDS}$ shall be replaced by $OHO_{t,b}^{RLS}$ for all $t \in TS$, $b \in B^{HE}$.

13.5 Outputs

13.5.1 Outputs of the Reference Level Pricing algorithm include the following:

13.5.1.1 shadow prices; and

13.5.1.2 *locational marginal prices* and their components.

14 Price Impact Test

14.1 Purpose

14.1.1 The *pre-dispatch calculation engine* shall perform the Price Impact Test whenever at least one *financial dispatch data parameter* for a *resource* failed the Conduct Test.

14.1.2 The Price Impact Test shall:

14.1.2.1 compare the *locational marginal prices* for *energy* or *operating reserve* produced by the Pre-Dispatch Pricing algorithm with those produced by the Reference Level Pricing algorithm; and

14.1.2.2 consider the corresponding *offer* parameters to have failed the price impact test if the difference in price in section 14.1.2.1 is greater than the applicable impact threshold in section 4.3.9.

14.2 Information, Sets, Indices and Parameters

14.2.1 Information, sets, indices and parameters for the Price Impact Test are described in sections 3 and 4. In addition, the following *locational marginal prices* from the Pre-Dispatch Pricing algorithm and the Reference Level Pricing algorithm shall be used:

14.2.1.1 $LMP_{t,b}^{PDP}$, which designates the *locational marginal price* for *energy* at bus $b \in B$ in time-step $t \in TS$ from the Pre-Dispatch Pricing algorithm;

14.2.1.2 $L30RP_{t,b}^{PDP}$, which designates the *locational marginal price* for *thirty-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$ from the Pre-Dispatch Pricing algorithm;

14.2.1.3 $L10NP_{t,b}^{PDP}$, which designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$ from the Pre-Dispatch Pricing algorithm;

14.2.1.4 $L10SP_{t,b}^{PDP}$, which designates the *locational marginal price* for synchronized *ten-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$ from the Pre-Dispatch Pricing algorithm;

14.2.1.5 $LMP_{t,b}^{RLP}$, which designates the *locational marginal price* for energy at bus $b \in B$ in time-step $t \in TS$ from the Reference Level Pricing algorithm;

14.2.1.6 $L30RP_{t,b}^{RLP}$, which designates the *locational marginal price* for *thirty-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$ from the Reference Level Pricing algorithm;

14.2.1.7 $L10NP_{t,b}^{RLP}$, which designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$ from the Reference Level Pricing algorithm; and

14.2.1.8 $L10SP_{t,b}^{RLP}$, which designates the *locational marginal price* for synchronized *ten-minute operating reserve* at bus $b \in B$ in time-step $t \in TS$ from the Reference Level Pricing algorithm.

14.3 Variables

14.3.1 The *pre-dispatch calculation engine* shall apply the Price Impact Test as set out in sections 14.4 and 14.5 for the *resources* identified in accordance with section 10.3.1, to identify:

14.3.1.1 A set of *resources* that failed the Price Impact Test for each condition for all time-steps $t \in TS$, where:

14.3.1.1.1 BIT_t^{NCA} designates the *resources* in a *narrow constrained area* that failed the Price Impact Test for the *locational marginal price* for *energy*;

14.3.1.1.2 BIT_t^{DCA} designates the *resources* in a *dynamic constrained area* that failed the Price Impact Test for *energy locational marginal price*;

14.3.1.1.3 BIT_t^{BCA} designates the *resources* in a broad constrained area that failed Price Impact Test for *energy locational marginal price*;

14.3.1.1.4 BIT_t^{GMP} designates the *resources* that failed the Global Market Power (*energy*) Price Impact Test for *energy locational marginal price*;

14.3.1.1.5 BIT_t^{ORL} designates the *resources* that failed the Local Market Power (*operating reserve*) Price Impact Test for at least one type of *operating reserve locational marginal price*;

14.3.1.1.6 BIT_t^{ORG} designates the *resources* that failed the Global Market Power (*operating reserve*) Price Impact Test for at least one type of *operating reserve locational marginal price*; and

14.3.1.1.7 $LMPIT_{t,b}$ designates the *locational marginal price* that failed the Price Impact Test for bus $b \in BIT_t^{NCA} \cup BIT_t^{DCA} \cup BIT_t^{BCA} \cup BIT_t^{GMP} \cup BIT_t^{ORL} \cup BIT_t^{ORG}$ in time-step $t \in TS$ and

14.3.1.2 *Locational marginal prices* for *energy* and *operating reserve* for each *resource* at bus $b \in B^{DG} \cup B^{DL}$ that failed the Price Impact Test, where:

14.3.1.2.1 $EnergyLMP$ designates that the *locational marginal price* for *energy* failed the Price Impact Test;

14.3.1.2.2 $OR10SLMP$ designates that the synchronized *ten-minute operating reserve locational marginal price* failed the Price Impact Test;

14.3.1.2.3 $OR10NLMP$ designates that the non-synchronized *ten-minute operating reserve locational marginal price* failed the Price Impact Test; and

14.3.1.2.4 $OR30RLMP$ designates that the *thirty-minute operating reserve locational marginal price* failed the Price Impact Test.

14.4 Price Impact Test for Energy

14.4.1 The *pre-dispatch calculation engine* shall perform the Price Impact Test for *resources* that were identified in the corresponding Conduct Test for *energy* in section 11.6.1.1, as follows:

14.4.1.1 For local market power for *energy*:

14.4.1.1.1 For each time-step $t \in TS$ and $b \in BCT_t^{NCA}$, if $LMP_{t,b}^{PDP} > min(LMP_{t,b}^{RLP} + (abs(LMP_{t,b}^{RLP}) * ITThresh1^{NCA}), LMP_{t,b}^{RLP} + ITThresh2^{NCA})$, the Price Impact Test was failed by the *resource* at bus b and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{NCA} and add $EnergyLMP$ to $LMPIT_{t,b}$;

14.4.1.1.2 For each time-step $t \in TS$ and $b \in BCT_t^{DCA}$, if $LMP_{t,b}^{PDP} > min(LMP_{t,b}^{RLP} + (abs(LMP_{t,b}^{RLP}) * ITThresh1^{DCA}), LMP_{t,b}^{RLP} + ITThresh2^{DCA})$, the Price Impact Test was failed by the *resource* at bus b and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{DCA} and add $EnergyLMP$ to $LMPIT_{t,b}$; and

14.4.1.1.3 For each time-step $t \in TS$ and $b \in BCT_t^{BCA}$, if $LMP_{t,b}^{PDP} > min(LMP_{t,b}^{RLP} + (abs(LMP_{t,b}^{RLP}) * ITThresh1^{BCA}), LMP_{t,b}^{RLP} + ITThresh2^{BCA})$, the Price Impact Test was failed by the *resource* at bus b and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{BCA} and add $EnergyLMP$ to $LMPIT_{t,b}$; and

14.4.1.2 For global market power for *energy*:

14.4.1.2.1 For each time-step $t \in TS$ and $b \in BCT_t^{GMP}$, if $LMP_{t,b}^{PDP} > min(LMP_{t,b}^{RLP} + (abs(LMP_{t,b}^{RLP}) * ITThresh1^{GMP}), LMP_{t,b}^{RLP} + ITThresh2^{GMP})$, the Price Impact Test was failed by the *resource* at bus b and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{GMP} and add $EnergyLMP$ to $LMPIT_{t,b}$.

14.5 Price Impact Test for Operating Reserve

14.5.1 The *pre-dispatch calculation engine* shall perform the Price Impact Test for *resources* that were identified in the corresponding Conduct Test for *operating reserve* in section 11.6.1.1, as follows:

14.5.1.1 For local market power for *operating reserve*, for each time-step $t \in TS$ and $b \in BCT_t^{ORL}$:

14.5.1.1.1 If $L30RP_{t,b}^{PDP} > L30RP_{t,b}^{RLP}$, then the Price Impact Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{ORL} and add $OR30RLMP$ to $LMPIT_{t,b}$;

14.5.1.1.2 If $L10NP_{t,b}^{PDP} > L10NP_{t,b}^{RLP}$, then the Price Impact Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{ORL} and add $OR10NLMP$ to $LMPIT_{t,b}$; and

14.5.1.1.3 If $L10SP_{t,b}^{PDP} > L10SP_{t,b}^{RLP}$, then the Price Impact Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{ORL} and add $OR10SLMP$ to $LMPIT_{t,b}$; and

14.5.1.2 For global market power for *operating reserve*, for each time-step $t \in TS$ and $b \in BCT_t^{ORG}$:

14.5.1.2.1 If $L30RP_{t,b}^{PDP} > min(L30RP_{t,b}^{RLP} + (abs(L30RP_{t,b}^{RLP}) * ITThresh1^{ORG}), L30RP_{t,b}^{RLP} + ITThresh2^{ORG})$, then the Price Impact Test was failed by *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{ORG} and add $OR30RLMP$ to $LMPIT_{t,b}$;

14.5.1.2.2 If $L10NP_{t,b}^{PDP} > min(L10NP_{t,b}^{RLP} + (abs(L10NP_{t,b}^{RLP}) * ITThresh1^{ORG}), L10NP_{t,b}^{RLP} + ITThresh2^{ORG})$, then the Price Impact Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign the *resource* to subset BIT_t^{ORG} and add $OR10NLMP$ to $LMPIT_{t,b}$; and

14.5.1.2.3 If $L10SP_{t,b}^{PDP} > min(L10SP_{t,b}^{RLP} + (abs(L10SP_{t,b}^{RLP}) * ITThresh1^{ORG}), L10SP_{t,b}^{RLP} + ITThresh2^{ORG})$, then the Price Impact Test was failed by the *resource* at bus *b* and the *pre-dispatch calculation engine* shall assign *resource* to subset BIT_t^{ORG} and add $OR10SLMP$ to $LMPIT_{t,b}$.

14.6 Revised Financial Dispatch Data Parameter Determination

14.6.1 A *resource* that fails the Price Impact Test in a time-step (t) shall have its *financial dispatch data parameters* revised as follows:

14.6.1.1 If the *resource* has failed a Price Impact Test for *energy* and is in BIT_t^{NCA}, BIT_t^{DCA}, BIT_t^{BCA}, BIT_t^{GMP}, the *financial dispatch data parameters* in $\mathrm{PARAME}_{t,b}$ shall be used to determine the *financial dispatch data parameters* that shall be replaced with the *resource's* applicable *reference level value*.

14.6.1.2 If the *resource* has failed a Price Impact Test for *operating reserve* and is in BIT_t^{ORL} or BIT_t^{ORG}, the *financial dispatch data parameters* in $PARAMOR_{t,b}$ shall be used to determine the *financial dispatch data parameters* that shall be replaced with the *resource's* applicable *reference level value*.

14.6.1.3 If a non-*quick-start resource* has failed a Price Impact Test in any time-step, the *commitment cost parameters* (*start-up offer*, *speed-no-load offer*, or *energy offer* associated with the *minimum loading point*) that failed the corresponding Conduct Test shall be replaced with the *resource's* applicable *reference level value* for that time-step. For any time-steps prior, any *commitment cost parameters* for that *resource* that failed the Conduct Test shall be replaced with the *resource's* applicable *reference level value* in those time-steps. This is expressed as:

14.6.1.3.1 For each time-step $t \in TS$ and all $b \in B^{NQS} \cap (BIT_t^{NCA} \cup BIT_t^{DCA} \cup BIT_t^{BCA} \cup BIT_t^{GMP})$, for hours prior to and including the hour that failed the Price Impact Test, $T \in \{1,..,t\}$, if $b \in BCT_T^{NCA} \cup BCT_T^{DCA} \cup BCT_T^{BCA} \cup BCT_T^{GMP}$ and $PARAME_{T,b}$ contains any of the *commitment cost parameters SUOffer*, *SNLOffer*, or

EnergyToMLP$_k$, replace these parameters with *reference level values*.

14.6.1.4 Section 14.6.1.3 shall apply to the tests for local market power and global market power for *operating reserve*, except $PARAMOR_{T,b}$ shall be checked in place of $PARAME_{T,b}$.

14.6.1.5 If a *resource* is in a *narrow constrained area* or a *dynamic constrained area* and has failed a Price Impact Test, each *resource* in the same *narrow constrained area* or *dynamic constrained area* that also failed the corresponding Conduct Test shall have its *offer* data replaced with its applicable *reference level value* for that hour. For each time-step $t \in TS$:

14.6.1.5.1 if BIT_t^{NCA} includes one or more *resources* in a *narrow constrained area*, *n*, each *resource* $\mathrm{b} \in \mathrm{BCT_t^{NCA}}$ for *narrow constrained area*, *n*, shall have the parameters in $\mathrm{PARAME_{t,b}}$ replaced with its *reference level values*; and

14.6.1.5.2 if BIT_t^{DCA} includes one or more *resources* in a *dynamic constrained area*, *d*, each *resource* $b \in BCT_t^{DCA}$ for *dynamic constrained area*, d, shall have the parameters in $\mathrm{PARAME_{t,b}}$ replaced with its *reference level values*.

14.6.1.6 If a *non-quick-start resource* in a *narrow constrained area* or a *dynamic constrained area* has failed a Price Impact Test, each *non-quick-start resource* in the *narrow constrained area* or *dynamic constrained area* that also failed the corresponding Conduct Test shall have its commitment cost parameters replaced with its applicable *reference level value* for that time-step. For any time-steps prior, if a *non-quick-start resource* in that *narrow constrained area* or *dynamic constrained area* has a commitment cost parameter that failed the Conduct Test, that commitment cost parameter shall be replaced with the *resource's* applicable *reference level* value in those time-steps. This is expressed as:

14.6.1.6.1 For all time-steps up to the time-step in which a *resource* failed the Price Impact Test for a *narrow constrained area* , for all $b \in BCT_t^{NCA}$, if $PARAME_{t,b}$ contains any of the *commitment cost parameters*

$SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with *reference level values*.

14.6.1.6.2 For all time-steps up to the time-step in which a *resource* failed the Price Impact Test for a *dynamic constrained area*, for all $b \in BCT_t^{DCA}$, if $PARAME_{t,b}$ contains any of the *commitment cost parameters* $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with *reference level values*.

14.6.1.7 If a *resource* fails the local market power for *operating reserve* Price Impact Test, all *resources* in the same *operating reserve* region with a non-zero *operating reserve* minimum requirement that failed the corresponding Conduct Test for at least one parameter shall have the parameter that failed the Conduct Test replaced with the *resource's* applicable *reference level value* for that hour. This is expressed as:

14.6.1.7.1 For each time-step $t \in TS$, if BIT_t^{ORL} includes one or more *resource* in *operating reserve* region, r, all *resources*, $b \in BIT_t^{ORL}$ for *operating reserve* region r, shall have the parameters in $PARAMOR_{t,b}$ replaced with *reference level values*.

14.6.1.8 If a *non-quick-start resource* fails the local market power for *operating reserve* Price Impact Test in any time-step, the *commitment cost parameters* for all *non-quick-start resources* in the same *operating reserve* region with a non-zero *operating reserve* minimum requirement that failed the corresponding Conduct Test shall be replaced with the *resource's* applicable *reference level value* for that time-step. For any time-steps prior, any *commitment cost parameters* of *non-quick-start resources* that failed the Conduct Test shall be replaced with the *resource's* applicable *reference level value* in those time-steps. This is expressed as:

14.6.1.8.1 For all time-steps up to the time-step in which a *resource* failed the Price Impact Test for r, for all $b \in BCT_t^{ORL}$, if $PARAME_{t,b}$ contains any of the *commitment cost parameters* $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with *reference level values*.

14.7 Outputs

14.7 The *pre-dispatch calculation engine* shall prepare the following outputs, subject to section 14.7.2, for each time-step $t \in TS$:

14.7.1.1 The set of *resources* that failed the Price Impact Test for all time-steps in the pre-dispatch look ahead period, by condition, in acordance to sections 14.4 and 14.5. Those *resources* shall be added to the accumulated set of *resources* from previous *pre-dispatch calculation engine* runs which failed the Price Impact Test in the current time-step $t \in TS$;

14.7.1.2 The *locational marginal prices* for *energy* and *operating reserve* that failed the Price Impact Test for each *resource* at bus b in acordance to sections 14.4 and 14.5;

14.7.1.3 A revised set of *offer* data to be used by the next *pre-dispatch calculation engine* run and next real-time hour. The revised set of offer data will be for the *resources* that failed the Price Impact Test:

14.7.1.3.1 in current *pre-dispatch calculation engine* run replacing *offer* data that failed the Conduct Test with the applicable *reference level values*, in accordance with section 14.6; and

14.7.1.3.2 in previous *pre-dispatch calculation engine* runs with *financial dispatch data parameters* that were decided to be mitigated in previous *pre-dispatch calculation engine* runs replaced with *reference level values*.

14.7.2 The *pre-dispatch calculation engine* shall not replace *financial dispatch data parameters* from a *resource* with that *resource's* applicable *reference level value* if the *financial dispatch data parameters* is less than the *reference level value*.

15 Pseudo-Unit Modelling

15.1 Pseudo-Unit Model Parameters

15.1.1 The *pre-dispatch calculation engine* shall use the following registration and daily *dispatch data* to determine the underlying relationship between a *pseudo-unit* and the associated physical *resources* for a *combined cycle plant* with K combustion turbine *resources* and one steam turbine *resource*:

15.1.1.1 $CMCR_k$ designates the registered *maximum continuous rating* of combustion turbine *resource* $k \in \{1,..,K\}$ in MW;

15.1.1.2 $CMLP_k$ designates the *minimum loading point* of combustion turbine *resource* $k \in \{1,..,K\}$ in MW;

15.1.1.3 $SMCR$ designates the registered *maximum continuous rating* of the steam turbine *resource* in MW;

15.1.1.4 $SMLP$ designates the *minimum loading point* of the steam turbine *resource* in MW for a 1x1 configuration;

15.1.1.5 SDF designates the amount of duct firing capacity available on the steam turbine *resource* in MW;

15.1.1.6 $STPortion_k$ designates the percentage of the steam turbine *resource* capacity attributed to *pseudo-unit* $k \in \{1,..,K\}$; and

15.1.1.7 $CSCM_k \in \{0,1\}$ designates whether *pseudo-unit* $k \in \{1,..,K\}$ is flagged to operate in *single cycle mode*, subject to section 15.5.

15.1.2 The *pre-dispatch calculation engine* shall calculate the following model parameters for each *pseudo-unit* $k \in \{1,..K\}$:

15.1.2.1 $MMCR_k$ designates the maximum continuous rating of *pseudo-unit k* and is calculated as follows:

$$CMCR_k \;+\; SMCR \cdot STPortion_k \cdot (1 - CSCM_k)$$

15.1.2.2 $MMLP_k$ designates the *minimum loading point* of *pseudo-unit k* and is calculated as follows:

$$CMLP_k \;+\; SMLP \cdot (1 - CSCM_k)$$

15.1.2.3 MDF_k designates the duct firing capacity of *pseudo-unit k* and is calculated as follows:

$$SDF \cdot STPortion_k \cdot (1 - CSCM_k)$$

15.1.2.4 MDR_k designates the *dispatchable* capacity of *pseudo-unit k* and is calculated as follows:

$$MMCR_k \;- MMLP_k - MDF_k$$

15.1.3 The *pre-dispatch calculation engine* shall define three operating regions of *pseudo-unit* $k \in \{1,..K\}$, as follows:

15.1.3.1 The *minimum loading point* region shall be the capacity between 0 and $MMLP_k$;

15.1.3.2 The *dispatchable* region shall be the capacity between $MMLP_k$ and $MMLP_k + MDR_k$;

15.1.3.3 The duct firing region shall be the capacity between $MMLP_k + MDR_k$ and $MMCR_k$.

15.1.4 The *pre-dispatch calculation engine* shall calculate the associated combustion turbine *resource* and steam turbine *resource* shares for the three operating regions of *pseudo-unit* $k \in \{1,..K\}$, as follows:

15.1.4.1 For the *minimum loading point* region:

15.1.4.1.1 Steam turbine *resource* share:

$$STShareMLP_k = \frac{SMLP \cdot (1 - CSCM_k)}{MMLP_k};$$

15.1.4.1.2 Combustion turbine *resource* share:

$$CTShareMLP_k = \frac{CMLP_k}{MMLP_k};$$ and

15.1.4.2 For the *dispatchable* region:

15.1.4.2.1 Steam turbine *resource* share:

$$STShareDR_k = \frac{(1 - CSCM_k)(SMCR \cdot STPortion_k - SMLP - SDF \cdot STPortion_k)}{MDR_k};$$

and

15.1.4.2.2 Combustion turbine *resource* share:

$$CTShareDR_k = \frac{CMCR_k - CMLP_k}{MDR_k};$$ and

15.1.4.3 For the duct firing region:

15.1.4.3.1 Steam turbine resource share shall be equal to 1; and

15.1.4.3.2 Combustion turbine *resource* share shall be equal to 0.

15.2 Application of Physical Resource Deratings to the Pseudo-Unit Model

15.2.1 The *pre-dispatch calculation engine* shall apply deratings submitted by *market participants* to the applicable *dispatchable* capacity and duct firing capacity parameters for a *pseudo-unit*, where:

15.2.1.1 $CTCap_{t,k}$ designates the capacity of combustion turbine *resource* $k \in \{1,..,K\}$ in time-step t as determined by submitted deratings;

15.2.1.2 $STCap_t$ designates the capacity of the steam turbine *resource* in time-step t as determined by submitted deratings; and

15.2.1.3 $TotalQ_{t,k}$ designates the total quantity of *energy* for *pseudo-unit* $k \in \{1,..,K\}$ in time-step t.

15.2.2 The *pre-dispatch calculation engine* shall solve for the following operating region parameters for each *pseudo-unit* $k \in \{1,..,K\}$:

15.2.2.1 $MLP_{t,k}$, which designates the *minimum loading point* of *pseudo-unit k* in time-step t;

15.2.2.2 $DR_{t,k}$, which designates the *dispatchable* region capacity of *pseudo-unit* k in time-step t; and

15.2.2.3 $DF_{t,k}$, which designates the duct firing region capacity of *pseudo-unit* k in time-step t.

15.2.3 Pre-Processing of De-rates

15.2.3.1 The *pre-dispatch calculation engine* shall perform the following pre-processing steps to determine the available operating regions for a *pseudo-unit* based on the combustion turbine *resource's* and steam turbine *resource's* share and the application of the *pseudo-unit* deratings. For *pseudo-unit* $k \in \{1,..,K\}$ for time-step $t \in TS$:

15.2.3.1.1 Step 1: Calculate the amount of *offered energy* attributed to each combustion turbine *resource* ($CTAmt_{t,k}$) and steam turbine *resource* portion ($STAmt_{t,k}$):

If $TotalQ_{t,k} < MMLP_k$ then:

Calculate $CTAmt_{t,k} = 0; and$

Calculate $STAmt_{t,k} = 0$.

Otherwise:

$CTAmtMLP = MMLP_k \cdot CTShareMLP_k$; and

$STAmtMLP = MMLP_k \cdot STShareMLP_k$.

If $TotalQ_{t,k} > MMLP_k + MDR_k$, then:

$CTAmtDR = MDR_k \cdot CTShareDR_k$;

$STAmtDR = MDR_k \cdot STShareDR_k$; and

$STAmtDF = (1 - CSCM_k) \cdot (TotalQ_{t,k} - MMLP_k - MDR_k)$.

Otherwise:

$CTAmtDR = (TotalQ_{t,k} - MMLP_k) \cdot CTShareDR_k$;

$STAmtDR = (TotalQ_{t,k} - MMLP_k) \cdot STShareDR_k$;

$STAmtDF = 0$;

$CTAmt_{t,k} = CTAmtMLP + CTAmtDR$; and

$STAmt_{t,k} = STAmtMLP + STAmtDR + STAmtDF$.

15.2.3.1.2 Step 2: Allocate the steam turbine *resource's* capacity to each *pseudo-unit*:

$$PRSTCap_{t,k} = \left(\frac{STAmt_{t,k}}{\sum_{w \in \{1,..,K\}} STAmt_{t,w}}\right) \cdot STCap_t$$

15.2.3.1.3 Step 3: Determine if the *pseudo-unit* is available:

If $CTAmt_{t.k} < CMLP_k$, then the *pseudo-unit* is unavailable.

If $STAmt_{t,k} < SMLP \cdot (1 - CSCM_k)$, then the *pseudo-unit* is unavailable.

If $CTCap_{t,k} < CMLP_k$, then the *pseudo-unit* is unavailable.

If $PRSTCap_{t,k} < SMLP \cdot (1 - CSCM_k)$, then the *pseudo-unit* is unavailable.

15.2.3.1.4 Step 4: Initialize the operating region parameters for time-step $t \in TS$ to the model parameter values:

Set $MLP_{t,k} = MMLP_k$.

Set $DR_{t,k} = MDR_k$.

Set $DF_{t,k} = MDF_k$.

15.2.3.1.5 Step 5: Apply the derating on the combustion turbine *resource* to the *dispatchable* region:

Calculate P so that $CMLP_k + P \cdot CTShareDR_k \cdot MDR_k = CTCap_{t,k}$; and

Set $DR_{t,k} = min(DR_{t,k}, P \cdot MDR_k)$.

15.2.3.1.6 Step 6: Apply the derating on the steam turbine *resource* to the duct firing and *dispatchable* regions for *pseudo-units* not operating in *single-cycle mode*:

Calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTCap_{t,k}$.

If $R \leq 1$, update $DF_{t,k} = 0$, and $DR_{t,k} = min(DR_{t,k}, R \cdot MDR_k)$.

If $R > 1$, update $DF_{t,k} = min(DF_{t,k}, PRSTCap_{t,k} - SMLP - STShareDR_k \cdot MDR_k)$.

15.2.4 Available Energy Laminations

15.2.4.1 The *pre-dispatch calculation engine* shall determine the *offer* quantity laminations that may be scheduled for *energy* and *operating reserve* in each operating region for time-step $t \in TS$ for each *pseudo-unit* $k \in \{1,..,K\}$, subject to section 15.2.4.2, where:

15.2.4.1.1 $QMLP_{t,k}$ designates the total quantity that may be scheduled in the *minimum loading point* region;

15.2.4.1.2 $QDR_{t,k}$ designates the total quantity that may be scheduled in the *dispatchable* region; and

15.2.4.1.3 $QDF_{t,k}$ designates the total quantity that may be scheduled in the duct firing region.

15.2.4.2 The available *offered* quantity laminations shall be subject to the following conditions:

$0 \leq QMLP_{t,k} \leq MLP_{t,k}$;

$0 \leq QDR_{t,k} \leq DR_{t,k}$;

$0 \leq QDF_{t,k} \leq DF_{t,k}$;

if $QMLP_{t,k} < MLP_{t,k}$, then the $pseudo-unit$ is unavailable and $QDR_{t,k} = QDF_{t,k} = 0$; and

if $QDR_{t,k} < DR_{t,k}$, then $QDF_{t,k} = 0$.

15.3 Convert Physical Resource Constraints to Pseudo-Unit Constraints

15.3.1 The *pre-dispatch calculation engine* shall convert physical *resource* constraints to *pseudo-unit* constraints, where:

15.3.1.1 $PSUMin^{q}_{t,k}$ designates the minimum limitation on *pseudo-unit* k determined by translating constraint q. When constraint q does not provide a minimum limitation on *pseudo-unit* k, then $PSUMin^{q}_{t,k}$ shall be set equal to 0;

15.3.1.2 $PSUMax^{q}_{t,k}$ designates the maximum limitation on *pseudo-unit* k determined by translating constraint q. When constraint q does not provide a maximum limitation on *pseudo-unit* k, then $PSUMax^{q}_{t,k}$ shall be set equal to $MLP_{t,k} + DR_{t,k} + DF_{t,k}$;

15.3.1.3 $CTCmtd_{t,k} \in \{0,1\}$ designates whether combustion turbine *resource* $k \in \{1,..K\}$ is considered committed in time-step $t \in TS$.

15.3.2 The *pre-dispatch calculation engine* shall calculate the minimum and maximum limitations, subject to section 15.3.3.1, as follows:

15.3.2.1 Minimum limitation: $MinDG_{t,k} = max_{q \in \{1,..Q\}} PSUMin^{q}_{t,k}$

15.3.2.2 Maximum limitation: $MaxDG_{t,k} = min_{q \in \{1,..Q\}} PSUMax^{q}_{t,k}$

where Q designates the number of constraints impacting a *combined cycle plant* that have been provided to the *pre-dispatch calculation engine*.

15.3.3 Pseudo-Unit Minimum and Maximum Constraints

15.3.3.1 *Pseudo-unit* minimum and maximum constraints shall be calculated as follows:

15.3.3.1.1 $PSUMin_{t,k} = PMin$, where $PMin$ shall be a minimum constraint provided on *pseudo-unit* $k \in \{1,...,K\}$ for time-step $t \in TS$; and

15.3.3.1.2 $PSUMax_{t,k} = PMax$, $PMax$ shall be a maximum constraint provided on *pseudo-unit* $k \in \{1,...,K\}$ for time-step $t \in TS$.

15.3.4 Combustion Turbine Resource Minimum and Maximum Constraints

15.3.4.1 If the *pseudo-unit* is not flagged to operate in *single cycle mode*, then the combustion turbine *resource's* minimum constraint shall be converted to a *pseudo-unit* constraint as follows:

If $CTMin < MLP_{t,k} \cdot CTShareMLP_k$, then set

$$STMinMLP = CTMin \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right); \text{ and}$$

$$STMinDR = 0.$$

Otherwise, if $CTMin \geq MLP_{t,k} \cdot CTShareMLP_k$, then set

$$STMinMLP = MLP_{t,k} \cdot STShareMLP_k; \text{ and}$$

$$STMinDR = \left(CTMin - MLP_{t,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$

Therefore:

$$PSUMin_{t,k} = CTMin + STMinMLP + STMinDR.$$

15.3.4.2 If a *pseudo-unit* is flagged to operate in *single cycle mode*, then the combustion turbine *resource's* minimum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PSUMin_{t,k} = CTMin.$$

15.3.4.3 If the *pseudo-unit* is not flagged to operate in *single cycle mode*, then the combustion turbine *resource's* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

If $CTMax < MLP_{t,k} \cdot CTShareMLP_k$, then the $pseudo-unit$ is unavailable (i.e. $PSUMax_{t,k} = 0$).

Otherwise, calculate the effect of the constraint on the steam turbine *resource* within the *minimum loading point* and *dispatchable* regions:

$$STMaxMLP = MLP_{t,k} \cdot STShareMLP_k$$

$$STMaxDR = \left(CTMax - MLP_{t,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right)$$

$$PSUMax_{t,k} = CTMax + STMaxMLP + STMaxDR$$

15.3.4.4 If a *pseudo-unit* is flagged to operate in *single cycle mode*, then the combustion turbine *resource's* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PSUMax_{t,k} = CTMax.$$

15.3.5 Steam Turbine Resource Minimum and Maximum Constraints

15.3.5.1 The *pre-dispatch calculation engine* shall convert a stream turbine *resource's* minimum constraint to a *pseudo-unit* constraints as follows:

15.3.5.1.1 Step 1: Identify $A \subseteq \{1,..,K\}$, which designates the set of *pseudo-units* to which the constraint may be allocated where *pseudo-unit* $k \in \{1,..,K\}$ is placed in set A if and only if $CSCM_k = 0$ and $CTCmtd_{t,k} = 1$. If the set A is empty, then no further steps are required, otherwise proceed to Step 2.

15.3.5.1.2 Step 2: Determine the steam turbine *resource's* portion of the capacity of *pseudo-unit* $k \in A$:

$$STCap_k = QMLP_{t,k} \cdot STShareMLP_k + QDR_{t,k} \cdot STShareDR_k + QDF_{t,k}.$$

15.3.5.1.3 Step 3: Allocate the $STMin$ constraint to each *pseudo-unit* $k \in A$, where $STMin$ constraint shall be allocated equally to each *pseudo-unit* $k \in A$ and and $STPMin_k$ is limited by $STCap_k$.

15.3.5.1.4 Step 4: The steam turbine *resource* portion minimum constraint shall be converted to a *pseudo-unit* constraint, where for each *pseudo-unit* $k \in A$:

If $STPMin_k < MLP_{t,k} \cdot STShareMLP_k$, then set

$CTMinMLP_k = STPMin_k \cdot \left(\frac{CTShareMLP_k}{STShareMLP_k}\right)$; and

$CTMinDR_k = 0.$

Otherwise, if $STPMin_k \geq MLP_{t,k} \cdot STShareMLP_k$, then set

$CTMinMLP_k = MLP_{t,k} \cdot CTShareMLP_k$; and

$CTMinDR_k = \left(STPMin_k - MLP_{t,k} \cdot STShareMLP_k\right) \cdot \left(\frac{CTShareDR_k}{STShareDR_k}\right).$

Therefore:

$$PSUMin_{t,k} = STPMin_k + CTMinMLP_k + CTMinDR_k.$$

15.3.5.2 If *pseudo-units* with sufficient steam turbine *resource* capacity are not commited, then the *pre-dispatch calculation engine* shall not convert the entire quantity of the steam turbine *resource's* minimum constraint to *pseudo-unit* constraints.

15.3.5.3 The steam turbine *resource's* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PRSTMax_{t,k} = \left(\frac{STAmt_{t,k}}{\sum_{w\in\{1,..,K\}} STAmt_{t,w}}\right) \cdot STMax.$$

15.3.5.3.1 If the converted steam turbine *resource* maximum constraint limits the steam turbine *resource* portion to below its *minimum loading point*, then

$$PSUMax_{t,k} = 0.$$

15.3.5.3.2 Otherwise, calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTMax_{t,k}$:

If $R \leq 1$, set $PSUMax_{t,k} = MLP_{t,k} + min(DR_{t,k}, R \cdot MDR_k)$.

If $R > 1$, set $PSUMax_{t,k} = MLP_{t,k} + DR_{t,k} + PRSTMax_{t,k} - SMLP - STShareDR_k \cdot MDR_k$.

15.3.5.4 If the steam turbine *resource's* minimum and maximum constraints are equal but do not convert to equal *pseudo-unit* minimum and maximum constraints, then the steam turbine *resource* minimum constraint conversion in section 15.3.5.1 shall be used to determine equal *pseudo-unit* minimum and maximum constraints.

15.4 Steam Turbine Resource Forced Outages

15.4.1 If the steam turbine *resource* experiences a *forced outage*, the *pre-dispatch calculation engine* shall evaluate the corresponding *pseudo-units* as *resources* being offered in *single cycle mode*.

15.5 Single-Cycle Mode Flag Across Two Dispatch Days

15.5.1 If the pre-dispatch look-ahead period spans two *dispatch days* and the *single cycle mode* flag across the two *dispatch days* differs, then the *pre-dispatch calculation engine* shall apply the following:

15.5.1.1 If there are no future minimum constraints for the *pseudo-unit* before the end of the first *dispatch day* and if the *IESO's energy management system* indicates that the combustion turbine *resource* associated with the *pseudo-unit* is not online, then the *pre-dispatch calculation engine* shall use the *single cycle mode* flag of the second *dispatch day* for the entire pre-dispatch look-ahead period.

15.5.1.2 If there are no minimum *reliability* or commitment constraints on the *pseudo-unit* which cross into the next *dispatch day* and either there is a future minimum *reliability* or commitment constraint on the *pseudo-unit* that ends before the end of the first *dispatch day* or if the *IESO's energy* management system indicates that the combustion turbine *resource* associated with the *pseudo-unit* is online, then the *pre-dispatch calculation engine* shall:

15.5.1.2.1 use the *single cycle mode* flag of the first *dispatch day* for the pre-dispatch look-ahead period in the first *dispatch day* and use the *single cycle mode* flag of the second *dispatch* day for the pre-dispatch look-ahead period in the second *dispatch* day; and

15.5.1.2.2 schedule the *pseudo-unit* to 0 MW in the first hour of the second *dispatch day*.

15.5.1.3 If there is a minimum *reliability* or commitment constraint on the *pseudo-unit* that crosses into the next *dispatch day*, then *the pre-dispatch calculation engine* shall:

15.5.1.3.1 use the *single cycle mode* flag of the first *dispatch day* for the pre-dispatch look-ahead period in the first *dispatch day* and the beginning hours of the second *dispatch day* to meet such constraint;

15.5.1.3.2 use the *single cycle mode* flag of the second *dispatch day* for pre-dispatch look-ahead period in the second *disptch day* after such constraint for the *pseudo-unit* has completed; and

15.5.1.3.3 schedule the *pseudo-unit* to 0 MW in the first hour for which no *reliability* or commitment constraint applies in the second *dispatch day*.

15.6 Conversion of Pseudo-Unit Schedules to Physical Resource Schedules

15.6.1 For a *combined cycle plant* with K combustion turbine *resources* and one steam turbine *resource*, the *pre-dispatch calculation engine* shall compute the following *energy* and *operating reserve* schedules for time-step $t \in TS$:

15.6.1.1 $CTE_{t,k}$, which designates the *energy* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

15.6.1.2 $STPE_{t,k}$, which designates the *energy* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$;

15.6.1.3 STE_t , which designates the *energy* schedule for the steam turbine *resource*;

15.6.1.4 $CT10S_{t,k}$, which designates the synchronized *ten-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

15.6.1.5 $STP10S_{t,k}$, which designates the synchronized *ten-minute operating reserve* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$;

15.6.1.6 $ST10S_t$, which designates the synchronized *ten-minute operating reserve* schedule for the steam turbine *resource*;

15.6.1.7 $CT10N_{t,k}$, which designates the non-synchronized *ten-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

15.6.1.8 $STP10N_{t,k}$, which designates the non-synchronized *ten-minute operating reserve* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$;

15.6.1.9 $ST10N_t$, which designates the non-synchronized *ten-minute operating reserve* schedule for the steam turbine *resource*;

15.6.1.10 $CT30R_{t,k}$, which designates the *thirty-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

15.6.1.11 $STP30R_{t,k}$, which designates the *thirty-minute operating reserve* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$; and

15.6.1.12 $ST30R_t$, which designates the *thirty-minute operating reserve* schedule for the steam turbine *resource*.

15.6.2 The *pre-dispatch calculation engine* shall determine the following *energy* and *operating reserve* schedules for *pseudo*-unit $k \in \{1,..,K\}$ in time-step $t \in TS$:

15.6.2.1 $SE_{t,k}$, which designates the total amount of *energy* scheduled and $SE_{t,k} = SEMLP_{t,k} + SEDR_{t,k} + SEDF_{t,k}$ where:

15.6.2.1.1 $SEMLP_{t,k}$ designates the portion of the schedule corresponding to the *minimum loading point* region, where $0 \leq SEMLP_{t,k} \leq QMLP_{t,k}$;

15.6.2.1.2 $SEDR_{t,k}$ designates the portion of the schedule corresponding to the *dispatchable* region, where $0 \leq SEDR_{t,k} \leq QDR_{t,k}$ and $SEDR_{t,k} > 0$ only if $SEMLP_{t,k} = QMLP_{t,k}$;

15.6.2.1.3 $SEDF_{t,k}$ designates the portion of the schedule corresponding to the duct firing region, where $0 \leq SEDF_{t,k} \leq QDF_{t,k}$ and $SEDF_{t,k} > 0$ only if $SEDR_{t,k} = QDR_{t,k}$;

15.6.2.2 $S10S_{t,k}$, which designates the total amount of synchronized *ten-minute operating reserve* scheduled;

15.6.2.3 $S10N_{t,k}$, which designates the total amount of non-synchronized *ten-minute operating reserve* scheduled. If the *pseudo-unit* cannot provide *operating reserve* from its duct firing region, then $0 \leq SE_{t,k} + S10S_{t,k} + S10N_{t,k} \leq QMLP_{t,k} + QDR_{t,k}$; and

15.6.2.4 $S30R_{t,k}$, which designates the total amount of *thirty-minute operating reserve* scheduled, where $0 \leq SE_{t,k} + S10S_{t,k} + S10N_{t,k} + S30R_{t,k} \leq QMLP_{t,k} + QDR_{t,k} + QDF_{t,k}$

15.6.3 The *pre-dispatch calculation engine* shall convert *pseudo-unit* schedules to physical generation *resource* schedules for *energy* and *operating reserve*, as follows:

15.6.3.1 If $SE_{h,k} \geq MLP_{h,k}$, then:

$$CTE_{t,k} = SEMLP_{t,k} \cdot CTShareMLP_k + SEDR_{h,k} \cdot CTShareDR_k;$$

$$STPE_{t,k} = SEMLP_{t,k} \cdot STShareMLP_k + SEDR_{t,k} \cdot STShareDR_k + SEDF_{t,k};$$

$$RoomDR_{t,k} = QDR_{t,k} - SEDR_{t,k};$$

$10SDR_{t,k} = min(RoomDR_{t,k}, S10S_{t,k})$;

$10NDR_{t,k} = min(RoomDR_{t,k} - 10SDR_{t,k}, S10N_{t,k})$;

$30RDR_{t,k} = min(RoomDR_{t,k} - 10SDR_{t,k} - 10NDR_{t,k}, S30R_{t,k})$;

$CT10S_{t,k} = 10SDR_{t,k} \cdot CTShareDR_k$;

$STP10S_{t,k} = 10SDR_{t,k} \cdot STShareDR_k + (S10S_{t,k} - 10SDR_{t,k})$;

$CT10N_{t,k} = 10NDR_{t,k} \cdot CTShareDR_k$;

$STP10N_{t,k} = 10NDR_{t,k} \cdot STShareDR_k + (S10N_{t,k} - 10NDR_{t,k})$;

$CT30R_{t,k} = 30RDR_{t,k} \cdot CTShareDR_k$; and

$STP30R_{t,k} = 30RDR_{t,k} \cdot STShareDR_k + (S30R_{t,k} - 30RDR_{t,k})$

15.6.3.2 If $SE_{t,k} < MLP_{t,k}$ and is ramping to *minimum loading point*, then the conversion shall be determined by the *ramp up energy to minimum loading point*.

15.6.3.3 The steam turbine *resources* portion schedules from section 15.6.3.1 shall be summed to obtain the steam turbine *resource* schedule as follows:

$STE_t = \sum_{k=1,..,K} STPE_{t,k}$;

$ST10S_t = \sum_{k=1,..,K} STP10S_{t,k}$;

$ST10N_t = \sum_{k=1,..,K} STP10N_{t,k}$; and

$ST30R_t = \sum_{k=1,..,K} STP30R_{t,k}$.

16 Pricing Formulas

16.1 Purpose

16.1.1 The *pre-dispatch calculation engine* shall calculate *locational marginal prices* using shadow prices, constraint sensitivities and marginal loss factors.

16.2 Sets, Indices and Parameters

16.2.1 The sets, indices and parameters used to calculate *locational marginal prices* are described in section 4. In addition, the following shadow prices from Pass 1 shall be used:

16.2.1.1 $SPEmT^1_{t,c,f}$, which designates the Pass 1 shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in time-step t;

16.2.1.2 $SPExtT^1_{t,z}$, which designates the Pass 1 shadow price for the import or export limit constraint $z \in Z_{Sch}$ in time-step t;

16.2.1.3 SPL^1_t , which designates the Pass 1 shadow price for the *energy* balance constraint in time-step t;

16.2.1.4 $SPNIUExtBwdT^1_t$, which designates the Pass 1 shadow price for the net interchange scheduling limit constraint limiting increases in net imports between time-step $(t-1)$ and time-step t;

16.2.1.5 $SPNIDExtBwdT^1_t$, which designates the Pass 1 shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between time-step $(t-1)$ and time-step t;

16.2.1.6 $SPNIUExtFwdT^1_t$, which designates the Pass 1 shadow price for the net interchange scheduling limit constraint limiting increases in net imports between time-step t and time-step $(t+1)$;

16.2.1.7 $SPNIDExtFwdT^1_t$, which designates the Pass 1 shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between time-step t and time-step $(t+1)$;

16.2.1.8 $SPNormT^1_{t,f}$, which designates the Pass 1 shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in time-step t;

16.2.1.9 $SP10S^1_t$, which designates the Pass 1 shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in time-step t;

16.2.1.10 $SP10R^1_t$, which designates the Pass 1 shadow price for the total *ten-minute operating reserve* requirement constraint in time-step t;

16.2.1.11 $SP30R_t^1$, which designates the Pass 1 shadow price for the total *thirty-minute operating reserve* requirement constraint in time-step *t*;

16.2.1.12 $SPREGMin10R_{r,t}^1$, which designates the Pass 1 shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in time-step *t*;

16.2.1.13 $SPREGMin30R_{r,t}^1$, which designates the Pass 1 shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in time-step *t*;

16.2.1.14 $SPREGMax10R_{r,t}^1$, which designates the Pass 1 shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in time-step *t*; and

16.2.1.15 $SPREGMax30R_{r,t}^1$, which designates the Pass 1 shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in time-step *t*.

16.3 Locational Marginal Prices for Energy

16.3.1 Energy Locational Marginal Prices for Delivery Points

16.3.1.1 The *pre-dispatch calculation engine* shall calculate a *locational marginal price* and components for *energy* for Pass 1 and each time-step $t \in TS$ for every bus $b \in L$ where a *non-dispatchable generation resource* or *dispatchable generation resource*, a *dispatchable load*, an *hourly demand response resource*, or a *non-dispatchable load* is sited and:

16.3.1.1.1 $LMP_{t,b}^1$ designates the Pass 1 time-step t *locational marginal price* for *energy*;

16.3.1.1.2 $PRef_t^1$ designates the Pass 1 time-step t *locational marginal price* for *energy* at the *reference bus*;

16.3.1.1.3 $PLoss_{t,b}^1$ designates the Pass 1 time-step t loss component; and

16.3.1.1.4 $PCong_{t,b}^1$ designates the Pass 1 time-step t congestion component.

16.3.1.2 The *pre-dispatch calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* at the *reference bus*, a loss component and a congestion component for Pass 1 at bus $b \in L$ in time-step $t \in TS$, as follows:

$$InitLMP_{t,b}^{1} = InitPRef_{t}^{1} + InitPLoss_{t,b}^{1} + InitPCong_{t,b}^{1}$$

where:

$$InitPRef_{t}^{1} = SPL_{t}^{1};$$

$$InitPLoss_{t,b}^{1} = MglLoss_{t,b}^{1} \cdot SPL_{t}^{1};$$

and

$$InitPCong_{t,b}^{1} = \sum_{f \in F_t} PreConSF_{t,f,b} \cdot SPNormT_{t,f}^{1} + \sum_{c \in C} \sum_{f \in F_{t,c}} SF_{t,c,f,b} \cdot SPEmT_{t,c,f}^{1}.$$

16.3.1.3 If the initial *locational marginal price* for *energy* at the *reference bus* ($InitPRef_t^1$) is not within the *settlement* bounds (*EngyPrcFlr*, *EngyPrcCeil*), then the *pre-dispatch calculation engine* shall modify the *locational marginal price* for *energy* at the *reference bus* as follows:

If $InitPRef_t^1 > EngyPrcCeil$, set $PRef_t^1 = EngyPrcCeil$

If $InitPRef_t^1 < EngyPrcFlr$, set $PRef_t^1 = EngyPrcFlr$

Otherwise, set $PRef_t^1 = InitPRef_t^1$

16.3.1.4 If the initial *locational marginal price* for *energy* ($InitLMP_{t,b}^1$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *pre-dispatch calculation engine* shall modify the *locational marginal price* for *energy* as follows:

If $InitLMP_{t,b}^1 > EngyPrcCeil$, set $LMP_{t,b}^1 = EngyPrcCeil$

If $InitLMP_{t,b}^1 < EngyPrcFlr$, set $LMP_{t,b}^1 = EngyPrcFlr$

Otherwise, set $LMP_{t,b}^1 = InitLMP_{t,b}^1$

16.3.1.5 The *pre-dispatch calculation engine* shall modify the loss component as follows:

If $PRef_t^1 \neq InitPRef_t^1$, set $PLoss_{t,b}^1 = MglLoss_{t,b}^1 \cdot PRef_t^1$

Otherwise, set $PLoss_{t,b}^{1} = InitPLoss_{t,b}^{1}$

16.3.1.6 The *pre-dispatch calculation engine* shall modify the congestion component as follows:

If $LMP_{t,b}^{1} - PRef_{t}^{1} - PLoss_{t,b}^{1}$ and $InitPCong_{t,b}^{1}$ have the same mathematical sign, then set $PCong_{t,b}^{1} = LMP_{t,b}^{1} - PRef_{t}^{1} - PLoss_{t,b}^{1}$

Otherwise, set $PCong_{t,b}^{1} = 0$ and set $PLoss_{t,b}^{1} = LMP_{t,b}^{1} - PRef_{t}^{1}$

16.3.2 Energy Locational Marginal Prices for Intertie Metering Points

16.3.2.1 The *pre-dispatch calculation engine* shall calculate a *locational marginal price* and components for *energy* for Pass 1 and each time-step $t \in TS$ for *intertie zone* bus $d \in D$, where:

16.3.2.1.1 $ExtLMP_{t,d}^{1}$ designates the Pass 1 time-step t *locational marginal price* for *energy*;

16.3.2.1.2 $IntLMP_{t,d}^{1}$ designates the Pass 1 time-step t *intertie border price* for *energy*;

16.3.2.1.3 $ICP_{t,d}^{1}$ designates the Pass 1 time-step t *intertie congestion price*;

16.3.2.1.4 $PRef_{t}^{1}$ designates the Pass 1 time-step t *locational marginal price* for *energy* at the *reference bus*;

16.3.2.1.5 $PLoss_{t,d}^{1}$ designates the Pass 1 time-step t loss component;

16.3.2.1.6 $PIntCong_{t,d}^{1}$ designates the Pass 1 time-step t internal congestion component for *energy*;

16.3.2.1.7 $PExtCong_{t,d}^{1}$ designates the Pass 1 time-step t external congestion component for the *intertie congestion price*; and

16.3.2.1.8 $PNISL_{t,d}^{1}$ designates the Pass 1 time-step t net interchange scheduling limit congestion component for the *intertie congestion price*.

16.3.2.2 The *pre-dispatch calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* for the *reference bus*, a loss components and a congestion components for *energy* for Pass 1 at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in time-step t, subject to sections 16.3.2.8 and 16.3.2.9, as follows:

$$InitExtLMP^1_{t,d} = InitIntLMP^1_{t,d} + InitICP^1_{t,d}$$

where:

$$InitPRef^1_t = SPL^1_t;$$

$$InitPLoss^1_{t,d} = MglLoss^1_{t,d} \cdot SPL^1_t;$$

$$InitPIntCong^1_{t,d} = \sum_{f \in F_t} PreConSF_{t,f,d} \cdot SPNormT^1_{t,f} + \sum_{c \in C} \sum_{f \in F_{t,c}} SF_{t,c,f,d} \cdot SPEmT^1_{t,c,f};$$

$$InitIntLMP^1_{t,d} = InitPRef^1_t + InitPLoss^1_{t,d} + InitPIntCong^1_{t,d};$$

$$InitPExtCong^1_{t,d} = \sum_{z \in Z_{sch}} EnCoeff_{a,z} \cdot SPExtT^1_{t,z};$$

and

$$InitPNISL^1_{t,d} = SPNIUExtBwdT^1_t - SPNIUExtFwdT^1_t - SPNIDExtBwdT^1_t + SPNIDExtFwdT^1_t;$$

$$InitICP^1_{t,d} = InitPExtCong^1_{t,d} + InitPNISL^1_{t,d}$$

16.3.2.3 If the initial *locational marginal price* for *energy* ($InitExtLMP^1_{t,d}$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *pre-dispatch calculation engine* shall modify the *intertie border price* for *energy*, and its components, as follows:

16.3.2.3.1 The initial *locational marginal price* for the *reference bus* ($InitPRef^1_t$) shall be modified as per section 16.3.1.3;

16.3.2.3.2 The initial *intertie border price* ($InitIntLMP^1_{t,d}$) shall be modified as per section 16.3.1.4, where $InitLMP^1_{t,b}$ = $InitIntLMP^1_{t,d}$;

16.3.2.3.3 The initial loss component ($InitPLoss^{1}_{t,d}$) shall be modified as per section 16.3.1.5; and

16.3.2.3.4 The initial internal congestion component ($InitPIntCong^{1}_{t,d}$) shall be modified as per section 16.3.1.6, where $InitPCong^{1}_{t,b} = InitPIntCong^{1}_{t,d}$.

16.3.2.4 If the initial *locational marginal price* for *energy* ($InitExtLMP^{1}_{t,d}$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *pre-dispatch calculation engine* shall modify the *locational marginal price* for *energy*, as follows:

If $InitExtLMP^{1}_{t,d} > EngyPrcCeil$, set $ExtLMP^{1}_{t,d} = EngyPrcCeil$

If $InitExtLMP^{1}_{t,d} < EngyPrcFlr$, set $ExtLMP^{1}_{t,d} = EngyPrcFlr$

Otherwise, set $ExtLMP^{1}_{t,d} = InitExtLMP^{1}_{t,d}$

16.3.2.5 If the modified *locational marginal price* for *energy* ($ExtLMP^{1}_{t,d}$) is equal to the *intertie border price* for *energy* ($IntLMP^{1}_{t,d}$), then the *pre-dispatch calculation engine* shall modify the external congestion component for the *intertie* congestion price and net interchange scheduling limit congestion component for the *intertie congestion price*, as follows:

If $ExtLMP^{1}_{t,d} = IntLMP^{1}_{t,d}$, set $PExtCong^{1}_{t,d} = 0$ and $PNISL^{1}_{t,d} = 0$

16.3.2.6 If the modified *locational marginal price* for *energy* ($ExtLMP^{1}_{t,d}$) is not equal to the *intertie border price* for *energy* ($IntLMP^{1}_{t,d}$), then the *pre-dispatch calculation engine* shall modify the external congestion component for the *intertie congestion price* and net interchange scheduling limit congestion component for the *intertie congestion price*, as follows:

If $ExtLMP^{1}_{t,d} \neq IntLMP^{1}_{t,d}$, set

$$PNISL^{1}_{t,d} = (ExtLMP^{1}_{t,d} - IntLMP^{1}_{t,d}) \cdot \left(\frac{InitPNISL^{1}_{h,d}}{InitPNISL^{1}_{t,d} + InitPExtCong^{1}_{t,d}}\right).$$

If $PNISL_{t,d}^{1} > NISLPen$, set $PNISL_{t,d}^{1} = NISLPen$

If $PNISL_{t,d}^{1} < (-1) \cdot NISLPen$, set $PNISL_{t,d}^{1} = (-1) \cdot NISLPen$

Then $PExtCong_{t,d}^{1} = ExtLMP_{t,d}^{1} - IntLMP_{t,d}^{1} - PNISL_{t,d}^{1}$

16.3.2.7 The *pre-dispatch calculation engine* shall calculate the *intertie* congestion price as follows:

$$ICP_{t,d}^{1} = PExtCong_{t,d}^{1} + PNISL_{t,d}^{1}$$

16.3.2.8 The *locational marginal price* for *energy* calculated by the *pre-dispatch calculation engine* shall be the same for all *boundary entity resource* buses at the same *intertie zone*. *Intertie* transactions associated with the same *boundary entity resource* bus, but specified as occurring at different *intertie zones*, subject to phase shifter operation, shall be modelled as flowing across independent paths. Pricing of these transactions shall utilize shadow prices associated with the internal transmission constraints, *intertie* limits and transmission losses applicable to the path associated to the relevant *intertie* zone.

16.3.2.9 When an *intertie zone* is out-of-service, the *intertie* limits for that *intertie zone* will be set to zero and all import and export *boundary entity resources* for that *intertie zone* will receive a zero schedule and the *locational marginal price* for *energy* shall be set to the *intertie border price* for *energy*.

16.3.3 Zonal Prices for Energy

16.3.3.1 The *pre-dispatch calculation engine* shall calculate the zonal price for *energy* and its components for Pass 1 and each time-step t for each *virtual transaction zone* $m \in M$, as follows:

$$VZonalP_{t,m}^{1} = PRef_{t}^{1} + VZonalPLoss_{t,m}^{1} + VZonalPCong_{t,m}^{1}$$

where

$$VZonalPLoss_{t,m}^{1} = \sum_{b \in L_m^{VIRT}} WF_{t,m,b}^{VIRT} \cdot PLoss_{t,b}^{1}$$

and

$$VZonalPCong_{t,m}^{1} = \sum_{b \in L_m^{VIRT}} WF_{t,m,b}^{VIRT} \cdot PCong_{t,b}^{1}$$

16.3.3.2 The *pre-dispatch calculation engine* shall calculate the zonal price for *energy* and its components for Pass 1 and each time-step t for each *non-dispatchable load* zone $y \in Y$, as follows:

$$ZonalP_{t,y}^{1} = PRef_t^1 + ZonalPLoss_{t,y}^{1} + ZonalPCong_{t,y}^{1}$$

where:

$$ZonalPLoss_{t,y}^{1} = \sum_{b \in L_y^{NDL}} WF_{t,y,b}^{NDL} \cdot PLoss_{t,b}^{1}$$

and

$$ZonalPCong_{t,y}^{1} = \sum_{b \in L_y^{NDL}} WF_{t,y,b}^{NDL} \cdot PCong_{t,b}^{1}$$

16.3.3.3 The *Ontario zonal price* is calculated per section 16.3.3.2 where the *non-dispatchable load* zone is comprised of all *non-dispatchable loads* within Ontario.

16.3.4 Pseudo-Unit Pricing

16.3.4.1 The *pre-dispatch calculation engine* shall calculate a *locational marginal price* and components for *energy* for Pass 1 and each time-step t for every *pseudo-unit* $k \in \{1,..,K\}$, where:

16.3.4.1.1 $CTMglLoss_{t,k}^{1}$ designates the marginal loss factor for the combustion turbine *resource* identified by *pseudo-unit* k for time-step t in Pass 1;

16.3.4.1.2 $STMglLoss_{t,k}^{p}$ designates the marginal loss factor for the steam turbine *resource* identified by *pseudo-unit* k for time-step t in Pass 1;

16.3.4.1.3 $CTPreConSF_{t,f,k}$ designates the pre-contingency sensitivity factor for the combustion turbine *resource* identified by *pseudo-unit k* on *facility f* during time-step t under pre-contingency conditions;

16.3.4.1.4 $STPreConSF_{t,f,k}$ designates the pre-contingency sensitivity factor for the steam turbine *resource* identified by *pseudo-unit k* on *facility f* during time-step t under pre-contingency conditions;

16.3.4.1.5 $CTSF_{t,c,f,k}$ designates the post-contingency sensitivity factor for the combustion turbine *resource* identified by *pseudo-unit k* on *facility f* during time-step t under post-contingency conditions for contingency *c*; and

16.3.4.1.6 $STSF_{t,c,f,k}$ designates the post-contingency sensitivity factor for the steam turbine *resource* identified by *pseudo-unit k* on *facility f* during time-step t under post-contingency conditions for contingency *c*.

16.3.4.2 The *pre-dispatch calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* at the *reference bus*, a loss component and a congestion component for Pass 1 and each time-step *t* for every *pseudo-unit* $k \in \{1,..,K\}$, as follows:

$$InitLMP^1_{t,k} = InitPRef^1_t + InitPLoss^1_{t,k} + InitPCong^1_{t,k}$$

where:

$InitPRef^1_t = SPL^1_t;$

$InitPLoss^1_{t,k} = MglLoss^1_{t,k} \cdot SPL^1_t;$

and

$$InitPCong^1_{t,k} = \sum_{f \in F_t} PreConSF_{t,f,k} \cdot SPNormT^1_{t,f} + \sum_{c \in C} \sum_{f \in F_{t,c}} SF_{t,c,f,k} \cdot SPEmT^1_{t,c,f}$$

16.3.4.3 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its *minimum loading point range* or not scheduled at all, its marginal loss and sensitivity factors shall be:

$$MglLoss^1_{t,k} = CTShareMLP_k \cdot CTMglLoss^1_{t,k} + STShareMLP_k \cdot STMglLoss^1_{t,k}$$

$$PreConSF_{t,f,k} = CTShareMLP_k \cdot CTPreConSF_{t,f,k} + STShareMLP_k \cdot STPreConSF_{t,f,k}$$

$$SF_{t,c,f,k} = CTShareMLP_k \cdot CTSF_{t,c,f,k} + STShareMLP_k \cdot STSF_{t,c,f,k}$$

16.3.4.4 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its *dispatchable* region, its marginal loss and sensitivity factors shall be:

$$MglLoss^1_{t,k} = CTShareDR_k \cdot CTMglLoss^1_{t,k} + STShareDR_k \cdot STMglLoss^1_{t,k}$$

$$PreConSF_{t,f,k} = CTShareDR_k \cdot CTPreConSF_{t,f,k} + STShareDR_k \cdot STPreConSF_{t,f,k}$$

$$SF_{t,c,f,k} = CTShareDR_k \cdot CTSF_{t,c,f,k} + STShareDR_k \cdot STSF_{t,c,f,k}$$

16.3.4.5 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its duct firing region, its marginal loss and sensitivity factors shall be:

$$MglLoss^1_{t,k} = STMglLoss^1_{t,k}$$

$$PreConSF_{t,f,k} = STPreConSF_{t,f,k}$$

$$SF_{t,c,f,k} = STSF_{t,c,f,k}$$

16.4 Locational Marginal Prices for Operating Reserve

16.4.1 Operating Reserve Locational Marginal Prices for Delivery Points

16.4.1.1 The *pre-dispatch calculation engine* shall calculate a *locational marginal price* and components for *operating reserve* for Pass 1 and each time-step t for a *delivery point* associated with the *dispatchable generation resource* and *dispatchable load* at bus $b \in B$, where:

16.4.1.1.1 $L30RP^1_{t,b}$ designates the Pass 1 time-step t *locational marginal price* for *thirty-minute operating reserve*;

16.4.1.1.2 $P30RRef^1_t$ designates the Pass 1 time-step t *locational marginal price* for *thirty-minute operating reserve* at the *reference bus*;

16.4.1.1.3 $P30RCong^{1}_{t,b}$ designates the Pass 1 time-step t congestion component for *thirty-minute operating reserve*;

16.4.1.1.4 $L10NP^{1}_{t,b}$ designates the Pass 1 time-step t *locational marginal price* for non-synchronized *ten-minute operating reserve*;

16.4.1.1.5 $P10NRef^{1}_{t}$ designates the Pass 1 time-step t *locational marginal price* for non-synchronized *ten-minute operating reserve* at the *reference bus*;

16.4.1.1.6 $P10NCong^{1}_{t,b}$ designates the Pass 1 time-step t congestion component for non-synchronized *ten-minute operating reserve*;

16.4.1.1.7 $L10SP^{1}_{t,b}$ designates the Pass 1 time-step t *locational marginal price* for synchronized *ten-minute operating reserve*;

16.4.1.1.8 $P10SRef^{1}_{t}$ designates the Pass 1 time-step t *locational marginal prices* for synchronized *ten-minute operating reserve* at the *reference bus*;

16.4.1.1.9 $P10SCong^{1}_{t,b}$ designates the Pass 1 time-step t congestion component for synchronized *ten-minute operating reserve*; and

16.4.1.1.10 $ORREG_b \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus b.

16.4.1.2 The *pre-dispatch calculation engine* shall calculate an initial *locational marginal price*, a *locational marginal price* at the *reference bus*, and congestion components for Pass 1 for a *delivery point* associated with the *dispatchable generation resource* and *dispatchable load* at bus $\mathrm{b} \in \mathrm{B}$ in time-step $\mathrm{t} \in \mathrm{TS}$, for each class of *operating reserve*, as follows:

$$InitL30RP_{t,b}^{1} = InitP30RRef_{t}^{1} + InitP30RCong_{t,b}^{1}$$

where

$$InitP30RRef_{t}^{1} = SP30R_{t}^{1}$$

and

$$InitP30RCong_{t,b}^{1} = \sum_{r \in ORREG_b} SPREGMin30R_{t,r}^{1} + \sum_{r \in ORREG_b} SPREGMax30R_{t,r}^{1}$$

$$InitL10NP_{t,b}^{1} = InitP10NRef_{t}^{1} + InitP10NCong_{t,b}^{1}$$

where

$$InitP10NRef_{t}^{1} = SP10R_{t}^{1} + SP30R_{t}^{1}$$

and

$$InitP10NCong_{t,b}^{1} = \sum_{r \in ORREG_b} \left(SPREGMin10R_{r,t}^{1} + SPREGMin30R_{r,t}^{1}\right) + \sum_{r \in ORREG_b} \left(SPREGMax10R_{r,t}^{1} + SPREGMax30R_{r,t}^{1}\right)$$

$$InitL10SP_{t,b}^{1} = InitP10SRef_t^1 + InitP10SCong_{t,b}^{1}$$

where

$$InitP10SRef_t^1 = SP10S_t^1 + SP10R_t^1 + SP30R_t^1$$

and

$$InitP10SCong_{t,b}^{1} = \sum_{r \in ORREG_b} \left(SPREGMin10R_{r,t}^{1} + SPREGMin30R_{r,t}^{1}\right) + \sum_{r \in ORREG_b} \left(SPREGMax10R_{r,t}^{1} + SPREGMax30R_{r,t}^{1}\right)$$

16.4.1.3 If the initial *locational marginal price* at the *reference bus* ($InitP30RRef_t^1$, $InitP10NRef_t^1$, or $InitP10SRef_t^1$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *pre-dispatch calculation engine* shall modify the *locational marginal price* at the *reference bus* for each class of *operating reserve* as follows:

If $InitP30RRef_t^1 > ORPrcCeil$, set $P30RRef_t^1 = ORPrcCeil$;

If $InitP30RRef_t^1 < ORPrcFlr$, set $P30RRef_t^1 = ORPrcFlr$;

Otherwise, set $P30RRef_t^1 = InitP30RRef_t^1$.

If $InitP10NRef_t^1 > ORPrcCeil$, set $P10NRef_t^1 = ORPrcCeil$

If $InitP10NRef_t^1 < ORPrcFlr$, set $P10NRef_t^1 = ORPrcFlr$

Otherwise, set $P10NRef_t^1 = InitP10NRef_t^1$

If $InitP10SRef_t^1, ORPrcFlr > ORPrcCeil$, set $10SRef_t^1 = ORPrcCeil$

If $InitP10SRef_t^1, ORPrcFlr < ORPrcFlr$, set $10SRef_t^1 = ORPrcFlr$

Otherwise, set $10SRef_t^1 = InitP10SRef_t^1$

16.4.1.4 If the initial *locational marginal price* ($InitL30RP_{t,b}^1$, $InitL10NP_{t,b}^1$, or $InitL10SP_{t,b}^1$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *pre-dispatch calculation engine* shall modify the *locational marginal price* for each class of *operating reserve* as follows:

If $InitL30RP^1_{t,b} > ORPrcCeil$, set $L30RP^1_{t,b} = ORPrcCeil$;

If $InitL30RP^1_{t,b} < ORPrcFlr$, set $L30RP^1_{t,b} = ORPrcFlr$;

Otherwise, set $L30RP^1_{t,b} = InitL30RP^1_{t,b}$.

If $InitL10NP^1_{t,b} > ORPrcCeil$, set $L10NP^1_{t,b} = ORPrcCeil$;

If $InitL10NP^1_{t,b} < ORPrcFlr$, set $L10NP^1_{t,b} = ORPrcFlr$;

Otherwise, set $L10NP^1_{t,b} = InitL10NP^1_{t,b}$t.

If $InitL10SP^1_{t,b} > ORPrcCeil$, set $L10SP^1_{t,b} = ORPrcCeil$;

If $InitL10SP^1_{t,b} < ORPrcFlr$, set $L10SP^1_{t,b} = ORPrcFlr$;

Otherwise, set $L10SP^1_{t,b} = InitL10SP^1_{t,b}$.

16.4.1.5 If the initial *locational marginal price* ($InitL30RP^1_{t,b}$, $InitL10NP^1_{t,b}$, or $InitL10SP^1_{t,b}$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *pre-dispatch calculation engine* shall modify the congestion component for each class of *operating reserve* as follows:

Set $P30RCong^1_{t,b} = L30RP^1_{t,b} - P30RRef^1_t$;

Set $P10NCong^1_{t,b} = L10NP^1_{t,b} - P10NRef^1_t$; and

Set $P10SCong^1_{t,b} = L10SP^1_{t,b} - P10SRef^1_t$.

16.4.1.6 Operating Reserve Locational Marginal Prices for Intertie Metering Points

16.4.1.7 The *pre-dispatch calculation engine* shall calculate a *locational marginal price* and components for *operating reserve* for Pass 1 and each time-step $t \in TS$ for *intertie zone* bus $d \in D$, where:

16.4.1.7.1 $ExtL30RP^1_{t,d}$ designates the Pass 1 time-step t *locational marginal price* for *thirty-minute operating reserve*;

16.4.1.7.2 $P30RRef_t^1$ designates the Pass 1 time-step t *locational marginal price* for *thirty-minute operating reserve* at the *reference bus*;

16.4.1.7.3 $P30RIntCong_{t,d}^1$ designates the Pass 1 time-step t internal congestion component *for thirty-minute operating reserve*;

16.4.1.7.4 $P30RExtCong_{t,d}^1$ designates the Pass 1 time-step t *intertie* congestion component *thirty-minute operating reserve*;

16.4.1.7.5 $ExtL10NP_{t,d}^1$ designates the Pass 1 time-step t *locational marginal price* for non-synchronized *ten-minute operating reserve*;

16.4.1.7.6 $\mathrm{P10NRef}_\mathrm{t}^1$ designates the Pass 1 time-step t *locational marginal price* for non-synchronized *ten-minute operating reserve* at the *reference bus*;

16.4.1.7.7 $P10NIntCong_{t,d}^1$ designates the Pass 1 time-step t internal congestion component for non-synchronized *ten-minute operating reserve*;

16.4.1.7.8 $P10NExtCong_{t,d}^1$ designates the Pass 1 time-step t external congestion component for non-synchronized *ten-minute operating reserve*; and

16.4.1.7.9 $ORREG_d \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus d.

16.4.1.8 The *pre-dispatch calculation engine* shall calculate initial *locational marginal price*, *locational marginal price* at the *reference bus*, internal congestion component and external congestion component for Pass 1 at *intertie zone bus* $d \in D_a$ in *intertie zone* $a \in A$ in time-step $t \in TS$, for each class of *operating reserve*, subject to sections 16.4.1.11 and 16.4.1.12, as follows:

$$InitExtL30RP^{1}_{t,d} = InitP30RRef^{1}_{t} + InitP30RIntCong^{1}_{t,d} + InitP30RExtCong^{1}_{t,d}$$

where:

$$InitP30RRef^{1}_{t} = SP30R^{1}_{t};$$

$$InitP30RIntCong^{1}_{t,d} = \sum_{r \in ORREG_d} SPREGMin30R^{1}_{t,r} + \sum_{r \in ORREG_d} SPREGMax30R^{1}_{t,r};$$

and

$$InitP30RExtCong^{1}_{t,d} = \sum_{z \in Z_{Sch}} 0.5 \cdot \left(EnCoeff_{a,z} + 1\right) \cdot SPExtT^{1}_{t,z}.$$

$$InitExtL10NP^{1}_{t,d} = InitP10NRef^{1}_{t} + InitP10NIntCong^{1}_{t,d} + InitP10NExtCong^{1}_{t,d}$$

where:

$$InitP10NRef^{1}_{t} = SP10R^{1}_{t} + SP30R^{1}_{t};$$

$$InitP10NIntCong^{1}_{t,d} = \sum_{r \in ORREG_d}\left(SPREGMin10R^{1}_{r,t} + SPREGMin30R^{1}_{r,t}\right) + \sum_{r \in ORREG_d}\left(SPREGMax10R^{1}_{r,t} + SPREGMax30R^{1}_{r,t}\right);$$

and

$$InitP10NExtCong^{1}_{t,d} = \sum_{z \in Z_{Sch}} 0.5 \cdot \left(EnCoeff_{a,z} + 1\right) \cdot SPExtT^{1}_{t,z}$$

16.4.1.9 If the initial *locational marginal price* ($InitExtL30RP^{1}_{t,b}$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *pre-dispatch calculation engine* shall modify the *locational marginal price*, the *locational marginal price* at the *reference bus*, and the external congestion component for *thirty-minute operating reserve* as follows:

$$IntL30R = InitP30RRef^{1}_{t} + InitP30RIntCong^{1}_{t,d};$$

If $InitP30RRef^{1}_{t} > ORPrcCeil$, set $P30RRef^{1}_{t} = ORPrcCeil$;

If $InitP30RRef^{1}_{t} < ORPrcFlr$, set $P30RRef^{1}_{t} = ORPrcFlr$;

Otherwise, set $P30RRef_t^1 = InitP30RRef_t^1$;

Set $P30RIntCong_{t,d}^1 = ExtL30RP_{t,b}^1 - P30RRef_t^1$;

If $InitExtL30RP_{t,b}^1 > ORPrcCeil$, set $ExtL30RP_{t,b}^1 = ORPrcCeil$;

If $InitExtL30RP_{t,b}^1 < ORPrcFlr$, set $ExtL30RP_{t,b}^1 = ORPrcFlr$;

Otherwise, $ExtL30RP_{t,b}^1 = InitExtL30RP_{t,b}^1$; and

Set $P30RExtCong_{t,d}^1 = ExtL30RP_{t,b}^1 - P30RRef_t^1 - P30RIntCong_{t,d}^1$

16.4.1.10 If the initial *locational marginal price* ($InitExtL10NP_{t,b}^1$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *pre-dispatch calculation engine* shall modify the initial *locational marginal price*, *locational marginal price* at the *reference bus*, and the external congestion component for *ten-minute operating reserve* as follows:

$IntL10N = InitP10NRef_t^1 + InitP10NIntCong_{t,d}^1$;

If $InitP10NRef_t^1 > ORPrcCeil$, set $P10NRef_t^1 = ORPrcCeil$;

If $InitP10NRef_t^1 < ORPrcFlr$, set $P10NRef_t^1 = ORPrcFlr$;

Otherwise, $P10NRef_t^1 = InitP10NRef_t^1$; and

Set $P10NIntCong_{t,d}^1 = L10NP_{t,b}^1 - P10NRef_t^1$;

If $InitExtL10NP_{t,b}^1 > ORPrcCeil$, set $ExtL10NP_{t,b}^1 = ORPrcCeil$;

If $InitExtL10NP_{t,b}^1 < ORPrcFlr$, set $ExtL10NP_{t,b}^1 = ORPrcFlr$;

Otherwise, $ExtL30RP_{t,b}^1 = InitExtL10NP_{t,b}^1$; and

Set $P10NExtCong_{t,d}^1 = ExtL10NP_{t,b}^1 - P10NRef_t^1 - P10NIntCong_{t,d}^1$

16.4.1.11 The *locational marginal price* calculated by the *pre-dispatch calculation engine* shall be the same for all *boundary entity resource* buses at the same *intertie zone*. Reserve imports associated with the same *boundary entity resource* bus, but specified as ocurring at a different *intertie zone*, subject to phase shifter operation, shall be modelled as flowing across independent paths. Pricing of these reserve imports shall utilize shadow prices associated with *intertie* limits and regional minimum and maximum *operating reserve* requirements applicable to the path associated to the relevant *intertie zone*.

16.4.1.12 When an *intertie zone* is out-of-service, the *intertie* limits for that *intertie zone* will be set to zero and all *boundary entity resources* for that *intertie zone* will receive a zero schedule for *energy* and *operating reserve* and the *intertie operating reserve* prices shall be set equal to the *locational marginal price* for the *reference bus* for that class of *operating reserve* plus the applicable shadow prices associated with regional minimum and maximum *operating reserve* requirements.

16.5 Pricing for Islanded Nodes

16.5.1 For *non-quick start resources* that are not connected to the *main island*, the *pre-dispatch calculation engine* may use the following reconnection logic where enabled by the *IESO* in the order set out below to calculate the *locational marginal prices* for *energy*:

16.5.1.1 Determine the connection paths over open switches that connect the *non-quick start resource* to the *main island*;

16.5.1.2 Determine the priority rating for each connection path identified based on a weighted sum of the base voltage over all open switches used by the reconnection path and the MW ratings of the newly connected branches; and

16.5.1.3 Select the reconnection path with the highest priority rating, breaking ties arbitrarily.

16.5.2 For all (i) *resources* other than those specified in section 16.5.1 not connected to the *main island*; (ii) *non-quick start resources* where a price was not able to be determined in accordance with section 16.5.1; the *pre-dispatch calculation engine* shall use the following logic in the order set out below to calculate *locational marginal prices* for *energy*, using a node-level and *facility*-level substitution list determined by the *IESO*:

16.5.2.1 Use the *locational marginal price* for *energy* at a node in the node-level substitution list where defined and enabled by the *IESO*, provided such node is connected to the *main island*;

16.5.2.2 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes at the same voltage level within the same *facility* that are connected to the *main island*;

16.5.2.3 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes within the same *facility* that are connected to the *main island*;

16.5.2.4 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes from another *facility* that is connected to the *main island*, as determined by the *facility*-level substitution list where defined and enabled by the *IESO*; and

16.5.2.5 If a price is unable to be determined in accordance with sections 16.5.2.2 through 16.5.2.4, use the *locational marginal price* for *energy* for the *reference bus*.

Appendix 7.6 – The Real-Time Calculation Engine Process

1.1 Purpose

1.1.1 This appendix describes the process used by the *real-time calculation engine* to determine schedules and prices for the *real-time market* and real-time look-ahead period.

2 Real-Time Calculation Engine

2.1 Real-Time Look-Ahead Period

2.11 The real-time look-ahead period is the time horizon of the multi-interval optimization that includes the *dispatch interval* and the subsequent ten five-minute intervals.

2.2 Real-Time Calculation Engine Pass

2.2.1 The *real-time calculation engine* shall execute one pass, Pass 1, the Real-Time Scheduling and Pricing Pass in accordance with section 7, to produce *real-time schedules* and *locational marginal prices*.

3 Information Used by the Real-Time Calculation Engine

3.1.1 The *real-time calculation engine* shall use the information in section 3A.1 of Chapter 7.

4 Sets, Indices and Parameters Used by the Real-Time Calculation Engine

4.1 Fundamental Sets and Indices

4.1.1 A designates the set of all *intertie zones*;

4.1.2 B designates the set of buses identifying all *dispatchable* and non-*dispatchable resources* within Ontario;

4.1.3 $B^{DG} \subseteq B$ designates the set of buses identifying *dispatchable generation resources*;

4.1.4 $B^{DL} \subseteq B$ designates the set of buses identifying *dispatchable loads*;

4.1.5 $B^{HDR} \subseteq B$ designates the set of buses identifying *hourly demand response resources*;

4.1.6 $B^{HE} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources*;

4.1.7 $B^{NDG} \subseteq B$ designates the set of buses identifying *non-dispatchable generation resources*;

4.1.8 $B^{NoBid} \subseteq B$ designates the set of buses identifying *dispatchable loads* with no *bid* for *energy*;

4.1.9 $B^{NoOffer} \subseteq B$ designates the set of buses identifying *generation resources* with no *offer* for *energy*;

4.1.10 $B^{NO10DF} \subseteq B^{PSU}$ designates the subset of buses identifying *pseudo-units* that cannot provide *ten-minute operating reserve* from the duct firing region;

4.1.11 $B^{NQS} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable non-quick start resources*;

4.1.12 $B^{PSU} \subseteq B^{NQS}$ designates the subset of buses identifying *pseudo-units*;

4.1.13 $B_r^{REG} \subseteq B$ designates the set of internal buses in *operating reserve* region $r \in ORREG$;

4.1.14 $B_p^{ST} \subseteq B^{PSU}$ designates the subset of buses identifying *pseudo-units* with a share of steam turbine *resource* $p \in PST$;

4.1.15 $B^{VG} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable variable generation resources*;

4.1.16 C designates the set of contingencies that shall be considered in the *security* assessment function;

4.1.17 D designates the set of buses outside Ontario, corresponding to imports and exports at *intertie zones*;

4.1.18 $D_r^{REG} \subseteq D$ designates the set of *intertie zone* buses identifying *boundary entity resources* in *operating reserve* region $r \in ORREG$;

4.1.19 $D_a \subseteq D$ designates the set of all buses identifying *boundary entity resources* in *intertie zone* $a \in A$;

4.1.20 $DI \subseteq D$ designates the subset of k *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers*;

4.1.21 $DI_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers* in *intertie zone* $a \in A$;

4.1.22 $DX \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids*;

4.1.23 $DX_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids* in *intertie zone* $a \in A$;

4.1.24 F designates the set of *facilities* and groups of *facilities* for which transmission constraints may be identified;

4.1.25 $F_i \subseteq F$ designates the set of *facilities* whose pre-contingency limit was violated in interval *i* as determined by a preceding *security* assessment function iteration;

4.1.26 $F_{i,c} \subseteq F$ designates the set of *facilities* whose post-contingency limit for contingency *c* is violated in interval *i* as determined by a preceding *security* assessment function iteration;

4.1.27 $I = \{1,..,n_I\}$ designates the set of all intervals, where n_I designates the number of five-minute intervals considered within the real-time look-ahead period;

4.1.28 $J_{i,b}^{E}$ designates the set of *bid* laminations for *energy* at $b \in B^{DL}$ for interval $i \in I$;

4.1.29 $J_{i,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B^{DL}$ for interval $i \in I$;

4.1.30 $J_{i,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B^{DL}$ for interval $i \in I$;

4.1.31 $J_{i,b}^{30R}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at bus $b \in B^{DL}$ for interval $i \in I$;

4.1.32 $K_{i,b}^{DF} \subseteq K_{i,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the duct firing region of a *pseudo-unit* at bus $b \in B^{PSU}$ in interval $i \in I$;

4.1.33 $K_{i,b}^{DR} \subseteq K_{i,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the *dispatchable* region of a *pseudo-unit* at bus $b \in B^{PSU}$ in interval $i \in I$;

4.1.34 $K_{i,b}^{E}$ designates the set of *offer* laminations for *energy* at $b \in B^{NDG} \cup B^{DG}$ for interval $i \in I$;

4.1.35 $K_{i,b}^{MLP} \subseteq K_{i,b}^{E}$ designates the set of *offer* laminations for *energy* corresponding to the *minimum loading point* region of a *pseudo-unit* at bus $b \in B^{PSU}$ in interval $i \in I$;

4.1.36 $K_{i,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B^{DG}$ for interval $i \in I$;

4.1.37 $K_{i,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B^{DG}$ for interval $i \in I$;

4.1.38 $K_{i,b}^{30R}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at bus $b \in B^{DG}$ for interval $i \in I$;

4.1.39 L designates the set of buses where the *locational marginal prices* represent prices for *delivery points* associated with *non-dispatchable generation resources* and *dispatchable generation resources*, *dispatchable loads*, *hourly demand response resources*, *price responsive loads* and *non-dispatchable loads*;

4.1.40 $L_{m}^{VIRT} \subseteq L$ designates the buses contributing to the *virtual zonal price* for *virtual transaction zone* $m \in M$;

4.1.41 $L_y^{NDL} \subseteq L$ designates the buses contributing to the zonal price for *non-dispatchable load* zone $y \in Y$;

4.1.42 M designates the set of *virtual transaction zones*;

4.1.43 PST designates the set of steam turbine *resources offered* as part of a *pseudo-unit*;

4.1.44 Y designates the *non-dispatchable load* zones in Ontario.

4.2 Market Participant Data Parameters

4.2.1 With respect to a *non-dispatchable generation resource* identified by bus $\mathrm{b} \in \mathrm{B}^{\mathrm{NDG}}$:

4.2.1.1 $FNDG_{i,b}$ designates the fixed quantity of *energy* scheduled for interval $i \in I$;

4.2.1.2 $PNDG_{i,b,k}$ designates the price for the maximum incremental quantity of *energy* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$; and

4.2.1.3 $QNDG_{i,b,k}$ designates the maximum incremental quantity of *energy* that may be scheduled in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$.

4.2.2 With respect to a *dispatchable generation resource* identified by bus $b \in B^{DG}$:

4.2.2.1 $DRRDG_{i,b,w}$ for $w \in \{1,..,NumRRDG_{i,b}\}$ designates the ramp rate in MW per minute at which the *resource* can decrease the amount of *energy* it supplies in interval $i \in I$ while operating in the range between $RmpRngMaxDG_{i,b,w\text{-}1}$ and $RmpRngMaxDG_{i,b,w}$;

4.2.2.2 $NumRRDG_{i,b}$ designates the number of ramp rates provided for interval $i \in I$;

4.2.2.3 $ORRDG_b$ designates the maximum *operating reserve* ramp rate in MW per minute;

4.2.2.4 $PDG_{i,b,k}$ designates the price for the maximum incremental quantity of *energy* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$;

4.2.2.5 $P10SDG_{i,b,k}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10S}$;

4.2.2.6 $P10NDG_{i,b,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10N}$;

4.2.2.7 $P30RDG_{i,b,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$;

4.2.2.8 $QDG_{i,b,k}$ designates the maximum incremental quantity of *energy* above the *minimum loading point* that may be scheduled in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$;

4.2.2.9 $Q10SDG_{i,b,k}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10S}$;

4.2.2.10 $Q10NDG_{i,b,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10N}$;

4.2.2.11 $Q30RDG_{i,b,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$;

4.2.2.12 $RLP30R_{i,b}$ designates the *reserve loading point* for *thirty-minute operating reserve* in interval $i \in I$;

4.2.2.13 $RLP10S_{i,b}$ designates the *reserve loading point* for synchronized *ten-minute operating reserve* in interval $i \in I$;

4.2.2.14 $RmpRngMaxDG_{i,b,w}$ for $w \in \{1,..,NumRRDG_{i,b}\}$ designates the w[th] ramp rate break point for interval $i \in I$;

4.2.2.15 $URRDG_{i,b,w}$ for $w \in \{1,..,NumRRDG_{i,b}\}$ designates the ramp rate in MW per minute at which the *resource* can increase the amount of *energy* it supplies in interval $i \in I$ while operating in the range between

$RmpRngMaxDG_{i,b,w\text{-}1}$ and $RmpRngMaxDG_{i,b,w}$, where $RmpRngMaxDG_{i,b,0}$ shall be equal to zero.

4.2.3 With respect to a *dispatchable non-quick start resource* identified by bus $b \in B^{NQS}$:

4.2.3.1 $MinQDG_b$ designates the *minimum loading point* indicating the minimum output at which the *resource* must be scheduled except for times when the *resource* is starting up or shutting down.

4.2.4 With respect to a *dispatchable* hydroelectric *generation resource* identified by bus $b \in B^{HE}$:

4.2.4.1 $(ForL_{i,b,w}, ForU_{i,b,w})$ for $w \in \{1,..,NFor_{i,b}\}$ designate the lower and upper limits of the *forbidden regions* in interval $i \in I$ and indicate that the *resource* cannot be scheduled between $ForL_{i,b,w}$ and $ForU_{i,b,w}$ for all $w \in \{1,..,NFor_{i,b}\}$.

4.2.5 With respect to a *pseudo-unit* identified by bus $b \in B^{PSU}$:

4.2.5.1 $STShareMLP_b$ designates the steam turbine *resource's* share of the *minimum loading point* region; and

4.2.5.2 $STShareDR_b$ designates the steam turbine *resource's* share of the *dispatchable* region.

4.2.6 With respect to a *generation resource* with no *offer* for *energy* identified by bus $b \in B^{NoOffer}$:

4.2.6.1 $FNOG_{i,b}$ designates the fixed quantity of *energy* scheduled for injection for interval $i \in I$ determined by the *IESO*'s *energy* management system.

4.2.7 With respect to a *dispatchable load* identified by bus $b \in B^{DL}$:

4.2.7.1 $DRRDL_{i,b,w}$ for $w \in \{1,..,NumRRDL_{i,b}\}$ designates the ramp rate in MW per minute at which the *dispatchable load* can decrease its amount of *energy* consumption in interval $i \in I$ while operating in the range between $RmpRngMaxDL_{i,b,w\text{-}1}$ and $RmpRngMaxDL_{i,b,w}$;

4.2.7.2 $NumRRDL_{i,b}$ designates the number of ramp rates provided for interval $i \in I$;

4.2.7.3 $ORRDL_b$ designates the *operating reserve* ramp rate in MW per minute for reductions in load consumption;

4.2.7.4 $PDL_{i,b,j}$ designates the price for the maximum incremental quantity of *energy* in interval $i \in I$ in association with *bid* lamination $j \in J_{i,b}^{E}$;

4.2.7.5 $P10NDL_{i,b,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10N}$;

4.2.7.6 $P10SDL_{i,b,j}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10S}$;

4.2.7.7 $P30RDL_{i,b,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$;

4.2.7.8 $QDL_{i,b,j}$ designates the maximum incremental quantity of *energy* that may be scheduled in interval $i \in I$ in association with *bid* lamination $j \in J_{i,b}^{E}$;

4.2.7.9 $QDLFIRM_{i,b}$ designates the quantity of *energy* that is *bid* at the *maximum market clearing price* in interval $i \in I$;

4.2.7.10 $Q10NDL_{i,b,j}$ designates the maximum incremental quanity of non-synchronized *ten-minute operating reserve* that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10N}$;

4.2.7.11 $Q10SDL_{i,b,j}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10S}$;

4.2.7.12 $Q30RDL_{i,b,j}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$;

4.2.7.13 $RmpRngMaxDL_{i,b,w}$ for $w \in \{1,..,NumRRDL_{i,b}\}$ designates the w[th] ramp rate break point for interval $i \in I$;

4.2.7.14 $URRDL_{i,b,w}$ for $w \in \{1,..,NumRRDL_{i,b}\}$ designates the ramp rate in MW per minute at which the *dispatchable load* can increase its amount of *energy* consumption in interval $i \in I$ while operating in the range between $RmpRngMaxDL_{i,b,w\text{-}1}$ and $RmpRngMaxDL_{i,b,w}$, where $RmpRngMaxDL_{i,b,0}$ shall be equal to zero.

4.2.8 With respect to an *hourly demand response resource* identified by bus $b \in B^{HDR}$:

4.2.8.1 $FHDR_{i,b}$ designates the fixed schedule of *energy* consumption for interval $i \in I$ determined by the activation of the *hourly demand response resource*.

4.2.9 With respect to a *dispatchable load* with no *bid* for *energy* at bus $b \in B^{NoBid}$:

4.2.9.1 $FNBL_{i,b}$ designates the fixed quantity of *energy* scheduled for consumption for interval $i \in I$ determined by the *IESO*'s *energy* management system.

4.2.10 With respect to a *boundary entity resource* import at *intertie zone* bus $d \in DI$, where the *locational marginal price* represents the price for the *intertie metering point* and its fixed schedules are the most recent *interchange schedules*:

4.2.10.1 $FIGPrc_{i,d}$ designates the fixed quantity of *energy* scheduled to import for interval $i \in I$ and used for calculating *locational marginal prices*;

4.2.10.2 $FIGSch_{i,d}$ designates the fixed quantity of *energy* scheduled to import for interval $i \in I$ and used for determining schedules;

4.2.10.3 $F10NIGPrc_{i,d}$ designates the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled for interval $i \in I$ and used for calculating *locational market prices*;

4.2.10.4 $F10NIGSch_{i,d}$ designates the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled for in interval $i \in I$ and used for determining schedules;

4.2.10.5 $F30RIGPrc_{i,d}$ designates the fixed quantity of *thirty-minute operating reserve* scheduled for interval $i \in I$ and used for calculating *locational marginal prices*; and

4.2.10.6 $F30RIGSch_{i,d}$ designates the fixed quantity of *thirty-minute operating reserve* scheduled for interval $i \in I$ and used for determining schedules.

4.2.11 With respect to a *boundary entity resource* export at *intertie zone* bus $d \in DX$, where the *locational marginal price* represents the price for the *intertie metering point* and its fixed schedules are the most recent *interchange schedules*:

4.2.11.1 $FXLPrc_{i,d}$ designates the fixed quantity of *energy* scheduled to export for interval $i \in I$ and used for calculating *locational marginal prices*;

4.2.11.2 $FXLSch_{i,d}$ designates the fixed quantity of *energy* scheduled to export for interval $i \in I$ and used for determining schedules;

4.2.11.3 $F10NXLPrc_{i,d}$ designates the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled for interval $i \in I$ and used for calculating *locational marginal prices*;

4.2.11.4 $F10NXLSch_{i,d}$ designates the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled for interval $i \in I$ and used for determining schedules;

4.2.11.5 $F30RXLPrc_{i,d}$ designates the fixed quantity of *thirty-minute operating reserve* scheduled for interval $i \in I$ and used for calculating *locational marginal prices*; and

4.2.11.6 $F30RXLSch_{i,d}$ designates the fixed quantity of *thirty-minute operating reserve* scheduled for interval $i \in I$ and used for determining schedules.

4.3 IESO Data Parameters

4.3.1 Variable Generation Forecast

4.3.1.1 $FG_{i,b}$ designates the *IESO's* centralized *variable generation* forecast for a *variable generation resource* identified by bus $b \in B^{VG}$ for interval $i \in I$.

4.3.2 Variable Generation Tie-Breaking

4.3.2.1 $NumVG_i$ designates the number of *variable generation resources* in the daily *dispatch* order for interval $i \in I$; and

4.3.2.2 $TBM_{i,b} \in \{1,..,NumVG_i\}$ designates the tie-breaking modifier for the *variable generation resource* at bus $b \in B^{VG}$ for interval $i \in I$.

4.3.3 Operating Reserve Requirements

4.3.3.1 $ORREG$ designates the set of regions for which regional *operating reserve* limits have been defined;

4.3.3.2 $REGMin10R_{i,r}$ designates the minimum requirement for total *ten-minute operating reserve* in region $r \in ORREG$ in interval $i \in I$;

4.3.3.3 $REGMin30R_{i,r}$ designates the minimum requirement for *thirty-minute operating reserve* in region $r \in ORREG$ in interval $i \in I$;

4.3.3.4 $REGMax10R_{i,r}$ designates the maximum amount of total *ten-minute operating reserve* that may be scheduled in region $r \in ORREG$ in interval $i \in I$;

4.3.3.5 $REGMax30R_{i,r}$ designates the maximum amount of *thirty-minute operating reserve* that may be scheduled in region $r \in ORREG$ in interval $i \in I$;

4.3.3.6 $TOT10S_i$ designates the synchronized *ten-minute operating reserve* requirement;

4.3.3.7 $TOT10R_i$ designates the total *ten-minute operating reserve* requirement; and

4.3.3.8 $TOT30R_i$ designates the *thirty-minute operating reserve* requirement.

4.3.4 Resource Minimums and Maximums

4.3.4.1 Where applicable the minimum or maximum output of a *dispatchable generation resource* and minimum or maximum consumption of a *dispatchable load* may be limited due to *reliability* constraints, applicable *contracted ancillary services*, *day-ahead operational commitments*, *pre-dispatch operational commitments*, *outages,* derates, *operating reserve* activation, and other constraints, such that:

4.3.4.1.1 $MaxDF_{i,b}$ designates the maximum output limit in interval i for the duct firing region of a *pseudo-unit* at bus $b \in B^{PSU}$;

4.3.4.1.2 $MaxDG_{i,b}$ designates the most restrictive maximum output limit for the *dispatchable generation resource* in interval *i* at bus $b \in B^{DG}$;

4.3.4.1.3 $MaxDL_{i,b}$ designates the most restrictive maximum consumption limit for the *dispatchable load* in interval *i* at bus $b \in B^{DL}$;

4.3.4.1.4 $MaxDR_{i,b}$ designates the maximum output limit in interval *i* for the *dispatchable* region of a *pseudo-unit* at bus $b \in B^{PSU}$;

4.3.4.1.5 $MinDG_{i,b}$ designates the most restrictive minimum output limit for the *dispatchable generation resource* in interval *i* at bus $b \in B^{DG}$; and

4.3.4.1.6 $MinDL_{i,b}$ designates the most restrictive minimum consumption limit for the *dispatchable load* in interval *i* at bus $b \in B^{DL}$.

4.3.5 Control Action Adjustments for Pricing

4.3.5.1 $CAAdj_i$ designates the *demand* adjustment required to calculate *locational marginal prices* appropriately when voltage reduction or load shedding has been implemented.

4.3.6 Constraint Violation Penalties for interval $i \in I$:

4.3.6.1 $(PLdViolSch_{i,w}, QLdViolSch_{i,w})$ for $w \in \{1,..,N_{LdViol_i}\}$ designate the price-quantity segments of the penalty curve for under *generation* used by the Real-Time Scheduling algorithm in section 8;

4.3.6.2 $(PLdViolPrc_{i,w}, QLdViolPrc_{i,w})$ for $w \in \{1,..,N_{LdViol_i}\}$ designate the price-quantity segments of the penalty curve for under *generation* used by the Real-Time Pricing algorithm in section 9;

4.3.6.3 $(PGenViolSch_{i,w}, QGenViolSch_{i,w})$ for $w \in \{1,..,N_{GenViol_i}\}$ designate the price-quantity segments of the penalty curve for over *generation* used by the Real-Time Scheduling algorithm in section 8;

4.3.6.4 $(PGenViolPrc_{i,w}, QGenViolPrc_{i,w})$ for $w \in \{1,..,N_{GenViol_i}\}$ designate the price-quantity segments of the penalty curve for over *generation* used by the Real-Time Pricing algorithm in section 9;

4.3.6.5 $(P10SViolSch_{i,w}, Q10SViolSch_{i,w})$ for $w \in \{1,..,N_{10SViol_i}\}$ designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used by the Real-Time Scheduling algorithm in section 8;

4.3.6.6 $(P10SViolPrc_{i,w}, Q10SViolPrc_{i,w})$ for $w \in \{1,..,N_{10SViol_i}\}$ designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used by the Real-Time Pricing algorithm in section 9;

4.3.6.7 $(P10RViolSch_{i,w}, Q10RViolSch_{i,w})$ for $w \in \{1,..,N_{10RViol_i}\}$ designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used by the Real-Time Scheduling algorithm in section 8;

4.3.6.8 $(P10RViolPrc_{i,w}, Q10RViolPrc_{i,w})$ for $w \in \{1,..,N_{10RViol_i}\}$ designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used by the Real-Time Pricing algorithm in section 9;

4.3.6.9 $(P30RViolSch_{i,w}, Q30RViolSch_{i,w})$ for $w \in \{1,..,N_{30RViol_i}\}$ designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used by the Real-Time Scheduling algorithm in section 8;

4.3.6.10 $(P30RViolPrc_{i,w}, Q30RViolPrc_{i,w})$ for $w \in \{1,..,N_{30RViol_i}\}$ designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used by the Real-Time Pricing algorithm in section 9;

4.3.6.11 $(PREG10RViolSch_{i,w}, QREG10RViolSch_{i,w})$ for $w \in \{1,..,N_{REG10RViol_i}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used by the Real-Time Scheduling algorithm in section 8;

4.3.6.12 $(PREG10RViolPrc_{i,w}, QREG10RViolPrc_{i,w})$ for $w \in \{1,..,N_{REG10RViol_i}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used by the Real-Time Pricing algorithm in section 9;

4.3.6.13 $(PREG30RViolSch_{i,w}, QREG30RViolSch_{i,w})$ for $w \in \{1,..,N_{REG30RViol_i}\}$ designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used by the Real-Time Scheduling algorithm in section 8;

4.3.6.14 $(PREG30RViolPrc_{i,w}, QREG30RViolPrc_{i,w})$ for $w \in \{1,..,N_{REG30RViol_i}\}$ designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used by the Real-Time Pricing algorithm in section 9;

4.3.6.15 $(PXREG10RViolSch_{i,w}, QXREG10RViolSch_{i,w})$ for $w \in \{1,..,N_{XREG10RViol_i}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used by the Real-Time Scheduling algorithm in section 8;

4.3.6.16 $(PXREG10RViolPrc_{i,w}, QXREG10RViolPrc_{i,w})$ for $w \in \{1,..,N_{XREG10RViol_i}\}$ designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used by the Real-Time Pricing algorithm in section 9;

4.3.6.17 $(PXREG30RViolSch_{i,w}, QXREG30RViolSch_{i,w})$ for $w \in \{1,..,N_{XREG30RViol_i}\}$ designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used by the Real-Time Scheduling algorithm in section 8;

4.3.6.18 $(PXREG30RViolPrc_{i,w}, QXREG30RViolPrc_{i,w})$ for $w \in \{1,..,N_{XREG30RViol_i}\}$ designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used by the Real-Time Pricing algorithm in section 9;

4.3.6.19 $(PPreITLViolSch_{f,i,w}, QPreITLViolSch_{f,i,w})$ for $w \in \{1,..,N_{PreITLViol_{f,i}}\}$ designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Real-Time Scheduling algorithm in section 8;

4.3.6.20 $(PPreITLViolPrc_{f,i,w}, QPreITLViolPrc_{f,i,w})$ for $w \in \{1,..,N_{PreITLViol_{f,i}}\}$ designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Real-Time Pricing algorithm in section 9;

4.3.6.21 $(PITLViolSch_{c,f,i,w}, QITLViolSch_{c,f,i,w})$ for $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$ designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Real-Time Scheduling algorithm in section 8;

4.3.6.22 $(PITLViolPrc_{c,f,i,w}, QITLViolPrc_{c,f,i,w})$ for $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$ designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used by the Real-Time Pricing algorithm in section 9; and

4.3.6.23 $NISLPen$ designates the net interchange scheduling limit constraint violation penalty price for *locational marginal pricing*.

4.3.7 Price Bounds

4.3.7.1 $EngyPrcCeil$ designates and is equal to the *maximum market clearing price* for *energy*;

4.3.7.2 $EngyPrcFlr$ designates and is equal to the *settlement floor price* for *energy*;

4.3.7.3 $ORPrcCeil$ designates and is equal to the *maximum operating reserve price* for all classes of *operating reserve*; and

4.3.7.4 $ORPrcFlr$ designates the minimum price for all classes of *operating reserve* and is equal to $0/MW.

4.3.8 Weighting Factors for Zonal Prices

4.3.8.1 $WF^{VIRT}_{i,m,b}$ designates the weighting factor for bus $b \in L^{VIRT}_{m}$ used to calculate the price for *virtual transaction zone* $m \in M$ for interval $i \in I$ and shall be equal to the weighting factor used in the *day-ahead market* for the applicable hour;

4.3.8.2 $WF^{NDL}_{i,y,b}$ designates the weighting factor for bus $b \in L^{NDL}_{y}$ used to calculate the price for *non-dispatchable load* zone $y \in Y$ for interval $i \in I$ and shall be obtained by renormalizing the load distribution factors so that the sum of weighting factors for a *non-dispatchable load* zone and for a given interval is one.

4.4 Other Data Parameters

4.4.1 Non-Dispatchable Demand Forecast

4.4.1.1 FL_i designates the five-minute province-wide non-*dispatchable demand* forecast for interval $i \in I$ calculated by the *security* assessment function.

4.4.2 Internal Transmission Constraints

4.4.2.1 $PreConSF_{i,f,b}$ designates the pre-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during interval i under pre-contingency conditions;

4.4.2.2 $AdjNormMaxFlow_{i,f}$ designates the limit corresponding to the maximum flow allowed on *facility* f in interval i under pre-contingency conditions;

4.4.2.3 $SF_{i,c,f,b}$ designates the post-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during interval i under post-contingency conditions for contingency c; and

4.4.2.4 $AdjEmMaxFlow_{i,c,f}$ designates the limit corresponding to the maximum flow allowed on *facility* f in interval i under post-contingency conditions for contingency c.

4.4.3 Transmission Losses

4.4.3.1 $LossAdj_i$ designates any adjustment needed for interval $i \in I$ to correct for any discrepancy between Ontario total system losses calculated using a base case power flow from the *security* assessment function and linearized losses that would be calculated using the marginal loss factors; and

4.4.3.2 $MglLoss_{i,b}$ designates the marginal loss factor and represents the marginal impact on transmission losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at *resource* bus $b \in B \cup D$ in interval $i \in I$.

5 Initialization

5.1 Purpose

5.1.1 The initialization processes set out in this section shall occur prior to the execution of the *real-time calculation engine* described in section 2.2.1 above.

5.2 Reference Bus

5.2.1 The *IESO* shall use Richview Transformer Station as the *real-time calculation engine's* default *reference bus* for the calculation of *locational marginal prices*.

5.2.2 If the default *reference bus* is out of service, another in-service bus shall be selected.

5.3 Islanding Conditions

5.3.1 In the event of a network split, the *real-time calculation engine* shall:

5.3.1.1 only evaluate *resources* that are within the *main island*;

5.3.1.2 use only forecasts of *demand* forecast areas in the *main island*; and

5.3.1.3 use a bus within the *main island* in place of the *reference bus* if the *reference bus* does not fall within the *main island*.

5.4 Variable Generation Tie-Breaking

5.4.1 For each interval $i \in I$, each *variable generation resource* bus $b \in B^{VG}$ and each *offer* lamination $k \in K^{E}_{i,b}$, the *offer* price $PDG_{i,b,k}$ shall be updated to $PDG_{i,b,k}$-$\left(\frac{TBM_{i,b}}{NumVG_i}\right)\rho$, where ρ is a small nominal value of order 10^{-4}.

5.5 Pseudo-Unit Constraints

5.5.1 Constraints for *pseudo-units* corresponding to the minimum and maximum constraints on physical *resources* shall be determined in accordance with section 10.

5.6 Initial Scheduling Assumptions

5.6.1 Initial Schedules

5.6.1.1 Initial *energy* schedules shall be based on the values determined by the *IESO's energy* management system and the schedules from the previous *real-time calculation engine* run, where:

5.6.1.1.1 $RTDLTel_{-1,b}$ designates the *energy* management system MW value for the *dispatchable load* at bus $b \in B^{DL}$;

5.6.1.1.2 $SDLSch_{0,b}^{Prev}$ designates the schedule determined for the *dispatchable load* at bus $b \in B^{DL}$ by the Real-Time Scheduling algorithm in section 8, of the previous *real-time calculation engine* run;

5.6.1.1.3 $RTDGTel_{-1,b}$ designates the *energy* management system MW value for the *dispatchable generation resource* at bus $b \in B^{DG}$;

5.6.1.1.4 $SDGSch_{0,b}^{Prev}$ designates the schedule determined for the *dispatchable generation resource* at bus $b \in B^{DG}$ by the Real-Time Scheduling algorithm in section 8, of the previous *real-time calculation engine* run;

5.6.1.1.5 $SDLPrc_{0,b}^{Prev}$ designates the schedule determined for the *dispatchable load* at bus $b \in B^{DL}$ by the Real-Time Pricing algorithm in section 9, of the previous *real-time calculation engine* run; and

5.6.1.1.6 $SDGPrc_{0,b}^{Prev}$ designates the schedule determined for the *dispatchable generation resource* at bus $b \in B^{DG}$ by the Real-Time Pricing algorithm in section 9, of the previous *real-time calculation engine* run.

5.6.1.2 For the *dispatchable load* at bus b, the intitial schedule, $SDLInitSch_{0,b}$, for the Real-Time Scheduling algorithm in section 8, shall be determined as follows:

5.6.1.2.1 Step 1: Calculate $TelUp_{0,b}$ using the submitted up ramp rates and break points to determine the maximum consumption level the *dispatchable load* can achieve in five minutes from $RTDLTel_{-1,b}$;

5.6.1.2.2 Step 2: Calculate $TelDown_{0,b}$ using the submitted down ramp rates and break points to determine the minimum consumption level the *dispatchable load* can achieve in five minutes from $RTDLTel_{-1,b}$; and

5.6.1.2.3 Step 3: If the schedule from the previous *real-time calculation engine* run is achievable by ramping from the $RTDLTel_{-1,b}$, then set the initial schedule to the schedule from the previous *real-time calculation engine* run. Otherwise, set the initial schedule to the nearest boundary:

If $TelDown_{0,b} \leq SDLSch_{0,b}^{Prev} \leq TelUp_{0,b}$, then set $SDLInitSch_{0,b} = SDLSch_{0,b}^{Prev}$

If $SDLSch_{0,b}^{Prev} < TelDown_{0,b}$, then set $SDLInitSch_{0,b} = TelDown_{0,b}$

Otherwise, set $SDLInitSch_{0,b} = TelUp_{0,b}$.

5.6.1.3 For the *dispatchable generation resource* at bus b, the intitial schedule, $SDGInitSch_{0,b}$, for the Real-Time Scheduling algorithm in section 8, shall be determined as follows:

5.6.1.3.1 Step 1: Calculate $TelUp_{0,b}$ using the submitted up ramp rates and break points to determine the maximum production level the *resource* can achieve in five minutes from $RTDGTel_{-1,b}$;

5.6.1.3.2 Step 2: Calculate $TelDown_{0,b}$ using the submitted down ramp rates and break points to determine the minimum production level the *resource* can achieve in five minutes from $RTDGTel_{-1,b}$; and

5.6.1.3.3 Step 3: If the schedule from the previous *real-time calculation engine* run is achievable by ramping from the $RTDGTel_{-1,b}$, then set the initial schedule to the schedule from the previous *real-time calculation engine* run. Otherwise, set the initial schedule to the nearest boundary:

If $TelDown_{0,b} \leq SDGSch_{0,b}^{Prev} \leq TelUp_{0,b}$ then set $SDGInitSch_{0,b} = SDGSch_{0,b}^{Prev}$

If $SDGSch_{0,b}^{Prev} < TelDown_{0,b}$ then set $SDGInitSch_{0,b} = TelDown_{0,b}$

Otherwise, set $SDGInitSch_{0,b} = TelUp_{0,b}$.

5.6.1.4 For the *dispatchable load* at bus b, the intitial schedule, $SDLInitPrc_{0,b}$, for the Real-Time Pricing algorithm in section 9, shall be determined as follows:

If $SDLSch_{0,b}^{Prev} \leq SDLPrc_{0,b}^{Prev} \leq SDLInitSch_{0,b}$ or $SDLInitSch_{0,b} \leq SDLPrc_{0,b}^{Prev} \leq SDLSch_{0,b}^{Prev}$, then set $SDLInitPrc_{0,b} = SDLInitSch_{0,b}$;

Otherwise set $SDLInitPrc_{0,b} = SDLPrc_{0,b}^{Prev}$.

5.6.1.5 For the *dispatchable generation* at bus *b*, the intitial schedule $SDGInitPrc_{0,b}$, for the Real-Time Pricing algorithm in section 9, designates the initial schedule for the *dispatchable generation resource* at bus *b* and is determined as follows:

If $SDGSch_{0,b}^{Prev} \leq SDGPrc_{0,b}^{Prev} \leq SDGInitSch_{0,b}$ or $SDGInitSch_{0,b} \leq SDGPrc_{0,b}^{Prev} \leq SDGSch_{0,b}^{Prev}$ then set $SDGInitPrc_{0,b} = SDGInitSch_{0,b}$;

Otherwise set $SDGInitPrc_{0,b} = SDGPrc_{0,b}^{Prev}$.

5.6.2 Start-up and Shutdown for Non-Quick Start Resources

5.6.2.1 The start-up and shutdown for *non-quick start resources* at bus $b \in B^{NQS}$ and interval $i \in I$ shall be based on the following parameters that are determined based on observed *resource* operation as well as confirmed start-up and shutdown times:

5.6.2.1.1 $AtZero_{i,b} \in \{0,1\}$, which designates that the *resource* is scheduled to be offline;

5.6.2.1.2 $SU_{i,b} \in \{0,1\}$, which designates that the *resource* must be scheduled on its start-up trajectory. This input may indicate an upcoming confirmed start-up or that the *resource* has started ramping up already;

5.6.2.1.3 $AtMLP_{i,b} \in \{0,1\}$, which designates that the *resource* is scheduled to operate at or above its *minimum loading point* due to a minimum generation constraint or the *resource* shutdown has yet to be confirmed by the *IESO*;

5.6.2.1.4 $EvalSD_{i,b} \in \{0,1\}$, which designates that the *resource* has been de-committed by the *pre-dispatch calculation engine*, such de-commitment has been confirmed by the *IESO,* and the *resource* can be evaluated for *energy* schedules below its *minimum loading point* but can still be scheduled at or above its *minimum loading point*; and

5.6.2.1.5 $SD_{i,b} \in \{0,1\}$, which designates that the *resource* must be scheduled on its shutdown trajectory. This input may indicate an upcoming mandatory shutdown or that the *resource* has already started ramping down.

5.6.2.2 For all parameters in section 5.6.2.1:

$$AtZero_{i,b} + SU_{i,b} + AtMLP_{i,b} + EvalSD_{i,b} + SD_{i,b} = 1$$

6 Security Assessment Function in the Real-Time Calculation Engine

6.1 Interaction between the Security Assessment Function and Optimization Functions

6.1.1 The scheduling and pricing algorithms of the *real-time calculation engine* pass shall perform multiple iterations of the optimization functions and the *security* assessment function to check for violations of monitored thermal limits and operating *security limits* using the schedules produced by the optimization functions.

6.1.2 As multiple iterations are performed, the transmission constraints produced by the *security* assessment function shall be used by the optimization functions.

6.1.3 The *security* assessment function shall use the physical *resource* representation of *combined cycle plant* that are registered as *pseudo-units*.

6.2 Inputs into the Security Assessment Function

6.2.1 The *security* assessment function shall use the following inputs:

6.2.1.1 the *IESO demand* forecasts; and

6.2.1.2 applicable *IESO-controlled grid* information pursuant to section 3A.1 of Chapter 7.

6.2.2 The *security* assessment function shall also use the following outputs of the optimization functions:

6.2.2.1 the schedules for *dispatchable loads* and *hourly demand response resources*;

6.2.2.2 the schedules for *non-dispatchable generation resources* and *dispatchable generation resources*; and

6.2.2.3 the schedules for *boundary entity resources* at each *intertie zone*.

6.3 Security Assessment Function Processing

6.3.1 The *security* assessment function shall determine the province-wide non-*dispatchable demand* forecast quantity, FL_i, using *demand* forecasts for *demand* forecast areas, the *IESO's energy* management system MW quantities and the scheduled quantities from the previous *real-time calculation engine* run as follows:

6.3.1.1 sum the *IESO* five-minute *demand* forecasts for *demand* forecast areas;

6.3.1.2 subtract the expected consumption of all physical *hourly demand response resources*;

6.3.1.3 subtract the expected consumption of all virtual *hourly demand response resources*; and

6.3.1.4 subtract the expected consumption of all *dispatchable loads*.

6.3.2 The *security* assessment function shall perform the following calculations and analyses:

6.3.2.1 A base case solution function shall prepare a power flow solution for each interval in the real-time look-ahead period. The base case solution function shall select the power system model state applicable to the forecast of conditions for the interval and input schedules.

6.3.2.2 The base case solution function shall use an AC power flow analysis. If the AC power flow analysis fails to converge, the base case solution function shall use a non-linear DC power flow analysis. If the non-linear DC power flow analysis fails to converge, the base case solution function shall use a linear DC power flow analysis.

6.3.2.3 If the AC or non-linear DC power flow analysis converges, continuous thermal limits for all monitored equipment and operating *security limits* shall be monitored to check for pre-contingency limit violations.

6.3.2.4 Violated pre-contingency limits shall be linearized using pre-contingency sensitivity factors and incorporated as constraints for use by the optimization functions.

6.3.2.5 If the linear DC power flow analysis is used, the pre-contingency *security* assessment may develop linear constraints to facilitate the convergence of the AC or non-linear DC power flow analysis in the subsequent iterations.

6.3.2.6 A linear power flow analysis shall be used to simulate contingencies, calculate post-contingency flows and check all monitored equipment for limited-time thermal limit violations.

6.3.2.7 Violated post-contingency limits shall be linearized using post-contingency sensitivity factors and incorporated as constraints for use by the optimization functions.

6.3.2.8 The base case solution shall be used to calculate Ontario *transmission system* losses, marginal loss factors and loss adjustment for each interval. The impact of losses on branches between the *resource* bus and the *resource connection point* to the *IESO-controlled grid* and losses on branches outside Ontario shall be excluded when determining marginal loss factors.

6.3.2.9 The *real-time calculation engine* shall use a set of fixed marginal loss factors for each *dispatch hour*. The same set of fixed marginal loss factors shall apply to all five-minute intervals that fall in the *dispatch hour.* The set of fixed marginal loss factors for each *dispatch hour* shall be determined based on the marginal loss factors calculated in the previous hour by the Real-Time Scheduling algorithm in section 8 of the *real-time calculation engine*.

6.3.2.10 The marginal loss factors for the advisory intervals that fall in the hour following the *dispatch hour* shall be determined based on the fixed marginal loss factors for the *dispatch hour* described in section 6.3.2.9 and the marginal loss factors calculated by the Real-Time Scheduling algorithm in section 8 of the previous *real-time calculation engine* run.

6.3.2.11 The Real-Time Scheduling and Real-Time Pricing algorithms in sections 8 and 9, respectively, shall use the same set of marginal loss factors.

6.4 Outputs from the Security Assessment Function

6.4.1 The outputs of the *security* assessment function used in the optimization functions include the following:

6.4.1.1 a set of linearized constraints for all violated pre-contingency and post-contingency limits for each interval. The sensitivities and limits associated with the constraints shall be those provided by the most recent *security* assessment function iteration;

6.4.1.2 pre-contingency and post-contingency sensitivity factors for each interval;

6.4.1.3 the marginal loss factors as described in sections 6.3.2.8 – 6.3.2.11; and

6.4.1.4 loss adjustment quantity for each interval.

7 Pass 1: Real-Time Scheduling and Pricing

7.1.1 Pass 1 shall use *market participant* and *IESO* inputs and *resource* and system constraints to determine a set of *resource* schedules and *locational marginal prices*. Pass 1 shall consist of the following algorithms:

- the Real-Time Scheduling algorithm described in section 8;
- the Real-Time Pricing algorithm described in section 9;

8 Real-Time Scheduling

8.1 Purpose

8.1.1 The Real-Time Scheduling algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade using *dispatch data* submitted by *registered market participants* or where applicable, the *reference level values* for *financial dispatch data parameters* mitigated in previous *pre-dispatch calculation engine* runs in accordance with Appendix 7.5A, section 14.7, to meet the *IESO's* province-wide non-*dispatchable demand* forecast and *IESO*-specified *operating reserve* requirements for each interval of the real-time look-ahead period.

8.2 Information, Sets, Indices and Parameters

8.2.1 Information, sets, indices and parameters used by Real-Time Scheduling algorithm are described in sections 3 and 4.

8.3 Variables and Objective Function

8.3.1 The Real-Time Scheduling algorithm shall solve for the following variables:

8.3.1.1 $SDL_{i,b,j}$, which designates the amount of *energy* that a *dispatchable load* scheduled at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{E}_{i,b}$;

8.3.1.2 $S10SDL_{i,b,j}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{10S}_{i,b}$;

8.3.1.3 $S10NDL_{i,b,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{10N}_{i,b}$;

8.3.1.4 $S30RDL_{i,b,j}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{30R}_{i,b}$;

8.3.1.5 $SNDG_{i,b,k}$, which designates the amount of *energy* that a *non-dispatchable generation resource* scheduled at bus $b \in B^{NDG}$ in interval $i \in I$ in association with lamination $k \in K^{E}_{i,b}$;

8.3.1.6 $SDG_{i,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{E}_{i,b}$;

8.3.1.7 $S10SDG_{i,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{10S}_{i,b}$;

8.3.1.8 $S10NDG_{i,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{10N}_{i,b}$;

8.3.1.9 $S30RDG_{i,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{30R}_{i,b}$;

8.3.1.10 $SCT_{i,b}$, which designates the schedule of the combustion turbine *resource* associated with the *pseudo-unit* at bus $b \in B^{PSU}$ in interval $i \in I$;

8.3.1.11 $SST_{i,p}$, which designates the schedule of steam turbine *resource* $p \in PST$ in interval $i \in I$;

8.3.1.12 TB_i, which designates any adjustment to the objective function to facilitate pro-rata tie-breaking in interval $i \in I$, as described in section 8.3.2.1; and

8.3.1.13 $ViolCost_i$, which designates the cost incurred in order to avoid having the schedules violate constraints for interval $i \in I$, as described in section 8.3.2.3.

8.3.2 The objective function for the Real-Time Scheduling algorithm shall maximize gains from trade by maximizing the following expression:

$$\sum_{i=1..n_I} (ObjDL_i - ObjNDG_i - ObjDG_i - TB_i - ViolCost_i)$$

where:

$$ObjDL_i = \sum_{b \in B^{DL}} \left(\begin{array}{l} \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} \cdot PDL_{i,b,j} - \sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \cdot P10SDL_{i,b,j} - \\ \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \cdot P10NDL_{i,b,j} - \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \cdot P30RDL_{i,b,j} \end{array} \right);$$

$$ObjNDG_i = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} \cdot PNDG_{i,b,k} \right);$$

and

$$ObjDG_i = \sum_{b \in B^{DG}} \left(\begin{array}{l} \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \cdot PDG_{i,b,k} + \sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \cdot P10SDG_{i,b,k} + \\ \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \cdot P10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \cdot P30RDG_{i,b,k} \end{array} \right).$$

8.3.2.1 The tie-breaking term (TB_i) shall sum a term for each *bid* or *offer* lamination. For each lamination, this term shall be the product of a small penalty cost and the quantity of the lamination scheduled. The penalty cost shall be calculated by multiplying a base penalty cost of $TBPen$ by the amount of the lamination scheduled and then dividing by the maximum amount that could have been scheduled. That is:

$$TB_i = TBDL_i + TBNDG_i + TBDG_i$$

where:

$$TBDL_i = \sum_{b \in B^{DL}} \left(\begin{array}{l} \sum_{j \in J_{i,b}^{E}} \left(\frac{\left(SDL_{i,b,j}\right)^2 \cdot TBPen}{QDL_{i,b,j}} \right) + \sum_{j \in J_{i,b}^{10S}} \left(\frac{\left(S10SDL_{i,b,j}\right)^2 \cdot TBPen}{Q10SDL_{i,b,j}} \right) + \\ \sum_{j \in J_{i,b}^{10N}} \left(\frac{\left(S10NDL_{i,b,j}\right)^2 \cdot TBPen}{Q10NDL_{i,b,j}} \right) + \sum_{j \in J_{i,b}^{30R}} \left(\frac{\left(S30RDL_{i,b,j}\right)^2 \cdot TBPen}{Q30RDL_{i,b,j}} \right) \end{array} \right);$$

$$TBNDG_i = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{i,b}^{E}} \left(\frac{\left(SNDG_{i,b,k}\right)^2 \cdot TBPen}{QNDG_{i,b,k}} \right) \right);$$

and

$$TBDG_i = \sum_{b \in B^{DG}} \left(\begin{array}{l} \sum_{k \in K_{i,b}^{E}} \left(\frac{\left(SDG_{i,b,k}\right)^2 \cdot TBPen}{QDG_{i,b,k}} \right) + \sum_{k \in K_{i,b}^{10S}} \left(\frac{\left(S10SDG_{i,b,k}\right)^2 \cdot TBPen}{Q10SDG_{i,b,k}} \right) + \\ \sum_{k \in K_{i,b}^{10N}} \left(\frac{\left(S10NDG_{i,b,k}\right)^2 \cdot TBPen}{Q10NDG_{i,b,k}} \right) + \sum_{k \in K_{i,b}^{30R}} \left(\frac{\left(S30RDG_{i,b,k}\right)^2 \cdot TBPen}{Q30RDG_{i,b,k}} \right) \end{array} \right).$$

8.3.2.1 $ViolCost_i$ shall be calculated for interval $i \in I$ using the following variables:

8.3.2.2.1 $SLdViol_{i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{LdViol_i}\}$ of the penalty curve for the *energy* balance constraint allowing under-generation;

8.3.2.2.2 $SGenViol_{i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{GenViol_i}\}$ of the penalty curve for the *energy* balance constraint allowing over-generation;

8.3.2.2.3 $S10SViol_{i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{10SViol_i}\}$ of the penalty curve for the synchronized *ten-minute operating reserve* requirement;

8.3.2.2.4 $S10RViol_{i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{10RViol_i}\}$ of the penalty curve for the total *ten-minute operating reserve* requirement;

8.3.2.2.5 $S30RViol_{i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{30RViol_i}\}$ of the penalty curve for the *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement;

8.3.2.2.6 $SREG10RViol_{r,i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{REG10RViol_i}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* minimum requirement in region $r \in ORREG$;

8.3.2.2.7 $SREG30RViol_{r,i,w}$, which designates the violation variable affiliated with segment $\mathrm{w} \in \{1,..,N_{REG30RViol_i}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* minimum requirement in region $r \in ORREG$;

8.3.2.2.8 $SXREG10RViol_{r,i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{XREG10RViol_i}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* maximum restriction in region $r \in ORREG$;

8.3.2.2.9 $SXREG30RViol_{r,i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{XREG30RViol_i}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* maximum restriction in region $r \in ORREG$;

8.3.2.2.10 $SPreITLViol_{f,i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{PreITLViol_{f,i}}\}$ of the penalty curve for violating the pre-contingency transmission limit for *facility* $f \in F$; and

8.3.2.2.11 $SITLViol_{c,f,i,w}$, which designates the violation variable affiliated with segment $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$ of the penalty curve for violating the post-contingency transmission limit for *facility* $f \in F$ and contingency $c \in C$.

8.3.2.2 $ViolCost_i$ shall be calculated as follows:

$$
\begin{aligned}
ViolCost_i = & \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \cdot PLdViolSch_{i,w} \\
& - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} \cdot PGenViolSch_{i,w} \\
& + \sum_{w=1..N_{10SViol_i}} S10SViol_{i,w} \cdot P10SViolSch_{i,w} \\
& + \sum_{w=1..N_{10RViol_i}} S10RViol_{i,w} \cdot P10RViolSch_{i,w} \\
& + \sum_{w=1..N_{30RViol_i}} S30RViol_{i,w} \cdot P30RViolSch_{i,w} \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG10RViol_i}} SREG10RViol_{r,i,w} \cdot PREG10RViolSch_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG30RViol_i}} SREG30RViol_{r,i,w} \cdot PREG30RViolSch_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \cdot PXREG10RViolSch_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG30RViol_i}} SXREG30RViol_{r,i,w} \cdot PXREG30RViolSch_{i,w} \right)
\end{aligned}
$$

$$+\sum_{f\in F_i}\left(\sum_{w=1..N_{PreITLViol_{f,i}}} SPreITLViol_{f,i,w}\cdot PPreITLViolSch_{f,i,w}\right)$$

$$+\sum_{c\in C}\sum_{f\in F_{i,c}}\left(\sum_{w=1..N_{ITLViol_{c,f,i}}} SITLViol_{c,f,i,w}\cdot PITLViolSch_{c,f,i,w}\right).$$

8.4 Constraints

8.4.1 The Real-Time Scheduling algorithm optimization function shall apply the constraints described in sections 8.5 – 8.7.

8.5 Dispatch Data Constraints Applying to Individual Intervals

8.5.1 Scheduling Variable Bounds

8.5.1.1 No schedule shall be negative, nor shall any schedule exceed the quantity *offered* for *energy* and *operating reserve* respectively. Therefore:

$0 \le SDL_{i,b,j} \le QDL_{i,b,j}$ for all $b\in B^{DL}$, $j\in J_{i,b}^{E}$;

$0 \le S10SDL_{i,b,j} \le Q10SDL_{i,b,j}$ for all $b\in B^{DL}$, $j\in J_{i,b}^{10S}$;

$0 \le S10NDL_{i,b,j} \le Q10NDL_{i,b,j}$ for all $b\in B^{DL}$, $j\in J_{i,b}^{10N}$;

$0 \le S30RDL_{i,b,j} \le Q30RDL_{i,b,j}$ for all $b\in B^{DL}$, $j\in J_{i,b}^{30R}$;

$0 \le SNDG_{i,b,k} \le QNDG_{i,b,k}$ for all $b\in B^{NDG}$, $k\in K_{i,b}^{E}$;

$0 \le SDG_{i,b,k} \le QDG_{i,b,k}$ for all $b\in B^{DG}$, $k\in K_{i,b}^{E}$;

$0 \le S10SDG_{i,b,k} \le Q10SDG_{i,b,k}$ for all $b\in B^{DG}$, $k\in K_{i,b}^{10S}$;

$0 \le S10NDG_{i,b,k} \le Q10NDG_{i,b,k}$ for all $b\in B^{DG}$, $k\in K_{i,b}^{10N}$; and

$0 \le S30RDG_{i,b,k} \le Q30RDG_{i,b,k}$ for all $b\in B^{DG}$, $k\in K_{i,b}^{30R}$

for all intervals $i\in I$.

8.5.1.2 A *non-quick start resource* cannot provide *energy* when it is scheduled to be offline. Therefore, for all intervals $i \in I$, *non-quick start resource* buses $b \in B^{NQS}$, and *offer* laminations $k \in K_{i,b}^{E}$:

$$0 \leq SDG_{i,b,k} \leq \left(1 - AtZero_{i,b}\right) \cdot QDG_{i,b,k}.$$

8.5.1.3 A *non-quick start resource* cannot provide *operating reserve* unless it is scheduled at or above its *minimum loading point*. Therefore, for all intervals $i \in I$ and *non-quick start resource* buses $b \in B^{NQS}$:

$$0 \leq S10SDG_{i,b,k} \leq (AtMLP_{i,b} + EvalSD_{i,b}) \cdot Q10SDG_{i,b,k} \qquad \text{for all } k \in K_{i,b}^{10S};$$

$$0 \leq S10NDG_{i,b,k} \leq (AtMLP_{i,b} + EvalSD_{i,b}) \cdot Q10NDG_{i,b,k} \qquad \text{for all } k \in K_{i,b}^{10N}; \text{ and}$$

$$0 \leq S30RDG_{i,b,k} \leq (AtMLP_{i,b} + EvalSD_{i,b}) \cdot Q30RDG_{i,b,k} \qquad \text{for all } k \in K_{i,b}^{30R}.$$

8.5.2 Resource Initial Conditions

8.5.2.1 The initial schedule for a *dispatchable load* at bus $b \in B^{DL}$ shall be fixed to the *resource* initial schedules. For all *dispatchable load* buses $b \in B^{DL}$:

$$\sum_{j \in J_{0,b}^{B}} SDL_{0,b,j} = SDLInitSch_{0,b}$$

8.5.2.2 The initial schedule for a *dispatchable generation resource* at bus $b \in B^{DG}$ shall be fixed to the *resource* initial schedules. For all *dispatchable generation resource* buses $b \in B^{DG}$:

$$\sum_{k \in K_{0,b}^{E}} SDG_{0,b,k} = SDGInitSch_{0,b}$$

8.5.3 Resource Minimums and Maximums for Energy

8.5.3.1 A constraint shall limit schedules for *dispatchable loads* within their minimum and maximum consumption for an interval. For all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$MinDL_{i,b} \leq \sum_{j \in J_{i,b}^{B}} SDL_{i,b,j} \leq MaxDL_{i,b}.$$

8.5.3.2 The non-*dispatchable* portion of a *dispatchable load* shall always be scheduled. For all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} \geq QDLFIRM_{i,b}.$$

8.5.3.3 The *non-dispatchable generation resources* shall be scheduled to the fixed quantity determined by their observed output. For all intervals $i \in I$ and all buses $b \in B^{NDG}$:

$$\sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} = FNDG_{i,b}.$$

8.5.3.4 A constraint shall limit schedules for *dispatchable generation resources* within their minimum and maximum output for an interval. For a *dispatchable variable generation resource*, the maximum schedule shall be limited by its forecast. That is:

8.5.3.4.1 For all intervals $i \in I$ and all buses $b \in B^{DG}$,

$$AdjMaxDG_{i,b} = \begin{cases} min(MaxDG_{i,b}, FG_{i,b}) & if\ b \in B^{VG} \\ MaxDG_{i,b} & otherwise \end{cases}$$

and

$$AdjMinDG_{i,b} = min\left(MinDG_{i,b}, AdjMaxDG_{i,b}\right).$$

8.5.3.4.2 For all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{i,b} \leq \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \leq AdjMaxDG_{i,b}.$$

8.5.3.5 A constraint shall limit the schedule for a *non-quick start resource* at or above its *minimum loading point* when such *resource* is committed or when the *resource* shutdown is yet to be confirmed by the *IESO*. For all *non-quick start resource* buses $b \in B^{NQS}$ and intervals $i \in I$:

$$\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \geq AtMLP_{i,b} \cdot MinQDG_{b}.$$

8.5.4 Operating Reserve Requirements

8.5.4.1 The total synchronized *ten-minute operating reserve*, non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* scheduled from a *dispatchable load* shall not exceed:

8.5.4.1.1 the *dispatchable load's* ramp capability over 30 minutes;

8.5.4.1.2 the total scheduled consumption less the non-*dispatchable* portion; and

8.5.4.1.3 the remaining portion of its capacity that is *dispatchable* after considering minimum load consumption constraints.

8.5.4.2 These restrictions shall be enforced by the following constraints for all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq 30 \cdot ORRDL_b;$$

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{B}} SDL_{i,b,j} - QDLFIRM_{i,b};$$

and

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{B}} SDL_{i,b,j} - MinDL_{i,b}.$$

8.5.4.3 The amount of both synchronized and non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide shall not exceed the amount by which the *dispatchable load* can decrease its consumption over 10 minutes, as limited by its *operating reserve* ramp rate. This restriction shall be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \leq 10 \cdot ORRDL_b.$$

8.5.4.4 The total *operating reserve* scheduled from a *dispatchable generation resource* shall not exceed the *resource*'s ramp capability over 30 minutes, its remaining capacity, and its unscheduled capacity. These restrictions shall be enforced by the following constraints for all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq 30 \cdot ORRDG_b;$$

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq \sum_{k \in K_{i,b}^{E}} (QDG_{i,b,k} - SDG_{i,b,k});$$

and

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq AdjMaxDG_{i,b} - \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k}.$$

8.5.4.5 The amount of both synchronized and non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall not exceed the amount by which the *resource* can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This restriction shall be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \leq 10 \cdot ORRDG_b.$$

8.5.4.6 The amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be limited by its *reserve loading point* for synchronized *ten-minute operating reserve*. This restriction shall be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DG}$ with $RLP10S_{i,b} > 0$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \leq \left(\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \right) \cdot \left(\frac{1}{RLP10S_{i,b}} \right) \cdot \left(min \left\{ 10 \cdot ORRDG_b, \sum_{k \in K_{i,b}^{10S}} Q10SDG_{i,b,k} \right\} \right).$$

8.5.4.7 The amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be limited by its *reserve loading point* for *thirty-minute operating reserve*. This restriction shall be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DG}$ with $RLP30R_{i,b} > 0$:

$$\sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq \left(\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \right) \cdot \left(\frac{1}{RLP30R_{i,b}} \right) \cdot \left(min \left\{ 30 \cdot ORRDG_b, \sum_{k \in K_{i,b}^{30R}} Q30RDG_{i,b,k} \right\} \right).$$

8.5.5 Pseudo-Units

8.5.5.1 A constraint shall be required to calculate physical *generation resource* schedules from *pseudo-unit* schedules using the steam turbine *resource's* shares in the operating regions of the *pseudo-unit* determined in section 10. For all intervals $i \in I$ and *pseudo-unit* buses $b \in B^{PSU}$:

$$SSTMod_{i,p} = \sum_{b \in B_p^{ST}} \begin{pmatrix} STShareMLP_b \cdot \left(\sum_{k \in K_{i,b}^{MLP}} SDG_{i,b,k} \right) + \\ STShareDR_b \cdot \left(\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} \right) + \sum_{k \in K_{i,b}^{DF}} SDG_{i,b,k} \end{pmatrix}.$$

$$SCTMod_{i,b} = (1 - STShareMLP_b) \cdot \left(\sum_{k \in K_{i,b}^{MLP}} SDG_{i,b,k} \right) + (1 - STShareDR_b) \cdot \left(\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} \right),$$

8.5.5.1.1 and for all intervals $i \in I$ and steam turbine *resources* $p \in PST$:

8.5.5.2 Maximum constraints shall be enforced on the operating region to which they apply for both *energy* and *operating reserve* schedules. For all intervals $i \in I$ and *pseudo-unit* buses $b \in B^{PSU}$:

$$\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} \leq MaxDR_{i,b},$$

$$\sum_{k \in K_{i,b}^{DF}} SDG_{i,b,k} \leq MaxDF_{i,b},$$

and

$$\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} + \sum_{k \in K_{i,b}^{DF}} SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq MaxDR_{i,b} + MaxDF_{i,b}.$$

8.5.5.3 For a *pseudo-unit* that cannot provide *ten-minute operating reserve* from its duct firing region, constraints shall limit the *pseudo-unit* from being scheduled to provide *ten-minute operating reserve* whenever the *pseudo-unit* is scheduled for *energy* in its duct firing region.

8.5.5.4 For the purposes of the *energy* balance constraint in section 8.7.1 and the transmission constraints in section 8.7.3, the combustion turbine *resource's* schedule for the *pseudo-unit* at bus $b \in B^{PSU}$ in interval $i \in I$, $SCT_{i,b}$ shall be equal to:

8.5.5.4.1 $SCTMod_{i,b}$ if the *pseudo-unit* is scheduled at or above *minimum loading point*;

8.5.5.4.2 the portion of $UpTraj_{i,b}$ or $DnTraj_{i,b}$ defined in the section 8.6.2 that was allocated to the combustion turbine *resource* in accordance with section 10.6 if the *resource* is ramping to or ramping from its *minimum loading point*; or

8.5.5.4.3 0 otherwise.

8.5.5.5 For the purposes of the *energy* balance constraint in section 8.7.1 and the transmission constraints in section 8.7.3, the steam turbine *resource's* schedule for $p \in PST$, $SST_{i,p}$ shall be equal to $SSTMod_{i,p}$ where $SST_{i,p}$ will be corrected to account for the contribution from *pseudo-units* $b \in B_p^{ST}$ ramping to or ramping from *minimum loading point* as determined by the allocation of $UpTraj_{i,b}$ or $DnTraj_{i,b}$ in accordance with section 10.6.

8.5.6 Dispatchable Hydroelectric Generation Resources

8.5.6.1 A *dispatchable* hydroelectric *generation resource* shall be scheduled within its *forbidden region* if the *resource* is being ramped through the *forbidden region* at its maximum *offered* ramp capability.

8.6 Dispatch Data Inter-Interval/Multi-Interval Constraints

8.6.1 Energy Ramping

8.6.1.1 For *disptachable loads*, the ramping constraint in section 8.6.1.4 uses $URRDL_b$ to represent a ramp up rate selected from $URRDL_{i,b,w}$ and uses $DRRDL_b$ to represent a ramp down rate selected from $DRRDL_{i,b,w}$.

8.6.1.2 For *disptachable generation resources*, the ramping constraint in section 8.6.1.5 uses $URRDG_b$ to represent a ramp up rate selected from $URRDG_{i,b,w}$ and uses $DRRDG_b$ to represent a ramp down rate selected from $DRRDG_{i,b,w}$.

8.6.1.3 The *real-time calculation engine* shall respect the ramping restrictions determined by the up to five *offered* MW quantity, ramp up rate and ramp down rate value sets.

8.6.1.4 In the case of *dispatchable loads*, *energy* schedules cannot vary by more than an interval's ramping capability for that *resource*. This constraint shall be enforced by the following for all intervals $i \in I$ and buses $b \in B^{DL}$:

$$\sum_{j \in J^E_{i-1,b}} SDL_{i-1,b,j} - 5 \cdot DRRDL_b \le \sum_{j \in J^E_{i,b}} SDL_{i,b,j} \le \sum_{j \in J^E_{i-1,b}} SDL_{i-1,b,j} + 5 \cdot URRDL_b.$$

8.6.1.5 *Energy* schedules for a *dispatchable generation resource* cannot vary by more than an interval's ramping capability for that *resource*. This constraint shall be enforced by the following for all intervals $i \in I$ and buses $b \in B^{DG}$:

$$\sum_{k \in K^E_{i-1,b}} SDG_{i-1,b,k} - 5 \cdot DRRDG_b \le \sum_{k \in K^E_{i,b}} SDG_{i,b,k} \le \sum_{k \in K^E_{i-1,b}} SDG_{i-1,b,k} + 5 \cdot URRDG_b.$$

Non-Quick Start Resource Start-up and Shutdown

8.6.2.1 For all intervals in the real-time look-ahead period in which a *non-quick start resource* is scheduled to start-up, such *resource* shall be scheduled on a fixed ramp-up trajectory as determined by its *offered* ramp rates. The ramp-up trajectory ($UpTraj_{i,b}$) for interval $i \in I$ such that $SU_{i,b}=1$ is determined as follows:

8.6.2.1.1 If $i = 1$, then $UpTraj_{i,b}$ shall be determined from the *resource* initial schedule and the *offered* ramp up capability;

8.6.2.1.2 If $i > 1$ and $SU_{i\text{-}1,b} = 0$, then $UpTraj_{i,b}$ shall be determined from the *offered* ramp up capability from 0; and

8.6.2.1.3 For all intervals $i \in I$ such that $SU_{i,b}$=1:

$$\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} = UpTraj_{i,b}.$$

8.6.2.2 For all intervals in the real-time look-ahead period in which a *non-quick start resource* is scheduled to shutdown, such *resource* shall be scheduled on a fixed ramp-down trajectory as determined by its *offered* ramp rates. The ramp-down trajectory ($DnTraj_{i,b}$) for interval $i \in I$ such that $SD_{i,b} = 1$ is determined as follows:

8.6.2.2.1 If $i = 1$, then $DnTraj_{i,b}$ shall be determined from the *resource* initial schedule and the *offered* ramp down capability;

8.6.2.2.2 If $i > 1$ and $SD_{i\text{-}1,b} = 0$, then $DnTraj_{i,b}$ shall be $MinQDG_b$; and

8.6.2.2.3 If $i > 1$ and $SD_{i\text{-}1,b} = 1$, then $DnTraj_{i,b}$ shall be determined from the *offered* ramp down capability from $DnTraj_{i\text{-}1,b}$.

8.6.2.2.4 For all intervals $i \in I$ such that $SD_{i,b} = 1$:

$$\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} = DnTraj_{i,b}.$$

8.6.3 Operating Reserve Ramping

8.6.3.1 Constraints shall be applied to recognize that interval to interval changes to a *dispatchable load*s schedule for *energy* may modify the amount of *operating reserve* that the *resource* can provide. For all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq - \sum_{j \in J_{i-1,b}^{E}} SDL_{i-1,b,j} + \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} + 30 \cdot ORRDL_b$$

and

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \leq - \sum_{j \in J_{i-1,b}^{E}} SDL_{i-1,b,j} + \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} + 10 \cdot ORRDL_b.$$

8.6.3.2 Constraints shall be applied to recognize that interval to interval changes in a *dispatchable generation resource's* schedule for *energy* may modify the amount of *operating reserve* that the *resource* can provide. For all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq \sum_{k \in K_{i-1,b}^{E}} SDG_{i-1,b,k} - \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} + 30 \cdot ORRDG_b$$

and

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \leq \sum_{k \in K_{i-1,b}^{E}} SDG_{i-1,b,k} - \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} + 10 \cdot ORRDG_b.$$

8.7 Constraints for Reliability Requirements

8.7.1 Energy Balance

8.7.1.1 The total amount of *energy* withdrawals scheduled at load bus $b \in B$ in interval $i \in I$, $With_{i,b}$ shall be:

$$With_{i,b} = \begin{cases} \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} & if\ b \in B^{DL} \\ FHDR_{i,b} & if\ b \in B^{HDR} \\ FNBL_{i,b} & if\ b \in B^{NoBid} \end{cases}$$

8.7.1.2 The total amount of export *energy* scheduled at *intertie zone* bus $d \in DX$ in interval $i \in I$, $With_{i,d}$, as the fixed exports from Ontario to the *intertie zone* export bus shall be:

$$With_{i,d} = FXLSch_{i,d}.$$

8.7.1.3 The total amount of injections scheduled at internal bus $b \in B$, in interval $i \in I$, $Inj_{i,b}$ shall be:

$$Inj_{i,b} = \begin{cases} \sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} & if\ b \in B^{NDG} \\ \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} & if\ b \in B^{DG} \\ FNOG_{i,b} & if\ b \in B^{NoOffer} \end{cases}$$

8.7.1.4 The total amount of import *energy* scheduled at *intertie zone* bus $d \in DI$ in interval $i \in I$, $Inj_{i,d}$, as the imports into Ontario from that *intertie zone* bus shall be:

$$Inj_{i,d} = FIGSch_{i,d}.$$

8.7.1.5 Injections and withdrawals at each bus shall be multiplied by one plus the marginal loss factor to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the demand constraint violation shall be subtracted from the total load or generation for the *real-time calculation engine* to produce a solution.

For interval $i \in I$, the *energy* balance shall be:

$$FL_i + \sum_{b \in B^{DL} \cup B^{HDR} \cup B^{NoBid}} (1 + MglLoss_{i,b}) \cdot With_{i,b} + \sum_{d \in DX} (1 + MglLoss_{i,d}) \cdot With_{i,d} - \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} = \sum_{b \in B^{NDG} \cup B^{DG} \cup B^{NoOffer}} (1 + MglLoss_{i,b}) \cdot Inj_{i,b} + \sum_{d \in DI} (1 + MglLoss_{i,d}) \cdot Inj_{i,d} - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} + LossAdj_i.$$

8.7.2 Operating Reserve Requirements

8.7.2.1 *Operating reserve* shall be scheduled to meet system-wide requirements for synchronized *ten-minute operating reserve*, total *ten-minute operating reserve*, and *thirty-minute operating reserve* while respecting all applicable regional minimum requirements and regional maximum restrictions for *operating reserve*.

8.7.2.2 Constraint violation penalty curves shall be used to impose a penalty cost for not meeting the *IESO's* system-wide *operating reserve* requirements, not meeting a regional minimum requirement, or not adhering to a regional maximum restriction. Full *operating reserve* requirements shall be scheduled unless the cost of doing so would be higher than the applicable penalty cost. For each interval $i \in I$:

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{w=1..N_{10SViol_i}} S10SViol_{i,w} \geq TOT10S_i;$$

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in DX} F10NXLSch_{i,d} + \sum_{d \in DI} F10NIGSch_{i,d} + \sum_{w=1..N_{10RViol_i}} S10RViol_{i,w} \geq TOT10R_i;$$

and

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in DX} F10NXLSch_{i,d} + \sum_{d \in DI} F10NIGSch_{i,d} + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \right) + \sum_{d \in DX} F30RXLSch_{i,d} + \sum_{d \in DI} F30RIGSch_{i,d} + \sum_{w=1..N_{30RViol_i}} S30RViol_{i,w} \geq TOT30R_i.$$

8.7.2.3 The following constraints shall be applied for each interval $i \in I$ and each region $r \in ORREG$:

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in D_r^{REG} \cap DX} F10NXLSch_{i,d} + \sum_{d \in D_r^{REG} \cap DI} F10NIGSch_{i,d} + \sum_{w=1..N_{REG10RViol_i}} SREG10RViol_{r,i,w} \geq REGMin10R_{i,r};$$

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in D_r^{REG} \cap DX} F10NXLSch_{i,d} + \sum_{d \in D_r^{REG} \cap DI} F10NIGSch_{i,d} - \sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \leq REGMax10R_{i,r};$$

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in D_r^{REG} \cap DX} F10NXLSch_{i,d} + \sum_{d \in D_r^{REG} \cap DI} F10NIGSch_{i,d} - \sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \leq REGMax10R_{i,r};$$

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10S}} S10SDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10S}} S10SDG_{i,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10N}} S10NDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10N}} S10NDG_{i,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX} F10NXLSch_{i,d}+\sum_{d\in D_r^{REG}\cap DI} F10NIGSch_{i,d}$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{30R}} S30RDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{30R}} S30RDG_{i,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX} F30RXLSch_{i,d}+\sum_{d\in D_r^{REG}\cap DI} F30RIGSch_{i,d}$$
$$+\sum_{w=1..N_{REG30RViol_i}} SREG30RViol_{r,i,w} \geq REGMin30R_{i,r};$$

and

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10S}} S10SDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10S}} S10SDG_{i,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10N}} S10NDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10N}} S10NDG_{i,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX} F10NXLSch_{i,d}+\sum_{d\in D_r^{REG}\cap DI} F10NIGSch_{i,d}$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{30R}} S30RDL_{i,b,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{30R}} S30RDG_{i,b,k}\right)+\sum_{d\in D_r^{REG}\cap DX} F30RXLSch_{i,d}$$
$$+\sum_{d\in D_r^{REG}\cap DI} F30RIGSch_{i,d}$$
$$-\sum_{w=1..N_{XREG30RViol_i}} SXREG30RViol_{r,i,w}$$
$$\leq REGMax30R_{i,r}.$$

8.7.3 IESO Internal Transmission Limits

8.7.3.1 A set of *energy* schedules shall be produced that do not violate any *security* limits in the pre-contingency state and the post-contingency state subject to the remainder of this section 8.7.3. The total amount of *energy* scheduled to be injected and withdrawn at each bus used by the *energy* balance constraint in section 8.7.1.5, shall be used to produce these schedules.

8.7.3.2 Pre-contigency, $SPreITLViol_{f,i,w}$, and post-contingency, $SITLViol_{c,f,i,w}$, transmission limit violation variables shall allow the *real-time calculation engine* to find a solution.

8.7.3.3 For all intervals $i \in I$ and *facilities* $f \in F_i$, the linearized constraints for violated pre-contingency limits obtained from the *security* assesment function shall take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG} \cup B^{NoOffer}} PreConSF_{i,f,b} \cdot Inj_{i,b} - \sum_{b \in B^{DL} \cup B^{HDR} \cup B^{NoBid}} PreConSF_{i,f,b} \cdot With_{i,b} + \sum_{d \in DI} PreConSF_{i,f,d} \cdot Inj_{i,d} - \sum_{d \in DX} PreConSF_{i,f,d} \cdot With_{i,d} - \sum_{w=1..N_{PreITLViol_{f,i}}} SPreITLViol_{f,i,w} \leq AdjNormMaxFlow_{i,f}.$$

8.7.3.4 For all intervals $i \in I$, contingencies $c \in C$, and *facilities* $f \in F_{i,c}$, the linearized constraints for violated post-contingency limits obtained from the *security* assesment function shall take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG} \cup B^{NoOffer}} SF_{i,c,f,b} \cdot Inj_{i,b} - \sum_{b \in B^{DL} \cup B^{HDR} \cup B^{NoBid}} SF_{i,c,f,b} \cdot With_{i,b} + \sum_{d \in DI} SF_{i,c,f,d} \cdot Inj_{i,d} - \sum_{d \in DX} SF_{i,c,f,d} \cdot With_{i,d} - \sum_{w=1..N_{ITLViol_{c,f,i}}} SITLViol_{c,f,i,w} \leq AdjEmMaxFlow_{i,c,f}.$$

8.7.4 Penalty Price Variable Bounds

8.7.4.1 Penalty price variables shall be restricted to the ranges determined by the constraint violation penalty curves for the Real-Time Scheduling algorithm and for all intervals $i \in I$:

$0 \leq SLdViol_{i,w} \leq QLdViolSch_{i,w}$ for all $w \in \{1,..,\mathrm{N}_{\mathrm{LdViol}_i}\}$;

$0 \leq SGenViol_{i,w} \leq QGenViolSch_{i,w}$ for all $w \in \{1,..,\mathrm{N}_{\mathrm{GenViol}_i}\}$;

$0 \leq S10SViol_{i,w} \leq Q10SViolSch_{i,w}$ for all $w \in \{1,..,N_{10SViol_i}\}$;

$0 \leq S10RViol_{i,w} \leq Q10RViolSch_{i,w}$ for all $w \in \{1,..,N_{10RViol_i}\}$;

$0 \leq S30RViol_{i,w} \leq Q30RViolSch_{i,w}$ for all $w \in \{1,..,N_{30RViol_i}\}$;

$0 \leq SREG10RViol_{r,i,w} \leq QREG10RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{REG10RViol_i}\}$;

$0 \leq SREG30RViol_{r,i,w} \leq QREG30RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,\mathrm{N}_{\mathrm{REG30RViol}_i}\}$;

$0 \leq SXREG10RViol_{r,i,w} \leq QXREG10RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{XREG10RViol_i}\}$;

$0 \leq SXREG30RViol_{r,i,w} \leq QXREG30RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,\mathrm{N}_{\mathrm{XREG30RViol}_i}\}$;

$0 \leq SPreITLViol_{f,i,w} \leq QPreITLViolSch_{f,i,w}$ for all $f \in F_i$, $w \in \{1,..,\mathrm{N}_{\mathrm{PreITLViol}_{f,i}}\}$;

and

$0 \leq SITLViol_{c,f,i,w} \leq QITLViolSch_{c,f,i,w}$ for all $c \in C$, $f \in F_{i,c}$, $w \in \{1,..,\mathrm{N}_{\mathrm{ITLViol}_{c,f,i}}\}$.

8.8 Outputs

8.8.1 Outputs for the Real-Time Scheduling algorithm includes *resource* schedules.

9 Real-Time Pricing

9.1 Purpose

9.1.1 The Real-Time Pricing algorithm shall perform a *security*-constrained economic *dispatch* to maximize gains from trade to meet the *IESO's* province-wide non-*dispatchable demand* forecast and the *IESO*-specified *operating reserve* requirements for each interval of the real-time look-ahead period.

9.2 Information, Sets, Indices and Parameters

9.2.1 Information, sets, indices and parameters used by the Real-Time Pricing algorithm are described in sections 3 and 4. In addition, the following *resource* schedules from the Real-Time Scheduling algorithm in section 8 shall be used in the Real-Time Pricing algorithm:

9.2.1.1 $SD_{i,b}^{RTS} \in \{0,1\}$, which designates whether the *dispatchable generation resource* at bus $b \in B^{NQS}$ was scheduled on a shutdown trajectory in interval $i \in I$ such that $EvalSD_{i,b} = 1$;

9.2.1.2 $SDLInitSch_{0,b}$, which designates the initial schedule for the *dispatchable load* at bus $b \in B^{DL}$ used in the Real-Time Scheduling algorithm in section 8; and

9.2.1.3 $SDGInitSch_{0,b}$, which designates the initial schedule for the *dispatchable generation resource* at bus $b \in B^{DG}$ used in the Real-Time Scheduling algorithm in section 8.

9.3 Variables and Objective Function

9.3.1 The Real-Time Pricing algorithm shall solve for the same variables as the Real-Time Scheduling algorithm in section 8.3.1.

9.3.2 The objective function for the Real-Time Pricing algorithm shall maximize gains from trade by maximizing the expression in section 8.3.2 for the Real-Time Scheduling algorithm.

9.3.3 $ViolCost_i$ shall be calculated as follows:

$$
\begin{aligned}
ViolCost_i = & \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \cdot PLdViolPrc_{i,w} \\
& - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} \cdot PGenViolPrc_{i,w} \\
& + \sum_{w=1..N_{10SViol_i}} S10SViol_{i,w} \cdot P10SViolPrc_{i,w} \\
& + \sum_{w=1..N_{10RViol_i}} S10RViol_{i,w} \cdot P10RViolPrc_{i,w} \\
& + \sum_{w=1..N_{30RViol_i}} S30RViol_{i,w} \cdot P30RViolPrc_{i,w} \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG10RViol_i}} SREG10RViol_{r,i,w} \cdot PREG10RViolPrc_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG30RViol_i}} SREG30RViol_{r,i,w} \cdot PREG30RViolPrc_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \cdot PXREG10RViolPrc_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG30RViol_i}} SXREG30RViol_{r,i,w} \cdot PXREG30RViolPrc_{i,w} \right) \\
& + \sum_{f \in F_i} \left(\sum_{w=1..N_{PreITLViol_{f,i}}} SPreITLViol_{f,i,w} \cdot PPreITLViolPrc_{f,i,w} \right) \\
& + \sum_{c \in C} \sum_{f \in F_{i,c}} \left(\sum_{w=1..N_{ITLViol_{c,f,i}}} SITLViol_{c,f,i,w} \cdot PITLViolPrc_{c,f,i,w} \right).
\end{aligned}
$$

9.3.3.1 The constraints in section 9.4 shall apply to the Real-Time Pricing algorithm.

9.4 Constraints

9.4.1 The Real-Time Pricing algorithm optimization function shall apply the constraints described in sections 9.5 – 9.8.

9.5 Dispatch Data Constraints Applying to Individual Intervals

9.5.1 Scheduling Variable Bounds

9.5.1.1 The constraints in section 8.5.1 shall apply in the Real-Time Pricing algorithm, with the following exceptions for a *non-quick start resource* bus $b \in B^{NQS}$ and interval $i \in I$, where:

9.5.1.1.1 $AtZero_{i,b}$ shall be replaced by $AtZero_{i,b}^{RTP}$;

9.5.1.1.2 $AtMLP_{i,b}$ shall be replaced by $AtMLP_{i,b}^{RTP}$; and

9.5.1.1.3 $EvalSD_{i,b}$ shall be replaced by $EvalSD_{i,b}^{RTP}$.

9.5.2 Resource Initial Conditions

9.5.2.1 The initial schedule for a *dispatchable load* at bus $b \in B^{DL}$ shall be fixed to the *resource* initial schedules. For all *dispatchable load* buses $b \in B^{DL}$:

$$\sum_{j \in J_{0,b}^{E}} SDL_{0,b,j} = SDLInitPrc_{0,b}$$

9.5.2.2 The initial schedule for a *dispatchable generation resource* at bus $b \in B^{DG}$ shall be fixed to the *resource* initial schedules. For all *dispatchable generation resource* buses $b \in B^{DG}$:

$$\sum_{k \in K_{0,b}^{E}} SDG_{0,b,k} = SDGInitPrc_{0,b}$$

9.5.3 Resource Minimums and Maximums

9.5.3.1 The constraints in section 8.5.3 shall apply in the Real-Time Pricing algorithm, with the following exception:

9.5.3.1.1 $AtMLP_{i,b}$ shall be replaced by $AtMLP_{i,b}^{RTP}$

where $AtMLP_{i,b}^{RTP}$ is determined in accordance with section 9.8.1.

9.5.4 Operating Reserve Requirements

9.5.4.1 The constraints in section 8.5.4 shall apply in the Real-Time Pricing algorithm.

9.5.5 Pseudo-Units

9.5.5.1 The constraints in section 8.5.5 shall apply in the Real-Time Pricing algorithm.

9.5.6 Dispatchable Hydroelectric Generation Resources

9.5.6.1 The constraints in section 8.5.6 shall apply in the Real-Time Pricing algorithm.

9.6 Dispatch Data Inter-Interval/Multi-Interval Constraints

9.6.1 Energy Ramping

9.6.1.1 The constraints in section 8.6.1 shall apply in the Real-Time Pricing algorithm.

9.6.2 Non-Quick Start Resource Start-up and Shutdown

9.6.2.1 The constraints in section 8.6.2 shall apply in the Real-Time Pricing algorithm, with the exception of the *non-quick start resource* start-up and shutdown statuses, which are determined in accordance with section 9.8.1.

9.6.3 Operating Reserve Ramping

9.6.3.1 The constraints in section 8.6.3 shall apply in the Real-Time Pricing algorithm.

9.7 Constraints for Reliability Requirements

9.7.1 Energy Balance

9.7.1.1 The constraint in section 8.7.1 shall apply in the Real-Time Pricing algorithm, with the following exceptions:

9.7.1.1.1 $FXLSch_{i,d}$ shall be replaced by $FXLPrc_{i,d}$ in section 8.7.1.2;

9.7.1.1.2 $FIGSch_{i,d}$ shall be replaced by $FIGPrc_{i,d}$ in section 8.7.1.4; and

9.7.1.1.3 The *energy* balance constraint in section 8.7.1.5 shall be modified to account for the *demand* adjustment required to calculate *locational marginal prices* when a voltage reduction or load shedding has been implemented, as follows:

$$
\begin{aligned}
FL_i + CAAdj_i + \sum_{b \in B^{DL} \cup B^{HDR} \cup B^{NoBid}} (1 + MglLoss_{i,b}) \cdot With_{i,b} \\
+ \sum_{d \in DX} (1 + MglLoss_{i,d}) \cdot With_{i,d} \\
- \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \\
= \sum_{b \in B^{NDG} \cup B^{DG} \cup B^{NoOffer}} (1 + MglLoss_{i,b}) \cdot Inj_{i,b} \\
+ \sum_{d \in DI} (1 + MglLoss_{i,d}) \cdot Inj_{i,d} \\
- \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} + LossAdj_i.
\end{aligned}
$$

9.7.2 Operating Reserve Requirements

9.7.2.1 The constraint in section 8.7.2 shall apply in the Real-Time Pricing algorithm, with the following exceptions:

9.7.2.1.1 $F10NXLSch_{i,d}$ shall be replaced by $F10NXLPrc_{i,d}$ for all $d \in DX$;

9.7.2.1.2 $F10NIGSch_{i,d}$ shall be replaced by $F10NIGPrc_{i,d}$ for all $d \in DI$;

9.7.2.1.3 $F30RXLSch_{i,d}$ shall be replaced by $F30RXLPrc_{i,d}$ for all $d \in DX$; and

9.7.2.1.4 $F30RIGSch_{i,d}$ shall be replaced by $F30RIGPrc_{i,d}$ for all $d \in DI$.

9.7.3 IESO Internal Transmission Limits

9.7.3.1 The constraints in section 8.7.3 shall apply in the Real-Time Pricing algorithm except the sensitivities and limits considered shall be those provided by the most recent *security* assessment function iteration of the Real-Time Pricing algorithm.

9.7.4 Penalty Price Variable Bounds

9.7.4.1 The following constraints shall restrict the penalty price variables to the ranges determined by the constraint violation penalty curves. For all intervals $i \in I$:

$0 \le SLdViol_{i,w} \le QLdViolPrc_{i,w}$ for all $w \in \{1,..,N_{LdViol_i}\}$;

$0 \le SGenViol_{i,w} \le QGenViolPrc_{i,w}$ for all w $\in \{1,..,N_{GenViol_i}\}$;

$0 \le S10SViol_{i,w} \le Q10SViolPrc_{i,w}$ for all $w \in \{1,..,N_{10SViol_i}\}$;

$0 \le S10RViol_{i,w} \le Q10RViolPrc_{i,w}$ for all $w \in \{1,..,N_{10RViol_i}\}$;

$0 \le S30RViol_{i,w} \le Q30RViolPrc_{i,w}$ for all $w \in \{1,..,N_{30RViol_i}\}$;

$0 \le SREG10RViol_{r,i,w} \le QREG10RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{REG10RViol_i}\}$;

$0 \le SREG30RViol_{r,i,w} \le QREG30RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{REG30RViol_i}\}$;

$0 \le SXREG10RViol_{r,i,w} \le QXREG10RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{XREG10RViol_i}\}$;

$0 \le SXREG30RViol_{r,i,w} \le QXREG30RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{XREG30RViol_i}\}$;

$0 \le SPreITLViol_{f,i,w} \le QPreITLViolPrc_{f,i,w}$ for all $f \in F_i$, $w \in \{1,..,N_{PreITLViol_{f,i}}\}$; and

$0 \le SITLViol_{c,f,i,w} \le QITLViolPrc_{c,f,i,w}$ for all $c \in C$, $f \in F_{i,c}$, $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$.

9.8 Constraints to Ensure the Price Setting Eligibility of Offer/Bid Laminations

9.8.1 Non-Quick Start Resources

9.8.1.1 The Real-Time Pricing algorithm shall modify the following start-up and shutdown statuses for a *non-quick start resource* at bus $b \in B^{NQS}$ and interval $i \in I$:

9.8.1.1.1 $AtZero_{i,b}^{RTP} \in \{0,1\}$, which designates that the *resource* is not scheduled and is calculated as follows:

$$AtZero_{i,b}^{RTP} = AtZero_{i,b}.$$

9.8.1.1.2 $SU_{i,b}^{RTP} \in \{0,1\}$, which designates that the *resource* must be scheduled for *energy* on its start-up trajectory and is calculated as follows:

$$SU_{i,b}^{RTP} = SU_{i,b}.$$

9.8.1.1.3 $AtMLP_{i,b}^{RTP} \in \{0,1\}$, which designates that the *resource* is scheduled for *energy* at or above the *minimum loading point* and is calculated as follows:

$$AtMLP_{i,b}^{RTP} = \begin{cases} AtMLP_{i,b} & if\ EvalSD_{i,b} = 0 \\ 1 - SD_{i,b}^{RTS} & if\ EvalSD_{i,b} = 1 \end{cases}$$

9.8.1.1.4 $EvalSD_{i,b}^{RTP} \in \{0,1\}$, which designates that the *resource* can be scheduled for *energy* below the *minimum loading point* and is calculated as follows:

$$EvalSD_{i,b}^{RTP} = 0.$$

9.8.1.1.5 $SD_{i,b}^{RTP} \in \{0,1\}$, which designates that the *resource* must be scheduled for *energy* on its shutdown trajectory and is calculated as follows:

$$SD_{i,b}^{RTP} = \begin{cases} SD_{i,b} & if\ EvalSD_{i,b} = 0 \\ SD_{i,b}^{RTS} & if\ EvalSD_{i,b} = 1 \end{cases}$$

9.9 Outputs

9.9.1 Outputs for the Real-Time Pricing algorithm include:

9.9.1.1 shadow prices;

9.9.1.2 *locational marginal prices* and their components; and

9.9.1.3 sensitivity factors.

10 Pseudo-Unit Modelling

10.1 Pseudo-Unit Model Parameters

10.1.1 The *real-time calculation engine* shall use the following registration and *dispatch data* to determine the underlying relationship between a *pseudo-unit* and the associated physical *resources* for a *combined cycle plant* with K combustion turbine *resources* and one steam turbine *resource*:

10.1.1.1 $CMCR_k$, which designates the registered *maximum continuous rating* of combustion turbine *resource* $k \in \{1,..,K\}$ in MW;

10.1.1.2 $CMLP_k$, which designates the *minimum loading point* of combustion turbine *resource* $k \in \{1,..,K\}$ in MW;

10.1.1.3 $SMCR$, which designates the registered *maximum continuous rating* of the steam turbine *resource* in MW;

10.1.1.4 $SMLP$, which designates the *minimum loading point* of the steam turbine *resource* in MW for a 1x1 configuration;

10.1.1.5 SDF, which designates the amount of duct firing capacity available on the steam turbine *resource* in MW;

10.1.1.6 $STPortion_k$, which designates the percentage of the steam turbine *resource's* capacity attributed to *pseudo-unit* $k \in \{1,..,K\}$; and

10.1.1.7 $CSCM_k \in \{0,1\}$, which designates whether *pseudo-unit* $k \in \{1,..,K\}$ is flagged to operate in *single cycle mode*.

10.1.2 The *real-time calculation engine* shall calculate the following model parameters for each *pseudo-unit* $k \in \{1,..K\}$:

10.1.2.1 $MMCR_k$, which designates the *maximum continuous rating* of *pseudo-unit* k and is calculated as follows:

$$CMCR_k + SMCR \cdot STPortion_k \cdot (1 - CSCM_k)$$

10.1.2.2 $MMLP_k$, which designates the *minimum loading point* of *pseudo-unit* k and is calculated as follows:

$$CMLP_k + SMLP \cdot (1 - CSCM_k)$$

10.1.2.3 MDF_k, which designates the duct firing capacity of *pseudo-unit* k and is calculated as follows:

$$SDF \cdot STPortion_k \cdot (1 - CSCM_k)$$

10.1.2.4 MDR_k, which designates the *dispatchable* capacity of *pseudo-unit* k and is calculated as follows:

$$MMCR_k - MMLP_k - MDF_k$$

10.1.3 The *real-time calculation engine* shall define three operating regions of *pseudo-unit* $k \in \{1,..K\}$, as follows:

10.1.3.1 The *minimum loading point* region shall be the capacity between 0 and $MMLP_k$;

10.1.3.2 The *dispatchable* region shall be the capacity between $MMLP_k$ and $MMLP_k + MDR_k$;

10.1.3.3 The duct firing region shall be the capacity between $MMLP_k + MDR_k$ and $MMCR_k$.

10.1.4 The *real-time calculation engine* shall calculate the associated combustion turbine *resource* and steam turbine *resource* shares for the three operating regions of *pseudo-unit* $k \in \{1,..K\}$, as follows:

10.1.4.1 For the *minimum loading point* region:

10.1.4.1.1 Steam turbine *resource* share:

$$STShareMLP_k = \frac{SMLP \cdot (1 - CSCM_k)}{MMLP_k};$$

10.1.4.1.2 Combustion turbine *resource* share:

$$CTShareMLP_k = \frac{CMLP_k}{MMLP_k}; \text{ and}$$

10.1.4.2 For the *dispatchable* region:

10.1.4.2.1 Steam turbine *resource* share:

$$STShareDR_k = \frac{(1 - CSCM_k)(SMCR \cdot STPortion_k - SMLP - SDF \cdot STPortion_k)}{MDR_k};$$

and

10.1.4.2.2 Combustion turbine *resource* share:

$$CTShareDR_k = \frac{CMCR_k - CMLP_k}{MDR_k}; \text{ and}$$

10.1.4.3 For the duct firing region:

10.1.4.3.1 Steam turbine *resource* share shall be equal to 1; and

10.1.4.3.2 Combustion turbine *resource* share shall be equal to 0.

10.2 Application of Physical Resource Deratings to the Pseudo-Unit Model

10.2.1 The *real-time calculation engine* shall apply deratings submitted by *market participants* to the applicable *dispatchable* capacity and duct firing capacity parameters for a *pseudo-unit*, where:

10.2.1.1 $CTCap_{i,k}$ designates the capacity of combustion turbine *resource* $k \in \{1,..,K\}$ in interval i as determined by submitted deratings;

10.2.1.2 $STCap_i$ designates the capacity of the steam turbine *resource* in interval i as determined by submitted deratings; and

10.2.1.3 $TotalQ_{i,k}$ designates the total *offered* quantity of *energy* for *pseudo-unit* $k \in \{1,..,K\}$ in interval i.

10.2.2 The *real-time calculation engine* shall solve for the following operating region parameters for each *pseudo-unit* $k \in \{1,..,K\}$:

10.2.2.1 $MLP_{i,k}$ designates the *minimum loading point* of *pseudo-unit* k in interval i;

10.2.2.2 $DR_{i,k}$ designates the *dispatchable* capacity region of *pseudo-unit* k in interval i; and

10.2.2.3 $DF_{i,k}$ designates the duct firing capacity region of *pseudo-unit* k in interval i.

10.2.3 Pre-Processing of De-rates

10.2.3.1 The *real-time calculation engine* shall perform the following pre-processing steps to determine the available operating regions for a *pseudo-unit* based on the combustion turbine *resource's* and steam turbine *resource's* share and the application of the *pseudo-unit* deratings. For *pseudo-unit* $k \in \{1,..,K\}$ for interval $i \in I$:

10.2.3.1.1 Step 1: Calculate the amount of the *offer* for *energy* that is attributed to each combustion turbine *resource* ($CTAmt_{i,k}$) and steam turbine *resource* portion ($STAmt_{i,k}$):

If $TotalQ_{i,k} < MMLP_k$, then:

Calculate $CTAmt_{i,k} = 0; and$

Calculate $STAmt_{i,k} = 0$.

Otherwise:

$CTAmtMLP = MMLP_k \cdot CTShareMLP_k$; and

$STAmtMLP = MMLP_k \cdot STShareMLP_k$.

If $TotalQ_{i,k} > MMLP_k + MDR_k$, then:

$CTAmtDR = MDR_k \cdot CTShareDR_k$;

$STAmtDR = MDR_k \cdot STShareDR_k$; and

$STAmtDF = (1 - CSCM_k) \cdot (TotalQ_{i,k} - MMLP_k - MDR_k)$.

Otherwise:

$CTAmtDR = (TotalQ_{i,k} - MMLP_k) \cdot CTShareDR_k$;

$STAmtDR = (TotalQ_{i,k} - MMLP_k) \cdot STShareDR_k$;

$STAmtDF = 0$;

$CTAmt_{i,k} = CTAmtMLP + CTAmtDR$; and

$STAmt_{i,k} = STAmtMLP + STAmtDR + STAmtDF$.

10.2.3.1.2 Step 2: Allocate the steam turbine *resource's* capacity to each *pseudo-unit*:

$$PRSTCap_{i,k} = \left(\frac{STAmt_{i,k}}{\sum_{w \in \{1,..,K\}} STAmt_{i,w}}\right) \cdot STCap_i$$

10.2.3.1.3 Step 3: Determine if the *pseudo-unit* is available:

If $CTAmt_{i,k} < CMLP_k$, then the *pseudo-unit* is unavailable.

If $STAmt_{i,k} < SMLP \cdot (1 - CSCM_k)$, then the *pseudo-unit* is unavailable.

If $CTCap_{i,k} < CMLP_k$, then the *pseudo-unit* is unavailable.

If$PRSTCap_{i,k} < SMLP \cdot (1 - CSCM_k)$, then the *pseudo-unit* is unavailable.

10.2.3.1.4 Step 4: Initialize the operating region parameters for interval $i \in I$ to the model parameter values:

Set $MLP_{i,k} = MMLP_k$.

Set $DR_{i,k} = MDR_k$.

Set $DF_{i,k} = MDF_k$.

10.2.3.1.5 Step 5: Apply the derating for the combustion turbine *resource* to the *dispatchable* region:

Calculate P so that $CMLP_k + P \cdot CTShareDR_k \cdot MDR_k = CTCap_{i,k}$; and

Set $DR_{i,k} = min(DR_{i,k}, P \cdot MDR_k)$.

10.2.3.1.6 Step 6: Apply the derating for the steam turbine *resource* to the duct firing and *dispatchable* regions for *pseudo-units* not operating in *single cycle mode*:

Calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTCap_{i,k}$.

If $R \leq 1, \text{update } DF_{i,k} = 0, \text{and } DR_{i,k} = min(DR_{i,k}, R \cdot MDR_k)$.

If $R > 1$, update $DF_{i,k} = min(DF_{i,k}, PRSTCap_{i,k} - SMLP - STShareDR_k \cdot MDR_k)$.

10.2.4 Available Energy Laminations

10.2.4.1 The *real-time calculation engine* shall determine the *offer* quantity laminations that may be scheduled for *energy* and *operating reserve* in each operating region for interval $i \in I$ for each *pseudo-unit* $k \in \{1,..,K\}$, subject to section 10.2.4.2, where:

10.2.4.1.1 $QMLP_{i,k}$ designates the total quantity that may be scheduled in the *minimum loading point* region;

10.2.4.1.2 $QDR_{i,k}$ designates the total quantity that may be scheduled in the *dispatchable* region; and

10.2.4.1.3 $QDF_{i,k}$ designates the total quantity that may be scheduled in the duct firing region.

10.2.4.2 The available *offered* quantity laminations shall be subject to the following conditions:

$0 \leq QMLP_{i,k} \leq MLP_{i,k}$;

$0 \leq QDR_{i,k} \leq DR_{i,k}$;

$0 \leq QDF_{i,k} \leq DF_{i,k}$;

if $QMLP_{i,k} < MLP_{i,k}$, then the $pseudo-unit$ is unavailable and $QDR_{i,k} = QDF_{i,k} = 0$; and

if $QDR_{i,k} < DR_{i,k}$, then $QDF_{i,k} = 0$.

10.3 Convert Physical Resource Constraints to Pseudo-Unit Constraints

10.3.1 The *real-time calculation engine* shall convert physical *resource* constraints to *pseudo-unit* constraints, where:

10.3.1.1 $PSUMin_{i,k}^{q}$ designates the minimum limitation on *pseudo-unit* k determined by translating constraint q. When constraint q does not provide a minimum limitation on *pseudo-unit* k, then $PSUMin^q_{i,k}$ shall be set equal to 0;

10.3.1.2 $PSUMax^q_{i,k}$ designates the maximum limitation on *pseudo-unit* k determined by translating constraint q. When constraint q does not provide a maximum limitation on *pseudo-unit* k, then $PSUMax^q_{i,k}$ shall be set equal to $MLP_{i,k}+DR_{i,k}+DF_{i,k}$; and

10.3.1.3 $CTCmtd_{i,k} \in \{0,1\}$ designates whether combustion turbine *resource* $k \in \{1,..K\}$ is considered committed in interval $i \in I$.

10.3.2 The *real-time calculation engine* shall calculate the minimum and maximum limitations, subject to section 10.3.3.1, as follows:

10.3.2.1 Minimum limitation: $\text{MinDG}_{i,k} = \max_{q\in\{1,..Q\}}\text{PSUMin}^q_{i,k}$

10.3.2.2 Maximum limitation: $\text{MaxDG}_{i,k} = \min_{q\in\{1,..Q\}}\text{PSUMax}^q_{i,k}$

where Q designates the number of constraints impacting a *combined cycle plant* that have been provided to the *real-time calculation engine*.

10.3.3 Pseudo-Unit Minimum and Maximum Constraints

10.3.3.1 *Pseudo-unit* minimum and maximum constraints shall be calculated as follows:

10.3.3.1.1 $PSUMin_{i,k} = PMin$ where $PMin$ shall be a minimum constraint provided on *pseudo-unit* $k \in \{1,..,K\}$ for interval $i \in I$; and

10.3.3.1.2 $PSUMax_{i,k} = PMax$ where $PMax$ shall be a maximum constraint provided on *pseudo-unit* $k \in \{1,..,K\}$ for interval $i \in I$.

10.3.4 Combustion Turbine Resource Minimum and Maximum Constraints

10.3.4.1 If the *pseudo-unit* is not flagged to operate in *single cycle mode*, then the combustion turbine *resource's* minimum constraint shall be converted to a *pseudo-unit* constraint as follows:

If $CTMin < MLP_{i,k} \cdot CTShareMLP_k$, then set

$$STMinMLP = CTMin \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right),$$

$$STMinDR = 0.$$

Otherwise, if $CTMin \geq MLP_{i,k} \cdot CTShareMLP_k$, then set

$$STMinMLP = MLP_{i,k} \cdot STShareMLP_k,$$

$$STMinDR = \left(CTMin - MLP_{i,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$

Therefore:

$$PSUMin_{i,k} = CTMin + STMinMLP + STMinDR.$$

10.3.4.2 If a *pseudo-unit* is flagged to operate in *single cycle mode*, then the combustion turbine *resource's* minimum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PSUMin_{i,k} = CTMin$$

10.3.4.3 If the *pseudo-unit* is not flagged to operate in *single cycle mode*, then the combustion turbine *resource's* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

If $CTMax < MLP_{i,k} \cdot CTShareMLP_k$, then $PSUMax_{i,k} = 0$ and the *pseudo-unit* is unavailable.

Otherwise, calculate the value of the constraint on the steam turbine *resource* within the *minimum loading point* and *dispatchable* regions:

$$STMaxMLP = MLP_{i,k} \cdot STShareMLP_k$$

$$STMaxDR = \left(CTMax - MLP_{i,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right)$$

$$PSUMax_{i,k} = CTMax + STMaxMLP + STMaxDR$$

10.3.4.4 If a *pseudo-unit* is flagged to operate in *single cycle mode*, then the combustion turbine *resource's* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PSUMax_{i,k} = CTMax.$$

10.3.5 Steam Turbine Resource Minimum and Maximum Constraints

10.3.5.1 The *real-time calculation engine* shall convert a stream turbine *resource's* minimum constraint to a *pseudo-unit* constraints as follows:

10.3.5.1.1 Step 1: Identify $A \subseteq \{1,..,K\}$, which designates the set of *pseudo-units* to which the constraint may be allocated where *pseudo-unit* $k \in \{1,..,K\}$ is placed in set A if and only if $CSCM_k = 0$ and $CTCmtd_{i,k} = 1$. If the set A is empty, then no further steps are required, otherwise proceed to Step 2.

10.3.5.1.2 Step 2: Determine the steam turbine *resource's* portion of the capacity for *pseudo-unit* $k \in A$:

$$STCap_k = QMLP_{i,k} \cdot STShareMLP_k + QDR_{i,k} \cdot STShareDR_k + QDF_{i,k}.$$

10.3.5.1.3 Step 3: Allocate the $STMin$ constraint to each *pseudo-unit* $k \in A$, where $STMin$ constraint shall be allocated equally to each *pseudo-unit* $k \in A$, where $STPMin_k$ is limited by $STCap_k$.

10.3.5.1.4 Step 4: The steam turbine *resource* portion minimum constraint shall be converted to a *pseudo-unit* constraint, where for each *pseudo-unit* $k \in A$:

If $STPMin_k < MLP_{i,k} \cdot STShareMLP_k$, then set

$$CTMinMLP_k = STPMin_k \cdot \left(\frac{CTShareMLP_k}{STShareMLP_k}\right); \text{ and}$$

$$CTMinDR_k = 0.$$

Otherwise, if $STPMin_k \geq MLP_{i,k} \cdot STShareMLP_k$, then set

$$CTMinMLP_k = MLP_{i,k} \cdot CTShareMLP_k; \text{ and}$$

$$CTMinDR_k = \left(STPMin_k - MLP_{i,k} \cdot STShareMLP_k\right) \cdot \left(\frac{CTShareDR_k}{STShareDR_k}\right).$$

Therefore:

$$PSUMin_{i,k} = STPMin_k + CTMinMLP_k + CTMinDR_k.$$

10.3.5.1.4 If *pseudo-units* with sufficient steam turbine *resource* capacity are not commited, then the *real-time calculation engine* shall not convert the entire quantity of the steam turbine *resource's* minimum constraint to *pseudo-unit* constraints.

10.3.5.2 The steam turbine *resource's* maximum constraint shall be converted to a *pseudo-unit* constraint as follows:

$$PRSTMax_{i,k} = \left(\frac{STAmt_{i,k}}{\sum_{w\in\{1,..,K\}} STAmt_{i,w}}\right) \cdot STMax.$$

If the converted steam turbine *resource* maximum constraint limits the steam turbine *resource* portion to below its *minimum loading point*, then

$$PSUMax_{i,k} = 0.$$

Otherwise, calculate *R* so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTMax_{i,k}$

If $R \leq 1$, set $PSUMax_{i,k} = MLP_{i,k} + min(DR_{i,k}, R \cdot MDR_k)$.

If $R > 1$, set $PSUMax_{i,k} = MLP_{i,k} + DR_{i,k} + PRSTMax_{i,k} - SMLP - STShareDR_k \cdot MDR_k$.

10.3.5.3 If the steam turbine *resource's* minimum and maximum constraints are equal but do not convert to equal *pseudo-unit* minimum and maximum constraints, then the steam turbine *resource* minimum constraint conversion in section 10.3.5.1 shall be used to determine equal *pseudo-unit* minimum and maximum constraints.

10.4 Steam Turbine Resource Forced Outages

10.4.1 If the steam turbine *resource* experiences a *forced outage*, the *real-time calculation engine* shall evaluate the corresponding *pseudo-units* as being *offered* in *single cycle mode*.

10.5 Determination of Energy Management System MW Values for Pseudo-Units

10.5.1 The *real-time calculation engine* shall determine the effective *energy* management system MW value for each *pseudo-unit* from the *IESO's energy* management system MW values for the corresponding physical *resources*, where:

10.5.1.1 $CTTel_k$ designates the *energy* management system MW value for combustion turbine *resource* $k \in \{1,..,K\}$;

10.5.1.2 $STTel$ designates the *energy* management system MW value for the steam turbine *resource*;

10.5.1.3 $PSUTel_k$ designates the effective *energy* management system MW value for *pseudo-unit* $k \in \{1,..,K\}$;

10.5.1.4 $TMLP_k$ designates the effective *minimim loading point* operating range for the time at which *energy* management system MW value was determined;

10.5.1.5 TDR_k designates the effective *dispatchable* region operating range for the time at which *energy* management system MW value was determined; and

10.5.1.6 TDF_k, designates the effective duct firing region operating range for the time at which *energy* management system MW value was determined.

10.5.2 The *real-time calculation engine* shall determine the effective *energy* management system MW values for *pseudo-units* as follows:

10.5.2.1 Step 1: For all combustion turbine *resources*, assign the following *energy* management system MW values to the corresponding *pseudo-unit* $k \in \{1,..,K\}$:

10.5.2.1.1 $CTMLPTel_k$, which designates the MW value assigned to the combustion turbine *resource's* share of the *minimum loading point* region and is calculated as follows:

$$CTMLPTel_k = min\{CTTel_k , CTShareMLP_k \cdot TMLP_k \}.$$

10.5.2.1.2 $CTDRTel_k$, which designates the MW value assigned to the combustion turbine *resource's* share of the *dispatchable* region and is calculated as follows:

If $CTMLPTel_k < CTTel_k$, then set $CTDRTel_k = min\{(CTTel_k - CTMLPTel_k), CTShareDR_k \cdot TDR_k\}$

Otherwise, set $CTDRTel_k = 0$.

10.5.2.2 Step 2: Determine the maximum *energy* management system MW value for the steam turbine *resource* that may be assigned to the steam turbine *resource's* share of the *pseudo-unit's minimum loading point* and *dispatchable* regions based on the amount assigned to the combustion turbine *resource's* share of the *minimum loading point* and *dispatchable* regions. For *pseudo-unit* $k \in \{1,..,K\}$:

10.5.2.2.1 $STMLPMax_k$ designates the maximum MW value that may be assigned to the steam turbine *resource's* share of the *minimum loading point* region and is calculated as follows:

$$STMLPMax_k = CTMLPTel_k \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right).$$

10.5.2.2.2 $STDRMax_k$ designates the maximum MW value that may be assigned to the steam turbine *resource's* share of the *dispatchable* region and is calculated as follows:

$$STDRMax_k = CTDRTel_k \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$

10.5.2.3 Step 3: Allocate the *energy* management system MW value for the steam turbine *resource* to the *minimum loading point* and *dispatchable* regions of the *pseudo-unit* in proportion to the maximum amount that may be allocated. For *pseudo-unit* $k \in \{1,..,K\}$:

10.5.2.3.1 $STMLPTel_k$ designates the MW value assigned to the steam turbine *resource's* share of the *minimum loading point* region and is calculated as follows:

$$STMLPTel_k = min\left\{STMLPMax_k, \left(\frac{STMLPMax_k}{\sum_{w=1..K}(STMLPMax_w + STDRMax_w)}\right) \cdot STTel\right\}.$$

10.5.2.3.2 $STDRTel_k$ designates the MW value assigned the steam turbine *resource's* share of the *dispatchable* region and is calculated as follows

$$STDRTel_k = min\left\{STDRMax_k, \left(\frac{STDRMax_k}{\sum_{w=1..K}(STMLPMax_w + STDRMax_w)}\right) \cdot STTel\right\}.$$

10.5.2.4 Step 4: Determine the remaining portion of the *energy* management system MW value for the steam turbine *resource* that is yet to be distributed ($STRemTel$) as follows:

$$STRemTel = STTel - \sum_{k=1..K}(STMLPTel_k + STDRTel_k).$$

10.5.2.5 Step 5: Determine the maximum *energy* management system MW value for the remaining steam turbine *resource* that may be assigned to the duct firing region for the *pseudo-unit* based on whether the *pseudo-unit* is fully loaded for its *minimum loading point* and *dispatchable* regions. For *pseudo-unit* $k \in \{1,..,K\}$:

10.5.2.5.1 $STDFMax_k$ designates the maximum MW value that may be assigned to the duct firing region and is calculated as follows:

If $(CTMLPTel_k + CTDRTel_k + STMLPTel_k + STDRTel_k) \geq TMLP_k + TDR_k$, then set $STDFMax_k = TDF_k$

Otherwise, set $STDFMax_k = 0$.

10.5.2.6 Step 6: Distribute the remaining portion of the *energy* management system MW value for the steam turbine *resource* to the duct firing regions of the *pseudo-unit* in proportion to the maximum amount that may be allocated. For *pseudo-unit* $k \in \{1,..,K\}$:

10.5.2.6.1 $STDFTel_k$ designates the MW value assigned to the duct firing region and is calculated as follows:

$$STDFTel_k = min\left\{STDFMax_k, \left(\frac{STDFMax_k}{\sum_{w=1..K} STDFMax_w}\right) \cdot STRemTel\right\}.$$

10.5.2.7 Step 7: Determine the effective real-time *energy* management system MW value for the *pseudo-unit* by summing the MW values assigned to operating regions of the *pseudo-unit*. For *pseudo-unit* $k \in \{1,..,K\}$:

$$PSUTel_k = CTMLPTel_k + CTDRTel_k + STMLPTel_k + STDRTel_k + STDFTel_k.$$

10.6 Conversion of Pseudo-Unit Schedules to Physical Resource Schedules

10.6.1 For a *combined cycle plant* with K combustion turbine *resources* and one steam turbine *resource*, the *real-time calculation engine* shall compute the following *energy* and *operating reserve* schedules for interval $i \in I$:

10.6.1.1 $CTE_{i,k}$ designates the *energy* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

10.6.1.2 $STPE_{i,k}$ designates the *energy* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$;

10.6.1.3 STE_i designates the *energy* schedule for the steam turbine *resource*;

10.6.1.4 $CT10S_{i,k}$ designates the synchronized *ten-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

10.6.1.5 $STP10S_{i,k}$ designates the synchronized *ten-minute operating reserve* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$;

10.6.1.6 $ST10S_i$ designates the synchronized *ten-minute operating reserve* schedule for the steam turbine *resource*;

10.6.1.7 $CT10N_{i,k}$ designates the non-synchronized *ten-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

10.6.1.8 $STP10N_{i,k}$ designates the non-synchronized *ten-minute operating reserve* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$;

10.6.1.9 $ST10N_i$ designates the non-synchronized *ten-minute operating reserve* schedule for the steam turbine *resource*;

10.6.1.10 $CT30R_{i,k}$ designates the *thirty-minute operating reserve* schedule for combustion turbine *resource* $k \in \{1,..,K\}$;

10.6.1.11 $STP30R_{i,k}$ designates the *thirty-minute operating reserve* schedule for the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$; and

10.6.1.12 $ST30R_i$ designates the *thirty-minute operating reserve* schedule for the steam turbine *resource*.

10.6.2 The *real-time calculation engine* shall determine the following *energy* and *operating reserve* schedules for *pseudo-unit* $k \in \{1,..,K\}$ in interval $i \in I$:

10.6.2.1 $SE_{i,k}$ designates the total amount of *energy* scheduled and $SE_{i,k} = SEMLP_{i,k} + SEDR_{i,k} + SEDF_{i,k}$, where:

10.6.2.1.1 $SEMLP_{i,k}$ designates the portion of the schedule corresponding to the *minimum loading point* region, where $0 \leq SEMLP_{i,k} \leq QMLP_{i,k}$;

10.6.2.1.2 $SEDR_{i,k}$ designates the portion of the schedule corresponding to the *dispatchable* region, where $0 \leq SEDR_{i,k} \leq QDR_{i,k}$ and $SEDR_{i,k} > 0$ only if $SEMLP_{i,k} = QMLP_{i,k}$;

10.6.2.1.3 $SEDF_{i,k}$ designates the portion of the schedule corresponding to the duct firing region, where $0 \leq SEDF_{i,k} \leq QDF_{i,k}$ and $SEDF_{i,k} > 0$ only if $SEDR_{i,k} = QDR_{i,k}$;

10.6.2.2 $S10S_{i,k}$ designates the total amount of synchronized *ten-minute operating reserve* scheduled;

10.6.2.3 $S10N_{i,k}$ designates the total amount of non-synchronized *ten-minute operating reserve* scheduled. If the *pseudo-unit* cannot provide *operating reserve* from its duct firing region, then $0 \leq SE_{i,k} + S10S_{i,k} + S10N_{i,k} \leq QMLP_{i,k} + QDR_{i,k}$; and

10.6.2.4 $S30R_{i,k}$ designates the total amount of *thirty-minute operating reserve* scheduled, where $0 \leq SE_{i,k} + S10S_{i,k} + S10N_{i,k} + S30R_{i,k} \leq QMLP_{i,k} + QDR_{i,k} + QDF_{i,k}$.

10.6.3 The *real-time calculation engine* shall convert *pseudo-unit* schedules to physical *generation resource* schedules for *energy* and *operating reserve*, where:

10.6.3.1 $STOn \in \{0,1\}$ designates whether the steam turbine *resource* is currently online;

10.6.3.2 $CTE_{0,k}$ designates the initial *energy* schedule allocated to the combustion turbine *resource* $k \in \{1,..,K\}$; and

10.6.3.3 $STPE_{0,k}$ designates the initial *energy* schedule allocated to the steam turbine *resource's* portion of *pseudo-unit* $k \in \{1,..,K\}$.

10.6.4 The *real-time calculation engine* shall convert *pseudo-unit* schedules to physical *resource* schedules for *energy* and *operating reserve*, as follows:

10.6.4.1 If $\mathrm{SE}_{\mathrm{i,k}} \geq \mathrm{MLP}_{\mathrm{i,k}}$, then:

$$CTE_{i,k} = SEMLP_{i,k} \cdot CTShareMLP_k + SEDR_{i,k} \cdot CTShareDR_k;$$

$$STPE_{i,k} = SEMLP_{i,k} \cdot STShareMLP_k + SEDR_{i,k} \cdot STShareDR_k + SEDF_{i,k};$$

$$RoomDR_{i,k} = QDR_{i,k} - SEDR_{i,k};$$

$$10SDR_{i,k} = min(RoomDR_{i,k}, S10S_{i,k});$$

$$10NDR_{i,k} = min(RoomDR_{i,k} - 10SDR_{i,k}, S10N_{i,k});$$

$$30RDR_{i,k} = min(RoomDR_{i,k} - 10SDR_{i,k} - 10NDR_{i,k}, S30R_{i,k});$$

$$CT10S_{i,k} = 10SDR_{i,k} \cdot CTShareDR_k;$$

$$STP10S_{i,k} = 10SDR_{i,k} \cdot STShareDR_k + (S10S_{i,k} - 10SDR_{i,k});$$

$$CT10N_{i,k} = 10NDR_{i,k} \cdot CTShareDR_k;$$

$$STP10N_{i,k} = 10NDR_{i,k} \cdot STShareDR_k + (S10N_{i,k} - 10NDR_{i,k});$$

$$CT30R_{i,k} = 30RDR_{i,k} \cdot CTShareDR_k; \text{ and}$$

$$STP30R_{i,k} = 30RDR_{i,k} \cdot STShareDR_k + (S30R_{i,k} - 30RDR_{i,k}).$$

10.6.4.2 If $SE_{i,k} < MLP_{i,k}$ and is on a ramp up trajectory, then the *energy* schedules for the combustion turbine *resource* and steam turbine *resource* are determined as follows:

10.6.4.3 If the steam turbine *resource* is not online, then the *pseudo-unit* schedule will be assigned to the combustion turbine *resource* as follows:

$CTE_{i,k} = SE_{i,k}$; and

$STPE_{i,k} = 0$.

10.6.4.4 If the steam turbine *resource* is online, the incremental *pseudo-unit* schedule will be assigned to the steam turbine *resource* until the assigned combustion turbine *resource's* and steam turbine *resource's* schedules adhere to the *pseudo-unit* model as follows:

$$\text{If} \left(\frac{STPE_{i-1,k}}{STPE_{i-1,k}+CTE_{i-1,k}}\right) < STShareMLP_k, \text{ then}$$

$CTE_{i,k} = CTE_{i-1,k}$,

$STPE_{i,k} = SE_{i,k} - CTE_{i-1,k}$.

Otherwise:

$CTE_{i,k} = SE_{i,k} \cdot CTShareMLP_k$; and

$STPE_{i,k} = SE_{i,k} \cdot STShareMLP_k$.

10.6.4.5 If $SE_{i,k} < MLP_{i,k}$ and is on a ramp-down trajectory, then the *energy* schedules for the combustion turbine *resource* and steam turbine *resource* are determined as follows:

10.6.4.6 If the steam turbine *resource* is not online, then the *pseudo-unit* schedule will be assigned to the combustion turbine *resource* as follows:

$CTE_{i,k} = SE_{i,k}$; and

$STPE_{i,k} = 0$.

10.6.4.7 If the steam turbine *resource* is online, the *pseudo-unit* schedule will be assigned according to the *pseudo-unit* model as follows

$CTE_{i,k} = SE_{i,k} \cdot CTShareMLP_k$; and

$STPE_{i,k} = SE_{i,k} \cdot STShareMLP_k$.

10.6.4.8 If $SE_{i,k} < MLP_{i,k}$, then the *operating reserve* schedules for the combustion turbine *resource* and steam turbine *resource* are as follows:

$$S10S_{i,k} = S10N_{i,k} = S30R_{i,k} = 0;$$

$$CT10S_{i,k} = 0;$$

$$STP10S_{i,k} = 0;$$

$$CT10N_{i,k} = 0;$$

$$STP10N_{i,k} = 0;$$

$CT30R_{i,k} = 0$; and

$$STP30R_{i,k} = 0.$$

10.6.4.9 The steam turbine *resources* portion schedules from section 10.6.4.1 through 10.6.4.8 shall be summed to obtain the steam turbine *resource* schedule as follows:

$$STE_i = \sum_{k=1,..,K} STPE_{i,k};$$

$$ST10S_i = \sum_{k=1,..,K} STP10S_{i,k};$$

$$ST10N_i = \sum_{k=1,..,K} STP10N_{i,k};$$

and

$$ST30R_i = \sum_{k=1,..,K} STP30R_{i,k};$$

11 Pricing Formulas

11.1 Purpose

11.1.1 The *real-time calculation engine* shall calculate *locational marginal prices* using shadow prices, constraint sensitivities and marginal loss factors.

11.2 Sets, Indices and Parameters

11.2.1 The sets, indices and parameters used to calculate *locational marginal prices* are described in section 4. In addition, the following shadow prices from Pass 1 shall be used:

11.2.1.1 $SPEmT^{1}_{i,c,f}$ designates the Pass 1 shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in interval i;

11.2.1.2 SPL^{1}_{i} designates the Pass 1 shadow price for the *energy* balance constraint in interval i;

11.2.1.3 $SPNormT^{1}_{i,f}$ designates the Pass 1 shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in interval i;

11.2.1.4 $SP10S^{1}_{i}$ designates the Pass 1 shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in interval i;

11.2.1.5 $SP10R^{1}_{i}$ designates the Pass 1 shadow price for the total *ten-minute operating reserve* requirement constraint in interval i;

11.2.1.6 $SP30R^{1}_{i}$ designates the Pass 1 shadow price for the total *thirty-minute operating reserve* requirement constraint in interval i;

11.2.1.7 $SPREGMin10R^{1}_{i,r}$ designates the Pass 1 shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in interval i;

11.2.1.8 $SPREGMin30R^{1}_{i,r}$ designates the Pass 1 shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in interval i;

11.2.1.9 $SPREGMax10R^{1}_{i,r}$ designates the Pass 1 shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in interval i;

11.2.1.10 $SPREGMax30R^{1}_{i,r}$ designates the Pass 1 shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in interval i.

11.3 Locational Marginal Prices for Energy

11.3.1 Energy Locational Marginal Prices for Delivery Points

11.3.1.1 The *real-time calculation engine* shall calculate a *locational marginal price* and components for *energy* for Pass 1 and each interval $i \in I$ for every bus $b \in L$ and:

11.3.1.1.1 $LMP^1_{i,b}$ designates the Pass 1 interval i *locational marginal price* for *energy*;

11.3.1.1.2 $PRef^1_i$ designates the Pass 1 interval i *locational marginal price* for *energy* at the *reference bus*;

11.3.1.1.3 $PLoss^1_{i,b}$ designates the Pass 1 interval i loss component; and

11.3.1.1.4 $PCong^1_{i,b}$ designates the Pass 1 interval i congestion component.

11.3.1.2 The *real-time calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* at the *reference bus*, a loss component and a congestion component for Pass 1 at bus $b \in L$ in interval $i \in I$, as follows:

$$InitLMP^1_{i,b} = InitPRef^1_i + InitPLoss^1_{i,b} + InitPCong^1_{i,b}$$

where:

$$InitPRef^1_i = SPL^1_i;$$

$$InitPLoss^1_{i,b} = MglLoss_{i,b} \cdot SPL^1_i;$$

and

$$InitPCong^1_{i,b} = \sum_{f \in F_i} PreConSF_{i,f,b} \cdot SPNormT^1_{i,f} + \sum_{c \in C} \sum_{f \in F_{i,c}} SF_{i,c,f,b} \cdot SPEmT^1_{i,c,f}.$$

11.3.1.3 If the initial *locational marginal price* for *energy* at the *reference bus* ($InitPRef^1_i$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price* for *energy* at the *reference bus* as follows:

If $InitPRef_i^1 > EngyPrcCeil$, set $PRef_i^1 = EngyPrcCeil$

If $InitPRef_i^1 < EngyPrcFlr$, set $PRef_i^1 = EngyPrcFlr$

Otherwise, set $PRef_i^1 = InitPRef_i^1$

11.3.1.4 If the initial *locational marginal price* for *energy* ($InitLMP_{i,b}^1$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price* for *energy* as follows:

If $InitLMP_{i,b}^1 > EngyPrcCeil$, set $LMP_{i,b}^1 = EngyPrcCeil$.

If $InitLMP_{i,b}^1 < EngyPrcFlr$, set $LMP_{i,b}^1 = EngyPrcFlr$.

Otherwise, set $LMP_{i,b}^1 = InitLMP_{i,b}^1$

11.3.1.5 The *real-time calculation engine* shall modify the loss component as follows:

If $PRef_i^1 \neq InitPRef_i^1$, set $PLoss_{i,b}^1 = MglLoss_{i,b} \cdot PRef_i^1$

Otherwise, set $PLoss_{i,b}^1 = InitPLoss_{i,b}^1$

11.3.1.6 The *real-time calculation engine* shall modify the congestion component as follows:

If $LMP_{i,b}^1 - PRef_i^1 - PLoss_{i,b}^1$ and $InitPCong_{i,b}^1$ have the same mathematical sign, then set $PCong_{i,b}^1 = LMP_{i,b}^1 - PRef_i^1 - PLoss_{i,b}^1$

Otherwise, set $PCong_{i,b}^1 = 0$ and set $PLoss_{i,b}^1 = LMP_{i,b}^1 - PRef_i^1$

11.3.2 Energy Locational Marginal Prices for Intertie Metering Points

11.3.2.1 The *real-time calculation engine* shall calculate a *locational marginal price* and components for *energy* for Pass 1 and each interval $i \in I$ for *intertie zone* bus $d \in D$, where:

11.3.2.1.1 $ExtLMP^{PD}_{i,d}$ designates the *locational marginal price* for *energy* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*;

11.3.2.1.2 $ICP^{1}_{i,d}$ designates the Pass 1 interval i *intertie congestion price*;

11.3.2.1.3 $ICP^{PD}_{i,d}$ designates the *intertie congestion price* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*;

11.3.2.1.4 $IntLMP^{1}_{i,d}$ designates the Pass 1 interval i *intertie border price* for *energy*;

11.3.2.1.5 $ExtLMP^{1}_{i,d}$ designates the Pass 1 interval i *locational marginal price* for *energy*;

11.3.2.1.6 $PExtCong^{1}_{i,d}$ designates the Pass 1 interval i external congestion component for the *intertie congestion price*;

11.3.2.1.7 $PExtCong^{PD}_{i,d}$ designates the external congestion component for the *intertie congestion price* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*;

11.3.2.1.8 $PIntCong^{1}_{i,d}$ designates the Pass 1 interval i internal congestion component for *energy*;

11.3.2.1.9 $PLoss^{1}_{i,d}$ designates the Pass 1 interval i loss component;

11.3.2.1.10 $PNISL^{1}_{i,d}$ designates the Pass 1 interval i net interchange scheduling limit congestion component for the *intertie congestion price*;

11.3.2.1.11 $PNISL^{PD}_{i,d}$ designates the net interchange scheduling limit congestion component for the *intertie congestion price* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*; and

11.3.2.2 The *real-time calculation engine* shall calculate an *intertie border price* for *energy*, a *locational marginal price* for *energy* for the *reference* *bus*, a loss component and a congestion component for *energy* for Pass 1 at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in interval $i \in I$, subject to section 11.3.2.11, as follows:

$$InitIntLMP_{i,d}^{1} = InitPRef_{i}^{1} + InitPLoss_{i,d}^{1} + InitPIntCong_{i,d}^{1}$$

where

$InitPRef_{i}^{1} = SPL_{i}^{1}$;

$InitPLoss_{i,d}^{1} = MglLoss_{i,d} \cdot SPL_{i}^{1}$;

and

$$InitPIntCong_{i,d}^{1} = \sum_{f \in F_i} PreConSF_{i,f,d} \cdot SPNormT_{i,f}^{1} + \sum_{c \in C} \sum_{f \in F_{i,c}} SF_{i,c,f,d} \cdot SPEmT_{i,c,f}^{1}$$

11.3.2.3 If there is import congestion in pre-dispatch such that $ICP_{i,d}^{PD} < 0$, the *real-time calculation engine* shall calculate an initial *locational marginal price*, an *intertie congestion price*, and the net interchange scheduling limit congestion component for the *intertie congestion price* for *energy* for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$ as follows:

$$InitExtLMP_{i,d}^{1} = min\left(InitIntLMP_{i,d}^{1}, ExtLMP_{i,d}^{PD}\right);$$

$$InitICP_{i,d}^{1} = InitExtLMP_{i,d}^{1} - InitIntLMP_{i,d}^{1};$$

where:

If $InitExtLMP_{i,d}^{1} = InitIntLMP_{i,d}^{1}$, then $InitICP_{i,d}^{1} = 0$ and $InitPNISL_{i,d}^{1} = 0$;

and

If $InitExtLMP_{i,d}^{1} = ExtLMP_{i,d}^{PD}$, then $InitICP_{i,d}^{1}$ and $InitPNISL_{i,d}^{1}$ shall be prorated based on their pre-dispatch magnitudes so that their sum equals the effective real-time *intertie congestion price*.

11.3.2.4 If there is export congestion in pre-dispatch such that $ICP_{i,d}^{PD} > 0$, the *real-time calculation engine* shall calculate an initial *locational marginal price*, an *intertie congestion price*, and the net interchange scheduling limit congestion component for the *intertie congestion price* for *energy* for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$ as follows:

$$InitExtLMP_{i,d}^{1} = InitIntLMP_{i,d}^{1} + InitICP_{i,d}^{1}$$

where:

$$InitICP_{i,d}^{1} = InitPExtCong_{i,d}^{1} + InitPNISL_{i,d}^{1};$$

$$InitPExtCong_{i,d}^{1} = PExtCong_{i,d}^{PD} ;$$

and

$$InitPNISL_{i,d}^{1} = PNISL_{i,d}^{PD}.$$

11.3.2.5 If there is no *intertie* congestion in pre-dispatch such that $ICP_{i,d}^{PD} = 0$ or an *intertie zone* is out-of-service in real-time, then the *real-time calculation engine* shall calculate an initial *locational marginal price*, an *intertie congestion price*, and the net interchange scheduling limit congestion component for the *intertie congestion price* for *energy* for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$ as follows:

$$InitExtLMP_{i,d}^{1} = InitIntLMP_{i,d}^{1} + InitICP_{i,d}^{1}$$

where

$$InitICP_{i,d}^{1} = InitPExtCong_{i,d}^{1} + InitPNISL_{i,d}^{1} = 0$$

$$InitPExtCong_{i,d}^{1} = PExtCong_{i,d}^{PD};$$

and

$$InitPNISL_{i,d}^{1} = PNISL_{i,d}^{PD}.$$

11.3.2.6 If the *intertie border price* for *energy* ($InitIntLMP_{i,d}^{1}$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *real-time calculation engine* shall modify the *intertie border price* for *energy*, and its components, as follows:

11.3.2.6.1 The initial *locational marginal price* for the *reference bus* ($InitPRef_i^1$) shall be modified as per section 11.3.1.3;

11.3.2.6.2 The initial *intertie border price* ($InitIntLMP_{i,d}^1$) shall be modified as per section 11.3.1.4, where $InitLMP_{i,b}^1$ = $InitIntLMP_{i,d}^1$;

11.3.2.6.3 The initial loss component ($InitPLoss_{i,d}^1$) shall be modified as per section 11.3.1.5; and

11.3.2.6.4 The initial internal congestion component ($InitPIntCong_{i,d}^1$) shall be modified as per section 11.3.1.6, where $InitPCong_{i,b}^1 = InitPIntCong_{i,d}^1$.

11.3.2.7 If the initial *locational marginal price* for *energy* ($InitExtLMP_{i,d}^1$) is not within the *settlement* bounds ($EngyPrcFlr$, $EngyPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price* for *energy*, as follows:

If $InitExtLMP_{i,d}^1 > EngyPrcCeil$, set $ExtLMP_{i,d}^1 = EngyPrcCeil$.

If $InitExtLMP_{i,d}^1 < EngyPrcFlr$, set $ExtLMP_{i,d}^1 = EngyPrcFlr$.

Otherwise, set $ExtLMP_{i,d}^1 = InitExtLMP_{i,d}^1$.

11.3.2.8 If the modified *locational marginal price* for *energy* ($ExtLMP_{i,d}^1$) determined in section 11.3.2.7 is equal to the *intertie border price* for *energy* ($IntLMP_{i,d}^1$), then the *real-time calculation engine* shall modify the external congestion component for the *intertie congestion price* and net interchange scheduling limit congestion component for the *intertie congestion price*, as follows:

If $ExtLMP_{i,d}^1 = IntLMP_{i,d}^1$, set $PExtCong_{i,d}^1 = 0$ and $PNISL_{i,d}^1 = 0$.

11.3.2.9 If the modified *locational marginal price* for *energy* ($ExtLMP_{i,d}^1$) determined in section 11.3.2.7 is not equal to the *intertie border price* for *energy* ($IntLMP_{i,d}^1$), then the *real-time calculation engine* shall modify the external congestion component for the *intertie congestion* *price* and net interchange scheduling limit congestion component for the *intertie congestion price*, as follows:

If $ExtLMP_{i,d}^{1} \neq IntLMP_{i,d}^{1}$, then set

$$PNISL_{i,d}^{1} = (ExtLMP_{i,d}^{1} - IntLMP_{i,d}^{1}) \cdot \left(\frac{InitPNISL_{i,d}^{1}}{InitPNISL_{i,d}^{1} + InitPExtCong_{i,d}^{1}}\right).$$

If $PNISL_{i,d}^{1} > NISLPen$, then set $PNISL_{i,d}^{1} = NISLPen$;

If $PNISL_{i,d}^{1} < (-1) \cdot NISLPen$, then set $PNISL_{i,d}^{1} = (-1) \cdot NISLPen$; and

Set $PExtCong_{i,d}^{1} = ExtLMP_{i,d}^{1} - IntLMP_{i,d}^{1} - PNISL_{i,d}^{1}$

11.3.2.10 The *real-time calculation engine* shall calculate the *intertie* congestion price as follows:

$$ICP_{i,d}^{1} = PExtCong_{i,d}^{1} + PNISL_{i,d}^{1}.$$

11.3.2.11 The *locational marginal price* for *energy* calculated by the *real-time calculation engine* shall be the same for all *boundary entity resource* buses at the same *intertie zone*. *Intertie* transactions associated with the same *boundary entity resource* bus, but specified as occurring at different *intertie zones*, subject to phase shifter operation, shall be modelled as flowing across independent paths. Pricing of these transactions shall utilize shadow prices associated with the internal transmission constraints, *intertie* limits and transmission losses applicable to the path associated to the relevant *intertie zone*.

11.3.3 Zonal Prices for Energy

11.3.3.1 The *real-time calculation engine* shall calculate the zonal price for *energy* and its components for Pass 1 and each interval $i \in I$, the *energy* price for *virtual transaction zone* $m \in M$, as follows:

$$VZonalP_{i,m}^{1} = PRef_{i}^{1} + VZonalPLoss_{i,m}^{1} + VZonalPCong_{i,m}^{1}$$

where:

$$VZonalPLoss_{i,m}^{1} = \sum_{b \in L_m^{VIRT}} WF_{i,m,b}^{VIRT} \cdot PLoss_{i,b}^{1}$$

and

$$VZonalPCong_{i,m}^{1} = \sum_{b \in L_m^{VIRT}} WF_{i,m,b}^{VIRT} \cdot PCong_{i,b}^{1}$$

11.3.3.2 The *real-time calculation engine* shall calculate the zonal price for *energy* and its components for Pass 1 and each interval $i \in I$ for *non-dispatchable load* zone $y \in Y$, as follows:

$$ZonalP_{i,y}^{1} = PRef_i^{1} + ZonalPLoss_{i,y}^{1} + ZonalPCong_{i,y}^{1}$$

where:

$$ZonalPLoss_{i,y}^{1} = \sum_{b \in L_y^{NDL}} WF_{i,y,b}^{NDL} \cdot PLoss_{i,b}^{1}$$

and

$$ZonalPCong_{i,y}^{1} = \sum_{b \in L_y^{NDL}} WF_{i,y,b}^{NDL} \cdot PCong_{i,b}^{1}$$

11.3.3.3 The *Ontario zonal price* is calculated per section 11.3.3.2 where the *non-dispatchable load* zone is comprised of all *non-dispatchable loads* within Ontario.

11.3.4 Pseudo-Unit Pricing

11.3.4.1 The *real-time calculation engine* shall calculate a *locational marginal price* and components for *energy* for Pass 1 and each interval $i \in I$ for every *pseudo-unit* $k \in \{1,..,K\}$, where:

11.3.4.1.1 $CTMglLoss_{i,k}^{1}$ designates the marginal loss factor for the combustion turbine *resource* identified by *pseudo-unit* k for each interval i in Pass 1;

11.3.4.1.2 $STMglLoss_{i,k}^{p}$ designates the marginal loss factor for the steam turbine *resource* identified by *pseudo-unit* k for each interval i in Pass 1;

11.3.4.1.3 $CTPreConSF_{i,f,k}$ designates the pre-contingency sensitivity factor for the combustion turbine *resource* identified by *pseudo-unit* k on *facility* f during interval i under pre-contingency conditions;

11.3.4.1.4 $STPreConSF_{i,f,k}$ designates the pre-contingency sensitivity factor for the steam turbine *resource* identified by *pseudo-unit* k on *facility* f during interval i under pre-contingency conditions;

11.3.4.1.5 $CTSF_{i,c,f,k}$ designates the post-contingency sensitivity factor for the combustion turbine *resource* identified by *pseudo-unit* k on *facility* f during interval i under post-contigency conditions for contingency c; and

11.3.4.1.6 $STSF_{i,c,f,k}$ designates the post-contingency sensitivity factor for the steam turbine *resource* identified by *pseudo-unit* k on *facility* f during interval i under post-contingency conditions for contingency c.

11.3.4.2 The *real-time calculation engine* shall calculate an initial *locational marginal price* for *energy*, a *locational marginal price* for *energy* at the *reference bus*, a loss component and a congestion component for Pass 1 and each interval i for every *pseudo-unit* $k \in \{1,..,K\}$, as follows:

$$InitLMP_{i,k}^{1} = InitPRef_{i}^{1} + InitPLoss_{i,k}^{1} + InitPCong_{i,k}^{1}$$

where:

$$InitPRef_{i}^{1} = SPL_{i}^{1};$$

$$InitPLoss_{i,k}^{1} = MglLoss_{i,k}^{1} \cdot SPL_{i}^{1};$$

and

$$InitPCong_{i,k}^{1} = \sum_{f \in F_i} PreConSF_{i,f,k} \cdot SPNormT_{i,f}^{1} + \sum_{c \in C} \sum_{f \in F_{i,c}} SF_{i,c,f,k} \cdot SPEmT_{i,c,f}^{1}$$

11.3.4.3 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its *minimum loading point* range or not scheduled at all, its marginal loss and sensitivity factors shall be:

$$MglLoss^1_{i,k} = CTShareMLP_k \cdot CTMglLoss^1_{i,k} + STShareMLP_k \cdot STMglLoss^1_{i,k}$$

$$PreConSF_{i,f.k} = CTShareMLP_k \cdot CTPreConSF_{i,f,k} + STShareMLP_k \cdot STPreConSF_{i,f,k}$$

$$SF_{i,c,f,k} = CTShareMLP_k \cdot CTSF_{i,c,f,k} + STShareMLP_k \cdot STSF_{i,c,f,k}$$

11.3.4.4 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its *dispatchable* region, its marginal loss and sensitivity factors shall be:

$$MglLoss^1_{i,k} = CTShareDR_k \cdot CTMglLoss^1_{i,k} + STShareDR_k \cdot STMglLoss^1_{i,k}$$

$$PreConSF_{i,f,k} = CTShareDR_k \cdot CTPreConSF_{i,f,k} + STShareDR_k \cdot STPreConSF_{i,f,k}$$

$$SF_{i,c,f,k} = CTShareDR_k \cdot CTSF_{i,c,f,k} + STShareDR_k \cdot STSF_{i,c,f,k}$$

11.3.4.5 If *pseudo-unit* $k \in \{1,..,K\}$ is scheduled within its duct firing region, its marginal loss and sensitivity factors shall be:

$$MglLoss^1_{i,k} = STMglLoss^1_{i,k}$$

$$PreConSF_{i,f,k} = STPreConSF_{i,f,k}$$

$$SF_{i,c,f,k} = STSF_{i,c,f,k}$$

11.4 Locational Marginal Prices for Operating Reserve

11.4.1 Operating Reserve Locational Marginal Prices for Delivery Points

11.4.1.1 The *real-time calculation engine* shall calculate *locational marginal prices* and components for *operating reserve* for Pass 1 and each interval i for a *delivery point* associated with the *dispatchable generation resource* or *dispatchable load* bus $b \in B$, where:

11.4.1.1.1 $L30RP^1_{i,b}$ designates the Pass 1 interval i *locational marginal price* for *thirty-minute operating reserve*;

11.4.1.1.2 $P30RRef^1_i$ designates the Pass 1 interval i *locational marginal price* for *thirty-minute operating reserve* at the *reference bus*;

11.4.1.1.3 $P30RCong^{1}_{i,b}$ designates the Pass 1 interval i congestion component for *thirty-minute operating reserve*;

11.4.1.1.4 $L10NP^{1}_{i,b}$ designates the Pass 1 interval i *locational marginal price* for non-synchronized *ten-minute operating reserve*;

11.4.1.1.5 $P10NRef^{1}_{i}$ designates the Pass 1 interval i *locational marginal price* for non-synchronized *ten-minute operating reserve* at the *reference bus*;

11.4.1.1.6 $P10NCong^{1}_{i,b}$ designates the Pass 1 interval i congestion component for non-synchronized *ten-minute operating reserve*;

11.4.1.1.7 $L10SP^{1}_{i,b}$ designates the Pass 1 interval i *locational marginal price* for synchronized *ten-minute operating reserve*;

11.4.1.1.8 $P10SRef^{1}_{i}$ designates the Pass 1 interval i *locational marginal price* for synchronized *ten-minute operating reserve* at the *reference bus*;

11.4.1.1.9 $P10SCong^{1}_{i,b}$ designates the Pass 1 interval i congestion component for synchronized *ten-minute operating reserve*; and

11.4.1.1.10 $ORREG_b \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus b.

11.4.1.2 The *real-time calculation engine* shall calculate an initial *locational marginal price*, a *locational marginal price* at the *reference bus*, and congestion components for Pass 1 for a *delivery point* associated with the *dispatchable generation resource* or *dispatchable load* at bus $b \in B$ in interval $i \in I$ for each class of *operating reserve*, as follows:

$$InitL30RP_{i,b}^{1} = InitP30RRef_{i}^{1} + InitP30RCong_{i,b}^{1}$$

where:

$$InitP30RRef_{i}^{1} = SP30R_{i}^{1}$$

and

$$InitP30RCong_{i,b}^{1} = \sum_{r \in ORREG_b} SPREGMin30R_{i,r}^{1} + \sum_{r \in ORREG_b} SPREGMax30R_{i,r}^{1}$$

$$InitL10\mathrm{N}P_{i,b}^{1} = InitP10NRef_{i}^{1} + InitP10NCong_{i,b}^{1}$$

where:

$$InitP10NRef_{i}^{1} = SP10R_{i}^{1} + SP30R_{i}^{1}$$

and

$$InitP10NCong_{i,b}^{1} = \sum_{r \in ORREG_b} \left(SPREGMin10R_{i,r}^{1} + SPREGMin30R_{i,r}^{1}\right) + \sum_{r \in ORREG_b} \left(SPREGMax10R_{i,r}^{1} + SPREGMax30R_{i,r}^{1}\right)$$

$$InitL10SP_{i,b}^{1} = InitP10SRef_{i}^{1} + InitP10SCong_{i,b}^{1}$$

where:

$$InitP10SRef_{i}^{1} = SP10S_{i}^{1} + SP10R_{i}^{1} + SP30R_{i}^{1}$$

and

$$InitP10SCong_{i,b}^{1} = \sum_{r \in ORREG_b} \left(SPREGMin10R_{i,r}^{1} + SPREGMin30R_{i,r}^{1}\right) + \sum_{r \in ORREG_b} \left(SPREGMax10R_{i,r}^{1} + SPREGMax30R_{i,r}^{1}\right)$$

11.4.1.3 If the initial *locational marginal price* at the *reference bus* ($InitP30RRef_{i}^{1}$, $InitP10NRef_{i}^{1}$ or $InitP10SRef_{i}^{1}$,) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price* at the *reference bus* for each class of *operating reserve* as follows:

If $InitP30RRef_{i}^{1} > ORPrcCeil$, set $P30RRef_{i}^{1} = ORPrcCeil$;

If $InitP30RRef_{i}^{1} < ORPrcFlr$, set $P30RRef_{i}^{1} = ORPrcFlr$;

Otherwise, set $P30RRef_{t}^{1} = InitP30RRef_{i}^{1}$.

If $InitP10NRef_{i}^{1} > ORPrcCeil$, set $P10NRef_{i}^{1} = ORPrcCeil$

If $InitP10NRef_{i}^{1} < ORPrcFlr$, set $P10NRef_{i}^{1} = ORPrcFlr$

Otherwise, set $P10NRef_{i}^{1} = InitP10NRef_{i}^{1}$

If $InitP10SRef_{i}^{1}, ORPrcFlr > ORPrcCeil$, set $P10SRef_{i}^{1} = ORPrcCeil$

If $InitP10SRef_{i}^{1}, ORPrcFlr < ORPrcFlr$, set $P10SRef_{i}^{1} = ORPrcFlr$

Otherwise, set $P10SRef_{i}^{1} = InitP10SRef_{i}^{1}$

11.4.1.4 If the initial *locational marginal price* ($InitL30RP_{i,b}^{1}$, $InitL10NP_{i,b}^{1}$, or $InitL10SP_{i,b}^{1}$) is not within the *settlement* bounds

($ORPrcFlr$, $ORPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price* for each class of *operating reserve* as *follows:*

If $InitL30RP_{i,b}^{1} > ORPrcCeil$, set $L30RP_{i,b}^{1} = ORPrcCeil$;

If $InitL30RP_{i,b}^{1} < ORPrcFlr$, set $L30RP_{i,b}^{1} = ORPrcFlr$;

Otherwise, set $L30RP_{i,b}^{1} = InitL30RP_{i,b}^{1}$.

If $InitL10NP_{i,b}^{1} > ORPrcCeil$, set $L10NP_{i,b}^{1} = ORPrcCeil$;

If $InitL10NP_{i,b}^{1} < ORPrcFlr$, set $L10NP_{i,b}^{1} = ORPrcFlr$;

Otherwise, set $L10NP_{i,b}^{1} = InitL10NP_{i,b}^{1}$.

If $InitL10SP_{i,b}^{1} > ORPrcCeil$, set $L10SP_{i,b}^{1} = ORPrcCeil$;

If $InitL10SP_{i,b}^{1} < ORPrcFlr$, set $L10SP_{i,b}^{1} = ORPrcFlr$;

Otherwise, set $L10SP_{i,b}^{1} = InitL10SP_{i,b}^{1}$.

11.4.1.5 If the initial *locational marginal price* ($InitL30RP_{i,b}^{1}$, $InitL10NP_{i,b}^{1}$, or $InitL10SP_{i,b}^{1}$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *real-time calculation engine* shall modify the congestion component for each class of *operating reserve* as follows:

Set $P30RCong_{i,b}^{1} = L30RP_{i,b}^{1} - P30RRef_{i}^{1}$;

Set $P10NCong_{i,b}^{1} = L10NP_{i,b}^{1} - P10NRef_{i}^{1}$; and

Set $P10SCong_{i,b}^{1} = L10SP_{i,b}^{1} - P10SRef_{i}^{1}$.

11.4.2 Operating Reserve Locational Marginal Prices for Intertie Metering Points

11.4.2.1 The *real-time calculation engine* shall calculate *locational marginal prices* and components for *operating reserve* for Pass 1 and each interval $i \in I$, for *intertie zone* bus $d \in D$, where:

11.4.2.1.1 $ExtL30RP_{i,d}^{1}$ designates the Pass 1 interval i *locational marginal price* for *thirty-minute operating reserve*;

11.4.2.1.2 $ExtL30RP_{i,d}^{PD}$ designates the *locational marginal price* for *thirty-minute operating reserve* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*;

11.4.2.1.3 $P30RExtCong^{1}_{i,d}$ designates the Pass 1 interval i congestion component for *thirty-minute operating reserve*;

11.4.2.1.4 $P30RExtCong^{PD}_{i,d}$ designates the *intertie* congestion *intertie* component for *thirty-minute operating reserve* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*;

11.4.2.1.5 $ExtL10NP^{1}_{i,d}$ designates the Pass 1 interval i *locational marginal price* for non-synchronized *ten-minute operating reserve*;

11.4.2.1.6 $ExtL10NP^{PD}_{i,d}$ designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*;

11.4.2.1.7 $P30RRef^{1}_{i}$ designates the Pass 1 interval i *locational marginal price* for *thirty-minute operating reserve* at the *reference bus*;

11.4.2.1.8 $\mathrm{P30RIntCong}^{1}_{i,d}$ designates the Pass 1 interval i internal congestion component for *thirty-minute operating reserve*;

11.4.2.1.9 $P10NRef^{1}_{i}$ designates the Pass 1 interval i *locational marginal price* for non-synchronized *ten-minute operating reserve* at the *reference bus*;

11.4.2.1.10 $P10NIntCong^{1}_{i,d}$ designates the Pass 1 interval i internal congestion component for non-synchronized *ten-minute operating reserve*;

11.4.2.1.11 $P10NExtCong^{1}_{i,d}$ designates the Pass 1 interval i *intertie* congestion component for non-synchronized *ten-minute operating reserve*; and

11.4.2.1.12 $P10NExtCong_{i,d}^{PD}$ designates the *intertie* congestion component for non-synchronized *ten-minute operating reserve* for the *dispatch hour* in which interval i falls as calculated by the *pre-dispatch calculation engine*.

11.4.2.2 The *real-time calculation engine* shall calculate an initial *locational marginal price*, a *locational marginal price* at the *reference bus*, an internal congestion component and an *intertie* congestion component for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$, for each class of *operating reserve*, subject to section 11.4.2.8, as follows:

$$InitIntL30RP_{i,d}^{1} = InitP30RRef_i^{1} + InitP30RIntCong_{i,d}^{1}$$

where:

$$InitP30RRef_i^{1} = SP30R_i^{1}$$

and

$$InitP30RIntCong_{i,d}^{1} = \sum_{r \in ORREG_d} SPREGMin30R_{i,r}^{1} + \sum_{r \in ORREG_d} SPREGMax30R_{i,r}^{1}$$

$$InitIntL10NP_{i,d}^{1} = InitP10NRef_i^{1} + InitP10NIntCong_{i,d}^{1}$$

where:

$$InitP10NRef_i^{1} = SP10R_i^{1} + SP30R_i^{1}$$

and

$$InitP10NIntCong_{i,d}^{1} = \sum_{r \in ORREG_d} \left(SPREGMin10R_{i,r}^{1} + SPREGMin30R_{i,r}^{1}\right) + \sum_{r \in ORREG_d} \left(SPREGMax10R_{i,r}^{1} + SPREGMax30R_{i,r}^{1}\right)$$

11.4.2.3 The *real-time calculation engine* shall calculate initial *locational marginal prices*, and its components for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$ for each class of *operating reserve* as follows:

11.4.2.3.1 If the *intertie* is import congested in pre-dispatch ($P30RExtCong_{i,d}^{PD} < 0$ or $P10NExtCong_{i,d}^{PD} < 0$), then the prices and components are determined in accordance with section 11.4.2.4;

11.4.2.3.2 If the *intertie* is not import congestion in pre-dispatch ($P30RExtCong_{i,d}^{PD} \geq 0$ or $P10NExtCong_{i,d}^{PD} \geq 0$) or if an *intertie zone* is out-of-service, then the prices and components are determined in accordance with section 11.4.2.5.

11.4.2.4 The *real-time calculation engine* shall calculate an initial *locational marginal price* and an external congestion component for the *intertie congestion price* for each class of *operating reserve* for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$ as follows:

$$InitExtL30RP_{i,d}^{1} = min(InitIntL30RP_{i,d}^{1}, ExtL30RP_{i,d}^{PD});$$

and

$$InitP30RExtCong_{i,d}^{1} = InitExtL30RP_{i,d}^{1} - InitIntL30RP_{i,d}^{1}.$$

$$InitExtL10NP_{i,d}^{1} = min(InitIntL10NP_{i,d}^{1}, ExtL10NP_{i,d}^{PD});$$

and

$$InitP10NExtCong_{i,d}^{1} = InitExtL10NP_{i,d}^{1} - InitIntL10NP_{i,d}^{1}.$$

11.4.2.5 The *real-time calculation engine* shall calculate an initial *locational marginal price* and an external congestion component for the *intertie congestion price* for each class of *operating reserve* for Pass 1 at *intertie zone* bus $d \in D$ in interval $i \in I$ as follows:

$$InitExtL30RP_{i,d}^{1} = InitIntL30RP_{i,d}^{1};$$

and

$$InitP30RExtCong_{i,d}^{1} = 0.$$

$$InitExtL10NP_{i,d}^{1} = InitIntL10NP_{i,d}^{1};$$

and

$$InitP10NExtCong_{i,d}^{1} \ = \ 0.$$

11.4.2.6 If the initial *locational marginal price* ($InitExtL30RP_{i,b}^{1}$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price*, the *locational marginal price* at the *reference bus*, and the congestion components for *thirty-minute operating reserve* as follows:

$$IntL30R \ = InitP30RRef_{i}^{1} + InitP30RIntCong_{i,d}^{1}$$

If $InitP30RRef_{i}^{1} \ > \ ORPrcCeil$, set $P30RRef_{i}^{1} \ = \ ORPrcCeil$;

If $InitP30RRef_{i}^{1} \ < \ ORPrcFlr$, set $P30RRef_{i}^{1} \ = \ ORPrcFlr$;

Otherwise, set $P30RRef_{i}^{1} \ = \ InitP30RRef_{i}^{1}$;

Set $P30RIntCong_{i,d}^{1} \ = \ ExtL30RP_{i,b}^{1} - P30RRef_{i}^{1}$;

If $InitExtL30RP_{i,b}^{1} \ > \ ORPrcCeil$, set $ExtL30RP_{i,b}^{1} \ = \ ORPrcCeil$;

If $InitExtL30RP_{i,b}^{1} \ < \ ORPrcFlr$, set $ExtL30RP_{i,b}^{1} \ = \ ORPrcFlr$;

Otherwise, $ExtL30RP_{i,b}^{1} \ = \ InitExtL30RP_{i,b}^{1}$; and

Set $P30RExtCong_{i,d}^{1} \ = \ ExtL30RP_{i,b}^{1} - P30RRef_{i}^{1} - P30RIntCong_{i,d}^{1}$

11.4.2.7 If the initial *locational marginal price* ($InitExtL10NP_{i,d}^{1}$) is not within the *settlement* bounds ($ORPrcFlr$, $ORPrcCeil$), then the *real-time calculation engine* shall modify the *locational marginal price*, the *locational marginal price* at the *reference bus*, and the congestion components for *ten-minute operating reserve* as follows:

$$IntL10N = InitP10NRef_{i}^{1} + InitP10NIntCong_{i,d}^{1}$$

If $InitP10NRef_{i}^{1} \ > \ ORPrcCeil$, set $P10NRef_{i}^{1} \ = \ ORPrcCeil$;

If $InitP10NRef_{i}^{1} \ < \ ORPrcFlr$, set $P10NRef_{i}^{1} \ = \ ORPrcFlr$;

Otherwise, $P10NRef_{i}^{1} \ = \ InitP10NRef_{i}^{1}$; and

Set $P10NIntCong_{i,d}^{1} \ = \ L10NP_{i,b}^{1} - P10NRef_{i}^{1}$

If $InitExtL10NP_{i,b}^{1} \ > \ ORPrcCeil$, set $ExtL10NP_{i,b}^{1} \ = \ ORPrcCeil$;

If $InitExtL10NP_{i,b}^{1} < ORPrcFlr$, set $ExtL10NP_{i,b}^{1} = ORPrcFlr$;

Otherwise, $ExtL30RP_{i,b}^{1} = InitExtL10NP_{i,b}^{1}$; and

Set $P10NExtCong_{i,d}^{1} = ExtL10NP_{i,b}^{1} - P10NRef_{i}^{1} - P10NIntCong_{i,d}^{1}$

11.4.2.8 The *locational marginal price* calculated by the *real-time calculation engine* shall be the same for all *boundary entity resource* buses at the same *intertie zone*. Reserve imports associated with the same *boundary entity resource* bus, but specified as ocurring at a different *intertie zone*, subject to phase shifter operation, shall be modelled as flowing across independent paths. Pricing of these reserve imports shall utilize shadow prices associated with *intertie* limits and regional minimum and maximum *operating reserve* requirements applicable to the path associated to the relevant *intertie zone*.

11.5 Pricing for Islanded Nodes

11.5.1 For *non-quick start resources* that are not connected to the *main island*, the *real-time calculation engine* shall use the following reconnection logic where enabled by the *IESO* in the order set out below to calculate the *locational marginal prices* for *energy*:

11.5.1.1 Determine the connection paths over open switches that connect the *non-quick start resource* to the *main island*;

11.5.1.2 Determine the priority rating for each connection path identified based on a weighted sum of the base voltage over all open switches used by the reconnection path and the MW ratings of the newly connected branches; and

11.5.1.3 Select the reconnection path with the highest priority rating, breaking ties arbitrarily.

11.5.2 For all (i) *resources* other than those specified in section 11.5.1 not connected to the *main island*; (ii) *non-quick start resources* where a price was not able to be determined in accordance with section 11.5.1; the *real-time calculation engine* shall use the following logic in the order set out below to calculate *locational* *marginal prices* for *energy*, using a node-level and *facility*-level substitution list determined by the *IESO*:

11.5.2.1 Use the *locational marginal price* for *energy* at a node in the node-level substitution list where defined and enabled by the *IESO*, provided such node is connected to the *main island*;

11.5.2.2 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes at the same voltage level within the same *facility* that are connected to the *main island*;

11.5.2.3 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes within the same *facility* that are connected to the *main island*;

11.5.2.4 If no such nodes are identified, use the average *locational marginal price* for *energy* of all nodes from another *facility* that is connected to the *main island*, as determined by the *facility*-level substitution list where defined and enabled by the *IESO*; and

11.5.2.5 If a price is unable to be determined in accordance with sections 11.5.2.1 through 11.5.2.4, use the *locational marginal price* for *energy* for the *reference bus*.

Appendix 7.7 – Radial Intertie Transactions

1.1 Applicable Configurations

1.1.1 An electricity *generation resource* associated with a *generation facility* that is connected electrically over a *radial intertie* to a neighbouring *control area* may only provide electricity or any *physical service* for delivery out of the *integrated power system* if it is, with the approval of the *IESO,* operating such *generation resource* in a *segregated mode of operation.*

1.2 Dispatch Data

1.2.1 *A market participant* that intends for a *generation resource* to operate in a *segregated mode of operation* shall maintain *dispatch data* that was submitted for that *generation resource* for each *dispatch hour* during which a *generation resource* will or is intended to operate in *segregated mode of operation*. The *market participant* may revise the applicable *dispatch data* in accordance with the timelines for submission of revised *dispatch data* specified in MR Ch.7 ss.3.2 and 3.3.

1.2.2 Notwithstanding the provisions of MR Ch.7 s.3.3, if the *IESO*:

1.2.2.1 denies a *Request for Segregation*; or

1.2.2.2 revokes its approval to operate a *generation resource* in a *segregated mode of operation* or terminates the operation of a *generation resource* in a *segregated mode of operation* in accordance with section 1.3.6,

the *IESO* shall permit new or revised *dispatch data* to be submitted to the *IESO* in respect of the *generation resource* for the *dispatch hours* to which such denied request pertains.

1.3 Scheduling & Scheduling Approval

1.3.1 A *registered market participant* shall, within the time required by section 1.3.3, submit a *Request for Segregation* to the *IESO* for approval to operate its *generation resource* in *a segregated mode of operation* and shall submit an *outage* request, in accordance with the provisions specified in MR Ch.5 s.6.4 and the applicable *market manual*, to the *IESO* for the *generation resources* intended to operate in a *segregated mode of operation*. The *registered market participant* shall make such a *Request for Segregation* in accordance with the applicable *market manual* and the information contained in such *Request for Segregation* shall include, but not be limited to:

1.3.1.1 the time at which operation in a *segregated mode of operation* is intended to commence;

1.3.1.2 the length of time that the applicable *generation resources* are intended to operate in a *segregated mode of operation*; and

1.3.1.3 a list of the *generation resources* that are intended to operate in a *segregated mode of operation*.

1.3.2 If a *registered market participant* wishes to revise the contents of a *Request for Segregation* it shall submit a new *Request for Segregation* and shall submit a new *outage* request to the *IESO* in accordance with section 1.3.1.

1.3.3 If a *Request for Segregation* requires an *outage* to equipment that the *IESO* has designated as critical in accordance with the applicable *market manual*, the request shall be made by 8:00 EPT on the day prior to the relevant *dispatch day*, unless otherwise agreed by the *IESO.* If a *Request for Segregation* does not require an *outage* to such equipment, the *registered market participant* shall make the *Request for Segregation* by 9:00 EPT on the day prior to the relevant *dispatch day* for inclusion in the *day-ahead market* or no later than two hours prior to the start of the first *dispatch hour* to which the request pertains for inclusion in the *real-time market*. When the *Request for Segregation* is for the operation of a *generation resource* in a *segregated mode of operation* for more than one day the *IESO* may approve such operation for up to two *business days*.

1.3.4 The *IESO* shall make a decision regarding a *Request for Segregation* prior to the run of the *day-ahead market calculation engine* if the request is submitted on the *day prior to the relevant dispatch day* by 8:00 EPT or 9:00 EPT as applicable, in accordance with section 1.3.3. The *IESO* shall make a decision regarding a *Request for Segregation* submitted after 9:00 EPT on the *day prior to the relevant dispatch day* as soon as practicable but no later than such time that allows the *transmitter*, referred to in section 1.3.5, a minimum of 90 minutes or such lesser time as agreed to by the *transmitter* to switch any applicable equipment or *facilities* required to permit implementation of the *segregated mode of operation* prior to the time set out in section 1.3.1.1, and shall notify the *registered market participant* of such decision. The *IESO*:

1.3.4.1 shall deny such *Request for Segregation* if:

a. such *Request for Segregation* pertains to a *generation resource* located in the province of Ontario and would threaten the reliability of the *IESO-controlled grid*; or

b. the *metering installation* for the *generation resource* to which such *Request for Segregation* relates does not comply with MR Ch. 6 s.4.1A.1; or

c. such *Request for Segregation* pertains to a *generation resource* located outside the province of Ontario and would threaten the *security* of the *IESO-controlled grid*; and

1.3.4.2 may deny such *Request for Segregation* if the *metered market participant* for the *metering installation* for the *generation resource* to which such *Request for Segregation* relates has previously failed to comply with MR Ch.6 App.6.1 s.1.2.1.7 for a period in which such *generation resource* operated in a *segregated mode of operation.*

1.3.5 If the *IESO* approves a *Request for Segregation,* it shall direct the relevant *transmitter* to:

1.3.5.1 switch any applicable equipment or *facilities* required to permit implementation of the *segregated mode of operation* at the time referred to in section 1.3.1.1;

1.3.5.2 switch any applicable equipment or *facilities* required to cease implementation of the *segregated mode of operation* at the expiry of the time referred to in section 1.3.1.2.

1.3.6 The *IESO* may at any time revoke its approval to operate a *generation resource* in a *segregated mode of operation* or terminate the operation of a *generation resource* in a *segregated mode of operation*, as the case may be, for the reason described in section 1.3.4.1(b), where the *metered market participant* is failing to comply with MR Ch.6 App.6.1 s. 1.2.1.7 in respect of the *metering installation* for such *generation resource* or where, in the *IESO's* opinion, such approval or such continued operation would threaten the reliability of a local area which forms part of the *IESO-controlled grid* or the security of the *integrated power system*, and shall notify the *registered market participant* accordingly. Where the *IESO* intends to revoke its approval to operate a *generation resource* in a *segregated mode of operation*, it shall revoke any direction issued pursuant to section 1.3.5. Where the *IESO* intends to terminate such operation, the *IESO* shall direct the relevant *transmitter* to switch any applicable equipment or *facilities* required to cease implementation of the *segregated mode of operation*. Where the *IESO* revokes its approval to operate a *generation resource* in a *segregated mode of operation* or terminates the operation of a *generation resource* in a *segregated mode of operation*, as the case may be, the *registered market participant* for that *generation resource* shall not be entitled to compensation for any costs, losses or damages from the *IESO* for such revocation or termination.

1.3.7 The *IESO* shall coordinate and confirm with the applicable *control area operator:*

1.3.7.1 the switching to be effected by the relevant *transmitter* in accordance with section 1.3.5 or 1.3.6; and

1.3.7.2 the names of the *generation resources* that will operate in a *segregated mode of operation*.

1.3.8 The *IESO* shall not issue *dispatch instructions* to a *generation resource* in respect of any *dispatch hour* during which *such generation resource* is operating in a *segregated mode of operation*. All instructions relating to *dispatch* for the *generation resource* while operating in a *segregated mode of operation* shall be sent directly by the applicable *control area operator* to the *registered market participant*.

1.3.9 A *registered market participant* may only cancel or revise a *Request for Segregation* that requires an *outage* to equipment that the *IESO* has designated as critical, in accordance with the applicable *market manual,* after 8:00 EPT on the *day prior to the relevant dispatch day* if operating its *generation resource* in a *segregated mode of operation* would endanger the safety of any person, damage equipment, or violate any *applicable law.*

1.3.10 A *registered market participant* may cancel a *Request for Segregation* that does not require an *outage* to equipment that the *IESO* has designated as critical, in accordance with the applicable *market manual,* at any time.

1.3.11 A *registered market participant* that cancels a *Request for Segregation* pursuant to sections 1.3.9 and 1.3.10 shall cancel the *outage* request associated with the *Request for Segregation* for its *generation resource*.

1.4 Settlements

1.4.1 The delivery of electricity or a *physical service* by a *generation resource* while operating in a *segregated mode of operation* shall be excluded from the *IESO's settlement process* and in no event shall the *IESO* be required to effect payment in respect of any electricity or *physical service* so delivered.

1.4.2 Notwithstanding section 1.4.1, a *registered market participant* that operates a *generation resource* in a *segregated mode of operation* shall submit such scheduling information to the *IESO* as may be necessary to enable the *IESO* to determine the amounts payable by the *registered market participant* for *export transmission service* related to such operation.

1.4.3 Any costs incurred by a *transmitter* in complying with a direction issued pursuant to section 1.3.5 or 1.3.6 shall be borne by the *registered market participant* or the *transmitter* in the manner specified in their *connection agreement.*

1.4.4 The *registered market participant* shall be solely liable in respect of any positive or negative inadvertent accumulated while its *generation resources* are operating in the *segregated mode of operation.*

Appendix 7.8 – Economic Operating Point

1. Introduction

1.1 Purpose

1.1.1 This appendix describes the processes used to determine the economic operating points for lost cost in the *day-ahead market* and *real-time market*, and for lost opportunity in the *real-time market.*

2. Day-Ahead Market Lost Cost Economic Operating Point

2.1 Purpose

2.1.1 This section describes the process used to determine the lost cost economic operating point for eligible *resources* in the *day-ahead market* (DAM LC EOP).

2.2 Sets, Indices and Parameters used in the DAM LC EOP Calculation

Fundamental Sets and Indices

2.2.1 A designates the set of all *intertie zones*;

2.2.2 B designates the set of buses identifying all *dispatchable* and *non-dispatchable resources* within Ontario;

2.2.3 $B^{DG} \subseteq B$ designates the set of buses identifying *dispatchable generation resources*;

2.2.4 $B^{DL} \subseteq B$ designates the set of buses identifying *dispatchable loads*;

2.2.5 $B^{HE} \subseteq B^{DG}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources*;

2.2.6 $B_s^{HE} \subseteq B^{HE}$ designates the subset of buses identifying *dispatchable* hydroelectric *generation resources* in set s ∈ SHE;

2.2.7 D designates the set of buses outside Ontario, corresponding to imports and exports in *intertie zones*;

2.2.8 $D_a \subseteq D$ designates the set of all buses identifying *boundary entity resources* in *intertie zone* $a \in A$;

2.2.9 $DI \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers*;

2.2.10 $DI_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers* in *intertie zone* $a \in A$;

2.2.11 $DX \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids*;

2.2.12 $DX_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids* in *intertie zone* $a \in A$;

2.2.13 $J_{h,b}^{E}$ designates the set of *bid* laminations for *energy* at bus $b \in B^{DL} \cup DX$ for hour $h \in \{1,..,24\}$;

2.2.14 $J_{h,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B^{DL}$ for hour $h \in \{1,..,24\}$;

2.2.15 $J_{h,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B^{DL} \cup DX$ for hour $h \in \{1,..,24\}$;

2.2.16 $J_{h,b}^{30R}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at $b \in B^{DL} \cup DX$ for hour $h \in \{1,..,24\}$;

2.2.17 $K_{h,b}^{E}$ designates the set of *offer* laminations for *energy* at bus $b \in B \cup DI$ for hour $h \in \{1,..,24\}$;

2.2.18 $K_{h,b}^{10S}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $\mathrm{b} \in B^{DG} \cup DI$ for hour $\mathrm{h} \in \{1,..,24\}$;

2.2.19 $K_{h,b}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $\mathrm{b} \in B^{DG} \cup DI$ for hour $\mathrm{h} \in \{1,..,24\}$;

2.2.20 $K_{h,b}^{30R}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B^{DG} \cup DI$ for hour $\mathrm{h} \in \{1,..,24\}$;

2.2.21 $\wp(B^{HE})$ designates the set of all subsets of the set B^{HE};

2.2.22 $B_{up}^{HE} \subseteq \wp(B^{HE})$ designates the set of buses identifying all upstream *dispatchable* hydroelectric *generation resources* with a *linked forebay*;

2.2.23 $B_{dn}^{HE} \subseteq \wp(B^{HE})$ designates the set of buses identifying all downstream *dispatchable* hydroelectric *generation resources* with a *linked forebay*;

Market Participant Data Parameters

2.2.24 With respect to all *resources*:

2.2.24.1 $Derate_{h,b}$ designates the maximum amount of *energy and operating reserve* that can be scheduled for a *resource* in a *dispatch hour* $h \in \{1, . . . , 24\}$.

2.2.25 With respect to a *dispatchable generation resource* identified by bus $b \in B^{DG}$;

2.2.25.1 $MinQDG_b$ designates the *minimum loading point*;

2.2.25.2 $ORRDG_b$ designates the maximum *operating reserve* ramp rate in MW per minute;

2.2.25.3 $PDG_{h,b,k}$ designates the price for the maximum incremental quantity of *energy* for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $\mathrm{k} \in \mathrm{K}_{\mathrm{h,b}}^{\mathrm{E}}$;

2.2.25.4 $P10SDG_{h,b,k}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $\mathrm{k} \in \mathrm{K}_{\mathrm{h,b}}^{\mathrm{10S}}$;

2.2.25.4 $P10NDG_{h,b,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{10N}$;

2.2.25.6 $P30RDG_{h,b,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{30R}_{h,b}$;

2.2.25.7 $QDG_{h,b,k}$ designates the maximum incremental quantity of *energy* above the *minimum loading point* that may be scheduled for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,b}$;

2.2.25.8 $Q10SDG_{h,b,k}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10S}_{h,b}$;

2.2.25.9 $Q10NDG_{h,b,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10N}_{h,b}$;

2.2.25.10 $Q30RDG_{h,b,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{30R}_{h,b}$;

2.2.25.11 $RLP10S_{h,b}$ designates the *reserve loading point* for synchronized *ten-minute operating reserve* for hour $h \in \{1,..,24\}$;

2.2.25.12 $RLP30R_{h,b}$ designates the *reserve loading point* for *thirty-minute operating reserve* for hour $h \in \{1,..,24\}$; and

2.2.25.13 $QDLFIRM_{h,b}$ designates the quantity of *energy* that is *bid* at the *maximum market clearing price* in hour $h \in \{1,..,24\}$;

2.2.26 With respect to a *dispatchable* hydroelectric *generation resource* identified by bus $b \in B^{HE}$:

2.2.26.1 $ForL_{b,i}, ForU_{b,i}$ shall designate the lower and upper limits, respectively, of the *resource's forbidden regions* indicating that the *resource* cannot be scheduled between $ForLb,i$ and $ForU_{b,i}$ for all $i \in \{1,..,N_{Forb}\}$;

2.2.26.2 $MaxStartsHE_b$ designates the *maximum number of starts per day* for the *resource*;

2.2.26.3 $MaxDEL_b$ designates the *maximum daily energy limit* for a single *resource* with or without a *linked forebay*;

2.2.26.4 $MinDEL_b$ designates the *minimum daily energy limit* for a single *resource* with or without a *linked forebay*;

2.2.26.5 $MinHMR_{h,b}$ designates the *hourly must-run* quantity for the *resource* for hour $h \in \{1,..,24\}$;

2.2.26.6 $MinHO_{h,b}$ designates the *minimum hourly output* quantity for the *resource* for hour $h \in \{1,..,24\}$; and

2.2.26.7 $StartMW_{b,i}$ for $i \in \{1,.., NStartMW_b\}$ designates the *start indication value* for measuring *maximum number of starts per day*;

2.2.27 With respect to *dispatchable* hydroelectric *generation resources* with a *linked forebay*:

2.2.27.1 $MaxSDEL_s$ designates the *maximum daily energy limit* shared by all *dispatchable* hydroelectric *generation resources* in set $s \in SHE$; and

2.2.27.2 $MinSDEL_s$ designates the *minimum daily energy limit* shared by all *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

2.2.28 With respect to a *dispatchable* hydroelectric *generation resource* for which a *MWh ratio* was respected:

2.2.28.1 $LNK \subseteq B_{up}^{HE} \times B_{dn}^{HE}$ designates the set of linked *dispatchable* hydroelectric *generation resources*, where LNK is a set with elements of the form $(\mathrm{b}_1, \mathrm{b}_2)$ and $\mathrm{b}_1 \in \mathrm{B}_{\mathrm{up}}^{\mathrm{HE}}$ and $\mathrm{b}_2 \in \mathrm{B}_{\mathrm{dn}}^{\mathrm{HE}}$;

2.2.29 With respect to a *pseudo-unit* identified by bus $b \in B^{PSU}$:

2.2.29.1 $CTShareMLP_b$ designates the combustion turbine share of the *minimum loading point* region;

2.2.29.2 $CTShareDR_b$ designates the combustion turbine share of the *dispatchable* region;

2.2.29.3 $STShareMLP_b$ designates the steam turbine share of the *minimum loading point* region; and

2.2.29.4 $STShareDR_b$ designates the steam turbine share of the *dispatchable* region;

2.2.30 With respect to a *dispatchable load* identified by bus $b \in B^{DL}$:

2.2.30.1 $PDL_{h,b,j}$ designates the price for the maximum incremental quantity of *energy* for hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J_{h,b}^{E}$;

2.2.30.2 $P10SDL_{h,b,j}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,b}^{10S}$;

2.2.30.3 $P10NDL_{h,b,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,b}^{10N}$;

2.2.30.4 $P30RDL_{h,b,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,b}^{30R}$;

2.2.30.5 $QDL_{h,b}$ shall designate the maximum *bid* quantity for *energy* at $b \in B^{DL}$ for hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J_{h,b}^{E}$;

2.2.30.6 $QDLFIRM_{h,b}$ designates the quantity of *energy* that is *bid* at the *maximum market clearing price* at $b \in B^{DL}$ for hour $h \in \{1,..,2\}$;

2.2.30.7 $Q10SDL_{h,b}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* that may be scheduled for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,b}^{10S}$;

2.2.30.8 $Q10NDL_{h,b}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,b}^{10N}$; and

2.2.30.9 $Q30RDL_{h,b}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,b}^{30R}$;

2.2.31 With respect to a *boundary entity resource* import from *intertie zone* bus $d \in DI$, where the *locational marginal price* represents the price at the *intertie metering point*:

2.2.31.1 $PIG_{h,d,k}$ designates the price for the maximum incremental quantity of *energy* that may be scheduled to import in hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$;

2.2.31.2 $P10NIG_{h,d,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{10N}$;

2.2.31.3 $P30RIG_{h,d,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{30R}$;

2.2.31.4 $QIG_{h,d,k}$ designates the maximum incremental quantity of *energy* for hour $\mathrm{h} \in \{1,..,24\}$ that may be scheduled in association with *offer* lamination $k \in K_{h,d}^{E}$;

2.2.31.5 $Q10NIG_{h,d,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{10N}$;

2.2.31.6 $Q30RIG_{h,d,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled for hour $\mathrm{h} \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{d,b}^{30R}$;

2.2.32 With respect to a *boundary entity resource* export at *intertie zone* bus $d \in DX$, where the *locational marginal price* represents the price at the *intertie metering point*;

2.2.32.1 $PXL_{h,d,j}$ designates the price for the maximum incremental quantity of *energy* that may be scheduled to export in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J_{h,d}^{E}$;

2.2.32.2 $P10NXL_{h,d,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{10N}$;

2.2.32.3 $P30RXL_{h,d,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{30R}$;

2.2.32.4 $QXL_{h,d,j}$ designates the maximum quantity of *energy* for hour $h \in \{1,..,24\}$ may be scheduled in association with *bid* lamination $j \in J_{h,d}^{E}$;

2.2.32.5 $Q10NXL_{h,d,j}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{10N}$;

2.2.32.6 $Q30RXL_{h,d,j}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J_{h,d}^{30R}$;

IESO Data Parameters

2.2.33 $ASDG_{h,b}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide by the *day-ahead market calculation engine* at bus b for hour $h \in \{1,..,24\}$;

2.2.34 $COMCYCMW_{h,b}$ designates the MWh constraint placed onto a *resource* that is not modelled as a *pseudo unit* at bus b for hour $h \in \{1,..,24\}$ to reflect that *resource's energy* capability in combined cycle mode;

2.2.35 $ExtLMP_{h,d}^{3}$ designates the *locational marginal price* for *energy* for hour $h \in \{1,..,24\}$ as determined by Pass 3 of the *day-ahead market calculation engine* for *intertie zone* bus $d \in D$;

2.2.36 $ExtL10NP_{h,d}^{3}$ designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* for the *dispatch hour* $h \in \{1,..,24\}$ as calculated by Pass 3 of the *day-ahead market calculation engine* for *intertie zone* bus $d \in D$;

2.2.37 $ExtL30RP_{h,d}^{3}$ designates the *locational marginal price* for *thirty-minute operating reserve* for the *dispatch hour* $h \in \{1,..,24\}$ as calculated by Pass 3 of the *day-ahead market calculation engine* for *intertie zone* bus $d \in D$;

2.2.38 $FG_{h,b}$ designates the *IESO's* centralized *variable generation* forecast for a *variable generation resource* identified by bus $b \in B^{VG}$ for hour $h \in \{1,..,24\}$;

2.2.39 $GridConnected_{h,b}$ designates whether the *resource* is connected to the *IESO-controlled grid* at bus b for hour $h \in \{1,..,24\}$;

2.2.40 $IHE_{h,b,i}$, designates whether the *dispatchable* hydroelectric *generation resource* at bus $b \in B^{HE}$ registered a start between hours $(h-1)$ and $h \in \{1,..,24\}$ as a result of its schedule increasing from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$ for $i \in \{1,...,NStartMW_b\}$;

2.2.41 $LMP^3_{h,b}$ designates the *locational marginal price* for *energy* for hour $h \in \{1,..,24\}$ as determined by Pass 3 of the *day-ahead market calculation engine*;

2.2.42 $L10SP^3_{h,b}$ designates the *locational marginal price* for synchronized *ten-minute operating reserve* for hour $h \in \{1,..,24\}$ as determined by Pass 3 of the *day-ahead market calculation engine*;

2.2.43 $L10NP^3_{h,b}$ designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* for hour $h \in \{1,...,24\}$ as determined by Pass 3 of the *day-ahead market calculation engine*;

2.2.44 $L30RP^3_{h,b}$ designates the *locational marginal price* for *thirty-minute operating reserve* for hour $h \in \{1,...,24\}$ as determined by Pass 3 of the *day-ahead market calculation engine*;

2.2.47 $REGULATIONMW_{h,b}$ designates the MWh constraint placed onto a *resource* at bus b for hour $h \in \{1,..,24\}$ for *regulation*;

2.2.48 SHE designates the set indexing the sets of *dispatchable* hydroelectric *generation resources* with a *maximum daily energy limit* or a *minimum daily energy limit* or both for a *linked forebay*; and

2.2.49 $SEALMW_{h,b}$ designates the MWh constraint placed onto a *resource* at bus b for hour $h \in \{1,..,24\}$ for actions taken to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*;

Constraint Violation Variables

2.2.50 $SLdViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{LdViol_h}\}$ of the penalty curve for the *energy* balance constraint allowing under-generation;

2.2.51 $SGenViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{GenViol_h}\}$ of the penalty curve for the *energy* balance constraint allowing over-generation;

2.2.52 $S10SViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{10SViol_h}\}$ of the penalty curve for the synchronized *ten-minute operating reserve* requirement;

2.2.53 $S10RViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{10RViol_h}\}$ of the penalty curve for the total *ten-minute operating reserve* requirement;

2.2.54 $S30RViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{30RViol_h}\}$ of the penalty curve for the *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement;

2.2.55 $SREG10RViol_{r,h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{REG10RViol_h}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* minimum requirement in region $r \in ORREG$;

2.2.56 $SREG30RViol_{r,h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{REG30RViol_h}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* minimum requirement in region $r \in ORREG$;

2.2.57 $SXREG10RViol_{r,h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{XREG10RViol_h}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* maximum restriction in region $r \in ORREG$;

2.2.58 $SXREG30RViol_{r,h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{XREG30RViol_h}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* maximum restriction in region $r \in ORREG$;

2.2.59 $SPreITLViol_{f,h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{PreITLViol_{f,h}}\}$ of the penalty curve for violating the pre-contingency transmission limit for *facility* $f \in F$;

2.2.60 $SITLViol_{c,f,h,i}$ designates the violation variable associated with segment $i \in \{1,.., N_{ITLViol_{c,f,h}}\}$ of the penalty curve for violating the post-contingency transmission limit for *facility* $f \in F$ and contingency $c \in C$;

2.2.61 $SPreXTLViol_{z,h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ of the penalty curve for violating the import/export limit associated with *intertie* limit constraint $z \in Z_{Sch}$;

2.2.62 $SNIUViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{NIUViol_h}\}$ of the penalty curve for exceeding the net interchange increase limit between hours $(h-1)$ and h;

2.2.63 $SNIDViol_{h,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{NIDViol_h}\}$ of the penalty curve for exceeding the net interchange decrease limit between hours $(h-1)$ and h;

2.2.64 $SMaxDelViol_{h,b,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{MaxDelViol_h}\}$ of the penalty curve for exceeding the *maximum daily energy limit* constraint for a *resource* at bus $b \in B^{ELR}$;

2.2.65 $SMinDelViol_{h,b,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{MinDelViol_h}\}$ of the penalty curve for violating the *minimum daily energy limit* constraint for a *resource* at bus $b \in B^{HE}$;

2.2.66 $SSMaxDelViol_{h,s,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{SMaxDelViol_h}\}$ of the penalty curve for exceeding the shared *maximum daily energy limit* constraint for *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

2.2.67 $SSMinDelViol_{h,s,i}$ designates the violation variable associated with segment $i \in \{1,..,N_{SMinDelViol_h}\}$ of the penalty curve for violating the shared *minimum daily energy limit* constraint for *dispatchable* hydroelectric *generation resources* in set $s \in SHE$;

2.2.68 $SOGenLnkViol_{h,(b_1,b_2),i}$ designates the violation variable associated with segment $i \in \{1,..,N_{OGenLnkViol_h}\}$ of the penalty curve for violating the *linked forebay* constraint for *dispatchable* hydroelectric *generation resources* by over-generating the downstream *resource*, for $(b_1,b_2) \in LNK$ such that $b_1 \in B^{HE}_{up}$ and $b_2 \in B^{HE}_{dn}$; and

2.2.69 $SUGenLnkViol_{h,(b_1,b_2),i}$ designates the violation variable associated with segment $i \in \{1,..,N_{UGenLnkViol_h}\}$ of the penalty curve for violating the *linked forebay* constraint for *dispatchable* hydroelectric *generation resources* by under-generating the downstream *resource*, for $(b_1,b_2) \in LNK$ such that $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$.

2.3 Objective Functions

2.3.1 The objective functions for the DAM LC EOP calculation shall solve for the following variables:

2.3.1.1 $ESDG_{h,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$;

2.3.1.2 $ES10SDG_{h,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{10S}$;

2.3.1.3 $ES10NDG_{h,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{10N}$;

2.3.1.4 $ES30RDG_{h,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{30R}$;

2.3.1.5 $ESIG_{h,d,k}$ which designates the amount of *energy* that a *boundary entity resource* is scheduled to import from *intertie zone* bus $d \in DI$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{E}$;

2.3.1.6 $ES10NIG_{h,d,k}$ which designates the amount of non-synchronized *ten-minute operating reserve* that an import *boundary entity resource* is scheduled to provide from *intertie zone* bus $d \in DI$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,d}^{E}$;

2.3.1.7 $ES30RIG_{h,d,k}$ which designates the amount of *thirty-minute operating reserve* that an import *boundary entity resource* is scheduled to provide at bus $d \in DI$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,d}$;

2.3.1.8 $ESDL_{h,b,j}$, which designates the amount of *energy* that a *dispatchable load* is scheduled to consume at bus $b \in B^{DL}$ for hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^{E}_{h,b}$;

2.3.1.9 $ES10SDL_{h,b,j}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$;

2.3.1.10 $ES10NDL_{h,b,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$;

2.3.1.11 $ES30RDL_{h,b,j}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$;

2.3.1.12 $ESXL_{h,d,k}$ which designates the amount of *energy* a *boundary entity resource* is scheduled to export at *intertie zone* at bus $d \in DX$ for hour $h \in \{1,..,24\}$ in association with *bid* lamination $k \in K^{E}_{h,d}$;

2.3.1.13 $ES10NXL_{h,d,k}$ which designates the amount of non-synchronized *ten-minute operating reserve* that an export *boundary entity resource* is scheduled to provide at *intertie zone* bus $d \in DX$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,d}$;

2.3.1.14 $ES30RXL_{h,d,k}$ which designates the amount of *thirty-minute operating reserve* that an export *boundary entity resource* is scheduled to provide at *intertie zone* bus $d \in DX$ for hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,d}$;

2.3.2 For each of the following *resource* types, the objective function for determining a DAM LC EOP shall maximize the value of the following expressions:

2.3.2.1 For *dispatchable generation resources*:

$$ObjSDG_h = \sum_{k \in K^E_{h,b}} ESDG_{h,b,k} \cdot \left(LMP^3_{h,b} - PDG_{h,b,k}\right)$$

$$Obj10SDG_h = \sum_{k \in K^{10S}_{h,b}} ES10SDG_{h,b,k} \cdot \left(L10SP^3_{h,b} - P10SDG_{h,b,k}\right)$$

$$Obj10NDG_h = \sum_{k \in K^{10N}_{h,b}} ES10NDG_{h,b,k} \cdot \left(L10NP^3_{h,b} - P10NDG_{h,b,k}\right)$$

$$Obj30RDG_h = \sum_{k \in K^{30R}_{h,b}} ES30RDG_{h,b,k} \cdot \left(L30RP^3_{h,b} - P30RDG_{h,b,k}\right)$$

2.3.2.2 For *dispatchable loads*:

$$ObjSDL_h = \sum_{j \in J^E_{h,b}} ESDL_{h,b,j} \cdot \left(PDL_{h,b,j} - LMP^3_{h,b}\right)$$

$$Obj10SDL_h = \sum_{j \in J^{10S}_{h,b}} ES10SDL_{h,b,j} \cdot \left(L10SP^3_{h,b} - P10SDL_{h,b,j}\right)$$

$$Obj10NDL_h = \sum_{j \in J^{10N}_{h,b}} ES10NDL_{h,b,j} \cdot \left(L10NP^3_{h,b} - P10NDL_{h,b,j}\right)$$

$$Obj30RDL_h = \sum_{j \in J^{30R}_{h,b}} ES30RDL_{h,b,j} \cdot \left(L30RP^3_{h,b} - P30RDL_{h,b,j}\right)$$

2.3.2.3 For import transactions associated with *boundary entity resources*:

$$ObjSIG_h = \sum_{k \in K_{h,d}^{E}} ESIG_{h,d,k} \cdot \left(ExtLMP_{h,d}^{3} - PIG_{h,d,k}\right)$$

$$Obj10NIG_h = \sum_{k \in K_{h,d}^{10N}} ES10NIG_{h,d,k} \cdot \left(ExtL10NP_{h,d}^{3} - P10NIG_{h,d,k}\right)$$

$$Obj30RIG_h = \sum_{k \in K_{h,d}^{30R}} ES30RIG_{h,d,k} \cdot \left(ExtL30RP_{h,d}^{3} - P30RIG_{h,d,k}\right)$$

2.3.2.4 For export transactions associated with *boundary entity resources*

$$ObjSXL_h = \sum_{j \in J_{h,b}^{E}} ESXL_{h,d,j} \cdot \left(PXL_{h,d,j} - \mathrm{ExtLMP}_{\mathrm{h,d}}^{3}\right)$$

$$Obj10NXL_h = \sum_{j \in J_{h,b}^{10N}} ES10NXL_{h,d,j} \cdot \left(\mathrm{ExtL10NP}_{\mathrm{h,d}}^{3} - P10NXL_{h,d,j}\right)$$

$$Obj30RXL_h = \sum_{j \in J_{h,b}^{30R}} ES30RXL_{h,d,j} \cdot \left(\mathrm{ExtL30RP}_{\mathrm{h,d}}^{3} - P30RXL_{h,d,j}\right)$$

2.4 Constraints

2.4.1 The constraints described in this section 2.4 shall apply to the objective functions used for the DAM LC EOP calculation.

Scheduling Variable Bounds

2.4.2 No DAM LC EOP shall be negative, nor shall any DAM LC EOP exceed the *offer* or *bid* quantity for *energy* or the *offer* quantity for *operating reserve*. Therefore, for all hours $h \in \{1,..,24\}$:

$0 \leq ESDL_{h,b,j} \leq QDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{E}_{h,b}$;

$0 \leq ES10SDL_{h,b,j} \leq Q10SDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{10S}_{h,b}$;

$0 \leq ES10NDL_{h,b,j} \leq Q10NDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{10N}_{h,b}$;

$0 \leq ES30RDL_{h,b,j} \leq Q30RDL_{h,b,j}$ for all $b \in B^{DL}, j \in J^{30R}_{h,b}$;

$0 \leq ESDG_{h,b,k} \leq QDG_{h,b,k}$ for all $b \in B^{DG}, k \in K^{E}_{h,b}$;

$0 \leq ES10SDG_{h,b,k} \leq Q10SDG_{h,b,k}$ for all $b \in B^{DG}, k \in K^{10S}_{h,b}$;

$0 \leq ES10NDG_{h,b,k} \leq Q10NDG_{h,b,k}$ for all $b \in B^{DG}, k \in K^{10N}_{h,b}$;

$0 \leq ES30RDG_{h,b,k} \leq Q30RDG_{h,b,k}$ for all $b \in B^{DG}, k \in K^{30R}_{h,b}$;

$0 \leq ESXL_{h,d,j} \leq QXL_{h,d,j}$ for all $b \in DX, j \in J^{E}_{h,d}$;

$0 \leq ES10NXL_{h,d,j} \leq Q10NXL_{h,d,j}$ for all $b \in DX, j \in J^{10N}_{h,d}$;

$0 \leq ES30RXL_{h,d,j} \leq Q30RXL_{h,d,j}$ for all $b \in DX, j \in J^{30R}_{h,d}$;

$0 \leq ESIG_{h,d,k} \leq QIG_{h,d,k}$ for all $b \in DI, k \in K^{E}_{h,d}$;

$0 \leq ES10NIG_{h,d,k} \leq Q10NIG_{h,d,k}$ for all $b \in DI, k \in K^{10N}_{h,d}$;

$0 \leq ES30RIG_{h,d,k} \leq Q30RIG_{h,d,k}$ for all $b \in DI, k \in K^{30R}_{h,d}$;

2.4.3 For a *dispatchable load*, its DAM LC EOP for each class of *operating reserve* shall not exceed its DAM LC EOP for *energy*:

$$\sum_{j \in J^{10S}_{h,b}} ES10SDL_{h,b,j} \leq \sum_{j \in J^{E}_{h,b}} ESDL_{h,b,j}$$

$$\sum_{j \in J^{10N}_{h,b}} ES10NDL_{h,b,j} \leq \sum_{j \in J^{E}_{h,b}} ESDL_{h,b,j}$$

$$\sum_{j \in J^{30R}_{h,b}} ES30RDL_{h,b,j} \leq \sum_{j \in J^{E}_{h,b}} ESDL_{h,b,j}$$

2.4.4 For a *dispatchable generation resource* for a *dispatch hour* $h \in \{1,..,24\}$:

For all $b \in B^{VG}$:

$$VGForecast_{h,b} = \begin{Bmatrix} AFG_{h,b} & if\ provided \\ FG_{h,b} & otherwise \end{Bmatrix}$$

For all $b \in B^{DG}$:

$$AdjMaxDG_{h,b} = \begin{Bmatrix} min\left(\sum_{k \in K_{h,b}^{E}} QDG_{h,b,k}, Derate_{h,b}, VGForecast_{h,b}\right) & if\ b \in B^{VG} \\ min\left(\sum_{k \in K_{h,b}^{E}} QDG_{h,b,k}, Derate_{h,b}\right) & otherwise \end{Bmatrix}$$

$$\sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k} \leq AdjMaxDG_{h,b}$$

$$\sum_{k \in K_{h,b}^{10S}} ES10SDG_{h,b,k} \leq AdjMaxDG_{h,b}$$

$$\sum_{k \in K_{h,b}^{10N}} ES10NDG_{h,b,k} \leq AdjMaxDG_{h,b}$$

$$\sum_{k \in K_{h,b}^{30R}} ES30RDG_{h,b,k} \leq AdjMaxDG_{h,b}$$

2.4.5 Subject to section 2.4.6, the DAM LC EOP for a *resource* that is a *GOG-eligible resource* or has a primary fuel type of uranium shall be greater than or equal to its *minimum loading point*:

$$\sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k} \geq MinQDG_{b}$$

2.4.6 For a *resource* that is a *GOG-eligible resource* or has a primary fuel type of uranium and that is scheduled below its *minimum loading point*, its DAM LC EOP shall be equal to its *day-ahead schedule*:

If $\sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k} < MinQDG_b$ for $b \in B^{NQS}$ then:

$$\sum_{k\in K_{h,b}^{E}E} ESDG_{h,b,k} = ASDG_{h,b}$$

Constraints for Regulation Requirements

2.4.7 For a *dispatchable generation resource,* its DAM LC EOP for *energy* shall be greater than or equal to any *regulation* constraint that is applied for hour $h \in \{1,..,24\}$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{h,b}^{E}} ESDG_{h,b,k} \geq REGULATIONMW_{h,b}$$

2.4.8 For a *dispatchable generation resource,* its DAM LC EOP for *energy* and each class of *operating reserve* shall not exceed the maximum available capacity the *resource* has less the *regulation constraint* that is applied for hour $h \in \{1,..,24\}$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{h,b}^{E}} ESDG_{h,b,k} \leq AdjMaxDG_{h,b} - REGULATIONMW_{h,b}$$

$$\sum_{k\in K_{h,b}^{10S}} ES10SDG_{h,b,k} \leq AdjMaxDG_{h,b} - REGULATIONMW_{h,b}$$

$$\sum_{k\in K_{h,b}^{10N}} ES10NDG_{h,b,k} \leq AdjMaxDG_{h,b} - REGULATIONMW_{h,b}$$

$$\sum_{k\in K_{h,b}^{30R}} ES30RDG_{h,b,k} \leq AdjMaxDG_{h,b} - REGULATIONMW_{h,b}$$

Constraints for Market Participant Requirements

2.4.9 For a *dispatchable generation resource,* its DAM LC EOP for *energy* shall be greater than or equal to any minimum $SEALMW_{h,b}$ constraint that is applied for hour $h \in \{1,..,24\}$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k} \geq SEALMW_{h,b}$$

2.4.10 For a *dispatchable load,* its DAM LC EOP for *energy* shall be greater than or equal to any minimum $SEALMW_{h,b}$constraint that is applied and for each class of *operating reserve*, the DAM LC EOP shall be less than or equal to the DAM LC EOP for *energy* for that *resource* less any minimum $SEALMW_{h,b}$ constraint that is applied for hour $h \in \{1, . . , 24\}$ and bus $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} \geq SEALMW_{h,b}$$

$$\sum_{j \in J_{h,b}^{10S}} ES10SDL_{h,b,k} \leq \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} \ - \ SEALMW_{h,b}$$

$$\sum_{j \in J_{h,b}^{10N}} ES10NDL_{h,b,k} \leq \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} \ - \ SEALMW_{h,b}$$

$$\sum_{j \in J_{h,b}^{30R}} ES30RDL_{h,b,k} \leq \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} \ - \ SEALMW_{h,b}$$

2.4.11 For a *dispatchable generation resource,* its DAM LC EOP for *energy* shall be less than or equal to any maximum $SEALMW_{h,b}$ constraint that is applied for hour $h \in \{1, . . , 24\}$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k} \leq SEALMW_{h,b}$$

2.4.12 For a *dispatchable load,* its DAM LC EOP for *energy* shall be less than or equal to any maximum $SEALMW_{h,b}$ constraint that is applied for hour $h \in \{1, . . , 24\}$ and bus $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} \leq SEALMW_{h,b}$$

2.4.13 For a *dispatchable generation resource,* its DAM LC EOP for *energy* shall be equal to any fixed $SEALMW_{h,b}$ constraint that is applied for hour $h \in \{1, . . , 24\}$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k} = SEALMW_{h,b}$$

2.4.14 For a *dispatchable load,* its DAM LC EOP for *energy* shall be equal to any fixed $SEALMW_{h,b}$ constraint that is applied and equal to zero for each class of *operating reserve* for hour $h \in \{1, . . , 24\}$ and bus $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} = SEALMW_{h,b}$$

$$\sum_{j \in J_{h,b}^{10S}} ES10SDL_{h,b,j} = 0$$

$$\sum_{j \in J_{h,b}^{10N}} ES10NDL_{h,b,j} = 0$$

$$\sum_{j \in J_{h,b}^{30R}} ES30RDL_{h,b,j} = 0$$

2.4.15 For a *dispatchable load,* its DAM LC EOP for *energy* shall be greater than or equal to the *bid* quantity for *energy* priced at the *maximum market clearing price*:

$$\sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} \geq QDLFIRM_{h,b}$$

2.4.16 For a *dispatchable load,* its DAM LC EOP for *operating reserve* shall be less than or equal its DAM LC EOP for *energy* less the *bid* quantity for *energy* priced at the *maximum market clearing price*:

$$\sum_{j \in J_{h,b}^{10S}} ES10SDL_{h,b,j} \leq \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} - QDLFIRM_{h,b}$$

$$\sum_{j \in J_{h,b}^{10N}} ES10NDL_{h,b,j} \leq \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} - QDLFIRM_{h,b}$$

$$\sum_{j \in J_{h,b}^{30R}} ES30RDL_{h,b,j} \leq \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j} - QDLFIRM_{h,b}$$

Constraints for Operating Reserve Ramping

2.4.18 For a *dispatchable generation resource* with $RLP10S_{h,b} > 0$, its DAM LC EOP for *ten-minute operating reserve* shall be less than or equal to its *reserve loading point* for *ten-minute operating reserve* for hour $h \in \{1,..,24\}$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{10S}} ES10SDG_{h,b,k} \leq \left(\sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k}\right) \cdot \left(\frac{1}{RLP10S_{h,b}}\right) \cdot \left(min\left\{10 \cdot ORRDG_{b}, \sum_{k \in K_{h,b}^{10S}} Q10SDG_{h,b,k}\right\}\right)$$

2.4.19 For a *dispatchable generation resource* with $RLP30R_{h,b} > 0$, its DAM LC EOP for *thirty-minute operating reserve* shall be less than or equal to its *reserve loading point* for *thirty-minute operating reserve* for hour $h \in \{1,..,24\}$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{h,b}^{30R}} ES30RDG_{h,b,k} \le \left(\sum_{k\in K_{i,b}^{E}} ESDG_{h,b,k}\right)\cdot\left(\frac{1}{RLP30R_{h,b}}\right)\cdot\left(min\left\{30\cdot ORRDG_b, \sum_{k\in K_{h,b}^{30R}} Q30RDG_{h,b,k}\right\}\right)$$

Constraints for Pseudo-Units

2.4.20 For a *pseudo-unit,* its DAM LC EOP for *energy* for the *dispatchable* region and duct firing region shall be less than or equal to the respective maximum capabilities for those regions for hour $h \in \{1,..,24\}$ and bus $b \in B^{PSU}$:

$$\sum_{k\in K_{h,b}^{DR}} ESDG_{h,b,k} \le MaxDR_{h,b}$$

$$\sum_{k\in K_{h,b}^{DF}} ESDG_{h,b,k} \le MaxDF_{h,b}$$

2.4.21 For a *pseudo-unit,* its DAM LC EOP for each class of *operating reserve* shall be less than or equal to the sum of the maximum capabilities for its *dispatchable* region and duct firing region for hour $h \in \{1,..,24\}$ and bus $b \in B^{PSU}$:

$$\sum_{k\in K_{h,b}^{10S}} ES10SDG_{h,b,k} \le MaxDR_{h,b} + MaxDF_{h,b}$$

$$\sum_{k\in K_{h,b}^{10N}} ES10NDG_{h,b,k} \le MaxDR_{h,b} + MaxDF_{h,b}$$

$$\sum_{k\in K_{h,b}^{30R}} ES30RDG_{h,b,k} \le MaxDR_{h,b} + MaxDF_{h,b}$$

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2.4.22 For a *pseudo-unit* that cannot provide *ten-minute operating reserve* from its duct firing region, the following constraint shall apply:

$$\sum_{k\in K_{h,b}^{E}} ESDG_{h,b,k} + \sum_{k\in K_{h,b}^{10S}} ES10SDG_{h,b,k} + \sum_{k\in K_{h,b}^{10N}} ES10NDG_{h,b,k} \le MINQDG_b + QDR_{h,k}$$

Constraints for Resources with Linked Forebays

2.4.23 For all *dispatchable* hydroelectric *generation resources* with a *linked forebay*, the DAM LC EOP for *energy* at the upstream *resources* in one hour shall result in a proportional DAM LC EOP for *energy* at the downstream *resources* in the hour determined by the *time lag*.

For all *dispatchable* hydroelectric *generation resources* with a *linked forebay* between upstream *resources* $b_1 \in B_{up}^{HE}$ and downstream *resources* $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK$ and hours $h \in \{1, . . . , 24\}$ such that $h + Lag_{b_1,b_2} \leq 24$:

$$\sum_{b_2 \in B_{dn}^{HE}} \left(\sum_{k \in K_{b_2,h+Lag_{b_1,b_2}}^{E}} ESDG_{k,h+Lag_{b_1,b_2},b_2} \right) = MWhRatio_{b_1,b_2} \cdot \sum_{b_1 \in B_{up}^{HE}} \left(\sum_{k \in K_{b_1,h}^{E}} ESDG_{k,h,b_1} \right)$$

2.5 Calculation of DAM LC EOP for Resources with a Linked Forebay Under Certain Conditions

2.5.1 For *dispatchable* hydroelectric *resources* with a *linked forebay,* the DAM LC EOP shall be equal to the *resource's day-ahead schedule* if the conditions in sections 2.4.24.1 and 2.4.24.2 are both satisfied:

2.4.24.1 The following constraint violation prices were non-binding in Pass 1 or Pass 3 of the *day-ahead market calculation engine* run for any *dispatch hour* in the *dispatch day*:

$\sum_{i=1:N_{MaxDelViol_h}} SMaxDelViol_{h,b,i} = 0$

$$\sum_{i=1:N_{MinDelViol_h}} SMinDelViol_{h,b,i} = 0$$

$$\sum_{i=1:N_{SMaxDelViol_h}} SSMaxDelViol_{h,s,i} = 0$$

$\sum_{i=1:N_{SMinDelViol_h}} SSMinDelViol_{h,s,i} = 0$; or

$$\sum_{i=1:N_{LdViol_h}} SLdViol_{h,i} = 0$$

$$\sum_{i=1:N_{GenViol_h}} SGenViol_{h,i} = 0$$

$$\sum_{i=1:N_{10SViol_h}} S10SViol_{h,i} = 0$$

$$\sum_{i=1:N_{10RViol_h}} S10RViol_{h,i} = 0$$

$$\sum_{i=1:N_{30RViol_h}} S30RViol_{h,i} = 0$$

$$\sum_{i=1:N_{REG10RViol_h}} SREG10RViol_{r,h,i} = 0$$

$$\sum_{i=1:N_{REG30RViol_h}} SREG30RViol_{r,h,i} = 0$$

$$\sum_{i=1:N_{XREG10RViol_h}} SXREG10RViol_{r,h,i} = 0$$

$$\sum_{i=1:N_{XREG30RViol_h}} SXREG30RViol_{r,h,i} = 0$$

$$\sum_{i=1:N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} = 0$$

$$\sum_{i=1:N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} = 0$$

$$\sum_{i=1:N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} = 0$$

$$\sum_{i=1:N_{NIUViol_h}} SNIUViol_{h,i} = 0$$

$$\sum_{i=1:N_{NIDViol_h}} SNIDViol_{h,i} = 0$$

$$\sum_{i=1:N_{OGenLnkViol_h}} SOGenLnkViol_{h,(b1,b2),i} = 0$$

$\sum_{i=1:N_{UGenLnkViol_h}} SUGenLnkViol_{h,(b1,b2),i} = 0$, and

2.4.24.2 At least one of the conditions set out in sections 2.4.24.2.1-2.4.24.2.4 is met:

2.4.24.2.1 At least one *resource* with a *linked forebay* has a *day-ahead schedule* that satisfies any one of the following conditions for a *dispatch hour* in which the *time lag* was evaluated:

a. $\sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k} \leq MinHMR_{h,b}$;

b. $\sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k} \leq MinHO_{h,b}$; or

c. $ForL_{b,i} \leq \sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k} \leq ForU_{b,i}$;

2.4.24.2.2 For all *resources* with a *linked forebay* where at least one of the following daily constraints are binding for at least one *dispatch hour* in a *dispatch day*:

$$\sum_{h=1..24}\left(\sum_{i=1..NStartMW_b} IHE_{h,b,i}\right) \geq MaxStartsHE_b$$

$$\sum_{h=1..H}\left(\sum_{b\,\in B_S^{HE}}\left(\sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k}\right)\right) + \sum_{b\,\in B_S^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}} S10SDG_{H,b,k} + \sum_{k\in K_{H,b}^{10N}} S10NDG_{H,b,k}\right) + 30ORConv\left(\sum_{k\in K_{H,b}^{30R}} S30RDG_{H,b,k}\right)\right) \geq MaxSDEL_s$$

$$\sum_{h=1..24}\left(\sum_{b\,\in B_S^{HE}}\left(\sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k}\right)\right) \leq MinSDEL_s;$$

2.4.24.2.3 For all *resources* with a *linked forebay* that do not have a binding *reliability* constraint applied for a *dispatch hour* in which the *time lag* was evaluated:

$$\sum_{k\in K_{h,b}^{E}} ASDG_{h,b,k} \neq RELIABILITYMW_{h,b} \quad where\ b \in B^{HE}$$

2.4.24.2.4 For all *resources* with a *linked forebay* that have at least one binding $SEALMW_{h,b}$ constraint for a *dispatch hour* in which the *time lag* was evaluated, at least one of the following conditions was met:

a. For a *resource* that has a fixed $SEALMW_{h,b}$constraint applied for hour $h \in \{1,..,24\}$ and bus $b \in B^{HE}$:

$$\sum_{k \in K_{h,b}^{E}} ASDG_{h,b,k} = SEALMW_{h,b}$$

For a *resource* that has a minimum $SEALMW_{h,b}$constraint applied for hour $h \in \{1,..,24\}$ and bus $b \in B^{HE}$:

$$\sum_{k \in K_{h,b}^{E}} ASDG_{h,b,k} \leq SEALMW_{h,b}$$

For a *resource* that has a maximum $SEALMW_{h,b}$constraint applied for hour $h \in \{1,..,24\}$ and bus $b \in B^{HE}$:

$$\sum_{k \in K_{h,b}^{E}} ASDG_{h,b,k} \geq SEALMW_{h,b}$$

2.6 Outputs

2.5.1 The DAM LC EOPs used for *settlement* for *energy* and *operating reserve* for all *resources* except *pseudo-units* for each hour of the *dispatch day* shall be the sum of each DAM LC EOP variable determined by the objective function in section 2.3 for that *resource*, subject to constraints in section 2.4 applicable for that *resource* determined as follows:

$$DGEnergyEOP_{h,b} = \sum_{k \in K_{h,b}^{E}} ESDG_{h,b,k}$$

$$DG10SEOP_{h,b} = \sum_{k \in K_{h,b}^{10S}} ES10SDG_{h,b,k}$$

$$DG10NEOP_{h,b} = \sum_{k \in K_{h,b}^{10N}} ES10NDG_{h,b,k}$$

$$DG30REOP_{h,b} = \sum_{k \in K_{h,b}^{30R}} ES30RDG_{h,b,k}$$

$$DLEnergyEOP_{h,b} = \sum_{j \in J_{h,b}^{E}} ESDL_{h,b,j}$$

$$DL10SEOP_{h,b} = \sum_{j \in J_{h,b}^{10S}} ES10SDL_{h,b,j}$$

$$DL10NEOP_{h,b} = \sum_{j \in J_{h,b}^{10N}} ES10NDL_{h,b,j}$$

$$DL30REOP_{h,b} = \sum_{j \in J_{h,b}^{30R}} ES30RDL_{h,b,j}$$

$$DIEnergyEOP_{h,b} = \sum_{k \in K_{h,b}^{E}} ESIG_{h,b,k}$$

$$DI10NEOP_{h,b} = \sum_{k \in K_{h,b}^{10N}} ES10NIG_{h,b,k}$$

$$DI30REOP_{h,b} = \sum_{k \in K_{h,b}^{30R}} ES30RIG_{h,b,k}$$

$$DXEnergyEOP_{h,b} = \sum_{j \in J_{h,b}^{E}} ESXL_{h,b,j}$$

$$DX10NEOP_{h,b} = \sum_{j \in J_{h,b}^{10N}} ES10NXL_{h,b,j}$$

$$DX30REOP_{h,b} = \sum_{j \in J_{h,b}^{30R}} ES30RXL_{h,b,j}$$

2.5.2 The DAM LC EOPs for *energy* and *operating reserve* for a *pseudo-unit* for each hour of the *dispatch day,* which will be used for converting the DAM LC EOPs to physical *resource* equivalents in accordance with sections 2.5.3 to 2.5.4, shall be determined as follows:

$$PSUMLPEnergyEOP_{h,k} = \sum_{k \in K_{h,b}^{MLP}} ESDG_{h,b,k}$$

$$PSUDREnergyEOP_{h,k} = \sum_{k \in K_{h,b}^{DR}} ESDG_{h,b,k}$$

$$PSUDFEnergyEOP_{h,k} = \sum_{k \in K_{h,b}^{DF}} ESDG_{h,b,k}$$

$$PSU10SEOP_{h,k} = \sum_{k \in K_{h,b}^{10S}} ES10SDG_{h,b,k}$$

$$PSU10NEOP_{h,k} = \sum_{k \in K_{h,b}^{10N}} ES10NDG_{h,b,k}$$

$$PSU30REOP_{h,k} = \sum_{k \in K_{h,b}^{30R}} ES30RDG_{h,b,k}$$

Conversion of DAM LC EOPs for Pseudo-Units to Physical Resource Equivalents

2.6.3 The DAM LC EOP used for *settlement* for *energy* for a combustion turbine and a steam turbine that is associated with *pseudo-unit* $k \in \{1, \dots, K\}$ in hour h shall be determined as follows:

$$CTEnergyEOP_{h,k} = PSUMLPEnergyEOP_{h,k} \cdot CTShareMLP_{h,k} + PSUDREnergyEOP_{h,k} \cdot CTShareDR_{h,k}$$

$$STEnergyEOP_{h,k} = PSUMLPEnergyEOP_{h,k} \cdot STShareMLP_{k} + PSUDREnergyEOP_{h,k} \cdot STShareDR_{k} + PSUDFEnergyEOP_{h,k}$$

2.6.4 The DAM LC EOPs used for *settlement* for *operating reserve* for a combustion turbine and a steam turbine that is associated with *pseudo-unit* $k \in \{1, \dots, K\}$ in hour h shall be determined as follows and in the following order for each class of *operating reserve*:

$$10SDR_{h,k} = \min\left(QDR_{h,k}, PSU10SEOP_{h,k}\right)$$

$$10NDR_{h,k} = \min\left(QDR_{h,k} - 10SDR_{h,k}, PSU10NEOP_{h,k}\right)$$

$$30RDR_{h,k} = \min\left(QDR_{h,k} - 10SDR_{h,k} - 10NDR_{h,k}, PSU30REOP_{h,k}\right)$$

$$CT10SEOP_{h,k} = 10SDR_{h,k} \cdot CTShareDR_{k}$$
$$ST10SEOP_{h,k} = 10SDR_{h,k} \cdot STShareDR_{k} + (PSU10SEOP_{h,k} - 10SDR_{h,k})$$

$$CT10NEOP_{h,k} = 10NDR_{k} \cdot CTShareDR_{h,k}$$
$$ST10NEOP_{h,k} = 10NDR_{h,k} \cdot STShareDR_{k} + (PSU10NEOP_{h,k} - 10NDR_{h,k})$$

$$CT30REOP_{h,k} = 30RDR_{k} \cdot CTShareDR_{h,k}$$
$$ST30REOP_{h,k} = 30RDR_{h,k} \cdot STShareDR_{k} + (PSU30REOP_{h,k} - 30RDR_{h,k})$$

3. Real-Time Market Lost Cost Economic Operating Point

3.1 Purpose

3.1.1 This section describes the process used to determine lost cost economic operating point (RT LC EOP) for eligible *resources* in the *real-time market*.

3.2 Sets, Indices and Parameters used by the Real-Time Lost Cost Economic Operating Point Calculation

Fundamental Sets and Indices

3.2.1 A designates the set of all *intertie zones*;

3.2.2 B designates the set of buses identifying all *dispatchable* and *non-dispatchable resources* within Ontario;

3.2.3 $B^{DG} \subseteq B$ designates the set of buses identifying *dispatchable generation resources*;

3.2.4 $B^{DL} \subseteq B$ designates the set of buses identifying *dispatchable loads*;

3.2.5 D designates the set of buses outside Ontario, corresponding to imports and exports in *intertie zones*;

3.2.6 $D_a \subseteq D$ designates the set of all buses identifying *boundary entity resources* in *intertie zone a* $\in$ *A*;

3.2.7 $DI \subseteq D$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers*;

3.2.8 $DI_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers* in *intertie zone a* $\in$ *A*;

3.2.9 $DX \subseteq B^{DL}$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to import *offers*;

3.2.10 $DX_a \subseteq D_a$ designates the subset of *intertie zone* buses identifying *boundary entity resources* that correspond to export *bids* in *intertie zone a* $\in$ *A*;

3.2.11 $ExtLMP^{PD}_{i,d}$ designates the *locational marginal price* for *energy* for the *dispatch hour* in which interval $i \in I$ falls as determined by Pass 1 of the *pre-dispatch calculation engine*;

3.2.12 $I = \{1,..,n_I\}$ designates the set of all intervals, where n_I designates the number of five-minute intervals considered within the real-time look-ahead period;

3.2.13 $J^E_{i,b}$ designates the set of *bid* laminations for *energy* at $b \in B^{DL} \cup DX$ for interval $i \in I$;

3.2.14 $J^{10S}_{i,b}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at $b \in B^{DL}$ for interval $i \in I$;

3.2.15 $J^{10N}_{i,b}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at $b \in B^{DL} \cup DX$ for interval $i \in I$;

3.2.16 $J^{30R}_{i,b}$ designates the set of *offer* laminations for *thirty-minute operating reserve* at $b \in B^{DL} \cup DX$ for interval $i \in I$;

3.2.17 $J^E_{t,d}$ designates the set of *bid* laminations for *energy* at *intertie zone* bus $d \in DX$ for time-step $t \in TS$;

3.2.18 $J^{10N}_{t,d}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at $d \in DX$ for time-step $t \in TS$;

3.2.19 $J^{30R}_{t,d}$ shall designate the set of *offer* laminations for *thirty-minute operating reserve* at $d \in DX$ for time-step $t \in TS$;

3.2.20 $K^E_{i,b}$ designates the set of *offer* laminations for *energy* at $b \in B^{DG} \cup DI$ for interval $i \in I$;

3.2.21 $K^{10S}_{i,b}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $b \in B^{DG}$ for interval $i \in I$;

3.2.22 $K^{10N}_{i,b}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $b \in B^{DG} \cup DI$ for interval $i \in I$;

3.2.23 $K^{30R}_{i,b}$ designates the set of *offer* laminations for non-synchronized *thirty-minute operating reserve* at bus $b \in B^{DG} \cup DI$ for interval $i \in I$;

3.2.24 $K_{t,d}^{E}$ designates the set of *offer* laminations for energy at $d \in DI$ for time-step $t \in TS$;

3.2.25 $K_{t,d}^{10N}$ designates the set of *offer* laminations for non-synchronized *ten-minute operating reserve* at bus $d \in DI$ for time-step $t \in TS$;

3.2.26 $K_{t,d}^{30R}$ designates the set of *offer* laminations for synchronized *ten-minute operating reserve* at bus $d \in DI$for time-step $t \in TS$; and

3.2.27 $TS = \{2, \ldots, n_{LAP}\}$ designates the set of all time-steps in the look-ahead period that are included in the *pre-dispatch calculation engine* optimization, where n_{LAP} designates the number of time-steps in the pre-dispatch look-ahead period;

Market Participant Data Parameters

3.2.28 With respect to all *resources*:

3.2.28.1 $Derate_{i,b}$ designates the maximum amount of *energy* and *operating reserve* that can be scheduled for a *resource* in a *dispatch interval*;

3.2.29 With respect to a *dispatchable generation resource* identified by bus $b \in B^{DG}$:

3.2.29.1 $MinQDG_{i,b}$ designates the *minimum loading point* indicating the minimum output at which a *resource* must be scheduled to except for times when the *resource* is starting up or shutting down at $b \in B^{DG}$ for interval i;

3.2.29.2 $ORRDG_{b}$ designates the maximum *operating reserve* ramp rate in MW per minute for the *resource* at $b \in B^{DG}$;

3.2.29.3 $PDG_{i,b,k}$ designates the price for the maximum incremental quantity of *energy* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$;

3.2.29.4 $P10SDG_{i,b,k}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10S}$;

3.2.30.5 $P10NDG_{i,b,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10N}$;

3.2.30.6 $P30RDG_{i,b,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$;

3.2.30.7 $QDG_{i,b,k}$ designates the maximum incremental quantity of *energy* above the *minimum loading point* that may be scheduled in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$;

3.2.30.8 $Q10SDG_{i,b,k}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10S}$;

3.2.30.9 $Q10NDG_{i,b,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10N}$; and

3.2.30.10 $Q30RDG_{i,b,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$;

3.2.31 With respect to a *dispatchable load* identified by bus $\mathrm{b} \in \mathrm{B}^{\mathrm{DL}}$:

3.2.31.1 $PDL_{i,b,j}$ designates the price for the maximum incremental quantity of *energy* for interval $i \in I$ in association with *bid* lamination $j \in J_{i,b}^{E}$;

3.2.31.2 $P10SDL_{i,b,j}$ designates the price for the maximum incremental quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10S}$;

3.2.31.3 $P10NDL_{i,b,j}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10N}$;

3.2.31.4 $P30RDL_{i,b,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$;

3.2.31.5 $QDL_{i,b}$ designates the maximum *bid* quantity for *energy* at $b \in B^{DL}$ for interval $i \in I$ in association with *bid* lamination $j \in J^{E}_{i,b}$;

3.2.31.6 $QDLFIRM_{i,b}$ designates the quantity of *energy* that is *bid* at the *maximum market clearing price* at $b \in B^{DL}$ in interval $i \in I$;

3.2.31.7 $Q10SDL_{i,b}$ designates the maximum incremental quantity of synchronized *ten-minute operating reserve* that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J^{10S}_{i,b}$;

3.2.31.8 $Q10NDL_{i,b}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J^{10N}_{i,b}$;

3.2.31.9 $Q30RDL_{i,b}$ designates the maximum incremental quantity of *thirty-minute operating reserve* that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J^{30R}_{i,b}$;

3.2.31.10 $RLP10S_{i,b}$ designates the *reserve loading point* for synchronized *ten-minute operating reserve* in interval $i \in I$; and

3.2.31.11 $RLP30R_{i,b}$ designates the *reserve loading point* for *thirty-minute operating reserve* in interval $i \in I$;

3.2.32 With respect to a *pseudo-unit* identified by bus $b \in B^{PSU}$:

3.2.32.1 $CTShareMLP_b$ designates the combustion turbine share of the *minimum loading point* region;

3.2.32.2 $CTShareDR_b$ designates the combustion turbine share of the *dispatchable* region;

3.2.32.3 $STShareMLP_b$ designates the steam turbine share of the *minimum loading point* region; and

3.2.32.4 $STShareDR_b$ designates the steam turbine share of the *dispatchable* region;

3.2.33 With respect to a *boundary entity resource* import from *intertie zone* bus $\mathrm{d} \in \mathrm{DI}$, where the *locational marginal price* represents the price at the *intertie metering point*:

3.2.33.1 $PIG_{t,d,k}$ designates the price for the maximum incremental quantity of *energy* that may be scheduled to import in time-step $t \in TS$ in association with *offer* lamination $k \in$;

3.2.33.2 $P10NIG_{t,d,k}$ designates the price for the maximum incremental quantity of non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,d}^{10N}$;

3.2.33.3 $P30RIG_{t,d,k}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,d}^{30R}$;

3.2.33.4 $QIG_{t,d,k}$ designates the maximum quantity of *energy* for which an import at bus $d \in DI$ in time-step $t \in TS$ may be scheduled in association with *offer* lamination $k \in K_{t,d}^{E}$;

3.2.33.5 $Q10NIG_{t,d,k}$ designates the maximum incremental quantity of non-synchronized *ten-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,d}^{10N}$; and

3.2.33.6 $Q30RIG_{t,d,k}$ designates the maximum incremental quantity of *thirty-minute operating reserve* quantity that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $k \in K_{t,d}^{30R}$;

3.2.34 With respect to a *boundary entity resource* export to *intertie zone* bus $\mathrm{d} \in \mathrm{DX}$, where the *locational marginal price* represents the price at the *intertie metering point*:

3.2.34.1 $PXL_{t,d,j}$ designates the price of the exporter at bus *d* for an incremental quantity of *energy* in time-step $t \in TS$ in association with *bid* lamination $j \in J_{t,d}^{E}$;

3.2.34.2 $P10NXL_{t,d,j}$ designates the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{10N}$;

3.2.34.3 $P30RXL_{t,d,j}$ designates the price for the maximum incremental quantity of *thirty-minute operating reserve* in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{30R}$;

3.2.34.4 $QXL_{t,d,j}$ designates the maximum quantity of *energy* for which the export at bus *b* in time-step $t \in TS$ may be scheduled in association with *bid* lamination $j \in J_{t,d}^{E}$;

3.2.34.5 $Q10NXL_{t,d,j}$ designates the quantity of non-synchronized *ten-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{10N}$; and

3.2.34.6 $Q30RXL_{t,d,j}$ designates the quantity of *thirty-minute operating reserve* that may be scheduled in time-step $t \in TS$ in association with *offer* lamination $j \in J_{t,d}^{30R}$;

IESO Data Parameters

3.2.35 $ASDG_{i,b}$ designates the amount of *energy* that a *dispatchable generation resource* is scheduled to provide by the *real-time calculation engine* at bus b for interval $i \in I$;

3.2.36 $COMCYCMW_{i,b}$ designates the MWh constraint placed onto a *resource* that is not modelled as a *pseudo-unit* at bus b for interval $i \in I$ to reflect that *resource's energy* capability in combined cycle mode;

3.2.37 $ExtL10NP_{i,d}^{PD}$ designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* for the *dispatch hour* in which interval $i \in I$ falls as calculated by Pass 1 of the *pre-dispatch calculation engine*;

3.2.38 $ExtL30RP_{i,d}^{PD}$ designates the *locational marginal price* for *thirty-minute operating reserve* for the *dispatch hour* in which interval $i \in I$ falls as calculated by Pass 1 of the *pre-dispatch calculation engine*;

3.2.39 $FG_{i,b}$ designates the *IESO's* centralized *variable generation* forecast for a *variable generation resource* identified by bus *b* for interval $i \in I$;

3.2.40 $LMP_{i,b}^{1}$ designates the *locational marginal price* for *energy* in interval $i \in I$ as determined by Pass 1 of the *real-time calculation engine*;

3.2.41 $L10SP^{1}_{i,b}$ designates the *locational marginal price* for synchronized *ten-minute operating reserve* in interval $i \in I$ as determined by Pass 1 of the *real-time calculation engine*;

3.2.42 $L10NP^{1}_{i,b}$ designates the *locational marginal price* for non-synchronized *ten-minute operating reserve* in interval $i \in I$ as determined by Pass 1 of the *real-time calculation engine*;

3.2.43 $L30RP^{1}_{i,b}$ designates the *locational marginal price* for *thirty-minute operating reserve* in interval $i \in I$ as determined by Pass 1 of the *real-time calculation engine*;

3.2.44 $REGULATIONMW_{h,b}$ designates the MWh constraint placed onto a *resource* at bus b for interval $i \in I$ for *regulation*; and

3.2.45 $SEALMW_{i,b}$ designates the MWh constraint placed onto a *resource* at bus b for interval $i \in I$ for actions taken to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*.

3.3 Objective Functions

3.3.1 The objective functions for the Real-Time Market Lost Cost Economic Operating Point calculation shall solve for the following variables:

3.3.1.1 $ESDG_{i,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K^{E}_{i,b}$;

3.3.1.2 $ES10SDG_{i,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K^{10S}_{i,b}$;

3.3.1.3 $ES10NDG_{i,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K^{10N}_{i,b}$;

3.3.1.4 $ES30RDG_{i,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$;

3.3.1.5 $ESIG_{i,d,k}$, which designates the amount of *dispatchable* imports scheduled at bus $d \in DI$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

3.3.1.6 $ES10NIG_{i,d,k}$ which designates the amount of non-synchronized *ten-minute operating reserve* scheduled at bus $d \in DI$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

3.3.1.7 $ES30RIG_{i,d,k}$ which designates the amount of *thirty-minute operating reserve* scheduled at bus $d \in DI$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

3.3.1.8 $ESDL_{i,b,j}$, which designates the amount of *energy* that a *dispatchable load* scheduled at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{E}$;

3.3.1.9 $ES10SDL_{i,b,j}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10S}$;

3.3.1.10 $ES10NDL_{i,b,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10N}$;

3.3.1.11 $ES30RDL_{i,b,j}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$;

3.3.1.12 $ESXL_{i,d,k}$ which designates the amount of *dispatchable* imports scheduled at bus $d \in DX$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

3.3.1.13 $ES10NXL_{i,d,k}$ which designates the amount of non-synchronized *ten-minute operating reserve* scheduled at bus $d \in DX$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$; and

3.3.1.14 $ES30RXL_{i,d,k}$ which designates the amount of *thirty-minute operating reserve* scheduled at bus $d \in DX$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$.

3.3.2 For each of the following *resource* types, the objective function for determining an RT LC EOP will maximize the value of the following expressions:

3.3.2.1 For *dispatchable generation resources*:

$$ObjSDG = \sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \cdot \left(LMP_{i,b}^{1} - PDG_{i,b,k} \right)$$

$$Obj10SDG = \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} \cdot \left(L10SP_{i,b}^{1} - P10SDG_{i,b,k} \right)$$

$$Obj10NDG = \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k} \cdot \left(L10NP_{i,b}^{1} - P10NDG_{i,b,k} \right)$$

$$Obj30RDG = \sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k} \cdot \left(L30RP_{i,b}^{1} - P30RDG_{i,b,k} \right)$$

3.3.2.2 For *dispatchable loads*:

$$ObjSDL_i = \sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} \cdot \left(PDL_{i,b,j} - LMP_{i,b}^{1}\right)$$

$$Obj10SDL_i = \sum_{j \in J_{i,b}^{10S}} ES10SDL_{i,b,j} \cdot \left(P10SDL_{i,b,j} - L10SP_{i,b}^{1}\right)$$

$$Obj10NDL_i = \sum_{j \in J_{i,b}^{10N}} ES10NDL_{i,b,j} \cdot \left(P10NDL_{i,b,j} - L10NP_{i,b}^{1}\right)$$

$$Obj30RDL_i = \sum_{j \in J_{i,b}^{30R}} ES30RDL_{i,b,j} \cdot \left(P30RDL_{i,b,j} - L30RP_{i,b}^{1}\right)$$

3.3.2.3 For import transactions associated with *boundary entity resources*:

$$ObjSIG_i = \sum_{k \in K_{i,d}^{E}} ESIG_{i,d,k} \cdot \left(ExtLMP_{i,d}^{PD} - PIG_{t,d,k}\right)$$

$$Obj10NIG_i = \sum_{k \in K_{i,d}^{10N}} ES10NIG_{i,d,k} \cdot \left(ExtL10NP_{i,d}^{PD} - P10NIG_{t,d,k}\right)$$

$$Obj30RIG_i = \sum_{k \in K_{i,d}^{30R}} ES30RIG_{i,d,k} \cdot \left(ExtL30RP_{i,d}^{PD} - P30RIG_{t,d,k}\right)$$

3.3.2.4 For export transactions associated with *boundary entity resources*:

$$ObjSXL_i = \sum_{j \in J_{i,d}^{E}} ESXL_{i,d,j} \cdot \left(PXL_{t,d,j} - ExtLMP_{i,d}^{PD}\right)$$

$$Obj10NXL_i = \sum_{j \in J_{i,d}^{10N}} ES10NXL_{i,d,j} \cdot \left(P10NXL_{t,d,j} - ExtL10NP_{i,d}^{PD}\right)$$

$$Obj30RXL_i = \sum_{j \in J_{i,d}^{30R}} ES30RXL_{i,d,j} \cdot \left(P30RXL_{t,d,j} - ExtL30RP_{i,d}^{PD}\right)$$

3.4 Constraints

3.4.1 The constraints described in this section 3.4 shall apply to the objective functions used for the RT LC EOP calculation.

Scheduling Variable Bounds

3.4.2 No RT LC EOP shall be negative, nor shall any RT LC EOP exceed the *offer* or *bid* quantity for *energy* or the *offer* quantity for *operating reserve.* For all intervals $i \in I$:

$0 \leq ESDL_{i,b,j} \leq QDL_{i,b,j}$	for all $b \in B^{DL}, j \in J^{E}_{i,b}$;
$0 \leq ES10SDL_{i,b,j} \leq Q10SDL_{i,b,j}$	for all $b \in B^{DL}, j \in J^{10S}_{i,b}$;
$0 \leq ES10NDL_{i,b,j} \leq Q10NDL_{i,b,j}$	for all $b \in B^{DL}, j \in J^{10N}_{i,b}$;
$0 \leq ES30RDL_{i,b,j} \leq Q30RDL_{i,b,j}$	for all $b \in B^{DL}, j \in J^{30R}_{i,b}$;
$0 \leq ESDG_{i,b,k} \leq QDG_{i,b,k}$	for all $b \in B^{DG}, k \in K^{E}_{i,b}$;
$0 \leq ES10SDG_{i,b,k} \leq Q10SDG_{i,b,k}$	for all $b \in B^{DG}, k \in K^{10S}_{i,b}$;
$0 \leq ES10NDG_{i,b,k} \leq Q10NDG_{i,b,k}$	for all $b \in B^{DG}, k \in K^{10N}_{i,b}$;
$0 \leq ES30RDG_{i,b,k} \leq Q30RDG_{i,b,k}$	for all $b \in B^{DG}, k \in K^{30R}_{i,b}$;
$0 \leq ESDX_{i,d,j} \leq QXL_{t,d,j}$	for all $d \in DX, j \in J^{E}_{t,d}$;
$0 \leq ES10NXL_{i,d,j} \leq Q10NXL_{t,d,j}$	for all $d \in DX, j \in J^{10N}_{t,d}$;
$0 \leq ES30RXL_{i,d,j} \leq Q30RXL_{t,d,j}$	for all $d \in DX, j \in J^{30R}_{t,d}$;
$0 \leq ESIG_{i,d,k} \leq QIG_{t,d,k}$	for all $d \in DI, k \in K^{E}_{t,d}$;
$0 \leq ES10NIG_{i,d,k} \leq Q10NIG_{t,d,k}$	for all $d \in DI, k \in K^{10N}_{t,d}$;
$0 \leq ES30RIG_{i,d,k} \leq Q30RIG_{t,d,k}$	for all $d \in DI, k \in K^{30R}_{t,d}$;

3.4.3 Subject to section 3.4.4, the RT LC EOP for a *non-quick start resource* shall be greater than or equal to its *minimum loading point* for interval $i \in I$ and bus $b \in B^{NQS}$:

$$\sum_{k \in K^{E}_{i,b}} ESDG_{i,b,k} \geq MinQDG_{b}$$

3.4.4 The RT LC EOP for a *non-quick start resource* shall be equal to its *real-time schedule* when it is scheduled below its *minimum loading point* for interval $i \in I$ and bus $b \in B^{NQS}$:

If $\sum_{k \in K_{i,b}^{E}} ASDG_{i,b,k} < MinQDG_b$ for $b \in B^{NQS}$ then:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} = ASDG_{i,b}$$

Constraints for Regulation Requirements

3.4.5 For a *dispatchable generation resource,* its RT LC EOP for *energy* shall be greater than or equal to any *regulation* constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \geq REGULATIONMW_{i,b}$$

3.4.6 For a *dispatchable generation resource,* its RT LC EOP for *energy* and each class of *operating reserve* shall not exceed the maximum available capacity the *resource* has less the *regulation* constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \leq AdjMaxDG_{i,b} - REGULATIONMW_{i,b}$$

$$\sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} \leq AdjMaxDG_{i,b} - REGULATIONMW_{i,b}$$

$$\sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k} \leq AdjMaxDG_{i,b} - REGULATIONMW_{i,b}$$

$$\sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq AdjMaxDG_{i,b} - REGULATIONMW_{i,b}$$

Constraints for Market Participant Requirements

3.4.7 For a *dispatchable generation resource,* its RT LC EOP for *energy* shall be greater than or equal to any minimum $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \geq SEALMW_{i,b}$$

3.4.8 For a *dispatchable load,* its RT LC EOP for *energy* shall be greater than or equal to any minimum $SEALMW_{i,b}$ constraint that is applied and for each class of *operating reserve*, the RT LC EOP shall be less than or equal to the RT LC EOP for *energy* for that *resource* less any minimum $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} \geq SEALMW_{i,b}$$

$$\sum_{j \in J_{i,b}^{10S}} ES10SDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} - SEALMW_{i,b}$$

$$\sum_{j \in J_{i,b}^{10N}} ES10NDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} - SEALMW_{i,b}$$

$$\sum_{j \in J_{i,b}^{30R}} ES30RDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} - SEALMW_{i,b}$$

3.4.9 For a *dispatchable generation resource,* its RT LC EOP for *energy* shall be less than or equal to any maximum $SEALMW_{i,b}$ constraint applied for all intervals $i \in I$ and buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \leq SEALMW_{i,b}$$

3.4.10 For a *dispatchable load,* its RT LC EOP for *energy* shall be less than or equal to any maximum $SEALMW_{i,b}$ constraint applied for all intervals $i \in I$ and buses $b \in B^{DG}$:

$$\sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} \leq SEALMW_{i,b}$$

3.4.11 For a *dispatchable generation resource,* its RT LC EOP for *energy* shall be equal to any fixed $SEALMW_{i,b}$constraint applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k \in K^E_{i,b}} ESDG_{i,b,k} = SEALMW_{i,b}$$

3.4.12 For a *dispatchable load,* its RT LC EOP for *energy* shall be equal to any fixed $SEALMW_{h,b}$constraint that is applied and equal to zero for each class of *operating reserve* for interval $i \in I$ and buses $b \in B^{DL}$:

$$\sum_{j \in J^E_{i,b}} ESDL_{i,b,j} = SEALMW_{i,b}$$

$$\sum_{j \in J^{10S}_{h,b}} ES10SDL_{i,b,k} = 0$$

$$\sum_{j \in J^{10N}_{h,b}} ES10NDL_{i,b,k} = 0$$

$$\sum_{j \in J^{30R}_{h,b}} ES30RDL_{i,b,k} = 0$$

3.4.13 For a *dispatchable load,* its RT LC EOP for *energy* shall be greater than or equal to the *bid* quantity for *energy* priced at the *maximum market clearing price*:

$$\sum_{j \in J^E_{i,b}} ESDL_{i,b,j} \geq QDLFIRM_{i,b}$$

3.4.14 For a *dispatchable load,* its RT LC EOP for *operating reserve* shall be less than or equal its RT LC EOP for *energy* less the *bid* quantity for *energy* priced at the *maximum market clearing price*:

$$\sum_{j\in J_{i,b}^{10S}} ES10SDL_{i,b,j} \leq \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} - QDLFIRM_{i,b}$$

$$\sum_{j\in J_{i,b}^{10N}} ES10NDL_{i,b,j} \leq \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} - QDLFIRM_{i,b}$$

$$\sum_{j\in J_{i,b}^{30R}} ES30RDL_{i,b,j} \leq \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} - QDLFIRM_{i,b}$$

Constraints for Operating Reserve Ramping

3.4.15 For a *dispatchable generation resource* with $RLP10S_{h,b} > 0$, the amount of *ten-minute operating reserve* that the *resource* is scheduled to provide shall be less than or equal to its *reserve loading point* for *ten-minute operating reserve* and , the following constraint shall apply for all hours $h \in \{1, .., 24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k} \leq \left(\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k}\right) \cdot \left(\frac{1}{RLP10S_{i,b}}\right) \cdot \left(min\left\{10 \cdot ORRDG_{i,b}, \sum_{k\in K_{i,b}^{10S}} Q10SDG_{i,b,k}\right\}\right)$$

3.4.16 For a *dispatchable generation resource* with $RLP30R_{h,b} > 0$, the amount of *thirty-minute operating reserve* that the *resource* is scheduled to provide shall be less than or equal to its *reserve loading point* for *thirty-minute operating reserve* and the following constraint shall apply for all hours $h \in \{1, .., 24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq \left(\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k}\right) \cdot \left(\frac{1}{RLP30R_{i,b}}\right) \cdot \left(min\left\{30 \cdot ORRDG_{i,b}, \sum_{k\in K_{i,b}^{30R}} Q30RDG_{i,b,k}\right\}\right)$$

Constraints for Pseudo-units

3.4.17 For a *pseudo-unit,* its RT LC EOP for *energy* for the *dispatchable* region and duct firing region shall be less than or equal to the respective maximum capabilities for those regions for interval $i \in \mathrm{I}$ and bus $b \in B^{PSU}$:

$$\sum_{k \in K_{i,b}^{DR}} ESDG_{i,b,k} \leq MaxDR_{i,b}$$

$$\sum_{k \in K_{i,b}^{DF}} ESDG_{i,b,k} \leq MaxDF_{i,b}$$

3.4.18 For a *pseudo-unit,* its RT LC EOP for each class of *operating reserve* shall be less than or equal to the sum of the maximum capabilities for its *dispatchable* region and duct firing region for hour $i \in \mathrm{I}$ and bus $b \in B^{PSU}$:

$$\sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} \leq MaxDR_{i,b} + MaxDF_{i,b}$$

$$\sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k} \leq MaxDR_{i,b} + MaxDF_{i,b}$$

$$\sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq MaxDR_{i,b} + MaxDF_{i,b}$$

3.4.19 For a *pseudo-unit* that cannot provide *ten-minute operating reserve* from its duct firing region, the following constraint shall apply:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} + \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k} \leq MINQDG_b + QDR_{i,k}$$

3.5 Outputs

3.5.1 The RT LC EOP s used for *settlement* for *energy* and *operating reserve* for all *resources* except *pseudo-unit resources* for each interval of the *dispatch hour* shall be the sum of each RT LC EOP variable determined by the objective function in section 3.3 for that *resource*, subject to constraints in section 3.4 applicable for that *resource* determined as follows:

$$DGEnergyEOP_{i,b}^{LC} = \sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k}$$

$$DG10SEOP_{i,b}^{LC} = \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k}$$

$$DG10NEOP_{i,b}^{LC} = \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k}$$

$$DG30REOP_{i,b}{}_{i,b}^{LC} = \sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k}$$

$$DLEnergyEOP_{i,b}^{LC} = \sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j}$$

$$DL10SEOP_{i,b}{}_{i,b}^{LC} = \sum_{j \in J_{i,b}^{10S}} ES10SDL_{i,b,j}$$

$$DL10NEOP_{i,b}^{LC} = \sum_{j \in J_{i,b}^{10N}} ES10NDL_{i,b,j}$$

$$DL30REOP_{i,b}{}_{i,b}^{LC} = \sum_{j \in J_{i,b}^{30R}} ES30RDL_{i,b,j}$$

$$DIEnergyEOP_{i,b}^{LC} = \sum_{k \in K_{i,b}^{E}} ESIG_{i,b,k}$$

$$DI10NEOP_{i,b}^{LC} = \sum_{k \in K_{i,b}^{10N}} ES10NIG_{i,b,k}$$

$$DI30REOP_{i,b}{}_{i,b}^{LC} = \sum_{k \in K_{i,b}^{30R}} ES30RIG_{i,b,k}$$

$$DXEnergyEOP_{i,b}^{LC} = \sum_{j \in J_{i,b}^{E}} ESXL_{i,b,j}$$

$$DX10NEOP_{i,b}^{LC} = \sum_{j \in J_{i,b}^{10N}} ES10NXL_{i,b,j}$$

$$DX30REOP_{i,b}^{LC} = \sum_{j \in J_{i,b}^{30R}} ES30RXL_{i,b,j}$$

3.5.2 The RT LC EOPs for *energy* and *operating reserve* for a *pseudo-unit* for each interval of the *dispatch hour,* which will be used for converting the RT LC EOPs to physical *resource* equivalents in accordance with sections 3.5.3 to 3.5.4, shall be determined as follows:

$$PSUMLPEnergyEOP_{i,k}^{LC} = \sum_{k \in K_{i,b}^{MLP}} ESDG_{i,b,k}$$

$$PSUDREnergyEOP_{i,k}^{LC} = \sum_{k \in K_{i,b}^{DR}} ESDG_{i,b,k}$$

$$PSUDFEnergyEOP_{i,k}^{LC} = \sum_{k \in K_{i,b}^{DF}} ESDG_{i,b,k}$$

$$PSU10SEOP_{i,k}^{LC} = \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k}$$

$$PSU10NEOP_{i,k}^{LC} = \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k}$$

$$PSU30REOP_{i,k}^{LC} = \sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k}$$

Conversion of RT LC EOPs for Pseudo-Units to Physical Resource Equivalents

3.5.3 The RT LC EOP used for *settlement* for *energy* for a combustion turbine and a steam turbine that is associated with *pseudo-unit* $k \in \{1, \ldots, K\}$ in interval i shall be determined as follows:

$$CTEnergyEOP_{i,k} = PSUMLPEnergyEOP_{i,k}^{LC} \cdot CTShareMLP_{i,k} + PSUDREnergyEOP_{i,k}^{LC} \cdot CTShareDR_{i,k}$$

$$STEnergyEOP_{i,k} = PSUMLPEnergyEOP_{i,k}^{LC} \cdot STShareMLP_{k} + PSUDREnergyEOP_{i,k}^{LC} \cdot STShareDR_{k} + PSUDFEnergyEOP_{i,k}^{LC}$$

3.5.4 The RT LC EOPs used for *settlement* for *operating reserve* for a combustion turbine and a steam turbine that is associated with *pseudo-unit* $k \in \{1, \ldots, K\}$ in interval i shall be determined as follows and in the following order for each class of *operating reserve*:

$$10SDR_{i,k} = \min\left(QDR_{i,k}, PSU10SEOP_{i,k}^{LC}\right)$$
$$10NDR_{i,k} = \min\left(QDR_{i,k} - 10SDR_{i,k}, PSU10NEOP_{i,k}^{LC}\right)$$
$$30RDR_{i,k} = \min\left(QDR_{i,k} - 10SDR_{i,k} - 10NDR_{i,k}, PSU30REOP_{i,k}^{LC}\right)$$

$$CT10SEOP_{i,k} = 10SDR_{i,k} \cdot CTShareDR_k$$
$$ST10SEOP_{i,k} = 10SDR_{i,k} \cdot STShareDR_k + (PSU10SEOP_{i,k}^{LC} - 10SDR_{i,k})$$

$$CT10NEOP_{i,k} = 10NDR_k \cdot CTShareDR_{i,k}$$
$$ST10NEOP_{i,k} = 10NDR_{i,k} \cdot STShareDR_k + (PSU10NEOP_{i,k}^{LC} - 10NDR_{i,k})$$

$$CT30REOP_{i,k} = 30RDR_k \cdot CTShareDR_{i,k}$$

$$ST30REOP_{i,k} = 30RDR_{i,k} \cdot STShareDR_k + (PSU30REOP_{i,k}^{LC} - 30RDR_{i,k})$$

4. Real-Time Market Lost Opportunity Cost Economic Operating Point

4.1 Purpose

4.1.1 This section describes the process used to determine the lost opportunity cost economic operating point for eligible *resources* in the *real-time market* (RT LOC EOP).

4.2 Sets, Indices and Parameters Used by the Real-Time Market Lost Opportunity Cost Economic Operating Point

Fundamental Sets and Indices

4.2.1 The fundamental inputs used to calculate RT LOC EOP are described in section 3.2.

Market Participant Data Parameters

4.2.2 In addition to the *market participant* data parameters described in section 3.2, the following parameters are also used to calculate the RT LOC EOP.

4.2.3 With respect to a *dispatchable generation resource* identified by bus $\mathrm{b} \in \mathrm{B}^{\mathrm{DG}}$:

4.2.3.1 $DRRDG_{i,b,w}$ designates the maximum rate in MW per minute at which the *resource* can decrease the amount of *energy* it supplies at $b \in B^{DG}$ for interval i while operating in the range between $RmpRngMaxDG_{i,b,w-1}$ and $RmpRngMaxDG_{i,b,w}$ for $w \in \{1, \dots, NumRRDG_{i,b}\}$;

4.2.3.2 $NumRRDG_{i,b}$ designates the number of ramp rates provided in time-step $i \in I$; and

4.2.3.3 $URRDG_{i,b,w}$ designates the maximum rate in MW per minute at which the *resource* can increase the amount of *energy* it supplies at $b \in B^{DG}$ for interval $i \in I$ while operating in the range between $RmpRngMaxDG_{i,b,w-1}$ and $RmpRngMaxDG_{i,b,w}$ for $w \in \{1, \dots, NumRRDG_{i,b}\}$;

4.2.4 With respect to a *dispatchable load* identified by bus $\mathrm{b} \in \mathrm{B}^{\mathrm{DL}}$:

4.2.4.1 $DRRDL_{i,b,w}$ designates the maximum rate in MW per minute at which the *resource* can decrease the amount of *energy* it supplies at $b \in B^{DL}$ for interval $i \in I$ while operating in the range between $RmpRngMaxDL_{i,b,w-1}$ and $RmpRngMaxDL_{i,b,w}$ for $w \in \{1, \dots, NumRRDG_{i,b}\}$;

4.2.4.2 $NumRRDL_{i,b}$ designates the number of ramp rates provided at $b \in B^{DL}$ for interval $i \in I$;

4.2.4.3 $ORRDL_b$ designates the *operating reserve* ramp rate in MW per minute of reductions in load consumption;

4.2.4.4 $RmpRngMaxDG_{i,b,w}$ designates the wth ramp rate break point provided at $b \in B^{DG}$ for interval $i \in I$ where $w \in \{1, \dots, NumRRDG_{i,b}\}$;

4.2.4.5 $RmpRngMaxDL_{i,b,w}$ designates the w[th] ramp rate break point provided at $b \in B^{DL}$ for interval $i \in I$ where $w \in \{1, \ldots, NumRRDG_{i,b}\}$; and

4.2.4.6 $URRDL_{i,b,w}$ designates the maximum rate in MW per minute at which the *resource* can increase the amount of *energy* it supplies at $b \in B^{DL}$ for interval $i \in I$ while operating in the range between $RmpRngMaxDL_{i,b,w-1}$ and $RmpRngMaxDL_{i,b,w}$ for $w \in \{1, \ldots, NumRRDL_{i,b}\}$.

IESO Data Parameters

4.2.5 In addition to the *IESO* data parameters described in section 3.2, the following parameters are also used to the calculate the RT LOC EOP.

4.2.5.1 $GridConnected_{i,b}$ designates if the *resource* is connected to the *IESO-controlled grid* at bus b for interval $i \in I$; and

4.2.5.2 $RELIABILITYMW_{i,b}$ designates the MWh constraint placed onto a *resource* at bus b for interval $i \in I$ for *reliability* purposes.

4.3 Objective Functions

4.3.1 The objective functions for the Real-Time Market Lost Opportunity Cost Economic Operating Point calculation shall solve for the following variables:

4.3.1.1 $ESDG_{i,b,k}$, which designates the amount of *energy* that a *dispatchable generation resource* is scheduled at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K^{E}_{i,b}$;

4.3.1.2 $ES10SDG_{i,b,k}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K^{10S}_{i,b}$;

4.3.1.3 $ES10NDG_{i,b,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K^{10N}_{i,b}$;

4.3.1.4 $ES30RDG_{i,b,k}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$;

4.3.1.5 $ESIG_{i,d,k}$, which designates the amount of *energy* that a *boundary entity resource* is scheduled to import from *intertie zone* bus $d \in DI$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

4.3.1.6 $ES10NIG_{i,d,k}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *boundary entity resource* is scheduled to provide from *intertie zone* bus $d \in DI$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

4.3.1.7 $ES30RIG_{i,d,k}$, which designates the amount of *thirty-minute operating reserve* that a *boundary entity resource* is scheduled to provide at bus $d \in DI$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

4.3.1.8 $ESDL_{i,b,j}$, which designates the amount of *energy* that a *dispatchable load* is scheduled to consume at bus $b \in B^{DL}$ in interval $i \in I$ in association with *bid* lamination $j \in J_{i,b}^{E}$;

4.3.1.9 $ES10SDL_{i,b,j}$, which designates the amount of synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10S}$;

4.3.1.10 $ES10NDL_{i,b,j}$, which designates the amount of non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10N}$;

4.3.1.11 $ES30RDL_{i,b,j}$, which designates the amount of *thirty-minute operating reserve* that a *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$;

4.3.1.12 $ESXL_{i,d,k}$ which designates the amount of *energy* a *boundary entity resource* is scheduled to export at *intertie zone* bus $d \in DX$ in interval $i \in I$ in association with *bid* lamination $k \in K_{i,d}^{E}$;

4.3.1.13 $ES10NXL_{i,d,k}$ which designates the amount of non-synchronized *ten-minute operating reserve* that a *boundary entity resource* is scheduled to provide at *intertie zone* bus $d \in DX$ in interval $i \in I$ in association with *offer* lamination $k \in K_{i,d}^{E}$;

4.3.1.14 $ES30RXL_{i,d,k}$ which designates the amount of *thirty-minute operating reserve* that a *boundary entity resource* is scheduled to provide at *intertie zone* bus $d \in DX$ in interval i in association with *offer* lamination $k \in K_{i,d}^{E}$;

4.3.1.15 $ESDGInitSch_{i,b}$ designates the initial schedule for a *dispatchable generation resource* at bus $b \in B^{DG}$; and

4.3.1.16 $ESDLInitSch_{i,b}$ designates the initial schedule for a *dispatchable load* at bus $b \in B^{DL}$.

4.3.2 For each of the following *resource* types, the objective function for determining an RT LOC EOP shall maximize the value of the following expressions:

4.3.2.1 For *dispatchable generation resources*:

$$
\begin{aligned}
ObjDG_i = \sum_{b \in B^{DG}} \Bigg(& \sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \cdot \left(LMP_{i,b}^{1} - PDG_{i,b,k} \right) \\
& + \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} \cdot \left(L10SP_{i,b}^{1} - P10SDG_{i,b,k} \right) \\
& + \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k} \cdot \left(L10NP_{i,b}^{1} - P10NDG_{i,b,k} \right) \\
& + \sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k} \cdot \left(L30RP_{i,b}^{1} - P30RDG_{i,b,k} \right) \Bigg)
\end{aligned}
$$

4.3.2.2 For *dispatchable loads*:

$$ObjDL_i = \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} \cdot \left(PDL_{i,b,j} - LMP_{i,b}^{1}\right) + \sum_{j \in J_{i,b}^{10S}} ES10SDL_{i,b,j} \cdot \left(P10SDL_{i,b,j} - L10SP_{i,b}^{1} - P10SDL_{i,b,j}\right) + \sum_{j \in J_{i,b}^{10N}} ES10NDL_{i,b,j} \cdot \left(L10NP_{i,b}^{1} - P10NDL_{i,b,j} - L10NP_{i,b}^{1}\right) + \sum_{j \in J_{i,b}^{30R}} ES30RDL_{i,b,j} \cdot \left(L30RP_{i,b}^{1} - P30RDL_{i,b,j} - L30RP_{i,b}^{1}\right) \right)$$

4.3.2.3 For an import transaction at an *intertie metering point* 'i' associated with a *boundary entity resource*:

$$ObjDI_i = \sum_{d \in DI} \left(\sum_{k \in K_{i,d}^{E}} EDIG_{i,d,k} \cdot \left(ExtLMP_{i,d}^{PD} - PIG_{t,d,k}\right) + \sum_{k \in K_{i,d}^{10N}} ES10NIG_{i,d,k} \cdot \left(ExtL10NP_{i,d}^{PD} - P10NIG_{t,d,k}\right) + \sum_{k \in K_{i,d}^{30R}} ES30RIG_{i,d,k} \cdot \left(ExtL30RP_{i,d}^{PD} - P30RIG_{t,d,k}\right) \right)$$

4.3.2.4 For an export transaction at an *intertie metering point* 'i' associated with a *boundary entity resource*:

$$ObjDX_i = \sum_{d \in DX} \left(\sum_{j \in J_{i,d}^{E}} ESXL_{i,d,j} \cdot \left(PXL_{t,d,j} - ExtLMP_{i,d}^{PD}\right) + \sum_{j \in J_{i,d}^{10N}} ES10NXL_{i,d,j} \cdot \left(ExtL10NP_{i,d}^{PD} - P10NXL_{t,d,j}\right) + \sum_{j \in J_{i,d}^{30R}} ES30RXL_{i,d,j} \cdot \left(ExtL30RP_{i,d}^{PD} - P30RXL_{t,d,j}\right) \right)$$

4.4 Constraints

4.4.1 The constraints described in this section 4.4 shall apply to the objective functions used for the RT LOC EOP calculation.

Scheduling Variable Bounds

4.4.2 No RT LOC EOP shall be negative, nor shall any RT LOC EOP exceed the *offer* or *bid* quantity for *energy* or the *offer* quantity for *operating reserve*. Therefore, for all intervals $i \in I$:

$0 \leq ESDL_{i,b,j} \leq QDL_{i,b,j}$ for all $b \in B^{DL}, j \in J^{E}_{i,b}$;

$0 \leq ES10SDL_{i,b,j} \leq Q10SDL_{i,b,j}$ for all $b \in B^{DL}, j \in J^{10S}_{i,b}$;

$0 \leq ES10NDL_{i,b,j} \leq Q10NDL_{i,b,j}$ for all $b \in B^{DL}, j \in J^{10N}_{i,b}$;

$0 \leq ES30RDL_{i,b,j} \leq Q30RDL_{i,b,j}$ for all $b \in B^{DL}, j \in J^{30R}_{i,b}$;

$0 \leq ESDG_{i,b,k} \leq QDG_{i,b,k}$ for all $b \in B^{DG}, k \in K^{E}_{i,b}$;

$0 \leq ES10SDG_{i,b,k} \leq Q10SDG_{i,b,k}$ for all $b \in B^{DG}, k \in K^{10S}_{i,b}$;

$0 \leq ES10NDG_{i,b,k} \leq Q10NDG_{i,b,k}$ for all $b \in B^{DG}, k \in K^{10N}_{i,b}$;

$0 \leq ES30RDG_{i,b,k} \leq Q30RDG_{i,b,k}$ for all $b \in B^{DG}, k \in K^{30R}_{i,b}$;

$0 \leq ESDX_{i,d,j} \leq QXl_{t,d,j}$ for all $d \in DX, j \in J^{E}_{t,d}$;

$0 \leq ES10NXL_{i,d,j} \leq Q10NXL_{t,d,j}$ for all $d \in DX, j \in J^{10N}_{t,d}$;

$0 \leq ES30RXL_{i,d,j} \leq Q30RXL_{t,d,j}$ for all $d \in DX, j \in J^{30R}_{t,d}$;

$0 \leq ESDI_{i,d,k} \leq QIG_{t,d,k}$ for all $d \in DI, k \in K^{E}_{t,d}$;

$0 \leq ES10NIG_{i,d,k} \leq Q10NIG_{t,d,k}$ for all $d \in DI, k \in K^{10N}_{t,d}$;

$0 \leq ES30RIG_{i,d,k} \leq Q30RIG_{t,d,k}$ for all $d \in DI, k \in K^{30R}_{t,d}$;

4.4.3 For a *dispatchable generation resource* that is not connected to the *IESO-controlled grid* and is not eligible for *dispatch*, its RT LOC EOP shall be set to zero for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k \in K^{E}_{i,b}} ESDG_{i,b,k} + \sum_{k \in K^{10S}_{i,b}} ES10SDG_{i,b,k} + \sum_{k \in K^{10N}_{i,b}} ES10NDG_{i,b,k} + \sum_{k \in K^{30R}_{i,b}} ES30RDG_{i,b,k} = 0$$

4.4.4 For a *dispatchable load* that is not connected to the *IESO-controlled grid* and is not eligible for *dispatch*, its RT LOC EOP shall be set to zero for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} + \sum_{j\in J_{i,b}^{10S}} ES10SDL_{i,b,j} + \sum_{j\in J_{i,b}^{10N}} ES10NDL_{i,b,j} + \sum_{j\in J_{i,b}^{30R}} ES30RDL_{i,b,j} = 0$$

4.4.5 For a *dispatchable load*, the sum of the RT LOC EOP for all classes of *operating reserve* for the *resource* shall not exceed its RT LOC EOP for *energy* for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j\in J_{i,b}^{10S}} ES10SDL_{i,b,j} + \sum_{j\in J_{i,b}^{10N}} ES10NDL_{i,b,j} + \sum_{j\in J_{i,b}^{30R}} ES30RDL_{i,b,j} \leq \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j}$$

4.4.6 For a *dispatchable generation resource,* its RT LOC EOP shall not exceed the maximum available capacity for the *resource* for interval $i \in I$ and bus $b \in B^{DG}$:

$$AdjMaxDG_{i,b} = \begin{Bmatrix} min\left(\sum_{k\in K_{i,b}^{E}} QDG_{i,b,k}\,, Derate_{i,b}, FG_{i,b}\right) & if\ b \in B^{VG} \\ min\left(\sum_{k\in K_{i,b}^{E}} QDG_{i,b,k}\,, Derate_{i,b}\right) & otherwise \end{Bmatrix}$$

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} + \sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k\in K_{i,b}^{10N}} ES10NDG_{i,b,k} + \sum_{k\in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq AdjMaxDG_{i,b}$$

4.4.7 Subject to section 4.4.8, the RT LOC EOP for a *non-quick start resource* shall be greater than or equal to its *minimum loading point* f for interval i ∈ I and bus $b \in B^{NQS}$:

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} \geq MinQDG_{b}$$

4.4.8 The RT LOC EOP for a *non-quick start resource* shall be equal to its *real-time schedule* when it is scheduled below its *minimum loading point* for interval i ∈ I and bus $b \in B^{NQS}$:

If $\sum_{k\in K_{i,b}^E} ASDG_{i,b,k} < MinQDG_b$ for $b \in B^{NQS}$, then:

$$\sum_{k\in K_{i,b}^E} ESDG_{i,b,k} = ASDG_{i,b}$$

Constraints for Reliability Requirements

4.4.9 For a *dispatchable generation resource,* its RT LOC EOP shall be greater than or equal to any minimum *reliability* constraint that is applied for interval i ∈ I and bus $b \in B^{DG}$

$$\sum_{k\in K_{i,b}^E} ESDG_{i,b,k} \geq RELIABILITYMW_{i,b}$$

4.4.10 For a *dispatchable load* its RT LOC EOP shall be greater than or equal to any minimum *reliability* constraint that is applied for interval $i \in I$ and bus $b \in B^{DL}$

$$\sum_{j\in J_{i,b}^E} ESDL_{i,b,k} \geq RELIABILITYMW_{i,b}$$

4.4.11 For a *dispatchable generation resource* its RT LOC EOP for *energy* shall be greater than or equal to any *regulation* constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^E} ESDG_{i,b,k} \geq REGULATIONMW_{i,b}$$

4.4.12 For a *dispatchable generation resource,* the sum of RT LOC EOP for *energy* and all classes of *operating reserve* shall be less than or equal to its maximum available capacity less the *regulation* constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} + \sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k\in K_{i,b}^{10N}} ES10NDG_{i,b,k} + \sum_{k\in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq AdjMaxDG_{i,b} - REGULATIONMW_{i,b}$$

Constraints for Market Participant Requirements

4.4.13 For a *dispatchable generation resource,* its RT LOC EOP for *energy* shall be greater than or equal to any minimum $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} \geq SEALMW_{i,b}$$

4.4.14 For a *dispatchable load,* its RT LOC EOP for *energy* shall be greater than or equal to any minimum $SEALMW_{i,b}$ constraint that is applied and the sum of RT LOC EOP for all classes of *operating reserve* shall be less than or equal to the RT LOC EOP for *energy* for that *resource* less the minimum $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} \geq SEALMW_{i,b}$$

$$\sum_{j\in J_{i,b}^{10S}} ES10SDL_{i,b,j} + \sum_{j\in J_{i,b}^{10N}} ES10NDL_{i,b,j} + \sum_{j\in J_{i,b}^{30R}} ES30RDL_{i,b,j} \leq \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} - SEALMW_{i,b}$$

4.4.15 For a *dispatchable generation resource,* the sum of its RT LOC EOPs for *energy* shall be less than or equal to any maximum $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} \leq SEALMW_{i,b}$$

4.4.16 For a *dispatchable load,* its RT LOC EOP for *energy* shall be less than or equal to any maximum $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} \leq SEALMW_{i,b}$$

4.4.17 For a *dispatchable generation resource,* its RT LOC EOP for *energy* shall be equal to any fixed $SEALMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} = SEALMW_{i,b}$$

4.4.18 For a *dispatchable load,* its RT LOC EOP for *energy* shall be equal to any fixed $SEALMW_{i,b}$ constraint that is applied and equal to zero for each class of *operating reserve* for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} = SEALMW_{i,b}$$

$$\sum_{j \in J_{h,b}^{10S}} ES10SDL_{i,b,k} = 0$$

$$\sum_{j \in J_{h,b}^{10N}} ES10NDL_{i,b,k} = 0$$

$$\sum_{j \in J_{h,b}^{30R}} ES30RDL_{i,b,k} = 0$$

4.4.19 For a *dispatchable non-quick start resource* that is not being modelled as a *pseudo-unit*, its RT LOC EOP for *energy* shall be greater than or equal to the $COMCYCMW_{i,b}$ constraint that is applied for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} \geq COMCYCMW_{i,b}$$

4.4.20 For a *dispatchable load,* its RT LOC EOP for *energy* shall be greater than or equal to the *bid* quantity for *energy* priced at the *maximum market clearing price* for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} \geq QDLFIRM_{i,b}$$

4.4.21 For a *dispatchable load,* the sum of RT LOC EOPs for all classes of *operating reserve* shall not exceed the RT LOC EOP for *energy* less the *bid* quantity for *energy* priced at the *maximum market clearing price* for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j\in J_{i,b}^{10S}} ES10SDL_{i,b,j} + \sum_{j\in J_{i,b}^{10N}} ES10NDL_{i,b,j} + \sum_{j\in J_{i,b}^{30R}} ES30RDL_{i,b,j} \leq \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j} - QDLFIRM_{i,b}$$

Constraints for Operating Reserve Ramping

4.4.22 For a *dispatchable resource*, the upper bound of the RT LOC EOP for all classes of *operating reserve* shall be less than or equal to it *operating reserve* ramp rates as follows:

4.4.22.1 For a *dispatchable generation resource,* for interval $i \in I$ and bus $b \in B^{DG}$:

$$\sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k\in K_{i,b}^{10N}} ES10NDG_{i,b,k} + \sum_{k\in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq 30 \cdot ORRDG_{b}$$

$$\sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k\in K_{i,b}^{10N}} ES10NDG_{i,b,k} \leq 10 \cdot ORRDG_{b}$$

4.4.22.2 For a *dispatchable load,* for interval $i \in I$ and bus $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} ES10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} ES10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} ES30RDL_{i,b,j} \leq 30 \cdot ORRDL_b$$

$$\sum_{j \in J_{i,b}^{10S}} ES10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} ES10NDL_{i,b,j} \leq 10 \cdot ORRDL_b$$

4.4.23 For a *dispatchable generation resource* with $RLP10S_{i,b} > 0$, the amount of *ten-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be less than or equal to its *reserve loading point* for *ten-minute operating reserve*:

$$\sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} \leq \left(\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \right) \cdot \left(\frac{1}{RLP10S_{i,b}} \right) \cdot \left(min \left\{ 10 \cdot ORRDG_b, \sum_{k \in K_{i,b}^{10S}} Q10SDG_{i,b,k} \right\} \right)$$

4.4.24 For all *dispatchable generation resources* with $RLP30R_{i,b} > 0$, the amount of *thirty-minute operating reserve* that a *dispatchable generation resource* is scheduled to provide shall be less than or equal to its *reserve loading point* for *thirty-minute operating reserve*:

$$\sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq \left(\sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \right) \cdot \left(\frac{1}{RLP30R_{i,b}} \right) \cdot \left(min \left\{ 30 \cdot ORRDG_b, \sum_{k \in K_{i,b}^{30R}} Q30RDG_{i,b,k} \right\} \right)$$

Constraints for Energy Ramping

4.4.25 With the exception of the first *interval* of each *dispatch day*, the RT LOC EOP shall use its RT LOC EOP for the prior interval as its initial starting point as follows:

4.4.25.1 For a *dispatchable generation resource,* its RT LOC EOP for *energy* cannot vary by more than five minutes of the *resource's energy* ramping capability for interval $i \in I$ and bus $b \in B^{DG}$:

$$ESDGInitSch_{\mathrm{i},b} - 5 \cdot DRRDG_{i,b,w} \leq \sum_{k \in K_{i,b}^{E}} ESDG_{i,b,k} \leq ESDGInitSch_{i,b} + 5 \cdot URRDG_{i,b,w}$$

4.4.25.2 For a *dispatchable load,* its RT LOC EOP for *energy* cannot vary by more than five minutes of the *resource's* energy ramping capability for interval $i \in I$ and bus $b \in B^{DL}$:

$$ESDLInitSch_{i,b} - 5 \cdot DRRDL_{i,b,w} \leq \sum_{j \in J_{i,b}^{E}} ESDL_{i,b,j} \leq ESDLInitSch_{i,b} + 5 \cdot URRDL_{i,b,w}$$

Constraints for Pseudo-Units

4.4.26 For a *pseudo-unit,* its RT LOC EOP for *energy* for the *dispatchable* region and duct firing region shall be less than or equal to the respective maximum capabilities for those regions for interval $i \in \mathrm{I}$ and bus $b \in B^{PSU}$:

$$\sum_{k \in K_{i,b}^{DR}} ESDG_{i,b,k} \leq MaxDR_{i,b}$$

$$\sum_{k \in K_{i,b}^{DF}} ESDG_{i,b,k} \leq MaxDF_{i,b}$$

4.4.27 For a *pseudo-unit,* the sum of its RT LOC EOP for *energy* and the RT LOC EOP s for all classes of *operating reserve* shall be less than or equal to the sum of the maximum capabilities for its *dispatchable* region and duct firing region for interval $i \in \mathrm{I}$ and bus $b \in B^{PSU}$

$$\sum_{k \in K_{i,b}^{DR}} ESDG_{i,b,k} + \sum_{k \in K_{i,b}^{DF}} ESDG_{i,b,k} + \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k} \leq MaxDR_{i,b} + MaxDF_{i,b}$$

4.4.28 For a *pseudo-unit* that cannot provide *ten-minute operating reserve* in from its duct firing region, the following constraint shall apply:

$$\sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k} + \sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k} + \sum_{k\in K_{i,b}^{10N}} ES10NDG_{i,b,k} \leq MINQDG_b + QDR_{i,k}$$

4.5 Outputs

4.5.1 The RT LOC EOP s used for *settlement* for *energy* and *operating reserve* for all *resources* except *pseudo-units* for each hour of the *dispatch day* shall be the sum of each RT LOC EOP variable determined by the objective function in section 4.3 for that *resource*, subject to constraints in section 4.4 applicable for that *resource* determined as follows:

$$DGEnergyEOP_{i,b}^{LOC} = \sum_{k\in K_{i,b}^{E}} ESDG_{i,b,k}$$

$$DG10SEOP_{i,b}^{LOC} = \sum_{k\in K_{i,b}^{10S}} ES10SDG_{i,b,k}$$

$$DG10NEOP_{i,b}^{LOC} = \sum_{k\in K_{i,b}^{10N}} ES10NDG_{i,b,k}$$

$$DG30REOP_{i,b}^{LOC} = \sum_{k\in K_{i,b}^{30R}} ES30RDG_{i,b,k}$$

$$DLEnergyEOP_{i,b}^{LOC} = \sum_{j\in J_{i,b}^{E}} ESDL_{i,b,j}$$

$$DL10SEOP_{i,b}^{LOC} = \sum_{j\in J_{i,b}^{10S}} ES10SDL_{i,b,j}$$

$$DL10NEOP_{i,b}^{LOC} = \sum_{j\in J_{i,b}^{10N}} ES10NDL_{i,b,j}$$

$$DL30REOP_{i,b}^{LOC} = \sum_{j\in J_{i,b}^{30R}} ES30RDL_{i,b,j}$$

$$DIEnergyEOP_{i,b}^{LOC} = \sum_{k\in K_{i,b}^{E}} ESDI_{i,b,k}$$

$$DI10NEOP_{i,b}^{LOC} = \sum_{k \in K_{i,b}^{10N}} ES10NDI_{i,b,k}$$

$$DI30REOP_{i,b}^{LOC} = \sum_{k \in K_{i,b}^{30R}} ES30RDI_{i,b,k}$$

$$DXEnergyEOP_{i,b}^{LOC} = \sum_{j \in J_{i,b}^{E}} ESDX_{i,b,j}$$

$$DX10NEOP_{i,b}^{LOC} = \sum_{j \in J_{i,b}^{10N}} ES10NDX_{i,b,j}$$

$$DX30REOP_{i,b}^{LOC} = \sum_{j \in J_{i,b}^{30R}} ES30RDX_{i,b,j}$$

4.5.2 The RT LOC EOPs for *energy* and *operating reserve* for a *pseudo-unit* for each interval of the *dispatch hour,* which will be used for converting the RT LOC EOPs to physical *resource* equivalents in accordance with sections 4.5.3 to 4.5.4, shall be determined as follows:

$$PSUMLPEnergyEOP_{i,k}^{LOC} = \sum_{k \in K_{i,b}^{MLP}} ESDG_{i,b,k}$$

$$PSUDREnergyEOP_{i,k}^{LOC} = \sum_{k \in K_{i,b}^{DR}} ESDG_{i,b,k}$$

$$PSUDFEnergyEOP_{i,k}^{LOC} = \sum_{k \in K_{i,b}^{DF}} ESDG_{i,b,k}$$

$$PSU10SEOP_{i,k}^{LOC} = \sum_{k \in K_{i,b}^{10S}} ES10SDG_{i,b,k}$$

$$PSU10NEOP_{i,k}^{LOC} = \sum_{k \in K_{i,b}^{10N}} ES10NDG_{i,b,k}$$

$$PSU30REOP_{i,k}^{LOC} = \sum_{k \in K_{i,b}^{30R}} ES30RDG_{i,b,k}$$

Conversion of RT LOC EOPs for Pseudo-Units to Physical Resource Equivalents

4.5.3 The RT LOC EOP *energy* and *operating reserve* for a combustion turbine and steam turbine that is associated with *pseudo-unit* $k \in \{1, \dots, K\}$ in interval i shall be determined as follows:

$$CTEnergyEOP_{i,k} = PSUMLPEnergyEOP_{i,k}^{LOC} \cdot CTShareMLP_k + PSUDREnergyEOP_{i,k}^{LOC} \cdot CTShareDR_k$$

$$STEnergyEOP_{i,k} = PSUMLPEnergyEOP_{i,k}^{LOC} \cdot STShareMLP_k + PSUDREnergyEOP_{i,k}^{LOC} \cdot STShareDR_k + PSUDFEnergyEOP_{i,k}^{LOC}$$

4.5.4 The RT LOC EOPs used for *settlement* for *operating reserve* for a combustion turbine and a steam turbine that is associated with *pseudo-unit* $k \in \{1, \dots, K\}$ in interval i shall be determined as follows and in the following order for each class of *operating reserve*:

$$RoomDR_{i,k} = QDR_{i,k} - PSUDREnergyEOP_{i,k}^{LOC}$$

$$10SDR_{i,k} = \min\left(RoomDR_{i,k}, PSU10SEOP_{i,k}^{LOC}\right)$$

$$10NDR_{i,k} = \min\left(RoomDR_{i,k} - 10SDR_{i,k}, PSU10NEOP_{i,k}^{LOC}\right)$$

$$30RDR_{i,k} = \min\left(RoomDR_{i,k} - 10SDR_{i,k} - 10NDR_{i,k}, PSU30REOP_{i,k}^{LOC}\right)$$

$$CT10SEOP_{i,k} = 10SDR_{i,k} \cdot CTShareDR_k$$
$$ST10SEOP_{i,k} = 10SDR_{i,k} \cdot STShareDR_k + (PSU10NEOP_{i,k}^{LOC} - 10SDR_{i,k})$$

$$CT10NEOP_{i,k} = 10NDR_k \cdot CTShareDR_{i,k}$$
$$ST10NEOP_{i,k} = 10NDR_{i,k} \cdot STShareDR_k + (PSU10NEOP_{i,k}^{LOC} - 10NDR_{i,k})$$

$$CT30REOP_{i,k} = 30RDR_k \cdot CTShareDR_{i,k}$$
$$ST30REOP_{i,k} = 30RDR_{i,k} \cdot STShareDR_k + (PSU30REOP_{i,k}^{LOC} - 30RDR_{i,k})$$

RUL-19

Renewed Market Rules

Chapter 0.8

Physical Bilateral Contracts and Financial Markets

Connecting Today.
Powering Tomorrow.

0.8

Renewed Market Rules – Chapter 0.8: Physical Bilateral Contracts and Financial Markets

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Table of Contents

Introduction

A.1 Chapter Scope and Operation

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

1. Introductory Rules

1.1 Purpose and Application

1.1.1 This Chapter sets forth the rules governing:

1.1.1.1 the submission of physical bilateral contract data by market participants and the use of such physical bilateral contract data by the IESO; and

1.1.1.2 the sale and administration of *transmission rights* by the *IESO*.

1.1.2 The rules in this Chapter apply to:

1.1.2.1 the *IESO*; and

1.1.2.2 any market participant submitting physical bilateral contract data to the IESO, or holding or buying transmission rights.

2. Physical Bilateral Contract Data and Quantities

2.0 Market Transition

2.0.1 Following a *market transition* this section 2 and the relevant provisions of MR Ch.9 applicable to *physical bilateral contract*s shall not apply to the extent that they apply to *physical bilateral contracts* and the *IESO* shall not administer and settle *physical bilateral contract*s. Such inapplicability shall continue until such time as the *IESO* resolves the relevant software inadequacies and *publishes* notice that such software inadequacies are resolved and the *IESO* is capable of administering and settling *physical bilateral contract*s.

2.1 Overview

2.1.1 Any *market participant* (or any other person) may, subject to *applicable laws*, enter into, administer and settle *physical bilateral contract*s with another *market participant* (or any other person). Provided that such *physical bilateral contract*s are matters strictly between the parties and are not in any way to affect the operation of the *physical markets*, such *physical bilateral contract*s:

2.1.1.1 may but need not be reported to the *IESO* for operational, *settlement* or any other purposes; and

2.1.1.2 are not subject in any way to these *market rules*.

2.1.2 The *IESO* shall offer a service whereby the *selling market participant* in a *physical bilateral contract* or the *selling market participant* under a financial bilateral contract may assume responsibility for components of the *buying market participant's settlement* obligations other than those for *energy*.

2.1.3 Any *selling market participant* selling under a *physical bilateral contract* to a *buying market participant* may submit *physical bilateral contract data* to the *IESO* in respect of the *day-ahead market* and/or the *real-time market*, complying with the requirements of this section 2, and the *IESO* shall:

2.1.3.1 use such *physical bilateral contract data* and, if necessary, operational data to determine the *physical bilateral contract quantities* of *energy* sold by the *selling market participant* to the *buying market participant* in each *settlement hour* at the location designated in the *physical bilateral contract data* in respect of the *day-ahead market* or the *real-time market*, as the case may be;

2.1.3.2 determine for the *physical bilateral contract* data submitted in respect of the *real-time market*, in respect of each of the *selling market participant* and the *buying market participant*, the value of the *physical bilateral contract quantity* referred to in section 2.1.3.1 for each applicable *metering interval* or *settlement hour*, as the case may be, of the relevant *trading day* based:

a. in the case of each *buying market participant* and the *selling market participant*, on the *day-ahead market* Ontario zonal price for *energy*, when the location specified pursuant to section 2.2.1 relates to a *non-dispatchable load*;

b. in the case of each of the *buying market participant* and the *selling market participant*, on the applicable *locational marginal price* of *energy* in the *real-time market*, when the location specified pursuant to section 2.2.1 relates to a *generation resource, electricity storage resource ,* or a *dispatchable load*; or

c. in the case of each of the *buying market participant* and the *selling market participan*t, on the applicable *locational marginal price* in the *real-time marke*t, when the location specified pursuant to section 2.2.1 is an *intertie metering point*;

and apply such value in determining the *selling market participant's* and the *buying market participant's* respective net energy market settlement amount in the real-time market for the applicable *metering interval* or *settlement hour*, as the case may be, pursuant to MR Ch.9 ss.3.1 and 3.2; and

2.1.3.3 determine for physical *bilateral contract data* submitted in respect of the *day-ahead market*, in respect of each of the *selling market participant* and the *buying market participant*, the value of the *physical bilateral contract quantity* referred to in section 2.1.3.1 for each applicable *metering interval* or *settlement hour*, as the case may be, of the relevant *trading day* based:

a. in the case of each of the *buying market participant* and the *selling market participant,* on the applicable *locational marginal price* of *energy* in the *day-ahead market,* when the location specified pursuant to section 2.2.1 relates to a *generation resource, electricity storage resource,* or a *dispatchable load;* or

b. in the case of each of the *buying market participant* and the *selling market participant*, on the applicable *locational marginal price* in the *day-ahead market*, when the location specified pursuant to section 2.2.1 is an *intertie metering point*;

and apply such value in determining the *selling market participant's* and the *buying market participant's* respective net *energy* market *settlement* amount in the *day-ahead market* for the applicable *metering interval* or *settlement hour*, as the case may be, pursuant to MR Ch.9 ss.3.1 and 3.2.

2.1.3.4 in the *settlement process* for each *settlement hour*, allocate the components of *hourly uplift* assessed on the *physical bilateral contract quantity* between the *buying market participant* and the *selling market participant* as specified in the *physical bilateral contract data*.

2.1.4 The *IESO* shall not, in any of its system operation, *physical market* operation or *settlement processes*, accept, acknowledge, record or use any *physical bilateral contract data* with respect to any contracts to which it is not itself a party, except as specified in this section 2.

2.2 The Content of Physical Bilateral Contract Data

2.2.1 Any *selling market participant* may submit to the *IESO physical bilateral contract data* defining *physical bilateral contract quantities* of *energy* that it is selling to a specified *buying market participant* in respect of the *day-ahead market* and/or the *real-time market* in specified *settlement hours* and at any location, so long as it:

2.2.1.1 is either a specified *delivery point* associated with a *registered wholesale meter* or a specified *intertie metering point*; and

2.2.1.2 in the context of *physical bilateral contract data* submitted in respect to the *day-ahead market*, does not relate to a *non-dispatchable load*.

2.2.2 A *selling market participant* may specify in its *physical bilateral contract data* that it will be responsible for some or all of the components of *hourly uplift,* as further described in the applicable *market manual,* that the *buying market participant* would otherwise pay on the *physical bilateral contract quantities.*

2.3 The Form of Physical Bilateral Contract Data

2.3.1 Subject to section 2.3.2, a *selling market participant* shall submit *physical bilateral contract data* in a form that has been approved by the *IESO*. Such *IESO*-approved forms shall include, but are not limited to, data files containing either of the following:

2.3.1.1 indication that the quantity of *energy* that the *selling market participant* is selling to a designated *buying market participant* in each *settlement hour*, is 100% of the applicable *market participant's metering data* at the location designated in the *physical bilateral contract data* pursuant to section 2.2.1, provided that:

a. such location is a specified *delivery point* associated with a *registered wholesale meter*; and

b. either the *selling market participant* or the *buying market participant* is the *metered market participant* in respect of the *registered wholesale meter(s)* associated with such location; or

2.3.1.2 the quantity of *energy*, in MWh and up to 1 decimal place, that the *selling market participant* is selling to the *buying market participant* in each *settlement hour* at the location designated in the *physical bilateral contract data* pursuant to section 2.2.1.

2.3.2 A *selling market participant* submitting *physical bilateral contract data* in respect of the *real-time market* shall submit *physical bilateral contract data* in only one of the two formats described in section 2.3.1.1 or section 2.3.1.2 pertaining to a particular location and a particular *buying market participant* for any *settlement hour* or combination of *settlement hours* within a single *trading day*. A *selling market participant* submitting *physical bilateral contract data* in respect of the *day-ahead market* shall submit *physical bilateral contract data* in only the format described in section 2.3.1.2 pertaining to a particular location and a particular *buying market participant* for any *settlement hour* or combination of *settlement hours* within a single *trading day.*

2.3.3 A *selling market participant* shall only submit a single set of *physical bilateral contract data* pertaining to a particular location and a particular *buying market participant,* for any given *settlement hour* within a single *trading day* in respect of the *real-time market* and/or the *day-ahead market* such that the most recent set of *physical bilateral contract data* submitted is the prevailing set used by the *IESO* in the *settlement process*.

2.4 Submitting and Revising Physical Bilateral Contract Data

2.4.1 A *selling market participant* submitting initial or revised *physical bilateral contract data* relating to a specified *trading day* for *settlement* purposes must do so:

2.4.1.1 no earlier than seven days prior to that *trading day* and no later than six *business days* after that *trading day*; and

2.4.1.2 using the same *electronic information system* used for the submission of *dispatch data* as described in MR Ch.7 s.3.2.1 or, if the *electronic information system* is not available, by such other means as may be specified by the *IESO* pursuant to MR Ch.7 s.3.2.2.3.

2.4.2 A *selling market participant* submitting *physical bilateral contract data* that will not change from *trading week* to *trading week*, may, in the same form but in place of its *physical bilateral contract data* described in section 2.3, submit standing *physical bilateral contract data* that conforms to the same data submission requirements specified in section 2.4.1.2. Such standing *physical bilateral contract data* shall:

2.4.2.1 define the physical bilateral contract data for each *settlement hour* of each *trading day* and specify whether it is in respect of the *real-time market* and/or the *day-ahead market*;

2.4.2.2 come into effect at the beginning of the second *trading day* after such *physical bilateral contract data* is submitted to the *IESO* by the *selling market participant*;

2.4.2.3 remain in effect until the expiration date specified in the standing *physical bilateral contract data* unless earlier withdrawn or earlier revised by the *selling market participant*; and

2.4.2.4 for the purposes of *settlement*, shall constitute the only *physical bilateral contract data* between the *selling market participant* and the *buying market participant* specific to the *real-time market* and/or the *day-ahead market* at the particular location specified so long as such standing *physical bilateral contract data* is in effect or until such standing *physical bilateral contract data* is superseded pursuant to section 2.4.3.

2.4.3 Where a *selling market participant* submits *physical bilateral contract data* pursuant to section 2.4.2 or section 2.4.1 pertaining to the same *buying market participant* at the same location and for the same *physical market* for *energy* specified in *physical bilateral contract data* previously submitted pursuant to section 2.4.2 or section 2.4.1, such *physical bilateral contract data* shall supersede any previously submitted *physical bilateral contract data* pertaining to the same *buying market participant* at the same location.

2.4.4 If the *IESO* issues a *notice of intent to suspend* or a *suspension order* to a *selling market participant*, MR Ch.3 s.6.3.4 shall apply and the *IESO* shall notify any *buying market participant* who is counterparty to any of *selling market participant's physical bilateral contracts* registered with the *IESO* of the *IESO's* actions.

2.4.5 If the *IESO* issues a *notice of intent to suspend* or a *suspension order* to a *buying market participant*, MR Ch.3 s.6.3.4 shall apply and the *IESO* shall notify any *selling market participant* who is a counterparty to any of the *buying market participant's physical bilateral contracts* registered with the *IESO* of the *IESO's* actions.

3. The Transmission Rights Market

3.1 Purpose, Interpretation, and Transition

3.1.1 This section 3 sets forth:

3.1.1.1 the manner in which the *IESO* shall operate the *TR market* established for the purchase of *transmission rights* associated solely with transactions between the *IESO control area* and an adjoining *TR zone*;

3.1.1.2 the procedures pursuant to which persons may apply to the *IESO* for authorization to participate in the *TR market*;

3.1.1.3 the terms and conditions under which *transmission rights* may be assigned by *TR holders*;

3.1.1.4 the manner in which the *IESO* will conduct *TR auctions* for the purchase of *transmission rights* associated with injections and withdrawals between specified *TR zones*; and

3.1.1.5 the manner in which the *IESO* will determine *TR market clearing prices*.

3.1.2 A reference in this section 3 and in Appendix 8.1 to a *transmission right* shall, in the case of *long-term transmission rights* assigned by a *TR holder*, be deemed to include a reference to the right to the *settlement amounts* relating to one or more periods of one month under that *long-term transmission right*.

3.1.3 [Intentionally left blank – section deleted]

3.1.4 [Intentionally left blank – section deleted]

3.1.5 [Intentionally left blank – section deleted]

3.1.6 The *IESO* may, for reasons of a failure in *TR participant* or *IESO* software, hardware or communication systems associated with a *TR auction*:

3.1.6.1 conduct a *TR auction* using contingency procedures, including but not limited to the contingency procedures defined in the applicable *market manual*;

3.1.6.2 conduct a *TR auction* and related activities along timelines other than those specified within this section 3; or

3.1.6.3 in the event that the *IESO* cannot conduct an effective *TR auction* in a commercially reasonable manner using contingency procedures and/or modified timelines, cancel all or part of a *TR auction*.

3.1.7 The *IESO* shall, as soon as practicable and prior to taking any action pursuant to section 3.1.6, notify all *TR participants* of any *TR auction* cancellation, and/or any contingency procedures, revised timelines and revised activity schedules which the *IESO* intend to implement.

3.1.8 *TR participants* shall comply with any applicable contingency procedures, revised activity schedules or revised timelines specified by the *IESO* under sections 3.1.6 and 3.1.7.

3.2 Denomination and Validity of Transmission Rights and TR Zones

3.2.1 Each *transmission right* shall be associated with a specified injection *TR zone* and a specified withdrawal *TR zone,* one of which shall be the *IESO control area* and the other of which shall be a *TR zone* other than the *IESO control area.*

3.2.2 Each *transmission right* shall be denominated in terms of 1 MW.

3.2.3 The period of validity of a *transmission right* shall be measured from the first hour in respect of which a *settlement amount* is to be paid to the *TR holder* under that *transmission right* to the last hour in respect of which a *settlement amount* is to be paid to the *TR holder* under that *transmission right.*

3.3 TR Holders

3.3.1 Subject to section 3.9.1, the *TR participant* that has purchased a *transmission right* in a *TR auction* shall be recognized by the *IESO* as the *TR holder* in respect of that *transmission right* as of the date on which the *IESO* receives payment for that *transmission right* from that *TR participant*.

3.4 Payments to TR Holders Under Transmission Rights

3.4.1 Subject to section 3.4.2, the amount owing by the *IESO* in respect of a *transmission right* that is valid for a given *settlement hour* shall be calculated for each applicable *TR holder* in accordance with MR Ch.9 s.3.8.1.

3.4.2 Notwithstanding MR Ch.9 s.3.8.1, where the *transmission transfer capability* between a withdrawal *TR zone* and an injection *TR zone,* determined for the *day-ahead market,* has been reduced to zero by reason of the *outage* of the relevant *interconnection*, the amount owing by the *IESO* in respect of a *transmission right* associated with such *TR zones* that is valid for a *settlement hour* during which such *transmission transfer capability* has been reduced to zero shall be zero.

3.4.3 Notwithstanding MR Ch.9 s.3.8.1, where the *IESO* suspends the *day-ahead market* pursuant to MR Ch.7 s.13, the amount owing by the *IESO* in respect of a *transmission right* that is valid for a *settlement hour* during the time when the *day-ahead market* is suspended shall be zero.

3.5 Awarding of Transmission Rights

3.5.1 The total of all *transmission rights* awarded in a given round of a *TR auction* shall not exceed the fixed amount of *transmission rights* available for such round of a *TR auction* that is determined in accordance with section 3.6, 3.7 and 3.11.10, if applicable. The *IESO* shall determine the number of *transmission rights* awarded to each *TR bidder* in a given round of a *TR auction* using the objective function and other processes described in Appendix 8.1. Such number shall be between zero and the number of *transmission rights* that the *TR bidder* bid to purchase in that round.

3.5.2 The objective function described in Appendix 8.1 shall have as its mathematical objective the maximization of the benefit, measured in dollars, of the aggregate willingness of *TR bidders* to pay for *transmission rights* that they have been awarded in a given round of a *TR auction.* Such maximization of benefit will be net of any unawarded *transmission rights* as described in Appendix 8.1, if applicable.

3.6 Simultaneous Feasibility

3.6.1 The *IESO* shall conduct a simultaneous feasibility test, as further described in the applicable *market manual,* during each *TR auction* to ensure that the *day-ahead market external congestion rent* collected by the *IESO* in respect of all *intertie metering points* and all applicable *settlement hours* shall, under most circumstances, be sufficient to cover any payment obligations owing by the *IESO* to *TR holders* under section 3.4.1 in respect of all *transmission rights* outstanding and all *transmission rights* to be offered during the *TR auction*.

3.6.2 For the purposes of the simultaneous feasibility test referred to in section 3.6.1, the *IESO* shall assume that each *transmission right* represents:

3.6.2.1 one MW of power injected at the injection *TR zone* associated with each *transmission right*; and

3.6.2.2 one MW of power withdrawn at the withdrawal *TR zone* associated with each *transmission right*.

3.6.3 The *IESO* shall, in conducting each simultaneous feasibility test referred to in section 3.6.1, use a forecast of available *transmission transfer capability* determined on the basis of the operating assumptions described in section 3.7.3.

3.6.4 A set of *transmission rights* shall pass the simultaneous feasibility test referred to in section 3.6.1 if all injections and withdrawals associated with such set of *transmission rights*, and every combination of subsets of such injections and withdrawals, could, if they represented power actually injected or withdrawn as described in section 3.6.2, be accommodated without causing the amount of power that passes over an *interconnection* between the *IESO control area* and an adjoining *TR zone* to exceed any limit applying to that *interconnection*.

3.7 Determination of Transmission Transfer Capabilities

3.7.1 The *IESO Board* shall establish a confidence level reflecting the degree to which the *day-ahead market external congestion rent* collected by the *IESO* in a given period described in section 3.18.1.1 will be sufficient to cover the *IESO's* payment obligations to *TR holders* under section 3.4.1 for that period.

3.7.2 The *IESO* shall, in accordance with section 3.7.3, establish operating assumptions for the purposes of forecasting the *transmission transfer capability* to be used during each *TR auction.* Such *transmission transfer capability* forecasts shall be used to limit the number of *transmission rights* awarded in each auction for the purpose of achieving the confidence level established under section 3.7.1.

3.7.3 The *IESO* shall establish the operating assumptions referred to in section 3.7.2 in accordance with the following:

3.7.3.1 transmission line ratings shall be calculated on a seasonal basis based on *good utility practice*, shall be the same ratings as those used by the *IESO* in its real-time operations and may differ when the *IESO-controlled grid* is undergoing a *contingency event* relative to the ratings that would apply when the *IESO-controlled grid* is in a *normal operating state*;

3.7.3.2 the *facilities*, *interties* and conditions that are monitored by the *IESO* for *security* reasons in its real-time operations shall be emulated;

3.7.3.3 transmission lines, *facilities* and *interties* within the *IESO control area* shall be assumed to be in service except where a prolonged *planned outage* of a transmission line or *facility* is scheduled for the time during which *transmission rights* that are to be sold at the *TR auction* will be valid or where the *IESO* believes that a prolonged *forced outage* of a transmission line or *facility* is likely to occur for the time during which *transmission rights* that are to be sold at the *TR auction* will be valid;

3.7.3.4 phase angle regulators within the *IESO control area* and on *interconnections* between the *IESO control area* and adjoining *control areas* shall be assumed to be operating in a manner consistent with normal operations, having regard to the joint control of such *interconnections*, during the *TR auction*;

3.7.3.5 the transmission limits of the *IESO-controlled grid* shall be adjusted to reflect an estimate of the transmission reliability margin observed by the *IESO* in its real-time operations;

3.7.3.6 the ability of *control area operators* in *control areas* that are not included in the contract path of an *energy* transaction to curtail that transaction in accordance with applicable *reliability standards* shall be taken into account when estimating the amount of power that can be *reliably* transferred between the *IESO control area* and each adjoining *control area*;

3.7.3.7 parallel flows that result from events outside the *IESO control area* shall be taken into account when estimating the amount of power that can be *reliably* transferred between the *IESO control area* and each adjoining *control area;*

3.7.3.8 estimates of *transmission transfer capability* may be conservative but shall not be reduced below a level sufficient to define all *transmission rights* that have been awarded in previous *TR auctions* and that remain valid as at the date of the *TR auction*; and

3.7.3.9 the operating assumptions shall otherwise be permitted to vary depending on the length of time between the date of a given *TR auction* and the period of validity of the *transmission rights* to be offered in that *TR auction.*

3.8 Participation in TR Markets and Rules Applicable to TR Participants

3.8.1 No person may participate in the *TR market* nor be a *TR holder* unless that person has been authorized by the *IESO* as a *TR participant* in accordance with MR Ch.2 s.3 and this section 3.8.

3.8.2 No *TR participant* may be a *TR bidder* in a round of a *TR auction* unless the *TR participant* has, no less than five *business days* prior to the date on which the round of the *TR auction* is to be conducted*,* provided to the *IESO* a *TR market deposit*, in one or both of the forms set forth in section 34.8.3, for the purpose of establishing that person's *bidding limit* in accordance with sections 3.14.1 or 3.20.4.2.

3.8.3 A *TR market deposit* shall be in one or both of the following forms:

3.8.3.1 an irrevocable commercial letter of credit provided by a bank named in a Schedule to the *Bank Act*, (Canada) S.C. 1991, c. 46; or

3.8.3.2 a cash deposit made with the *IESO* by or on behalf of the *TR participant.*

3.8.4 Where all or part of a *TR market deposit* is in the form of a standby letter of credit, the following provisions shall apply:

3.8.4.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 2007 Revision, ICC Publication No. 600 or The International Standby Practices 1998;

3.8.4.2 the *IESO* shall be named as beneficiary in the letter of credit, the letter of credit shall be irrevocable and partial draws on the letter of credit shall not be prohibited;

3.8.4.3 the only condition on the ability of the *IESO* to draw on the letter of credit shall be the delivery of a certificate of an officer of the *IESO* that a specified amount is owing by the *TR bidder* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate;

3.8.4.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *TR bidder* shall arrange for and deliver additional *TR market deposits* if the *TR bidder* intends to continue to participate in the *TR market*. If such additional *TR market deposits* are not received by the *IESO* ten (10) *business days* before the expiry of a letter of credit, the *IESO* shall be entitled as of that time to payment of the full face amount of the letter of credit which amount, once drawn by the *IESO*, shall be treated as a *TR market deposit* in the form of cash; and

3.8.4.5 by including a letter of credit as part of a *TR market deposit*, the *TR bidder* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *TR bidder*.

3.8.5 Notwithstanding any other provision of these *market rules*, a person that applies for authorization to participate in the *TR market* and that has not applied for authorization to participate, or is not participating in, any other *IESO-administered* *market* shall not be required to comply with any requirements for authorization other than those set forth in sections 3.8.1 to 3.8.4.

3.8.6 The following provisions of these *market rules* shall not apply to a person that is authorized by the *IESO* to participate only in the *TR market*:

3.8.6.1 MR Ch.4, Ch.5, Ch.6 and Ch.7;

3.8.6.2 MR Ch.8 other than this section 3; and

3.8.6.3 MR Ch.10.

3.9 Assignment of Transmission Rights

3.9.1 A *TR holder* may assign to another *TR participant* its right to the *settlement amounts* under a *transmission right,* provided that such assignment shall only be recognized by the *IESO,* for *settlement* purposes, in accordance with section 3.9.5.

3.9.2 A *TR holder* that wishes the *IESO* to recognize, for *settlement* purposes, an assignment of its right to the *settlement amounts* under a *transmission right* shall apply to the *IESO* for recognition of the assignment in such form as shall be established by the *IESO*. The *IESO* shall verify whether the assignee is a *TR participant* and shall advise the assigning *TR holder* within two *business days* of the date of receipt of the application as to the results of such verification.

3.9.3 The *IESO* shall for *settlement purposes* recognize, in accordance with section 3.9.5, an assignment of the right to the *settlement amounts* under a *transmission right* unless the assignee is not a *TR participant.*

3.9.4 Where the *IESO* determines in accordance with section 3.9.3 that it shall not recognize, for *settlement* purposes, an assignment of the right to the *settlement* amounts under a *transmission right,* the *IESO* shall advise the assigning *TR holder* of the reasons for such determination.

3.9.5 Where the *IESO* recognizes, for *settlement* purposes, an assignment of the right to all *settlement amounts* under a *transmission right* in accordance with section 3.9.3, the assignee shall be deemed to be the *TR holder* in respect of the *settlement amounts* under that *transmission right* with effect from the *billing period* immediately following the date on which the *IESO* advises the assigning *TR holder* of the results of the *IESO's* verification pursuant to section 3.9.2 until such time as:

3.9.5.1 [Intentionally left blank – section deleted]

3.9.5.2 the right to the *settlement amounts* under the *transmission right* has been assigned to another *TR participant* and the *IESO* has recognized such assignment for *settlement* purposes in accordance with sections 3.9.2, and 3.9.3 and 3.9.5.

3.10 Short-Term Auctions

3.10.1 The *IESO* shall conduct a *short-term auction* between the 1st and 15th day of each month in which *transmission rights* valid for the following month shall be available.

3.10.2 Each *short-term auction* shall consist of only one round and shall offer *short-term transmission rights* valid for the immediately following month.

3.11 Long-Term Auctions

3.11.1 The *IESO* shall conduct a *long-term auction* at least thirty days but not more than ninety days prior to the beginning of each quarter.

3.11.2 Each *long-term auction* conducted by the *IESO;*

3.11.2.1 shall offer *transmission rights* that are valid for a period of one year, commencing on the first day of the quarter immediately succeeding the quarter in which the *long-term auction* occurs; and

3.11.2.2 Any residual *transmission rights* from a *long-term auction* shall, subject to section 3.7, be offered as *short-term transmission rights* in the manner described in section 3.10.

3.11.3 [Intentionally left blank – section deleted]

3.11.4 [Intentionally left blank – section deleted]

3.11.5 Each *long-term auction* referred to in section 3.11.2 shall consist of multiple rounds. In each case:

3.11.5.1 the number of rounds shall be determined by the *IESO* on the basis of the *IESO's* assessment of the appropriate balance between providing *TR participants* with opportunities for price discovery and the administrative burden on the *IESO* and *TR participants* of conducting varying numbers of rounds;

3.11.5.2 each round shall be conducted independently of all others;

3.11.5.3 *TR market clearing prices* shall be determined for each round; and

3.11.5.4 *transmission rights* shall be awarded in each round on the basis of the *TR market clearing prices* determined for that round.

3.11.6 For each *long-term auction* that is conducted in multiple rounds in accordance with section 3.11.5, the *transmission transfer capability* that is used to define the *transmission rights* shall be allocated within each of the rounds as follows:

3.11.6.1 the portion of *transmission transfer capability* allocated to each round shall increase with each successive round; and

3.11.6.2 the portion of *transmission transfer capability* allocated to the final round shall be at least three times the portion of *transmission transfer capability* allocated to the first round.

3.12 Pre-auction Publication

3.12.1 The *IESO* shall *publish*, at least thirty days prior to each *TR auction*:

3.12.1.1 the $DAM\_PEC_h^i$, as defined in MR Ch.9 App.9.2, and the *day-ahead market locational marginal price* of *energy* for each *TR zone* for each *settlement hour* of the preceding twelve months or, in the case of a *TR auction* conducted less than twelve months following the *market transition completion date,* since the *market transition completion date*;

3.12.1.2 the *TR market clearing price* for each *transmission right* sold during any *TR auctions* conducted in the preceding eighteen months or, in the case of a *TR auction* conducted less than eighteen months following the *market transition completion date*, since the *market transition completion date*;

3.12.1.3 *energy* scheduled for injection or withdrawal in the *day-ahead market* over each *interconnection* for each *settlement hour* during the preceding twelve months or, in the case of a *TR auction* conducted less than twelve months following the *market transition completion date,* since the *market transition completion date*;

3.12.1.4 the hourly *transmission transfer capability* used in the *DAM calculation engine* of each *interconnection* during the preceding twelve months or, in the case of a *TR auction* conducted less than twelve months following the *market transition completion date*, since the *market transition completion date*; and

3.12.1.5 identification of any *transmission transfer capability* limits, parallel flow assumptions and other applicable constraints that may limit the number of *transmission rights* that can be awarded in the *TR auction*, and the operating assumptions established in respect of the *TR auction* pursuant to section 3.7.2.

3.13 TR Bids and TR Laminations

3.13.1 A *TR participant* may submit no more than one *TR bid* with respect to a given injection *TR zone* and withdrawal *TR zone* for each round of any *TR auction.* A *TR bid* shall conform to the following requirements:

3.13.1.1 The *TR bid* shall indicate the name of the TR bidder, the injectionTR zone and the withdrawal TR zone for each transmission right that the TR bidder is bidding to purchase, and the round of the TR auction to which the TR bid relates;

3.13.1.2 Each *TR bid* must contain at least 1 and may contain up to 20 *TR laminations* for an injection *TR zone* and withdrawal *TR zone*;

3.13.1.3 the price in each *TR lamination* shall be a positive amount, be expressed in dollars and whole cents per MW, and represent the maximum price that the *TR bidder* is bidding to purchase the quantity of *transmission rights* identified in the *TR lamination*;

3.13.1.4 the quantity in each *TR lamination* shall be a positive amount, not exceed the total amount of *transmission rights* available in the relevant round of the *TR auction,* be expressed in whole numbers, and represent the maximum quantity of *transmission rights* that the *TR bidder* is bidding to purchase at the price identified in the *TR lamination*; and

3.13.1.5 if a *TR bid* is composed of multiple *TR laminations*, such *TR laminations* shall be in monotonically increasing quantities with decreasing prices.

3.13.2 [Intentionally left blank – section deleted]

3.13.3 [Intentionally left blank – section deleted]

3.13.4 [Intentionally left blank – section deleted]

3.13.5 *TR bids* shall be submitted to the *IESO* no earlier than 09:00 EST on the date that is two *business days* prior to the date on which a round of a *TR auction* is to be conducted and no later than 17:00 EST on the day before the date on which the round of the *TR auction* is to be conducted.

3.13.6 [Intentionally left blank – section deleted].

3.13.7 *TR bids* shall be submitted to the *IESO* using the *electronic information system* and the communication protocol described in the applicable *market manual*.

3.13.8 The *IESO* shall:

3.13.8.1 stamp each *TR bid* with the time that it was received by the *IESO*;

3.13.8.2 confirm receipt of each *TR bid* within the time specified in the applicable *market manual* using the communication protocol referred to in section 3.13.7; and

3.13.8.3 *publish* and notify *TR participants* of alternative means of submitting and confirming receipt of *TR bids* when the communication protocol referred to in section 3.13.7 is unavailable.

3.13.9 The *IESO* shall reject any *TR bid* that does not comply with the rules set forth in this section 3.13 and shall provide the reasons for such rejection to the *TR participant* submitting the *TR bid*.

3.13.10 A *TR participant* that does not receive from the *IESO* confirmation of receipt of a *TR bid* in accordance with section 3.13.8.2 shall immediately contact the *IESO* by telephone or other means specified in the applicable *market manual* seeking confirmation of receipt.

3.13.11 A *TR participant* shall, if requested by the *IESO*, resubmit a *TR bid* by such means as may be specified by the *IESO* in the request.

3.14 Bidding Limits

3.14.1 Subject to section 3.20.4.2, the *IESO* shall establish, for each *TR participant* that intends to be a *TR bidder* in a *TR auction*, a *bidding limit* equal to ten times the amount or value of the *TR market deposit* provided to the *IESO* by that *TR participant* pursuant to section 3.8.2.

3.14.2 The *IESO* shall refuse to accept a *TR bid* from a *TR bidder* where the price multiplied by the quantity of any *TR lamination* within the *TR bid* equals a value which exceeds the *TR bidder's* remaining *bidding limit* after accounting for all other accepted *TR bids* from such *TR bidder* in the relevant *TR auction*.

3.14.3 Where a *TR bidder* has been awarded a *transmission right* in a *TR auction* and the *TR market deposit* provided by the *TR bidder* pursuant to section 3.14.1 consists in whole or in part of a cash deposit, the *IESO* shall apply the cash deposit to offset any amounts owing to the *IESO* by that *TR bidder* under section 3.17.1 for the purchase of the *transmission right.*

3.14.4 Where the amount of a cash deposit provided by a *TR participant* as a *TR market deposit* pursuant to section 3.14.1 exceeds the amount owing to the *IESO* by that *TR participant* under section 3.17.1 for the purchase of *transmission rights* in respect of a given *TR auction*, the *IESO* shall, if so requested by the *TR participant* at the time at which the cash deposit was so provided, include such excess as a credit on the *invoice* submitted to the *TR participant* for that *TR auction*. Where the *TR participant* has not so requested that such a credit be effected, the excess shall be held by the *IESO* and shall form part of that *TR participant's TR market deposit* for purposes of a subsequent *TR auction* in which the *TR participant* wishes to participate.

3.14.5 Where a *TR participant* has provided to the *IESO* a *TR market deposit,* in a form other than a cash deposit, pursuant to section 3.14.1 in respect of a given *TR auction*, the *IESO* shall, upon receipt of payment in full by the *TR participant* of the net amount of any *invoice* submitted to the *TR participant* for that *TR auction* and subject to the terms of the *TR market deposit*:

3.14.5.1 if so requested by the *TR participant* at the time at which the *TR market deposit* was so provided, return the *TR market deposit* to the *TR participant*; or

3.14.5.2 if the *TR participant* did not make the request referred to in section 3.14.5.1, hold the *TR market deposit,* which *TR market deposit* shall form part of that *TR participant's TR market deposit* for purposes of a subsequent *TR auction* in which the *TR participant* wishes to participate.

3.15 TR Market Clearing Prices

3.15.1 The *IESO* shall determine a *TR market clearing price* for each *transmission right* in each round of a *TR auction* in accordance with section 3.15.2, independent of the calculation of the *TR market clearing prices* for *transmission rights* in other rounds of the same *TR auction*.

3.15.2 The *TR market clearing price* for a given *transmission right* in a given round of a *TR auction* shall be equal to the lowest *bid* price of all *TR laminations* that were awarded *transmission rights*, as determined by Appendix 8.1.

3.16 Post-Auction Notification and Publication

3.16.1 The *IESO* shall, as soon as practicable and no later than the end of the next *business day* following the conclusion of a round of a *TR auction*, and in any event prior to the time at which *TR bids* may be submitted in respect of the next round of the *TR auction*, notify each *TR bidder* of the following:

3.16.1.1 the number of *transmission rights* awarded to the *TR bidder* during that round;

3.16.1.2 the *TR market clearing price* of each *transmission right* awarded to the *TR bidder* during that round;

3.16.1.3 the injection *TR zone* and the withdrawal *TR zone* in respect of each *transmission right* awarded to the *TR bidder* during that round; and

3.16.1.4 the period for which each *transmission right* awarded to the *TR bidder* during that round is valid.

3.16.2 [Intentionally left blank – section deleted]

3.16.3 The *IESO* shall, as soon as practicable and no later than the end of the next *business day* following the conclusion of a round of a *TR auction*, and in any event prior to the time at which *TR bids* may be submitted in respect of the next round of the *TR auction*, *publish* the following:

3.16.3.1 the *TR market clearing price* for each *transmission right* sold during that round;

3.16.3.2 the number of *transmission rights* sold during that round;

3.16.3.3 the injection *TR zone* and withdrawal *TR zone* for each *transmission right* sold during that round; and

3.16.3.4 the period of validity of each *transmission right* sold during that round.

3.17 Payment for Purchase of Transmission Rights

3.17.1 The amount payable to the *IESO* by a successful *TR bidder* in respect of *transmission rights* awarded to that successful *TR bidder* in a given round of a *TR auction* shall be the aggregate of the *TR market clearing price* of each *transmission right* awarded to that successful *TR bidder* in that round.

3.18 TR Clearing Account

3.18.1 The *IESO* shall establish and maintain a *TR clearing account* and shall:

3.18.1.1 credit to the *TR clearing account*, in respect of each *settlement hour*, the amount calculated in accordance with MR Ch.9 s.3.8.2;

3.18.1.2 credit to the *TR clearing account* the amounts referred to in sections 3.20.2 and 3.20.3;

3.18.1.3 subject to section 3.19.5, credit to the *TR clearing account* the net revenues received from the sale of *transmission rights* in a *TR auction* in accordance with section 3.19.4;

3.18.1.4 debit from the *TR clearing account* any amounts required to be paid to *TR holders* pursuant to section 3.19.2;

3.18.1.5 debit from the *TR clearing account* any amounts authorized to be debited and used to offset *transmission services charges* in accordance with section 3.18.2;

3.18.2 Subject to section 3.18.3, the *IESO Board* may, at such times as it determines appropriate, authorize the debit of funds from the *TR clearing account* in accordance with MR Ch.9 s.3.8.3 for the purpose of using those funds to offset *transmission services charges*.

3.18.3 The *IESO Board* shall establish a reserve threshold for the *TR clearing account.*

3.19 Settlement

3.19.1 All amounts payable to *TR holders* under *transmission rights* in accordance with section 3.4.1 shall be *settled* by the *IESO* in accordance with MR Ch.9 s.6.

3.19.2 Payments required to be made by the *IESO* to *TR holders* in accordance with section 3.4.1 shall be funded by means of the disbursement of the *day-ahead market external congestion rent* and where the *day-ahead market external congestion rent* for a given *billing period* is insufficient to cover such payments to *TR holders,* by debits from the *TR clearing account.* Where the aggregate amount payable to *TR holders* in a given *billing period* under section 3.4.1 exceeds all funds available in the *TR clearing account*, the shortfall shall be funded by the borrowing of short-term funds in accordance with MR Ch.9 s.6.16.5.

3.19.3 Where the aggregate amount payable to *TR holders* in a given *billing period* under section 3.4.1 is less than the *day-ahead market external congestion rent* collected during that *billing period*, the excess shall be used first, to repay any short-term funds borrowed by the *IESO* on account of a shortfall referred to in sections 3.19.2 and 3.19.7, second, subject to section 3.19.6, to reimburse *market participants* for funds recovered by the *IESO* under MR Ch.9 s.6.16.6.2, on a prorated basis according to, and in an amount that does not exceed, the amount so recovered, third, to replenish the reserve threshold specified in section 3.18.3, and the balance shall remain in the *TR clearing account*.

3.19.4 All amounts payable to the *IESO* on account of the purchase of *transmission rights* in accordance with section 3.17.1 in respect of all rounds of a given *TR auction* shall be settled by the *IESO* in accordance with MR Ch.9 s.6.

3.19.5 In respect of a given *TR auction*, the aggregate amount received by the *IESO* in respect of the purchase of *transmission rights* shall be used first to repay any short-term funds borrowed by the *IESO* on account of a shortfall referred to in sections 3.19.2, second, subject to section 3.19.6, to reimburse *market participants* for funds recovered by the *IESO* under MR Ch.9 s.6.16.6.2, on a prorated basis according to, and in an amount that does not exceed, the amount so recovered*,* third, to replenish the reserve threshold specified in section 3.18.3, and the balance shall remain in the *TR clearing account*.

3.19.6 In the event that the *IESO* cannot, after taking all reasonable steps to do so, locate *market participants* from which funds were recovered by the *IESO* under MR Ch.9 s.6.16.6.2, any amount that would otherwise be distributed to such *market participants* under sections 3.19.3 and 3.19.5 shall remain in the *TR clearing account.*

3.20 Default in Payment

3.20.1 Where a successful *TR bidder* fails to remit to the *IESO* any payment due on account of a *transmission right* awarded to that *TR bidder* during a *TR auction* on the applicable *market participant payment date*:

3.20.1.1 the *transmission right* shall not be issued to the *TR bidder*, and

3.20.1.2 the *TR bidder* shall forfeit:

a. its TR market deposit; or
b. that portion of its *TR market deposit* that is equal to 10% of the value of all *transmission rights* awarded to the *TR bidder* during the applicable *TR auction*,

whichever is the lesser.

3.20.2 Where section 3.20.1.2 applies and the *TR market deposit* is in the form of a cash deposit, the *IESO* may draw upon the cash deposit and credit the *TR clearing account* with the amount of the penalty or may invoice the *market participant* for the amount of the penalty, as the case may be, and may remit to the *TR bidder* the difference, if any, between such amount and the amount of the *TR market deposit.*

3.20.3 Where section 3.20.1.2 applies and the *TR market deposit* is in the form of an irrevocable letter of credit, the *IESO* may claim and realize upon the letter of credit in respect of the amount referred to in section 3.20.1.2(a) or 3.20.1.2(b), as the case may be, and shall credit to the *TR clearing account* the proceeds of such realization.

3.20.4 Where a successful *TR bidder* has defaulted in payment of any amount due on account of a *transmission right* awarded to that *TR bidder* during a given *TR auction*, the *IESO* may impose one or both of the following conditions on the participation by that *TR bidder* in a subsequent *TR auction*:

3.20.4.1 require the *TR bidder* to provide a *TR market deposit* in the form of a cash deposit only; or

3.20.4.2 establish the *TR bidder's bidding limit* for that *TR auction* as an amount that is less than ten times the amount or value of the *TR market deposit* provided by that *TR bidder* in respect of that *TR auction*.

RUL-20

Renewed Market Rules

Chapter 0.8

Physical Bilateral Contracts and Financial Markets - Appendices

Connecting Today.
Powering Tomorrow.

Renewed Market Rules – Chapter 0.8: Physical Bilateral Contracts and Financial Markets - Appendices

0.8

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Table of Contents

Appendix 8.1 – Mathematical Formulation of the TR Objective Function

1.1 This Appendix describes the objective function and additional processes used to determine the number of *transmission rights* to be awarded to each *TR bidder,* as described in MR Ch.8 s.3.5.1, and the *TR market clearing price* in a given round of a *TR auction.*

1.2 The objective function, outlined in section 1.3, describes the maximization of the benefit of awarded *TR laminations* net of any unawarded *transmission rights* as determined in accordance with section 1.4(e), if applicable*. Transmission rights* are awarded in quantities to *TR bidders* ranging from zero up to the maximum quantity of their *TR lamination*. The total amount of *transmission rights* awarded to all *TR bidders* in a round of a *TR auction* will not exceed the total number of *transmission rights* available in such round of the *TR auction*. *Transmission rights* will be awarded optimally from highest price to lowest price of the *TR laminations* received for the relevant round of the *TR auction* unless and until such time as there are multiple *TR laminations* that share the same price and cannot all be fully awarded based on the available *transmission rights*, which shall be resolved in accordance with section 1.4*.* If there are insufficient *transmission rights* available to award the entire quantity of a *TR lamination* and section 1.4 does not apply, such *TR bidder* shall be awarded the remainder of the *transmission rights* available.

1.3 The objective for each injection *TR zone* and withdrawal *TR zone* for each round of a given *TR auction* is to maximize the following function:

$$Z = \sum_{i} \mathrm{p}_i * q_\mathrm{i}$$

where:

(a) 'Z' is the benefit as described in MR Ch.8 s.3.5.2 for the relevant round of the *TR auction;*

(b) 'i' is an index into the set of all *TR laminations* received for the relevant round of the *TR auction;*

(c) 'p_i' is the price of *TR lamination 'i',* submitted in accordance with MR Ch.8 s. 3.13.1.3*;*

(d) 'q_i' is the quantity of awarded *transmission rights* associated with *TR lamination 'i',* submitted in accordance with MR Ch.8 s.3.13.1.4, where the quantity of awarded *transmission rights* is determined as follows, as applicable:

(i) the sum of all q_{i} is less than or equal to the fixed amount of *transmission rights* available for such round of a *TR auction* that is determined in accordance with MR Ch.8 ss.3.6, 3.7, and 3.11.10, if applicable;

(ii) where *TR lamination 'i'* is the highest price *TR lamination* for such *TR bidder* and has an associated price is equal to or greater than the *TR market clearing price* for such round of the *TR auction*, the entire quantity of the *TR lamination* or a portion thereof as determined in accordance with section 1.4, or, where section 1.4 does not apply, the portion that will result in all available *transmission rights* being awarded;

(iii) for *TR laminations 'i'* with a price that is equal to or greater than the *TR market clearing price* for such round of the *TR auction,* other than the one referred to in (ii) for the same *TR bidder*, the quantity that is incremental to the *TR bidder's* previous *TR lamination*, as ranked from highest to lowest price, or a portion thereof as determined in accordance with section 1.4, or, where section 1.4 does not apply, the portion that will result in all available *transmission rights* being awarded; and

(iv) for *TR laminations 'i'* with a price that is less than the *TR market clearing price* for such round of the *TR auction,* such quantity shall be zero.

1.4 Where multiple *TR laminations* share the same price and cannot all be fully awarded based on the available *transmission rights*, the awarding of remaining available *transmission rights* will be determined in accordance with the following:

(a) First, the *IESO* will award to each tied *TR bidder* their proportional share of the remaining *transmission rights* available, rounded down to nearest whole number. Each *TR bidders* proportional share will be determined based on the quantity of their tied *TR lamination* relative to the amount of all tied *TR laminations*, where the quantity of a tied *TR lamination* that is not the *TR bidders* highest priced *TR lamination* will be the quantity that is incremental to the *TR bidder's* previous *TR lamination*, as ranked from highest to lowest price;

(b) second, if there continues to be a remainder of *transmission rights* within the relevant round of the *TR auction,* such remainder shall be awarded in accordance with the following:

(i) The *IESO* will rank all such *TR bidders* from the highest to lowest based on the difference between the proportional quantity determined in section 1.4(a) prior to being rounded down and the proportional quantity determined in section 1.4(a) that was awarded to such *TR bidder*; and

(ii) The *IESO* will award one *transmission right* to each such *TR bidder* in sequence from highest to lowest ranking until either there are no more remaining *transmission rights* to be awarded or one or more such *TR bidders* is tied in their ranking and there are insufficient remaining *transmission rights* to award to them all;

(c) third, where there are still remaining *transmission rights* following the completion of section 1.4(b), such remainder shall be awarded in accordance with the following:

(i) The *IESO* will rank the *TR bidders* whom tied, as contemplated under section 1.4(b)(ii), from highest to lowest based on the quantity of *transmission rights* in their *TR lamination* that is incremental to the *TR bidder's* previous *TR lamination*, as ranked from highest to lowest price, if applicable; and

(ii) The *IESO* will award one *transmission right* to each such *TR bidder* in sequence from highest to lowest ranking until either there are no more remaining *transmission rights* to be awarded or one or more such *TR bidders* is tied in their ranking and there are insufficient remaining *transmission rights* to award to them all;

(d) fourth, where there are still remaining *transmission rights* following the completion of section 1.4(c), such remainder shall be awarded in accordance with the following:

(i) The *IESO* will rank the *TR bidders* whom tied, as contemplated under section 1.4(c)(ii), from earliest to latest based on the timestamps of the date and time, to the second, reflecting the time when the *TR bidder* submits the relevant *TR laminations*; and

(ii) The *IESO* will award one *transmission right* to each such *TR bidder* in sequence from earliest to latest ranking until either there are no more remaining *transmission rights* to be awarded or one or more such *TR* *bidders* is tied in their ranking and there are insufficient remaining *transmission rights* to award to them all;

(e) finally, where the remainder of *transmission rights* within the relevant round of the *TR auction* are unable to be awarded in accordance with section 1.4(d), such remainder shall not be awarded to any *TR bidder*.

RUL-21

Renewed Market Rules

Chapter 0.9

Settlements and Billing

0.9

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Table of Contents

Introduction

A.1 Chapter Scope and Operation

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

B.1 Exceptions

B.1.1 Following a *market transition*, if the registration status of *price responsive load* is unavailable for any reason, including software inadequacy, the *IESO* shall, notwithstanding anything to the contrary in this MR Ch.9, conduct the *settlement process* in a manner which treats *self-scheduling storage resources* that are registered to withdraw, which would otherwise be *settled* in the same manner as *price responsive loads*, as *non-dispatchable loads*.

B.1.2 Notwithstanding section 6.3.14, the applicable timeline to notify the *IESO* of any errors or omissions in a *preliminary settlement statement* shall be as follows:

(a) Upon commencement of *market transition*, the applicable timeline to notify the *IESO* of any such errors or omissions in accordance with section 6.8 shall be ten *business days;* and

(b) Commencing 8 months after the first calendar day of the month in which the *market transition completion* date occurs, and for a period of 6 months, the applicable timeline to notify the *IESO* of any such errors or omissions in accordance with section 6.8 shall be eight *business days.*

For greater certainty, this provision does not alter the timelines set out in section 6.3.3, and following the operation of section B.1.2(b), the relevant timelines will return to as they are stated in section 6.3.14.

1. Introductory Rules

1.1 Regulated Settlement Amounts and Related Payment Charges

1.1.1 Notwithstanding any other provision within the *market rules*, the *IESO* shall, for determining, collecting and remitting applicable *settlement amounts*, comply with the relevant provisions of *applicable law* including the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*.

1.1.2 Notwithstanding any other provision within the *market rules*, *market participants* shall remit to the *IESO* such applicable *settlement amounts* and other payments as may be required under the relevant provisions of *applicable law* including the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*.

2. Settlement Data Collection and Management

2.1 Metering and Metering Responsibilities

2.1.1 Subject to section 2.1.2, every *meter* utilized for determining *settlement amounts* according to this Chapter must be a *registered wholesale meter.*

2.1.2 Nothing in section 2.1.1 shall be construed as requiring the *IESO* to determine *settlement amounts* on the basis of a *registered wholesale meter* in circumstances where:

2.1.2.1 it is permitted to use another *meter* for this purpose pursuant to section 2.4.6;

2.1.2.2 in circumstances where the *IESO* has determined that the determination of *settlement amounts* using a *metering installation* whose registration has expired is required for the efficient operation of the *IESO-administered markets;*

2.1.2.3 the *IESO* has not permitted the use of the *registered wholesale meter* for determining *settlement amounts* for the reason specified in MR Ch.6 s.4.2.2A; and

2.1.2.4 the *IESO* is determining *settlement amounts* related to *capacity obligations* using measurement data submitted by *capacity market participants* with an *hourly demand response resource*.

2.1.3 A single *metered market participant* must be designated for each *registered wholesale meter* that is not an *intertie metering point*.

2.1.4 The same *metered market participant* must be designated for all *primary registered wholesale meters*, other than *intertie metering points*, for which any *metering data* will be allocated to any single *resource*.

2.1.5 The *IESO* shall be responsible for *metering data* and its allocation for all *intertie metering points*. The *IESO*, in accordance with *interconnection agreements*, shall:

2.1.5.1 to the extent required to fulfill its obligations under this Chapter, interpret and apply the protocols governing *interconnections* between the *IESO-controlled grid* and other *control areas*;

2.1.5.2 provide to the *settlement process* the *interchange schedule data* described in section 2.6; and

2.1.5.3 determine the allocated quantities called for by section 8 of Appendix 9.2 based on scheduled *intertie* flows even when these differ from actual flows as determined by *metering data*.

2.2 Station Service

2.2.1 The *market participant* responsible for registering a *facility* consuming *transmission station service* or *connection station service* shall:

2.2.1.1 identify to the *IESO* the fraction of the *energy* withdrawn at that *facility* supplied from the *IESO-controlled grid,* which is not such *station service*; and

2.2.1.2 ensure that the consumption of the *energy* referred to in section 2.2.1.1 is measured by a *registered wholesale meter* that complies with the requirements of MR Ch.6.

2.2.2 For *settlement* purposes, *transmission station service* shall be treated as a transmission loss.

2.2.3 Where *connection station service* is not separately metered by a *registered wholesale meter*, the *energy* consumption associated with *connection station service* shall be estimated and submitted by the *market participant* responsible for registering the relevant *connection facility* in accordance with the equations and procedures described in the applicable *market manuals*, which estimate shall be stamped by a registered professional engineer and shall be subject to audit by the *IESO*.

2.2.4 For *settlement* purposes, *connection station service* shall be treated as follows:

2.2.4.1 where the *energy* consumption associated with *connection station service* is included in the *energy* consumption measured by a *registered wholesale meter*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned amongst those *market participants* whose *facilities* are *connected* to the relevant *connection facility* in the proportions provided by the *metering service provider* for that *registered wholesale meter*, and the provision of such proportions shall constitute certification by such *metering service provider* that such proportions have been agreed between the *metering service provider* and all *market participants* whose *facilities* are *connected* to the relevant *connection facility*.

2.2.4.2 where the *energy* consumption associated with *connection station service* is not included in the *energy* consumption measured by a *registered wholesale meter*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

a. amongst those *market participants* whose *resources* are associated with the relevant *connection facility* in the proportions provided by the *metering service provider* for each *registered wholesale meter* measuring the flow of *energy* taken from the *connection facility*. The proportions provided by each *metering service provider* shall reflect agreement amongst all applicable *metering service providers* and shall only be accepted by the *IESO* if the proportions provided by all applicable *metering service providers* sum to one. The provision of such proportions shall constitute certification by each such *metering service provider* that it has reached agreement with all other applicable *metering service providers* in respect of such proportions; or

b. where one or more of the *metering service providers* referred to in section 2.2.4.2(a) has not provided the *IESO* with the proportions referred to in that section, amongst those *market participants* whose *resources* are associated with the relevant *connection facility* on the basis of the number of *load serving breakers* serving each such *market participant*.

2.2.5 A *metering service provider* who provides to the *IESO* factors for apportioning *connection station service* and site-specific losses pursuant to section 2.2.4.1 or

2.2.4.2(a) may, no more than once in each calendar year or more frequently if required by the registration of a new *registered wholesale meter*, submit to the *IESO* revised proportions for the purposes of apportioning the *energy* referred to in section 2.2.4. The provision of such revised proportions shall constitute certification by such *metering service provider* as to the agreement referred to in section 2.2.4.1 or 2.2.4.2(a), as the case may be.

2.2.6 For greater certainty, nothing in section 2.2.4 shall be construed as permitting the apportionment of *connection station service* and site-specific losses to a *market participant* in respect of a *facility* that is an *embedded load facility*, an *embedded generation facility*, or an *embedded electricity storage facility*.

2.2.7 Where the sum of *energy* associated with *connection station service* and with site-specific losses is apportioned by the *IESO* pursuant to section 2.2.4.2(b) by reason of the failure of all applicable *metering service providers* to reach agreement as to the proportions referred to in sections 2.2.4.1 or 2.2.4.2(a) as the case may be, any *market participant* that is the subject of such apportionment may submit the matter to the dispute resolution process set forth in MR Ch.3 s.2 and shall, in the *notice of dispute*:

2.2.7.1 name all other *market participants* that are the subject of the same apportionment as *respondents*; and

2.2.7.2 request that the *arbitrator* determine an alternative apportionment.

2.2.8 Where an *arbitrator* determines an alternative apportionment pursuant to section 2.2.7, the *metering service provider* for each applicable *registered wholesale meter* shall, within five *business days* of the date of the award of the *arbitrator*, file with the *IESO* proportions for apportioning the sum of *energy* associated with *connection station service* and with site specific losses that reflect such alternative apportionment.

2.2.9 Subject to section 2.2.12, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by a *generation resource* passing through the *metering installation* net of all applicable *generation station service*, the costs associated with *generation station service* shall, for *settlement purposes*, be apportioned:

2.2.9.1 amongst those *generation resources* consuming such *generation station service* in the proportions provided by the *metering service provider* for the relevant *metering installation*; or

2.2.9.2 where the *metering service provider* has not provided the proportions referred to in section 2.2.9.1, equally amongst all such *generation resources*, provided that, in either case such apportionment results in a totalization of the applicable *registered wholesale meters* that is identical to the totalization of the *meters* required to meet the monitoring requirements of MR Ch.4 s.7.3, 7.3A, 7.4, 7.5 or 7.6, as the case may be.

2.2.10 Subject to section 2.2.13, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by an *electricity storage resource* passing through the *metering installation* net of all applicable *electricity storage station service*, the costs associated with *electricity storage station service* shall, for *settlement purposes*, be apportioned:

2.2.10.1 amongst those *electricity storage resources* consuming such *electricity storage station service* in the proportions provided by the *metering service provider* for the relevant *metering installation*; or

2.2.10.2 where the *metering service provider* has not provided the proportions referred to in section 2.2.10.1, equally amongst all such *electricity storage resources*,

provided that, in either case such apportionment results in a totalization of the applicable *registered wholesale meters* that is identical to the totalization of the *meters* required to meet the monitoring requirements of MR Ch.4 s.7.3, 7.3A, 7.4, 7.5 or 7.6, as the case may be.

2.2.11 A *metering service provider* who provides the *IESO* with proportions pursuant to section 2.2.9.1 may submit up to two requests in a calendar year to the *IESO* to have such proportions revised, provided that the giving of effect to such revisions shall be subject to the mutual agreement of the *metering service provider* and the *IESO*.

2.2.12 If the consumption of *generation station service* results in:

2.2.12.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 8 of Appendix 9.2, accruing at the *delivery point* of a *generation resource* associated with an eligible *generation facility* within the meaning of section 2.2.15 in circumstances where the injection of *energy* by that *generation facility* as a whole exceeds the withdrawal of *energy* by that *generation facility* as a whole during a given *metering interval*; and

2.2.12.2 such accrual of AQEW results in *hourly uplift*, non-hourly *settlement amounts*, or both, accruing at the *delivery point* referred to in section 2.2.12.1 during any *metering interval* within an *energy market billing period*, the *metered market participant* for that *generation resource* associated with that *generation facility* shall, subject to section 2.2.14 and the application process described in the applicable *market manual*, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.2.12.2.

2.2.13 If the consumption of *electricity storage station service* results in:

2.2.13.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 8 of Appendix 9.2, accruing at the *delivery point* of an *electricity storage resource* associated with an eligible *electricity storage facility* within the meaning of section 2.2.16 in circumstances where the injection of *energy* by that *electricity storage facility* as a whole exceeds the withdrawal of *energy* by that *electricity storage facility* as a whole during a given *metering interval*; and

2.2.13.2 such accrual of AQEW results in *hourly uplift*, non-hourly uplift *settlement amounts*, or both, accruing at the *delivery point* referred to in section 2.2.13.1 during any *metering interval* within an *energy market billing period*,

the *metered market participant* for that *electricity storage resource* associated with that *electricity storage facility* shall, subject to section 2.2.14 and the application process described in the applicable *market manual*, be reimbursed the *hourly uplift* and non-hourly uplift *settlement amounts* referred to in section 2.2.13.2.

2.2.14 No reimbursement will be provided to a *metered market participant* pursuant to section 2.2.12 or 2.2.13 in respect of amounts attributable to the following:

2.2.14.1 *transmission services charges*;

2.2.14.2 any applicable penalties, awards or adjustments reflected in the *invoice* issued to the *metered market participant*; or

2.2.14.3 any other *settlement amounts* where such a reimbursement:

a. is prohibited by *applicable law* or the *market rules*; or

b. where the *settlement amount* is collected by the *IESO* pursuant to an obligation imposed upon it by *applicable law*, is not permitted by such *applicable law*.

2.2.15 For the purposes of section 2.2.12.1, a *generation facility* may be designated by the *IESO* as an eligible *generation facility* where the *generation facility*:

2.2.15.1 is comprised of two or more *facilities* that have the same *metered market participant*

2.2.15.2 is located within the *IESO control area*; and

2.2.15.3 has associated with it *generation station service* that serves more than one *facility* included within that *generation facility*.

2.2.16 For the purposes of section 2.2.13.1, an *electricity storage facility* may be designated by the *IESO* as an eligible *electricity storage facility* where the *electricity storage facility*:

2.2.16.1 is comprised of two or more *facilities* that have the same *metered market participant*;

2.2.16.2 is located within the *IESO control area*; and

2.2.16.3 has associated with it *electricity storage station service* that serves more than one *facility* included within that *electricity storage facility*.

2.2.17 The *IESO* shall recover any amount reimbursed pursuant to section 2.2.12 or 2.2.13 as described in section 4.14.12.

2.3 Metering Data Recording and Collection Frequency

2.3.1 All *metering data* must be recorded for each *metering interval* except as otherwise provided in section 2.3.2 or elsewhere in these *market rules*.

2.3.2 *Demand metering data* for *non-dispatchable loads*, *non-dispatchable generation resources*, or *self-scheduling electricity storage resources* shall be recorded by a *metering installation* at a given instant or averaged over such *metering intervals* as the *IESO* may specify in the applicable *market manual*.

2.3.3 An *intertie metering point* shall record *metering data* in a manner consistent with the applicable interchange protocol.

2.3.4 *Metering data* shall be collected by or delivered to the *IESO* in accordance with Appendix 9.1 or in accordance with such other schedule as the *IESO* may determine from time to time.

2.4 Collection and Validation of Metering Data

2.4.1 The *IESO* shall collect or receive *metering data* directly from *registered wholesale meters*, in such other manner as may be specified in Appendix 9.1 and from such other processes as may be appropriate. Such *metering data* will initially be "raw" data that have not been validated or corrected by the *VEE process*.

2.4.2 The raw *metering data* collected by or delivered to the *IESO* shall be subjected to the *VEE process* described in Appendix 9.1. The *VEE process* shall:

2.4.2.1 convert raw *metering data* into validated, corrected or estimated "*settlement* ready" *metering data* suitable for use in determining *settlement amounts*;

2.4.2.2 operate according to the *settlement* schedule specified in section 6;

2.4.2.3 detect errors in *metering data* resulting from improper operational conditions and/or hardware/software malfunctions, including failures of or errors in metering or communication hardware, and from *metering data* exceeding pre-defined variances or tolerances; and

2.4.2.4 use operational system data, including historical generation and load patterns and data collected by or delivered to the *IESO*, as appropriate, for validating raw *metering data*, and for editing, estimating and correcting *metering data* found to be erroneous or missing.

2.4.3 While undergoing the *VEE process*, *metering data* from a given registered *metering installation* in respect of a given *trading day* or, where applicable, estimates thereof, shall bear appropriate flags and shall be accessible by electronic means by any person referred to in MR Ch.6 s.10.1.3 on the day following such *trading day*.

2.4.4 Subject to section 2.4.5, all *metering data* in respect of a given *metering installation* for a given *trading day* used for determining *settlement amounts* pursuant to this Chapter shall be "*settlement* ready" *metering data* that has been validated and corrected by the *VEE process*. Such "*settlement* ready" *metering data* shall be accessible by electronic means by any person referred to in MR Ch.6 s.10.1.3 no later than five *business days* following such *trading day*, providing that the applicable *metering service provider* has resolved any trouble call pertaining to such *metering data*.

2.4.5 *Metering data* used for determining *settlement amounts* pursuant to this Chapter shall, where applicable, be adjusted to reflect the estimation or deeming provisions set forth in MR Ch.6 s.11.1.4 and 11.1.6, respectively.

2.4.6 For the purposes of Appendix 9.2, location 'm', 'c' or 's' in respect of *market participant* 'k' shall mean the location of:

2.4.6.1 the relevant *meter* used by *market participant* 'k' to meet the monitoring requirements of MR Ch.4 s.7.3, 7.4, 7.5 or 7.6, as the case may be, in respect of *facility* k/m, k/c, or k/s, as the case may be, where such requirements apply in respect of *facility* k/m, k/c or k/s, respectively; or

2.4.6.2 the *registered wholesale meter* for *facility* k/m, k/c, or k/s, as the case may be, where the monitoring requirements of MR Ch.4 s.7.3, 7.4, 7.5 or 7.6, as the case may be, do not apply in respect of *facility* k/m, k/c or k/s, respectively.

2.5 Delivery Points

2.5.1 The *delivery point* for given *registered wholesale meters* shall be determined by the *IESO* by:

2.5.1.1 adjusting the *metering data* from those *registered wholesale meters* in accordance with MR Ch.6 s.4.2.3; and

2.5.1.2 summing the *metering data* from those *registered wholesale meters* with *metering data* from all other applicable *registered wholesale meters* in accordance with the applicable totalization table comprised in the relevant *meter point* documentation submitted in respect of those *registered wholesale meters* pursuant to MR Ch.6 App.6.5 s.1.3.

2.5.2 For the purposes of the determination of the *settlement amounts* referred to in sections 3, 4 and 5, all references to a *registered wholesale meter*, a *registered wholesale meter* ‘m’, ‘c’ or ‘s’ or a *resource* ‘k’/’m’, ‘k’/’c’, or ‘k’/’s’ shall be deemed to be a reference to the *delivery point* associated with such *registered wholesale meter(s)*. All references to a *delivery point* shall be deemed to be references to the *resource* associated with such *delivery point.*

2.6 Collection of Interchange Schedule Data

2.6.1 The *IESO* shall, in co-operation with other *control area operators*, *security coordinators* and *interconnected transmitters* and in accordance with applicable interchange protocols, determine the following *interchange schedule data* for each *settlement hour*:

2.6.1.1 the total scheduled flows of *energy*, and of any other physical quantity or physical service traded in the *IESO-administered markets*, across each *intertie* between the *IESO-controlled grid* and an *intertie zone*; and

2.6.1.2 the allocation of each scheduled *intertie* flow among *market participants*.

2.6.2 The *IESO settlement process* shall use the *interchange schedule data* to determine *settlement amounts* even though the total scheduled flows on all *interties* may be either more or less than actual physical flows as measured by all *intertie metering points*. The *IESO* shall manage deviations between scheduled and actual *intertie* flows in accordance with interchange protocols with other *control areas* and the requirements of applicable *standards authorities*, with any resulting financial gains or losses ultimately accruing or charged to *market participants* through the *hourly uplift*.

2.6.3 The *IESO* shall *publish* the total scheduled and actual flows of *energy* between the *IESO-controlled grid* and each *intertie zone*.

2.7 Collection of Physical Bilateral Contract Data

2.7.1 Any *selling market participant* may, under the provisions of MR Ch.8, submit to the *IESO physical bilateral contract data* for the *day-ahead market* and/or the *real-time market* that define *physical bilateral contract quantities* of *energy* that it is selling to a specified *buying market participant* in specified *settlement hours* and at specified *primary registered wholesale meter*s or *intertie metering points*.

2.7.2 *Physical bilateral contract quantities* shall not be included in the quantities of *energy* used to determine *settlement amounts* related to *energy*, although they may be used to determine other *settlement amounts* as provided in this Chapter.

2.7.3 *Physical bilateral contract quantities* must specify total quantities for each *settlement hour*, not quantities for *metering intervals* within a *settlement hour*. The *IESO* shall divide hourly *physical bilateral contract quantities* into equal *metering interval* quantities when necessary for determining *settlement amounts* as provided for in section 6 of Appendix 9.2.

2.7.4 The *IESO* shall submit directly to the *settlement process* the *physical bilateral contract quantities* submitted by each *market participant* for each *settlement hour* as provided in section 6 of Appendix 9.2.

2.8 Collection of Transmission Right (TR) Data

2.8.1 The *IESO* shall implement, in accordance with MR Ch.8, *TR auctions* that will result in an allocation among *market participants* of *transmission rights* associated with the transactions referred to in MR Ch.8 s.3.1.1.1 and conveying rights to *settlement amounts* based on the external congestion component of the relevant *day-ahead market intertie zone locational marginal price*.

2.8.2 The *IESO* shall submit to the *settlement process* by the sixth *business day* after each *dispatch day* the following data related to *TRs*:

2.8.2.1 the quantities (in MW) of *transmission rights* held by each *TR holder* for each applicable pair of specified injection and withdrawal *TR zones* for each *settlement hour* of such *dispatch day*; and

2.8.2.1 the total proceeds from the sale of *transmission rights* in respect of all rounds of a *TR auction* that is concluded on such *dispatch day*.

2.9 Collection of Ancillary Service Data

2.9.1 The *IESO* shall submit to the *settlement process* the data from *contracted ancillary service* contracts and from the daily *dispatch* process necessary to determine *contracted ancillary service* payments.

2.10 Collection of Market Price and Other Settlement Data

2.10.1 The *IESO* shall submit to the *settlement process* all *market prices* determined by the *IESO* according to the provisions of MR Ch.7 and its appendices, all *metering data* and other *operating results*, and any other information available to the *IESO* as may be needed by the *settlement process* for determining *settlement amounts* pursuant to this Chapter.

2.11 Settlement Record Retention, Confidentiality, and Reliability

2.11.1 Subject to section 2.11.3, the *IESO* shall retain all *settlement* records for a period adequate to support the *settlement* audit referred to in section 6.19, matters described in section 6.8.12.4, and/or a *dispute outcome*, but in no case for less than seven years.

2.11.2 The *IESO* shall periodically review the period for which *settlement* records are retained and shall, if required and subject to section 2.11.3, take such steps as may be required to effect a change in such period.

2.11.3 The period for which *settlement* records are retained shall comply with the requirements of any regulatory authority having jurisdiction over the *IESO* or *market participants*.

2.11.4 *Settlement* and supporting data for each *trading day* of a *billing period* shall be made available by direct electronic means to the relevant *market participant* as soon as the data become available to the *IESO*. The data shall remain available via electronic access until the earlier of 60 days from the end of the *billing period* and the date on which invoicing and payment activities for that *billing period* have been completed.

2.11.5 The *IESO* shall safeguard any *settlement* information that is *confidential information* in accordance with MR Ch.3 s.5.

2.11.6 The *IESO* shall assure that back-up computer and communication systems are available for the *settlement process* and shall, in accordance with section 6.1, use such back-up systems in the event that equipment failure or an emergency evacuation makes the primary systems referred to in section 6.1.1 unavailable.

2.12 Settlement Variables and Data

2.12.1 Subject to section 2.14, the *IESO* shall:

2.12.1.1 provide the variables and data described in Appendix 9.2 directly to the *settlement process*; and

2.12.1.2 determine *settlement amounts* using the variables, data, mathematical functions and information described in and, where applicable, determined in accordance with Appendix 9.2.

2.13 Adjustments of Ineligible Settlement Amounts

2.13.1 Subject to the same time restrictions as set out in section 6.9.2, if the *IESO* determines that any *settlement amount*, or part thereof, was disbursed to or collected from a *market participant* despite that *market participant* not being eligible for such *settlement amount*, or part thereof, the *IESO* may recover or issue such amounts and shall settle any resulting adjustment in accordance with section 4.14.12 and 4.14.13. For greater certainty, nothing in this section shall limit the *IESO's* ability to recover or otherwise adjust amounts in accordance with MR Ch.3 s.6.

2.14 Market Remediation

2.14.1 Notwithstanding any other provisions in this MR Ch.9, if the *IESO* implements *administrative prices* in accordance with MR Ch.7 s.8.4A, the *IESO* shall utilize the *administrative prices* during the *settlement process.*

2.14.2 Notwithstanding any other provisions in this MR Ch.9, if the *IESO* declares a *day-ahead market* failure in accordance with MR Ch.7 s.4.3 or the *IESO* declares a suspension of *market operations* that suspends the *day-ahead market* in accordance with MR Ch.7 s.13, the *IESO* shall:

a. not calculate *settlement amounts* related to the *day-ahead market*;

b. determine all of the *real-time market settlement amounts* only using *real-time market* data and variables; and

c. calculate the hourly *physical transaction settlement amount* for *non-dispatchable loads,* set out in section 3.2*,* using the hourly *real-time market Ontario zonal price* and the load forecast deviation adjustment ($LFDA_h$) shall not be applicable.

3 Hourly Settlement Amounts

3.1 Two-Settlement

3.1.1 The *IESO* shall operate a two-*settlement* system to support the *day-ahead market* and the *real-time market* in accordance with the following:

3.1.1.1 The hourly *physical transaction settlement amounts* shall be calculated for each *settlement hour* 'h' and disbursed to or collected from *market participant* 'k' in accordance with the following:

a. For amounts associated with *physical bilateral contracts*, the *day-ahead market settlement* hourly *physical transaction settlement amount* ("$HPTSA\{1\}\_PBC_{k,h}$") and the real-time balancing *settlement* hourly *physical transaction settlement amount* ("$HPTSA\{2\}\_PBC_{k,h}$") shall be determined by the equations set out in sections 3.1.2 and 3.1.5, respectively;

b. For *dispatchable loads*, *dispatchable generation resources*, *non-dispatchable generation resources, self-scheduling electricity storage resources* that are registered to inject, *dispatchable electricity storage resources*, and *energy traders* participating with *boundary entity resources*, the *day-ahead market settlement* hourly *physical transaction settlement amount* ("$HPTSA\{1\}_{k,h}$") and the real-time balancing *settlement* hourly *physical transaction settlement amount* ("$HPTSA\{2\}_{k,h}$") shall be determined by the equations set out in sections 3.1.3 and 3.1.6, respectively; and

c. For *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw, the *day-ahead market settlement* hourly *physical transaction settlement amount* ("$HPTSA\{1\}\_PRL_{k,h}$") and the real-time balancing *settlement* hourly *physical transaction settlement amount* ("$HPTSA\{2\}\_PRL_{k,h}$") shall be determined by the equations set out in sections 3.1.4 and 3.1.7, respectively;

3.1.1.2 The hourly *virtual transaction settlement amounts* shall be calculated for each *settlement hour* 'h' and disbursed to or collected from *market participant* 'k' in accordance with the following:

a. For all *virtual zonal resources*, the *day-ahead market settlement* hourly *virtual transaction settlement amount* ("$HVTSA\{1\}_{k,h}$") and the real-time balancing *settlement* hourly *virtual transaction settlement* *amount* ("$HVTSA\{2\}_{k,h}$") shall be determined by the equations set out in sections 3.1.8 and 3.1.9, respectively;

3.1.1.3 The hourly *operating reserve settlement amounts* shall be calculated for each *settlement hour* 'h' and disbursed to or collected from *market participant* 'k' in accordance with the following:

a. For *energy traders* participating with *boundary entity resources*, *dispatchable loads*, *dispatchable electricity storage resources,* and *dispatchable generation resources*, the *day-ahead market settlement* hourly *operating reserve settlement amount* ("$HORSA\{1\}_{k,h}$") and the real-time balancing *settlement* hourly *operating reserve settlement amount* ("$HORSA\{2\}_{k,h}$") shall be determined by the equations set out in sections 3.1.10 and 3.1.11, respectively; and

3.1.1.4 In calculating hourly *physical transaction settlement amounts* and hourly *operating reserve settlement amounts* in this section 3.1, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

a. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i';

b. 'M1' is the set of all *delivery points* 'm' for *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw; and

c. 'M2' is the set of all *delivery points* 'm' for *price responsive loads* associated with *load equipment* used as physical *hourly demand response resources* to fulfill *capacity obligations*.

Hourly Physical Transaction Settlement Amount – Day-Ahead Market Settlement

3.1.2 For all *delivery points* 'm' and *intertie metering points* 'i' associated with a *physical bilateral contract*:

$$HPTSA\_PBC\{1\}_{k,h} = \sum^{M}\Big[DAM\_LMP_h^m \ x \left(\sum_S DAM\_BCQ_{s,k,h}^m - \sum_B DAM\_BCQ_{k,b,h}^m\right) + DAM\_LMP_h^i \ x \left(\sum_S DAM\_BCQ_{s,k,h}^i - \sum_B DAM\_BCQ_{k,b,h}^i\right)\Big]$$

3.1.3 For all *delivery points* 'm' and *intertie metering points* 'i' associated with a *dispatchable load*, a *dispatchable generation resource,* a *non-dispatchable generation resources,* a *self-scheduling electricity storage resource* that is registered to inject, a *dispatchable electricity storage resource,* or an *energy trader* participating with a *boundary entity resource:*

$$HPTSA\{1\}_{k,h} = \sum^{M}\left[\left(DAM\_QSI_{k,h}^{m} - DAM\_QSW_{k,h}^{m}\right) x\ DAM\_LMP_{h}^{m} + \left(DAM\_QSI_{k,h}^{i} - DAM\_QSW_{k,h}^{i}\right) x\ DAM\_LMP_{h}^{i}\right]$$

3.1.4 For all *delivery points* 'm' associated with a *price responsive load* or a *self-scheduling electricity storage resource* that is registered to withdraw:

$$HPTSA\{1\}\_PRL\_SSW_{k,h} = -1\ x\left[\sum^{M1}\left(DAM\_QSW_{k,h}^{m} \times DAM\_LMP_{h}^{m}\right) + \sum^{M2}\left(DAM\_QSW_{k,h}^{m} \times DAM\_LMP_{h}^{m}\right)\right]$$

Hourly Physical Transaction Settlement Amount – Real-Time Balancing Settlement

3.1.5 For all *delivery points* 'm' and *intertie metering points* 'i' associated with a *physical bilateral contract*:

$$HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP_{h}^{m,t}\ x\left(\sum_{S} BCQ_{s,k,h}^{m,t} - \sum_{B} BCQ_{k,b,h}^{m,t}\right) + \sum^{M,T} RT\_LMP_{h}^{i,t}\ x\left(\sum_{S} BCQ_{s,k,h}^{i,t} - \sum_{B} BCQ_{k,b,h}^{i,t}\right)$$

Where:

a. If the location specified pursuant to MR Ch.8 s.2.2.1 relates to a *non-dispatchable load*, the $RT\_LMP_{h}^{m,t}$ shall be replaced with the $DAM\_LMP_{h}^{z}$.

3.1.6 For all *delivery points* 'm' and *intertie metering points* 'i' associated with a *dispatchable load*, a *dispatchable generation resource,* a *non-dispatchable generation resources,* a *self-scheduling electricity storage resource* that is registered to inject, a *dispatchable electricity storage resource,* or an *energy trader* participating with a *boundary entity resource*:

$$HPTSA\{2\}_{k,h} = \sum^{M,T} RT\_LMP_{h}^{m,t}\ x\frac{\left(\left(AQEI_{k,h}^{m,t} - DAM\_QSI_{k,h}^{m}\right) - \left(AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m}\right)\right)}{12} + RT\_LMP_{h}^{i,t}\ x\frac{\left(\left(SQEI_{k,h}^{i,t} - DAM\_QSI_{k,h}^{i}\right) - \left(SQEW_{k,h}^{i,t} - DAM\_QSW_{k,h}^{i}\right)\right)}{12}$$

3.1.7 For all *delivery points* 'm' associated with a *price responsive load* or a *self-scheduling electricity storage resource* that is registered to withdraw:

$$HPTSA\{2\}\_PRL\_SSW_{k,h} = -1\ x \left[\sum^{M1,T} RT\_LMP_h^{m,t}\ x \frac{\left(AQEW_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m}\right)}{12} - \sum^{M2,T} RT\_LMP_h^{m,t}\ x \frac{DAM\_QSW_{k,h}^{m}}{12}\right]$$

Hourly Virtual Transaction Settlement Amount – Day-Ahead Market Settlement

3.1.8 For all *virtual zonal resources* 'v':

$$HVTSA\{1\}_{k,h} = \sum^{V} (DAM\_QVSI_{k,h}^{v} - DAM\_QVSW_{k,h}^{v}) \times DAM\_LMP_h^{vz}$$

Hourly Virtual Transaction Settlement Amount – Real-Time Balancing Settlement

3.1.9 For all *virtual zonal resources* 'v':

$$HVTSA\{2\}_{k,h} = -1\ x \sum^{V,T} (DAM\_QVSI_{k,h}^{v} - DAM\_QVSW_{k,h}^{v})/12\ x\ RT\_LMP_h^{vz,t}$$

Hourly Operating Reserve Settlement Amount – Day-Ahead Market Settlement

3.1.10 For all *delivery points* 'm' and *intertie metering points* 'i' associated with an *energy trader* participating with a *boundary entity resource*, a *dispatchable load*, a *dispatchable electricity storage resource,* or a *dispatchable generation resource*:

$$HORSA\{1\}_{k,h} = \sum_{R}^{M} \left(DAM\_PROR_{r,h}^{m} \times DAM\_QSOR_{r,k,h}^{m} + DAM\_PROR_{r,h}^{i} \times DAM\_QSOR_{r,k,h}^{i}\right)$$

Hourly Operating Reserve Settlement Amount – Real-Time Balancing Settlement

3.1.11 For all *delivery points* 'm' and *intertie metering points* 'i' associated with an *energy trader* participating with a *boundary entity resource*, a *dispatchable load*, a *dispatchable electricity storage resource,* or a *dispatchable generation resource*:

$$HORSA\{2\}_{k,h} = \sum_{R}^{M,T} \{RT\_PROR_{r,h}^{m,t}\ x\ (RT\_QSOR_{r,k,h}^{m,t} - DAM\_QSOR_{r,k,h}^{m}) + RT\_PROR_{r,h}^{i,t}\ x\ (RT\_QSOR_{r,k,h}^{i,t} - DAM\_QSOR_{r,k,h}^{i})\}$$

3.2 Hourly Physical Transaction Settlement Amount – Non-Dispatchable Loads

3.2.1 Notwithstanding MR Ch.5 s.7.3A.1, the hourly *physical transaction settlement amount* for *non-dispatchable loads* shall be calculated for each *settlement hour* and collected from the *market participants* of *non-dispatchable loads* in accordance with sections 3.2.2 and 3.2.3. In calculating hourly *physical transaction settlement amounts* for *non-dispatchable loads* in this section 3.2, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

a. 'K' is the set of all *market participants* 'k' with *non-dispatchable loads*;

b. 'M' is the set of all *delivery points* 'm' relating to *non-dispatchable loads*; and

c. 'M2' is the set of all *hourly demand response resources* 'd' that are not associated with *load equipment* registered as *price responsive loads*.

3.2.2 For all *non-dispatchable loads* for a *market participant*, the hourly *physical transaction settlement amount* for *non-dispatchable loads* applicable to *market participant* 'k' in *settlement hour* 'h' ("$HPTSA\_NDL_{k,h}$") is calculated as follows:

$$HPTSA\_NDL_{k,h} = -1\ \mathrm{x}\ (DAM\_LMP_{h}^{z} + LFDA_{h})\ \mathrm{x} \sum^{T} (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$$

Where:

a. '$LFDA_h$' is the load forecast deviation adjustment for *settlement hour* 'h' determined in accordance with section 3.2.3.

3.2.3 The *IESO* shall determine the load forecast deviation adjustment for all *non-dispatchable loads* ("$LFDA_h$") for each *settlement hour* 'h' in accordance with the following:

$$LFDA_h = \frac{Real\_Time\ Purchase\ Cost\_Benefit_h + DAM\ Volume\ Factor\ Cost\_Benefit_h}{\sum_{K,h}^{M,T}(AQEW - AQEI)_{k,h}^{m,t}}$$

Where:

a. $Real\_Time\ Purchase\ Cost\_Benefit = \sum_{K,h}^{M,T}\left[RT\_LMP_h^{m,t} \times (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m})/12\right] - \sum_{K,h}^{M2,T}\left[RT\_LMP_h^{d,t} \times DAM\_QSW_{k,h}^{d}/12\right]$;

b. $DAM\ Volume\ Factor\ Cost\_Benefit = DAM\_LMP_h^{z} \times \left[\sum_{K,h}^{M,T}\left(DAM\_QSW_{k,h}^{m} - AQEW_{k,h}^{m,t} + AQEI_{k,h}^{m,t}\right)/12\right] + \sum_{K}^{M2}\left[DAM\_LMP_h^{z} \times DAM\_QSW_{k,h}^{d}\right]$

3.3 Day-Ahead Market Balancing Credit

3.3.1 The *day-ahead market* balancing credit s*ettlement amount* for *market participant* 'k' in *settlement hour* 'h' ("$DAM\_BC_{k,h}$") shall be calculated and disbursed to the *market participants* of *GOG-eligible resources* and *energy traders* participating with *boundary entity resources* in accordance with the eligibility and equations set out in this section 3.3 and the operating profit function described in section 10 of Appendix 9.2.

3.3.2 *GOG-eligible resources* and *energy traders* participating with *boundary entity resources* are eligible for the *day-ahead market* balancing credit *settlement amount* in each *metering interval* where:

3.3.2.1 for *energy traders* participating with *boundary entity resources*, such *resource* is *dispatched* for *operating reserve*; or

3.3.2.2 Where:

a. a *GOG-eligible resource* or an *energy trader* participating with a *boundary entity resource*, as the case may be, is *dispatched* to a quantity of *energy* less than its *day-ahead schedule* by the *IESO* in order to maintain the *reliability* of the *IESO-controlled grid* and does not receive a real-time make whole payment *settlement amount* pursuant to section 3.5 in relation to such *energy* for the same *metering intervals*; or

b. a *GOG-eligible resource's day-ahead operational commitment* for *energy* is cancelled by the *IESO* in order to maintain the *reliability* of the *IESO-controlled grid* and such *resource* does not receive a real-time make whole payment *settlement amount* pursuant to section 3.5 in relation to such *energy* for the same *metering intervals*.

3.3.3 Notwithstanding section 3.3.2, *energy traders* participating with a *boundary entity resources* shall be ineligible for the *day-ahead market* balancing credit *settlement amount* for the following transactions:

3.3.3.1 *Energy* transactions which form part of a *linked wheeling through transaction;*

3.3.3.2 *Energy* import transactions when:

a. $DAM\_LMP_{h}^{i,t}$ is equal to or greater than $RT\_LMP_{h}^{i,t}$; or

b. $Min\,(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i})$ is equal to or less than $SQEI_{k,h}^{i}$; and

3.3.3.3 *Energy* export transactions when:

a. $DAM\_LMP_{h}^{i,t}$ is equal to or less than $RT\_LMP_{h}^{i,t}$; or

b. $Min\,(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i})$ is equal to or less than $SQEW_{k,h}^{i}$.

3.3.3.4 *Operating reserve* transactions when:

a. $DAM\_PROR_{r,h}^{i,t}$ is equal to or greater than $RT\_PROR_{r,h}^{i,t}$; or

b. $Min\,(RT\_OR\_LOC\_EOP_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i})$ is equal to or less than $RT\_QSOR_{r,k,h}^{i,t}$

3.3.4 For *delivery point* 'm' associated with a *GOG-eligible resource*, the *day-ahead market* balancing credit s*ettlement amount* shall be calculated as follows:

$$DAM\_BC_{k,h}^{m} = DAM\_BCE_{k,h}^{m} + DAM\_BCOR_{k,h}^{m}$$

Where:

a. $DAM\_BCE_{k,h}^{m}$ is the *energy* component of the *day-ahead market* balancing credit *settlement amount* and is calculated as follows:

$$DAM\_BCE_{k,h}^{m} = \sum^{T} Max\left[0, \left(RT\_LMP_{h}^{m,t} - DAM\_LMP_{h}^{m}\right) \times Max\left(0, \left(DAM\_QSI_{k,h}^{m} - AQEI_{k,h}^{m,t}\right)\right)\right]/12$$

b. $DAM\_BCOR^{m}_{k,h}$ is the *operating reserve* component of the *day-ahead market* balancing credit s*ettlement amount* and is calculated as follows:

$$DAM\_BCOR^{m}_{k,h} = \sum^{R,T} Max\left(0, RT\_PROR^{m,t}_{r,h} - DAM\_PROR^{m}_{r,h}\right) \times Max\left(0, DAM\_QSOR^{m}_{r,k,h} - RT\_QSOR^{m,t}_{r,k,h}\right)/12$$

3.3.5 Subject to section 3.3.5.1 and 3.3.5.2 and at an *intertie metering point* 'i' associated with an *energy trader* participating with a *boundary entity resource*, the *day-ahead market* balancing credit *settlement amount* shall be calculated as follows:

$$DAM\_BC^{i}_{k,h} = DAM\_BCE^{i}_{k,h} + DAM\_BCOR^{i}_{k,h}$$

Where:

a. for an import transaction, $DAM_BCE^{i}_{k,h}$is the *energy* component of the *day-ahead market* balancing credit s*ettlement amount* and calculated as follows:

$$DAM\_BCE^{i}_{k,h} = MAX\{0, \sum^{T} OP(RT\_LMP^{i,t}_{h}, Min(RT\_LOC\_EOP^{i,t}_{k,h}, DAM\_QSI^{i}_{k,h}), BE^{i,t}_{k,h}) - OP(RT\_LMP^{i,t}_{h}, SQEI^{i,t}_{k,h}, BE^{i,t}_{k,h})\} /12$$

b. for an export transaction, $DAM_BCE^{i}_{k,h}$is the *energy* component of the *day-ahead market* balancing credit s*ettlement amount* and calculated as follows:

$$DAM\_BCE^{i}_{k,h} = -1 \times MIN\{0, \sum^{T} OP(RT\_LMP^{i,t}_{h}, Min(RT\_LOC\_EOP^{i,t}_{k,h}, DAM\_QSW^{i}_{k,h}), BL^{i,t}_{k,h}) - OP(RT\_LMP^{i,t}_{h}, SQEW^{i,t}_{k,h}, BL^{i,t}_{k,h})\}/12$$

c. $DAM\_BCOR^{i}_{k,h}$ is the *operating reserve* component of the *day-ahead market* balancing credit s*ettlement amount* and calculated as follows:

$$DAM\_BCOR^{i}_{k,h} = \sum^{R} MAX\{0, \sum^{T} OP(RT\_PROR^{i,t}_{r,h}, Min(RT\_OR\_LOC\_EOP^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}) - OP(RT\_PROR^{i,t}_{r,h}, RT\_QSOR^{i,t}_{r,k,h}, BOR^{i,t}_{r,k,h})\}/12$$

3.3.5.1 Where the *offer* price for *energy* or *operating reserve*, as the case may be, being used to determine the appropriate *day-ahead market* balancing credit s*ettlement amount* is less than the applicable *real-time market locational marginal price* for such *energy* or *operating reserve,* the *IESO* shall adjust, for the purposes of determining the *day-ahead market* balancing credit *settlement amount*, such *offer* price to be equal to the applicable *real-time market locational marginal price* for such *energy* or *operating reserve*.

3.3.5.2 Where the *bid* price for *energy* being used to determine the appropriate *day-ahead market* balancing credit s*ettlement amount* is greater than the applicable *real-time market locational marginal price* for such *energy*, the *IESO* shall adjust, for the purposes of determining the *day-ahead market* balancing credit *settlement amount*, such *bid* price to be equal to the applicable *real-time market locational marginal price* for such *energy*.

3.4 Day-Ahead Market Make-Whole Payment

3.4.1 Subject to section 3.4.2, 3.4.3 and the mitigation process described in section 5 and Appendix 9.4, the *day-ahead market* make-whole payment *settlement amount* for *market participant* 'k' in *settlement hour* 'h' ("$DAM\_MWP_{k,h}$") shall be calculated for each *settlement hour* for the *market participants* of *dispatchable loads, price responsive loads, energy traders* participating with *boundary entity resources, dispatchable electricity storage resources, self-scheduling electricity storage resources* that are registered to withdraw, or *dispatchable generation resources:*

3.4.1.1 that have a *day-ahead schedule* for *energy* or *operating reserve*; and

3.4.1.2 except for hydroelectric *generation resources* associated with *linked forebays* and hydroelectric *generation resources* not associated with *linked forebays* that have Attained Max Starts*,* as defined in section 3.4.13, where their *day-ahead schedule* for the applicable *settlement hour* for *energy* or *operating reserve,* as the case may be, is greater than their economic operating point for *energy* or *operating reserve,* as the case may be, for the same *settlement hour.*

3.4.2 The *day-ahead market* make-whole payment *settlement amount* shall be disbursed to the *market participants* of such *resources* in accordance with the eligibility and equations set out in section 3.4, and the operating profit function described in section 10 of Appendix 9.2. The *day-ahead market* make-whole payment *settlement amount* consists of the following components where applicable:

3.4.2.1 Component 1 is the shortfall in payment on the *day-ahead schedule* for *energy*, as determined in accordance with sections 3.4.7(a), 3.4.8(a), 3.4.9(a), 3.4.10(a), 3.4.11(a), 3.4.12(a), 3.4.13.3, 3.4.13.4(b), 3.4.13.5.2, 3.4.14(a) or 3.4.15(a), as applicable; and

3.4.2.2 Component 2 is the shortfall in payment on the *day-ahead schedule* for *operating reserve*, as determined in accordance with sections 3.4.7(b), 3.4.8(b), 3.4.11(b), 3.4.12(b), 3.4.13.3, 3.4.13.4(c), 3.4.13.5.2, 3.4.14(b) or 3.4.15(b), as applicable.

3.4.3 Notwithstanding anything in section 3.4 to the contrary and for the purpose of determining the *day-ahead market* make-whole payment *settlement amount* for a *market participant,* the *IESO* shall adjust any:

3.4.3.1 *Offer* price and their substitutions as per section 5.1.2.2, as applicable, associated with a *generation resource, dispatchable electricity storage resource* that is registered to inject, or an *energy trader* participating with a *boundary entity resource* that is injecting that is less than (i) 0.00 $/MWh; and (ii) the applicable *day-ahead market locational marginal price* for the applicable *metering interval,* to the lesser of 0.00 $/MWh and such *day-ahead market locational marginal price;* and

3.4.3.2 *Bid* price and their substitutions as per section 5.1.2.2, as applicable, associated with a *dispatchable load, price responsive load, dispatchable electricity storage resource* that is registered to withdraw, or an *energy trader* participating with a *boundary entity resource* that is withdrawing that is less than (i) the price determined in accordance with the applicable *market manual*; and (ii) the applicable *day-ahead market locational marginal price* for the applicable *metering interval,* to the lesser of the price determined in accordance with the applicable *market manual* and such *day-ahead market locational marginal price.*

Day-Ahead Market Make-Whole Payment - Ineligibilities

3.4.4 Notwithstanding this section 3.4 but subject to section 3.4.6, the following *resources* shall not be eligible to receive a *day-ahead market* make-whole payment *settlement amount* for:

3.4.4.1 a *resource* that is a *GOG-eligible resource* or has a primary fuel type of uranium for any *settlement hour* where the *resource* has a *day-ahead schedule* less than its *minimum loading point*;

3.4.4.2 a *generation resource* or a *dispatchable electricity storage resource* for a *called capacity export*

3.4.4.3 an *energy trader* participating with a *boundary entity resource* for any *settlement hour* in which the *energy trader* participating with the *boundary entity resource* has a *day-ahead schedule* for any *linked wheeling through transactions*;

3.4.4.4 a hydroelectric *generation resource* for any *settlement hour* in respect of which the hydroelectric *generation resource* receives either a *minimum hourly output* binding constraint or an *hourly must run* binding constraint;

3.4.4.5 *dispatchable loads* and *dispatchable electricity storage resources* that are registered to withdraw for any quantity of *energy* that they *bid* at the *maximum market clearing price* and which was scheduled in the *day-ahead market;*

3.4.4.6 combustion turbine *resources* or steam turbine *resources* that are not operating as a *pseudo-unit* for *settlement hours* in which they have a minimum constraint applied for combined cycle operation consistent with combustion turbine commitment; and

3.4.4.7 *dispatchable electricity storage resources* for any *settlement hour* for which such *resource* is ineligible to receive a *day-ahead market* make-whole payment in accordance with MR Ch.7 s.21.4.3.

3.4.5 Notwithstanding this section 3.4 but subject to section 3.4.6, the following *resources* shall not be eligible to receive the *energy* component of the *day-ahead market* make-whole payment *settlement amount* for a *trading day*:

3.4.5.1 hydroelectric *generation resources* that are not registered on the same *forebay* as one or more other hydroelectric *generation resources,* if the sum of the quantity of *energy* scheduled in the *day-ahead market* for all *settlement hours* of the *trading day* for each such *resource* is equal to its *minimum daily energy limit;* and

3.4.5.2 hydroelectric *generation resources* that are registered on the same *forebay* as one or more other hydroelectric *generation resources,* if the sum of the quantity of *energy* scheduled in the *day-ahead market* in such *trading day* for all *resources* that are registered to a *forebay* is equal to the *minimum daily energy limit* of such *forebay*.

3.4.6 Notwithstanding section 3.4.4 and 3.4.5, a *day-ahead market* make-whole payment *settlement amount*, or the *energy* component of the *day-ahead market* make-whole payment *settlement amount*, as the case may be, shall be determined for any *settlement hour* where a *resource* receives a *day-ahead schedule* resulting from a *reliability* constraint.

Day-Ahead Market Make-Whole Payment for Dispatchable Generation Resources That Are Not Pseudo-Units and Dispatchable Electricity Storage Resources That Are Registered to Inject

3.4.7 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* that is registered to inject or a *dispatchable generation resource* that is not a *pseudo-unit* and that is not registered as a hydroelectric *generation resource*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^m_{k,h} = Max\left[0, DAM\_COMP1^m_{k,h} + DAM\_COMP2^m_{k,h}\right]$$

Where:

a. $DAM\_COMP1^m_{k,h} = -1 \times \left[OP\left(DAM\_LMP^m_h, DAM\_QSI^m_{k,h}, DAM\_BE^m_{k,h}\right) - OP\left(DAM\_LMP^m_h, DAM\_EOP^m_{k,h}, DAM\_BE^m_{k,h}\right)\right]$

b. $DAM\_COMP2^m_{k,h} = -1 \times \sum_R\left[OP\left(DAM\_PROR^m_{r,h}, DAM\_QSOR^m_{r,k,h}, DAM\_BOR^m_{r,k,h}\right) - OP\left(DAM\_PROR^m_{r,h}, DAM\_OR\_EOP^m_{r,k,h}, DAM\_BOR^m_{r,k,h}\right)\right]$

Day-Ahead Market Make-Whole Payment for Dispatchable Loads and Dispatchable Electricity Storage Resources That Are Registered to Withdraw

3.4.8 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* that is registered to withdraw or *dispatchable load*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^m_{k,h} = Max\left[0, DAM\_COMP1^m_{k,h} + DAM\_COMP2^m_{k,h}\right]$$

Where:

a. $DAM\_COMP1^m_{k,h} = OP\left(DAM\_LMP^m_h, DAM\_QSW^m_{k,h}, DAM\_BL^m_{k,h}\right) - OP\left(DAM\_LMP^m_h, DAM\_EOP^m_{k,h}, DAM\_BL^m_{k,h}\right)$

b. $DAM\_COMP2^m_{k,h} = -1 \times \sum_R\left[OP\left(DAM\_PROR^m_{r,h}, DAM\_QSOR^m_{r,k,h}, DAM\_BOR^m_{r,k,h}\right) - OP\left(DAM\_PROR^m_{r,h}, DAM\_OR\_EOP^m_{r,k,h}, DAM\_BOR^m_{r,k,h}\right)\right]$

Day-Ahead Market Make-Whole Payment for Non-HDR Price Responsive Loads and Self-Scheduling Storage Resources That Are Registered to Withdraw

3.4.9 For a *delivery point* 'm' associated with a *self-scheduling electricity storage resource* that is registered to withdraw or a *price responsive load* that is not associated with *load equipment* registered as a physical *hourly demand response resource*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP_{k,h}^{m} = Max\left[0, DAM\_COMP1_{k,h}^{m}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{m} = OP\left(DAM\_LMP_{h}^{m}, DAM\_QSW_{k,h}^{m}, DAM\_BL_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BL_{k,h}^{m}\right)$

Day-Ahead Market Make-Whole Payment for Physical Hourly Demand Response Price Responsive Loads

3.4.10 For a *price responsive load* associated with *load equipment* that is registered as a physical *hourly demand response resource*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP_{k,h}^{m} = Max\left[0, DAM\_COMP1_{k,h}^{m}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{m} = Max\left\{0, \left[OP\left(DAM\_LMP_{h}^{m}, DAM\_QSW_{k,h}^{m}, DAM\_BL_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BL_{k,h}^{m}\right)\right]\right\} + Max\left\{0, \left[OP\left(DAM\_LMP_{h}^{m}, DAM\_HDR\_QSW_{k,h}^{m}, DAM\_HDR\_BL_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_HDR\_BL_{k,h}^{m}\right)\right]\right\}$

b. 'm' is the *delivery point* for the *price responsive load* and the physical *hourly demand response resource* associated with the *price responsive load for metered market participant* 'k'.

Day-Ahead Market Make-Whole Payment for Boundary Entity Resources - Imports

3.4.11 For an import transaction at an *intertie metering point* 'i' associated with an *energy trader* participating with a *boundary entity resource*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^{i}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

Where:

a. $DAM\_COMP1^{i}_{k,h} = -1 \times \left[OP\left(DAM\_LMP^{i}_{h}, DAM\_QSI^{i}_{k,h}, DAM\_BE^{i}_{k,h}\right) - OP\left(DAM\_LMP^{i}_{h}, DAM\_EOP^{i}_{k,h}, DAM\_BE^{i}_{k,h}\right)\right]$

b. $DAM\_COMP2^{i}_{k,h} = -1\, x\, \sum_{R}\left[OP\left(DAM\_PROR^{i}_{r,h}, DAM\_QSOR^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right) - OP\left(DAM\_PROR^{i}_{r,h}, DAM\_\mathrm{OR}\_EOP^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right)\right]$

Day-Ahead Market Make-Whole Payment for Boundary Entity Resources - Exports

3.4.12 For an export transaction at an *intertie metering point* 'i' associated with an *energy traders* participating with a *boundary entity resource*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^{i}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

Where:

a. $DAM\_COMP1^{i}_{k,h} = OP\left(DAM\_LMP^{i}_{h}, DAM\_QSW^{i}_{k,h}, DAM\_BL^{i}_{k,h}\right) - OP\left(DAM\_LMP^{i}_{h}, DAM\_EOP^{i}_{k,h}, DAM\_BL^{i}_{k,h}\right)$

b. $DAM\_COMP2^{i}_{k,h} = -1\, x\, \sum_{R}\left[OP\left(DAM\_PROR^{i}_{r,h}, DAM\_QSOR^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right) - OP\left(DAM\_PROR^{i}_{r,h}, DAM\_\mathrm{OR}\_EOP^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right)\right]$

Day-Ahead Market Make-Whole Payment for Hydroelectric Generation Resources

3.4.13 For a *delivery point* 'm' associated with a hydroelectric *generation resource*, the *day-ahead market* make-whole payment *settlement amount* is calculated in accordance with the following:

3.4.13.1 for the purposes of this section 3.4.13, the following expressions shall have the following meanings:

a. "Attained Max Starts" means that the number of starts of a hydroelectric *generation resource* during a *trading day,* determined by the *IESO* in accordance with the applicable *market manual,* is equal to its *maximum number of starts per day*; and

b. "Not Attained Max Starts" means either that the number of starts of a hydroelectric *generation resource* during a *trading day,* determined by the *IESO* in accordance with the applicable *market manual,* is not equal to its *maximum number of starts per day* or that a hydroelectric *generation resource* has not submitted a *maximum number of starts per day;*

3.4.13.2 where applicable, $FROP_{k,h}^{m}$ shall be determined as follows:

a. If $DAM\_QSI_{k,h}^{m}$ is not equal to $FR\_UL_{k}^{m,f}$, or the *resource* does not have a *forbidden region*,

$$FROP_{k,h}^{m} = 0$$

b. Otherwise,

$$FROP_{k,h}^{m} = OP\left(DAM\_LMP_{h}^{m}, FR\_UL_{k}^{m,f}, DAM\_BE_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, Max(DAM\_EOP_{k,h}^{m}, FR\_LL_{k}^{m,f}), DAM\_BE_{k,h}^{m}\right)$$

Where:

i. '$FR\_UL_{k}^{m,f}$' is the *forbidden region* upper limit from *forbidden region* set 'f' where $DAM\_QSI_{k,h}^{m} = FR\_UL_{k}^{m,f}$, as submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data;*

ii. '$FR\_LL_{k}^{m,f}$' is the *forbidden region* lower limit from *forbidden region* set 'f' where $DAM\_QSI_{k,h}^{m} = FR\_UL_{k}^{m,f}$, as submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data;* and

iii. 'f' = (1…N) of the *forbidden region* set $\{FR\_UL_{k}^{m,f}, FR\_LL_{k}^{m,f}\}$ and N is the maximum number of *forbidden regions* submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

3.4.13.3 if a hydroelectric *generation resource,* excluding those associated with *linked forebays,* has:

a. Not Attained Max Starts, then for all *settlement hours* of its *day-ahead schedule*;

b. Attained Max Starts, but has a *day-head schedule* with *settlement hours* with a *reliability* constraint, then for such *settlement hours* with a *reliability* constraint; or

c. Attained Max Starts, but has a *day-head schedule* with *settlement hours* the are not within a start event, as determined in accordance with the applicable *market manual,* then for such *settlement hours* that are not within a start event,

the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^m_{k,h} = Max\left[0, DAM\_COMP1^m_{k,h} + DAM\_COMP2^m_{k,h}\right]$$

Where:

i. $DAM\_COMP1^m_{k.h} = (-1) \times \left[OP\left(DAM\_LMP^m_h, DAM\_QSI^m_{k.h}, DAM\_BE^m_{k.h}\right) - OP\left(DAM\_LMP^m_h, DAM\_EOP^m_{k,h}, DAM\_BE^m_{k,h}\right) - FROP^m_{k,h}\right]$

ii. $FROP^m_{k.h}$ is determined in accordance with the formulation outlined in section 3.4.13.2.

iii. $DAM\_COMP2^m_{k.h} = -1 \times \sum_R \left[OP\left(DAM\_PROR^m_{r.h}, DAM\_QSOR^m_{r.k.h}, DAM\_BOR^m_{r.k.h}\right) - OP\left(DAM\_PROR^m_{r,h}, DAM\_OR\_EOP^m_{r,k,h}, DAM\_BOR^m_{r,k,h}\right)\right]$

3.4.13.4 if a hydroelectric *generation resource,* excluding those associated with *linked forebays,* has Attained Max Starts, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^m_{k,s} = Max\left[0, DAM\_COMP1^m_{k,s} + DAM\_COMP2^m_{k,s}\right]$$

Where:

a. 's' is a start event consisting of a set of *settlement hours* for *market participant* 'k' at *delivery point* 'm', as determined in accordance with the applicable *market manual;*

b. $DAM\_COMP1^m_{k,s} = (-1) \times \left\{\left[\sum_{Hp} OP\left(DAM\_LMP^m_h, DAM\_QSI^m_{k,h}, DAM\_BE^m_{k,h}\right) - FROP^m_{k,h}\right] + \left[\sum_{Hn} OP\left(DAM\_LMP^m_h, DAM\_QSI^m_{k,h}, DAM\_BE^m_{k,h}\right) - OP\left(DAM\_LMP^m_h, DAM\_EOP^m_{k,h}, DAM\_BE^m_{k,h}\right) - FROP^m_{k,h}\right]\right\}$

And where:

i. 'Hp' is the set of all *settlement hours* within start 's' where $OP(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m})$ is positive, excluding those *settlement hours* in which the *resource* has a *reliability* constraint;

ii. 'Hn' is the set of all *settlement hours* within start 's' where $OP(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m})$ is negative and $DAM\_QSI_{k,h}^{m}$ is greater than $DAM\_EOP_{k,h}^{m}$, excluding those *settlement hours* in which the *resource* has a *reliability* constraint or a binding constraint referred to in section 3.4.4.4; and

iii. $FROP_{k,h}^{m}$ is determined in accordance with the formulation outlined in section 3.4.13.2.

c. $DAM\_COMP2_{k,s}^{m} = (-1) \times \sum_{H}\sum_{R}\left[OP\left(DAM\_PROR_{r,h}^{m}, DAM\_QSOR_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m}\right) - OP\left(DAM\_PROR_{r,h}^{m}, DAM\_\mathrm{OR}\_EOP_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m}\right)\right]$

And where:

i. 'H' is the set of all *settlement hours* within start 's'.

3.4.13.5 For hydroelectric *generation resources* associated with *linked forebays,* the *day-ahead market* make-whole payment *settlement amount* is calculated in accordance with the following:

3.4.13.5.1 For those hydroelectric *generation resources* associated with *linked forebays* that have Attained Max Starts*,* the *IESO* shall apply the formulation specified in section 3.4.13.4 for those *resources*;

3.4.13.5.2 Subject to Section 3.4.13.5.3, for those hydroelectric *generation resources* associated with *linked forebays* that has:

a. Not Attained Max Starts, then for all *settlement hours* of its *day-ahead schedule*;

b. Attained Max Starts but has a *day-ahead schedule* with *settlement hours* with a *reliability* constraint, then for such *settlement hours* with a *reliability* constraint; or

c. Attained Max Starts but has a *day-head schedule* with *settlement hours* the are not within a start event, as determined in accordance with the applicable *market manual,* then for such *settlement hours* the are not within a start event,

the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^{m}_{k,h+TL_m} = DAM\_COMP1^{m}_{k,h+TL_m} + DAM\_COMP2^{m}_{k,h+TL_m}$$

Where:

i. $DAM\_COMP1^{m}_{k,h+TL_m} = (-1) \times \{OP[DAM\_LMP^{m}_{h+TL_m}, DAM\_QSI^{m}_{k,h+TL_m}, DAM\_BE^{m}_{k,h+TL_m}] - OP[DAM\_LMP^{m}_{h+TL_m}, DAM\_EOP^{m}_{k,h+TL_m}, DAM\_BE^{m}_{k,h+TL_m}] - FROP^{m}_{k,h+TL_m}\}$

ii. $FROP^{m}_{k,h+TL_m}$ is determined in accordance with the formulation outlined in section 3.4.13.2, except all references to subscript 'h' shall be replaced with subscript $h + TL_m$;

iii. $DAM\_COMP2^{m}_{k,h+TL_m} = -1 \times \sum_R [OP(DAM\_PROR^{m}_{r,h+TL_m}, DAM\_QSOR^{m}_{r,k,h+TL_m}, DAM\_BOR^{m}_{r,k,h+TL_m}) - OP(DAM\_PROR^{m}_{r,h+TL_m}, DAM\_OR\_EOP^{m}_{r,k,h+TL_m}, DAM\_BOR^{m}_{r,k,h+TL_m})]$

'TL_m' is the *time-lag*, for each *delivery point* 'm', equal to the number of hours downstream that the *delivery point* is from the furthest upstream *delivery point* determined by the *time-lag*, submitted by the *market participant* in the daily *dispatch data* for the *linked forebay*.

3.4.13.5.3 Notwithstanding section 3.4.13.5.2, hydroelectric *generation resources* associated with *linked forebays,* which are subject to the calculation of the *day-ahead market* make-whole payment *settlement amount* in accordance with section 3.4.13.5.2, shall only receive the *day-ahead market* make-whole payment *settlement amount* pursuant to such section for a *settlement hour* when the following condition is true for such *settlement hour*:

a. the total sum of all applicable components of such *day-ahead market* make-whole payment *settlement amounts* for all *resources* associated with *linked forebays* within a *cascade group* for such *settlement hour* each as calculated in accordance with section 3.4.13.5.2, regardless of whether the *resource* has Attained Max Starts, is greater than zero, as expressed as follows:

$$\sum^{M} [DAM\_COMP1^{m}_{k,h+TL_m} + DAM\_COMP2^{m}_{k,h+TL_m}] > 0$$

Where:

i. 'M' is set of all *delivery points* 'm' associated with the *linked forebays* that are associated with the hydroelectric *generation resources*, as submitted by the *market participant* in its daily *dispatch data*;

ii. 'TL_m' is the *time-lag*, for each *delivery point* 'm', equal to the number of hours downstream that the *delivery point* is from the furthest upstream *delivery point* determined by the *time-lag*, submitted by the *market participant* in the daily *dispatch data* for the *linked forebay*; and

iii. For greater certainty, this condition is assessed using the equation specified in section 3.4.13.5.2 for all of the *resources* associated with the *linked forebay* regardless of whether the *resources'* own entitlement to the *day-ahead market* make-whole payment *settlement amount* is determined in accordance with section 3.4.13.5.2 or 3.4.13.4.

Day-Ahead Market Make-Whole Payment for Dispatchable Generation Resources That Are Pseudo-Units

Combustion Turbine

3.4.14 For a *delivery point* 'c' for a combustion turbine *resource* associated with a *pseudo-unit*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^c_{k,h} = Max\left[0, DAM\_COMP1^c_{k,h} + DAM\_COMP2^c_{k,h}\right]$$

Where:

a. $DAM\_COMP1^c_{k,h} = -1 \times \left[OP\left(DAM\_LMP^c_h, DAM\_QSI^c_{k,h}, DAM\_DIPC^c_{k,h}\right) - OP\left(DAM\_LMP^c_h, DAM\_EOP^c_{k,h}, DAM\_DIPC^c_{k,h}\right)\right]$

b. $DAM\_COMP2^c_{k,h} = -1 \times \sum_R\left[OP\left(DAM\_PROR^c_{r,h}, DAM\_QSOR^c_{r,k,h}, DAM\_OR\_DIPC^c_{r,k,h}\right) - OP\left(DAM\_PROR^c_{r,h}, DAM\_\mathrm{OR}\_EOP^c_{r,k,h}, DAM\_OR\_DIPC^c_{r,k,h}\right)\right]$

Steam Turbine

3.4.15 For a *delivery point* 's' for a steam turbine *resource* associated with a *pseudo-unit*, the *day-ahead market* make-whole payment *settlement amount* is calculated as follows:

$$DAM\_MWP^{s}_{k,h} = DAM\_COMP1^{s}_{k,h} + DAM\_COMP2^{s}_{k,h}$$

Where:

a. $DAM\_COMP1^{s}_{k,h} = -1 \times \left[OP\left(DAM\_LMP^{s}_{h}, DAM\_DIGQ^{s}_{k,h}, DAM\_DIPC^{s}_{k,h}\right) - OP\left(DAM\_LMP^{s}_{h}, DAM\_EOP\_DIGQ^{s}_{k,h}, DAM\_DIPC^{s}_{k,h}\right)\right]$

b. $DAM\_COMP2^{s}_{k,h} = -1 \times \sum_{R}\left[OP\left(DAM\_PROR^{s}_{r,h}, DAM\_QSOR^{s}_{r,k,h}, DAM\_OR\_DIPC^{s}_{r,k,h}\right) - OP\left(DAM\_PROR^{s}_{r,h}, DAM\_OR\_EOP^{s}_{r,k,h}, DAM\_OR\_DIPC^{s}_{r,k,h}\right)\right]$

3.5 Real-Time Make-Whole Payment

3.5.1 Subject to section 3.5.2, section 3.5.3, and the mitigation process described in section 5 and Appendix 9.4, the real-time make-whole payment *settlement amount* for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h' ("$RT\_MWP^{m,t}_{k,h}$") shall be calculated and disbursed to the *market participants* for *dispatchable loads*, *energy traders* participating with *boundary entity resources*, *dispatchable electricity storage resources,* or *dispatchable generation resources* for each *settlement hour* where such *resource*:

3.5.1.1 has a *real-time schedule* for *energy* that was issued by the *IESO* due to a manual constraint or that was determined to be uneconomic upon completion of the *real-time calculation engine*, and the *resource* injects or withdraws, as the case may be, *energy* into the *IESO-controlled grid* in accordance with such *real-time schedule*; or

3.5.1.2 has a *real-time schedule* for *operating reserve* that was issued by the *IESO* due to a manual constraint or that was determined to be uneconomic upon completion of the *real-time calculation engine*, and the *resource* provides *operating reserve* into the *IESO-controlled grid* in accordance with such *real-time schedule.*

The real-time make-whole payment *settlement amount* shall be disbursed to the *market participants* for such *resources* in accordance with the eligibility and equations set out in this section 3.5 and the operating profit function described in section 10 of Appendix 9.2. The real-time make-whole payment *settlement amount* consists of the following components, where applicable:

a. *Energy* lost cost component ("ELC") is the shortfall in payment on the *real-time schedule* for *energy*, as determined in accordance with sections 3.5.6(a), 3.5.7(a), 3.5.8(a), 3.5.8.1(a), 3.5.8.2(a), 3.5.9(a) or 3.5.10(a), as applicable;

b. *Operating reserve* lost cost component ("OLC") is the shortfall in payment on the *real-time schedule* for *operating reserve*, as determined in accordance with sections 3.5.6(b), 3.5.7(b), 3.5.8.1(b), 3.5.8.2(b), 3.5.8.3, 3.5.9(b) or 3.5.10(b), as applicable;

c. *Energy* lost opportunity cost component ("ELOC") is the compensation for the lost opportunity for *energy* based on the *resource's* RT_LOC_EOP and *real-time schedule*, as determined in accordance with sections 3.5.6(c), 3.5.7(c), 3.5.9(c) or 3.5.10(c), as applicable; and

d. *Operating reserve* lost opportunity cost component ("OLOC") is the compensation for the lost opportunity for *operating reserve* based on the *resource's* RT_OR_LOC_EOP and *real-time schedule*, as determined in accordance with sections 3.5.6(d), 3.5.7(d), 3.5.9(d) or 3.5.10(d), as applicable.

Real-Time Make-Whole Payment - Ineligibilities

3.5.2 Notwithstanding this section 3.5 but subject to section 3.5.3, a real-time make-whole payment *settlement amount* shall not be paid for:

a. a *called capacity export*;

b. an import or export transaction during any *settlement hours* in which the associated *energy trader* has a *real-time schedule* for any *linked wheeling through transactions*;

c. a *resource* for any *settlement hour* for which it was *dispatched*, on request from the *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law,* and the constraint resulting from such request is binding in the *real-time market;*

d. a *resource* that is not a *pseudo-unit* and that is a *GOG-eligible resource* or has a primary fuel type of uranium, for any *settlement hour* in which its *real-time schedule* is less than its *minimum loading point*;

e. a combustion turbine *resource* associated with a *pseudo-unit* and that is a *GOG-eligible resource* or has a primary fuel type of uranium*,* for any *settlement hour* in which its *real-time schedule* is less than its *minimum loading point;*

f. a steam turbine *resource* associated with a *pseudo-unit* and that is a *GOG-eligible resource* or has a primary fuel type of uranium*,* for any *settlement hour* where none of the combustion turbine *resource* associated with the steam turbine *resource* have a *real-time schedule* greater than its *minimum loading point*;

g. a *variable generation resource* for any *settlement hour* in which it is subject to a *release notification*;

h. an *energy trader* participating with a *boundary entity resource* for an export transaction *dispatched* with a reason code associated with a pre-dispatch pricing discrepancy, as set out in the applicable *market manual,* when the applicable *locational marginal price* in either the most recent run of the *pre-dispatch calculation engine* or the *real-time market* does not exceed the export transaction *bid* costs for the last scheduled *price-quantity pair bid* lamination; or

i. *a dispatchable electricity storage resource* for such *settlement hours* for which such *resource* is ineligible to receive a real-time make-whole payment in accordance with MR Ch.7 s.21.4.3.

3.5.3 Notwithstanding sections 3.5.2(a), (b), (c), (g), (h), and (i), a real-time make-whole payment *settlement amount*, shall be determined for any *settlement hour* where a *resource* receives a *real-time schedule* resulting from a *reliability* constraint.

3.5.4 Notwithstanding this section 3.5, the following *resources* shall be ineligible for the following components of the real-time make-whole payment *settlement amount*:

3.5.4.1 The following *resources* shall be ineligible for ELC and ELOC:

a. *dispatchable loads* and *dispatchable electricity storage resources* that are registered to withdraw for any quantity of *energy* that they *bid* at the *maximum market clearing price* and which was scheduled in the *real-time market*;

b. combustion turbine *resources* or steam turbine *resources* that are registered as a *pseudo-unit* but not operating as a *pseudo-unit* for *metering intervals* in which they have a minimum constraint applied for combined cycle operation consistent with combustion turbine commitment;

c. hydroelectric *generation resources:*

i. for any *settlement hour* for which the hydroelectric *generation resource* receives an *hourly must run* binding constraint;

ii. that are registered to the same *forebay* as one or more other hydroelectric *generation resources,* for a *trading day,* except for any *metering intervals* for which it receives a *reliability* constraint, if the sum of the quantity of *energy* scheduled in the *real-time market* for all *settlement hours* of the *trading day* for all *resources* that are registered to the same *forebay* is less than or equal to the *minimum daily energy limit* of such *forebay;* or

iii. that are not registered to the same *forebay* as one or more other hydroelectric *generation resources,* for a *trading day,* except for any *metering intervals* for which it receives a *reliability* constraint*,* if the sum of the quantity of *energy* scheduled in the *real-time market* for all *settlement hours* of the *trading day* for such *resources* is less than or equal to its *minimum daily energy limit;*

3.5.4.2 *energy traders* participating with *boundary entity resources* shall be ineligible for ELC, ELOC, and OLOC for import transactions;

3.5.4.3 *energy traders* participating with *boundary entity resources* shall be ineligible for ELOC and OLOC for export transactions;

3.5.4.4 *dispatchable load resources* and *dispatchable electricity storage resources* that are registered to withdraw shall be ineligible for ELOC where the *price-quantity pairs* contained in its *energy bid* for a *settlement hour* are not the same as the *price-quantity pairs* contained in its *energy bid* for the immediately preceding and next *settlement hour* and such change results in the ramping of the *resource* described in the applicable *market manual;*

3.5.4.5 *resources* shall be ineligible for ELC when it is injecting or withdrawing energy below it's RT_LC_EOP;

3.5.4.6 *resources* shall be ineligible for ELOC when it is injecting or withdrawing energy above RT_LOC_EOP;

3.5.4.7 *resources* shall be ineligible for OLC when its *real-time schedule* for *operating reserve* is less than its RT_OR_LC_EOP;

3.5.4.8 *resources* shall be ineligible for OLOC when its *real-time schedule* for *operating reserve* is less than its RT_OR_LOC_EOP;

3.5.4.9 *non-quick start resources* shall be ineligible for ELOC and OLOC when its *real-time schedule* is less than its *minimum loading point*; and

3.5.4.10 Subject to section 3.5.4.10.1, *dispatchable loads* and *dispatchable electricity storage resources* that are registered to withdraw shall be ineligible for ELOC when (i) its RT_LOC_EOP is greater than its *real-time schedule;* (ii) its RT_LOC_EOP is greater than its actual quantity of *energy* withdrawn; and (iii) any of the following conditions exists:

a. its *real-time schedule* exceeds its actual quantity of *energy* withdrawn in the previous *metering interval* plus 2.5 minutes of ramping unless it is ramping up or down as specified in the applicable *market manual*; or

b. the *resource* has desynchronized from the *IESO-controlled grid* or is unable to follow its *dispatch instruction.*

3.5.4.10.1 Notwithstanding section 3.5.4.10, *dispatchable loads* and *dispatchable electricity storage resources* that are registered to withdraw shall be eligible for ELOC in the circumstances described in section 3.5.4.10 in any of the following circumstances:

a. the applicable *real-time market locational marginal price* for the relevant *metering interval* is greater than or equal to the *resource's bid* price for the last scheduled *price-quantity pair* for the current, next or previous *metering interval*;

b. the *metering interval* is part of an activation for *operating reserves* as specified in the applicable *market manual*; or

c. the *resource* was *dispatched* by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

3.5.5 Notwithstanding anything in section 3.5 to the contrary and for the purpose of determining the real-time make-whole payment *settlement amount* for a *market participant,* the *IESO* shall adjust any:

3.5.5.1 *Offer* price and their substitions as per section 5.1.2.2, as applicable, associated with a *generation resource, dispatchable electricity storage resource* that is registered to inject, or an *energy trader* participating with a *boundary entity resource* that is injecting that is less than, (i) 0.00 $/MWh; and (ii) the applicable *real-time market locational marginal price* for the applicable *metering interval,* to the lesser of 0.00 $/MWh and such *real-time market locational marginal price;* and

3.5.5.2 *Bid* price and their substitions as per section 5.1.2.2, as applicable, associated with a *dispatchable load, dispatchable electricity storage resource* that is registered to withdraw, or an *energy trader* participating with a *boundary entity resource* that is withdrawing that is less than, (i) the price determined in accordance with the applicable *market manual*; and (ii) the applicable *real-time market locational marginal price* for the applicable *metering interval,* to the lesser of price determined in accordance with the applicable *market manual* and such *real-time market locational marginal price.*

Real-Time Make-Whole Payment for Dispatchable Generation Resources That Are Not Pseudo-Units and Dispatchable Electricity Storage Resources That Are Registered to Inject

3.5.6 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* that is registered to inject or a *dispatchable generation resource* that is not a *pseudo-unit*, the real-time make-whole payment *settlement amount* is calculated as follows:

$$RT\_MWP_{k,h}^{m} = \sum^{T} Max\left(0, RT\_ELC_{k,h}^{m,t} + RT\_OLC_{k,h}^{m,t}\right) + Max\left(0, RT\_ELOC_{k,h}^{m,t} + RT\_OLOC_{k,h}^{m,t}\right)$$

Where:

a. $RT\_ELC_{k,h}^{m,t}$ is calculated in accordance with section 3.5.6.1;

b. $RT\_OLC_{k,h}^{m,t} = \sum_{R}\{-1 \times \left[OP\left(RT\_PROR_{r,h}^{m,t}, Max(DAM\_QSOR_{r,k,h}^{m}, RT\_QSOR_{r,k,h}^{m,t}), BOR_{r,k,h}^{m,t}\right) - OP\left(RT\_PROR_{r,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r,k,h}^{m,t}, DAM\_QSOR_{r,k,h}^{m}), BOR_{r,k,h}^{m,t}\right)\right]/12\}$

c. $RT\_ELOC_{k,h}^{m,t}$ is calculated in accordance with section 3.5.6.2;

d. $RT\_OLOC_{k,h}^{m,t} = \sum_{R}\left[\{OP\left(RT\_PROR_{r,h}^{m,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right) - Max\left[0, OP\left(RT\_PROR_{r,h}^{m,t}, RT\_QSOR_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right)\right]\}/12\right]$

Where:

i. if the *offer* price of $BOR_{r,k,h}^{m,t}$ is greater than $RT\_PROR_{r,h}^{m,t}$, the *IESO* shall revise the *offer* price of $BOR_{r,k,h}^{m,t}$ to be equal to $RT\_PROR_{r,h}^{m,t}$.

3.5.6.1 The *IESO* shall calculate $RT\_ELC_{k,h}^{m,t}$ as follows:

$$RT\_ELC_{k,h}^{m,t} = -1\,x\,\left[\!\left[\left[OP\left(RT\_LMP_{h}^{m,t}, Max(DAM\_QSI_{k,h}^{m}, Min(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})), BE_{k,h}^{m,t}\right) - OP\left(RT\_LMP_{h}^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}), BE_{k,h}^{m,t}\right)\right] - RT\_FROP\_LC_{k,h}^{m,t}\right]\!\right] /12$$

Where:

a. the *dispatchable generation resource* is registered as a hydroelectric *generation resource,* $RT\_QSI_{k,h}^{m,t}$ is greater than $FR\_LL_{k}^{m,f}$, and $RT\_QSI_{k,h}^{m,t}$ is less than or equal to $FR\_UL_{k}^{m,f}$, then:

$$RT\_FROP\_LC_{k,h}^{m,t} = OP\left(RT\_LMP_{h}^{m,t}, Max\left(DAM\_QSI_{k,h}^{m}, Min(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}\right), BE_{k,h}^{m,t}\right) - OP\left(RT\_LMP_{h}^{m,t}, Max(FR\_LL_{k,h}^{m,f}, DAM\_QSI_{k,h}^{m}, RT\_LC\_EOP_{k,h}^{m,t}), BE_{k,h}^{m,t}\right)$$

Where:

i. '$FR\_UL_{k}^{m,f}$' is the *forbidden region* upper limit from *forbidden region* set 'f' where $RT\_QSI_{k,h}^{m,t} <= FR\_UL_{k}^{m,f}$, as submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

ii. '$FR\_LL_{k}^{m,f}$' is the *forbidden region* lower limit from *forbidden region* set 'f' where $RT\_QSI_{k,h}^{m,t} > FR\_LL_{k}^{m,f}$, as submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

iii. 'f' = (1…N) of the *forbidden region* set $\{FR\_UL_{k}^{m,f}, FR\_LL_{k}^{m,f}\}$ and 'N' is the maximum number of *forbidden regions* submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

b. Otherwise $RT\_FROP\_LC_{k,h}^{m,t}$ shall equal zero.

3.5.6.2 The *IESO* shall calculate $RT\_ELOC_{k,h}^{m,t}$ as follows:

$$RT\_ELOC_{k,h}^{m,t} = \{OP\left(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) - Max\left[0, OP\left(RT\_LMP_{h}^{m,t}, Max(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}\right)\right] - RT\_FROP\_LOC_{k,h}^{m,t}\}/12$$

Where:

a. if the *offer* price of $BE_{k,h}^{m,t}$ is greater than $RT\_LMP_{h}^{m,t}$, the *IESO* shall revise the *offer* price of $BE_{k,h}^{m,t}$ to be equal to $RT\_LMP_{h}^{m,t}$

b. if the *dispatchable generation resource* is registered as a hydroelectric *generation resource,* $RT\_QSI_{k,h}^{m,t}$ is greater than or equal to $FR\_LL_{k}^{m,f}$ and $RT\_QSI_{k,h}^{m,t}$ is less than $FR\_UL_{k}^{m,f}$, then:

$$RT\_FROP\_LOC_{k,h}^{m,t}$$
$$= OP\left(RT\_LMP_{h}^{m,t}, Min(FR\_UL_{k,h}^{m,\cancel{t},f}, RT\_LOC\_EOP_{k,h}^{m,t}), BE_{k,h}^{m,t}\right)$$
$$- Max\left[0, OP\left(RT\_LMP_{h}^{m,t}, Max(RT\_QSI_{k,h}^{m,t,f}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}\right)\right]$$

Where:

i. '$FR\_UL_{k}^{m,f}$' is the *forbidden region* upper limit from *forbidden region* set 'f' where $RT\_QSI_{k,h}^{m,t}$ < $FR\_UL_{k}^{m,f}$, as submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

ii. '$FR\_LL_{k}^{m,f}$' is the *forbidden region* lower limit from *forbidden region* set 'f' where $RT\_QSI_{k,h}^{m,t}$ >= $FR\_LL_{k}^{m,f}$, as submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

iii. 'f' = (1…N) of the *forbidden region* set {$FR\_UL_{k}^{m,f}$, $FR\_LL_{k}^{m,f}$} and 'N' is the maximum number of *forbidden regions* submitted by *market participant* 'k' for *delivery point* 'm' as daily *dispatch data*.

c. Otherwise $RT\_FROP\_LOC_{k,h}^{m,t}$ shall equal zero.

Real-Time Make-Whole Payment for Dispatchable Loads and Dispatchable Electricity Storage Resources That Are Registered to Withdraw

3.5.7 For a *delivery point* 'm' associated with a *dispatchable load* or *dispatchable electricity storage resource* that is registered to withdraw, the real-time make-whole payment *settlement amount* is calculated as follows:

$$RT\_MWP_{k,h}^{m} = \sum^{T} Max\left(0, RT\_ELC_{k,h}^{m,t} + RT\_OLC_{k,h}^{m,t}\right) + Max(0, RT\_ELOC_{k,h}^{m,t} + RT\_OLOC_{k,h}^{m,t})$$

a. $RT\_ELC_{k,h}^{m,t} = \left[OP\left(RT\_LMP_{h}^{m,t}, Max(DAM\_QSW_{k,h}^{m}, Min(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t})), BL_{k,h}^{m,t}\right) - OP\left(RT\_LMP_{h}^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSW_{k,h}^{m}), BL_{k,h}^{m,t}\right)\right]/12$

b. $RT\_OLC_{k,h}^{m,t} = \sum_{R}\{-1 \times \left[OP\left(RT\_PROR_{r,h}^{m,t}, Max(DAM\_QSOR_{r,k,h}^{m}, RT\_QSOR_{r,k,h}^{m,t}), BOR_{r,k,h}^{m,t}\right) - OP\left(RT\_PROR_{r,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r,k,h}^{m,t}, DAM\_QSOR_{r,k,h}^{m}), BOR_{r,k,h}^{m,t}\right)\right]/12\}$

c. $RT\_ELOC_{k,h}^{m,t} = -1 \times \{OP\left(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BL_{k,h}^{m,t}\right) - OP\left(RT\_LMP_{h}^{m,t}, Max(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t}\right)\}/12$

And where:

i. if the *bid* price of $BL^{m,t}_{k,h}$ is less than $RT\_LMP_{h}^{m,t}$, the *IESO* shall revise the *bid* price of $BL^{m,t}_{k,h}$ to be equal to $RT\_LMP_{h}^{m,t}$

d. $RT\_OLOC_{k,h}^{m,t} = \sum_{R}\left[\{OP\left(RT\_PROR_{r,h}^{m,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right) - Max\left[0, OP\left(RT\_PROR_{r,h}^{m,t}, RT\_QSOR_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right)\right]\}/12\right]$

And where:

i. if the *offer* price of $BOR^{m,t}_{r,k,h}$ is greater than $RT\_PROR_{r.h}^{m,t}$, the *IESO* shall revise the *offer* price of $BOR^{m,t}_{r,k,h}$ to be equal to $RT\_PROR_{r,h}^{m,t}$

Real-Time Make-Whole Payment for Boundary Entity Resources

3.5.8 For a transaction at an *intertie metering point* 'i' associated with an *energy trader* participating with a *boundary entity resource*, the real-time make-whole payment *settlement amount* is calculated in accordance with the following:

3.5.8.1 For an export transaction *dispatched* with a reason code associated with manual *dispatch* out-of-merit, as set out in the applicable *market manual*:

$$RT\_MWP^{i}_{k,h} = \sum^{T} Max\left(0, RT\_ELC^{i,t}_{k,h} + RT\_OLC^{i,t}_{k,h}\right)$$

Where:

a. $RT\_ELC^{i,t}_{k,h} = \{OP\left(RT\_LMP^{i,t}_{h}, Max(SQEW^{i,t}_{k,h}, DAM\_QSW^{i}_{k,h}), BL^{i,t}_{k,h}\right) - OP\left(RT\_LMP^{i,t}_{h}, Max(RT\_LC\_EOP^{i,t}_{k,h}, DAM\_QSW^{i}_{k,h}), BL^{i,t}_{k,h}\right)\}/12$

b. $RT\_OLC^{i,t}_{k,h} = \sum_{R}[-1 \times \{OP\left(RT\_PROR^{i,t}_{r,h}, Max(RT\_QSOR^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}\right) - OP\left(RT\_PROR^{i,t}_{r,h}, Max(RT\_OR\_LC\_EOP^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}\right)\}/12]$

3.5.8.2 For an export transaction *dispatched* with a reason code associated with a pre-dispatch pricing discrepancy, as set out in the applicable *market manual*:

$$RT\_MWP^{i}_{k,h} = \sum^{T} Max\left(0, RT\_ELC^{i,t}_{k,h} + RT\_OLC^{i,t}_{k,h}\right)$$

Where:

a. $RT\_ELC^{i,t}_{k,h} = \{OP\left(Min(RT\_LMP^{i,t}_{h}, PD\_LMP^{i}_{h}), Max(SQEW^{i,t}_{k,h}, DAM\_QSW^{i}_{k,h}), BL^{i,t}_{k,h}\right) - OP\left(Min(RT\_LMP^{i,t}_{h}, PD\_LMP^{i}_{h}), Max(RT\_LC\_EOP^{i,t}_{k,h}, DAM\_QSW^{i}_{k,h}), BL^{i,t}_{k,h}\right)\}/12$

b. $RT\_OLC^{i,t}_{k,h} = \sum_{R}\{-1 \times [OP\left(RT\_PROR^{i,t}_{r,h}, Max(RT\_QSOR^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}\right) - OP\left(RT\_PROR^{i,t}_{r,h}, Max(RT\_OR\_LC\_EOP^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}\right)] /12\}$

3.5.8.3 For an import transaction:

$$RT\_MWP^{i}_{k,h} = \sum^{T} Max\left(0, RT\_OLC^{i,t}_{k,h}\right)$$

Where:

a. $RT\_OLC^{i,t}_{k,h} = \sum_{R}\{-1 \times [OP\left(RT\_PROR^{i,t}_{r,h}, Max(RT\_QSOR^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}\right) - OP\left(RT\_PROR^{i,t}_{r,h}, Max(RT\_OR\_LC\_EOP^{i,t}_{r,k,h}, DAM\_QSOR^{i}_{r,k,h}), BOR^{i,t}_{r,k,h}\right)] /12\}$

Real-Time Make-Whole Payment for Dispatchable Generation Resources That Are Pseudo-Units

Combustion turbine

3.5.9 For a *delivery point* 'c' for a combustion turbine *resource* associated with a *pseudo-unit*, the real-time make-whole payment *settlement amount* is calculated as follows:

$$RT\_MWP^{c}_{k,h} = \sum^{T} Max\left(0, RT\_ELC^{c,t}_{k,h} + RT\_OLC^{c,t}_{k,h}\right) + Max\left(0, RT\_ELOC^{c,t}_{k,h} + RT\_OLOC^{c,t}_{k,h}\right)$$

Where:

a. $RT\_ELC^{c,t}_{k,h} = (-1) \times \left[OP\left(RT\_LMP^{c,t}_{h}, Max(DAM\_QSI^{c}_{k,h}, Min\left(RT\_QSI^{c,t}_{k,h}, AQEI^{c,t}_{k,h}\right)), RT\_DIPC^{c,t}_{k,h}\right) - OP\left(RT\_LMP^{c,t}_{h}, Max\left(RT\_LC\_EOP^{c,t}_{k,h}, DAM\_QSI^{c}_{k,h}\right), RT\_DIPC^{c,t}_{k,h}\right)\right]/12$

b. $RT\_OLC^{c,t}_{k,h} = \sum_{R}\left[(-1) \times \left\{OP\left(RT\_PROR^{c,t}_{r,h}, Max(DAM\_QSOR^{c}_{r,k,h}, RT\_QSOR^{c,t}_{r,k,h}), RT\_OR\_DIPC^{c,t}_{r,k,h}\right) - OP\left(RT\_PROR^{c,t}_{r,h}, Max(RT\_OR\_LC\_EOP^{c,t}_{r,k,h}, DAM\_QSOR^{c}_{r,k,h}), RT\_OR\_DIPC^{c,t}_{r,k,h}\right)\right\}/12\right]$

And where:

i. If the *offer* price in the $RT\_OR\_DIPC^{c,t}_{r,k,h}$ *offer* curve is greater than $RT\_PROR^{c,t}_{r,h}$ for the same *class r reserve*, the *IESO* shall revise the *offer* price of $RT\_OR\_DIPC^{c,t}_{r,k,h}$ to be equal to $RT\_PROR^{c,t}_{r,h}$.

c. $RT\_ELOC^{c,t}_{k,h} = \left\{OP\left(RT\_LMP^{c,t}_{h}, RT\_LOC\_EOP^{c,t}_{k,h}, RT\_DIPC^{c,t}_{k,h}\right) - Max\left[0, OP\left(RT\_LMP^{c,t}_{h}, Max\left(RT\_QSI^{c,t}_{k,h}, AQEI^{c,t}_{k,h}\right), RT\_DIPC^{c,t}_{k,h}\right)\right]\right\}/12$

And where:

i. If the *offer* price in the $RT\_DIPC^{c,t}_{k,h}$ *offer* curve is greater than $RT\_LMP^{c,t}_{h}$, the *IESO* shall revise the *offer* price of $RT\_DIPC^{c,t}_{k,h}$ to be equal to $RT\_LMP^{c,t}_{h}$

d. $RT\_OLOC^{c,t}_{k,h} = \sum_{R}\left[OP\left(RT\_PROR^{c,t}_{r,h}, RT\_OR\_LOC\_EOP^{c,t}_{r,k,h}, RT\_OR\_DIPC^{c,t}_{r,k,h}\right) - Max\left[0, OP\left(RT\_PROR^{c,t}_{r,h}, RT\_QSOR^{c,t}_{r,k,h}, RT\_OR\_DIPC^{c,t}_{r,k,h}\right)\right]\right]/12$

And where:

i. If the *offer* price in the $RT\_OR\_DIPC^{c,t}_{r,k,h}$ *offer* curve is greater than $RT\_PROR^{c,t}_{r,h}$ for the same *class r reserve*, the *IESO* shall revise the *offer* price of $RT\_OR\_DIPC^{c,t}_{r,k,h}$ to be equal to $RT\_PROR^{c,t}_{r,h}$.

Steam turbine

3.5.10 For a *delivery point* 's' for a steam turbine *resource* associated with a *pseudo-unit* where at least one of the combustion turbine *resources* associated with the *pseudo-unit* has a *real-time schedule* greater than or equal to its *minimum loading point* during the applicable *settlement hour*, the real-time make-whole payment *settlement amount* is calculated as follows:

$$RT\_MWP_{k,h}^{s} = \sum^{T} Max\left(0, RT\_ELC_{k,h}^{s,t} + RT\_OLC_{k,h}^{s,t}\right) + Max\left(0, RT\_ELOC_{k,h}^{s,t} + RT\_OLOC_{k,h}^{s,t}\right)$$

Where:

a. $RT\_ELC_{k,h}^{s,t} = (-1) \times \left[OP\left(RT\_LMP_{h}^{s,t}, Max(DAM\_DIGQ_{k,h}^{s}, Min\left(RT\_QSI\_DIGQ_{k,h}^{s,t}, AQEI_{k,h}^{s,t}\right)), RT\_DIPC_{k,h}^{s,t}\right) - OP\left(RT\_LMP_{h}^{s,t}, Max\left(RT\_LC\_EOP\_DIGQ_{k,h}^{s,t}, DAM\_DIGQ_{k,h}^{s}\right), RT\_DIPC_{k,h}^{s,t}\right)\right]/12$

b. $RT\_OLC_{k,h}^{s,t} = \sum_{R}\left[(-1) \times \left\{OP\left(RT\_PROR_{r,h}^{s,t}, Max(DAM\_QSOR_{r,k,h}^{s}, RT\_QSOR_{r,k,h}^{s,t}), RT\_OR\_DIPC_{r,k,h}^{s,t}\right) - OP\left(RT\_PROR_{r,h}^{s,t}, Max\left(RT\_OR\_LC\_EOP_{r,k,h}^{s,t}, DAM\_QSOR_{r,k,h}^{s}\right), RT\_OR\_DIPC_{r,k,h}^{s,t}\right)\right\}/12\right]$

And where:

i. If the *offer* price in the $RT\_OR\_DIPC_{r,k,h}^{s,t}$ *offer* curve is greater than $RT\_PROR_{r,h}^{s,t}$ for the same *class r reserve*, the *IESO* shall revise the *offer* price of $RT\_OR\_DIPC_{r,k,h}^{s,t}$ to be equal to $RT\_PROR_{r,h}^{s,t}$.

c. $RT\_ELOC_{k,h}^{s,t} = \left\{OP\left(RT\_LMP_{h}^{s,t0}, RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t0}, RT\_DIPC_{k,h}^{s,t0}\right) - Max\left[0, OP\left(RT\_LMP_{h}^{s,t0}, Max\left(RT\_QSI\_DIGQ_{k,h}^{s,t0}, AQEI_{k,h}^{s,t0}\right), RT\_DIPC_{k,h}^{s,t0}\right)\right]\right\}/12 + \left\{OP\left(RT\_LMP_{h}^{s,t1}, RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t1}, RT\_DIPC_{k,h}^{s,t1}\right) - Max\left[0, OP\left(RT\_LMP_{h}^{s,t1}, RT\_QSI\_DIGQ_{k,h}^{s,t1}, RT\_DIPC_{k,h}^{s,t1}\right)\right]\right\}/12$

And where:

i. 't_0' is *metering interval* 't' in *settlement hour* 'h' when none of the combustion turbine *resources* associated with the steam turbine *resource* have a *real-time schedule* that is less than its respective *minimum loading point*. For greater certainty, 't_1' and 't_0' *metering intervals* are mutually exclusive, and the calculation will be conducted using either the 't_1' or 't_0' variables, depending on whether the relevant *metering interval* meets the criteria of 't_1' or 't_0', respectively;

ii. 't_1' is *metering interval* 't' in *settlement hour* 'h' when (1) at least one combustion turbine *resource* associated with the steam turbine *resource* has a *real-time schedule* greater than or equal to its *minimum loading point*; and (2) at least one of the combustion turbine *resources* associated with the steam turbine *resource* has a *real-time schedule* that is less than its respective *minimum loading point.* For greater certainty, 't_1' and 't_0' *metering intervals* are mutually exclusive, and the calculation will be conducted using either the 't_1' or 't_0' variables, depending on whether the relevant *metering interval* meets the criteria of 't_1' or 't_0', respectively*;* and

iii. If the *offer* price in the $RT\_DIPC_{k,h}^{s,t}$ *offer* curve is greater than $RT\_LMP_h^{s,t}$, the *IESO* shall revise the *offer* price of $RT\_DIPC_{k,h}^{s,t}$ to be equal to $RT\_LMP_h^{s,t}$.

d. $RT\_OLOC_{k,h}^{s} = \sum_R \left[\left\{ OP\left(RT\_PROR_{r,h}^{s,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{s,t}, RT\_OR\_DIPC_{r,k,h}^{s,t}\right) - Max\left[0, OP\left(RT\_PROR_{r,h}^{s,t}, RT\_QSOR_{r,k,h}^{s,t}, RT\_OR\_DIPC_{r,k,h}^{s,t}\right)\right] \right\} / 12 \right]$

And where:

i. If the *offer* price in the $RT\_OR\_DIPC_{r,k,h}^{s,t}$ *offer* curve is greater than $RT\_PROR_{r,h}^{s,t}$ for the same *class r reserve*, the *IESO* shall revise the *offer* price of $RT\_OR\_DIPC_{r,k,h}^{s,t}$ to be equal to $RT\_PROR_{r,h}^{s,t}$.

3.6 Real-Time Intertie Offer Guarantee

3.6.1 Subject to section 3.6.2, the real-time *intertie offer* guarantee *settlement amount* shall be calculated and disbursed to the *energy trader* participating with a *boundary entity resource* in accordance with this section 3.6 for each *settlement hour* in which such *energy trader* participating with *boundary entity resource* has either an *energy* import transaction scheduled in the *real-time market* that is incremental to its *day-ahead schedule* for the same *settlement hour* or an *energy* import transaction scheduled in the *real-time market* for a *settlement hour* in which the *energy trader* participating with a *boundary entity resource* does not have a *day-ahead schedule.*

3.6.2 *Energy* import transactions which form part of a *linked wheeling through transaction* shall not be eligible to receive a real-time *intertie offer* guarantee *settlement amount.*

3.6.3 The real-time *intertie offer* guarantee *settlement amount* for *market participant* 'k' in *settlement hour* 'h' in respect of *intertie metering point* 'i' ("$RT\_IOG_{k,h}^{i}$") shall be determined for each eligible *energy* import transaction scheduled in the *real-time market*, and determined by the following equation and the operating profit function described in section 10 of Appendix 9.2:

$$RT\_IOG_{k,h}^{i} = Max\left[Potential\_IOG_{k,h}^{i} - IOG\_Offset_{k,h}^{i}, 0\right]$$

Where:

a. $IOG\_Offset_{k,h}^{i}$ is the real-time *intertie offer* guarantee *settlement amount* offset for *market participant* 'k' in *settlement hour* 'h' in respect of *intertie metering point* 'i', as determined in accordance with section 3.6.4; and

b. $$Potential\_IOG_{k,h}^{i} = (-1) \times Min\left[0, \sum^{T} OP\left(RT\_LMP_{h}^{i,t}, SQEI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - \sum^{T} OP\left(RT\_LMP_{h}^{i,t}, Min\left[SQEI_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i}\right], BE_{k,h}^{i,t}\right)\right]/12$$

3.6.4 The real-time *intertie offer* guarantee offset for *market participant* 'k' in *settlement hour* 'h' in respect of *intertie metering point* 'i' ("$IOG\_Offset_{k,h}^{i}$") is determined by the following equation:

$$IOG\_Offset_{k,h}^{i} = OFFSET\_MW_{k,h}^{i} \times IOG\_RATE_{k,h}^{i}$$

Where:

a. $$IOG\_RATE_{k,h}^{i} = \frac{Potential\_IOG_{k,h}^{i}}{\left(\sum^{T} SQEI_{k,h}^{i,t} - DAM\_QSI_{k,h}^{i}\right)/12}$$

b. $IOG\_RATE_{k,h}^{i}$ shall be zero if $DAM\_QSI_{k,h}^{i}$ is greater than or equal to $SQEI_{k,h}^{i}$; and

c. $OFFSET\_MW_{k,h}^{i}$ is the offset quantity of an eligible *energy* import transaction scheduled in the *real-time market*, as determined in accordance with section 3.6.5.

3.6.5 The offset quantity of *energy* of an eligible *energy* import transaction scheduled in the *real-time market* ($OFFSET\_MW_{k,h}^{i}$) shall be:

3.6.5.1 determined for each eligible *energy* import transaction scheduled in the *real-time market* with a $IOG\_Rate_{k,h}^{i}$ that is greater than $0/MW. For greater certainty, those eligible *energy* import transaction scheduled in the *real-time market* with an $IOG\_Rate_{k,h}^{i}$ that is equal to $0/MW shall not receive any real-time *intertie offer* guarantee *settlement amount*;

3.6.5.2 equal to the total value of all *energy* quantities offset against such transaction which shall be determined in accordance with the following:

a. the offsetting process will produce an $OFFSET\_MW_{k,h}^{i}$ value for each eligible *energy* import transaction scheduled in the *real-time market* with a non-zero $IOG\_Rate_{k,h}^{i}$, and it shall not exceed the scheduled *energy* quantity of such import transaction;

b. the offsetting process will include all import and export transactions scheduled in the *real-time market* and the *day-ahead market* which were scheduled to occur during the same *settlement hour* but shall not include any transactions that form part of a *linked wheeling through transaction*;

c. the calculation of the $OFFSET\_MW^{i}_{k,h}$ for an *energy* import transaction scheduled in the *real-time market* is cumulative. Each amount may only be offset or applied to offset once during the offsetting process and any amount specified during a step of the offsetting process is a reference to such amounts remaining following the application of the previous steps. For greater certainty, partial offsets are permitted;

d. within each step of the offsetting process, an eligible *energy* import transaction scheduled in the *real-time market* will be offset in ascending order of their respective $IOG\_Rate^{i}_{k,h}$, from those with the lowest $IOG\_Rate^{i}_{k,h}$ to those with the highest $IOG\_Rate^{i}_{k,h}$. Once $OFFSET\_MW^{i}_{k,h}$ equals the *energy* quantity of the applicable eligible *energy* import transaction scheduled in the *real-time market,* the process shall restart in respect of the next eligible *energy* import transaction scheduled in the *real-time market* scheduled during the same *settlement hour*;

e. where the *IESO* determines that the *market participant* has an agreement or arrangement to share the real-time *intertie offer* guarantee *settlement amount* with one or more other *market participants,* the offsetting process shall include the applicable transactions of all such *market participants* as part of the same process*;* and

f. the offsetting process shall be conducted in accordance with the process outlined in the applicable *market manual*, which will, in the following order:

   i. offset export transaction quantities scheduled in the *real-time market* by the amount of *day-ahead market energy* export transaction quantities scheduled in the *day-ahead market* for the same *boundary entity resource* and *energy trader;*

   ii. for each *intertie*:

      a. offset eligible *energy* import transaction quantities scheduled in the *real-time market* by *day-ahead market* *energy* import transaction quantities on the same *intertie* that were not scheduled in the *real-time market*; and

b. offset eligible *energy* import transaction quantities scheduled in the *real-time market* by *energy* export transaction quantities scheduled in the *real-time market* on the same *intertie*;

iii. for each *neighbouring electricity system*:

a. offset *energy* import transaction quantities scheduled in the *real-time market* by *day-ahead market energy* import transaction quantities relating to the same *neighbouring electricity system* that were not scheduled in the *real-time market*; and

b. offset *energy* import transaction quantities scheduled in the *real-time market* by *energy* export transaction quantities scheduled in the *real-time market* relating to the same *neighbouring electricity system*; and

iv. for the *IESO control area*:

a. offset *energy* import transaction quantities scheduled in the *real-time market* by any other *day-ahead market energy* import transaction quantities not scheduled in the *real-time market*; and

b. offset *energy* import transaction quantities scheduled in the *real-time market* by any other *energy* export transaction quantities scheduled in the *real-time market*.

3.7 Real-Time Intertie Failure Charges

3.7.1 The real-time import failure charge and the real-time export failure charge, referred to in MR Ch.7 s.7.5.8B, are *settlement amounts* calculated for each transaction meeting the eligibility criteria outlined in sections 3.7.3 and 3.7.5, respectively, and shall be collected from *energy traders* participating with *boundary entity resources* in accordance with sections 3.7.4 and 3.7.6, respectively.

3.7.2 The *IESO* shall determine, in accordance with the applicable *market manual*, any price bias adjustment factors to be used in the calculation of the real-time import failure charge or the real-time export failure charge, and shall *publish* all applicable price bias adjustment factors in advance of the *settlement hours* to which such price bias adjustment factors apply.

Real-Time Import Failure Charge

3.7.3 The *IESO* shall assess a *market participant* with a real-time import failure charge *settlement amount* for any quantity of *energy* scheduled in its *real-time schedule* for injection at an *intertie metering point* where:

3.7.3.1 the *market participant* receives a *real-time schedule* for a greater quantity of *energy* scheduled for injection than it was scheduled to inject in accordance with its *day-ahead schedule* in respect of the same *metering interval* of the same *settlement hour* at the same *intertie metering point*;

3.7.3.2 the *market participant* does not receive a *real-time schedule* for at least the same quantity of *energy* scheduled for injection as it was scheduled to inject in accordance with its latest *pre-dispatch schedule* in respect of the same *metering interval* of the same *settlement hour* at the same *intertie metering point*; and

3.7.3.3 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO*, that the circumstances described in sections 3.7.3.1 and 3.7.3.2 was due to bona fide and legitimate reasons as described in MR Ch.7 s.7.5.8B.

3.7.4 For each import transaction scheduled in the *real-time schedule* that meets the criteria set out in section 3.7.3, the real-time import failure charge for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' ($RT\_IMFC_{k,h}^{i}$) shall be determined as follows:

$$RT\_IMFC_{k,h}^{i} = \sum^{T} \Big[(-1) \times Min\Big(Max\left(0, \left(RT\_IBP_{h}^{i,t} + PB\_IM_{h}^{t} - PD\_IBP_{h}^{i}\right) \times RT\_ISD_{k,h}^{i,t}\right), Max\left(0, RT\_IBP_{h}^{i,t} \times RT\_ISD_{k,h}^{i,t}\right)\Big) + Min\left(0, \left(RT\_PEC_{h}^{i,t} + RT\_PNISL_{h}^{i,t}\right) \times RT\_ISD_{k,h}^{i,t}\right)\Big] / 12$$

Where:

a. $RT\_ISD_{k,h}^{i,t}$ is the real-time import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h', and calculated as follows:

$$RT\_ISD_{k,h}^{i,t} = Max\left(PD\_QSI_{k,h}^{i} - Max\left(DAM\_QSI_{k,h}^{i}, SQEI_{k,h}^{i,t}\right), 0\right)$$

Real-Time Export Failure Charge

3.7.5 The *IESO* shall assess a *market participant* with a real-time export failure charge *settlement amount* for any quantity of *energy* scheduled in its *real-time schedule* for withdrawal at an *intertie metering point* where:

3.7.5.1 the *market participant* receives a *real-time schedule* for a greater quantity of *energy* scheduled for withdrawal than it was scheduled to withdraw in accordance with its *day-ahead schedule* in respect of the same *metering interval* of the same *settlement hour* at the same *intertie metering point*;

3.7.5.2 the *market participant* does not receive a *real-time schedule* for at least the same quantity of *energy* scheduled for withdrawal as it was scheduled to withdraw in accordance with its latest *pre-dispatch schedule* in respect of the same *metering interval* of the same *settlement hour* at the same *intertie metering point*; and

3.7.5.3 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO*, that the circumstances described in sections 3.7.5.1 and 3.7.5.2 was due to bona fide and legitimate reasons described in MR Ch.7 s.7.5.8B.

3.7.6 For each export transaction scheduled in the *real-time schedule* that meets the criteria set out in section 3.7.5, the real-time export failure charge for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' ($RT\_EXFC_{k,h}^{i}$) shall be determined as follows:

$$RT\_EXFC_{k,h}^{i} = \sum^{T} \Big[(-1) \times Min\Big(Max\big(0, \big(PD\_IBP_{h}^{i} - PB\_EX_{h}^{t} - RT\_IBP_{h}^{i,t}\big) \times RT\_ESD_{k,h}^{i,t}\big), Max\big(0,\ PD\_IBP_{h}^{i} \times\ RT\_ESD_{k,h}^{i,t}\big)\Big) - Max\big(0, \big(RT\_PEC_{h}^{i,t} + RT\_PNISL_{h}^{i,t}\big)\ \times\ RT\_ESD_{k,h}^{i,t}\big)\Big] / 12$$

Where:

a. $RT\_ESD_{k,h}^{i,t}$ is the real-time export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h', and calculated as follows:

$$RT\_ESD_{k,h}^{i,t} = Max\big(PD\_QSW_{k,h}^{i} - Max\big(DAM\_QSW_{k,h}^{i}, SQEW_{k,h}^{i,t}\big), 0\big)$$

3.7A Day-Ahead Market Intertie Failure Charges

3.7A.1 The day-ahead import failure charge and the day-ahead export failure charge, referred to in MR Ch.7 s.7.5.8B, are *settlement amounts* calculated for all, or the portion, of each transaction for injection or withdrawal at an *intertie metering point* that is scheduled in the *day-ahead market* and subsequently scheduled in the *pre-dispatch process* but not scheduled in the *real-time market.* The day-ahead import failure charge and the day-ahead export failure charge shall be collected from *energy traders* participating with *boundary entity resources* in accordance with sections 3.7A.2 and 3.7A.3, respectively.

Day-Ahead Import Failure Charge

3.7A.2 For import transactions, the day-ahead import failure charge for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' ($DAM\_IMFC_{k,h}^{i}$) shall be determined as follows:

$$DAM\_IMFC_{k,h}^{i} = \sum^{T} Min\left(0, \left(RT\_PEC_{h}^{i,t} + RT\_PNISL_{h}^{i,t}\right) \times DAM\_ISD_{k,h}^{i,t}/12\right)$$

Where:

a. $DAM\_ISD_{k,h}^{i,t}$ is the *day-ahead market* import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h', and calculated as follows:

$$DAM\_ISD_{k,h}^{i,t} = Max\left(Min\left(DAM\_QSI_{k,h}^{i}, PD\_QSI_{k,h}^{i}\right) - SQEI_{k,h}^{i,t}, 0\right)$$

Day-Ahead Market Export Failure Charge

3.7A.3 For export transactions, the day-ahead export failure charge for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' ($DAM\_EXFC_{k,h}^{i}$) shall be determined as follows:

$$DAM\_EXFC_{k,h}^{i} = \sum^{T} (-1) \times Max\left(0, \left(RT\_PEC_{h}^{i,t} + RT\_PNISL_{h}^{i,t}\right) \times DAM\_ESD_{k,h}^{i,t}/12\right)$$

Where:

a. $DAM\_ESD_{k,h}^{i,t}$ is the day-ahead export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h', and calculated as follows:

$$DAM\_ESD_{k,h}^{i,t} = Max\left(Min\left(DAM\_QSW_{k,h}^{i}, PD\_QSW_{k,h}^{i}\right) - SQEW_{k,h}^{i,t}, 0\right)$$

3.8 Hourly Settlement Amounts for Transmission Rights

3.8.1 The *transmission right settlement* credit *settlement amount* for *market participant* 'k' in *settlement hour* 'h' ("$TRSC_{k,h}$") shall, other than where MR Ch.8 s.3.4.2 or 3.4.3 applies, be determined by the following:

3.8.1.1 if the injection *TR zone* of the *transmission right* is in the *IESO control area*, determined by the following equation:

$$TRSC_{k,h} = Max\left[0, QTR_{k,h}^{iz,jz} \times DAM\_PEC_h^{iz}\right]$$

3.8.1.2 if the withdrawal *TR zone* of the *transmission right* is in the *IESO control area*, determined by the following equation:

$$TRSC_{k,h} = Max\left[0, -1 \times QTR_{k,h}^{iz,jz} \times DAM\_PEC_h^{jz}\right]$$

Where:

a. $DAM\_PEC_h^{iz}$ is the *day-ahead market* external congestion price for *energy* in injection *TR zone* 'iz' in *settlement hour* 'h'; and

b. $DAM\_PEC_h^{jz}$ is the *day-ahead market* external congestion price for *energy* in withdrawal *TR zone* 'jz' in *settlement hour* 'h'.

3.8.2 The amount of the *day-ahead market* net external congestion residual, which is the *day-ahead market external congestion rent* remaining following the disbursement of the *transmission right settlement* credit *settlement amount,* in *settlement hour* 'h' ("DAM_NECR_h") shall be calculated as follows:

$$DAM\_NECR_h = \sum_K^I \left[\left(DAM\_QSW_{k,h}^i - DAM\_QSI_{k,h}^i\right) x\ DAM\_PEC_h^i\right] - \sum_K \left[TRSC_{k,h}\right]$$

3.8.3 Disbursements from the *TR clearing account* authorized by the *IESO Board* pursuant to MR Ch.8 s.3.18.2 shall be disbursed by the *IESO* in accordance with section 4.9.

3.8.4 Any net revenues received from the sale of a *transmission right* in a *TR auction,* along with the DAM_NECR_h and any other credits referred to in MR Ch.8 s.3.18.1*,* shall be credited to the *TR clearing account* and shall be used in accordance with the provisions of section 3.8.3 and the provisions of MR Ch.8.

3.9 Operating Deviations (ORSSD)

3.9.1 The *IESO* may adjust by means of a debit to the *settlement statement* of any *market participant* who is compensated in the market for providing *operating reserve* from a specific *resource* that operates in a way that does not provide the service for which it has been paid. Such debits in any *settlement hour* may represent either the decreased value of services provided in that same *settlement hour*, or the value of *operating reserve* services deemed not to have been provided in earlier *dispatch* *hours* as a result of failure to perform when called in the later *dispatch hour* associated with that *settlement hour*. The hourly *settlement* debits for failure to provide *energy* from *operating reserve* when it is called are set forth in this section 3.9.

3.9.2 The *operating reserve* shortfall *settlement* debit *settlement amount* may be calculated and collected from *market participants* for each *settlement hour* where such *market participants' resources* have a *real-time schedule* to provide *ten-minute operating reserve* or *thirty-minute operating reserve* and then fails to provide *energy* from that class of *operating reserve* when instructed to do so by the *IESO* according to these *market rules*. The *operating reserve* shortfall *settlement* debit *settlement amount* for *market participant* 'k' for *class r reserve* for *settlement hour* 'h' ("$ORSSD_{k,r,h}$") is determined in accordance with the following:

3.9.2.1 where the most recent *dispatch instruction* issued to the *market participant* for the activation of *class r reserve* prior to the current *metering interval* was issued within the 719 *settlement hours* preceding the current *settlement hour* and resulted in $ORESF_{k,r,h}^{m,t}$ that exceeded the value referred to in section 3.9.5,

$$ORSSD_{k,r,h} = \sum_{m,t}[ORESF_{k,r,h}^{m,t} \times \sum_{T,H}(ORRSC_{k,r,H}^{m,T})] \text{; or}$$

3.9.2.2 in all other cases,

$$ORSSD_{k,r,h} = \sum_{m,t}[ORESF_{k,r,h}^{m,t} \times \sum_{T,H}(ORRSC_{k,r,H}^{m,T}) \ /2]$$

Where:

a. $ORESF_{k,r,h}^{m,t}$ is calculated in accordance with section 3.9.3;

b. $ORRSC_{k,r,H}^{m,T}$ is calculated in accordance with section 3.9.4;

c. 't' is all *metering intervals* in *settlement hour* 'h' in which $ORESF_{k,r,h}^{m,t}$ exceeds the value referred to in section 3.9.5;

d. 'T' is all *metering intervals* referred to in section 3.9.4 (a) or 3.9.4(b), as the case may be;

e. 'H' is all *settlement hours* referred to in section 3.9.4 (a) or 3.9.4(b), as the case may be; and

f. 'm' is all *registered wholesale meters* serving *market participant* 'k's *resources*.

3.9.3 The *energy* shortfall fraction for *class r reserve* for *resource* 'k/m' in *metering interval* 't' of *settlement hour* 'h' ("$ORESF_{k,r,h}^{m,t}$") is determined in accordance with the following:

3.9.3.1 where *operating reserve* is provided from a *generation resource* or from an *electricity storage resource* registered to inject *energy*:

$$ORESF_{k,r,h}^{m,t} = Max\ [(SE_{k,h}^{m,t} - AQEI_{k,h}^{m,t})/SE_{k,h}^{m,t}, 0]$$

3.9.3.2 where *operating reserve* is provided from a *dispatchable load* or from an *electricity storage resource* registered to withdraw *energy*:

$$ORESF_{k,r,h}^{m,t} = Max\ [(AQEW_{k,h}^{m,t} - SE_{k,h}^{m,t})/AQEW_{k,h}^{m,t}, 0]$$

3.9.3.3 in either of the above cases, $ORESF_{k,r,h}^{m,t}$ shall be 0 if:

a. $SE_{k,h}^{m,t}=0$;

b. no *class r reserve* is activated for *resource* 'k/m', at *registered wholesale meter* 'm' during *metering interval* 't' of *settlement hour* 'h'; or

c. $ORESF_{k,r,h}^{m,t}$ is less than the value established by the *IESO Board* and *published* in accordance with section 3.9.5.

Where:

i. $SE_{k,h}^{m,t}$ = total scheduled *energy* in the *real-time market*, including activated *operating reserve*, from *resource* 'k/m' at *registered wholesale meter* 'm', determined on the basis of the *dispatch instructions* for *metering interval* 't' of *settlement hour* 'h'.

3.9.4 define $\sum_{T,H}(ORRSC_{k,r,H}^{m,T})$ = total *settlement* credits for *class r reserve* (including real-time make whole payment *settlement amount* related to *class r reserve*) during the lesser of:

3.9.4.1 where *resource* 'k/m' has not been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour*, all *metering intervals* during the current *settlement hour* and all of the *metering intervals* within the 719 *settlement hours* preceding the current *settlement hour*; or

3.9.4.2 where *resource* 'k/m' has been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour* all *metering intervals* between the current *metering interval*, including the current *metering interval* and the most recent *metering interval* preceding the current *metering interval*, in which the *market participant* 'k' received a *dispatch instruction* for the activation of *class r reserve* from *resource* 'k/m'.

3.9.5 For the purposes of section 3.9.3.3, the *IESO Board* shall establish, and the *IESO* shall *publish*, a value below which $ORESF_{k,r,h}^{m,t}$ shall be set at zero. Where the *IESO Board* revises such value:

3.9.5.1 any such revised value shall be *published* by the *IESO*; and

3.9.5.2 the revised value shall not be used for the purposes of calculating $ORESF_{k,r,h}^{m,t}$ until the 31st *trading day* following the date of *publication*.

3.10 Operating Reserve Non-Accessibility Charge and Associated Reversal Charges

3.10.1 The *operating reserve* non-accessibility charge *settlement amount* for *market participant* 'k' for *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h' ("$ORSCB^{m,t}_{r,k,h}$") shall be calculated for each *metering interval* for the *market participants* of *dispatchable loads, dispatchable electricity storage resources,* or *dispatchable generation resources,* individually or as aggregated in accordance with MR Ch.7 s.2.3, as applicable, for each type of *class r reserve*. The *operating reserve* non-accessibility charge *settlement amount* shall be calculated and collected from such *market participants* for each instance in which they meet the eligibility criteria outlined in sections 3.10.7, 3.10.11 and 3.10.14, as applicable, and as calculated in accordance with sections 3.10.8, 3.10.9, 3.10.12, and 3.10.15, as applicable.

3.10.2 The real-time make whole payment reversal charge *settlement amount* for *market participant* 'k' for *delivery point* 'm' in *settlement hour* 'h' ($RT\_MWP\_RC^{m}_{k,h}$) shall be calculated for each *settlement hour* for the *market participants* of *dispatchable loads, dispatchable electricity storage resources,* or *dispatchable generation resources,* individually or as aggregated in accordance with MR Ch.7 s.2.3, as applicable. The real-time make whole payment reversal charge *settlement amount* shall be calculated and collected from such *market participants* for each *settlement hour* for which they received a real-time make whole payment *settlement amount* and meet the conditions set out in section 3.10.7, and as calculated in accordance with sections 3.10.17, 3.10.20, and 3.10.23, as applicable.

3.10.3 The real-time *generator offer* guarantee claw back *settlement amount* for *market participant* 'k' for *delivery point* 'm' in *settlement hour* 'h' ($RT\_GOG\_CB^{m}_{k,h}$) shall be calculated for each *settlement hour* for the *market participants* of *GOG-eligible resources,* individually or as aggregated in accordance with MR Ch.7 s.2.3, as applicable. The real-time *generator offer* guarantee claw back *settlement amount* shall be calculated and collected for each *settlement hour* for which they received a real-time *generator offer* guarantee *settlement amount* and meet the conditions set out in section 3.10.7, and as calculated in accordance with sections 3.10.26, 3.10.29, and 3.10.32, as applicable.

3.10.4 Notwithstanding anything in this section 3.10, if the relevant *resource* for the relevant *settlement hour* received a real-time make whole payment *settlement amount* or real-time *generator offer* guarantee *settlement amount* based on the EMFC *settlement amount,* as defined in section 5.1.2.2, then the calculation for real-time make whole payment reversal charge *settlement amount* and real-time *generator offer* guarantee claw back *settlement amount,* respectively, will utilize the same substitutions provided for in section 5.1.2.2.

3.10.5 Notwithstanding anything to the contrary in this section 3.10, a *resource* will not be subject to the real-time make whole payment reversal charge *settlement amount* or real-time *generator offer* guarantee claw back *settlement amount* if the relevant *resource* for the relevant *settlement hour* did not receive a real-time make whole payment *settlement amount* related to *operating reserve* or real-time *generator offer* guarantee *settlement amount* related to *operating reserve*, respectively.

3.10.6 For the purposes of this section 3.10, $TAOR_{k,h}^{m,t}$, $TAOR\_CT_{k,h}^{c,t}$, and $TAOR_ST_{k,h}^{s,t}$will be calculated as follows:

a. For a *dispatchable electricity storage resource* or a *dispatchable generation resource*, the total accessible *operating reserve* is calculated as follows:

$$TAOR_{k,h}^{m,t} = Max\left(0, MAX\_CAP_{k,h}^{m,t} - AQEI_{k,h}^{m,t}\right)$$

Where:

i. $MAX\_CAP_{k,h}^{m,t}$ is the maximum limit for *market participant* 'k' for *delivery point* 'm' used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process for *metering interval* 't' in *settlement hour* 'h'.

b. For a *dispatchable load*, the total accessible *operating reserve* is calculated as follows:

$$TAOR_{k,h}^{m,t} = Max\left(0, AQEW_{k,h}^{m,t} - MC_{k,h}^{m,t}\right)$$

Where:

i. $MC_{k,h}^{m,t}$ is the minimum consumption level for *metering interval* 't' in *settlement hour* 'h' for *market participant* 'k' for *delivery point* 'm', equal to the quantity in the *price-quantity pair* where the *bid* price is the *maximum market clearing price.*

c. For a combustion turbine *resource* associated with a *pseudo unit*, the total accessible *operating reserve* is calculated as follows:

i. If the combustion turbine *resource* is injecting into the *IESO-controlled grid* an amount of *energy* that is equal to or greater than the *resource's minimum loading point* in *metering interval* 't', then:

$$TAOR\_CT_{k,h}^{c,t} = Max\left(0, MAX\_CAP_{k,h}^{c,t} - AQEI_{k,h}^{c,t}\right)$$

ii. If the combustion turbine *resource* is injecting into the *IESO-controlled grid* an amount *energy* that is less than the *resource's minimum loading point* in *metering interval* 't', then

$$TAOR\_CT_{k,h}^{c,t} = 0$$

d. For a steam turbine *resource* associated with a *pseudo unit*, the total accessible *operating reserve* is calculated as follows:

$$TAOR\_ST_{k,h}^{s,t} = Max\left[0, \left(\sum_{D}^{P1} RT\_ORRQ_{k,d}^{p}\right) - \left(\sum^{C1} MAX\_CAP_{k,h}^{c,t}\right) - AQEI_{k,h}^{s,t}\right]$$

Where:

i. 'P1' is the set of the *resource's pseudo-units* 'p' where the associated combustion turbine *resource* is injecting *energy* into the *IESO-controlled grid* in an amount equal to or greater than its *minimum loading point* and is not operating in *single cycle mode*;

ii. 'C1' is the set of the *resource's* combustion turbine *resources* 'c' associated with the steam turbine *resource* and where the combustion turbine *resources* are injecting *energy* into the *IESO-controlled grid* in an amount equal to or greater than its *minimum loading point* and is not operating in *single cycle mode*; and

iii. 'D' is the set of *pseudo-unit* operating regions 'd1', 'd2', and 'd3'.

3.10.7 The *operating reserve* non-accessibility charge *settlement amount,* real-time make whole payment reversal charge *settlement amount* and real-time *generator offer* guarantee claw back *settlement amount* shall be calculated and collected from the following *resources* in the following circumstances:

a. *dispatchable loads*, *electricity storage resources* and non-aggregated *generation resources* will be subject to the *operating reserve* non-accessibility charge *settlement amount* for any *metering interval* when the *market participant* was not activated by the *IESO* to provide *operating reserve* and the following is true:

   i. $\sum_R RT\_QSOR^{m,t}_{r,k,h} > 0$; and
   ii. $\sum_R RT\_QSOR^{m,t}_{r,k,h} > TAOR^{m,t}_{k,h}$

b. aggregated *generation resources* will be subject to the *operating reserve* non-accessibility charge *settlement amount* for any *metering interval* when, at one or more of the aggregated *delivery points,* the *market participant* was not activated by the *IESO* to provide *operating reserve* and the following is true:

   i. $\sum_R RT\_QSOR^{m,t}_{r,k,h} > 0$; and
   ii. $\sum_R RT\_QSOR^{m,t}_{r,k,h} > TAOR^{m,t}_{k,h}$

Operating Reserve Non-Accessibility Charge for Dispatchable Loads, Dispatchable Electricity Storage Resources, and Non-Aggregated Dispatchable Generation Resources

3.10.8 For a *delivery point* 'm' associated with a *dispatchable load*, *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource*, the *operating reserve* non-accessibility charge *settlement amount* is calculated as follows for each type of *class r reserve*:

a. For synchronized *ten-minute operating reserve*:

$$ORSCB^{m,t}_{r1,k,h} = Min\left[0, \left(TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h}\right) \times RT\_PROR^{m,t}_{r1,h}\right]$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB^{m,t}_{r2,k,h} = Min\left\{0, \left[Max\left(0, TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h}\right) - RT\_QSOR^{m,t}_{r2,k,h}\right] \times RT\_PROR^{m,t}_{r2,h}\right\}$$

c. For *thirty-minute operating reserve*:

$$ORSCB^{m,t}_{r3,k,h} = Min\left\{0, \left[Max\left(0, TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h} - RT\_QSOR^{m,t}_{r2,k,h}\right) - RT\_QSOR^{m,t}_{r3,k,h}\right] \times RT\_PROR^{m,t}_{r3,h}\right\}$$

Operating Reserve Non-Accessibility Charge for Aggregated Dispatchable Generation Resources That Are Not Pseudo-Units

3.10.9 For each *delivery point* 'm' associated with an aggregated *dispatchable generation resources*, the *operating reserve* non-accessibility charge *settlement amount* is calculated as follows for each type of *class r reserve*:

a. For synchronized *ten-minute operating reserve*:

$$ORSCB_{r1,k,h}^{m,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r1,k,h}^{m,t}}{\sum_R^M ORIA_{r,k,h}^{m,t}}$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB_{r2,k,h}^{m,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r2,k,h}^{m,t}}{\sum_R^M ORIA_{r,k,h}^{m,t}}$$

c. For *thirty-minute operating reserve*:

$$ORSCB_{r3,k,h}^{m,t} = ORSCB_{k,h}^{M,t} \times \frac{ORIA_{r3,k,h}^{m,t}}{\sum_R^M ORIA_{r,k,h}^{m,t}}$$

Where:

i. 'M' is the set of all *delivery points* 'm' of the aggregated group of *dispatchable generation resources;*

ii. $ORIA_{r1,k,h}^{m,t}$ is the amount of inaccessible synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA_{r1,k,h}^{m,t} = Min\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right)$$

iii. $ORIA_{r2,k,h}^{m,t}$ is the amount of inaccessible non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA_{r2,k,h}^{m,t} = Min\left[0, Max\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right) - RT\_QSOR_{r2,k,h}^{m,t}\right]$$

iv. $ORIA_{r3,k,h}^{m,t}$ is the amount of inaccessible *thirty-minute operating reserve*, and determined in accordance with the following:

$$ORIA_{r3,k,h}^{m,t} = Min\left[0, Max\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}\right) - RT\_QSOR_{r3,k,h}^{m,t}\right]$$

v. $ORSCB_{k,h}^{M,t}$ is the total amount of *operating reserve* non-accessibility charge calculated for all *delivery points* 'm' of the aggregated group of *dispatchable generation resources* 'M', as calculated in section 3.10.10;

3.10.10 For the purposes of calculating the *operating reserve* non-accessibility charge *settlement amount* set out in section 3.10.9*,* $ORSCB_{k,h}^{M,t}$ is calculated as follows:

$$ORSCB_{k,h}^{M,t} = Min\left[0, \sum\nolimits_{R}^{M}\left(NORD_{r,k,h}^{m,t} \times RT\_PROR_{r,k,h}^{m,t}\right)\right]$$

Where:

a. 'M' is the set of all *delivery points* 'm' of the aggregated group of *dispatchable generation resources;*

b. $NORD_{r,k,h}^{m,t}$ is the net *operating reserve* deviation, and is calculated as follows for each type of *class r reserve*:

i. For synchronized *ten-minute operating reserve*:

$$NORD_{r1,k,h}^{m,t} = Min\left(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{k,h}^{m,t}\right) + REAH_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}$$

ii. For non-synchronized *ten-minute operating reserve*:

$$NORD_{r2,k,h}^{m,t} = Min[RT\_QSOR_{r2,k,h}^{m,t}, Max\ (0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}) + REAH_{r2,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}$$

iii. For *thirty-minute operating reserve*:

$$NORD_{r3,k,h}^{m,t} = Min[RT\_QSOR_{r3,k,h}^{m,t}, Max\ (0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}) + REAH_{r3,k,h}^{m,t} - RT\_QSOR_{r3,k,h}^{m,t}$$

Where:

i. $REAH_{r,k,h}^{m,t}$ is the allocated excess available headroom for the relevant *dispatchable generation resources,* and is calculated as follows for each type of *class r reserve*:

$$REAH_{r,k,h}^{m,t} = TREAH_{r,k,h}^{M,t} \times \frac{EAH_{k,h}^{m,t}}{\sum^{M} EAH_{k,h}^{m,t}}$$

ii. $EAH_{k,h}^{m,t}$ is the total amount of excess available headroom for the relevant *delivery point* 'm', and is calculated as follows:

$$EAH_{k,h}^{m,t} = Max\left(0, TAOR_{k,h}^{m,t} - \sum\nolimits_{R} RT\_QSOR_{r,k,h}^{m,t}\right)$$

iii. $TREAH_{r,k,h}^{M,t}$ is the total reallocated excess available headroom for the aggregated *dispatchable generation resources*. When $\sum^{M} EAH_{k,h}^{m,t}$ is equal to zero, then $TREAH_{r,k,h}^{M,t}$ will also equal zero, and when $\sum^{M} EAH_{k,h}^{m,t}$ is greater than zero, then $TREAH_{r,k,h}^{M,t}$ is calculated as follows for each *class r reserve*:

a. $TREAH_{r1,k,h}^{M,t}$ is the total reallocated excess available headroom for synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$TREAH_{r1,k,h}^{M,t} = Min\left(\sum\nolimits^{M} EAH_{k,h}^{m,t}, (-1) \times \sum\nolimits^{M} ORIA_{r1,k,h}^{m,t}\right)$$

b. $TREAH_{r2,k,h}^{M,t}$ is the total reallocated excess available headroom for non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$TREAH_{r2,k,h}^{M,t} = Min\left[\left(\sum\nolimits^{M} EAH_{k,h}^{m,t}\right) - TREAH_{r1,k,h}^{M,t}, (-1) \times \sum\nolimits^{M} ORIA_{r2,k,h}^{m,t}\right]$$

c. $TREAH_{r3,k,h}^{M,t}$ is the total reallocated excess available headroom for *thirty-minute operating reserve*, and determined in accordance with the following:

$$TREAH_{r3,k,h}^{M,t} = Min\left[\left(\sum\nolimits^{M} EAH_{k,h}^{m,t}\right) - TREAH_{r1,k,h}^{M,t} - TREAH_{r2,k,h}^{M,t}, (-1) \times \sum\nolimits^{M} ORIA_{r3,k,h}^{m,t}\right]$$

Operating Reserve Non-Accessibility Charge for Dispatchable Generation Resources That Are Pseudo-Units

Combustion Turbine

3.10.11 The *operating reserve* non-accessibility charge *settlement amount* shall be calculated and collected from the combustion turbine *resource* of a non-aggregated *dispatchable generation resource* that is a *pseudo unit* for any *metering interval* when the *market participant* was not activated by the *IESO* to provide *operating reserve* and the following is true:

a. $\sum_R RT\_QSOR^{c,t}_{r,k,h} > 0$; and

b. $\sum_R RT\_QSOR^{c,t}_{r,k,h} > TAOR\_CT^{c,t}_{k,h}$

3.10.12 For each combustion turbine *resource delivery point* 'c' associated with an aggregated *dispatchable generation resources*, the *operating reserve* non-accessibility charge *settlement amount* is calculated as follows for each type of *class r reserve*:

a. For synchronized *ten-minute operating reserve*:

$$ORSCB^{c,t}_{r1,k,h} = ORSCB^{M,t}_{k,h} \times \frac{ORIA^{c,t}_{r1,k,h}}{\sum_R^M (ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h})}$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB^{c,t}_{r2,k,h} = ORSCB^{M,t}_{k,h} \times \frac{ORIA^{c,t}_{r2,k,h}}{\sum_R^M (ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h})}$$

c. For *thirty-minute operating reserve*:

$$ORSCB^{c,t}_{r3,k,h} = ORSCB^{M,t}_{k,h} \times \frac{ORIA^{c,t}_{r3,k,h}}{\sum_R^M (ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h})}$$

Where:

i. 'M' is the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources;*

ii. $ORIA^{c,t}_{r1,k,h}$ is the amount of inaccessible synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA^{c,t}_{r1,k,h} = Min\left(0, TAOR\_CT^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h}\right)$$

iii. $ORIA^{c,t}_{r2,k,h}$ is the amount of inaccessible non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA^{c,t}_{r2,k,h} = Min\left[0, Max\left(0, TAOR\_CT^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h}\right) - RT\_QSOR^{c,t}_{r2,k,h}\right]$$

iv. $ORIA^{c,t}_{r3,k,h}$ is the amount of inaccessible *thirty-minute operating reserve*, and determined in accordance with the following:

$$ORIA^{c,t}_{r3,k,h} = Min\left[0, Max\left(0, TAOR\_CT^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h} - RT\_QSOR^{c,t}_{r2,k,h}\right) - RT\_QSOR^{c,t}_{r3,k,h}\right]$$

v. $ORSCB^{M,t}_{k,h}$ is the total amount of *operating reserve* non-accessibility charge calculated for all *delivery points* 'm' of the aggregated group of *dispatchable generation resources* 'M', as calculated in section 3.10.15.

Steam Turbine

3.10.13 The *operating reserve* non-accessibility charge *settlement amount* shall be calculated and collected from the steam turbine *resource* of a non-aggregated *dispatchable generation resources* that is a *pseudo unit* for any *metering interval* when the *market participant* was not activated by the *IESO* to provide *operating reserve* and the following is true:

a. $\sum_R RT\_QSOR^{s,t}_{r,k,h} > 0$; and

b. $\sum_R RT\_QSOR^{s,t}_{r,k,h} > TAOR\_ST^{s,t}_{k,h}$

3.10.14 For each steam turbine *resource delivery point* 's' associated with an aggregated *dispatchable generation resources*, the *operating reserve* non-accessibility charge *settlement amount* is calculated as follows for each type of *class r reserve*:

a. For synchronized *ten-minute operating reserve*:

$$ORSCB^{s,t}_{r1,k,h} = ORSCB^{M,t}_{k,h} \times \frac{ORIA^{s,t}_{r1,k,h}}{\sum_R^M (ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h})}$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB^{s,t}_{r2,k,h} = ORSCB^{M,t}_{k,h} \times \frac{ORIA^{s,t}_{r2,k,h}}{\sum_R^M (ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h})}$$

c. For *thirty-minute operating reserve*:

$$ORSCB^{s,t}_{r3,k,h} = ORSCB^{M,t}_{k,h} \times \frac{ORIA^{s,t}_{r3,k,h}}{\sum_R^M (ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h})}$$

Where:

i. 'M' is the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources;*

ii. $ORIA^{s,t}_{r1,k,h}$ is the amount of inaccessible synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA^{s,t}_{r1,k,h} = Min\left(0, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h}\right)$$

iii. $ORIA^{s,t}_{r2,k,h}$ is the amount of inaccessible non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA^{s,t}_{r2,k,h} = Min\left[0, Max\left(0, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h}\right) - RT\_QSOR^{s,t}_{r2,k,h}\right]$$

iv. $ORIA^{s,t}_{r3,k,h}$ is the amount of inaccessible *thirty-minute operating reserve*, and determined in accordance with the following:

$$ORIA^{s,t}_{r3,k,h} = Min\left[0, Max\left(0, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h}\right) - RT\_QSOR^{s,t}_{r3,k,h}\right]$$

v. $ORSCB^{M,t}_{k,h}$ is the total amount of *operating reserve* non-accessibility charge calculated for all *delivery points* 'm' of the aggregated group of *dispatchable generation resources* 'M', as calculated in section 3.10.15;

Pseudo-Units

3.10.15 For the purposes of calculating the *operating reserve* non-accessibility charge *settlement amount* set out in sections 3.10.12 and 3.10.14*,* $ORSCB^{M,t}_{k,h}$ is calculated as follows:

$$ORSCB^{M,t}_{k,h} = Min\left[0, \sum_{R}^{M}\left(\left(NORD^{c,t}_{r,k,h} \times RT\_PROR^{c,t}_{r,k,h}\right) + \left(NORD^{s,t}_{r,k,h} \times RT\_PROR^{s,t}_{r,k,h}\right)\right)\right]$$

Where:

a. 'M' is the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources;*

b. $NORD^{c,t}_{r,k,h}$ is the net *operating reserve* deviation for a combustion turbine *resource*, and is calculated as follows for each type of *class r reserve*:

i. For synchronized *ten-minute operating reserve*:

$$NORD^{c,t}_{r1,k,h} = Min\left(RT\_QSOR^{c,t}_{r1,k,h}, TAOR^{c,t}_{k,h}\right) + REAH^{c,t}_{r1,k,h} - RT\_QSOR^{c,t}_{r1,k,h}$$

ii. For non-synchronized *ten-minute operating reserve*:

$$NORD^{c,t}_{r2,k,h} = Min[RT\_QSOR^{c,t}_{r2,k,h}, Max\ (0, TAOR^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h})] + REAH^{c,t}_{r2,k,h} - RT\_QSOR^{c,t}_{r2,k,h}$$

iii. For *thirty-minute operating reserve*:

$$NORD^{c,t}_{r3,k,h} = Min[RT\_QSOR^{c,t}_{r3,k,h}, Max\ (0, TAOR^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h} - RT\_QSOR^{c,t}_{r2,k,h})] + REAH^{c,t}_{r3,k,h} - RT\_QSOR^{c,t}_{r3,k,h}$$

Where:

i. $REAH^{c,t}_{r,k,h}$ is the allocated excess available headroom for the relevant *dispatchable generation resources,* and is calculated as follows for each type of *class r reserve*:

$$REAH^{c,t}_{r,k,h} = TREAH^{M,t}_{r,k,h} \times \frac{EAH^{c,t}_{k,h}}{\sum^{M}\left(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}\right)}$$

ii. $EAH^{c,t}_{k,h}$ is the total amount of excess available headroom for the relevant combustion turbine *resource delivery point* ‘c’, and is calculated as follows:

$$EAH^{c,t}_{k,h} = Max\left(0, TAOR\_CT^{c,t}_{k,h} - \sum\nolimits_{R} RT\_QSOR^{\ c,t}_{r,k,h}\right)$$

c. $NORD^{s,t}_{r,k,h}$ is the net *operating reserve* deviation for a steam turbine *resource*, and is calculated as follows for each type of *class r reserve*:

i. For synchronized *ten-minute operating reserve*:

$$NORD^{s,t}_{r1,k,h} = Min\left(RT\_QSOR^{s,t}_{r1,k,h}, TAOR^{s,t}_{k,h}\right) + REAH^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r1,k,h}$$

ii. For non-synchronized *ten-minute operating reserve*:

$$NORD^{s,t}_{r2,k,h} = Min[RT\_QSOR^{s,t}_{r2,k,h}, Max\ (0, TAOR^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h})] + REAH^{s,t}_{r2,k,h} - RT\_QSOR^{s,t}_{r2,k,h}$$

iii. For *thirty-minute operating reserve*:

$$NORD^{s,t}_{r3,k,h} = Min[RT\_QSOR^{s,t}_{r3,k,h}, Max\ (0, TAOR^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h})] + REAH^{s,t}_{r3,k,h} - RT\_QSOR^{s,t}_{r3,k,h}$$

Where:

i. $REAH^{s,t}_{r,k,h}$ is the allocated excess available headroom for the relevant *dispatchable generation resources,* and is calculated as follows for each type of *class r reserve*:

$$REAH^{s,t}_{r,k,h} = TREAH^{M,t}_{r,k,h} \times \frac{EAH^{s,t}_{k,h}}{\sum^{M}\left(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}\right)}$$

ii. $EAH^{s,t}_{k,h}$ is the total amount of excess available headroom for the relevant steam turbine *resource delivery point* 's', and is calculated as follows:

$$EAH^{s,t}_{k,h} = Max\left(0, TAOR\_ST^{s,t}_{k,h} - \sum\nolimits_{R} RT\_QSOR^{\ s,t}_{r,k,h}\right)$$

d. $TREAH^{M,t}_{r,k,h}$ is the total reallocated excess available headroom for the aggregated *dispatchable generation resources*, as calculated in accordance with section 3.10.16.

3.10.16 For the purposes of calculating the *operating reserve* non-accessibility charge *settlement amount* set out in sections 3.10.12 and 3.10.14*,* $TREAH^{M,t}_{r,k,h}$ is the total reallocated excess available headroom for the aggregated *dispatchable generation resources*. When $\sum^{M}(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h})$ is equal to zero, then $TREAH^{M,t}_{r,k,h}$ will also equal zero, and when $\sum^{M}(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h})$ is greater than zero, then $TREAH^{M,t}_{r,k,h}$ is calculated as follows for each *class r reserve*:

a. $TREAH^{M,t}_{r1,k,h}$ is the total reallocated excess available headroom for synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$TREAH^{M,t}_{r1,k,h} = Min\left(\sum\nolimits^{M}(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}), (-1) \times \sum\nolimits^{M}(ORIA^{c,t}_{r1,k,h} + ORIA^{s,t}_{r1,k,h})\right)$$

$TREAH^{M,t}_{r2,k,h}$ is the total reallocated excess available headroom for non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$TREAH^{M,t}_{r2,k,h} = Min\left[\left(\sum\nolimits^{M}\left(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}\right)\right) - TREAH^{M,t}_{r1,k,h}, (-1) \times \sum\nolimits^{M}\left(ORIA^{c,t}_{r2,k,h} + ORIA^{s,t}_{r2,k,h}\right)\right]$$

b. $TREAH^{M,t}_{r3,k,h}$ is the total reallocated excess available headroom for *thirty-minute operating reserve*, and determined in accordance with the following:

$$TREAH^{M,t}_{r3,k,h} = Min\left[\left(\sum^{M}\left(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}\right)\right) - TREAH^{M,t}_{r1,k,h} - TREAH^{M,t}_{r2,k,h}, (-1) \times \sum^{M}\left(ORIA^{c,t}_{r3,k,h} + ORIA^{s,t}_{r3,k,h}\right)\right]$$

Real-Time Make-Whole Payment Reversal Charge for Dispatchable Loads, Dispatchable Electricity Storage Resources, and Dispatchable Generation Resources That Are Not Pseudo-Units

3.10.17 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* or a *dispatchable generation resource* that is not a *pseudo-unit*, the real-time make-whole payment reversal charge *settlement amount* ($RT\_MWP\_RC^{m}_{k,h}$) is calculated as follows:

$$RT\_MWP\_RC^{m}_{k,h} = \sum^{T}(RT\_OLC\_RC^{m,t}_{k,h} + RT\_OLOC\_RC^{m,t}_{k,h})$$

Where:

a. The *operating reserve* non-accessibility lost cost reversal, $RT\_OLC\_RC^{m,t}_{k,h}$, is calculated in accordance with section 3.10.18.

b. The *operating reserve* non-accessibility lost opportunity cost reversal, $RT\_OLOC\_RC^{m,t}_{k,h}$, is calculated in accordance with section 3.10.19.

3.10.18 The *operating reserve* lost cost component reversal charge, $RT\_OLC\_RC^{m,t}_{k,h}$, is calculated as follows:

$$RT\_OLC\_RC^{m,t}_{k,h} = Min[0, Max\,(-1 \times (RT\_ELC^{m,t}_{k,h} + RT\_OLC^{m,t}_{k,h}), \sum_{R} OLC\_CB^{m,t}_{r,k,h})]$$

Where:

a. For synchronized *ten-minute operating reserve*:

i. if $TAOR_{k,h}^{m,t} < RT\_QSOR_{r1,k,h}^{m,t}$ and if $RT\_OR\_LC\_EOP_{r1,k,h}^{m,t} < RT\_QSOR_{r1,k,h}^{m,t}$ then:

$$OLC\_CB_{r1,k,h}^{m,t} = \{OP\left(RT\_PROR_{r1,h}^{m,t}, Max(DAM\_QSOR_{r1,k,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}), BOR_{r1,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r1,h}^{m,t}, Max\left(TAOR_{k,h}^{m,t}, RT\_OR\_LC\_EOP_{r1,k,h}^{m,t}, DAM\_QSOR_{r1,k,h}^{m,t}\right), BOR_{r1,k,h}^{m,t}\right] /12$$

ii. Otherwise, $OLC\_CB_{r1,k,h}^{m,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} < RT\_QSOR_{r2,k,h}^{m,t}$ and if $RT\_OR\_LC\_EOP_{r2,k,h}^{m,t} < RT\_QSOR_{r2,k,h}^{m,t}$, then:

$$OLC\_CB_{r2,k,h}^{m,t} = \{OP\left(RT\_PROR_{r2,h}^{m,t}, Max(DAM\_QSOR_{r2,k,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}), BOR_{r2,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r2,h}^{m,t}, Max\left(TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}, RT\_OR\_LC\_EOP_{r2,k,h}^{m,t}, DAM\_QSOR_{r2,k,h}^{m,t}\right), BOR_{r2,k,h}^{m,t}\right]/12$$

ii. Otherwise, $OLC\_CB_{r2,k,h}^{m,t} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t} < RT\_QSOR_{r3,k,h}^{m,t}$ and if $RT\_OR\_LC\_EOP_{r3,k,h}^{m,t} < RT\_QSOR_{r3,k,h}^{m,t}$, then:

$$OLC\_CB_{r3,k,h}^{m,t} = \{OP\left(RT\_PROR_{r3,h}^{m,t}, Max(DAM\_QSOR_{r3,k,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}\right) - OP\left[RT\_PROR_{r3,h}^{m,t}, Max\left(TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}, RT\_OR\_LC\_EOP_{r3,k,h}^{m,t}, DAM\_QSOR_{r3,k,h}^{m,t}\right), BOR_{r3,k,h}^{m,t}\right]/12$$

ii. Otherwise, $OLC\_CB_{r3,k,h}^{m,t} = 0$

3.10.19 The *operating reserve* lost opportunity cost component reversal charge, $RT\_OLOC\_RC_{k,h}^{m}$, is calculated as follows:

$$RT\_OLOC\_RC_{k,h}^{m} = Min[0, Max\,(-1 \times (RT\_ELOC_{k,h}^{m,t} + RT\_OLOC_{k,h}^{m,t}), \sum_{R} OLOC\_CB_{r,k,h}^{m,t})]$$

Where:

a. If the *offer* price of $BOR_{r,k,h}^{m,t}$ is greater than $RT\_PROR_{r,h}^{m,t}$, the *offer* price of $BOR_{r,k,h}^{m,t}$ shall be adjusted to be equal to $RT\_PROR_{r,h}^{m,t}$.

b. For synchronized *ten-minute operating reserve*:

i. (i) if $TAOR_{k.h}^{m,t} < RT\_OR\_LOC\_EOP_{r1.k.h}^{m,t}$ and if $RT\_QSOR_{r1.k.h}^{m,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}$ then:

$$OLOC\_CB_{r1,k,h}^{m,t} = (-1) \times \{OP(RT\_PROR_{r1,h}^{m,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t}) - OP[RT\_PROR_{r1,h}^{m,t}, Max(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{k,h}^{m,t}), BOR_{r1,k,h}^{m,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r1,k,h}^{m,t} = 0$

c. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR_{k.h}^{m,t} - RT\_QSOR_{r1.k.h}^{m,t} < RT\_OR\_LOC\_EOP_{r2.k.h}^{m,t}$ and if $RT\_QSOR_{r2,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}$, then:

$$OLOC\_CB_{r2,k,h}^{m,t} = (-1) \times \{OP(RT\_PROR_{r2,h}^{m,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t}) - OP[RT\_PROR_{r2,h}^{m,t}, Max(RT\_QSOR_{r2,k,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}), BOR_{r2,k,h}^{m,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r2,k,h}^{m,t} = 0$

d. For *thirty-minute operating reserve*:

i. if $TAOR_{k.h}^{m,t} - RT\_QSOR_{r1.k.h}^{m,t} - RT\_QSOR_{r2.k.h}^{m,t} < RT\_OR\_LOC\_EOP_{r3.k.h}^{m,t}$ and if $RT\_QSOR_{r3,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}$, then:

$$OLOC\_CB_{r3,k,h}^{m,t} = (-1) \times \{OP(RT\_PROR_{r3,h}^{m,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}) - OP[RT\_PROR_{r3,h}^{m,t}, Max(RT\_QSOR_{r3,k,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}), BOR_{r3,k,h}^{m,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r3,k,h}^{m,t} = 0$

Real-Time Make-Whole Payment Reversal Charge for Dispatchable Generation Resources That Are Pseudo-Units

Combustion Turbine

3.10.20 For a *delivery point* 'c' for a combustion turbine *resource* associated with a *pseudo unit*, the real-time make-whole payment reversal charge *settlement amount* ($RT\_MWP\_RC^{c}_{k,h}$) is calculated as follows:

$$RT\_MWP\_RC_{k,h}^{c} = \sum^{T} (RT\_OLC\_RC_{k,h}^{c,t} + RT\_OLOC\_RC_{k,h}^{c,t})$$

Where:

a. The *operating reserve* non-accessibility lost cost reversal, $RT\_OLC\_RC_{k,h}^{c}$, is calculated in accordance with section 3.10.21.

b. The *operating reserve* non-accessibility lost opportunity cost reversal, $RT\_OLOC\_RC_{k,h}^{c}$, is calculated in accordance with section 3.10.22.

3.10.21 The *operating reserve* lost cost component reversal charge, $RT\_OLC\_RC^{c}_{k,h}$, is calculated as follows:

$$RT\_OLC\_RC^{c,t}_{k,h} = Min[0, Max\ (-1 \times (RT\_ELC^{c,t}_{k,h} + RT\_OLC^{c,t}_{k,h}), \sum_{R} OLC\_CB^{c,t}_{r,k,h})]$$

Where:

a. For synchronized *ten-minute operating reserve*:

i. if $TAOR^{c,t}_{k,h} < RT\_QSOR^{c,t}_{r1,k,h}$ and if $RT\_OR\_LC\_EOP^{c,t}_{r1,k,h} < RT\_QSOR^{c,t}_{r1,k,h}$ then:

$$OLC\_CB^{c,t}_{r1,k,h} = \{OP(RT\_PROR^{c,t}_{r1,h}, Max\ (DAM\_QSOR^{c}_{r1,k,h}, RT\_QSOR^{c}_{r1,k,h}), RT\_OR\_DIPC^{c,t}_{r1,k,h}) - OP[RT\_PROR^{c,t}_{r1,h}, Max(TAOR\_CT^{c,t}_{k,h}, RT\_OR\_LC\_EOP^{c,t}_{r1,k,h}, DAM\_QSOR^{c}_{r1,k,h}), RT\_OR\_DIPC^{c,t}_{r1,k,h}]\} /12$$

ii. Otherwise, $OLOC\_CB^{c,t}_{r1,k,h} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h} < RT\_QSOR^{c,t}_{r2,k,h}$ and if $RT\_OR\_LC\_EOP^{c,t}_{r2,k,h} < RT\_QSOR^{c,t}_{r2,k,h}$ then:

$$OLC\_CB^{c,t}_{r2,k,h} = \{OP(RT\_PROR^{c,t}_{r2,h}, Max\ (DAM\_QSOR^{c}_{r2,k,h}, RT\_QSOR^{c}_{r2,k,h}), RT\_OR\_DIPC^{c,t}_{r2,k,h}) - OP[RT\_PROR^{c,t}_{r2,h}, Max(TAOR\_CT^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h}, RT\_OR\_LC\_EOP^{c,t}_{r2,k,h}, DAM\_QSOR^{c}_{r2,k,h}), RT\_OR\_DIPC^{c,t}_{r2,k,h}]\}/12$$

ii. Otherwise, $OLOC\_CB^{c,t}_{r2,k,h} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h} - RT\_QSOR^{c,t}_{r2,k,h} < RT\_QSOR^{c,t}_{r3,k,h}$ and if $RT\_OR\_LC\_EOP^{c,t}_{r3,k,h} < RT\_QSOR^{c,t}_{r3,k,h}$ then:

$$OLC\_CB^{c,t}_{r3,k,h} = \{OP(RT\_PROR^{c,t}_{r3,h}, Max\ (DAM\_QSOR^{c}_{r3,k,h}, RT\_QSOR^{c}_{r3,k,h}), RT\_OR\_DIPC^{c,t}_{r3,k,h}) - OP[RT\_PROR^{c,t}_{r3,h}, Max(TAOR\_CT^{c,t}_{k,h} - RT\_QSOR^{c,t}_{r1,k,h} - RT\_QSOR^{c,t}_{r2,k,h}, RT\_OR\_LC\_EOP^{c,t}_{r3,k,h}, DAM\_QSOR^{c}_{r3,k,h}), RT\_OR\_DIPC^{c,t}_{r3,k,h}]\}/12$$

ii. Otherwise, $OLOC\_CB^{c,t}_{r3,k,h} = 0$

3.10.22 The *operating reserve* lost opportunity cost component reversal charge, $RT\_OLOC\_RC^{c}_{k,h}$, is calculated as follows:

$$RT\_OLOC\_RC_{k,h}^{c,t} = Min[0, Max\,(-1 \times (RT\_ELOC_{k,h}^{c,t} + RT\_OLOC_{k,h}^{c,t}), \sum_{R} OLOC\_CB_{r,k,h}^{c,t})]$$

Where:

a. If the *offer* price of $RT\_OR\_DIPC_{r,k,h}^{c,t}$ is greater than $RT\_PROR_{r,h}^{c,t}$, the *offer* price of $RT\_OR\_DIPC_{r,k,h}^{c,t}$ shall be adjusted to be equal to $RT\_PROR_{r,h}^{c,t}$.

b. For synchronized *ten-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}$ and if $RT\_QSOR_{r1,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}$ then:

$$OLOC\_CB_{r1,k,h}^{c,t} = \Big\{(-1) \times \{OP\big(RT\_PROR_{r1,h}^{c,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r1,k,h}^{c,t}\big) - OP\big[RT\_PROR_{r1,h}^{c,t}, Max(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}), RT\_OR\_DIPC_{r1,k,h}^{c,t}\big]\}\Big\}/12$$

ii. Otherwise, $OLOC\_CB_{r1,k,h}^{c,t} = 0$

c. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}$ and if $RT\_QSOR_{r2,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}$ then:

$$OLOC\_CB_{r2,k,h}^{c,t} = \Big\{(-1) \times \{OP\big(RT\_PROR_{r2,h}^{c,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t}\big) - OP\big[RT\_PROR_{r2,h}^{c,t}, Max(RT\_QSOR_{r2,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}), RT\_OR\_DIPC_{r2,k,h}^{c,t}\big]\}\Big\}/12$$

ii. Otherwise, $OLOC\_CB_{r2,k,h}^{c,t} = 0$

d. For *thirty-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2\ k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}$ and if $RT\_QSOR_{r3,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}$ then:

$$OLOC\_CB_{r3,k,h}^{c,t} = \Big\{(-1) \times \{OP\big(RT\_PROR_{r3,h}^{c,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}\big) - OP\big[RT\_PROR_{r3,h}^{c,t}, Max(RT\_QSOR_{r3,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}), RT\_OR\_DIPC_{r3,k,h}^{c,t}\big]\}\Big\}/12$$

ii. Otherwise, $OLOC\_CB_{r3,k,h}^{c,t} = 0$

Steam Turbine

3.10.23 For a *delivery point* 's' for a steam turbine *resource* associated with a *pseudo unit*, the real-time make-whole payment reversal charge *settlement amount* ($RT\_MWP\_RC^{s}_{k,h}$) is calculated as follows:

$$RT\_MWP\_RC_{k,h}^{s} = \sum^{T} (RT\_OLC\_RC_{k,h}^{s,t} + RT\_OLOC\_RC_{k,h}^{s,t})$$

Where:

a. The *operating reserve* non-accessibility lost cost reversal, $RT\_OLC\_RC_{k,h}^{s}$, is calculated in accordance with section 3.10.24.

b. The *operating reserve* non-accessibility lost opportunity cost reversal, $RT\_OLOC\_RC_{k,h}^{s}$, is calculated in accordance with section 3.10.25.

3.10.24 The *operating reserve* lost cost component reversal charge, $RT\_OLC\_RC_{k,h}^{s}$, is calculated as follows:

$$RT\_OLC\_RC_{k,h}^{s,t} = Min[0, Max\ (-1 \times (RT\_ELC_{k,h}^{s,t} + RT\_OLC_{k,h}^{s,t}), \sum\nolimits_{R} OLC\_CB_{r,k,h}^{s,t})]$$

Where:

a. For synchronized *ten-minute operating reserve*:

i. if $TAOR\_ST^{s,t}_{k,h} < RT\_QSOR^{s,t}_{r1,k,h}$ and if $RT\_OR\_LC\_EOP^{s,t}_{r1,k,h} < RT\_QSOR^{s,t}_{r1,k,h}$ then:

$$OLC\_CB^{s,t}_{r1,k,h} = \{OP(RT\_PROR^{s,t}_{r1,h}, Max(DAM\_QSOR^{s,t}_{r1,k,h}, RT\_QSOR^{s,t}_{r1,k,h}), RT\_OR\_DIPC^{s,t}_{r1,k,h}) - OP[RT\_PROR^{s,t}_{r1,h}, Max(TAOR\_ST^{s,t}_{k,h}, RT\_OR\_LC\_EOP^{s,t}_{r1,k,h}, DAM\_QSOR^{s,t}_{r1,k,h}), RT\_OR\_DIPC^{s,t}_{r1,k,h}] /12$$

ii. Otherwise, $OLC\_CB^{s,t}_{r1,k,h} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} < RT\_QSOR^{s,t}_{r2,k,h}$ and if $RT\_OR\_LC\_EOP^{s,t}_{r2,k,h} < RT\_QSOR^{s,t}_{r2,k,h}$ then:

$$OLC\_CB^{s,t}_{r1,k,h} = \{OP(RT\_PROR^{s,t}_{r2,h}, Max(DAM\_QSOR^{s,t}_{r2,k,h}, RT\_QSOR^{s,t}_{r2,k,h}), RT\_OR\_DIPC^{s,t}_{r2,k,h}) - OP[RT\_PROR^{s,t}_{r2,h}, Max(TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h}, RT\_OR\_LC\_EOP^{s,t}_{r2,k,h}, DAM\_QSOR^{s,t}_{r2,k,h}), RT\_OR\_DIPC^{s,t}_{r2,k,h}] /12$$

ii. Otherwise, $OLC\_CB^{s,t}_{r2,k,h} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR\_ST^{s,t}_{k,h} - RT_{QSOR}{}^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h} < RT\_QSOR^{s,t}_{r3,k,h}$ and if $RT\_OR\_LC\_EOP^{s,t}_{r3,k,h} < RT\_QSOR^{s,t}_{r3,k,h}$ then:

$$OLC\_CB^{s,t}_{r3,k,h} = \{OP(RT\_PROR^{s,t}_{r3,h}, Max(DAM\_QSOR^{s,t}_{r3,k,h}, RT\_QSOR^{s,t}_{r3,k,h}), RT\_OR\_DIPC^{s,t}_{r3,k,h}) - OP[RT\_PROR^{s,t}_{r3,h}, Max(TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h}, RT\_OR\_LC\_EOP^{s,t}_{r3,k,h}, DAM\_QSOR^{s,t}_{r3,k,h}), RT\_OR\_DIPC^{s,t}_{r3,k,h}]/12$$

ii. Otherwise, $OLC\_CB^{s,t}_{r3,k,h} = 0$

3.10.25 The *operating reserve* lost opportunity cost component reversal charge, $RT\_OLOC\_RC^{s}_{k,h}$, is calculated as follows:

$$RT\_OLOC\_RC^{s}_{k,h} = Min[0, Max\,(-1 \times (RT\_ELOC^{s,t}_{k,h} + RT\_OLOC^{c,t}_{k,h}), \sum_{R} OLOC\_CB^{s,t}_{r,k,h})]$$

Where:

a. If the *offer* price of $RT\_OR\_DIPC^{s,t}_{r,k,h}$ is greater than $RT\_PROR^{s,t}_{r,h}$, the *offer* price of $RT\_OR\_DIPC^{s,t}_{r,k,h}$ shall be adjusted to be equal to $RT\_PROR^{s,t}_{r,h}$.

b. For synchronized *ten-minute operating reserve*:

i. if $TAOR\_ST_{k,h}^{s,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{s,t}$ and if $RT\_QSOR_{r1,k,h}^{s,t} < RT\_OR\_LC\_EOP_{r1,k,h}^{s,t}$ then:

$$OLOC\_CB_{r1,k,h}^{s,t} = (-1) \times \{OP(RT\_PROR_{r1,h}^{s,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{s,t}, RT\_OR\_DIPC_{r1,k,h}^{s,t}) - OP[RT\_PROR_{r1,h}^{s,t}, Max(RT\_QSOR_{r1,k,h}^{s,t}, TAOR\_ST_{k,h}^{s,t}), RT\_OR\_DIPC_{r1,k,h}^{s,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r1,k,h}^{s,t} = 0$

c. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{s,t}$ and if $RT\_QSOR_{r2,k,h}^{s,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{s,t}$, then:

$$OLOC\_CB_{r2,k,h}^{s,t} = (-1) \times \{OP(RT\_PROR_{r2,h}^{s,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{s,t}, RT\_OR\_DIPC_{r2,k,h}^{s,t}) - OP[RT\_PROR_{r2,h}^{s,t}, Max(RT\_QSOR_{r2,k,h}^{s,t}, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}), RT\_OR\_DIPC_{r2,k,h}^{s,t}]\} /12$$

ii. Otherwise, $OLOC\_CB_{r2,k,h}^{s,t} = 0$

d. For *thirty-minute operating reserve*:

i. if $TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{s,t}$ and if $RT\_QSOR_{r3,k,h}^{s,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{s,t}$, then:

$$OLOC\_CB_{r3,k,h}^{s,t} = (-1) \times \{OP(RT\_PROR_{r3,h}^{s,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{s,t}, RT\_OR\_DIPC_{r3,k,h}^{s,t}) - OP[RT\_PROR_{r3,h}^{s,t}, Max(RT\_QSOR_{r3,k,h}^{s,t}, TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}), RT\_OR\_DIPC_{r3,k,h}^{s,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r3,k,h}^{s,t} = 0$

Real-Time Generator Offer Guarantee Clawback for GOG-Eligible Resources That Are Not Pseudo-Units

3.10.26 For a *delivery point* 'm' associated with a *GOG-eligible resource* that is not a *pseudo-unit*, the real-time *generator offer* guarantee *clawback settlement amount* ($RT\_GOG\_CB^{m}_{k,h}$) is calculated as follows:

$$RT\_GOG\_CB_k^m = Max\{(-1) \times RT_{GOG}{}_k^m, Min[0, \textstyle\sum_R^{T1}[ORSCB\_REV_{r,k,h}^{m,t} + COMP2\_CB_{r,k,h}^{m,t} - ORIA\_AMT_{r,k,h}^{m,t}] - \sum_R RT\_MWP\_RC_{k,h}^{m,t}]\}$$

Where:

a. 'T1' is the set of all *metering intervals* 't' beginning from the first *metering interval* that the *generation unit* is at *minimum loading point* within a *real-time commitment period* or a *real-time reliability commitment period* until the last *metering interval* that the *generation unit* is at *minimum loading point* within such *real-time commitment period* or a *real-time reliability commitment period*, as applicable.

b. $ORSCB\_REV_{r,k,h}^{m,t}$ = (-1) x $ORSCB_{r,k,h}^{m,t}$

c. $COMP2\_CB_{r,k,h}^{m,t}$ is calculated in accordance with section 3.10.27.

d. $ORIA\_AMT_{r,k,h}^{m,t}$ is calculated in accordance with section 3.10.28.

3.10.27 $COMP2\_CB_{r,k,h}^{m,t}$ is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $TAOR_{k,h}^{m,t} < RT\_QSOR_{r1,k,h}^{m,t}$, then:

$$COMP2\_CB_{r1,k,h}^{m,t} = \{OP[RT\_PROR_{r1,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t}] - OP(RT\_PROR_{r1,h}^{m,t}, TAOR_{k,h}^{m,t}, BOR_{r1,k,h}^{m,t})\}$$

ii. Otherwise, $COMP2\_CB_{r1,k,h}^{m,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} < RT\_QSOR_{r2,k,h}^{m,t}$, then:

$$COMP2\_CB_{r2,k,h}^{m,t} = \{OP[RT\_PROR_{r2,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t}] - OP(RT\_PROR_{r2,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r2,k,h}^{m,t})\}$$

ii. Otherwise, $COMP2\_CB_{r2,k,h}^{m,t} = 0$

c. For *thirty-minute operating reserve*:

i. If $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t} < RT\_QSOR_{r3,k,h}^{m,t}$, then:

$$COMP2\_CB_{r3,k,h}^{m,t} = \{OP[RT\_PROR_{r3,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}] - OP(RT\_PROR_{r3,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r3,k,h}^{m,t})$$

ii. Otherwise, $COMP2\_CB_{r3,k,h}^{m,t} = 0$

3.10.28 The revenue earned for non-accessible *operating reserve*, $ORIA\_AMT^{m,t}_{r,k,h}$, is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $TAOR^{m,t}_{k,h} < RT\_QSOR^{m,t}_{r1,k,h}$, then:

$$ORIA\_AMT^{m,t}_{r1,k,h} = \left[RT\_PROR^{m,t}_{r1,h} \times \left(RT\_QSOR^{m,t}_{r1,k,h} - TAOR^{m,t}_{k,h}\right)\right]$$

ii. Otherwise, $ORIA\_AMT^{m,t}_{r1,k,h} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h} < RT\_QSOR^{m,t}_{r2,k,h}$, then:

$$ORIA\_AMT^{m,t}_{r2,k,h} = \left[RT\_PROR^{m,t}_{r2,h} \times \left(RT\_QSOR^{m,t}_{r2,k,h} - Max(0, TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h})\right)\right]$$

ii. Otherwise, $ORIA\_AMT^{m,t}_{r2,k,h} = 0$

c. For *thirty-minute operating reserve*:

i. If $TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h} - RT\_QSOR^{m,t}_{r2,k,h} < RT\_QSOR^{m,t}_{r3,k,h}$, then:

$$ORIA\_AMT^{m,t}_{r3,k,h} = \left[RT\_PROR^{m,t}_{r3,h} \times \left(RT\_QSOR^{m,t}_{r3,k,h} - TAOR^{m,t}_{k,h} - RT\_QSOR^{m,t}_{r1,k,h} - RT\_QSOR^{m,t}_{r2,k,h}\right)\right]$$

ii. Otherwise, $ORIA\_AMT^{m,t}_{r3,k,h} = 0$

Real-Time Generator Offer Guarantee Clawback for GOG-Eligible Resources That Are Pseudo-Units

Steam Turbine

3.10.29 For a *delivery point* 's' associated with a steam turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit*, the real-time *generator offer* guarantee *clawback settlement amount* ($RT\_GOG\_CB^{s}_{k,h}$) is calculated as follows:

$$RT\_GOG\_CB^{s}_{k} = Max\{(-1) \times RT_{GOG}{}^{s}_{k}, Min[0, \sum_{R}^{T1}[ORSCB\_REV^{s,t}_{r,k,h} + COMP2\_CB^{s,t}_{r,k,h} - ORIA\_AMT^{s,t}_{r,k,h}] - \sum^{T1} RT\_MWP\_RC^{s,t}_{k,h}$$

Where:

a. 'T1' is the set of all *metering intervals* 't' beginning from the first *metering interval* that the steam turbine *resource* is at *minimum loading point* within a *real-time commitment period* or a *real-time reliability commitment period* until the last *metering interval* that the steam turbine *resource* is at *minimum loading point* within such *real-time commitment period* or a *real-time reliability commitment period*, as applicable.

b. $ORSCB\_REV_{k,h}^{s,t} = -1 \times ORSCB_{k,h}^{s,t} \times \frac{\sum_R RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}}{\sum_R RT\_QSOR_{r,k,h}^{s,t}}$

c. $COMP2\_CB_{r,k,h}^{s,t}$ is calculated in accordance with section 3.10.30

d. $ORIA\_AMT_{r,k,h}^{s,t}$ is calculated in accordance with section 3.10.31

e. for the purposes of section 3.10.30 and section 3.10.31, $RT\_GOG\_TAOR\_ST_{k,h}^{s,t}$ is calculated as follows:

$$RT\_GOG\_TAOR\_ST_{k,h}^{s,t} = TAOR\_ST_{k,h}^{s,t} \times \frac{\sum_R RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}}{\sum_R RT\_QSOR_{r,k,h}^{s,t}}$$

3.10.30 $COMP2\_CB_{r,k,h}^{s,t}$ is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}$, then:

$$COMP2\_CB_{r1,k,h}^{s,t} = \{OP[RT\_PROR_{r1,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r1,k,h}^{s,t}] - OP(RT\_PROR_{r1,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r1,k,h}^{s,t})\}$$

ii. Otherwise, $COMP2\_CB_{r1,k,h}^{s,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}$, then:

$$COMP2\_CB_{r2,k,h}^{s,t} = \{OP[RT\_PROR_{r2,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r2,k,h}^{s,t}] - OP(RT\_PROR_{r2,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r2,k,h}^{s,t})\}$$

ii. Otherwise, $COMP2\_CB_{r2,k,h}^{s,t} = 0$

c. For *thirty-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t}$, then:

$$COMP2\_CB_{r3,k,h}^{s,t} = \{OP[RT\_PROR_{r3,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r3,k,h}^{s,t}] - OP(RT\_PROR_{r3,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r3,k,h}^{s,t})\}$$

ii. Otherwise, $COMP2\_CB_{r2,k,h}^{s,t} = 0$

3.10.31 The revenue earned for non-accessible *operating reserve*, $ORIA\_AMT_{r,k,h}^{s,t}$, is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}$, then:

$$ORIA\_AMT_{r1,k,h}^{s,t} = [RT\_PROR_{r1,h}^{s,t} \times (RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_GOG\_TAOR\_ST_{k,h}^{s,t})]$$

ii. Otherwise, $ORIA\_AMT_{r1,k,h}^{s,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t}$, then:

$$ORIA\_AMT_{r2,k,h}^{s,t} = [RT\_PROR_{r2,h}^{s,t} \times (RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t} - Max(0, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}))]$$

ii. Otherwise, $ORIA\_AMT_{r2,k,h}^{s,t} = 0$

c. For *thirty-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r2,k,h}^{s,t} < RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t}$, then:

$$ORIA\_AMT_{r3,k,h}^{s,t} = [RT\_PROR_{r3,h}^{s,t} \times (RT\_OR\_CMT\_DIGQ_{r3,k,h}^{s,t} - Max(0, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t} - RT\_OR\_CMT\_DIGQ_{r1,k,h}^{s,t}))]$$

ii. Otherwise, $ORIA\_AMT_{r3,k,h}^{s,t} = 0$

Combustion Turbine

3.10.32 For a *delivery point* 'c' associated with a combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit*, the real-time *generator offer* guarantee *operating reserve* non-accessibility reversal *settlement amount* ($RT\_GOG\_CB^{c}_{k,h}$) is calculated as follows:

$$RT\_GOG\_CB^{c}_{k} = Max\{(-1) \times RT\_GOG^{c}_{k}, Min[0, \sum_{R}^{T1}[ORSCB\_REV^{c,t}_{r,k,h} + COMP2\_CB^{c,t}_{r,k,h} - ORIA\_AMT^{c,t}_{r,k,h}] - \sum^{T1} RT\_MWP\_RC^{c,t}_{k,h}]\}$$

Where:

a. 'T1' is the set of all *metering intervals* 't' beginning from the first *metering interval* that the combustion turbine *resource* is at *minimum loading point* within a *real-time commitment period* or a *real-time reliability commitment period* until the last *metering interval* that the combustion turbine *resource* is at *minimum loading point* within such *real-time commitment period* or a *real-time reliability commitment period*, as applicable.

b. $ORSCB\_REV^{c,t}_{r,k,h}$ = (-1) x $ORSCB^{c,t}_{r,k,h}$

c. $COMP2\_CB^{c,t}_{r,k,h}$ is calculated in accordance with section 3.10.33.

d. $ORIA\_AMT^{c,t}_{r,k,h}$ is calculated in accordance with section 3.10.34.

3.10.33 $COMP2\_CB^{c,t}_{r,k,h}$ is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $TAOR\_CT^{c,t}_{k,h} < RT\_QSOR^{c,t}_{r1,k,h}$, then:

$$COMP2\_CB^{c,t}_{r1,k,h} = OP(RT\_PROR^{c,t}_{r1,h}, RT\_QSOR^{c,t}_{r1,k,h}, RT\_OR\_DIPC^{c,t}_{r1,k,h}) - OP(RT\_PROR^{c,t}_{r1,h}, TAOR\_CT^{c,t}_{k,h}, RT\_OR\_DIPC^{c,t}_{r1,k,h})$$

ii. Otherwise, $COMP2\_CB^{c,t}_{r1,k,h} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_QSOR_{r2,k,h}^{c,t}$, then:

$$COMP2\_CB_{r2,k,h}^{c,t} = OP\left(RT\_PROR_{r2,h}^{c,t}, RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t}\right) - OP\left(RT\_PROR_{r2,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}, RT\_OR\_DIPC_{r2,k,h}^{c,t}\right)$$

ii. Otherwise, $COMP2\_CB_{r2,k,h}^{c,t} = 0$

c. For *thirty-minute operating reserve*:

i. If $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$, then:

$$COMP2\_CB_{r3,k,h}^{c,t} = OP\left(RT\_PROR_{r3,h}^{c,t}, RT\_QSOR_{r3,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}\right) - OP\left(RT\_PROR_{r3,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_DIPC_{r3,k,h}^{c,t}\right)$$

ii. Otherwise, $COMP2\_CB_{r3,k,h}^{c,t} = 0$

3.10.34 The revenue earned for non-accessible *operating reserve*, $ORIA\_AMT_{r,k,h}^{c,t}$, is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $TAOR\_CT_{k,h}^{c,t} < RT\_QSOR_{r1,k,h}^{c,t}$, then:

$$ORIA\_AMT_{r1,k,h}^{c,t} = \left[RT\_PROR_{r1,h}^{c,t} \times \left(RT\_QSOR_{r1,k,h}^{c,t} - TAOR\_CT_{k,h}^{c,t}\right)\right]$$

ii. Otherwise, $ORIA\_AMT_{r1,k,h}^{c,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_QSOR_{r2,k,h}^{c,t}$, then:

$$ORIA\_AMT_{r2,k,h}^{c,t} = \left[RT\_PROR_{r2,h}^{c,t} \times \left(RT\_QSOR_{r2,k,h}^{c,t} - Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right)\right)\right]$$

ii. Otherwise, $ORIA\_AMT_{r2,k,h}^{c,t} = 0$

c. For *thirty-minute operating reserve*:

i. If $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$, then:

$$ORIA\_AMT_{r3,k,h}^{c,t} = \left[RT\_PROR_{r3,h}^{c,t} \times \left(RT\_QSOR_{r3,k,h}^{c,t} - Max\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}\right)\right)\right]$$

ii. Otherwise, $ORIA\_AMT_{r3\ k,h}^{c,t} = 0$

3.11 Hourly Uplifts

Hourly Uplift Settlement Amount

3.11.1 The total *hourly uplift* for *settlement hour* 'h' ("$HUSA_h$") to be recovered from *market participants* shall be determined according to the following equation:

$$HUSA_h = \sum_K \left(HORSA\{1\}_{k,h} + HORSA\{2\}_{k,h} + DAM\_BC_{k,h} + RT\_MWP_{k,h} + RT\_IOG_{k,h} + RT\_NISLR_h\right) - \sum_K \left(\sum_R ORSSD_{r,k,h} + \sum_R ORSCB_{r,k,h} + RT\_IMFC_{k,h} + RT\_EXFC_{k,h} + DAM\_IMFC_{k,h} + DAM\_EXFC_{k,h} + RT\_RLSC_{k,h} + DAM\_RLSC_{k,h}\right)$$

Where:

a. $HORSA\{1\}_{k,h}$ is the hourly *operating reserve settlement amount* calculated in accordance with section 3.1.10 for *market participant* 'k' in *settlement hour* 'h';

b. $HORSA\{2\}_{k,h}$ is the hourly *operating reserve settlement amount* calculated in accordance with section 3.1.11 for *market participant* 'k' in *settlement hour* 'h';

c. $DAM\_BC_{k,h}$ is the *day-ahead market* balancing credit calculated in accordance with section 3.3 for *market participant* 'k' in *settlement hour* 'h';

d. $RT\_MWP_{k,h}$ is the real-time make-whole payment *settlement amount* calculated in accordance with section 3.5 for *market participant* 'k' in *settlement hour* 'h', as reduced by any $RT\_MWP\_RC^{m}_{k,h}$ calculated in accordance with sections 3.10.2 for such *market participant, delivery point,* and *settlement hour*;

e. $RT\_IOG_{k,h}$ is the net real-time *intertie offer* guarantee *settlement amount* calculated in accordance with section 3.6 for *market participant* 'k' in *settlement hour* 'h';

f. $RT\_IMFC_{k,h}$ is the real-time *intertie* failure charge *settlement amount* for import transactions calculated in accordance with section 3.7.4 for *market participant* 'k' in *settlement hour* 'h';

g. $RT\_EXFC_{k,h}$ is the real-time *intertie* failure charge *settlement amount* for export transactions calculated in accordance with section 3.7.6 for *market participant* 'k' in *settlement hour* 'h';

h. $DAM\_IMFC_{k,h}$ is the hourly *day-ahead market* import failure charge *settlement amount* calculated in accordance with section 3.7A.2 for *market participant* 'k' in *settlement hour* 'h';

i. $DAM\_EXFC_{k,h}$ is the hourly *day-ahead market* export failure charge *settlement amount* calculated in accordance with section 3.7A.3 for *market participant* 'k' in *settlement hour* 'h';

j. RT_NISLR_h is the *real-time market* net interchange scheduling limit (NISL) residual calculated in accordance with section 4.8.8 for *settlement hour* 'h';

k. $GFC\_MPC_{k,h}$ is the *market price* component of the *generator failure* charge *settlement amount* calculated in accordance with sections 4.10.5 and 4.10.8 for *market participant* 'k' in *settlement hour* 'h';

l. $RT\_RLSC_{k,h}$ is the *real-time market reference level settlement* charge *settlement amount* calculated in accordance with section 5.3 for *market participant* 'k' in *settlement hour* 'h';

m. $DAM\_RLSC_{k,h}$ is the *day-ahead market reference level settlement* charge *settlement amount* calculated in accordance with section 5.2 for *market participant* 'k' in *settlement hour* 'h';

n. $ORSSD_{r,k,h}$ is the *operating reserve* shortfall *settlement* debit *settlement amount* calculated in accordance with section 3.9.2 for *market participant* 'k' for *class r reserve* for *settlement hour* 'h'; and

o. $ORSCB_{r,k,h}$ is the *operating reserve* non-accessibility charge *settlement amount* calculated in accordance with section 3.10.1 for *market participant* 'k' for *class r reserve* for *settlement hour* 'h'.

3.11.2 The *IESO* shall allocate the *hourly uplift* to all *market participants* on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *delivery points* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* within each *settlement hour* in which an *hourly uplift* accrues. The *hourly uplift settlement amount* to be collected or disbursed to *market participant* 'k' in *settlement hour* 'h' ("$HUSA_{k,h}$") shall be determined as follows:

$$HUSA_{k,h} = \mathrm{HUSA_h}\ x \left[\sum^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} + RQ_{k,h}^{m,i,t}\right) / \sum_{K}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

a. 'M' is all *delivery points* 'm' and *intertie metering points* 'i'.

3.11.3 The *hourly uplift settlement amount* may be disaggregated by the *IESO* on *settlement statements* in such manner as the *IESO* determines appropriate.

4 Non-Hourly Settlement Amounts

4.1 Transmission Tariff Charges

4.1.1 The *IESO* shall collect from *transmission customers*, and distribute to *transmitters*, *transmission services charges* approved by the *OEB* in accordance with MR Ch.10.

4.2 Ancillary Service Payments

4.2.1 The *IESO* shall have the authority to negotiate *reliability must-run contracts* with *registered market participants* or prospective *registered market participants* regarding the operation of *reliability must-run resources* in accordance with MR Ch.7 s.9. Where such *reliability must-run contracts* provide both for payments from the *energy market* and *operating reserve market* pursuant to section 3 and additional payments for making *physical services*, other than *contracted ancillary services*, available to those markets, any such additional payments required to be made in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *registered wholesale meters* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.2 The *IESO* shall contract for *certified black start facilities* adequate to permit the *IESO* to meet its obligations under MR Ch.5. The costs to the *IESO* of contracting for such *certified black start facilities* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *registered wholesale meters* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.3 The *IESO* shall contract for *regulation* adequate to permit the *IESO* to meet its obligations under MR Ch.5. The costs to the *IESO* of contracting for *regulation* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *registered wholesale meters* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period.*

4.2.4 The *IESO* shall contract for *reactive support service* and *voltage control service* adequate to permit the *IESO* to meet its obligations under MR Ch.5. The costs to the

IESO of contracting for such *reactive support service* and *voltage control service* in a given *energy market billing period* shall be recovered in accordance with the following:

4.2.4.1 *market participants* shall pay for such costs through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *registered wholesale meters* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period;*

4.2.4.2 there shall be no power factor requirements or penalties associated with electrical power flowing out of Ontario through *intertie metering points*; and

4.2.4.3 there shall be no separate compensation from the *IESO* for *reactive support service* and *voltage control service* from equipment such as capacitor banks, reactor banks, and synchronous condensers owned by *transmitters*. Any compensation for providing such *ancillary services* shall be included in the *transmission services charges* to the extent provided by the *OEB*.

4.2.5 Subject to MR Ch.7 ss.9.4.2 and 9.4.4, no compensation shall be paid for *ancillary services* provided pursuant to the connection requirements of MR Ch.4.

4.3 IESO Administration Charge, Penalties, and Fines

4.3.1 The *IESO* shall determine a methodology for calculating and allocating an *IESO administration charge.*

4.4 Day-Ahead Market Generator Offer Guarantee

General

4.4.1 Subject to section 4.4.2 and the mitigation process described in section 5 and Appendix 9.4, the *day-ahead market generator offer* guarantee *settlement amount* for *market participant* 'k' ("DAM_GOG_k") shall be calculated for each *settlement hour* within a *day-ahead commitment period* for each *GOG-eligible resource* and disbursed to the *market participant* for such *resource* in accordance with the operating profit function described in section 10 of Appendix 9.2, and this section 4.4.

4.4.1.1 In determining the *day-ahead market generator offer* guarantee *settlement amount* in this section 4.4, the following expressions shall have the following meanings:

a. "Day 0" refers to the day the *day-ahead market calculation engine* runs to set the *day-ahead schedule* for Day 1;

b. "Day 1" refers to the *dispatch day* for which the *day-ahead market generator offer* guarantee *settlement amount* is being calculated; and

c. *day-ahead commitment period* is the set of contiguous *settlement hours* with *day-ahead schedules* from the start of *minimum generation block run-time* to the end of the *day-ahead operational commitment* or *extended pre-dispatch operational commitment*, as applicable.

4.4.1.2 The *day-ahead market generator offer* guarantee *settlement amount* will be determined utilizing one of three possible variants each of which consists of the following components, where applicable:

a. Component 1 is any shortfall in payment on the *day-ahead schedule* for *energy* based upon the *resource's* operating profit for *energy* and its *speed no-load offers*, and is calculated in accordance with sections 4.4.6, 4.4.15, or 4.4.22, as applicable;

b. Component 2 is any shortfall in payment on the *day-ahead schedule* for *operating reserve* based upon the *resource's* operating profit for *operating reserve,* and is calculated in accordance with sections 4.4.7, 4.4.16, or 4.4.23, as applicable;

c. Component 3 is the amount calculated by Component 1 up to the *minimum loading point* for the *settlement hours* of *minimum generation block run-time* scheduled over midnight into Day 1, and is calculated in accordance with sections 4.4.8, 4.4.17, or 4.4.24, as applicable;

d. Component 4 is any as-offered *start-up costs* to bring an offline *GOG-eligible resource* through its specific start-up procedures to meet its *day-ahead operational commitment*, including synchronization and ramp-up to *minimum loading point*, and is calculated in accordance with sections 4.4.9, 4.4.18, or 4.4.25, as applicable; and

e. Component 5 is any *day-ahead market* make-whole payment *settlement amount* that was received in respect of the same *day-ahead commitment period* and is calculated in accordance with sections 4.4.11, 4.4.20, or 4.4.26, as applicable.

4.4.2 Notwithstanding section 4.4.1, a *market participant* shall be ineligible to receive a *day-ahead market generator offer* guarantee *settlement amount* for a *settlement hour* where:

4.4.2.1 the *GOG-eligible resource* has committed its capacity to an external *control area* and the external *control area operator* has called a *called capacity export*:

a. prior to the *GOG-eligible resource* receiving a *day-ahead operational commitment*; or

b. after the *GOG-eligible resource* receives a *day-ahead operational commitment* and the *IESO* restricts other transactions on *interconnected systems* in accordance with MR Ch.5 s.2.3 and 5.7, while maintaining the *called capacity export* transaction; or

4.4.2.2 when all of the following circumstances are true:

a. the *GOG-eligible resource* has a *day-ahead operational commitment* or *pre-dispatch operational commitment* in the last *settlement hour* of Day 0 at the time the *day-ahead market calculation engine* determines the *day-ahead schedule* for Day 1;

b. the *GOG-eligible resource* has completed its scheduled *minimum generation block run-time* in Day 0 and has a *day-ahead operational schedule* in the first *settlement hour* of Day 1 in order to ramp down the *GOG-eligible resource* to an offline status; and

c. the *GOG-eligible resource* did not receive an *extended pre-dispatch operational commitment* for the first *settlement hour* of Day 1.

Day-Ahead Market Generator Offer Guarantee for Non-Pseudo Units

Formulations

Variant #1

4.4.3 If a *GOG-eligible resource* that is not a *pseudo-unit* meets any of the following conditions:

4.4.3.1 The *GOG-eligible resource* has:

a. a *day-ahead operational schedule* to start in Day 1 to meet a *day-ahead operational commitment* without any preceding *day-ahead operational commitment, pre-dispatch operation commitment,* or *reliability* commitment; or

b. a *day-ahead operational schedule* with a preceding *advanced pre-dispatch operational commitment* or *reliability* commitment that extends less than the *resource's minimum generation block run-time* plus its *minimum generation block down-time,*

the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for *delivery point* 'm':

$$DAM\_GOG_k^m = Max\big[0, DAM\_\_GOG\_COMP1_k^m + DAM\_GOG\_COMP2_k^m + DAM\_GOG\_COMP4_{k,h}^m - DAM\_GOG\_COMP5_k^m\big]$$

Where:

a. $DAM\_GOG\_COMP1_k^m$, $DAM\_GOG\_COMP2_k^m$, $DAM\_GOG\_COMP4_{k,h}^m$ and $DAM\_GOG\_COMP5_k^m$ are calculated in accordance with sections 4.4.6, 4.4.7, 4.4.9,and 4.4.11, respectively.

Variant #2

4.4.4 If a *GOG-eligible resource* that is not a *pseudo-unit* (1) has a *pre-dispatch operational commitment* or a *day-ahead operational commitment* in the last *settlement hour* of Day 0 at the time the *day-ahead market calculation engine* determined the *day-ahead schedule* for Day 1; and (2) is scheduled to complete its *minimum generation block run-time* in Day 1*,* the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for a *delivery point* 'm':

$$DAM\_GOG_k^m = Max[0, DAM\_GOG\_COMP1_k^m + DAM\_GOG\_COMP2_k^m - DAM\_GOG\_COMP3_k^m - DAM\_GOG\_COMP5_k^m]$$

Where:

a. $DAM\_GOG\_COMP1_k^m$, $DAM\_GOG\_COMP2_k^m$, $DAM\_GOG\_COMP3_k^m$ and $DAM\_GOG\_COMP5_k^m$ are calculated in accordance with sections 4.4.6, 4.4.7, 4.4.8, and 4.4.11, respectively.

Variant #3

4.4.5 If a *GOG-eligible resource* that is not a *pseudo-unit* meets any of the following conditions*:*

4.4.5.1 such *resource* (1) has a *day-ahead schedule* in the first *settlement hour* of Day 1; (2) has either a *day-ahead operational commitment* or *pre-dispatch operational commitment* in the last *settlement hour* of Day 0 at the time the *day-ahead market calculation engine* determines the *day-ahead schedule* for Day 1; and (3) completed its *minimum generation block run-time* in the last *settlement hour* of Day 0;

4.4.5.2 such *resource* has a *day-ahead operational schedule* that is not eligible under section 4.4.4 and which immediately follows a *day-ahead operational commitment* that is eligible under section 4.4.4; or

4.4.5.3 such *resource* has a *day-ahead operational commitment* in Day 1 that immediately follows a *pre-dispatch operational commitment* that:

a. extends for at least as long as the *resource's minimum generation block run-time* plus its *minimum generation block down-time;* or

b. follows a prior *day-ahead operational commitment,*

the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for a *delivery point* 'm':

$$DAM\_GOG_k^m = Max[0, DAM\_GOG\_COMP1_k^m + DAM\_GOG\_COMP2_k^m - DAM\_GOG\_COMP5_k^m]$$

Where:

a. $DAM\_GOG\_COMP1_k^m$ $DAM\_GOG\_COMP2_k^m$ and $DAM\_GOG\_COMP5_k^m$ are calculated in accordance with sections 4.4.6, 4.4.7, and 4.4.11, respectively.

Components

Component #1 – applicable to Variant # 1, 2 and 3

4.4.6 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP1_k^m$ as follows:

$$DAM\_GOG\_COMP1_k^m = \sum^{H}\left[-1\ x\ \left(OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)\right) + \left(DAM\_BE\_SNL_{k,h}^m\ x\ N_{k,h}^m/12\right)\right] - \sum^{RH}\left[DAM\_LMP_h^m\ x\ DAM\_QSI_{k,h}^m\right]$$

Where:

a. 'H' is the set of *settlement hours* within the relevant *day-ahead commitment period*;

b. 'RH' is the set of contiguous *settlement hours* with *day-ahead schedules* for the ramp-up period;

c. '$N_{k,h}^{m}$' is the number of *metering intervals* in *settlement hour* 'h' during which *delivery point* 'm' for *market participant* 'k' was synchronized and injecting *energy* into the *IESO-controlled grid;* and

d. If the combustion turbine *resource* or steam turbine *resource* is registered as a *pseudo-unit* but is not operating as a *pseudo-unit* and has a minimum constraint applied for combined cycle operation consistent with combustion turbine commitment, then $DAM\_QSI_{k,h}^{m}$ will be replaced with $DAM\_EOP_{k,h}^{m}$ for those *settlement hours* in which they have such constraint.

Component #2 – applicable to Variant # 1, 2 and 3

4.4.7 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP2_{k}^{m}$ as follows:

$$DAM\_GOG\_COMP2_{k}^{m} = -1\,x \sum_{R}^{H}\left[OP\left(DAM\_PROR_{r,h}^{m}, DAM\_QSOR_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m}\right)\right]$$

Where:

a. 'H' is the set of *settlement hours* within the relevant *day-ahead commitment period*.

Component #3 – applicable to Variant # 2

4.4.8 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP3_{k}^{m}$ as follows:

$$DAM\_GOG\_COMP3_{k}^{m} = \sum^{H}\left[(-1)\,x\left(OP(DAM\_LMP_{h}^{m}, MLP_{k}^{m}, DAM\_BE_{k,h}^{m})\right) + DAM\_BE\_SNL_{k,h}^{m} \times \frac{N_{k,h}^{m}}{12}\right]$$

Where:

a. 'H' is the set of *settlement hours* within the *day-ahead commitment period* that are required to complete the *resource's minimum generation block run-time* that began in Day 0;

b. 'MLP_{k}^{m}' is the *minimum loading point* of the *GOG-eligible resource* for Day 0 for *market participant* 'k' for *delivery point* 'm'; and

c. '$N_{k,h}^{m}$' is the number of *metering intervals* in *settlement hour* 'h' during which *delivery point* 'm' for *market participant* 'k' was synchronized and injecting *energy* into the *IESO-controlled grid*.

Component #4 – applicable to Variant # 1

4.4.9 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP4_{k,h}^{m}$ in accordance with the following:

4.4.9.1 Subject to section 4.4.10, if the *GOG-eligible resource* synchronizes and injects *energy* into the *IESO-controlled grid* to complete its *day-ahead operational commitment*, the *GOG-eligible resource* completed its *minimum generation block run-time*, and:

a. the *GOG-eligible resource* achieved its *minimum loading point* within the first six *metering intervals* of the first *settlement hour* of its *day-ahead operational commitment*, then:

$$DAM\_GOG\_COMP4_{k,h}^{m} = DAM\_BE\_SU_{k,h}^{m} \text{ ; or}$$

b. the *GOG-eligible resource* achieved its *minimum loading point* after the first six *metering intervals* of the start of its *minimum generation block run-time* but before the 19th *metering interval* following the start of its *minimum generation block run-time*, then:

$$DAM\_GOG\_COMP4_{k,h}^{m} = DAM\_BE\_SU_{k,h}^{m} - (DAM\_BE\_SU_{k,h}^{m} \times N\_INT\ /12)$$

Where:

a. 'N_INT' is the number of *metering intervals* after the first six *metering intervals* that the *GOG-eligible resource* took to achieve its *minimum loading point;*

4.4.9.2 Otherwise,

$$DAM\_GOG\_COMP4_{k,h}^{m} = 0$$

4.4.10 If the sole reason that a *GOG-eligible resource* did not complete its *minimum generation block run-time* is because the *IESO* directed such *GOG-eligible resource* to de-synchronize from the *IESO-controlled grid* after the commencement of its *day-ahead operational commitment*, then the *GOG-eligible resource* is not required to complete its *minimum generation block run-time* in order for section 4.4.9.1 to apply.

Component #5 – applicable to Variant # 1, 2 and 3

4.4.11 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP5_k^m$ as follows:

$$DAM\_GOG\_COMP5_k^m = \sum^H DAM\_MWP_{k,h}^m$$

Where:

a. 'H' is the set of *settlement hours* within the relevant *day-ahead commitment period*.

Day-Ahead Market Generator Offer Guarantee – Combustion Turbine Associated with a Pseudo-Unit

Formulations

Variant #1

4.4.12 If the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit* meets any of the following conditions:

4.4.12.1 The combustion turbine *resource* has:

a. A *day-ahead operational schedule* to start in Day 1 to meet a *day-ahead operational commitment* without any preceding *day-ahead operational commitment, pre-dispatch operation commitment,* or *reliability* commitment; or

b. a *day-ahead operational schedule* with a preceding *advanced pre-dispatch operational commitment* or *reliability* commitment that extends less than the *resource's minimum generation block run-time* plus its *minimum generation block down-time,*

the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *resource delivery point* 'c':

$$DAM\_GOG_k^c = Max\left[0, DAM\_GOG\_COMP1_k^c + DAM\_GOG\_COMP2_k^c + DAM\_GOG\_COMP4_{k,h}^c - DAM\_GOG\_COMP5_k^c\right]$$

Where:

a. $DAM\_GOG\_COMP1_k^c$, $DAM\_GOG\_COMP2_k^c$, $DAM\_GOG\_COMP4_{k,h}^c$ and $DAM\_GOG\_COMP5_k^c$ are calculated in accordance with sections 4.4.15, 4.4.16, 4.4.18 and 4.4.20, respectively.

Variant #2

4.4.13 If the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit* has either a *day-ahead operational commitment* or *pre-dispatch operational commitment* for the last *settlement hour* of Day 0 and is scheduled to complete its *minimum generation block run-time* in the first *settlement hour* of Day 1, the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *resource delivery point* 'c':

$$DAM\_GOG_k^c = Max[0, DAM\_GOG\_COMP1_k^c + DAM\_GOG\_COMP2_k^c - DAM\_GOG\_COMP3_k^c - DAM\_GOG\_COMP5_k^c\ ]$$

Where:

a. $DAM\_GOG\_COMP1_k^c$, $DAM\_GOG\_COMP2_k^c$, $DAM\_GOG\_COMP3_k^c$, and $DAM\_GOG\_COMP5_k^c$ are calculated in accordance with sections 4.4.15, 4.4.16, 4.4.17 and 4.4.20, respectively.

Variant #3

4.4.14 If the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit* meets any of the following conditions:

4.4.14.1 such *resource* (1) has a *day-ahead schedule* in the first *settlement hour* of Day 1; (2) has either a *day-ahead operational commitment* or a *pre-dispatch operational commitment* for the last *settlement hour* of Day 0 at the time the *day-ahead market calculation engine* determines the *day-ahead schedule* for Day 1; and (3) has completed its *minimum generation block run-time* when the *day-ahead operational commitment* in the first *settlement hour* of Day 1 was scheduled;

4.4.14.2 has a *day-ahead operational schedule* that is not eligible under section 4.4.13 and which immediately follows a *day-ahead operational commitment* that is eligible under section 4.4.13*;* or

4.4.14.3 has a *day-ahead operational commitment* in Day 1 that immediately follows a *pre-dispatch operational commitment* that:

a. extends for at least as long as the *resource's minimum generation block run-time* plus its *minimum generation block down-time;* or

b. follows a prior *day-ahead operational commitment,*

the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for a *delivery point* 'm':

$$DAM\_GOG_k^c = Max[0, DAM\_GOG\_COMP1_k^c + DAM\_GOG\_COMP2_k^c - DAM\_GOG\_COMP5_k^c]$$

Where:

a. $DAM\_GOG\_COMP1_k^c$, $DAM\_GOG\_COMP2_k^c$, and $DAM\_GOG\_COMP5_k^c$ are calculated in accordance with sections 4.4.15, 4.4.16, and 4.4.20, respectively.

Components

Component #1 - applicable to Variant # 1, 2 and 3

4.4.15 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP1_k^c$ as follows:

$$DAM\_GOG\_COMP1_k^c = \sum^{H}\left[(-1)\ x\ OP(DAM\_LMP_h^c, DAM\_QSI_{k,h}^c, DAM\_DIPC_{k,h}^c) + DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^c}{12} \times \left(1 - ST\_Portion_{k,d1}^p\right)\right] - \sum^{RH}\left[DAM\_LMP_h^c \times DAM\_QSI_{k,h}^c\right]$$

Where:

a. 'H' is the set of *settlement hours* within the combustion turbine *resource*'s relevant *day-ahead commitment period*;

b. 'RH' is the set of contiguous *settlement hours* that the combustion turbine *resource* has a *day-ahead schedule* for the ramp-up period, scheduled greater than zero but less than the combustion turbine *resource*'s *minimum loading point;*

c. 'p' is the *pseudo-unit* associated with combustion turbine *resource delivery point* 'c'; and

d. '$N_{k,h}^c$' is the number of *metering intervals* in the *settlement hour* 'h' during which combustion turbine *resource delivery point* 'c' for *market participant* 'k' was synchronized and injecting *energy* into the *IESO-controlled grid*.

Component #2 - applicable to Variant # 1, 2 and 3

4.4.16 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP2_k^c$ as follows:

$$DAM\_GOG\_COMP2_k^c = \sum^R \sum^H [(-1) \times OP(DAM\_PROR_{r,h}^c, DAM\_QSOR_{r,k,h}^c, DAM\_OR\_DIPC_{r,k,h}^c)]$$

Where:

a. 'H' is the set of *settlement hours* within the combustion turbine *resource*'s relevant *day-ahead commitment period.*

Component #3 - applicable to Variant # 2

4.4.17 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP3_k^c$ as follows:

$$DAM\_GOG\_COMP3_k^c = \sum^H \left[(-1)x\ OP(DAM\_LMP_h^c, MLP_k^c, DAM\_DIPC_{k,h}^c) + DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^c}{12} \times (1 - ST\_Portion_{k,d1}^p)\right]$$

Where:

a. 'H' is the set of *settlement hours* within the *day-ahead commitment period* that are required to complete the associated *pseudo-unit's minimum generation block run-time* that began in Day 0;

b. 'p' is the *pseudo-unit* associated with combustion turbine *resource delivery point* 'c';

c. 'MLP_k^c' is the *minimum loading point* of the combustion turbine *resource* associated with combustion turbine *resource delivery point* 'c'; and

d. '$\mathrm{N}_{k,h}^c$' is the number of *metering intervals* in the *settlement hour* 'h' during which combustion turbine *resource delivery point* 'c' for *market participant* 'k' was synchronized and injecting *energy* into the *IESO-controlled grid*.

Component #4 - applicable to Variant # 1

4.4.18 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP4_{k,h}^c$ in accordance with the following:

4.4.18.1 Subject to section 4.4.19, if the combustion turbine *resource* synchronizes and injects *energy* into the *IESO-controlled grid* to complete its *day-*

ahead operational commitment, its *day-ahead operational commitment* does not immediately follow another *day-ahead operational commitment*, it completes its *minimum generation block run-time*, and:

a. the combustion turbine *resource* achieved its *minimum loading point* within the first six *metering intervals* of the first *settlement hour* of its *day-ahead operational commitment*, then:

$$DAM\_GOG\_COMP4^{c}_{k,h} = DAM\_BE\_SU^{p}_{k,h} \times \left(1 - ST\_Portion^{p}_{k,d1}\right);$$ or

b. the combustion turbine *resource* achieved its *minimum loading point* after the first six *metering intervals* of the start of its *day-ahead operational commitment* but before the 19th *metering interval* following the start of its *day-ahead operational commitment*, then:

$$DAM\_GOG\_COMP4^{c}_{k,h} = DAM\_BE\_SU^{p}_{k,h} \times \left(1 - \frac{N\_INT}{12}\right) \times \left(1 - ST\_Portion^{p}_{k,d1}\right)$$

Where:

i. 'N_INT' is the number of *metering intervals* after the first six *metering intervals* that the combustion turbine *resource* took to achieve *minimum loading point.*

4.4.18.2 Otherwise,

$$DAM\_GOG\_COMP4^{c}_{k,h} = 0$$

4.4.19 If the sole reason that the combustion turbine *resource* did not complete its *minimum generation block run-time* is because the *IESO dispatched*, in order to maintain the *reliability* of the *IESO-controlled grid*, such combustion turbine *resource* after the commencement of its *day-ahead operational commitment*, then the combustion turbine *resource* is not required to complete its *minimum generation block run-time* in order for section 4.4.18.1 to apply.

Component #5 - applicable to Variant # 1, 2 and 3

4.4.20 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP5^{c}_{k}$ as follows:

$$DAM\_GOG\_COMP5^{c}_{k} = \sum^{H} DAM\_MWP^{c}_{k,h}$$

Where:

i. 'H' is the set of *settlement hours* within the combustion turbine *resource*'s relevant *day-ahead commitment period.*

Day-Ahead Market Generator Offer Guarantee – Steam Turbine Associated with a Pseudo-Unit

Formulation

4.4.21 For a *delivery point* 's' for a steam turbine *resource* associated with a *GOG-eligible resource* that is a *pseudo-unit*, the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows:

$$DAM\_GOG_k^s = Max[0, DAM\_GOG\_COMP1_k^s + DAM\_GOG\_COMP2_k^s - DAM\_GOG\_COMP3_k^s + DAM\_GOG\_COMP4_{k,h}^s - DAM\_GOG\_COMP5_k^s]$$

Where:

a. $DAM\_GOG\_COMP1_k^s$, $DAM\_GOG\_COMP2_k^s$, $DAM\_GOG\_COMP3_{k,h}^s$, $DAM\_GOG\_COMP4_{k,h}^s$ and $DAM\_GOG\_COMP5_k^s$ are calculated in accordance with sections 4.4.22, 4.4.23, 4.4.24, 4.4.25, and 4.4.26, respectively.

Components

Component #1

4.4.22 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the steam turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP1_k^s$ as follows:

$$DAM\_GOG\_COMP1_k^s = \sum^{H}\left[(-1) \times OP\left(DAM\_LMP_h^s, DAM\_DIGQ_{k,h}^s, DAM\_DIPC_{k,h}^s\right) + \sum_{p=1}^{M}\left(DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p\right)\right] - \sum^{RH}\left[DAM\_LMP_h^s \times DAM\_QSI_{k,h}^s\right]$$

Where:

a. 'H' is the set of all *settlement hours* within the steam turbine *resource*'s *day-ahead commitment period* when at least one of the *pseudo-units* associated with the steam turbine *resource* has a *day-ahead schedule* greater than or equal to its respective *pseudo-unit's minimum loading point;*

b. 'M' is the set of all *pseudo-units* 'p' associated with steam turbine *resource delivery point* 's' that have a *day-ahead schedule* greater than or equal to their respective *minimum loading point* in *settlement hour* 'h';

c. 'RH' is the set of all *settlement hours* in the steam turbine *resource*'s *day-ahead operational commitment* when all of the *pseudo-units* associated with the steam turbine *resource* are scheduled less than their *minimum loading point*; and

d. '$N^{p}_{k,h}$' is the number of *metering intervals* in the *settlement hour* 'h' during which the combustion turbine *resource* associated with *pseudo-unit* 'p' for *market participant* 'k' was synchronized and injecting *energy* into the *IESO-controlled grid*.

Component #2

4.4.23 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the steam turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP2^{s}_{k}$ as follows:

$$DAM\_GOG\_COMP2^{s}_{k} = \sum^{R}\sum^{H}\left[(-1) \times OP\left(DAM\_PROR^{s}_{r,h}, DAM\_QSOR^{s}_{r,k,h}, DAM\_OR\_DIPC^{s}_{r,k,h}\right)\right]$$

Where:

a. 'H' is the set of all *settlement hours* within the steam turbine *resource*'s *day-ahead commitment period* when at least one of the *pseudo-units* associated with the steam turbine *resource* has a *day-ahead schedule* greater than or equal to its respective *pseudo-unit's minimum loading point.*

Component #3

4.4.24 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the steam turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP3^{s}_{k}$ as follows:

$$DAM\_GOG\_COMP3^{s}_{k} = \sum^{V}\sum^{MHR_p}\left[(-1) \times OP\left(DAM\_LMP^{s}_{h}, MLP^{s}_{k}, DAM\_DIPC^{s}_{k,h}\right) + DAM\_BE\_SNL^{p}_{k,h} \times \frac{N^{p}_{k,h}}{12} \times ST\_Portion^{p}_{k,d1}\right]$$

Where:

a. 'V' is the set of all *pseudo-units* 'p' associated with steam turbine *resource delivery point* 's' whose associated combustion turbine *resource* has a variant #2 (section 4.4.13) *day-ahead operational commitment* that overlaps with the steam turbine *resource day-ahead operational commitment;*

b. 'MHR$_p$' is the set of *settlement hours* within the *day-ahead commitment period* that are required to complete *minimum generation block run-time* that began in Day 0 for *pseudo-unit* 'p' associated with the steam turbine *resource*;

c. 'MLP_k^s' is the *minimum loading point* of steam turbine *resource*, associated with *pseudo-unit* 'p', for *market participant* 'k'; and

d. '$\mathrm{N}_{k,h}^{p}$' is the number of *metering intervals* in the *settlement hour* 'h' during which the combustion turbine *resource* associated with *pseudo-unit* 'p' for *market participant* 'k' was synchronized and injecting *energy* into the *IESO-controlled grid.*

Component #4

4.4.25 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the steam turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP4_{k,h}^{s}$ as follows:

$$DAM\_GOG\_COMP4_{k,h}^{s} = \sum_{c=1}^{C} \sum_{x=1}^{X_c} \left[DAM\_GOG\_COMP4_{k,x}^{c} \times \frac{ST\_Portion_{k,d1}^{p}}{(1 - ST\_Portion_{k,d1}^{p})} \right]$$

Where:

a. 'C' is the set of all combustion turbine *resource delivery points* 'c' associated with steam turbine *resource delivery point* 's';

b. $DAM\_GOG\_COMP4_{k,x}^{c}$ is determined in accordance with section 4.4.18 for combustion turbine *resource delivery point* 'c' for *market participant* 'k' for *day-ahead commitment period 'x';* and

c. 'X$_c$' is the set of all *day-ahead commitment periods* 'x' for combustion turbine *resource delivery point* 'c' that are entitled to a *day-ahead market generator offer* guarantee *settlement amount* pursuant to section 4.4.12 (variant #1) that overlap with the steam turbine *resource*'s *day-ahead commitment period.*

Component #5

4.4.26 In determining the *day-ahead market generator offer* guarantee *settlement amount* for the steam turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP5_{k}^{s}$ as follows:

$$DAM\_GOG\_COMP5_{k}^{s} = \sum^{H} DAM\_MWP_{k,h}^{s}$$

Where:

a. 'H' is the set of all *settlement hours* within the steam turbine *resource*'s *day-ahead commitment period* when at least one of the *pseudo-units* associated with steam turbine *resource delivery point* 's' has a *day-ahead schedule* greater than or equal to its respective *minimum loading point.*

4.5 Real-Time Generator Offer Guarantee

General

4.5.1 Subject to section 4.5.2 and the mitigation process described in section 5 and Appendix 9.4, the real-time *generator offer* guarantee *settlement amount* for *market participant* 'k' ("RT_GOG_k") shall be calculated for each *settlement hour* within a *real-time commitment period* or a *real-time reliability commitment period* for each *GOG-eligible resource* and disbursed to the *market participant* for such *resource* in accordance with the operating profit function described in section 10 of Appendix 9.2, and this section 4.5.

4.5.1.1 In determining the real-time *generator offer* guarantee *settlement amount* in this section 4.5, the following expressions shall have the following meanings:

a. "Day 0" refers to the day before Day 1;

b. "Day 1" refers to the *dispatch day* for which the real-time *generator offer* guarantee *settlement amount* is being calculated;

c. *Real-time commitment period* is the set of contiguous *settlement hours* of a *resource* with *real-time schedules* in Day 1:

i. beginning with the first *settlement hour*:

a. of the *resource's pre-dispatch operational commitment* that does not have a corresponding *day-ahead schedule;* and

b. the *resource* has a *real-time schedule* for an amount equal to or greater than its *minimum loading point;* and

ii. ending with the earlier of:

a. the end of the *resource's pre-dispatch operational commitment;*

b. the *settlement hour* prior to first *settlement hour* the *resource* has a *day-ahead schedule;* or

c. the *settlement hour* in which the *resource* has a *real-time schedule* for an amount less than its *minimum loading point;*

d. *Real-time reliability commitment period* is the set of contiguous *settlement hours* of a *resource* with *real-time schedules* in Day 1:

i. beginning with the first *settlement hour:*

a. of the *resource's reliability* commitment that does not have a corresponding *day-ahead schedule;* and

b. the *resource* has a *real-time schedule* for an amount equal to or greater than its *minimum loading point;* and

ii. ending with the earlier of:

a. the end of the *resource's reliability* commitment*;*

b. the *settlement hour* prior to first *settlement hour* the *resource* has a *day-ahead schedule;* or

c. the *settlement hour* in which the *resource* has a *real-time schedule* for an amount less than its *minimum loading point.*

4.5.1.2 The real-time *generator offer* guarantee *settlement amount* will be determined utilizing one of three possible variants each of which consists of the following components, where applicable:

a. Component 1 is any shortfall in payment over the *real-time commitment period* or *real-time reliability commitment period* for *energy* based upon the *resource's* operating profit for *energy* and its *speed no-load offers,* and is calculated in accordance with sections 4.5.6, 4.5.15, or 4.5.22, as applicable;

b. Component 2 is any shortfall in payment over the *real-time commitment period* or *real-time reliability commitment period* for *operating reserve* based upon the *resource's* operating profit for *operating reserve,* and is calculated in accordance with sections 4.5.7, 4.5.16, or 4.5.23, as applicable;

c. Component 3 is the amount calculated by Component 1 up to the *minimum loading point* for the *settlement hours* of *minimum generation block run-time* scheduled over midnight into Day 1 and is calculated in accordance with sections 4.5.8, 4.5.17, or 4.5.24, as applicable;

d. Component 4 is any as-offered *start-up costs* to bring an offline *GOG-eligible resource* through its specific start-up procedures to meet its *pre-dispatch operational commitment,* including synchronization and ramp-up to *minimum loading point*, and is calculated in accordance with sections 4.5.9, 4.5.18, or 4.5.25, as applicable*;* and

e. Component 5 is any real-time make-whole payment *settlement amount* that was received for any *settlement hour* within the relevant *real-time commitment period* or *real-time reliability commitment period* and is calculated in accordance with sections 4.5.11, 4.5.20, or 4.5.26, as applicable.

4.5.2 Notwithstanding section 4.5.1, a *market participant* shall be ineligible to receive a real-time *generator offer* guarantee *settlement amount* in respect of a *GOG-eligible resource* for:

a. any *metering intervals* where it has a *real-time schedule* less than its *minimum loading point* to ramp offline; or

b. for a *settlement hour* where:

i. the *resource* has committed its capacity to an external *control area* and an external *control area operator* has called a *called capacity export*:

a. prior to the *resource* receiving a *pre-dispatch operational commitment*; or

b. after the *resource* receives a *pre-dispatch operational commitment* and the *IESO* restricts other transactions on *interconnected systems* in accordance with MR Ch.5 ss.2.3 and 5.7, while maintaining the *called capacity export* transaction;

ii. the *resource* received a *real-time schedule* to synchronize to the *IESO-controlled grid* and inject *energy* in an amount equal to or greater than its *minimum loading point* for its *minimum generation block run time* or in advance of a *day-ahead market operational commitment*, *pre-dispatch operational commitment,* or *reliability* commitment, on request from the *market participant,* to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law;*

iii. the *resource* was *dispatched* to continue injecting *energy* in an amount equal to or greater than its *minimum loading point* following an existing *day-ahead market operational commitment*, *pre-dispatch operational commitment*, on request from the *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; or

iv. the steam turbine *resource* where the *pseudo-unit* received a *pre-dispatch operational commitment* while operating in combined cycle-mode but, due to a failure or *outage* at the steam turbine *resource*, operates in *single cycle mode*.

Real-Time Generator Offer Guarantee for Non-Pseudo Units

Formulations

Variant #1

4.5.3 If a *GOG-eligible resource* that is not a *pseudo-unit*:

a. injects into the *IESO-controlled grid* in Day 1 to meet a *pre-dispatch operational commitment*; and

b. such *pre-dispatch operational commitment* does not immediately follow a *day-ahead operational commitment* or *reliability* commitment,

the real-time *generator offer* guarantee *settlement amount* is calculated as follows for *delivery point* 'm':

$$RT\_GOG_k^m = Max\big[0,\ RT\_GOG\_COMP1_k^m + RT\_GOG\_COMP2_k^m + RT\_GOG\_COMP4_{k,h}^m - RT\_GOG\_COMP5_{k,h}^m\big]$$

Where:

a. $RT\_GOG\_COMP1_{k,h}^m$, $RT\_GOG\_COMP2_k^m$, $RT\_GOG\_COMP4_{k,h}^m$ and $RT\_GOG\_COMP5_{k,h}^m$ are calculated in accordance with sections 4.5.6, 4.5.7, 4.5.9 and 4.5.11, respectively.

Variant #2

4.5.4 If a *GOG-eligible resource* that is not a *pseudo-unit* has a *pre-dispatch operational commitment* in the first *settlement hour* of Day 1 where such *pre-dispatch operational commitment* requires the *resource* to complete its *minimum generation block run-time* that began in Day 0, the real-time *generator offer* guarantee *settlement amount* is calculated as follows for a *delivery point* 'm' for the *settlement hours* of the *pre-dispatch operational commitment* required to complete its *minimum generation block run-time*:

$$RT\_GOG_k^m = Max\big[0,\ RT\_\mathrm{GOG}\_COMP1_k^m + RT\_\mathrm{GOG}\_COMP2_k^m - RT\_\mathrm{GOG}\_COMP3_{k,h}^m - RT\_\mathrm{GOG}\_COMP5_{k,h}^m\big]$$

Where:

a. $RT\_GOG\_COMP1_{k,h}^m$ $RT\_GOG\_COMP2_k^m$, $RT\_GOG\_COMP3_{k,h}^m$, and $RT\_GOG\_COMP5_{k,h}^m$ are calculated in accordance with sections 4.5.6, 4.5.7, 4.5.8, and 4.5.11, respectively.

Variant #3

4.5.5 If a *GOG-eligible resource* that is not a *pseudo-unit*:

a. has a *pre-dispatch operational commitment* in the first *settlement hour* of Day 1 where such *pre-dispatch operational commitment* requires the *resource* to operate continuously from Day 0 after completing its *minimum generation block-run time* in Day 0;

b. has a *pre-dispatch operational commitment* that is not eligible under section 4.5.4 and which immediately follows a *pre-dispatch operational commitment* that is eligible under section 4.5.4; or

c. such *pre-dispatch operational commitment* immediately follows a *day-ahead operational schedule* or *reliability* commitment,

the real-time *generator offer* guarantee *settlement amount* is calculated as follows for *delivery point* 'm' for the *settlement hours* of the *pre-dispatch operational commitment* following the completion of its *minimum generation block run-time*:

$$RT\_GOG_k^m = Max\left[0,\ RT\_GOG\_COMP1_k^m + RT\_GOG\_COMP2_k^m - RT\_GOG\_COMP5_{k,h}^m\right]$$

Where:

a. $RT\_GOG\_COMP1_{k,h}^m$, $RT\_GOG\_COMP2_k^m$, and $RT\_GOG\_COMP5_{k,h}^m$ are calculated in accordance with sections 4.5.6, 4.5.7, and 4.5.11, respectively.

Components

Component #1 – applicable to Variant # 1, 2 and 3

4.5.6 In determining the real-time *generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP1_{k,h}^m$ as follows:

$$\begin{aligned} RT\_GOG\_COMP1_k^m &= \sum^{T1}\Big[(-1) \\ &\times Max\left(OP\left(RT\_LMP_h^{m,t}, RT\_QSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(RT\_LMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) \\ &+ \frac{PD\_BE\_SNL_{k,h}^m}{12}\Big] - \sum^{T0}\left[RT\_LMP_h^{m,t} \times AQEI_{k,h}^{m,t}\right] \\ &+ \sum^{RH}\left[DAM\_LMP_h^m\ x\ DAM\_QSI_{k,h}^m/12\right] \end{aligned}$$

Where:

a. 'T1' is the set of contiguous *metering intervals* 't' within the *real-time commitment period* or the *real-time reliability commitment period*, as the case may be.

b. 'T0' is the set of all *metering intervals* between the time when the *resource* is synchronized and injecting *energy* into the *IESO-controlled grid* and the time when the *resource* achieves its *minimum loading point*.

c. 'RH' is the set of contiguous *settlement hours* 'h' with *day-ahead schedules* for the ramp-up period in the *day-ahead market* that do not overlap with a *pre-dispatch operational commitment*.

d. If the combustion turbine *resource* or steam turbine *resource* is registered as a *pseudo-unit* but is not operating as a *pseudo-unit* and has a minimum constraint applied for combined cycle operation consistent with combustion turbine commitment, then $RT\_QSI_{k,h}^{m,t}$ will be replaced with $RT\_LC\_EOP^{m,t}{}_{k,h}$ for those *metering intervals* in which they have such constraint.

Component #2 - applicable to Variant # 1, 2 and 3

4.5.7 In determining the real-time *generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP2_{k,h}^{m}$ as follows:

$$RT\_GOG\_COMP2_{k}^{m} = (-1) \times \sum\nolimits_{R}^{T1} OP\left(RT\_PROR_{r,h}^{m,t}, RT\_\mathrm{QSOR}_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right)$$

Where:

a. 'T1' is the set of contiguous *metering intervals* 't' within the *real-time commitment period* or the *real-time reliability commitment period*, as the case may be.

Component #3 - applicable to Variant # 2

4.5.8 In determining the real-time *generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP3_{k,h}^{m}$ as follows:

$$RT\_GOG\_COMP3_{k}^{m} = \sum\nolimits^{T2} [(-1)\, x \left(OP(RT\_LMP_{h}^{m,t}, MLP_{k}^{m}, BE_{k,h}^{m,t})\right) + \frac{PD\_BE\_SNL_{k,h}^{m}}{12}]$$

Where:

a. 'T2' is the set of contiguous *metering intervals* 't' beginning with the first *metering interval* of Day 1 and ending with the *metering interval* in Day 1 in which the *resource* completes its *minimum generation block run-time* that began in Day 0; and

b. 'MLP_k^m' is the *minimum loading point* of the *resource* for Day 1 for *market participant* 'k' for *delivery point* 'm'.

Component #4 - applicable to Variant # 1

4.5.9 In determining the real-time *generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP4_{k,h}^m$ in accordance with the following:

a. If the *resource* achieved its *minimum loading point* within the first six *metering intervals* of the start of its *minimum generation block run-time*, then

$$RT\_GOG\_COMP4_k^m = RT\_GOG\_SU_{k,h}^m$$

b. If the *resource* achieved its *minimum loading point* after the first six *metering intervals* of the start of its *minimum generation block run-time* but before the 19th *metering interval* following the start of its *minimum generation block run-time*, then

$$RT\_GOG\_COMP4_k^m = RT\_GOG\_SU_{k,h}^m - (RT\_GOG\_SU_{k,h}^m \times N\_INT\ /12)$$

Where:

i. 'N_INT' is the number of *metering intervals* after the first six *metering intervals* that the *resource* took to achieve its *minimum loading point.*

c. Otherwise,

$$RT\_GOG\_COMP4_k^m = 0$$

Where:

a. if the *resource* has either (a) a *stand-alone pre-dispatch operational commitment;* or (b) an *advanced pre-dispatch operational commitment,* that extends for longer than or equal to the *resource's minimum generation block run-time* plus its *minimum generation block down-time* for the hot *thermal state*, then:

$$RT\_GOG\_SU_{k,h}^m = PD\_BE\_SU_{k,h}^m$$

b. if the *resource* receives an *advanced pre-dispatch operational commitment* that extends for a period that is less than the *resource's minimum* *generation block run-time* plus its *minimum generation block down-time* for the hot *thermal state*, then:

$$RT\_GOG\_SU_{k,h}^{m} = Max\left(0, PD\_BE\_SU_{k,h}^{m} - DAM\_BE\_SU_{k,h}^{m}\right)$$

Where:

i. notwithstanding section 5, $DAM\_BE\_SU^{m}_{k,h}$ shall be equal to the $EMFC\_DAM\_BE\_SU^{m}_{k,h}$ exclusively when the EMFC *settlement amount*, as defined in section 5.1.2.2, is the applicable *settlement amount* for the *day-ahead market generator offer* guarantee *settlement amount* for such *resource.*

c. Otherwise,

$$RT\_GOG\_SU_{k,h}^{m} = 0$$

4.5.10 If the sole reason that a *resource* did not complete its *minimum generation block run-time* is because the *IESO* required, in order to maintain the *reliability* of the *IESO-controlled grid*, such *resource* to de-synchronize from the *IESO-controlled grid* after the commencement of its *pre-dispatch operational commitment*, then the *resource* is not required to complete its *minimum generation block run-time* in order for section 4.5.9(a) to apply.

Component #5 – applicable to Variant # 1, 2 and 3

4.5.11 In determining the real-time *generator offer* guarantee *settlement amount* for the *GOG-eligible resource* that is not a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP5_{k,h}^{m}$ as follows:

$$RT\_GOG\_COMP5_{k}^{m} = \sum^{T1} RT\_MWP_{k,h}^{m}$$

Where:

a. 'T1' is the set of contiguous *metering intervals* 't' within the *real-time commitment period* or the *real-time reliability commitment period*, as the case may be.

Real-Time Generator Offer Guarantee – Combustion Turbine Associated with a Pseudo-Unit

Formulations

Variant #1

4.5.12 If the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit:*

a. injects into the *IESO-controlled grid* in Day 1 to meet a *pre-dispatch operational commitment*; and

b. such *pre-dispatch operational commitment* does not immediately follow a *day-ahead operational commitment* or *reliability* commitment,

the real-time *generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *resource delivery point* 'c':

$$RT\_GOG_k^c = Max[0, RT\_GOG\_COMP1_k^c + RT\_GOG\_COMP2_k^c + RT\_GOG\_COMP4_k^c - RT\_GOG\_COMP5_k^c]$$

Where:

i. $RT\_GOG\_COMP1_k^c$, $RT\_GOG\_COMP2_k^c$, $RT\_GOG\_COMP4_k^c$ and $RT\_GOG\_COMP5_k^c$ are calculated in accordance with sections 4.5.15, 4.5.16, 4.5.18, and 4.5.20, respectively.

Variant #2

4.5.13 If the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit* has a *pre-dispatch operational commitment* in the first *settlement hour* of Day 1 where such *pre-dispatch operational commitment* requires the *resource* to complete its *minimum generation block run-time* that began in Day 0, the real-time *generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *resource delivery point* 'c' for the *settlement hours* of the *pre-dispatch operational commitment* required to complete its *minimum generation block run-time:*

$$RT\_GOG_k^c = Max[0, RT\_GOG\_COMP1_k^c + RT\_GOG\_COMP2_k^c - RT\_GOG\_COMP3_k^c - RT\_GOG\_COMP5_k^c]$$

Where:

a. $RT\_GOG\_COMP1_k^c$, $RT\_GOG\_COMP2_k^c$, $RT\_GOG\_COMP3_k^c$, and $RT\_GOG\_COMP5_k^c$ are calculated in accordance with sections 4.5.15, 4.5.16, 4.5.17, and 4.5.20, respectively.

Variant #3

4.5.14 If the combustion turbine *resource* of a *GOG-eligible resource* that is a *pseudo-unit:*

a. has a *pre-dispatch operational commitment* in the first *settlement hour* of Day 1 where such *pre-dispatch operational commitment* requires the *resource* to operate continuously from Day 0 after completing its *minimum generation block-run time* in Day 0; or

b. such *pre-dispatch operational commitment* immediately follows a *day-ahead operational schedule* or *reliability* commitment,

the real-time *generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *resource delivery point* 'c' for the *settlement hours* of the *pre-dispatch operational commitment* following the completion of its *minimum generation block run-time*:

$$RT\_GOG_k^c = Max[0, RT\_GOG\_COMP1_k^c + RT\_GOG\_COMP2_k^c - RT\_GOG\_COMP5_k^c]$$

Where:

a. $RT\_GOG\_COMP1_k^c$, $RT\_GOG\_COMP2_k^c$, and $RT\_GOG\_COMP5_k^c$ are calculated in accordance with sections 4.5.15, 4.5.16, and 4.5.20, respectively.

Components

Component #1 - applicable to Variant # 1, 2 and 3

4.5.15 In determining the real-time *generator offer* guarantee *settlement amount* for a combustion turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP1_k^c$ as follows:

$$RT\_GOG\_COMP1_k^c = \sum^{T1}\Big[(-1) \times \text{Max}\Big(OP\big(RT\_LMP_h^{c,t}, RT\_QSI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\big), OP\big(RT\_LMP_h^{c,t}, AQEI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\big)\Big) + \frac{PD\_BE\_SNL_{k,h}^p}{12} \times (1 - ST\_Portion_{k,d1}^p)\Big] - \sum^{T0}\big(RT\_LMP_h^{c,t} \times AQEI_{k,h}^{c,t}\big) + \sum^{RH}\big[DAM\_LMP_h^c \times DAM\_QSI_{k,h}^c / 12\big]$$

Where:

a. 'T1' is the set of contiguous *metering intervals* 't' within the *real-time commitment period* or the *real-time reliability commitment period*, as the case may be, for the combustion turbine *resource*;

b. 'p' is the *pseudo-unit* associated with combustion turbine *resource delivery point* 'c';

c. 'T0' is the set of all *metering intervals* 't' between the time when the combustion turbine *resource* is synchronized and injecting *energy* into the *IESO-controlled grid* and the time when the combustion turbine *resource* achieves its *minimum loading point*;

d. 'RH' is the set of contiguous *settlement hours* 'h' with *day-ahead schedules* for the ramp-up period in the *day-ahead market* that do not overlap with a *pre-dispatch operational commitment*; and

e. Where the *pseudo-unit* associated with the combustion turbine *resource* received a *pre-dispatch operational commitment* while operating in combined cycle mode but, due to a failure or *outage* at the associated steam turbine *resource*, operates in *single cycle mode*, then the applicable $RT\_DIPC_{k,h}^{c,t}$ shall be the one determined just prior to the failure or *outage*.

Component #2 - applicable to Variant # 1, 2 and 3

4.5.16 In determining the real-time *generator offer* guarantee *settlement amount* for a combustion turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP2_k^c$ as follows:

$$RT\_GOG\_COMP2_k^c = \sum_{R}^{T1}\left[(-1) \times OP\left(RT\_PROR_{r,h}^{c,t}, RT\_QSOR_{r,k,h}^{c,t}, RT\_OR\_DIPC_{r,k,h}^{c,t}\right)\right]$$

Where:

a. 'T1' is the set of contiguous *metering intervals 't'* within the *real-time commitment period* or the *real-time reliability commitment period*, as the case may be, for the combustion turbine *resource*.

Component #3 - applicable to for Variant # 2

4.5.17 In determining the real-time *generator offer* guarantee *settlement amount* for a combustion turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP3_k^c$ as follows:

$$RT\_GOG\_COMP3_k^c = \sum^{T2}\left[(-1) \times \left(OP\left(RT\_LMP_h^{c,t}, MLP_k^c, RT\_DIPC_{k,h}^{c,t}\right)\right) + \frac{PD\_BE\_SNL_{k,h}^{p}}{12} \times (1 - ST\_Portion_{k,d1}^{p})\right]$$

Where:

a. 'T2' is the set of contiguous *metering intervals* 't' beginning with the first *metering interval* of Day 1 and ending with the *metering interval* in Day 1 in which the *resource* completes its *minimum generation block run-time* that began in Day 0;

b. 'MLP_k^c' is the *minimum loading point* of the combustion turbine *resource* associated with combustion turbine *resource delivery point* 'c'; and

c. 'p' is the *pseudo-unit* associated with combustion turbine *resource delivery point* 'c'.

Component #4 - applicable to Variant # 1

4.5.18 Subject to section 4.5.19, in determining the real-time *generator offer* guarantee *settlement amount* for a combustion turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP4_k^c$ in accordance with the following:

a. For a *pre-dispatch operational commitment* where the associated *pseudo-unit* has a *stand-alone pre-dispatch operational commitment* or where the associated *pseudo-unit* receives a *pre-dispatch operational commitment* in advance of an existing *day-ahead market operational commitment* by a period that is greater than or equal to the *resource's minimum generation block run-time* plus its *minimum generation block down-time* for the hot *thermal state*:

i. If the combustion turbine *resource* achieved its *minimum loading point* within the first six *metering intervals* of the start of the *pre-dispatch operational commitment*, then:

$$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times (1 - ST\_Portion_{k,d1}^p)$$

ii. If the combustion turbine *resource* achieved its *minimum loading point* after the first six *metering intervals* of the start of its *pre-dispatch operational commitment* but before the 19th *metering interval* following the start of its *pre-dispatch operational commitment*, then:

$$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times (1 - ST\_Portion_{k,d1}^p) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$

Where:

a. '$N\_INT_k^c$' is the number of *metering intervals* after the first six *metering intervals* that the combustion turbine *resource* took to achieve its *minimum loading point.*

iii. Otherwise,

$$RT\_GOG\_COMP4_k^c = 0$$

b. For a *pre-dispatch operational commitment* where the associated *pseudo-unit* has a *pre-dispatch operational commitment* in advance of an existing *day-ahead market operational commitment* by a period that is less than the *resource's minimum generation block run-time* plus its *minimum generation block down-time* for the hot *thermal state*, then:

i. If the combustion turbine *resource* achieved its *minimum loading point* within the first six *metering intervals* of the start of the *pre-dispatch operational commitment*, then:

$$RT\_GOG\_COMP4_k^c = Max\left(0, PD\_BE\_SU_{k,h}^p - DAM\_BE\_SU_{k,h}^p\right) \times \left(1 - ST\_Portion_{k,d1}^p\right)$$

Where:

a. notwithstanding section 5, $DAM\_BE\_SU^p_{k,h}$ shall be equal to the $EMFC\_DAM\_BE\_SU^p_{k,h}$ exclusively when the EMFC *settlement amount*, as defined in section 5.1.2.2, is the applicable *settlement amount* for the *day-ahead market generator offer* guarantee *settlement amount* for such *resource.*

ii. If the combustion turbine *resource* achieved its *minimum loading point* after the first six *metering intervals* of the start of its *pre-dispatch operational commitment* but before the 19th *metering interval* following the start of its *pre-dispatch operational commitment*, then:

$$RT\_GOG\_COMP4_k^c = Max\left(0, PD\_BE\_SU_{k,h}^p - DAM\_BE\_SU_{k,h}^p\right) \times \left(1 - ST\_Portion_{k,d1}^p\right) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$

Where:

a. '$N\_INT^c_k$' is the number of *metering intervals* after the first six *metering intervals* that the combustion turbine *resource* took to achieve its *minimum loading point;* and

b. notwithstanding section 5, $DAM\_BE\_SU^p_{k,h}$ shall be equal to the $EMFC\_DAM\_BE\_SU^p_{k,h}$ exclusively when the EMFC *settlement amount*, as defined in section 5.1.2.2, is the applicable *settlement amount* for the *day-ahead market generator offer* guarantee *settlement amount* for such *resource.*

iii. Otherwise,

$$RT\_GOG\_COMP4_k^c = 0$$

4.5.19 If the sole reason that the combustion turbine *resource* did not complete its *minimum generation block run-time* is because the *IESO* required, in order to maintain the *reliability* of the *IESO-controlled grid*, such combustion turbine *resource* to de-synchronize from the *IESO-controlled grid* after the commencement of its *pre-dispatch operational commitment*, then the combustion turbine *resource* is not required to complete its *minimum generation block run-time* in order for section 4.5.18(a) to apply.

Component #5 - applicable to Variant # 1, 2 and 3

4.5.20 In determining the real-time *generator offer* guarantee *settlement amount* for a combustion turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP5_k^c$ as follows:

$$RT\_GOG\_COMP5_k^c = \sum^{T1} RT\_MWP_{k,h}^c$$

Where:

a. 'T1' is the set of contiguous *metering intervals 't'* within the *real-time commitment period* or the *real-time reliability commitment period*, as the case may be, for the combustion turbine *resource.*

Real-Time Generator Offer Guarantee – Steam Turbine Associated with a Pseudo-Unit

Formulation

4.5.21 For a *delivery point* 's' for a steam turbine *resource* associated with a *GOG-eligible resource* that is a *pseudo-unit*, the real-time *generator offer* guarantee *settlement amount* is calculated as follows:

$$RT\_GOG_k^s = Max[0, RT\_GOG\_COMP1_k^s + RT\_GOG\_COMP2_k^s - RT\_GOG\_COMP3_k^s + RT\_GOG\_COMP4_k^s - RT\_GOG\_COMP5_k^s]$$

Where:

a. $RT\_GOG\_COMP1_k^s$, $RT\_GOG\_COMP2_k^s$, $RT\_GOG\_COMP3_k^s$, $RT\_GOG\_COMP4_k^s$, and $RT\_GOG\_COMP5_k^s$ are calculated in accordance with sections 4.5.22, 4.5.23, 4.5.24, 4.5.25, and 4.5.26, respectively.

Components

Component #1

4.5.22 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP1_k^s$ as follows:

$$RT\_GOG\_COMP1_k^s = \sum^{T1}\Bigg[(-1)\times OP\left(RT\_LMP_h^{s,t}, RT\_CMT\_DIGQ_{k,h}^{s,t}, RT\_CMT\_DIPC_{k,h}^{s,t}\right) + \sum_{p=1}^{N}\left(\frac{PD\_BE\_SNL_{k,h}^{p}}{12}\times ST\_Portion_{k,d1}^{p}\right) + \sum_{p=1}^{D}\left(DAM\_LMP_h^s\times\frac{\left[DAM\_QSI_{k,h}^{p}\times\left(ST\_Portion_{k,d1}^{p}\right)\right]}{12}\right)\Bigg] - \sum^{T0}\left(RT\_LMP_h^{s,t}\times AQEI_{k,h}^{s,t}\right)$$

Where:

a. 'T1' is the set of all *metering intervals* 't' in the steam turbine *resource*'s *real-time commitment period* where at least one of the associated *pseudo-units' real-time schedule* is greater than or equal to its *minimum loading point* in accordance with a *pre-dispatch operational commitment;*

b. 'N' is the set of all *pseudo-units* 'p' associated with steam turbine *resource delivery point* 's' that are eligible for a real-time *generator offer* guarantee *settlement amount* in *metering interval* 't' of *settlement hour* 'h';

c. 'D' is the set of all *pseudo-units* 'p' associated with steam turbine *resource delivery point* 's' that have: (i) a *pre-dispatch operational commitment* greater than its *minimum loading point* in *metering interval* 't'; (ii) an associated combustion turbine *resource* that is injecting *energy* into the *IESO-controlled grid* in an amount greater than or equal to its *minimum loading point* in *metering interval* 't'; and (iii) a *day-ahead schedule* less than its *minimum loading point* in *metering interval* 't'; and

d. 'T0' is the set of all *metering intervals* 't' in the steam turbine *resource*'s *real-time commitment period* when: (i) the steam turbine *resource* is injecting *energy* into the *IESO-controlled grid* in an amount that is less than its 1-on-1 *minimum loading point*; and (ii) none of the associated *pseudo-units* have a *day-ahead schedule.*

Component #2

4.5.23 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP2_k^s$ as follows:

$$RT\_GOG\_COMP2_k^s = \sum\nolimits_R^{T1} \left[(-1) \times OP\left(RT\_PROR_{r,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r,k,h}^{s,t}\right)\right]$$

Where:

a. 'T1' is the set of all *metering intervals* 't' in the steam turbine *resource*'s *real-time commitment period* where at least one of the associated *pseudo-units* is greater than or equal to its *minimum loading point* in accordance with a *pre-dispatch operational commitment.*

Component #3

4.5.24 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP3_k^s$ as follows:

$$RT\_GOG\_COMP3_k^s = \sum^U \sum^{T_p} \left[(-1) \times \left(OP\left(RT\_LMP_h^{s,t}, \left(MLP_k^p \times ST\_Portion_{k,d1}^p\right), BE_{k,h}^{p,t}\right)\right) + \frac{PD\_BE\_SNL_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p\right]$$

Where:

a. 'U' is the set of all *pseudo-units* 'p' associated with steam turbine *resource delivery point* 's' that have a *real-time schedule* in the first *settlement hour* of Day 1 to complete its *minimum generation block run-time* as part of a *pre-dispatch operational commitment* that began in Day 0 and forms part of the steam turbine *resource*'s *real-time commitment period;*

b. 'T_p' is the set of *metering intervals* 't' where: (i) the associated *pseudo-unit* had a *real-time schedule* in the first *settlement hour* of Day 1 to complete its *minimum generation block run-time;* and (ii) the combustion turbine *resource* associated with *pseudo-unit* 'p' actually injected *energy* into the *IESO-controlled grid* in an amount equal to or greater than its *minimum loading point;* and

c. 'MLP_k^p' is the *minimum loading point* of *pseudo-unit* 'p' for *market participant* 'k' for Day 1.

Component #4

4.5.25 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP4_k^s$ in accordance with the following:

$$RT\_GOG\_COMP4_k^s = \sum_{c=1}^{C} \sum^{X_c} \left[RT\_GOG\_COMP4_{k,x}^c \times \frac{ST\_Portion_{k,d1}^p}{\left(1 - ST\_Portion_{k,d1}^p\right)} \right]$$

Where:

a. 'C' is the set of all combustion turbine *resource delivery points* 'c' associated with steam turbine *resource delivery point* 's';

b. $RT\_GOG\_COMP4_{k,x}^c$ is determined in accordance with section 4.5.18 for combustion turbine *resource delivery point* 'c' for *market participant* 'k' for *pre-dispatch operational commitment 'x';* and

c. 'X_c' is the set of all *pre-dispatch operational commitments* 'x' that are classified as variant 1 and were incurred by combustion turbine *resource* 'c' during the steam turbine *resource*'s *real-time commitment period*.

Component #5

4.5.26 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *resource,* the *IESO* shall calculate $RT\_GOG\_COMP5_k^s$ as follows:

$$RT\_GOG\_COMP5_k^s = \sum^{T1} RT\_MWP_{k,h}^s$$

Where:

a. 'T1' is the set of all *metering intervals* 't' in the steam turbine *resource*'s *real-time commitment period* where at least one of the associated *pseudo-units* is greater than or equal to its *minimum loading point* in accordance with a *pre-dispatch operational commitment.*

4.6 Real-Time Ramp-Down Settlement Amount

Real-Time Ramp-Down Settlement Amount

4.6.1 Subject to section 4.6.3 and to the mitigation process described in section 5 and Appendix 9.4, the real-time ramp-down *settlement amount* for *market participant* 'k' at *delivery point* 'm' ("$RT\_RDSA_k^m$") shall be calculated and disbursed to the *market participant* for a *GOG-eligible resource* that is not a *pseudo-unit* for each instance where such *resource* injects *energy* into the *IESO-controlled grid,* receives a *real-time schedule* less than its *minimum loading point,* and desynchronizes from the *IESO-controlled grid*. The real-time ramp-down *settlement amount* shall be disbursed to such *GOG-eligible resources* in accordance with the eligibility and equations set out in this section 4.6, and the operating profit function described in section 10 of Appendix 9.2.

4.6.2 In calculating the real-time ramp-down *settlement amount* in accordance with sections 4.6.4 and 4.6.5, the following subscripts and superscripts shall have the following meaning unless otherwise specified:

4.6.2.1 'T' is the ramp-down period determined as the set of all *metering intervals* 't' beginning with the first *metering interval* that the *GOG-eligible resource* is scheduled in the *real-time market* less than its *minimum loading point* and ends with the first *metering interval* following the start of 'T' in which the *real-time schedule* is zero or in which there is no *real-time schedule*; and

4.6.2.2 $BE_{k,h}^{m,t}$ shall be the matrix of 'n' *price-quantity pairs offered* by *market participant* 'k' to supply *energy* during the *settlement hour* 'h' determined in accordance with the applicable *market manual*, where *price* is adjusted by being multiplied by the ramp-down factor specified in the applicable *market manual*.

4.6.3 Notwithstanding section 4.6.1, a *market participant* shall be ineligible to receive a real-time ramp-down *settlement amount*:

4.6.3.1 for a *settlement hour* where the *GOG-eligible resource* that is not a *pseudo-unit* received a *real-time schedule* for the duration of its *minimum generation block run-time*, on request from the *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; or

4.6.3.2 where the *GOG-eligible resource* that is not a *pseudo-unit* fails to achieve its *minimum loading point* in accordance with its *real-time schedule* prior to de-synchronizing from the *IESO-controlled grid.*

4.6.4 For a *GOG-eligible resource* that is not a *pseudo-unit* that receives a *real-time schedule* less than its *minimum loading point* during a period when the *GOG-eligible resource* has a *day-ahead schedule,* the real-time ramp-down *settlement amount* is calculated as follows:

$$RT\_RDSA_k^m = Max\left(0, \sum^T \left[(-1) \times OP\left(DAM\_LMP_h^m, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) - Max\left(0, (-1) \times OP\left(DAM\_LMP_h^m, AQEI_{k,h}^{m,t}, DAM\_BE_{k,h}^m\right)\right)\right]\right)$$

4.6.5 For a *GOG-eligible resource* that is not a *pseudo-unit* that receives a *real-time schedule* less than its *minimum loading point* during a period when the *GOG-eligible resource* does not have a *day-ahead schedule,* the real-time ramp-down *settlement amount* is calculated as follows:

$$RT\_RDSA_k^m = Max\left(0, \sum^T \left[(-1) \times OP\left(RT\_LMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right]\right)$$

Pseudo-Units – Combustion Turbine

4.6.6 Subject to section 4.6.8 and to the mitigation process described in section 5 and Appendix 9.4, the real-time ramp-down *settlement amount* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' ("$RT\_RDSA_k^c$") shall be calculated and disbursed to the *market participant* for a *GOG-eligible resource* that is a *pseudo-unit* for each instance where such *resource* injects *energy* into the *IESO-controlled grid,* receives a *real-time schedule* less than its *minimum loading point,* and desynchronizes from the *IESO-controlled grid.* The real-time ramp-down *settlement amount* shall be disbursed to such *GOG-eligible resources* in accordance with the eligibility and equations set out in this section 4.6, and the operating profit function described in section 10 of Appendix 9.2.

4.6.7 In calculating the real-time ramp-down *settlement amount* in accordance with sections 4.6.9 and 4.6.10, the following subscripts and superscripts shall have the following meaning unless otherwise specified:

4.6.7.1 'T' is the ramp-down period determined as the set of all *metering intervals* 't' beginning with the first *metering interval* that the *GOG-eligible resource* is scheduled in the *real-time market* less than its *minimum loading point* and ends with the first *metering interval* following the start of 'T' in which the *real-time schedule* is zero or in which there is no *real-time schedule*; and

4.6.7.2 $RT\_DIPC_{k,h}^{c,t}$ shall be the matrix of 'n' *price-quantity pairs* during the *settlement hour* 'h' determined in accordance with the applicable *market manual,* where the *price* is adjusted by being multiplied by the ramp-down factor specified in the applicable *market manual*.

4.6.8 Notwithstanding section 4.6.6, a *market participant* shall be ineligible to receive a real-time ramp-down *settlement amount:*

4.6.8.1 for a *settlement hour* where the *GOG-eligible resource* that is a *pseudo-unit*, or an associated physical unit *resource*, received a *real-time schedule* for the duration of its *minimum generation block run-time*, on request from the *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; or

4.6.8.2 where the *GOG-eligible resource* that is a *pseudo-unit* fails to achieve its *minimum loading point* in accordance with its *real-time schedule* prior to de-synchronizing from the *IESO-controlled grid.*

4.6.9 For a *GOG-eligible resource* that is a *pseudo-unit* that receives a *real-time schedule* less than its *minimum loading point* during a period when the *GOG-eligible resource* has a *day-ahead schedule,* the real-time ramp-down *settlement amount* is calculated as follows:

$$RT\_RDSA_k^c = Max\left(0, \sum^T \left[(-1) \times OP\left(DAM\_LMP_h^c, AQEI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\right) - Max\left(0, (-1) \times OP\left(DAM\_LMP_h^c, AQEI_{k,h}^{c,t}, DAM\_DIPC_{k,h}^{c}\right)\right)\right]\right)$$

4.6.10 For a *GOG-eligible resource* that is a *pseudo-unit* that receives a *real-time schedule* less than its *minimum loading point* during a period when the *GOG-eligible resource* does not have a *day-ahead schedule,* the real-time ramp-down *settlement amount* is calculated as follows:

$$RT\_RDSA_k^c = Max\left(0, \sum^T \left[(-1) \times OP\left(RT\_LMP_h^{c,t}, AQEI_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\right)\right]\right)$$

Pseudo-Units – Steam Turbine

4.6.11 Subject to section 4.6.13 and to the mitigation process described in section 5 and Appendix 9.4, the real-time ramp-down *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' ("$RT\_RDSA_k^s$") shall be calculated and disbursed to the *market participant* for a *GOG-eligible resource* that is a *pseudo-unit* for each instance where such *resource* injects *energy* into the *IESO-controlled grid,* receives a *real-time schedule* less than its 1-on-1 *minimum loading point,* and desynchronizes from the *IESO-controlled grid*. The real-time ramp-down *settlement amount* shall be disbursed to such *GOG-eligible resources* in accordance with the eligibility and equations set out in this section 4.6, and the operating profit function described in section 10 of Appendix 9.2.

4.6.12 In calculating the real-time ramp-down *settlement amount* in accordance with sections 4.6.14 and 4.6.15, the following subscripts and superscripts shall have the following meaning unless otherwise specified:

4.6.12.1 'T' is the ramp-down period determined as the set of all *metering intervals* 't' beginning with the first *metering interval* that the *GOG-eligible resource* is scheduled in the *real-time market* less than its 1-on-1 *minimum loading point* and ends with the first *metering interval* following the start of 'T' in which the *real-time schedule* is zero or in which there is no *real-time schedule*; and

4.6.12.2 $RT\_DIPC_{k,h}^{s,t}$ shall be the matrix of 'n' *price-quantity pairs,* during the *settlement hour* 'h' determined in accordance with the applicable *market manual,* where the *price* is adjusted by being multiplied by the ramp-down factor specified in the applicable *market manual.*

4.6.13 Notwithstanding section 4.6.11, a *market participant* shall be ineligible to receive a real-time ramp-down *settlement amount:*

4.6.13.1 for a *settlement hour* where the *GOG-eligible resource* that is a *pseudo-unit*, or an associated physical unit *resource,* received a *real-time schedule* for the duration of its *minimum generation block-run time*, on request from the *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; or

4.6.13.2 where the *GOG-eligible resource* that is a *pseudo-unit* fails to achieve its *minimum loading point* in accordance with its *real-time schedule* prior to de-synchronizing from the *IESO-controlled grid.*

4.6.14 For a *GOG-eligible resource* that is a *pseudo-unit* that receives a *real-time schedule* less than its 1-on-1 *minimum loading point* during a period when the *GOG-eligible resource* has a *day-ahead schedule,* the real-time ramp-down *settlement amount* is calculated as follows:

$$RT\_RDSA_k^s = Max\left(0, \sum\nolimits^T \left[(-1) \times OP\left(DAM\_LMP_h^s, AQEI_{k,h}^{s,t}, RT\_DIPC_{k,h}^{s,t}\right) - Max\left(0, (-1) \times OP\left(DAM\_LMP_h^s, AQEI_{k,h}^{s,t}, DAM\_DIPC_{k,h}^{s}\right)\right)\right]\right)$$

4.6.15 For a *GOG-eligible resource* that is a *pseudo-unit* that receives a *real-time schedule* less than its 1-on-1 *minimum loading point* during a period when the *GOG-eligible resource* does not have a *day-ahead schedule,* the real-time ramp-down *settlement amount* is calculated as follows:

$$RT\_RDSA_k^s = Max\left(0, \sum\nolimits^T \left[(-1) \times OP\left(RT\_LMP_h^{s,t}, AQEI_{k,h}^{s,t}, RT\_DIPC_{k,h}^{s,t}\right)\right]\right)$$

4.7 Internal Congestion and Loss Residuals

4.7.1 The internal congestion and loss residual *settlement amount* shall be calculated for each *energy market billing period* and disbursed to or collected from the *market participants* for *non-dispatchable loads*, *dispatchable loads* and *price responsive loads* in accordance with section 4.7.3. In calculating the internal congestion and loss residual *settlement amount*, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

4.7.1.1 'H' is the set of all *settlement hours* 'h' in the current *energy market billing period*;

4.7.1.2 'M1' is the set of all *delivery points* 'm' for *non-dispatchable loads*; and

4.7.1.3 'M0' is the set of all *delivery points* 'm' except those for *non-dispatchable loads*.

4.7.2 The *IESO* shall determine for each *energy market billing period* the congestion rent and loss residual ("CRLR"), which shall be calculated as follows:

$$\begin{aligned}\text{CRLR} = \sum_{K,H}^{M0} \Big[& \left(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}\right) x\ DAM\_LMP_{h}^{m} \\ & + \sum^{T} \Big(\left(AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}\right) \\ & - \left(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}\right) \Big)\ x\ RT\_LMP_{h}^{m,t}/12 \Big] \\ & + \sum_{K,H}^{V} \Big[\Big(DAM\_QVSW_{k,h}^{v} \\ & - DAM\_QVSI_{k,h}^{v}\Big)\ x \sum^{T} \left(DAM\_LMP_{h}^{vz} - RT\_LMP_{h}^{vz,t}\right) \Big] \\ & + \sum_{K,H}^{M1} \Big[\left(DAM\_LMP_{h}^{z} + LFDC_{h}\right) x \sum^{T} AQEW_{k,h}^{m,t} \Big] \\ & + \sum_{K,H}^{I} \Big[\left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) x\ DAM\_LMP_{h}^{i} \\ & + \sum^{T} \Big(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\right) \\ & - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) \Big)\ x\ RT\_LMP_{h}^{i,t}/12 \Big] \\ & - \sum_{K,H}^{I} \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) x\ DAM\_PEC_{h}^{i} \\ & - \sum_{K,H}^{I} \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) x\ DAM\_PNISL_{h}^{i} \\ & - \sum_{K,H}^{I,T} \Big(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) \Big) \\ & \times\ RT\_PEC_{h}^{i,t}/12 \\ & - \sum_{K,H}^{I,T} \Big(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) \Big) \\ & \times\ RT\_PNISL_{h}^{i,t}/12 \end{aligned}$$

4.7.3 The internal congestion and loss residual *settlement amount* is disbursed to or collected from *market participant* 'k' ("$ICLR_k$") in the current *energy market billing period* shall be calculated as follows:

$$ICLR_{k} = CRLR \times \sum_{H}^{M,T} AQEW_{k,h}^{m,t} / \sum_{K,H}^{M,T} AQEW_{k,h}^{m,t}$$

4.8 Real-Time External Congestion, Real-Time NISL Residual, and Day-Ahead Market NISL Residuals

Real-Time External Congestion Residual

4.8.1 The real-time external congestion residual *settlement amount* shall be calculated for each *energy market billing period* and disbursed to or collected from the *market participants* for *non-dispatchable loads*, *dispatchable loads*, *price responsive loads*, and *energy traders* participating with *boundary entity resources* engaging in export transactions in accordance with sections 4.8.3 and 4.8.4. In calculating the real-time external congestion residual *settlement amount*, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

4.8.1.1 'H' is the set of all *settlement hours* 'h' in the current *energy market billing period*;

4.8.1.2 'TD_C' is the total dollar value of monthly service *charge type* 'C' in the current *energy market billing period*;

4.8.1.3 '$TD_{C,C1}$' is the total dollar value of monthly service *charge type* 'C' and 'C1' in the current *energy market billing period*;

4.8.1.4 'TD_{C1}' is the total dollar value of monthly service *charge type* 'C1' in the current *energy market billing period*;

4.8.1.5 'C' is the set of all monthly provincial *transmission services charge charge types* in the current *energy market billing period* as follows: 650, 651, 652;

4.8.1.6 'C1' is the set of all monthly export *transmission services charge charge types* in the current *energy market billing period* as follows: 653; and

4.8.1.7 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'.

4.8.2 The *IESO* shall determine for each *energy market billing period* the real-time external congestion residual ("RT_ECR") which shall be calculated as follows:

$$RT\_ECR = \sum_{K,H}^{I,T} \left(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t} \right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i} \right) \right) \times RT\_PEC_{h}^{i,t} / 12$$

4.8.3 In respect of *non-dispatchable loads*, *dispatchable loads* and *price responsive loads,* the real-time external congestion residual uplift *settlement amount* to be disbursed to or collected from *market participant* 'k' ("RT_ECRU_k") in the current *energy market billing period* shall be calculated as follows:

$$RT\_ECRU_k = RT\_ECR_L \times \sum_{H}^{M,T} AQEW_{k,h}^{m,t} / \sum_{K,H}^{M,T} AQEW_{k,h}^{m,t}$$

Where:

a. RT_ECR_L is the portion of the real-time external congestion residual in the current *energy market billing period* allocated to *market participants* that have paid provincial *transmission services charges* "C" in the current *energy market billing period*, and calculated as follows:

$$RT\_ECR_L = RT\_ECR \times \sum_{K} TD_C / \sum_{K} TD_{C,C1}$$

4.8.4 In respect of export transactions for *energy traders* participating with *boundary entity resources,* the real-time external congestion residual uplift *settlement amount* to be disbursed to or collected from *market participant* 'k' ("RT_ECRU_k") in the current *energy market billing period* shall be calculated as follows:

$$RT\_ECRU_k = RT\_ECR_E \times \sum_{H}^{I,T} SQEW_{k,h}^{i,t} / \sum_{K,H}^{I,T} SQEW_{k,h}^{i,t}$$

Where:

a. RT_ECR_E is the portion of the real-time external congestion residual in the current *energy market billing period* allocated to *market participants* that have paid export *transmission services charges* "C1" in the current *energy market billing period*, and calculated as follows:

$$RT\_ECR_E = RT\_ECR \times \sum_{K} TD_{C1} / \sum_{K} TD_{C,C1}$$

Day-Ahead Market NISL Residual

4.8.5 The *day-ahead market* net interchange scheduling limit residual *settlement amount* shall be calculated for each *trading day* and disbursed to or collected from the *market participants* for *load resources*, *electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaging in export transactions in accordance with section 4.8.7. In calculating the *day-ahead market* net interchange scheduling limit residual uplift *settlement amount*, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

4.8.5.1 'T' is the set of all *metering intervals* 't' in the set of all *settlement hours* 'H'; and

4.8.5.2 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'.

4.8.6 The *IESO* shall determine for each *trading day* the *day-ahead market* net interchange scheduling limit residual ("DAM_NISLR"), which shall be calculated as follows:

$$DAM\_NISLR = \sum\nolimits_{K,H}^{I} \left[\left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i} \right) x \; DAM\_PNISL_{h}^{i} \right]$$

4.8.7 The *day-ahead market* net interchange scheduling limit residual uplift *settlement amount* to be disbursed to or collected from *market participant* 'k' ("DAM_NISLU$_k$") for the applicable *trading day* shall be calculated as follows:

$$DAM\_NISLU_k = DAM\_NISLR \; x \left[\sum\nolimits_{H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) / \sum\nolimits_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t} \right) \right]$$

Real-Time NISL Residual

4.8.8 The *IESO* shall determine the *real-time market* net interchange scheduling limit residual for *settlement hour* 'h' ("RT_NISLR$_h$") which shall be uplifted through the *hourly uplift* and is calculated as follows:

$$RT\_NISLR_h = \sum\nolimits_{K}^{I,T} \left(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t} \right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i} \right) \right) \times RT\_PNISL_{h}^{i,t} / 12$$

4.9 Transmission Rights Clearing Account Disbursements

4.9.1 Disbursements from the *TR clearing account* ordered by the *IESO Board* pursuant to MR Ch.8 s.3.18.2 shall be distributed among *market participants* based on the proportionate share of all *transmission services charges* paid during *energy market billing periods* immediately preceding the current *energy market billing period,* in accordance with this section 4.9.

4.9.1.1 The portion of the total disbursements from the *TR clearing account* allotted to *market participants* that have paid provincial transmission charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of *energy* withdrawn from the *IESO-controlled grid* at all *registered wholesale meters* excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.9.2 and 4.9.3.

4.9.1.2 The portion of the total disbursements from the *TR clearing account* allotted to *market participants* that have paid export *transmission service charges* shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of *energy* withdrawn from the *IESO-controlled grid* at all *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.9.2 and 4.9.3.

4.9.2 The portion of any disbursement from the *TR clearing account* payable to *market participant* 'k' in the current *energy market billing period* shall be calculated as follows:

4.9.2.1 For *market participants* that have paid provincial *transmission services charges* in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$$TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} [(AQEW_{k,h}{}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t})$$

4.9.2.2 For *market participants* that have paid export *transmission services charges* in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$$TRCAC_k = TRCAD_E \times \sum_H{}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

a. $TRCAD_L = (\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAD$

b. $TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAD$

c. $TRCAC_k$ = the *TR clearing account* credit payable to *market participant* 'k' in the current *energy market billing period;*

d. TRCAD = the total dollar value (in $ and up to 2 decimal places) of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period;*

e. $TRCAD_L$ = the portion of the total dollar value (in $ and up to 2 decimal places) of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period* allocated to *market participants* that have paid provincial *transmission services charges* "C" in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board;*

f. $TRCAD_E$ = the portion of the total dollar value (in $ and up to 2 decimal places) of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the *current energy market billing period* allocated to *market participants* that have paid export *transmission service* charges "C1" in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board;*

g. M = the set of all *registered wholesale meters* 'm' excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

h. I = the set of all *intertie metering points* 'i' during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board;*

i. K = the set of all *market participants* 'k' during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board;*

j. T = the set of all *metering intervals* 't' in *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board;*

k. H = the set of all *settlement hours* 'h' in *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board;*

l. C = the set of all monthly service *charge types* 'c' as follows: 650,651,652; and

m. C1 = the set of all monthly export transmission *charge types* 'c' as follows: 653.

4.9.3 Where a *TRCAC$_k$* is payable to a former *market participant*, the *IESO* will endeavour to distribute the *TRCAC$_k$* as specified in the applicable *market manual*. If the *IESO* cannot distribute a *TRCAC$_k$* to a former *market participant* as specified in the applicable *market manual,* such amounts shall remain in the *TR clearing account* for subsequent debits in accordance with MR Ch.8 s.3.18.1.

4.10 Generator Failure Charge

4.10.1 The *generator failure* charge – *market price* component *settlement amount* and the *generator failure* charge – guarantee cost component *settlement amount* shall be calculated for each *settlement hour* of a *generator failure*, and collected from the *market participant* for the *GOG-eligible resource* which experienced the *generator failure* in accordance with this section 4.10. In calculating each component of the *generator failure* charge in this section 4.10, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

a. 'T1' is the set of all contiguous *metering intervals* at *delivery point* 'm', combustion turbine *resource delivery point* 'c', or steam turbine *resource delivery point* 's', as applicable, of the relevant *generator failure,* determined in accordance with the applicable *market manual*; and

b. 'T' is the set of all *metering intervals* within *settlement hour* 'h' during which a *generator failure* is determined, in accordance with the applicable *market manual,* to have occurred at *delivery point* 'm', combustion turbine *resource delivery point* 'c', or steam turbine *resource delivery point* 's', as applicable.

Exclusions

4.10.2 If a *GOG-eligible resource* receives a *day-ahead schedule* for any period that is within the *settlement hours* of a *generator failure*, the *IESO* shall not consider these *day-ahead scheduled* quantities of *energy* as *energy* not delivered during such *settlement hours.*

4.10.3 A *generator failure* shall not be considered to have occurred where the *IESO* has determined, or the *market participant* has demonstrated to the satisfaction of the *IESO*, that the circumstances giving rise to the *generator failure* were solely due to:

a. the *GOG-eligible resource* being incapable of injecting *energy* into the *IESO-controlled grid* due to an unplanned *outage* on the *IESO-controlled grid*;

b. the *IESO* dispatching the *GOG*-eligible *resource* in order to maintain the *reliability* of the *IESO-controlled grid*; or

c. the *GOG-eligible resource* being *dispatched* to an amount equal to or greater than its *minimum loading point*, on request from the *market participant*, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law.*

Non-Pseudo-Unit – Failure Events

4.10.4 Subject to section 4.10.3 and for a *GOG-eligible resource* that is not a *pseudo-unit,* a *generator failure* will have occurred when the *GOG-eligible resource* fails to:

a. achieve its *minimum loading point* by the start of the *pre-dispatch operational commitment*; or

b. inject *energy* into the *IESO-controlled grid* greater than or equal to its *minimum loading point* for the duration of the *pre-dispatch operational commitment*, including any *extended pre-dispatch operational commitments* that immediately follow.

Non-Pseudo-Unit – Market Price Component

4.10.5 For a *GOG-eligible resource* that is not a *pseudo-unit* where a *generator failure* is determined to have occurred, the *IESO* shall calculate the *generator failure* charge – *market price* component *settlement amount* for *market participant* 'k' at *delivery point* 'm' for each *settlement hour* 'h' within the *generator failure* ($GFC\_MPC_{k,h}^{m}$) in accordance with the following:

a. if th*e market participant* provides less than four hours of advance notice of a give*n generator failure* or fails to provide such notice, $GFC\_MPC_{k,h}^{m}$ shall be determined as follows:

$$GFC\_MPC_{k,h}^{m} = \sum^{T} Min\left[0, -1 \times \left(RT\_LMP_{h}^{m,t} - PD\_LMP_{h}^{m,pdm}\right) \times Max\left(0, PD\_QSI_{k,h}^{m,pdm} - Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}\right)\right)\right]/12$$

b. if the *market participant* provides four hours or greater advance notice of a given *generator failure*, $GFC\_MPC_{k,h}^{m}$ shall be determined as follows:

$$GFC\_MPC_{k,h}^{m} = \sum^{T} Min\big[0, -1 \times \big(Min\big(RT\_LMP_{h}^{m,t}, PD\_LMP_{h}^{m,pd1}\big) - PD\_LMP_{h}^{m,pdm}\big) \times Max\big(0, PD\_QSI_{k,h}^{m,pdm} - Max\big(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}\big)\big)\big] / 12$$

Non-Pseudo-Unit – Guarantee Cost Component

4.10.6 For a *GOG-eligible resource* that is not a *pseudo-unit* where a *generator failure* is determined to have occurred, the *IESO* shall calculate the *generator failure* charge – guarantee cost component *settlement amount* for *market participant* 'k' at *delivery point* 'm' for each *generator failure* 'f' ($GFC\_GCC_{k,f}^{m}$) in accordance with the following and the operating profit function described in section 10 of Appendix 9.2:

$$GFC\_GCC_{k,f}^{m} = -1 \times Max\left[0, PD\_SU\_Ratio_{k,f}^{m} \times SU\_INCR_{k,f}^{m} + \sum^{T1} \frac{PD\_BE\_SNL_{k,h}^{m,pdm}}{12} - \sum^{T1} OP\big(PD\_LMP_{h}^{m,pdm}, PD\_QSI_{k,h}^{m,pdm}, PD\_BE^{m,pdm}\big)/12\right] \times M1$$

Where:

a. 'M1' is the prorating factor based on the quantity of *energy* that the *resource* failed to deliver and calculated as follows:

$$M1 = \left[1 - \frac{\sum^{T1} Min\left(PD\_QSI_{k,h}^{m,pdm}, Max\big(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}\big)\right)}{\left(\sum^{T1} PD\_QSI_{k,h}^{m,pdm}\right)}\right]$$

b. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f':

   i. advances a *day-ahead operational commitment*; and

   ii. the number of advancement hours of the *advanced pre-dispatch operational commitment* is less than its *minimum generation block run-time* plus its *minimum generation block down-time*, then:

$$SU\_INCR_{k,f}^{m} = Max\left(0, PD\_BE\_SU_{k,f}^{m,pdm} - DAM\_BE\_SU_{k,f}^{m}\right)$$

b. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$SU\_INCR_{k,f}^{m} = 0$$

c. Otherwise:

$$SU\_INCR_{k,f}^{m} = PD\_BE\_SU_{k,f}^{m,pdm}$$

d. $PD\_SU\_Ratio_{k,f}^{m}$ is a prorating factor for *market participant* 'k' at *delivery point* 'm' for *generator failure* 'f', and calculated as follows:

i. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$PD\_SU\_RATIO_{k,f}^{m} = 0$$

ii. Otherwise:

$$PD\_SU\_Ratio_{k,f}^{m} = \mathrm{Min}\left(1, \frac{MLP\_INJ_{k,f}^{m}}{PD\_MGBRT_{k,f}^{m}}\right)$$

Where:

a. $MLP\_INJ_{k,f}^{m}$ is the number of *metering intervals* where the *GOG-eligible resource* for *market participant* 'k' injects *energy* into the *IESO-controlled grid* at *delivery point* 'm' in an amount less than its *minimum loading point* during the *minimum generation block run-time* associated with the *pre-dispatch operational commitment* associated with *generator failure* 'f'; and

b. $PD\_MGBRT_{k,f}^{m}$ is the number of *metering intervals* of the *minimum generation block run-time* associated with the *pre-dispatch operational commitment* associated with *generator failure* 'f' for *market participant* 'k' at *delivery point* 'm'.

Pseudo-Unit – Failure Events

4.10.7 Subject to section 4.10.3 and for a *GOG-eligible resource* that is a *pseudo-unit,* a *generator failure* will have occurred in the following circumstances:

4.10.7.1 for a combustion turbine *resource* associated with a *pseudo-unit*, if at any time during a *settlement hour* where:

a. the combustion turbine *resource* fails to achieve its *minimum loading point* by the start of the *pre-dispatch operational commitment* of its associated *pseudo-unit*;

b. the combustion turbine *resource* fails to inject *energy* into the *IESO-controlled grid* greater than or equal to its *minimum loading point* for the duration of the *pre-dispatch operational commitment* of its associated *pseudo-unit,* including any *extended pre-dispatch operational commitments* that immediately follow; or

c. the associated *pseudo-unit* activates a single cycle flag during its *pre-dispatch operational commitment,* including any *extended pre-dispatch operational commitments* that immediately follow, and increases its *offer* price*;*

4.10.7.2 for a steam turbine *resource* associated with a *pseudo-unit*, if:

a. one or more of the combustion turbine *resource* associated with the steam turbine *resource*:

b. fails to achieve its *minimum loading point* by the start of the *pre-dispatch operational commitment* of its associated *pseudo-unit*; or

c. fails to inject *energy* into the *IESO-controlled grid* greater than or equal to its *minimum loading point* for the duration of the *pre-dispatch operational commitment* of its associated *pseudo-unit*, including any *extended pre-dispatch operational commitments* that immediately follow; or

b. one or more of the *pseudo-units* associated with the steam turbine *resource* activates a single cycle flag during its *pre-dispatch operational commitment,* including any *extended pre-dispatch operational commitments* that immediately follow*.*

Pseudo-Unit – Market Price Component

4.10.8 For a combustion turbine *resource* associated with a *pseudo-unit* where a *generator failure* has occurred, the *IESO* shall calculate the *generator failure* charge – *market price* component *settlement amount* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' for each *settlement hour* 'h' within the *generator failure* ($GFC\_MPC_{k,h}^{c}$) in accordance with the following:

4.10.8.1 If the *market participant* provides less than four hours of advance notice of the *generator failure* or fails to provide such notice, $GFC\_MPC_{k,h}^{c}$ shall be determined as follows:

$$GFC\_MPC_{k,h}^{c} = \sum^{T} Min\left[0, (-1) \times \left(RT\_LMP_{h}^{c,t} - PD\_LMP_{h}^{c,pdm}\right) \times Max\left(PD\_QSI_{k,h}^{c,pdm} - Max\left(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}\right), 0\right)\right]/12$$

4.10.8.2 If the *market participant* provides four hours or greater advance notice of the *generator failure*, $GFC\_MPC^{c}_{k,h}$ shall be determined as follows:

$$GFC\_MPC^{c}_{k,h} = \sum^{T} Min\big[0, (-1) \times \big(Min\big(RT\_LMP^{c,t}_{h}, PD\_LMP^{c,pd1}_{h}\big) - PD\_LMP^{c,pdm}_{h}\big) \times Max\big(PD\_QSI^{c,pdm}_{k,h} - Max\big(AQEI^{c,t}_{k,h}, DAM\_QSI^{c}_{k,h}\big), 0\big)\big]/12$$

4.10.9 For a steam turbine *resource* associated with a *pseudo-unit* where a *generator failure* has occurred*,* the *IESO* shall calculate the *generator failure* charge – *market price* component *settlement amount* for *market participant* 'k' steam turbine *resource delivery point* 's' for each *settlement hour* 'h' within the *generator failure* ($GFC\_MPC^{s}_{k,h}$) in accordance with the following:

$$GFC\_MPC^{s}_{k,h} = \sum^{T} GFC\_MPC^{s,t}_{k,h}$$

Where:

a. If the *market participant* provides less than four hours of advance notice of the *generator failure* or fails to provide such notice, $GFC\_MPC^{s,t}_{k,h}$ shall be determined as follows:

$$GFC\_MPC^{s,t}_{k,h} = (-1) \times Max\big(RT\_LMP^{s,t}_{h} - Min\{c \in CT_F | PD\_LMP^{s,pdm}_{h}\}, 0\big) \times Max\left(\sum^{M_t}\big[RT\_STP\_QSI^{p,t}_{k,h}\big] + \sum^{N_t}\big[PD\_STP\_QSI^{p,pdm}_{k,h}\big] - AQEI^{s,t}_{k,h}, 0\right)/12$$

b. If the *market participant* provides four hours or greater advance notice of the *generator failure*, $GFC\_MPC^{s,t}_{k,h}$ shall be determined as follows:

$$GFC\_MPC^{s,t}_{k,h} = (-1) \times Max\big(Min\big(RT\_LMP^{s,t}_{h}, PD\_LMP^{s,pd1}_{h}\big) - Min\{c \in CT_F | PD\_LMP^{s,pdm}_{h}\}, 0\big) \times Max\left(\sum^{M_t}\big[RT\_STP\_QSI^{p,t}_{k,h}\big] + \sum^{N_t}\big[PD\_STP\_QSI^{p,pdm}_{k,h}\big] - AQEI^{s,t}_{k,h}, 0\right)/12$$

Where:

i. 'CT_F' is the set of all combustion turbine *resources* associated with steam turbine *resource delivery point* 's' having a combustion turbine *resource* failure interval or are operating in *single cycle mode* during *metering interval* 't';

ii. 'M_t' is the set of all *pseudo-units* associated with the steam turbine *resource delivery point* 's' whose associated combustion turbine *resource* does not have a combustion turbine *resource* failure interval and are not operating in *single cycle mode* during *metering interval* 't'; and

iii. 'N_t' is the set of all *pseudo-units* associated with the steam turbine *resource delivery point* 's' whose associated combustion turbine *resource* has a combustion turbine *resource* failure interval or are operating in *single cycle mode* during *metering interval* 't'.

Pseudo-Unit – Guarantee Cost Component

4.10.10 For a combustion turbine *resource* associated with a *pseudo-unit* where a *generator failure* has occurred, the *IESO* shall calculate the *generator failure* charge – guarantee cost component *settlement amount* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' for each *generator failure* 'f' that occurs ($GFC\_GCC^{c}_{k,f}$) in accordance with the following and the operating profit function described in section 10 of Appendix 9.2:

$$GFC\_GCC^{c}_{k,f} = (-1) \times Max\left[0, PD\_SU\_Ratio^{c}_{k,f} \times SU\_INCR^{p,pdm}_{k,f} \times \left(1 - ST\_Portion^{p}_{k,d1}\right) + \sum^{T1}\left(\frac{PD\_BE\_SNL^{p,pdm}_{k,h}}{12} \times \left(1 - ST\_Portion^{p}_{k,d1}\right) - \frac{OP\left(PD\_LMP^{c,pdm}_{h}, PD\_QSI^{c,pdm}_{k,h}, PD\_DIPC^{c,t}_{k,h}\right)}{12}\right)\right] \times M1$$

Where:

a. 'M1' is the prorating factor based on the quantity of *energy* that the *resource* failed to deliver and calculated as follows:

$$M1 = \left[1 - \frac{\sum^{T1} Min\left(PD\_QSI^{c,pdm}_{k,h}, Max\left(AQEI^{c,t}_{k,h}, DAM\_QSI^{c}_{k,h}\right)\right)}{\left(\sum^{T1} PD\_QSI^{c,pdm}_{k,h}\right)}\right]$$

b. If the *pre-dispatch operational commitment* violated by failure 'f' bridges with a *day-ahead operational commitment* and the number of advancement hours of the *advanced pre-dispatch operational commitment* is less than its *minimum generation block run-time* plus its *minimum generation block down-time*, then:

$$SU\_INCR_{k,f}^{p,pdm} = Max\,(0, PD\_BE\_SU_{k,f}^{p,pdm} - DAM\_BE\_SU_{k,f}^{p})$$

c. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$SU\_INCR_{k,f}^{p,pdm} = 0$$

d. Otherwise:

$$SU\_INCR_{k,f}^{p,pdm} = PD\_BE\_SU_{k,f}^{p,pdm}$$

e. $PD\_SU\_Ratio_{k,f}^{c}$ is a prorating factor for *market participant* 'k' at combustion turbine *resource delivery point* 'c' for *generator failure* 'f', and calculated as follows:

i. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$PD\_SU\_Ratio_{k,f}^{c} = 0$$

ii. Otherwise:

$$PD\_SU\_Ratio_{k,f}^{c} = Min\left(1, \frac{MLP\_INJ_{k,f}^{c}}{PD\_MGBRT_{k,f}^{c}}\right)$$

Where:

a. $MLP\_INJ_{k,f}^{c}$ is the number of *metering intervals* where the *GOG-eligible resource* for *market participant* 'k' injects *energy* into the *IESO-controlled grid* at combustion turbine *resource delivery point* 'c' in an amount less than its *minimum loading point* during the *minimum generation block-run time* associated with the *pre-dispatch operational commitment* associated with *generator failure* 'f'; and

b. $PD\_MGBRT_{k,f}^{c}$ is, for *market participant* 'k' at combustion turbine *resource delivery point* 'c', the number of *metering intervals* of the *minimum generation block run-time* associated with the *pre-dispatch operational commitment* associated with *generator failure* 'f'.

4.10.11 For a steam turbine *resource* associated with a *pseudo-unit* where a *generator failure* has occurred, the *IESO* shall calculate the *generator failure* charge – guarantee cost component *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' ($GFC\_GCC_k^s$) in accordance with the following and the operating profit function described in section 10 of Appendix 9.2:

$$GFC\_GCC_k^s = (-1) \times Max\Bigg[0, \sum^{F}\left(PD\_SU\_Ratio_{k,f}^{c} \times SU\_INCR_{k,f}^{p,pdm} \times ST\_Portion_{k,d1}^{p}\right) + \sum^{T1}\sum^{CT_f}\left(\frac{PD\_BE\_SNL_{k,h}^{p,pdm}}{12} \times ST\_Portion_{k,d1}^{p}\right) - \sum^{T1}\left(OP\left[Min\{c \in CT_F \mid PD\_LMP_h^{s,pdm}\}, PD\_DIGQ_{k,h}^{s,t}, PD\_DIPC_{k,h}^{s,t}\right]/12\right)\Bigg] \times M1$$

Where:

a. 'M1' is the prorating factor based on the quantity of *energy* that the *resource* failed to deliver and calculated as follows:

$$M1 = \left[1 - \frac{\sum^{T1} Min(\sum^{N_t}[PD\_STP\_QSI_{k,h}^{p,pdm}], Max(AQEI_{k,h}^{s,t} - \sum^{M_t}(RT\_STP\_QSI_{k,h}^{p,t}), \sum^{N_t} DAM\_STP\_QSI_{k,h}^{p}))}{\sum^{T1}\sum^{N_t}[PD\_STP\_QSI_{k,h}^{p,pdm}]}\right]$$

b. If the combustion turbine *resource*'s *pre-dispatch operational commitment* violated by failure 'f' bridges with a *day-ahead operational commitment* and the number of pre-dispatch advancement hours is less than its *minimum generation block run-time* plus its *minimum generation block down-time*, then:

$$SU\_INCR_{k,f}^{p,pdm} = Max\left(0, PD\_BE\_SU_{k,f}^{p,pdm} - DAM\_BE\_SU_{k,f}^{p}\right)$$

c. If the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$SU\_INCR_{k,f}^{p,pdm} = 0$$

d. Otherwise,

$$SU\_INCR_{k,f}^{p,pdm} = PD\_BE\_SU_{k,f}^{p,pdm}$$

e. $PD\_SU\_Ratio_{k,f}^{c}$ is a prorating factor for *market participant* 'k' at combustion turbine *resource delivery point* 'c' for *generator* failure 'f', and calculated as follows:

i. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$PD\_SU\_Ratio_{k,f}^{c} = 0$$

ii. Otherwise:

$$PD\_SU\_Ratio_{k,f}^{c} = Min\left(1, \frac{MLP\_INJ_{k,f}^{c}}{PD\_MGBRT_{k,f}^{c}}\right)$$

Where:

a. 'CT_f' is the set of all combustion turbine *resources* associated with steam turbine *resource delivery point* 's' having a combustion turbine *resource* failure interval during *metering interval* 't';

b. 'M_t' is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' whose associated combustion turbine *resource* does not have a combustion turbine *resource* failure interval and are not operating in *single cycle mode* during *metering interval* 't';

c. 'N_t' is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' whose associated combustion turbine *resource* has a combustion turbine *resource* failure interval or are operating in *single cycle mode* during *metering interval* 't';

d. 'F' is the set of all combustion turbine *resource* or steam turbine *resource* failures 'f' occurring during the period 'T1';

e. $MLP\_INJ_{k,f}^{c}$ has the same meaning as section 4.10.10(e)(ii)(a); and

f. $PD\_MGBRT_{k,f}^{c}$ has the same meaning as section 4.10.10(e)(ii)(b).

4.11 Fuel Cost Compensation Credit

4.11.1 Subject to this section 4.11, the fuel cost compensation credit *settlement amount* for *market participant* 'k' (FCC_k) shall be calculated and disbursed to the *market participants* for *GOG-eligible resources* in the following circumstances:

4.11.1.1 the *market participant* for the *GOG-eligible resource*, following the issuance of the *GOG-eligible resource's start-up notice*, has acknowledged receipt of such *start-up notice* and has indicated that it reasonably expects to comply with the *start-up notice*;

4.11.1.2 the *IESO*, in order to maintain the *reliability* of the *IESO-controlled grid*, requires the *GOG-eligible resource* that has a *day-ahead operational commitment* or a *pre-dispatch operational commitment* to either de-synchronize from the *IESO-controlled grid* prior to the end of its *day-ahead operational commitment* or *pre-dispatch operational commitment, as the case may be,* or not to synchronize to the *IESO-controlled grid* prior to the start of its *day-ahead operational commitment* or *pre-dispatch operational commitment,* as the case may be;

4.11.1.3 the *market participant* submits a claim, in accordance with the process specified in the applicable *market manual*, to the *IESO* requesting compensation for financial losses related to the procurement of fuel for operation during its *day-ahead operational commitment* or *pre-dispatch operational commitment,* as the case may be, which was not ultimately utilized by that *GOG-eligible resource*, as detailed in section 4.11.2; and

4.11.1.4 the *IESO* determines such claim, or part thereof, to be valid.

4.11.2 In determining whether claims, or part thereof, made pursuant to sections 4.11.1 are valid, the *IESO* shall apply the following principles:

4.11.2.1 Financial losses related to the procurement of fuel required for the *GOG-eligible resource* to achieve and maintain its *minimum loading point* for the duration of its *day-ahead operational commitment* or *pre-dispatch operational commitment* that were impacted by the *IESO's* actions as described in section 4.11.1.2 are eligible for compensation, and may include:

a. direct fuel costs, which will be compensated for based on the replacement cost of such fuel, provided such fuel was not ultimately utilized by that *GOG-eligible resource*, as determined by the *IESO* using the most appropriate comparator price for the relevant fuel, as determined by the *IESO* in its sole discretion;

b. transportation costs relating to the transportation of fuel to the *GOG-eligible resource*, including normal losses of fuel in transit. For greater certainty, fixed transportation costs are not eligible for compensation;

c. storage injection or withdrawal charges, where such costs were unavoidable and incurred following the *IESO's* actions as described in section 4.11.1.2 by the *market participant* as a result of storing the procured fuel for later utilization; and

d. any other fuel-related costs the *market participant* incurred directly as a result of the *IESO's* actions as described in section 4.11.1.2 that the *IESO* determines was unavoidable; and

4.11.2.2 Notwithstanding the foregoing, compensation will not be provided for the following costs:

a. where the loss claimed was mitigated by the *market participant* through some means, including purchased fuel being put into storage and used by the *GOG-eligible resource* or another *resource* for the benefit of the *market participant* or an *affiliate*. For greater certainty, only the portion of the claimed loss that was mitigated is not eligible for compensation;

b. operating and maintenance costs, including *station service*, planned maintenance, contractual service agreement fees, consumable parts, disposal costs, balance-of-plant maintenance, and *transmission services charges* and *connection charges*;

c. any costs incurred in relation to *settlement hours* for which the *market participant* has already received a *day-ahead market generator offer* guarantee *settlement amount* or a *real-time market generator offer* guarantee *settlement amount*.

4.11.3 Where the *IESO* determines that a claim, or part thereof, made under section 4.11.1 are valid, the amount of the claim determined to be valid will be applied to the *market participant's settlement statement* for the last *trading day* of the *energy market billing period* in which the *IESO* made such determination.

4.11.4 All claims made to the *IESO* pursuant to section 4.11.1 may be subject to audit by the *IESO*, which may obligate the *market participant* to demonstrate or otherwise make a binding declaration that the financial loss being claimed was not mitigated through the actions of:

a. the *market participant*;

b. an *affiliate* or subsidiary of the *market participant*; or

c. any other party that may have a commercial relationship with the *market participant* where that commercial relationship involves compensation of any kind that is directly related to the mitigation of the financial loss being claimed.

4.12 Forecasting for Variable Generation

4.12.1 The *IESO* may contract for forecasting services relating to *variable generation*.

4.13 Capacity Obligations

Capacity Obligation Availability Payment

4.13.1 The *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CAAP^m_k$") shall be calculated for each *energy market billing period* and disbursed to *capacity market participants* who have a *capacity obligation* during the relevant *obligation period* and which shall be calculated as follows:

$$CAAP^m_k = \Sigma^H CCO^m_{k,h} \times CACP^z_h$$

Where:

a. 'H' is the set of all *settlement hours* 'h' within the *availability window* of all *business days* in the relevant *energy market billing period*.

Capacity Obligation Availability Charge

4.13.2 The *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *trading day* ("$CAAC^m_k$") shall be collected from such *capacity market participants* in accordance with the following:

4.13.2.1 In regard to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*, the *capacity obligation* availability charge *settlement amount* shall be calculated for each *trading day* for which it fails for any *settlement hour* of the *availability window* during such *trading day* to submit a *demand response energy bid* in an amount that is greater than or equal to its *capacity obligation* in the *day-ahead market* and maintain such *energy bid* through the *real-time market.* Where a *capacity market participant* participating with an *hourly demand response resource* does not receive a standby notice, the *demand response energy bid* is instead required to be maintained until 7:00 am EST of the relevant *trading day*. The *capacity obligation* availability charge *settlement amount* is calculated as follows:

$$CAAC^m_k = \Sigma^H (-1) \times Max(0, CCO^m_{k,h} – DREBQ^m_{k,h}) \times CACP^z_h \times CNPF_{tm}$$

Where:

a. 'H' is the set of all *settlement hours* 'h' within the *availability window* during the relevant *trading day*;

b. If the *capacity market participant* did not submit a *demand response energy bid* for its *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be, for *settlement hour* 'h' in the *day-ahead market* or failed to maintain such *energy bid* through the *real-time market* or until 7:00 am EST as the case may be, $DREBQ^m_{k,h} = 0$;

c. In regard to *hourly demand response resource*, if the *demand response energy bids* submitted for *settlement hour* 'h' in either the *day-ahead market* or the *real-time market* does not form part of *energy bids* spanning at least four consecutive *settlement hours* during the relevant *availability window*, $DREBQ^m_{k,h} = 0$;

d. If the *demand response energy bid* submitted in the *day-ahead market* for *settlement hour* 'h' is not equal to the *demand response energy bid* submitted in the *real-time market* for the same *settlement hour*, $DREBQ^m_{k,h}$ shall be equal to the lesser of the two *demand response energy bids*; and

e. Notwithstanding any of the foregoing, $DREBQ^m_{k,h}$ shall not exceed the $CARC^m_k$ for the *hourly demand response resource*.

4.13.2.2 For a *capacity market participant* participating with a *capacity generation resource*, *system-backed capacity import resource*, *generator-backed capacity import resource*, or *capacity storage resource*, the *capacity obligation* availability charge *settlement amount* shall be calculated for each *trading day* it fails for any *settlement hour* of an *availability window* during such *trading day* to submit *energy offer* in an amount that is greater than or equal to its *capacity obligation* in the *day-ahead market* and maintain such *energy offer* as follows: (a) for *system-backed capacity import resources* or *generator-backed capacity import resources*, through to pre-dispatch; (b) for *capacity storage resources*, through the *real-time market*; and (c) for *capacity generation resources*, in accordance with the applicable *market manual*. The *capacity obligation* availability charge *settlement amount* is calculated as follows:

$$CAAC^m_k = \Sigma^H (-1) \times Max(0, CCO^m_{k,h} - CAEO^m_{k,h}) \times CACP^z_h \times CNPF_{tm}$$

Where:

a. 'H' is the set of all *settlement hours* 'h' within the *availability window* during the relevant *trading day*;

b. If the *capacity market participant* did not submit an *energy offer* in the *day-ahead market* or failed to maintain such *energy offer* through to pre-dispatch or the *real-time market*, as the case may be, for *settlement hour* 'h', $CAEO^{m}_{k,h} = 0$;

c. If the *energy offer* submitted in the *day-ahead market* for *settlement hour* 'h' is not equal to the *energy offer* submitted in the *pre-dispatch process* for the same *settlement hour*, $CAEO^{m}_{k,h}$ shall be equal to the lesser of the two *energy offers*; and

d. If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window,* the $CAEO^{m}_{k,h}$ for the remaining *settlement hours* of the *availability window* after receiving such non-zero *energy dispatch instruction* shall be equal to the *energy offer* applicable to the *settlement hour* in which they receive such non-zero energy dispatch instruction.

Capacity Obligation Dispatch Charge

4.13.3 Subject to MR Ch.7 ss.19.4.5 and 7.5.3, the *capacity obligation* dispatch charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' ("$CADC^{m}_{k,h}$") shall be calculated and collected from such *capacity market participant* participating with a commercial and industrial *hourly demand response resource* for each *settlement hour* of an *availability window* in which the *hourly demand response resource* fails to comply with an activation notice, as determined in accordance with section 4.13.3.1, and which shall be calculated in accordance with the following:

$$CADC^{m}_{k,h} = (-1) \times DRSQty^{m}_{k,h} \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

a. 'h' is a *settlement hour* in which the *hourly demand response resource* failed to comply with its activation notice, as determined in accordance with the applicable *market manual.*

4.13.3.1 A commercial and industrial *hourly demand response resource* is determined to have failed to comply with an activation notice if the following condition is true:

$$C\&I\_HDR\_BL^{m,t}_{k,h} - HDR\_AC^{m,t}_{k,h} < 85\% \times (TBQ^{m,t}_{k,h} - DQSW_{k,h}{}^{m,t})$$

Where:

a. "$C\&I\_HDR\_BL^{m,t}_{k,h}$" is the amount calculated pursuant to the applicable *market manual*.

b. "$HDR\_AC^{m,t}_{k,h}$" is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *metering interval* 't' of *settlement hour* "h", as determined in accordance with the submitted measurement data and its allocated quantity of *energy* withdrawn, as the case may be.

c. "$TBQ^{m,t}_{k,h}$" has the same meaning as ascribed to the same variable within the definition of $HDRDC^{m}_{k,h}$ in section 11 of Appendix 9.2.

Capacity Obligation Administration Charge

4.13.4 The *capacity obligation* administration charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAADM^{m}_{k}$") shall be calculated and collected from each *capacity market participant* participating with a virtual *hourly demand response resource* or a *generator-backed capacity import resource* for each *energy market billing period* in which such *capacity market participant* fails to provide timely, accurate and complete data, including measurement data to the *IESO* in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CAADM^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

a. '$CAAP^{m}_{k}$' is the *capacity obligation* availability payment *settlement amount*, calculated in accordance with section 4.13.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Charge

4.13.5 The *capacity obligation* capacity charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *energy market billing period* ("$CACC^{m}_{k}$") shall be calculated and collected from each *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to deliver its *cleared ICAP* within the applicable threshold, as set out in the applicable *market manual,* in response to a *capacity obligation capacity test*, and which shall be calculated as follows:

$$CACC^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

a. '$CAAP^{m}_{k}$' is the *capacity obligation* availability payment *settlement amount*, calculated in accordance with section 4.13.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Import Call Failure Charge

4.13.6 Subject to MR Ch.7 s.7.5.8A, the *capacity obligation* capacity import failure *settlement amount* for *capacity market participant* 'k' participating with a *generator-backed capacity import resource* at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CACIF^m_k$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to satisfy its *capacity obligation* in response to a *capacity import call*, as determined in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CACIF^m_k = (-1) \times CAAP^m_k$$

Where:

a. '$CAAP^m_k$' is the *capacity obligation* availability payment *settlement amount*, calculated in accordance with section 4.13.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Deficiency Charge

4.13.7 The *capacity obligation* capacity deficiency *settlement amount* for *capacity market participant* 'k' at *intertie metering point* 'i' for the relevant *energy market billing period* ("$CACD^i_k$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which the *IESO* has determined that all or a portion of the *capacity market participant's capacity obligation* is *over committed capacity*, and which shall be calculated and collected for the entire *obligation period* in accordance with the following:

$$CACD^i_k = \Sigma^H (-1.5) \times OCMW^i_k \times CACP^z_h$$

Where:

a. 'H' is the set of all *settlement hours* 'h' within the *availability window* of all *trading days* within the relevant *energy market billing period*.

4.13.7.1 If the *IESO* determines that all or a portion of the *capacity market participant's capacity obligation* is *over committed capacity*, the *capacity market participant's capacity obligation* shall be reduced by the amount of *over committed capacity* effective as of the first *trading day* of the subsequent *energy market billing period*. If such reduction in the *capacity market participant's capacity obligation* for such resource results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such resource is forfeited effective as of the first *trading day* of the subsequent *energy market billing period*.

Capacity Obligation In-Period Cleared UCAP Adjustment Charge

4.13.8 The *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAIPA^m_k$") shall be calculated and collected from such *capacity market participant* for i) the *energy market billing period* in which the *IESO* provided notice to the *capacity market participant* that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*; ii) each prior *energy market billing period* of the relevant *obligation period* included as an adjustment to the next scheduled *recalculated settlement statement* for such *energy market billing period*; and iii) if the *capacity market participant* has filed a *notice of disagreement* in regards to the outcome of a *capacity auction capacity test,* each subsequent *energy market billing period* of the relevant *obligation period*. The *capacity obligation* in-period UCAP adjustment charge *settlement amount* is calculated as follows:

$CAIPA^m_k$ = (-1 x Max (0, ($CAAP^m_k$ x (UCAP Adjustment) + Σ^H $CAAC^m_{k,h}$))

Where:

a. $CAAP^m_k$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.13.1;

b. $CAAC^m_{k,h}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as calculated pursuant to section 4.13.2;

c. 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *energy market billing period;* and

d. 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response resource's* delivered performance during a *capacity auction capacity test*, as determined in accordance with the applicable *market manual*. If the *capacity market participant* has filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with section 6.8, and but for filing such *notice of disagreement* the *capacity market participant* would have forfeited any of its *capacity obligation* pursuant to MR Ch.7 s. 19.4.18, then the UCAP Adjustment shall equal 100%.

Capacity Obligation Buy-Out Charge

4.13.9 A *capacity market participant* or a *capacity auction participant* may elect to be subject to a *capacity obligation* buy-out charge *settlement amount* for all, or a portion of, their *capacity obligation* in accordance with the applicable *market manual*. Upon the *IESO's* acceptance of a buy-out request, the *capacity market participant's capacity obligation* shall be reduced to reflect the approved buy-out and the *IESO* shall calculate the *capacity obligation* buy-out charge *settlement amount* for such *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' ("$CABOC^{m}_{k}$") which shall be calculated as follows:

$$CABOC^{m}_{k} = 50\% \times \Sigma^{H}\, CBOC^{m}_{k} \times CACP^{z}_{h} \times (1 - CNPF_{tm})$$

Where:

a. 'H' is the set of all *settlement hours* 'h' within the *availability window* of all *trading days* from the buy-out effective date to the end of the *capacity auction commitment period*.

Measurement Data Audit

4.13.10 At any time, the *IESO* may audit any submitted measurement data and supporting information and a *capacity market participant* shall provide such information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that actual measurement data and supporting information differed from the submitted measurement data and supporting information, the *IESO* shall recover from or distribute to a *capacity market participant* any resulting over or under payment, as applicable.

Capacity Obligation Test Activation and Emergency Activation Payment

4.13.11 Subject to section 4.13.11.3, the *IESO* shall calculate and disburse a *capacity obligation dispatch test* payment *settlement amount* or *capacity obligation* emergency activation payment *settlement amount* for a valid *capacity auction dispatch test* or emergency activation, respectively, of an *hourly demand response resource* to the applicable *capacity market participant*, in accordance with the following:

4.13.11.1 in regards to *capacity auction dispatch tests*, the c*apacity obligation dispatch test* payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CATAP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CATAP^{m}_{k,h} = HDRTAPR \times HDRDC^{m}_{k,h}$$

4.13.11.2 in regards to *emergency operating state* activation, the *capacity obligation emergency operating state* activation payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* that is not associated with *load equipment* registered as a *price responsive load* at *delivery point* 'm' in *settlement hour* 'h' ("$CAEOP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CAEOP^{m}_{k,h} = Max(0, HDRBP^{m}_{k,h} – Max(0, DAM\_LMP^{z}_{h} + LFDA_{h})) \text{ X } HDRDC^{m}_{k,h}$$

Where:

a. '$LFDA_h$' is the load forecast deviation adjustment for *settlement hour* 'h' determined in accordance with section 3.2.3.

4.13.11.3 in regards to *emergency operating state* activation, the *capacity obligation emergency operating state* activation payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* that is associated with *load equipment* registered as a *price responsive load* at *delivery point* 'm' in *settlement hour* 'h' ("$CAEOP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CAEOP^{m}_{k,h} = Max(0, HDRBP^{m}_{k,h} – Max(0,RT\_LMP^{z}_{h})) \text{ X } HDRDC^{m}_{k,h}$$

4.13.11.4 If measurement data for any *metering interval* within a *settlement hour* was not submitted to the *IESO* in accordance with the applicable *market manual,* the *capacity market participant* shall not be eligible to receive a *capacity obligation* test activation payment *settlement amount* or a *capacity obligation emergency operating state* activation payment *settlement amount* for such *settlement hour*.

Capacity Obligation Availability Charge True-Up Payment

4.13.12 The *capacity obligation* availability charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CAACT^{m}_{k}$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which (i) the *capacity market participant* was subject to an availability charge pursuant to section 4.13.2.1 or 4.13.2.2; and (ii) the lowest quantity of capacity *offered* in the *day-ahead market, pre-dispatch process,* and *real-time market* by the *capacity market participant* is in excess of the *capacity obligation* of the relevant *capacity auction resource* for at least one *settlement hour* within the *availability window* of the applicable *obligation period*. The *capacity obligation* availability charge true-up *settlement amount* shall be calculated as follows*:*

$$CAACT^{m}_{k} = (Min ((-1) \text{ x } \Sigma^{TM} ((\Sigma^{D} CAAC^{m}_{k}) + \text{UCAP Adjustment x } CAAP^{m}_{k} + CAIPA^{m}_{k}), \Sigma^{H} Max (0,(RAC_{k} – CCO_{k,h}) \text{ x } CACP_{h} \text{ x } CNPF_{tm}))$$

Where:

a. $CAAC^m_k$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *trading day,* as calculated as the sum of the *capacity obligation* availability charge *settlement amount* of each *settlement hour* within the relevant *availability window* determined pursuant to section 4.13.2.1;

b. 'UCAP Adjustment' is a de-rate (in %) determined in accordance with section 4.13.8;

c. $CAAP^m_k$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.13;

d. $CAIPA^m_k$ is the *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.13.8*;*

e. 'D' is the set of all *trading days* within the relevant *energy market billing period*;

f. 'TM' is the set of all *energy market billing periods* within the relevant *obligation period;* and

g. 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period.*

Capacity Obligation Capacity Auction Charges True-up Payment

4.13.13 The *capacity obligation* charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CACT^m_k$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which the *capacity market participant* has a *capacity obligation*. The *capacity obligation* charge true-up *settlement amount* shall be calculated as follows*:*

$$CACT^m_k = -1 \times \text{Min}\left(0, \left(\sum_H TD_{C,k,h}^m + \sum_H TD_{P,k,h}^m\right)\right)$$

Where:

a. $TD_{C,k,h}^m$ is the total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where:

i. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4.13.2, 4.13.2.1, 4.13.4, 4.13.5, 4.13.6, 4.13.7, and 4.13.8.

b. $TD_{P\,k,h}^{m}$ is the total dollar value of all *settlement amounts* 'P' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where:

ii. 'P' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4. 13.1 and 4.13.12.

c. 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period*.

Capacity Auction Uplift

4.13.14 The *capacity obligation* uplift *settlement amount* for *market participant* 'k' at *delivery point* 'm' in the *energy market billing period* ("CAU^{m}_{k}") will be calculated and collected from or disbursed to *market participants* for load facilities, as defined in *Ontario Regulation 429/04,* for each *energy market billing period*. The *capacity obligation* uplift *settlement amount* shall be determined in accordance with sections 4.13.14.1 and 4.13.14.2. In calculating the *capacity obligation* uplift *settlement amount* in this section 4.13.14, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

(a) 'H' is the set of all *settlement hours* 'h' in the relevant *energy market billing period;*

(b) 'M' is the set of all *delivery points* 'm' of *market participant* 'k';

(c) 'Class B Load' as defined in the applicable *market manual*;

(d) '$EGEI_k$' as defined in the applicable *market manual.*

4.13.14.1 for *market participants* that are classified as a 'Class A Market Participants' in respect of the relevant load facility, as defined in *Ontario Regulation 429/04,* in accordance with *applicable law,* the *capacity obligation* uplift *settlement amount* for such load facility shall be calculated as follows:

$$CAU^{m}_{k} = \Sigma_{H,M}\,(TD_{C,k,h}^{m} \times PDF_{k})$$

Where:

a. '$TD_{C,k,h}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where:

i. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.13.1, 4.13.2, 4.13.9, 4.13.11, 4.13.12, and 4.13.13.

b. 'PDF$_k$' is the Peak Demand Factor for 'Class A Market Participant' or Distributor 'k' for the relevant *energy market billing period*, as determined in accordance with *applicable law,* where if the 'Class A Market Participant' or Distributor 'k' ceases to be a 'Class A Market Participant' in respect of the relevant load facility during the relevant *energy market billing period,* the PDF$_k$ shall be pro-rated accordingly.

4.13.14.2 for *market participants* that are classified as 'Class B Market Participants' in respect of the relevant load facility, as defined in *Ontario Regulation 429/04,* in accordance with *applicable law,* the *capacity obligation* uplift *settlement amount* shall for such load facility shall be calculated in accordance with the following:

a. for Fort Frances Power Corporation Distribution Inc.:

$$CAU^m_k = (\Sigma_{H,M}\ TD_{C,k,h}{}^m - TD_{C1350,k,h}{}^m) \times Max((\ \Sigma_H{}^{M,T}\ AQEW_{k,h}{}^{m,t} + EGEI_k - EEQ),0) / Class\ B\ Load$$

Where:

i. '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.13.1, 4.13.2, 4.13.9, 4.13.11, 4.13.12, and 4.13.13.

ii. '$TD_{C1350,k,h}{}^m$' is total dollar value of *settlement amounts* applied pursuant to section 4.13.14.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

iii. 'EEQ' as defined in the applicable *market manual;*

b. For other *market participants* that are classified as 'Class B Market Participants' in respect of the relevant *load facility* in accordance with *applicable law*:

$$CAU^m_k = (\Sigma_{H,M}\ TD_{C,k,h}{}^m - TD_{C1350,k,h}{}^m) \times Max((\Sigma_H{}^{M,T}\ AQEW_{k,h}{}^{m,t} + EGEI_k - GA\_AQEW_{g,k,h,M}{}^{m,t} - PGS_{h,M}\ ),0) / Class\ B\ Load$$

Where:

i. '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. 4.13.1, 4.13.2, 4.13.9, 4.13.11, 4.13.12, and 4.13.13.

ii. '$TD_{C1350,k,h}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.13.14.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

iii. '$GA\_AQEW_{g,k,h,M}^{m,t}$' as defined in the applicable *market manual*.

iv. '$PGS_{h,M}$' as defined in the applicable *market manual*.

4.14 Non-Hourly Uplifts

Generator Failure Charge – Guarantee Cost Component Uplift

4.14.1 The *generator failure* charge – guarantee cost component uplift *settlement amount* will be calculated and disbursed to the *market participants* for *load resources* , *electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each *trading day* in which the *IESO* applies the *generator failure* charge – guarantee cost component in accordance with section 4.10.6 or 4.10.10. The *generator failure* charge – guarantee cost component uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("GFC_GCCU_k") shall be determined as follows:

$$GFC\_GCCU_k = -1\ x \sum_{K,F}^{M} GFC\_GCC_{k,f}^{m} \times \left[\sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \Big/ \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})\right]$$

Where:

a. $GFC\_GCC_{k,f}^{m}$ is the *generator failure* charge – guarantee cost component calculated in accordance with section 4.10 for *market participant* 'k' at *delivery point* 'm' for *generator failure* 'f';

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

c. 'F' is the set of all *generator failures* 'f'.

Real-Time Generator Offer Guarantee Uplift

4.14.2 The real-time *generator offer* guarantee uplift *settlement amount* will be calculated and collected from the *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each *trading day* in which the *IESO* applies the real-time *generator offer* guarantee in accordance with section 4.5. The real-time *generator offer* guarantee uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("$RT\_GOG^{m}_{k,h}$") shall be determined as follows:

$$RT\_GOGU_k = -1\,x \sum_{K,H}^{M,T}\left(RT\_GOG^{m}_{k,h} + RT\_GOG\_CB^{m}_{k,h}\right) \times \left[\sum_{H}^{M,T}(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h}) \,/ \sum_{K,H}^{M,T}\left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h}\right)\right]$$

Where:

a. $RT\_GOG^{m}_{k,h}$ is the real-time *generator offer* guarantee *settlement amount* calculated in accordance with sections 4.5 for *market participant* 'k' at *delivery point 'm'* for *settlement hour 'h';*

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

c. $RT\_GOG\_CB^{m}_{k,h}$ is the real-time *generator offer* guarantee clawback *settlement amount* calculated in accordance with sections 3.10.3 for *market participant* 'k' at *delivery point* 'm' for *settlement hour 'h'.*

Day-Ahead Market Uplift

4.14.3 The *day-ahead market* uplift *settlement amount* will be calculated and collected from the *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each *trading day* in which the *IESO* applies the *day-ahead market* make whole payment or the *day-ahead market generator offer* guarantee in accordance with section 3.4 or 4.4, respectively. The *day-ahead market* uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("DAM_UPL_k") shall be determined as follows:

$$DAM\_UPL_k = -1\,x\left(\sum_{H}^{M}\left(DAM\_MWP^{m}_{k,h} + DAM\_GOG^{m}_{k}\right) - DAM\_P2\_PMT\right) \times \sum_{H}^{M,T}\left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h}\right) / \sum_{K,H}^{M,T}\left(AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h}\right)$$

Where:

a. $DAM\_MWP^{m}_{k,h}$ is the *day-ahead market* make-whole payment *settlement amount* calculated in accordance with sections 3.4 for *market participant* 'k' at *delivery point 'm'* for *settlement hour 'h';*

b. $DAM\_GOG^{m}_{k}$ is the *day-ahead market generator offer* guarantee *settlement amount* calculated in accordance with sections 4.4 for *market participant* 'k' at *delivery point 'm';*

c. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

d. DAM_P2_PMT is as calculated in accordance with section 4.14.5.

Day-Ahead Market Reliability Scheduling Uplift

4.14.4 The *day-ahead market reliability* scheduling uplift *settlement amount* will be calculated and collected from the *market participants* for *virtual zonal resources* with *day-ahead schedules* to inject *energy*, *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each applicable *trading day*. The *day-ahead market reliability* scheduling uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("$DRSU_k$") shall be determined in accordance with the following:

4.14.4.1 First, the *IESO* shall determine the *day-ahead market reliability* scheduling uplift *settlement amount* for *market participants* for *virtual zonal resources* with *day-ahead schedules* to inject *energy* as follows:

$$V\_DRSU_k = DAM\_P2\_PMT \times \sum_{H}^{V} DAM\_QVSI_{k,h}^{v} \Big/ \left(\sum_{K,H}^{V} DAM\_QVSI_{k,h}^{v} + DAM\_NDL\_OF\right)$$

Where:

i. 'DAM_P2_PMT' is as calculated in accordance with section 4.14.5; and

ii. 'DAM_NDL_OF' is the total quantity of *energy* that was over-forecasted in the *day-ahead market* for *non-dispatchable loads* in Pass 2: Reliability Scheduling and Commitment of the *day-ahead market calculation engine,* as determined by the *IESO* as follows:

$$DAM\_NDL\_OF = Max\left[\sum_{H,K}^{M} (DAM\_QSW_{k,h}^{m,p2} + DAM\_HDR\_QSW_{k,h}^{m1,p2} - AQEW_{k,h}^{m,t}),0\right]$$

Where:

a. 'M' is the set of all *delivery points* 'm' for non-dispatchable loads and physical *hourly demand response resources* that are not associated with *load equipment* registered as *price responsive loads*; and

b. 'm1' is the set of all *delivery points* 'm' for physical *hourly demand response resources*.

c. 'p2' is Pass 2: Reliability Scheduling and Commitment of the *day-ahead market calculation engine.*

4.14.4.2 Second, the *IESO* shall determine the *day-ahead market reliability* scheduling uplift *settlement amount*, if any, for *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions as follows:

$$EL\_DRSU_k = \left(DAM\_P2\_PMT - \sum_K V\_DRSU_k\right) \times \sum_H^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})$$

Where:

a. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'.

4.14.5 The *IESO* shall calculate the total amount of *day-ahead market* make-whole payment disbursed to *energy traders* participating with *boundary entity resources* engaged in import transactions and *day-ahead market generator offer* guarantee disbursed to *GOG-eligible resources*, in each instance for those *resources* that were scheduled in Pass 2: Reliability Scheduling and Commitment but were not scheduled in Pass 1: Market Commitment and Market Power Mitigation Pass of the *day-ahead market calculation engine* (DAM_P2_PMT) as follows:

$$DAM\_P2\_PMT = -1 \times \sum_{H,K}^{M} Max(Imp\_DAM\_MWP_{k,h}^{i,p2} - Imp\_DAM\_MWP_{k,h}^{i,p1}, 0) + DAM\_GOG_{k,h}^{m}$$

Where:

a. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i';

b. $Imp\_DAM\_MWP_{k,h}^{i,p2}$ is as calculated in accordance with section 4.14.6;

c. $Imp\_DAM\_MWP_{k,h}^{i,p1}$ is as calculated in accordance with section 4.14.7; and

d. $DAM\_GOG_{k,h}^{m}$ is the $DAM\_GOG_{k,h}^{m}$ calculated in accordance with section 4.4 for the *GOG-eligible resources* scheduled in Pass 2: Reliability Scheduling and Commitment but were not scheduled in Pass 1: Market Commitment and Market Power Mitigation Pass.

4.14.6 The *IESO* shall calculate the *day-ahead market* make-whole payment disbursed to *energy traders* participating with *boundary entity resources* with import transactions that were scheduled in Pass 2: Reliability Scheduling and Commitment ($Imp\_DAM\_MWP^{i,p2}_{k,h}$) as follows:

$$Imp\_DAM\_MWP^{i,p2}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

Where:

a. $DAM\_COMP1^{i}_{k,h} = -1 \times \left[OP\left(DAM\_LMP^{i}_{h}, DAM\_QSI^{i,p2}_{k,h}, DAM\_BE^{i}_{kh}\right) - OP\left(DAM\_LMP^{i}_{h}, DAM\_EOP^{i}_{k,h}, DAM\_BE^{i}_{kh}\right)\right]$

b. $DAM\_COMP2^{i}_{k,h} = -1 \times \sum_{R}\left[OP\left(DAM\_PROR^{i}_{r,h}, DAM\_QSOR^{i,p2}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right) - OP\left(DAM\_PROR^{i}_{r,h}, DAM\_OR\_EOP^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right)\right]$

4.14.7 The *IESO* shall calculate the *day-ahead market* make-whole payment disbursed to *energy traders* participating with *boundary entity resources* with import transactions that were scheduled in Pass 1: Market Commitment and Market Power Mitigation Pass ($Imp\_DAM\_MWP^{i,p1}_{k,h}$) as follows:

$$Imp\_DAM\_MWP^{i,p1}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

Where:

a. $DAM\_COMP1^{i}_{k,h} = -1 \times \left[OP\left(DAM\_LMP^{i}_{h}, DAM\_QSI^{i,p1}_{k,h}, DAM\_BE^{i}_{k,h}\right) - OP\left(DAM\_LMP^{i}_{h}, DAM\_EOP^{i}_{k,h}, DAM\_BE^{i}_{k,h}\right)\right]$

b. $DAM\_COMP2^{i}_{k,h} = -1 \times \sum_{R}\left[OP\left(DAM\_PROR^{i}_{r,h}, DAM\_QSOR^{i,p1}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right) - OP\left(DAM\_PROR^{i}_{r,h}, DAM\_OR\_EOP^{i}_{r,k,h}, DAM\_BOR^{i}_{r,k,h}\right)\right]$

Fuel Cost Compensation Uplift

4.14.8 The fuel cost compensation uplift *settlement amount* will be calculated and collected from the *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each *energy market billing period* in which the *IESO* applies the fuel cost compensation *settlement amount* in accordance with section 4.11. The fuel cost compensation uplift *settlement amount* for *market participant* 'k' for the relevant *energy market billing period* ("$FCCU_k$") shall be determined as follows:

$$FCCU_k = -1 \times \sum_{K}^{M} FCC_k^m \times \sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})$$

Where:

a. FCC_k^m is the fuel cost compensation *settlement amount* calculated in accordance with sections 4.11 for *market participant* 'k' at *delivery point 'm';*

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

c. 'H' is the set of all *settlement hours* 'h' in the *energy market billing period.*

Mitigation Amount for Physical Withholding Uplift

4.14.9 The ex-post mitigation for *physical withholding settlement* charge uplift *settlement amount* will be calculated and disbursed to the *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each *trading day* in which the *IESO* applies the mitigation for *physical withholding settlement amount,* in accordance with section 5.5. The ex-post mitigation *physical withholding settlement* charge uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("$\mathrm{EXP\_PWSU}_k$") shall be determined as follows:

$$EXP\_PWSU_k = -1\, x \sum_{K}^{M} (EXP\_PWSC_k^m) \times \sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})$$

Where:

a. $EXP\_PWSC_k^m$ is the mitigation for *physical withholding settlement amount* calculated in accordance with sections 5.4 for *market participant* 'k' at *delivery point* 'm';

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

c. 'H' is the set of all *settlement hours* 'h' in the relevant *trading day.*

Mitigation Amount for Intertie Economic Withholding Uplift

4.14.10 The ex-post mitigation amount for *intertie economic withholding* uplift *settlement amount* will be calculated and collected from the *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy* *traders* participating with *boundary entity resources* engaged in export transactions for each *trading day* in which the *IESO* applies the mitigation for *intertie economic withholding settlement amount,* in accordance with section 5.5. The ex-post mitigation amount for *intertie economic withholding* uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("$\mathrm{EXP\_EWSCU}_k$") shall be determined as follows:

$$EXP\_EWSCU_k = \sum_K^M (EXP\_EWSC_k^i) \text{ x } \sum_H^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)$$

Where:

a. $EXP\_EWSC_k^i$ is the mitigation for *intertie economic withholding settlement amount* calculated in accordance with sections 5.5 for *market participant* 'k' at *intertie metering point* 'i';

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

c. 'H' is the set of all *settlement hours* 'h' in the relevant *trading day.*

Real-Time Ramp-Down Settlement Amount Uplift

4.14.11 The real-time ramp-down uplift *settlement amount* will be calculated and collected from the *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions for each *trading day* in which the *IESO* applies the ramp-down *settlement amount* in accordance with section 4.6. The real-time ramp-down uplift *settlement amount* for *market participant* 'k' for the relevant *trading day* ("RT_RDSAU_k") shall be determined as follows:

$$RT\_RDSAU_k = -1 \times \sum_K^{M,T} RT\_RDSA_k^m \times \left[\sum^{M,T}(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \,/ \sum_K^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

a. $RT\_RDSA_k^m$ is the real-time ramp-down *settlement amount* calculated in accordance with sections 4.6 for *market participant* 'k' at *delivery point* 'm'*;* and

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'.

Additional Non-Hourly Uplifts

4.14.12 The *IESO* shall, at the end of each *energy market billing period*, calculate and collect from *market participants* for *load resources, electricity storage resources* that are registered to withdraw, and *energy traders* participating with *boundary entity resources* engaged in export transactions, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *registered wholesale meters* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, any compensation, out-of-pocket expenses, costs, or reimbursements, as the case may be, paid or incurred in that *energy market billing period* by the *IESO* pursuant to:

a. MR Ch.4 s.5.3.4;

b. MR Ch.5 s.2.3.3A;

c. MR Ch.5 s.5.3.4;

d. MR Ch.5 s.6.7.4;

e. MR Ch.5 s.8.2.6;

f. MR Ch.7 s.8.4A.9;

g. Section 2.2.17;

h. Section 2.13.1;

i. Section 4.12.1; and

j. MR.Ch.7 s.22.8.11.2

4.14.13 The *IESO* shall, at the end of each *energy market billing period*, distribute to *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *registered wholesale meters* and across all scheduled quantities of *energy* withdrawn at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, any compensation, payments, or proceeds, as the case may be, received, recovered, or collected in that *energy market billing period* by the *IESO* pursuant to:

a. MR Ch.3 s.6.6.10A.2;

b. MR Ch.5 s.4.4A.1; and

c. Section 2.13.1.

4.14.14 The *IESO* shall, at the end of each *energy market billing period*, recover from *market participants*, in the manner specified in the applicable *market manual*, the following amounts:

a. any compensation for *capacity market participants* paid in that *energy market billing period* by the *IESO* pursuant to section 4.13; and

b. any funds borrowed by the *IESO* and any associated interest costs incurred by the *IESO* in the preceding *energy market billing period* pursuant to section 6.16.6.2.

4.14.15 The *IESO* shall distribute to *market participants*, in the manner specified in the *applicable market manual*, the following amounts:

a. any adjustments to *capacity market participant* payments pursuant to section 4.13.

5 Market Power Mitigation

5.1 Mitigation of Settlement Amounts

5.1.1 Notwithstanding sections 3.4, 3.5, 4.4, 4.5 and 4.6, the *IESO* shall conduct the mitigation process set out in section 5.1.2 for the following *settlement amounts* in the following order:

5.1.1.1 *day-ahead market* make-whole payment *settlement amount*;

5.1.1.2 *day-ahead market* generator *offer* guarantee settlement amount;

5.1.1.3 real-time make-whole payment *settlement amount*;

5.1.1.4 real-time *generator offer* guarantee *settlement amount*; and

5.1.1.5 real-time ramp down *settlement amount*.

5.1.2 Subject to section 5.1.4 and 5.1.5, where a *resource* which is otherwise eligible to receive a *settlement amount* referred to in section 5.1.1 fails a conduct test specified in section 2.4 or 3.4 of Appendix 9.4, as the case may be, for a *settlement hour* included within a period for which they were otherwise eligible to receive such *settlement amount*, the *IESO* shall calculate the applicable *settlement amount* in accordance with the following process:

5.1.2.1 First, the *IESO* shall calculate the *settlement amount* in accordance with the equations set out in sections 3.4, 3.5, 4.4, 4.5 and 4.6, as the case may be (the "initial *settlement amount*").

5.1.2.2 Second, the *IESO* shall calculate the *settlement amount* in accordance with the equations set out in sections 3.4, 3.5, 4.4, 4.5 and 4.6, as the case may be, except with the following substitutions for such *settlement hours* that failed the applicable conduct test, as applicable:

a. $EMFC\_DAM\_BE^{m}_{k,h}$ shall replace $DAM\_BE^{m}_{k,h}$;

b. $EMFC\_DAM\_BOR^{m}_{r,k,h}$ shall replace $DAM\_BOR^{m}_{r,k,h}$;

c. $EMFC\_DAM\_BE\_SU^{m}_{k,h}$ shall replace $DAM\_BE\_SU^{m}_{k,h}$;

d. $EMFC\_DAM\_SNL^{m}_{k,h}$ shall replace $DAM\_BE\_SNL^{m}_{k,h}$;

e. $EMFC\_RT\_BE^{m}_{k,h}$ shall replace $BE^{m}_{k,h}$;

f. $EMFC\_RT\_BOR^{m}_{r,k,h}$ shall replace $BOR^{m}_{r,k,h}$;

g. $EMFC\_RT\_SU^{m}_{k,h}$ shall replace $RT\_GOG\_SU^{m}_{k,h}$; and

h. $EMFC\_RT\_SNL^{m}_{k,h}$ shall replace $PD\_BE\_SNL^{m}_{k,h}$;

i. all of the above substitutions shall apply to their respective counterparts for steam turbine *delivery points* 's', and combustion turbine *delivery points* 'c';

j. for greater certainty, the aforementioned substitutions shall also apply to the calculation of the following, including the intermediate variables necessary to derive the following:

i. $DAM\_MWP\_DIPC^{c}_{k,h}$;
ii. $DAM\_MWP\_DIPC^{c}_{r,k,h}$;
iii. $DAM\_MWP\_DIPC^{s}_{k,h}$;
iv. $DAM\_MWP\_DIPC^{s}_{r,k,h}$; and
v. the assessment of the condition set out in section 3.4.13.5.3.

(the "EMFC *settlement amount*")

5.1.2.3 Third, the *IESO* shall determine the final applicable *settlement amount* in accordance with the following:

a. where the initial *settlement amount* is greater than the EMFC *settlement amount* multiplied by the applicable mitigation impact threshold, then the EMFC *settlement amount* shall apply;

b. otherwise, the initial *settlement amount* shall apply;

c. the applicable mitigation impact threshold will be determined as follows:

   i. where the *resource* failed a *narrow constrained area* conduct test, the applicable mitigation impact threshold is 1.1;
   ii. where the *resource* failed a *dynamic constrained area* conduct test, the applicable mitigation impact threshold is 1.1;
   iii. where the *resource* failed a broad constrained area conduct test, the applicable mitigation impact threshold is 1.2;
   iv. where the *resource* failed a global market power conduct test for *energy*, the applicable mitigation impact threshold is 1.2;
   v. where the *resource* failed a *reliability* conduct test, the applicable mitigation impact threshold is 1.0;
   vi. where the *resource* failed a local market power conduct test for *operating reserve*, the applicable mitigation impact threshold is 1.0; and
   vii. where the resource failed a global market power conduct test for *operating reserve*, the applicable mitigation impact threshold is 1.1;

d. notwithstanding section 5.1.2.3(a), where:

   i. the relevant *resource* is subject to a global market power mitigation conduct test for *energy*, as outlined in section 3.3.5 of Appendix 9.4;
   ii. of the conditions outlined in Appendix 9.4 ss. 3.3.5.1, 3.3.5.2, and 3.3.5.3, only the condition outlined in section 3.3.5.2 Appendix 9.4 is met; and
   iii. the initial *settlement amount* is less than or equal to $15,000, then the initial *settlement amount* shall apply; and

e. notwithstanding section 5.1.2.3(a), where:

i. the relevant *resource* is subject to a global market power mitigation conduct test for *operating reserve*, as outlined in section 3.3.8 of Appendix 9.4;

ii. of the conditions outlined in Appendix 9.4 ss. 3.3.8.1, 3.3.8.2, and 3.3.8.3, only the condition outlined in section 3.3.8.2 Appendix 9.4 is met;

iii. and the initial *settlement amount* is less than or equal to $15,000,

then the initial *settlement amount* shall apply.

5.1.3 Where a *resource* which is otherwise eligible to receive a *settlement amount* referred to in section 5.1.1 does not fail any applicable conduct tests specified in section 2.4 or 3.4 of Appendix 9.4, as the case may be, for a *settlement hour* in which they were otherwise eligible to receive such *settlement amount*, the *IESO* shall calculate the applicable *settlement amount* in accordance with the equations set out in sections 3.4, 3.5, 4.4, 4.5 and 4.6, as the case may be.

5.1.4 Notwithstanding section 5.1.2, no substitutions shall be made pursuant to section 5.1.2 for:

a. *energy traders* participating with *boundary entity resources* in regards to any *settlement amount*;

b. *dispatchable loads* and *dispatchable electricity storage resource* that is registered to withdraw in determining the real-time make-whole payment *settlement amount* and the *day-ahead market* make-whole payment *settlement amount* each as they relate to *energy*. For greater certainty, these substitutions will be made as they pertain to the *operating reserve* elements of such *settlement amounts;* and

c. hydroelectric *generation resources* in determining the *day-ahead market* make-whole payment in accordance with section 3.4.13.4 for *settlement hours* that fall within period 'Hp'.

5.1.5 Notwithstanding section 5.1.2 but subject to section 5.1.4, the *IESO* shall apply the process set out in section 5.1.2 with the following alterations in the following circumstances*:*

a. where a *resource* is otherwise eligible to receive the ramp-down *settlement amount*, the *IESO* shall calculate the applicable ramp-down *settlement amount* in accordance with section 5.1.2 when the *resource* fails a conduct test specified in section 2.4 or 3.4 of Appendix 9.4, as the case may be, for the *settlement hour* determined in accordance with the applicable *market manual*; and

b. where a hydroelectric *generation resource* is eligible for a *day-ahead market* make-whole payment in accordance with section 3.4.13.4, the *IESO* shall apply the process set out in section 5.1.2 to each *settlement hour* within the period 's' to determine the hourly data to use in the final calculation of the *day-ahead market* make-whole payment *settlement amount* for such *resource.*

5.2 Day-Ahead Market Reference Level Settlement Charge

5.2.1 The *day-ahead market reference level settlement* charge *settlement amount* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' ("$DAM\_RLSC_{k,h}^{m}$") shall be calculated in each instance a *dispatchable generation resource* or *dispatchable electricity storage resource* that is registered to inject meets the conditions set out in section 5.2.1.1 and collected from the *market participant* for such *resources* as follows:

$$DAM\_RLSC_{k,h}^{m} = -1 \times DAM\_QSI_{k,h}^{m} \times (DAM\_LMP_{h}^{m} - DAM\_PLCP_{k,h}^{m})$$

Where for the purposes of this section 5.2.1:

a. $DAM\_PLCP_{k,h}^{m}$ is the price component P_n of N-by-2 matrix $(DAM\_RLL_{k,h}^{m})$ of *price quantity pairs* where 'n' is the highest indexed row of the matrix such that $DAM\_QSI_{k,h}^{m} \leq Q_n$.

Conditions

5.2.1.1 The *IESO* shall apply the *day-ahead market reference level settlement* charge for each *settlement hour* for which a *resource* meets all of the following conditions:

5.2.1.1.1 $DAM\_PHCP_{k,h}^{m} >= DAM\_LMP_{h}^{m}$;

a. Where:

$DAM\_PHCP_{k,h}{}^{m}$ is the price component P_n of N-by-2 matrix $(DAM\_RLH_{k,h}^{m})$ of *price quantity pairs* where 'n' is the highest indexed row of the matrix such that $DAM\_QSI_{k,h}^{m} \leq Q_n$.

5.2.1.1.2 $DAM\_LMP_{h}^{m} > DAM\_PLCP_{k,h}^{m}$; and

5.2.1.1.3 where either of the following conditions is true:

a. where the *registered market participant* for such *resource* requested a change to its fuel cost component for the *day-*

ahead market in accordance with MR Ch.7 ss.22.5.5 and 22.5.7.1, the *IESO* is not satisfied that the fuel cost component will not reflect the *resource's short-run marginal costs* for fuel in one or more hours of a *dispatch day*; or

b. where the *registered market participant* for such *resource* requested to use its higher cost profile *reference levels* for the *day-ahead market* in accordance with MR Ch.7 ss.22.5.6 and 22.5.7.1, the *registered market participant* for such *resource* failed to provide the documentation required pursuant to MR Ch.7 s.22.5.11 within two *business days* of the *trading day* for which the request was made or the *IESO* is not satisfied that the *resource* needed to use the set of *reference levels* associated with the profile with the highest costs.

5.2.1.2 Where a *resource* is subject to the conduct test captured in section 2.4 of Appendix 9.4 for the relevant *settlement hour*, *the IESO* shall apply such conduct tests in accordance with the following:

a. if the conditions set out in sections 5.2.1.1.1, 5.2.1.1.2, and 5.2.1.1.3 are met, the *IESO* will utilize the *resource's reference level value* without taking into account the requested fuel cost change;

b. if the conditions set out in sections 5.2.1.1.1, 5.2.1.1.2, and 5.2.1.1.4 are met, the *IESO* will utilize the *resource's* lower cost profile *reference level values*; and

c. if the conditions set out in sections 5.2.1.1.1, 5.2.1.1.2, 5.2.1.1.3 and 5.2.1.1.4 are all met, the *IESO* will utilize the *resource's* lower cost profile *reference level values* without taking into account the requested fuel cost change.

5.3 Real-Time Market Reference Level Settlement Charge

5.3.1 The *real-time market reference level settlement* charge *settlement amount* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' ("$RT\_RLSC_{k,h}^{m}$") shall be calculated in each instance a *dispatchable generation resource* or *dispatchable electricity storage resource* that is registered to inject meets the conditions set out in section 5.3.1.1 and collected from the *market participant* for such *resources* as follows:

$$RT\_RLSC_{k,h}^{m} = -1 \times \sum^{T} (RT\_QSI_{k,h}^{m,t} \times (RT\_LMP_{h}^{m,t} - RT\_PLCP_{k,h}^{m}))$$

Where for the purposes of this section 5.3.1:

a. $RT\_PLCP_{k,h}^{m}$ is the price component P_n of N-by-2 matrix $(RT\_RLL_{k,h}^{m})$ of *price-quantity pairs* where 'n' is the highest indexed row of the matrix such that $RT\_QSI_{k,h}^{m} \leq Q_n$.

Conditions

5.3.1.1 The *IESO* shall apply the *real-time market reference level settlement* charge each *settlement hour* for which a *resource* meets all of the following conditions for any *metering interval* within the *settlement hour*:

5.3.1.1.1 $RT\_PHCP_{k,h}^{m} >= RT\_LMP_{h}^{m,t}$;

Where:

a. $RT\_PHCP_{k,h}{}^{m}$ is the price component P_n of N-by-2 matrix $(\mathrm{RT\_RLH}_{k,h}^{m})$ of *price-quantity pairs* where 'n' is the highest indexed row of the matrix such that $RT\_QSI_{k,h}^{m} \leq Q_n$,

5.3.1.1.2 $RT\_LMP_{h}^{m,t} > RT\_PLCP_{k,h}^{m}$; and

5.3.1.1.3 where either of the following conditions is true:

a. where the *registered market participant* for the *resource* has requested a change to its fuel cost component for the *real-time market* in accordance with MR Ch.7 ss.22.5.5 and 22.5.7.2, the *IESO* is not satisfied that the fuel cost component will not reflect the *resource's short-run marginal costs* for fuel in one or more hours of a *dispatch day;* or

b. where the *registered market participant* for the *resource* has requested to use its higher cost profile *reference levels* for the *real-time market* in accordance with MR Ch.7 ss.22.5.6 and 22.5.7.2, the *registered market participant* for such *resource* failed to provide the documentation required pursuant to MR Ch.7 s.22.5.11 within two *business days* of the *trading day* for which the request was made or the *IESO* is not satisfied that the *resource* needed to use the set of *reference levels* associated with the profile with the highest costs.

5.3.1.2 Where a *resource* is subject to the conduct test captured in Appendix 9.4 s.3.4 for the relevant *settlement hour*, *the IESO* shall apply such conduct tests in accordance with the following:

a. if the conditions set out in sections 5.3.1.1.1, 5.3.1.1.2, and 5.3.1.1.3 are met, the *IESO* will utilize the *resource's reference level value* without taking into account the requested fuel cost change;

b. if the conditions set out in sections 5.3.1.1.1, 5.3.1.1.2, and 5.3.1.1.4 are met, the *IESO* will utilize the *resource's* lower cost profile *reference level values*; and

c. if the conditions set out in sections 5.3.1.1.1, 5.3.1.1.2, 5.3.1.1.3, and 5.3.1.1.4 are all met, the *IESO* will utilize the *resource's* lower cost profile *reference level values* without taking into account the requested fuel cost change.

5.4 Ex-Post Mitigation for Physical Withholding

5.4.1 The ex-post mitigation for *physical withholding settlement amount* for *energy* and *operating reserve* shall be calculated for *market participants* of *dispatchable generation resources*, *dispatchable loads*, and *dispatchable electricity storage resources* each *trading day* for which the *IESO* issues a second notice of *physical withholding* to such *market participant* pursuant to MR Ch.7 s.22.15.25. The mitigation for *physical withholding settlement amount* for *energy* or *operating reserve* shall be calculated and collected from such *market participant* 'k' for such *resource* at *delivery point* 'm' for such *trading day* ("$EXP\_PWSC_k^m$") as follows:

$$EXP\_PWSC_k^m = -1 \text{ x } (PW\_E_k^m + PW\_OR_k^m)$$

Where:

a. $PW\_E_k^m$ is determined in accordance with section 5.4.1.1; and

b. $PW\_OR_k^m$ is determined in accordance with section 5.4.1.2.

5.4.1.1 The *IESO* shall determine $PW\_E_k^m$ as follows:

$$PW\_E_k^m = \sum^{H} Max(DAM\_PW_{k,h}^m, RT\_PW_{k,h}^m) \times PM\_PW_{mcepw}$$

Where:

a. 'H' is the set of *settlement hours* 'h' of the *trading day* for which the *IESO* determined that the *market participant* engaged in *physical withholding* in the *day-ahead market,* the *real-time market,* or both;

b. PM_PW_{mcepw} is the persistence multiplier applicable to the relevant *trading day* for the *market control entity for physical withholding* 'mcepw' that the *registered market participant* for the applicable *resource* designated, as determined in accordance with the applicable *market manual*;

c. $DAM\_PW_{k,h}^{m} = 1.5 \times \left(MWhs\ Failed_{k,h}^{m}\right) \times (DAM\_LMP_{h}^{m})$

Where:

i. 'h' is the *settlement hour* in the relevant *trading day* for which the *IESO* determined that the *market participant* engaged in *physical withholding* in the *day-ahead market*; and

ii. '$MWhs\ Failed_{k,h}^{m}$' is the quantity of *energy* (in MWhs) for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as determined in accordance with the following:

a. if the *IESO* is assessing *physical withholding* in only the *real-time market*, it is deemed to be zero; and

b. otherwise, it is determined by subtracting the *market participant's energy offer* from the *energy reference quantity value* or *alternative reference quantity value*, as the case may be, of the *resource* associated with the *offer*.

d. $RT\_PW_{k,h}^{m} = 1.5 \times \sum^{T}\left(MWhs\ Failed_{k,h}^{m,t}\right) \times \left(RT\_LMP_{h}^{m,t}\right)$

Where:

i. 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h' for which the *IESO* determined that the *market participant* engaged in *physical withholding* in the *real-time market;* and

ii. '$MWhs\ Failed_{k,h}^{m,t}$' is the quantity of *energy* (in MWhs) for *market participant* 'k' at *delivery point* 'm' in *metering interval 't'* of *settlement hour 'h'*, as determined in accordance with the following:

a. if the *IESO* is assessing *physical withholding* in only the *day-ahead market*, it is deemed to be zero; and

b. otherwise, it is determined by subtracting the *market participant's energy offer* from the *energy reference quantity value* or *alternative reference quantity value*, as the case may be, of the *resource* associated with the *offer*.

5.4.1.2 The *IESO* shall determine $PW\_OR_{k}^{m}$ as follows:

$$PW\_OR_k^m = \sum^H Max(DAM\_PW_{k,h}^m, RT\_PW_{k,h}^m) \times PM\_PW_{mcepw}$$

Where:

a. 'H' is the set of *settlement hours* 'h' of the *trading day* for which the *IESO* determined that the *market participant* engaged in *physical withholding* in either the *day-ahead market* or the *real-time market*;

b. PM_PW_{mcepw} is the persistence multiplier applicable to the relevant *trading day* for the *market control entity for physical withholding 'mcepw'* that the *registered market participant* for the applicable *resource* designated, as determined in accordance with the applicable *market manual*;

c. $DAM\_PW_{k,h}^m = 1.5 \times \sum_R (MWs\ Failed_{r,k,h}^m \times DAM\_PROR_{r,h}^m)$

Where:

i. 'h' is the *settlement hour* in the relevant *trading day* for which the *IESO* determined that the *market participant* engaged in *physical withholding* in the *day-ahead market*; and

ii. '$MWs\ Failed_{r,k,h}^m$' is the quantity of *class r reserve* (in MWs) for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as determined in accordance with the following:

   a. if the *IESO* is assessing *physical withholding* in only the *real-time market*, it is deemed to be zero; and

   b. otherwise, it is determined by subtracting the *market participant's operating reserve offer* from the *operating reserve reference quantity value* or *alternative reference quantity value*, as the case may be, of the *resource* associated with the *offer*.

d. $RT\_PW_{k,h}^m = 1.5 \times \sum_R^T (MWs\ Failed_{r,k,h}^{m,t} \times RT\_PROR_{r,h}^{m,t})$

Where:

i. 'T' is the set of all the *metering intervals* 't' in *settlement hour* 'h' for which the *IESO* determined that the *market participant* engaged in *physical withholding* in the *real-time market;* and

ii. '$MWs\ Failed^{m,t}_{r,k,h}$' is the quantity of *class r reserve* (in MWs) for *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with the following:

a. if the *IESO* is assessing *physical withholding* in only the *day-ahead market*, it is deemed to be zero; and

b. otherwise, it is determined by subtracting the *market participant's operating reserve offer* from the *operating reserve reference quantity value* or *alternative reference quantity value*, as the case may be, of the *resource* associated with the *offer*.

5.5 Ex-Post Mitigation for Intertie Economic Withholding

5.5.1 The ex-post mitigation for *intertie economic withholding settlement amount* for *energy* and *operating reserve* shall be calculated for each *trading day* for which the *IESO* issues a second notice of *intertie economic withholding* pursuant to MR Ch.7 s.22.19.8. The mitigation for *intertie economic withholding settlement amount* for *energy* and *operating reserve* shall be calculated and collected from such *market participant* 'k' at *intertie metering point* 'i' for the relevant *trading day* ("$EXP\_EWSC^i_k$") as follows:

$$EXP\_EWSC^i_k = -1 \text{ x } (EW\_E^i_k + EW\_MWP^i_k + EW\_OR^i_k)$$

Where:

a. $EW\_E^i_k$ is determined in accordance with section 5.5.1.1;

b. $EW\_MWP^i_k$ is determined in accordance with section 5.5.1.2; and

c. $EW\_OR^i_k$ is determined in accordance with section 5.5.1.3.

5.5.1.1 The *IESO* shall determine $EW\_E^i_k$ as follows:

$$EW\_E^i_k = \sum^{H} Max(DAM\_EWUI^i_{k,h}, RT\_EWUI^i_{k,h})$$

Where:

a. 'H' is the set of *settlement hours* 'h' of the *trading day* for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in the *day-ahead market,* the *real-time market,* or both;

b. $DAM\_EWUI^{i}_{k,h} = \left(MWhs\ Failed^{i}_{k,h}\right) \times DAM\_LMP^{i}_{h}$

Where:

i. 'h' is the *settlement hour* for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in the *day-ahead market*; and

ii. '$MWhs\ Failed^{i}_{k,h}$' is the quantity of *energy* (in MWhs) for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h', as determined in accordance with the following:

   a. if the *IESO* is assessing *intertie economic withholding* in only the *real-time market*, it is deemed to be zero; and

   b. otherwise, it is determined by subtracting the *market participant's energy offer* from the *energy reference quantity value* of the *resource* associated with the *offer*.

c. $RT\_EWUI^{i}_{k,h} = \sum^{T}\left(MWhs\ Failed^{i,t}_{k,h}\right) \times (RT\_LMP^{i,t}_{h})$

Where:

i. 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h' for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in the *real-time market*; and

ii. '$MWhs\ Failed^{i,t}_{k,h}$' is the quantity of *energy* (in MWhs) for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h', as determined in accordance with the following:

   a. if the *IESO* is assessing *intertie economic withholding* in only the *day-ahead market*, it is deemed to be zero; and

   b. otherwise, it is determined by subtracting the *market participant's energy offer* from the *energy reference* *quantity value* of the *resource* associated with the *offer*.

5.5.1.2 The *IESO* shall determine $EW\_MWP_k^i$ as follows:

$$EW\_MWP_k^i = \sum^{H}\left(DAM\_MWP_{k,h}^i - IRL\_DAM\_MWP_{k,h}^i\right) + (RT\_MWP_{k,h}^i - IRL\_RT\_MWP_{k,h}^i\ ) + \left(RT\_IOG_{k,h}^i - IRL\_RT\_IOG_{k,h}^i\right)$$

Where:

a. 'H' is the set of *settlement hours* 'h' of the *trading day* for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in the *day-ahead market,* the *real-time market,* or both;

b. $IRL\_DAM\_MWP_{k,h}^i$ is the *day-ahead market* make-whole payment amount calculated in accordance with section 3.4 utilizing the *resource's intertie reference level value* that was used by the *IESO* to assess *intertie economic withholding* in accordance with MR Ch.7 s.22.18;

c. $IRL\_RT\_MWP_{k,h}^i$ is the real-time make-whole payment amount calculated in accordance with section 3.5 utilizing the *resource's intertie reference level value* that was used by the *IESO* to assess *intertie economic withholding* in accordance with MR Ch.7 s.22.18; and

d. $IRL_RT_IOG_{k,h}^i$is the real-time *intertie offer* guarantee amount calculated in accordance with section 3.6 utilizing the *resource's intertie reference level value* that was used by the *IESO* to assess *intertie economic withholding* in accordance with MR Ch.7 s.22.18.

5.5.1.3 The *IESO* shall determine $EW\_OR_k^i$ as follows:

$$EW\_OR_k^i\ = \sum^{H} Max(DAM\_EWUI_{k,h}^i\,, RT\_EWUI_{k,h}^i)$$

Where:

a. 'H' is the set of *settlement hours* 'h' of the *trading day* for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in either the *day-ahead market* or the *real-time market*;

b. $DAM\_EWUI_{k,h}^{i} = \sum_{R}(MWs\ Failed_{r,k,h}^{i} \times DAM\_PROR_{r,h}^{i})$

Where:

i. 'h' is the *settlement hour* for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in the *day-ahead market*; and

ii. '$MWs\ Failed_{r,k,h}^{i}$' is the quantity of *class r reserve* (in MWs) for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h', as determined in accordance with the following:

   a. if the *IESO* is assessing *intertie economic withholding* in only the *real-time market*, it is deemed to be zero; and

   b. otherwise, it is determined by subtracting the *market participant's operating reserve offer* from the *operating reserve reference quantity value* of the *resource* associated with the *offer.*

c. $RT\_EWUI_{k,h}^{i} = \sum_{R}^{T}(MWs\ Failed_{r,k,h}^{i,t} \times RT\_PROR_{r,h}^{i,t})$

Where:

i. 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h' for which the *IESO* determined that the *market participant* engaged in *intertie economic withholding* in the *real-time market*; and

ii. '$MWs\ Failed_{r,k,h}^{i,t}$' is the quantity of *class r reserve* (in MWs) for *market participant* 'k' at *intertie metering point* 'i' for *metering interval* 't' in *settlement hour* 'h', as determined in accordance with the following:

   a. if the *IESO* is assessing *intertie economic withholding* in only the *day-ahead market*, it is deemed to be zero; and

   b. otherwise, it is determined by subtracting the *market participant's operating reserve offer* from the *operating reserve reference quantity value* of the *resource* associated with the *offer*.

6 Settlement Statements

6.1 Communication of Settlement Information

6.1.1 All communications between *market participants* and the *IESO* relating to the *settlement process* shall be effected using the *electronic information system* and other such means of communication as may be specified in applicable *market manuals*.

6.1.2 If there is a failure of a communication system and it is not possible to communicate in accordance with the *electronic information system* or where applicable, the means of communication specified in the applicable *market manuals*, then the *IESO* or the *market participant*, as the case may be, shall communicate information relating to the *settlement process* by other alternative means specified by the *IESO*.

6.2 Settlement Schedule and Payments Calendar

6.2.1 By November 1 of each year, the *IESO* shall *publish* the *IESO Settlement Schedule & Payments Calendar* or *SSPC* for the following calendar year showing the dates referred to in sections 6.3.2 to 6.3.23 as fixed dates within such calendar year.

6.2.2 If the *IESO* becomes aware of any change required to the *SSPC*, the *IESO* shall *publish* an updated *SSPC* to reflect the necessary changes. The *IESO* shall use reasonable efforts to provide *market participants* with at least two weeks' notice of any changes to the *SSPC*.

6.2.3 The *SSPC* is *published* by the *IESO* for *market participant* ease of reference and the applicable dates that are binding on the *IESO* and *market participants* are the dates determined in accordance with sections 6.3.1 to 6.3.23. Notwithstanding anything to the contrary, any reference in these *market rules* to the *SSPC* shall be deemed to be references to the dates specified in accordance with sections 6.3.1 to 6.3.23.

6.3 Settlement Cycles

6.3.1 Subject to section 6.3.24 to 6.3.33, section 6.3.2 to 6.3.23 set out the applicable dates for the *settlement process* and issuance of *settlement statements* and *invoices*.

TR Auctions

6.3.2 The *preliminary settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued two *business days* after the *trading day*.

6.3.3 After the *preliminary settlement statement* referred to in section 6.3.2 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.4 The *final settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued six *business days* after the *trading day*.

6.3.5 After the *final settlement statement* referred to in section 6.3.4 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.6 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a) or as otherwise required, *recalculated settlement statements* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued at the following times:

6.3.6.1 the first *recalculated settlement statement* shall, where applicable, be issued on the last *business day* of the month immediately following the month of the *trading day* to which the *recalculated settlement statement* relates;

6.3.6.2 the *final recalculated settlement statement* shall be issued on the last *business day* of the month that is 22 months after the month of the *trading day* to which the *final recalculated settlement statement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement statement*; and

6.3.6.3 notwithstanding the foregoing, and at the *IESO's* sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlements statement* referred to in section 6.3.6.1 and section 6.3.6.2, an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement statement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* in the preceding 23-month period.

6.3.7 After a *recalculated settlement statement* referred to in section 6.3.6 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.8 The *IESO* shall issue one invoice to each *market participant*, covering all *trading days* within a *billing period*, on the same *business day* it issues the *final settlement statement* for the last *trading day* of that *billing period*.

6.3.9 The *market participant payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.10 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant's* payments in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.11 The *IESO payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* after the corresponding *market participant payment date*.

6.3.12 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant* in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach each *market participant's settlement account* no later than the *close of banking business* (of the bank at which the *market participant's settlement account* is held) on the *IESO payment date.*

Day-Ahead Market and Real-Time Market

6.3.13 The *preliminary settlement statement* for each *trading day* in the *day-ahead market, real-time market* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the *trading day*.

6.3.14 After the *preliminary settlement statement* referred to in section 6.3.13 is issued, each *market participant* shall have six *business days* to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.15 The *final settlement statement* for each *trading day* in the *day-ahead market, real-time market* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the issuance of the *preliminary settlement statement* for that *trading day.*

6.3.16 After the *final settlement statement* referred to in section 6.3.15 is issued, each *market participant* shall have ten *business days* in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.17 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a) or as otherwise required, *recalculated settlement statements* for each *trading day* in the *day-ahead market, real-time market* and in the *TR market*, other than in respect of the element referred to in section 6.3.1, shall be issued at the following times:

6.3.17.1 the first *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is one month after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the first *recalculated settlement statement* is issued on the same date for all the *trading days* of a given month;

6.3.17.2 the second *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is two months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the second *recalculated settlement statement* is issued on the same date for all the *trading days* of a given month;

6.3.17.3 the third *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is five months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the third *recalculated settlement statement* is issued on the same date for all the *trading days* of a given month;

6.3.17.4 the fourth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eight months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fourth *recalculated settlement statement* is issued on the same date for all the *trading days* of a given month;

6.3.17.5 the fifth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eleven months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fifth *recalculated settlement statement* is issued on the same date for all the *trading days* of a given month;

6.3.17.6 the sixth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is seventeen months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the sixth *recalculated settlement statement* is issued on the same date for all the *trading days* of a given month;

6.3.17.7 the *final recalculated settlement statement* shall be issued on the same date as the *invoice* for the month that is 23 months after the month which contains the *trading day* to which the *recalculated settlement* *statement* relates.. For greater certainty, the *IESO* shall always issue the *final recalculated settlement statement* and the *final recalculated settlement statement* is issued on the same date for all the *trading days* of a given month*;* and

6.3.17.8 notwithstanding the foregoing, and at the *IESO's* sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlements statements* referred to in section 6.3.17.1 to section 6.3.17.7, an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement statement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* that was first *invoiced* in the preceding 23-month period.

6.3.18 After a *recalculated settlement statement* referred to in section 6.3.17 is issued, other than in respect of a *final recalculated settlement statement*, each *market participant* shall have ten *business days* in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.19 The *IESO* shall issue one *invoice* to each *market participant*, covering all *trading days* within a *billing period,* and such other information specified in accordance with section 6.12.1, on the same day it issues the *preliminary settlement statement* for the last *trading day* of that *billing period*.

6.3.20 The *market participant payment date* for each *billing period* shall be the *second business day* following the issuance of the *invoice*.

6.3.21 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant's* payments for each *billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.22 The *IESO payment date* for each *billing period* shall be the second *business day* after the *market participant payment date*.

6.3.23 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant, forecasting entity,* and to each *transmitter* for each *billing period* reach the *market participant's settlement account* or the *transmitter's transmission services settlement account*, as the case may be, no later than the *close of banking business* (of the bank at which the *market participant's settlement account* or the *transmitter's transmission services settlement account* is held) on the *IESO payment date*.

Delays

6.3.24 The *IESO* may delay the issuance of *settlement statements* for a *trading day* to a date later than that provided for in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, where, in the *IESO's* opinion significant inaccuracies exist in the *settlement statements* such as to justify such delay.

6.3.25 Where the *IESO* delays the issuance of one or more *settlement statements* for a *trading day* pursuant to section 6.3.24:

6.3.25.1 the issuance of *settlement statements* for any immediately succeeding *trading days* that would otherwise be required pursuant to sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, to be issued prior to the date referred to in section 6.3.26.1 shall be delayed to that date or to such later date(s) as may be determined and *published* by the *IESO*; and

6.3.25.2 the date by which *market participants* must notify the *IESO* of errors or omissions in any delayed *settlement statements* for each of the *trading days* referred to in section 6.3.25.1 shall be delayed by the same number of days which the *settlement statement* to which the date relates is delayed.

6.3.26 Where the *IESO* delays the issuance of a *settlement statement* for a *trading day* pursuant to section 6.3.24, the *IESO* shall *publish* notice of such delay, which notice shall indicate:

6.3.26.1 the date on which such *settlement statement* shall be issued in lieu of the date referred to in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be;

6.3.26.2 the date by which *market participants* must notify the *IESO* of errors or omissions in such *settlement statements*, determined in accordance with section 6.3.25.2; and

6.3.26.3 whether the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27.

6.3.27 Where the *IESO* determines that it will be unable to issue *invoices* calculated in accordance with section 6.12.1 in respect of a given *billing period* on or within one *business day* of the applicable date determined in accordance with section 6.3.8 or 6.3.19, the *IESO* shall, within two *business days* of the applicable date, issue to each *market participant* an estimated *invoice* for such *energy market billing period* in a net amount determined in accordance with section 6.3.29.

6.3.28 Where the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27 or to delay the issuance of *invoices* pursuant to section 6.3.33, the *IESO* shall *publish* a notice indicating whether the *IESO* intends, in accordance with section 6.3.31, to delay each of the *market participant payment date* and the *IESO payment date* associated with such *invoices* or estimated *invoices* and, if so, the revised payment dates.

6.3.29 The amount of an estimated *invoice* issued to a *market participant* pursuant to section 6.3.27 shall, subject to section 6.3.30, be determined in accordance with the following:

6.3.29.1 The amount referred to in section 6.4.2.1 shall be equal to the aggregate of:

6.3.29.1.1 the net total amount for that *market participant* for all *trading days* that occurred during the *energy market billing period* prior to the date on which the issuance of *preliminary settlement statements* commenced to be delayed pursuant to section 6.3.24 or 6.3.25.1, as the case may be;

6.3.29.1.2 for each *trading day* in the *energy market billing period* that occurred subsequent to the date referred to in section 6.3.29.1, the net total amount for that *market participant* as set forth in the *final settlement statements* issued to that *market participant* in the preceding *energy market billing period*, commencing with the *final settlement statement* issued for the last *trading day* of such preceding *energy market billing period* and using a number of *final settlement statements* equal to the number of *trading days* in the current *energy market billing period* occurring subsequent to the date referred to in section 6.3.29.1; and

6.3.29.1.3 for greater certainty, any net total amount for that *market participant* reflected on a *recalculated settlement statement* which would have otherwise been included on the *invoice* for the relevant *energy market billing period* shall not be reflected on the estimated *invoice.*

6.3.29.2 The amount referred to in section 6.4.2.2 shall be equal to:

6.3.29.2.1 the net total amount for that *market participant* reflected on the relevant post-auction report issued pursuant to MR Ch.8 s.3.16.1 for the aggregate of the amounts for the purchase of *TRs* by the *market participant* in all rounds of any *TR auction* that is concluded within the relevant financial market *billing period*.

6.3.30 Where the data required to determine the amount of an estimated *invoice* in accordance with section 6.3.29.1 is not readily available at the relevant time, the *IESO* shall issue to each applicable *market participant* an estimated *invoice* in an amount equal to:

6.3.30.1 the net amount of the *invoice* issued to the *market participant* for the preceding *energy market billing period* minus any amounts on such *invoice* included on a *recalculated settlement statement*; or

6.3.30.2 zero, if no *invoice* was issued to the *market participant* for the preceding *energy market billing period*.

6.3.31 Where the *IESO* issues estimated *invoices* pursuant to section 6.3.28 or delays the issuance of *invoices* pursuant to section 6.3.33 in respect of a given *energy market billing period*, the *IESO* may, where the delay resulting in the need to issue an estimated *invoice* or to delay the issuance of the *invoices* has or is likely to have an adverse effect on the operation of the *IESO settlement clearing account*, delay each of the *market participant payment date* and the *IESO payment date* associated with such estimated *invoice* or delayed *invoice* by one *business day* relative to the periods referred to in sections 6.3.9 or 6.3.15, or sections 6.3.11 or 6.3.17, respectively.

6.3.32 Where the *IESO* issues to a *market participant* an estimated *invoice* in respect of a given *energy market billing period* pursuant to section 6.3.27, the *IESO* shall adjust the *invoice* issued to the *market participant* for the next *energy market billing period* to reflect any net difference between the amount of the estimated *invoice* and the amount that would have been set forth on the *market participant's invoice* had the *invoice* been calculated in accordance with section 6.12.1 rather than estimated in accordance with section 6.3.27, including adding any net amounts reflected on any *recalculated settlement statements* for the same *energy market billing period*.

6.3.33 Where the *IESO* determines that:

6.3.33.1 it will be unable to issue *invoices* calculated in accordance with section 6.12.1 in respect of a given *energy market billing period* on the applicable date specified in accordance with sections 6.3.8 or 6.3.19 by reason of the delay in issuance of *settlement statements* referred to in section 6.3.24 or 6.3.25.1, or for any other reason; and

6.3.33.2 it is able to issue such *invoices* within one *business day* of the applicable date specified in accordance with sections 6.3.8 or 6.3.19 such that the estimated *invoice* procedure referred to in sections 6.3.27 to 6.3.32 does not apply, the *IESO* may delay the issuance of such *invoices* for such *energy market billing period* for a period of up to one *business day* relative to the applicable date specified in accordance with sections 6.3.8 or 6.3.19, as the case may be.

6.4 Settlement Statement Process

6.4.1 The *IESO* shall issue *settlement statements* to each *market participant* to cover each *trading day* in accordance with sections 6.5 to 6.7, and shall provide the *settlement* data included in such *settlement statements* into the *settlement process*.

6.4.2 For each *settlement statement*, the *IESO* shall calculate a net *settlement amount* for each *market participant* for the *trading day*. The net *settlement amount* shall be comprised of:

6.4.2.1 the aggregate of the trading amounts from each transaction in each *settlement hour* in the *trading day*; and

6.4.2.2 the aggregate of the amounts for the purchase of *TR*s in all rounds of any *TR auction* that is concluded on the *trading day*,adjusted to reflect any fees payable by the *market participant* and any other adjustment amounts payable or receivable pursuant to these *market rules.*

6.4.3 The net *settlement amount* referred to in section 6.4.2 shall be a positive or negative dollar amount for each *market participant* and:

6.4.3.1 where the net *settlement amount* for a *market participant* is negative, the absolute value of the *settlement amount* shall be an amount payable by the *market participant* to the *IESO*; or

6.4.3.2 where the net *settlement amount* for a *market participant* is positive, the *settlement amount* shall be an amount receivable by the *market participant* from the *IESO*.

6.4.4 *Settlement statements* shall be considered issued to *market participant*s when issued in accordance with the applicable *market manuals*.

6.4.5 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive a *preliminary settlement statement*, *final settlement statement*, or *final recalculated settlement statement* on the date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in section 6.3.25.1 and 6.3.26. Each *market participant* shall be deemed to have received such *settlement statements* on the relevant date specified in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, unless it notifies the *IESO* to the contrary within two *business days* of the date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23.

6.4.6 In the event that a *market participant* notifies the *IESO* that it has failed to receive a *settlement statement* on the date specified for that *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26*,* the *IESO* shall re-issue such *settlement statement*, in which case the *settlement statement* shall be considered to have been received on the date the re-issued *settlement statement* is sent to the *market participant.*

6.5 Preliminary Settlement Statement Coverage

6.5.1 The *IESO* shall issue to each *market participant* an individualized *preliminary settlement statement* to cover:

6.5.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.5.1.2 transactions in the *day-ahead market, real-time market* and in the *TR market*, other than in respect of the element referred to in section 6.5.1.1,

6.5.1.3 any adjustments which may be required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C,

6.5.1.4 in accordance with the timelines set forth in sections 6.3.2, 6.3.13, 6.3.24 and 6.3.25.1, as may be applicable.

6.5.2 *Preliminary settlement statements* related to each *market participant* for all rounds of any *TR auction* that is concluded on a given *trading day* shall include, in electronic format, for each *settlement hour* of the relevant *trading day* or for each such *TR auction*, as the case may be, referenced by applicable *charge type*:

6.5.2.1 the applicable *market price* in that *settlement hour*;

6.5.2.2 the payment for the *settlement hour*, either from the *market participant* to the *IESO*, or from the *IESO* to the *market participant*;

6.5.2.3 all fees, charges, credits and payments applicable to the *market participant* in respect of the purchase of a *TR* in all rounds of such *TR auction*; and

6.5.2.4 for each *charge type* listed, the total *trading day's* charges and a *billing period*-to-date total.

6.5.3 *Preliminary settlement statements* related to each *market participant* for the *day-ahead market, real-time market* and for the *TR market,* other than in respect of the element referred to in section 6.5.2, shall include the *settlement amounts,* prices and quantities described in section 6.5.4, presented as follows:

6.5.3.1 for each *hourly settlement amount* referred to in section 3, by *metering interval* or *settlement hour,* as the case may be, depending upon the manner of calculation of the *settlement amount* as described in section 3;

6.5.3.2 for each non-hourly *settlement amount* referred to in section 4 or section 5 that is required to be calculated over or in respect of a given *billing period,* by *billing period,* provided that such non-hourly *settlement amounts* shall be included only in the *preliminary settlement statement* issued in respect of the last *trading day* of a *billing period*; and

6.5.3.3 for each non-hourly *settlement amount,* other than those referred to in section 6.5.3.2, by *metering interval, settlement hour,* or *trading day,* as the case may be, depending upon the time period over or with respect to which the relevant *settlement amount* is required to be calculated pursuant to section 4 or section 5.

6.5.4 The *preliminary settlement statements* referred to in section 6.5.3 shall be in electronic format and shall set forth, for the *market participant* to whom the *preliminary settlement statement* is issued and referenced by applicable *charge type*:

6.5.4.1 the *energy* scheduled to be injected or withdrawn by each of that *market participant's resources* as determined in each of the *day-ahead schedule* and the *real-time schedule*.

6.5.4.2 the allocated quantities of *energy* withdrawn or injected by each of that *market participant's resources*.

6.5.4.3 the aggregate quantity of each class of *operating reserve* provided by each of that *market participant's resources* as determined in each of the *day-ahead schedule* and the *real-time schedule*.

6.5.4.4 the aggregate quantities or capacities, as the case may be, of each *contracted ancillary service* scheduled and provided from each of that *market participant's resources;*

6.5.4.5 the *physical bilateral contract quantities* for that *market participant*;

6.5.4.6 the availability payments to be made in each *billing period* under *reliability must-run contracts* to each of that *market participant's reliability must-run resources*;

6.5.4.7 details of performance incentive payments or penalties applicable to the *market participant*;

6.5.4.8 the applicable *energy market price* applying to each of that *market participant's resources*;

6.5.4.9 the applicable *market price* for each class of *operating reserve* for each of that *market participant's resources*;

6.5.4.10 detailed calculations of applicable *transmission services charges*, and the *market participant's* share of these;

6.5.4.11 the total of each type of *contracted ancillary service* charges, and the *market participant's* share of these;

6.5.4.12 all *real-time market* fees, charges and credits applicable to the *market participant* and the basis for deriving those fees, charges or credits;

6.5.4.13 for each *charge type* listed, the total *trading day's* charges and credits and a *billing period*-to-date total; and

6.5.4.14 all *TR market* fees, charges and credits applicable to the *market participant.*

6.6 Final Settlement Statement Coverage

6.6.1 The *IESO* shall issue to each *market participant* separate *final settlement statements* to cover:

6.6.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*;

6.6.1.2 transactions in the *day-ahead market, real-time market* and in the *TR market*, other than in respect of the element referred to in section 6.6.1.1; and

6.6.1.3 adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C,

6.6.1.4 in accordance with the timelines set forth in sections 6.3.4, 6.3.14, 6.3.24 and 6.3.25.1, as may be applicable.

6.6.2 The *final settlement statement* shall be in the same form as the *preliminary settlement statement* and shall include all of the information provided in the *preliminary settlement statement*, as amended following the validation procedure set forth in section 6.8 and 6.9, where applicable.

6.6.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, and 6.9.4, *final settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *final settlement statement*.

6.6.4 Each *market participant* that receives a *final settlement statement* is required to pay any net debit amount shown in the *final settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *final settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding *settlement* disagreement regarding the amount of such debit or credit.

6.7 Recalculated Settlement Statement Coverage

6.7.1 The *IESO* shall, when applicable, issue to each *market participant* separate *recalculated settlement statements* to cover adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C in respect of:

6.7.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.7.1.2 transactions in the *day-ahead market, real-time market* and in the *TR market,* other than in respect of the element referred to in section 6.7.1.1,

6.7.1.3 in accordance with the timelines set forth in sections 6.3.6, 6.3.17, 6.3.24 and 6.3.25.1 , as may be applicable.

6.7.2 The *recalculated settlement statement* shall be in the same form as the *final settlement statement* and shall include all of the information provided in the most recently issued *settlement statement* for the *trading day* for which the *recalculated settlement statement* relates, as amended following the validation procedure set forth in section 6.8 and 6.9 and the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C, where applicable.

6.7.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, and the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C, where applicable, *recalculated settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *recalculated settlement statement*.

6.7.4 Each *market participant* that receives a *recalculated settlement statement* is required to pay any net debit amount shown in the *recalculated settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *recalculated settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding *settlement* disagreement regarding the amount of such debit or credit.

6.8 Market Participant Validation of Settlement Statements

6.8.1 Each *market participant* shall review all of its *settlement statements* upon receipt. Subject to the terms of this section 6.8, a *market participant* may register a disagreement with the *IESO* with respect to any *settlement statement* other than a *final recalculated settlement statement* by filing a *notice of disagreement* in accordance with the timelines set forth in sections 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be.

6.8.2 Subject to section 6.8.12, if a *market participant* disagrees with any item or calculation set forth in a *preliminary settlement statement* that it has received, or considers that there is an omission in such *preliminary settlement statement,* it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4.

6.8.3 Subject to section 6.8.12, if a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* or a *recalculated settlement statement*, other than a *final recalculated settlement statement*, that*:*

6.8.3.1 differs in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag;

6.8.3.2 is an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag; or

6.8.3.3 the *market participant* considers that there is an omission in such *settlement statement*, including where the *IESO* does not issue a *recalculated settlement statement* because it has determined an adjustment is not necessary and the *market participant* disagrees with such determination*,* it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4. For greater certainty, a *market participant* shall not provide a *notice of disagreement* to the *IESO* if the item or calculation on a *final settlement statement* or *recalculated settlement statement* with which the *market participant* disagrees is not captured by sections 6.8.3.1 or 6.8.3.2.

6.8.4 *Notices of disagreement* shall relate to only one *settlement statement* and shall include at least the following information:

6.8.4.1 the date of issuance of the *settlement statement* in question;

6.8.4.2 the *trading day* in question;

6.8.4.3 the item(s) or omission(s) in question;

6.8.4.4 clearly state, with supporting material, the reasons for the disagreement;

6.8.4.5 where applicable and with supporting material, the proposed adjustment to the data used to calculate any relevant *settlement amount* on the *settlement statement*; and

6.8.4.6 where applicable and with supporting material, the proposed correction to any calculation of the relevant *settlement amount* on the *settlement statement.*

6.8.5 Where a *notice of disagreement* includes a proposed adjustment to:

6.8.5.1 *physical bilateral contract data*; or

6.8.5.2 any data of a comparable nature which may be identified by the *IESO* from time to time,

the *IESO* shall notify any other *market participant* to whom items 6.8.5.1 or 6.8.5.2 relates of such proposed adjustment prior to taking any action under section 6.8.9.

6.8.6 The *notice of disagreement* issued by the *market participant* shall be acknowledged by the *IESO* upon receipt.

6.8.7 The issuance of a *notice of disagreement* shall not remove the obligation of the *market participant* to settle any *invoice* based on the *preliminary settlement statement*, *final settlement statement* or *recalculated settlement statement*.

6.8.8 Subject to section 6.8.12, the *IESO* shall use the information provided in and with a *notice of disagreement*, and any other information available to the *IESO,* to consider the subject-matter of the disagreement and determine the necessary corrections, if any.

6.8.9 Following the determination described in section 6.8.8, the *IESO* shall inform the *market participant* of its determination, provide the *market participant* the opportunity to respond within ten *business days*, and, after considering any such response, take one of the following actions:

6.8.9.1 if the *IESO* concludes that no adjustment or correction is required in the *settlement statement,* it shall take no further action; or

6.8.9.2 if the *IESO* concludes that an adjustment or correction is required, take one of the following actions:

a. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement.* For clarity, where the *notice of disagreement* relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; or

c. if the *notice of disagreement* is with respect to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, the IESO shall make the adjustment in the next scheduled *recalculated settlement statement*.

6.8.10 If the *IESO* does not make its determination before the date for issuing any subsequent *settlement statements,* as applicable, the *IESO* shall issue such *settlement statements* without taking into account the disagreement.

6.8.11 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.8 shall, subject to section 6.18.3, be included as:

6.8.11.1 a debit or credit in the *final settlement statement*, or

6.8.11.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period allocation* to a *recalculated settlement statement*, or a subsequent *preliminary settlement statement* where the *notice of disagreement* relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements*, issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a current period adjustment to a subsequent *preliminary settlement statement.*

6.8.12 No *market participant* may submit a *notice of disagreement*, and any such *notice of disagreement* shall not be valid and any adjustment resulting from such *notice of disagreement* shall be void, the *IESO* shall not investigate the subject-matter of a *notice of disagreement* if the *notice of disagreement*:

6.8.12.1 is submitted to the *IESO* after the time specified in 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be;

6.8.12.2 relates to an issue which falls outside the permitted scope of such *notice of disagreement* outlined in sections 6.8.2 or 6.8.3, as the case may be;

6.8.12.3 relates to a *final recalculated settlement statement*;

6.8.12.4 relates to a compliance and enforcement action described in MR Ch.3 s.6, or matters relating to section 3.9.1, section 3.9.2, or section 4.11;

6.8.12.5 relates to a dispute referred to in section 2.2.7;

6.8.12.6 relates to an adjustment made on a *settlement statement* reflecting a *dispute outcome*;

6.8.12.7 relates to a matter described in the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C;

6.8.12.8 relates to the calculation of *market prices* ;

6.8.12.9 relates to a matter which the *market participant* has already submitted a *notice of disagreement*, including in regards to an earlier *settlement statement;* or

6.8.12.10 relates to a matter that is subject to the independent review process set out in MR Ch.7 s.22.8.

6.8.13 Subject to the processes outlined in MR Ch.6 s.10.4 and MR Ch.10 s.6C, *market participants* that fail to submit a *notice of disagreement* in accordance with section 6.8 in regards to a *settlement statement* shall have no further recourse in regards to the amount of any *settlement amount* contained on such *settlement statement.*

6.8.14 Nothing in section 6.8.12 shall prevent a *market participant* from submitting, or the *IESO* from making a determination in regards to, a *notice of disagreement* that relates to the manner in which any of the elements noted in section 6.8.12.8 have been applied for purposes of the calculation of the *market participant's* net *settlement amount.*

6.8.15 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.8.9 or the *IESO* has not made its determination prior to the earlier of either :

a. the date that is 23 months after the date on which the relevant *trading day* was first *invoiced*; or

b. twelve months after the date the *notice of disagreement* was issued by the *market participant*,

the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1. Additionally, if a *market participant* disagrees with an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1.

6.9 IESO Validation of Settlement Statements

6.9.1 Subject to section 6.9.2, if the *IESO* becomes aware of a possible error within an *IESO* system or *settlement process* that a *market participant* would not have reasonably been able to identify and address through section 6.8, and which may result in *settlement amounts* being calculated incorrectly, the *IESO* shall use the information available to the *IESO* to consider the possible error and:

6.9.1.1 if the *IESO* concludes that no material adjustment or correction is required, it shall take no further action; and

6.9.1.2 if the *IESO* concludes that a material adjustment or correction is required, take one or more of the following actions:

a. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statements.* For clarity, where the correction relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements*, the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; and

c. if the correction is with respect to an item or calculation on any other *settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statement*.

6.9.2 Notwithstanding section 6.9.1 and commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amounts* which were *invoiced*, or should have been *invoiced*, more than 23 months before the day on which the *IESO* issues the *settlement statement* referred to in section 6.9.1.2. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amount* if a limitation period applicable to such *settlement amount* prescribed in *applicable law* has lapsed.

6.9.3 If the *IESO* does not make its determination before the date for issuing any *settlement statements*, as applicable, the *IESO* shall issue such *settlement statements* without taking into account the error being considered.

6.9.4 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.9 shall, subject to section 6.18.3, be included as:

6.9.4.1 a debit or credit in the *final settlement statement*, or

6.9.4.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period allocation* to a *recalculated settlement statement,* or a subsequent *preliminary settlement statement* where the *notice of disagreement* relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

6.9.5 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.9.1.2, the *market participant* may pursue their disagreement through the *market participant* validation procedure described in section 6.8, or, if the adjustment is made on a *final recalculated settlement statement* or on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued*,* through the dispute resolution procedure described in section 6.10.1.

6.9.6 Notwithstanding the foregoing, nothing in this section 6.9 limits the *IESO's* ability to apply an adjustment related to matters described in section 6.8.12.4, including as a *current period adjustment* to a *preliminary settlement statement* issued more than two years after the *invoice* for the relevant *trading day* was issued.

6.10 Dispute Resolution

6.10.1 Subject to section 6.10.2, if a *market participant* wishes to initiate a dispute in regards to matters described in section 6.8.15, section 6.9.5, section 6.8.12.4, or in regards to a *final recalculated settlement statement*, it may submit the matter to the dispute resolution process set forth in MR Ch.3 s.2.

6.10.2 In regards to matters described in section 6.10.1, no *market participant* may submit a *notice of dispute*, and any such *notice of dispute* shall not be valid, if:

6.10.2.1 in regards to disputes pertaining to *settlement statements* other than a *final recalculated settlement statement,* the *notice of dispute* relates to a matter which, pursuant to section 6.8.2, section 6.8.3, or section 6.8.12, except for section 6.8.12.4, is not an item or calculation for which the the *market participant* is permitted to submit a *notice of disagreement*, unless the only reason that a *market participant* is not permitted to submit a *notice of disagreement* is because the new or adjusted item or calculation is not identified as associated with an adjustment flag;

6.10.2.2 in regards to disputes pertaining to a *final recalculated settlement statement,* the *notice of dispute* relates to a matter:

a. which does not differ in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day*;
b. is not an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day*;
c. is not an item or calculation which the *market participant* considers that there is an omission in such *settlement statement*; or
d. described in sections 6.8.12.5 to 6.8.12.9.

6.10.2.3 subject to MR Ch.3 s.2.5.1B, the *notice of dispute* was submitted by the *market participant*:

a. in regards to matters described in section 6.8.15 where the *IESO* has made its determination, more than twenty *business days* after either the *IESO* notifies the *market participant* in accordance with section 6.8.9.1 or issues the relevant *settlement statement* in accordance with section 6.8.9.2, as the case may be;

b. in regards to matters described in section 6.8.15 where the *IESO* has not made its determination, prior to the date referred to in section 6.8.15;

c. in regards to matters described in section 6.9.5 where the adjustment is made on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued, more than twenty *business days* after the *IESO* issues the ad hoc *recalculated settlement statement;*

d. in regards to disputes pertaining to a *final recalculated settlement statement*, more than twenty *business days* after the *IESO* issues the *final recalculated settlement statement*;

e. in regards to matters described in section 6.8.12.4, except for a compliance and enforcement action described in MR Ch.3 s.6, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed;

f. in regards to a compliance and enforcement action described in MR Ch.3 s.6, outside of the applicable timeline set forth in MR Ch.3 s.2.5.1A; and

g. in regards to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed.

6.10.3 Following the resolution of a dispute, the *IESO* shall arrange to have the *dispute outcome* carried out as soon as is reasonably practicable following the resolution of the dispute, subject to the availability of data and of the *IESO's* resources.

6.10.4 To implement a *dispute outcome*, the *IESO* shall:

6.10.4.1 for the *market participant* that originally filed the *notice of dispute* that resulted in the *dispute outcome*, reflect the amounts to be debited or credited in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits on the next scheduled *recalculated settlement statement*; or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on the final *recalculated settlement statement*, the *IESO* shall reflect such credits or debits on a subsequent *preliminary settlement statement* issued for the *market participant*.

6.10.4.2 ensure any credit adjustment made to such *market participant*, being a refund of payments already made, shall include interest at the *default interest rate* from the date the overpayment was received to the time that the repayment is credited to the relevant *market participant settlement account*;

6.10.4.3 arrange to have all net adjustments for each *market participant*, and any interest on such net adjustments, placed into the *IESO adjustment account*; and

6.10.4.4 for any other *market participant* affected by the *dispute outcome*, reflect the incremental dollar amount determined in section 6.10.4.1 as a debit or credit in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as an *adjustment period allocation* on the next scheduled *recalculated settlement statement*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a *current period adjustment* to a subsequent *preliminary settlement statement*; or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as a *current period adjustment* on a subsequent *preliminary settlement statement* issued for the *market participant.*

6.10.4.5 Notwithstanding section 6.10.4.1(a) and 6.10.4.4(a), where the *dispute outcome* requires an adjustment within a specified time period and the next scheduled *recalculated settlement statements* follows such time period, the *IESO* shall issue an ad hoc *recalculated settlement statement* to reflect such adjustments within the required timeframe.

6.11 Responsibility of the IESO

6.11.1 In carrying out its *settlement* responsibilities, the *IESO* shall operate in a non-discriminatory manner.

6.11.2 The *IESO* shall not be a counter-party to any trade transacted through the *day-ahead market* and *real-time market*.

6.12 Settlement Invoices

6.12.1 Unless the *IESO* has invoked the estimated *invoice* procedure pursuant to section 6.3.27, each *invoice* issued by the *IESO* to a *market participant* shall be based on all of the *settlement statements* issued to the *market participant* since their last *invoice* was issued except for any that may pertain to the next *billing period*, as more particularly described in the applicable *market manual*. In each *invoice*, other than an estimated *invoice* issued pursuant to section 6.3.27:

6.12.1.1 each line item shall correspond to a distinct commodity or service bought or sold over the *billing period*; and

6.12.1.2 the *charge type* appearing on the *invoice* shall allow *invoice* line items to be cross-referenced to the relevant *settlement statements.*

6.12.2 The *IESO* shall, on the days specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33, issue an *invoice* to each *market participant* showing:

6.12.2.1 the dollar amounts which are to be paid by or to the *market participant*, according to *settlement statements* as specified in section 6.12.1 or as estimated pursuant to section 6.3.27;

6.12.2.2 the *market participant payment date* by which such amounts (if any) are to be paid by the *market participant* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held);

6.12.2.3 the *IESO payment date* by which the *IESO* is to make payments (if any) to the *market participant* no later than the *close of banking business* (of the bank at which the *market participant settlement account* is held); and

6.12.2.4 details of the *IESO settlement clearing account*, including the bank name, account number and *electronic funds transfer* instructions, to which any amounts owed by the *market participant* are to be paid in accordance with section 6.12.2.2.

6.12.3 *Invoices* shall be considered issued to *market participants* when issued by the *IESO* in accordance with the applicable *market manual*.

6.12.4 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive an *invoice* on the date specified for the issuance of such *invoice* in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33. Each *market participant* shall be deemed to have received its *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.33*,* unless it notifies the *IESO* to the contrary.

6.12.5 In the event that a *market participant* notifies the *IESO* that it has failed to receive an *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* the *IESO* shall re-issue the appropriate *invoice* and the *invoice* shall be considered received on the date the re-issued *invoice* is sent to the *market participant.*

6.13 Payment of Invoices

6.13.1 Subject to section 6.13.2, each *market participant* shall pay the full net *invoice* amount by the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31 and 6.3.33, regardless of whether or not the *market participant* has initiated or continues to have a dispute respecting the net amount payable.

6.13.2 A *market participant* may pay at an earlier date than the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33 in accordance with the following:

6.13.2.1 notification must be given to the *IESO* before submitting such prepayment or before converting an existing overpayment by the *market participant* into a prepayment;

6.13.2.2 the prepayment notification shall specify the dollar amount prepaid;

6.13.2.3 a prepayment shall be made by the *market participant* into the *IESO prepayment account* designated by the *IESO*;

6.13.2.4 on any *market participant payment date,* the *IESO* may initiate the transfer of necessary funds from the *IESO prepayment account* to the *IESO settlement clearing account* to discharge, up to the amount of the prepayment, that *market participant*'s outstanding payment obligations arising in relation to that *market participant payment date;* and

6.13.2.5 subject to MR Ch.2 s.5.6.3, and notwithstanding MR Ch.8 s.4.18.1.2, funds held in an *IESO prepayment account* on behalf of a *market participant* may be applied by the *IESO* to any outstanding financial obligations of that *market participant* to the *IESO* for transactions carried out in the *IESO-administered markets.*

6.13.3 With respect to *transmission services charges*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *transmitter's transmission services settlement account* sufficient funds to pay in full the *transmission services charges* falling due to that *transmitter* on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33.

6.13.4 With respect to the *IESO administration charge*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account sufficient funds to pay in full the *IESO administration charge* falling due on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 in priority to any other payments to be made on that *IESO payment date* or on subsequent days out of the *IESO settlement clearing account.*

6.13.5 With respect to the smart metering charge*,* the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account only those funds that were received in the *IESO settlement clearing account* in payment of the smart metering charge*.* The smart metering charge is the fee approved by the *OEB* to recover costs incurred by the *IESO* solely as a result of the *IESO* acting as the Smart Metering Entity and its responsibilities related to the smart metering initiative.

6.13.6 The *IESO* shall, on the *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* determine the amounts available in the *IESO settlement clearing account* for distribution to *market participant*s or the *forecasting entity*, and shall, if necessary, borrow funds in accordance with the provisions of section 6.16 if necessary to enable the *IESO settlement clearing account* to clear no later than 11:00 am on the *IESO payment date*.

6.14 Funds Transfer

6.14.1 All payments by *market participants* in respect of *settlement* matters shall be made to the *IESO settlement clearing account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.2 All payments by the *IESO* to *market participants* in respect of *settlement* matters shall be made to each *market participant's market participant settlement account* or to each *transmitter's transmission services settlement account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.3 In the event of failure of any *electronic funds transfer* system affecting the ability of either a *market participant* or the *IESO* to make payments, the affected party shall arrange for alternative means of payment so as to ensure that payment is effected by the dates and times specified in this Chapter.

6.14.4 No *market participant* shall include in any *electronic funds transfer* amounts attributable to more than one *invoice* or prepayment, unless such *electronic funds transfer* is in such form as may be specified in the applicable *market manual.*

6.14.5 The *IESO* shall be entitled to and shall rely on the information contained in or accompanying an *electronic funds transfer* received pursuant to section 6.14.4 for the purpose of allocating the aggregate amount of an *electronic funds transfer* referred to in that section and, notwithstanding MR Ch.1 s.13:

6.14.5.1 the *IESO* shall not be liable to any person in respect of the allocation of:

a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or
b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2; and

6.14.5.2 the *market participant* providing the *IESO* with such information shall indemnify and hold harmless the *IESO* in respect of any claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation by the *IESO* of:

a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2.

6.14.6 Where a *market participant* that initiates an *electronic funds transfer* to which section 6.14.4 applies fails to provide the information contained in or accompanying an *electronic funds transfer* referred to in section 6.14.4, the *IESO* shall allocate:

6.14.6.1 the aggregate amount of the *electronic funds transfer;* and

6.14.6.2 the entire amount of any associated overpayment or underpayment, to that *market participant*.

6.15 Confirmation Notices

6.15.1 At the end of each calendar month, the *IESO* shall issue a *monthly confirmation notice* to each *market participant* which shall contain statements of the amounts received from or paid out to the *market participant* on each *market participant payment date* and *IESO payment date* in that month and any payments outstanding.

6.16 Payment Default

6.16.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account*.

6.16.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.

6.16.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.13.2**,** the provisions of MR Ch.3 s.6.3 shall apply and *default interest* shall accrue on all amounts outstanding.

6.16.4 If the *market participant's invoice* includes a *settlement amount* owing for the smart metering charge under section 6.13.5 and the *market participant:*

a. fails to remit the full *invoice* amount due by the *market participant payment date*; and
b. does not direct the *IESO* how to apportion the payment between the smart metering charge and all other *settlement amounts* on the *invoice* prior to the *IESO payment date*, the *IESO* shall allocate the payment made by the *market*

participant first to satisfying any *settlement amounts* due under the *market rules* before being applied to the smart metering charge.

6.16.5 The *IESO* shall be authorized to borrow short-term funds to clear the credits in any *settlement* cycle only if the following conditions are met:

6.16.5.1 there are insufficient funds remitted into the *IESO settlement clearing account* or *TR clearing account* to pay all applicable *market creditors* due for payment from the funds in the *IESO settlement clearing account* or *TR clearing account*, and clear the *IESO settlement clearing account* or *TR clearing account* on a given *IESO payment date*, due to:

a. payment default by one or more *market participants* in the *day-ahead market* and *real-time market*; or
b. the circumstances referred to in MR Ch.8 s.3.19.2 or 3.19.7;

6.16.6 If the *IESO* borrows short-term funds pursuant to section 6.16.5, it shall recover this borrowing:

6.16.6.1 where the insufficient funds were due to a payment default referred to in section 6.16.5.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules,* including, if necessary, by imposing the *default levy* in accordance with MR Ch.2 s.8; or

6.16.6.2 where the insufficient funds were due to the circumstances referred to in section 6.16.5.1 (b), in the manner referred to in MR Ch.8, ss.3.19.3 and 3.19.5 and then, if necessary, by recovering from *market participants* proportionately based on *transmission services charges* paid during all *metering intervals* and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.16.6.2.1 Where a *market participant* has paid provincial *transmission services charges*, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *registered wholesale meters* excluding *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.2.2 Where a *market participant* has paid export *transmission services charges*, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *intertie metering points* during all intervals and *settlement hours* within the *energy market billing* *period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.3 The portion of any short-term funds borrowed by the *IESO* to be recovered from *market participant* 'k' in the current *energy market billing period* shall be calculated as follows:

6.16.6.3.1 For *market participants* that have paid provincial *transmission services charges* in the current *energy market billing period*:

$$TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} [(AQEW_{k,h}{}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t})$$

6.16.6.3.2 For *market participants* that have paid export *transmission services charges* in the current *energy market billing period*:

$$TRCAC_k = TRCAD_E \times \sum_H{}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

i. $TRCAC_k$ = the *TR clearing account* credit (in $ and up to 2 decimal places) collected from *market participant* 'k' in the current *energy market billing period;*

ii. $TRCAD_L =(\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAR$

iii. $TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAR$

iv. TRCAR = the total dollar value (in $ and up to 2 decimal places) of TR shortfall recovery from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*

v. C = the set of all monthly service *charge types* 'c' as follows: 650,651,652; and

vi. C1 = the set of all monthly export transmission *charge types* 'c' as follows: 653.

6.16.7 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account*, and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participants* or to the circumstances referred to in section 6.16.5.1 (b), the *IESO* shall borrow funds in accordance with section 6.16.5 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date*.

6.16.8 If the *IESO* has exhausted credit availability contemplated by section 6.16.5, then the *IESO* shall pay *market creditors* on a pro rata basis in proportion to the amounts owed to each *market creditor*. Any amounts that remain owing to *market creditors* shall bear interest at the *default interest rate* until paid.

6.16.9 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default levy*, the *IESO* shall first repay all existing lines of credit and other banking facilities, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *market creditors* owed amounts pursuant to section 6.16.8.

6.17 Payment Errors, Adjustments, and Interest

6.17.1 If a *market participant* receives an overpayment on any *IESO payment date:*

6.17.1.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* of the overpayment or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.1.2 if the *IESO* determines or becomes aware of the overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* of the overpayment;

6.17.1.3 the *market participant* receiving the overpayment shall, until it has refunded the overpayment to the *IESO*, be deemed to be holding the amount of such overpayment in trust for any other *market participant*s that may have been underpaid in consequence of such overpayment, pro rata to the amount of the underpayment;

6.17.1.4 the *IESO* shall be entitled to treat the overpayment and any interest accruing thereon as an unpaid amount to which section 6.16 applies; and

6.17.1.5 if not repaid fully within 2 *business days* of receiving the overpayment, the unpaid amount of any overpayment shall bear interest at the *default interest rate* from the date of overpayment until the date on which repayment is credited to the *IESO's* relevant *settlement account*.

6.17.2 The *IESO* shall be responsible for identifying any *market participant*s who have been underpaid as a result of an overpayment to another *market participant*.

6.17.3 The *IESO* shall pay any underpaid *market participant* for the amounts of their underpayment, including interest calculated from the date the *market participant* should have been paid, as soon as practicable following repayment by the overpaid *market participant*.

6.17.4 If a *market participant* has overpaid the *IESO* on any *market participant* payment date:

6.17.4.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.4.2 if the *IESO* determines or becomes aware of such overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly;

6.17.4.3 the *market participant* may request that the overpaid amount be either refunded or treated as a prepayment pursuant with section 6.13.2; and

6.17.4.4 any related administration and transaction costs incurred by the *IESO* in managing and resolving the over-payment shall be charged to the account of the *market participant* involved.

6.17.5 If the *IESO* underpays any *market participant* on any *IESO payment date*:

6.17.5.1 the *market participant* shall notify the *IESO* of such underpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.5.2 if the *IESO* determines or becomes aware of the underpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly; and

6.17.5.3 the *IESO* shall use all reasonable endeavors to promptly correct any underpayments, including interest thereon at the *default interest rate*.

6.17.6 If the *IESO* is underpaid by a *market participant* on any *market participant payment date,* the provisions of section 6.16 or of MR Ch.8 s.4.20 shall apply.

6.17.7 If the *IESO* borrows funds in accordance with section 6.16.5 because a payment due from a *market participant* was received too late to be credited to the *IESO settlement clearing account* by *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* when such payment was due, then such remittance when it does arrive shall be used to repay the borrowed funds. Any such late payments shall be charged the *Canadian prime interest rate* plus 2%.

6.17.8 If the *IESO* holds or has under its control after five *business days* from receipt in the *IESO settlement clearing account* amounts which it ought properly to have paid to *market participant*s, such *market participant*s shall be entitled to interest on such amounts at the *default interest rate* from the date on which the *IESO* commenced to improperly hold or have such amounts under its control to the date on which such amounts are paid to the relevant *market participants.*

6.17.9 Monies in the *IESO settlement account*s at the end of each year which have been earned from interest on funds in the *IESO settlement account*s and which are not attributable to any incomplete *settlement process* or outstanding *settlement* dispute shall be used to off-set the *IESO administration charge* in the following year.

6.17.10 Where an amount is payable to a former *market participant* as a result of a *settlement* adjustment, the *IESO* shall endeavor to distribute the amount as specified in the applicable *market manual*. If the *IESO* cannot distribute the amount to the former *market participant* as specified in the applicable *market manual*, such amount shall be used to offset the *IESO administration charge*.

6.18 Settlement Financial Balance/Maximum Amount Payable by IESO

6.18.1 The *IESO* shall provide and operate a *settlement* control process to monitor the financial balance of the calculated charges and payments so as to ensure that, subject to section 6.18.3:

6.18.1.1 for *day-ahead market* and *real-time market* transactions, other than transactions in the *TR market*, the sum of all payments for all *market creditors* involved in such market transactions exactly equals the sum of all charges for *market debtors* involved in such market transactions for each *trading day* of a *billing period*; and

6.18.1.2 for all other transactions, other than transactions in the *TR market* including daily and monthly charges, adjustment charges and payments, the sum of all payments to *market creditors* of those transactions exactly equals the sum of all charges to *market debtors* of those transactions for each *billing period*.

6.18.2 Subject to the provisions of section 6.16, the *IESO* shall not be liable to make payments in excess of the amount it receives for transactions in the *day-ahead market* and *real-time market*.

6.18.3 If there is an aggregate imbalance for all transactions for a given *trading day* or *billing period,* the *IESO* shall, in accordance with section 6.18.4 or by such other means as the *IESO* determines appropriate, recover that portion of the imbalance that arises by virtue of the rounding of *day-ahead market* and *real-time market settlement amounts* or of an adjustment to the *settlement statement* of one *market* *participant* that is too small to be reflected in corresponding *settlement statement* of other *market participants* provided that:

6.18.3.1 the manner of calculation of that portion of the imbalance can be evidenced in a manner satisfactory for purposes of the audit referred to in section 6.19; and

6.18.3.2 that portion of the imbalance has accumulated to an amount which is sufficient to permit recovery.

6.18.4 The *IESO* may recover the portion of an aggregate imbalance referred to in section 6.18.3 by means of an adjustment to a *settlement statement* applied:

6.18.4.1 to *market participants* to whom *hourly uplift* may be allocated pursuant to these *market rules*;

6.18.4.2 in the same manner as *hourly uplift;* and

6.18.4.3 in respect of all *settlement hours* of the last day of the *billing period* in which the portion of such aggregate imbalance is determined to arise and be recoverable pursuant to section 6.18.3.

6.19 Audit

6.19.1 The audit of *settlement* functions referred to in this section 6.19 shall serve to examine and evaluate compliance with management control objectives and operational effectiveness of *settlement process*es and procedures.

6.19.2 The audits referred to in section 6.19.3 shall be performed by an external, independent auditing firm.

6.19.3 Unless otherwise directed by the *IESO Board*, the *IESO* shall every two years, on the anniversary of the *market commencement date*, direct a comprehensive external audit on the *settlement process*es and procedures. The audit shall include the following tasks:

6.19.3.1 gauge the performance of the *settlement process* in meeting the objectives of these *market rules;*

6.19.3.2 review the accuracy and timeliness of the production of *settlement statements*, including *settlement* calculations and financial allocations;

6.19.3.3 review the accuracy and timeliness of the production of *invoice*s and supporting market and system information;

6.19.3.4 review the *reliability* and integrity of the market and system operational data used in the *settlement process*es and procedures;

6.19.3.5 review the *reliability* and security of the information technology system infrastructure used to measure, validate, classify, compute and report *settlement* information;

6.19.3.6 review the adequacy of *settlement processes* and procedures to safeguard *confidential information*; and

6.19.3.7 review the adequacy and effectiveness of risk management controls of the *settlement process*es and tools, including the effectiveness of the *disaster recovery plan.*

6.19.4 *Settlement statements*, financial *settlement* records and any documentation pertaining to the *IESO's settlement* activities shall, subject to sections 2.11.1 to 2.11.3, be kept in secure storage for a period of at least seven years and made available for auditing purposes.

6.19.5 An audit report shall be prepared by the auditors in respect of each audit conducted pursuant to this section 6.19 and shall be commissioned on the basis that the audit report must be provided to the *IESO* within one month after completion of the audit activities.

6.19.6 Each audit report prepared pursuant to this section 6.19 shall be made available to a *market participant* upon request, subject to such measures as may be required to be taken to safeguard any *confidential information* contained in such audit report.

6.20 Settlement Accounts

6.20.1 The *IESO* shall establish and maintain the *settlement accounts* described in this section 6.20 for the operation of its *settlement* and billing systems.

6.20.2 The *IESO* shall obtain lines of credit and other banking facilities it deems necessary for the operation of the *settlement accounts* described in this section 6.20, which lines of credit and other banking facilities shall not exceed an aggregate amount approved by the *IESO Board*.

6.20.3 The *IESO* may establish *settlement accounts* in addition to those referred to in this section 6.20 as may be necessary to implement the *settlement* and billing processes outlined in this Chapter. *Market participant*s shall be notified 60 *business days* prior to any such additional *settlement accounts* becoming *operational*.

6.20.4 The *IESO* shall open and maintain the *IESO settlement clearing account* as a single bank account to and from which all *settlement* payments shall be made in accordance with the provisions of this Chapter and the details of which shall appear in the *invoice*s sent by the *IESO* to *market participant*s as provided in section 6.12.2.4**.**

6.20.5 The *IESO* shall open and maintain the *IESO adjustment account*, which *account* shall operate as follows:

6.20.5.1 the *IESO adjustment account* shall be a single bank account established to receive and disburse payments related to penalties, damages, fines and payment adjustments arising from resolved *settlement* disputes, and to reimburse the *IESO* for any associated costs or expenses;

6.20.5.2 any amounts paid into the *IESO adjustment account* by *market participant*s shall first be applied to reimburse the *IESO* in respect of any costs or expenses described in section 6.20.5.1 which it has or will incur. Any remaining amount shall be credited to the *IESO adjustment account;* and

6.20.5.3 the *IESO Board* shall review, at least annually, the allocation of any credit balance of the *IESO adjustment account*, and may:

a. establish an amount to be retained in the *IESO adjustment account*;
b. direct that some or all of the credit balance be applied to special education projects or initiatives; and/or
c. direct that some or all of the balance be distributed to *market participants* on a basis to be determined by the *IESO Board*.

6.20.6 The *IESO* shall open and maintain the *IESO prepayment account,* which *account* shall operate as follows:

6.20.6.1 the *IESO prepayment account* shall be a bank account established for *market participants* to deposit prepayments at an earlier date than the specified *market participant payment date*; and

6.20.6.2 the arrangements for making the prepayment and transferring funds from the *IESO prepayment account* to the *IESO settlement clearing account* shall be in accordance with the provisions of section 6.13.2.

6.20.7 The *IESO* shall open and maintain the *TR clearing account*, which *account* shall operate in the manner described in MR Ch.8 ss.4.18 and 4.19.

6.20.8 Unless otherwise specified, the *IESO* shall recover all banking costs reasonably incurred in opening and operating the *IESO's settlement accounts* through the *IESO administration charge.*

6.20.9 The *IESO* shall maintain its *settlement accounts* at a bank or financial institution in the Province of Ontario approved by the *IESO Board*.

6.20.10 Each *transmitter* shall be required to open and maintain a *transmission services settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.11 Each *transmitter* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *transmitter's transmission services settlement account*.

6.20.12 Each *market participant* shall be required to open and maintain a *market participant settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.13 Each *market participant* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *market participant's market participant settlement account*.

6.20.14 The *settlement accounts* referred to in this section 6.20 may be changed or closed as follows:

6.20.14.1 the *IESO* may change the bank or the details of any of its *settlement accounts*, on the condition that the bank or financial institution is reasonably acceptable to the *IESO Board* and that all *market participant*s are notified by the *IESO* in writing at least 60 *business days* before the change takes effect; and

6.20.14.2 any *transmitter* or *market participant* may change its bank or the details of its *settlement account*, on the condition that the *IESO* is notified in writing at least 60 *business days* before the change takes effect.

RUL-22

Renewed Market Rules

Chapter 0.9

Settlements and Billing - Appendices

0.9

Renewed Market Rules – Chapter 0.9: Settlements and Billing - Appendices

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Table of Contents

Appendix 9.1 – VEE Process

1.1 Introduction and Interpretation

1.1.1 This Appendix sets forth the obligations of the *IESO* and of *metered market participants* with respect to the validation, estimation and editing of *metering data*.

1.1.2 For the purposes of this Appendix, a reference to an interval means:

1.1.2.1 in the case of a *metering installation* that collates *metering data* by *metering intervals*, a *metering interval*; and

1.1.2.2 in all other cases, such multiple of *metering intervals* for which the *metering installation* collates *metering data*.

1.2 Manner of Data Collection by the IESO

1.2.1 The *IESO* shall collect or receive *metering data* for *settlement* purposes using, in respect of a given *registered wholesale meter*, one or more of the following methods as may be applicable:

1.2.1.1 electronic access to the *registered wholesale meter* as described in MR Ch.6;

1.2.1.2 a wide area network; or

1.2.1.3 such manual collection method as may be required to resolve a trouble call in respect of the *registered wholesale meter*.

1.3 Obligation of the Metered Market Participant to Provide Data

1.3.1 Each *metered market participant* shall, for each *registered wholesale meter* in respect of which it is the *metered market participant* and that is a *main/alternate metering installation*, provide to the *IESO*, for validation purposes, *metering data* from each of the main *meter* and the alternate *meter* in accordance with the provisions of MR Ch.6 and the *VEE standard*.

1.3.2 Each *metered market participant* shall, for each *registered wholesale meter* in respect of which it is the *metered market participant* and that is a *single metering installation*, provide to the *IESO*, for validation purposes:

1.3.2.1 *metering data* from the *meter* in accordance with the provisions of MR Ch.6 and the *VEE standard*; and

1.3.2.2 the validation criteria for *single metering installations* set forth in section 2.4 of the *VEE standard*.

1.4 Automated Processes and Trouble Calls

1.4.1 The validation and estimation procedures described in this Appendix 9.1 shall be effected by means of automated processes following the collection or receipt of *metering data* by the *IESO's* automated systems.

1.4.2 Where the *metering data* from any *meter* in a *registered wholesale meter* is unavailable or fails to successfully pass the validation procedures referred to in:

1.4.2.1 sections 1.5.1 and, where applicable, 1.5.2; or

1.4.2.2 sections 1.6.1 and, where applicable, 1.6.2,

as the case may be, the *IESO* shall:

1.4.2.3 issue a trouble call to the *metering service provider* for the *metering installation* to which the *metering data* relates; and

1.4.2.4 notify the *metered market participant* for the *metering installation* of the issuance of the trouble call.

1.4.3 A *metering service provider* to whom a trouble call has been issued pursuant to section 1.4.2.3 shall respond to and resolve the trouble call in accordance with the requirements of MR Ch.6 ss.11.1.2.1 and 11.1.2.2.

1.4.4 A *metering service provider* that has resolved a trouble call issued pursuant to section 1.4.2.3 shall:

1.4.4.1 so notify the *IESO*;

1.4.4.2 provide the *IESO* with a written description of the cause of and the actions taken to resolve the trouble call; and

1.4.4.3 where applicable, provide to the *IESO* a request for an adjustment to the *metering data* that was the subject of the trouble call, together with auditable documentary justification for the adjustment,

in accordance with the requirements of the *VEE standard* and in such form and manner as may be required by the *IESO*.

1.5 Validation, Estimation and Editing: Main/Alternate Metering Installation

1.5.1 The following validation procedures shall be conducted, in accordance with the *VEE standard*, by the *IESO's* automated validation process in respect of each *registered wholesale meter* that is a *main/alternate metering installation* to the extent permitted by the configuration of such *metering installation*:

1.5.1.1 determine whether any *metering data* has failed to be delivered to or received by the *IESO* from each of:

a. the main *meter*; and

b. the alternate *meter*,

in the manner and at the time required by these *market rules* and the intervals for which such *metering data* is missing;

1.5.1.2 test current and voltage data, if it has been provided;

1.5.1.3 conduct the data transmission/multiplier verification;

1.5.1.4 test for synchronization of the clock in each of:

a. the main *meter*; and

b. the alternate *meter*,

against the standard of accuracy described in MR Ch.6 s.11.2.2;

1.5.1.5 test for replacement of the *data logger* in each of the main *meter* and the alternate *meter*;

1.5.1.6 monitor error messages, flags and alarms received from each of:

a. the main *meter*; and

b. the alternate *meter*; and

1.5.1.7 compare the *metering data* collected or received from the main *meter* with the *metering data* collected or received from the alternate *meter*.

1.5.2 The *IESO* may, in addition to the validation procedures referred to in section 1.5.1, carry out such additional automated validation procedures in respect of *registered wholesale meters* that are *main/alternate metering installations* as it determines appropriate.

1.5.3 Where the *metering data* from each of:

1.5.3.1 the main *meter*; and

1.5.3.2 the alternate *meter*,

in a *registered wholesale meter* that is a *main/alternate metering installation* has successfully passed the validation procedures referred to in sections 1.5.1 and, where applicable, 1.5.2, such *metering data* shall be deemed validated *metering data* and the *metering data* from the main *meter* shall, subject to any adjustment and totalization that may be required pursuant to MR Ch.6 be used by the *IESO* for *settlement* purposes.

1.5.4 Where the *metering data* from the main *meter* in a *registered wholesale meter* that is a *main/alternate metering installation* has successfully passed the validation procedures described in sections 1.5.1 and, where applicable, 1.5.2, such *metering data* shall, subject to:

1.5.4.1 any adjustment and totalization that may be required pursuant to MR Ch.6; and

1.5.4.2 any subsequent adjustment made pursuant to section 1.5.10.2,

be used for *settlement* purposes notwithstanding that the *metering data* from the alternate *meter* is unavailable or has not successfully passed such validation procedures.

1.5.5 Where the *metering data* from the main *meter* in a *registered wholesale meter* that is a *main/alternate metering installation* is unavailable or has not successfully passed the validation procedures referred to in section 1.5.1 and, where applicable, 1.5.2, the *metering data* from the alternate *meter* shall, subject to:

1.5.5.1 any adjustment and totalization that may be required pursuant to MR Ch.6; and

1.5.5.2 any subsequent adjustment made pursuant to section 1.5.11.2,

be used for *settlement* purposes provided that the *metering data* from the alternate *meter* has successfully passed the validation procedures referred to in sections 1.5.1 and, where applicable, 1.5.2. The substitution of the *metering data* from the alternate *meter* for the *metering data* from the main *meter* shall be flagged in the *metering database*.

1.5.6 Where the *metering data* from both *meters* in a *registered wholesale meter* that is a *main/alternate metering installation* is unavailable or has not successfully passed the validation procedures referred to in sections 1.5.1 and, where applicable, 1.5.2, an estimate of the *metering data* shall be prepared by automated process in accordance with section 1.5.7 and the *VEE standard*. Such estimate shall, subject to:

1.5.6.1 any adjustment and totalization that may be required pursuant to MR Ch.6; and

1.5.6.2 any subsequent adjustment made pursuant to section 1.5.12.2,

be used for *settlement* purposes. Such estimation shall be flagged in the *metering database*.

1.5.7 An estimate of *metering data* referred to in section 1.5.6, 1.6.4 or 1.7.1.2 shall be based:

1.5.7.1 where the period for which the *metering data* is unavailable or has not successfully passed the validation procedures described in:

a. section 1.5.1 and, where applicable, 1.5.2; or

b. section 1.6.1 and, where applicable, 1.6.2,

is less than one hour, on a straight line joining the demand observed in the *metering data* in the interval immediately preceding such period and the interval immediately following such period; or

1.5.7.2 where such period is one hour or more, on validated *metering data* collected or received from the *metering installation* in the three most recent comparable *trading days* selected in accordance with section 1.5.8.

1.5.8 For the purposes of section 1.5.7.2, where the *metering data*:

1.5.8.1 relates to a *generation resource*, the *metering data* for the interval recording the lowest quantity shall be used for estimation;

1.5.8.2 relates to a *load resource*, the *metering data* for the interval recording the highest quantity shall be used for estimation;

1.5.8.3 relates to the injections for an *electricity storage resource*; the *metering data* for the interval recording the lowest quantity shall be used for estimation; and

1.5.8.4 relates to the withdrawals for an *electricity storage resource*, the *metering data* for the interval recording the highest quantity shall be used for estimation.

1.5.9 For the purposes of section 1.5.7.2, validated *metering data* shall include, where applicable, *metering data* that has been:

1.5.9.1 used in accordance with section 1.5.4 or 1.6.3;

1.5.9.2 substituted in accordance with section 1.5.5; or

1.5.9.3 estimated in accordance with section 1.5.6, 1.6.4 or 1.7.1.2,

subject to such adjustments as may have been made to such *metering data* in accordance with those sections at the time that the estimate is prepared pursuant to section 1.5.7.2.

1.5.10 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where the *metering data* from the main *meter* is being used in accordance with section 1.5.4:

1.5.10.1 use such *metering data* for *settlement* purposes provided that the *IESO* is satisfied that such *metering data* is correct and any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly; or

1.5.10.2 adjust such *metering data* in accordance with section 1.7.1 if the *IESO* is satisfied that such *metering data* has been affected by the failure of the alternate *meter*.

1.5.11 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where the *metering data* from the alternate *meter* is being used in accordance with section 1.5.5:

1.5.11.1 use such *metering data* for *settlement* purposes provided that the *IESO* is satisfied that such *metering data* is correct and any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly; or

1.5.11.2 adjust such *metering data* in accordance with section 1.7.1 if the *IESO* is satisfied that such *metering data* has been affected by the failure of the main *meter*.

1.5.12 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where an estimate has been prepared pursuant to section 1.5.6:

1.5.12.1 adjust such estimate in accordance with section 1.7.1 if the *IESO* is satisfied that resolution of the trouble call has identified a source of *metering data* that is more accurate that such estimate; or

1.5.12.2 in all other cases, use such estimate for *settlement* purposes.

1.6 Validation, Estimation and Editing: Single Metering Installations

1.6.1 The following validation procedures shall be conducted, in accordance with the *VEE standard*, by the *IESO's* automated validation process in respect of each *registered wholesale meter* that is a *single metering installation*:

1.6.1.1 determine whether any *metering data* has failed to be delivered to or received by the *IESO* from the *meter* in the manner and at the time required by these *market rules* and the intervals for which such *metering data* is missing;

1.6.1.2 test current and voltage data, if it has been provided;

1.6.1.3 conduct the data transmission/multiplier verification;

1.6.1.4 test for synchronization of the *meter* clock against the standard of accuracy described in MR Ch.6 s.11.2.2;

1.6.1.5 test for replacement of the *data logger* in the *meter*; and

1.6.1.6 monitor error messages, flags and alarms received from the *meter*.

1.6.2 The *IESO* may, in addition to the validation procedures referred to in section 1.6.1, carry out such additional automated validation procedures in respect of *registered wholesale meters* that are *single metering installations* as it determines appropriate.

1.6.3 Where the *metering data* from the *meter* in a *single metering installation* has not successfully passed the validation procedures referred to in section 1.6.1 and, where applicable, 1.6.2, such *metering data* shall, subject to:

1.6.3.1 any adjustment and totalization that may be required pursuant to MR Ch.6; and

1.6.3.2 any adjustment made pursuant to section 1.6.5.2,

nonetheless be used for *settlement* purposes by the *IESO*. Such failure of validation shall be flagged in the *metering database*.

1.6.4 Where the *metering data* from the *meter* in a *single metering installation* is unavailable, an estimate of the *metering data* shall be prepared by automated process in accordance with section 1.5.7 and the *VEE standard*. Such estimate shall, subject to:

1.6.4.1 any adjustment and totalization that may be required pursuant to MR Ch.6; and

1.6.4.2 any subsequent adjustment made pursuant to section 1.6.6.1,

be used for *settlement* purposes. Such estimation shall be flagged in the *metering database*.

1.6.5 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where the *metering data* from the *meter* is being used pursuant to section 1.6.3:

1.6.5.1 use such *metering data* for *settlement* purposes if the *IESO* is satisfied that such *metering data* is correct and any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly; or

1.6.5.2 adjust such *metering data* in accordance with section 1.7.1.

1.6.6 Upon the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where an estimate has been prepared pursuant to section 1.6.4:

1.6.6.1 adjust such estimate in accordance with section 1.7.1 if the *IESO* is satisfied that resolution of the trouble call has identified a source of *metering data* that is more accurate than such estimate; or

1.6.6.2 in all other cases, use such estimate for *settlement* purposes.

1.7 Adjustments and Failure to Resolve Trouble Call

1.7.1 An adjustment referred to in section 1.5.10.2, 1.5.11.2, 1.5.12.1, 1.6.5.2 or 1.6.6.1, as the case may be, shall be effected by the *IESO* by means of:

1.7.1.1 the application of a multiplier, an adder or subtractor or an absolute value for each applicable *metering interval*; or

1.7.1.2 the application of the estimation process referred to in section 1.5.7,

as the *IESO* determines appropriate in accordance with section 1.7.2, having regard to the written description and, where applicable, the request made by the *metering service provider* pursuant to section 1.4.4. Any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly.

1.7.2 The *IESO* shall, as between the adjustment methods referred to in section 1.7.1, select the method that in the *IESO's* opinion will result in the use of *metering data* for *settlement* purposes that most closely reflects the flow of *energy* through the *registered wholesale meter* during the applicable intervals. Where both methods are determined by the *IESO* to be equivalent in this regard, the *IESO* shall select the method that is less likely to result in the *metered market participant* for the *registered wholesale meter* to which the *metering data* relates obtaining a benefit from the adjustment relative to what the *metered market participant's* position would otherwise have been.

1.7.3 Where a trouble call has been issued pursuant to section 1.4.2.3 and:

1.7.3.1 the *IESO* does not receive the notification referred to in section 1.4.4.1;

1.7.3.2 the *IESO* does not receive the written description referred to in section 1.4.4.2; or

1.7.3.3 the trouble call is not resolved to the satisfaction of the *IESO*,

the *IESO* shall for *settlement* purposes use:

1.7.3.4 the *metering data*, substituted *metering data* or estimated *metering data* referred to in section 1.5.4, 1.5.5, 1.5.6, 1.6.3 or 1.6.4, as the case may be; and

1.7.3.5 where applicable, the estimates referred to in MR Ch.6 s.11.1.4A, until such time as the trouble call is resolved to the satisfaction of the *IESO*.

Appendix 9.2 – Data Inputs and Variables

1 General/Overview

1.1 In MR Ch.9, and the appendices thereto, the following variables have the following meanings:

1.1.1 In regards to *class r reserve*, the following are the three types of *class r reserve*:

1.1.1.1 'r1' is synchronized *ten-minute operating reserve*;

1.1.1.2 'r2' is non-synchronized *ten-minute operating reserve*; and

1.1.1.3 'r3' is *thirty-minute operating reserve*.

1.1.2 In regards to pre-dispatch run 'pdr', the following are the three types of pre-dispatch run 'pdr' of the *pre-dispatch calculation engine*:

1.1.2.1 'pdm' is the pre-dispatch run that issued the most recent *start-up notice* or extended *pre-dispatch operational commitment* for a single *delivery point* 'm';

1.1.2.2 'pd1' is the hour-ahead pre-dispatch run in the hour preceding *settlement hour* 'h';

1.1.2.3 'pdi' is the pre-dispatch run that issued the *start up notice* for the *pre-dispatch operational commitment.*

1.1.3 In regards to operating region 'd', the following are the three types of operating regions:

a. 'd1' is the *pseudo-unit* operating region quantity for the *minimum loading point* operating region, as defined in MR Ch.7 App.7.5;

b. 'd2' is the *pseudo-unit* operating region quantity for the *dispatchable* operating region, as defined in MR Ch.7 App.7.5*;* and

c. 'd3' is the *pseudo-unit* operating region quantity for the duct firing operating region, as defined in MR Ch.7 App.7.5.

1.2 In MR Ch.9, and the appendices thereto, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

1.2.1 'M' is the set of all *delivery points* 'm';

1.2.2 'K' is the set of all *market participants* 'k';

1.2.3 'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

1.2.4 'I' is the set of all *intertie metering points* 'i';

1.2.5 'S' is the set of all *selling market participants* 's';

1.2.6 'B' is the set of all *buying market participants* 'b';

1.2.7 'V' is the set of all *virtual zonal resources* 'v';

1.2.8 'R' is the set of each applicable *class r reserve;* and

1.2.9 'H' is the set of all *settlement hours* 'h' in the *trading day.*

2 Registration and General Data and Information

2.1 The *IESO* shall provide directly to the *settlement process* any relevant registration data and any adjustments required pursuant to the *market rules,* including any as a result of a compliance and enforcement action described in MR Ch.3 s.6.

3 Day-Ahead Market Variables, Data and Information

3.1 The *IESO* shall determine the following *day-ahead market energy market prices* and scheduled *energy* quantities from the set of results from the *day-ahead market calculation engine*, unless otherwise specified, and provide them directly to the *settlement process*:

3.1.1 $DAM\_QSI_{k,h}^{i}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' for an import transaction at *intertie metering point* 'i' in *settlement hour* 'h'.

3.1.2 $DAM\_QSI_{k,h}^{m}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

3.1.3 $DAM\_QSI_{k,h}^{p}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h'.

3.1.4 $DAM\_QSI^{c}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h'.

3.1.5 $DAM\_QSI^{s}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h'.

3.1.6 $DAM\_QVSI^{v}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at *virtual zonal resource* 'v' in *settlement hour* 'h'.

3.1.7 $DAM\_QSW^{m}_{k,h}$ = quantity of *energy* scheduled (in MWh and up to 1 decimal place) for withdrawal by *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

3.1.8 $DAM\_QSW^{i}_{k,h}$ = quantity of *energy* scheduled (in MWh and up to 1 decimal place) for withdrawal by *market participant* 'k' for an export transaction at *intertie metering point* 'i' in *settlement hour* 'h'.

3.1.9 $DAM\_HDR\_\ QSW^{m}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for withdrawal by *market participant* 'k' at physical *hourly demand response resource* 'm' in *settlement hour* 'h'.

3.1.10 $DAM\_QVSW^{v}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for withdrawal by *market participant* 'k' at *virtual zonal resource* 'v' in *settlement hour* 'h'.

3.1.11 $DAM\_QSW^{d}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for withdrawal by *market participant* 'k' at *hourly demand response resource* 'd' in *settlement hour* 'h'.

3.1.12 $DAM\_QSI^{i,p1}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h', as scheduled by Pass 1: Market Commitment and Market Power Mitigation.

3.1.13 $DAM\_QSI^{i,p2}_{k,h}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h', as scheduled by Pass 2: Reliability Scheduling and Commitment.

3.1.14 $ST\_Portion^{p}_{k,d}$ = the steam turbine *resource* portion (in %) of the *energy* calculated by the applicable calculation engine as being attributed to the steam turbine *resource* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in operating region 'd'.

3.1.15 $DAM\_LMP_h^z$ = the *day-ahead market Ontario zonal price* for *energy* (in $/MWh and up to 2 decimal places) at electrical zone 'z' in *settlement hour* 'h', where the relevant electrical zone is Ontario.

3.1.16 $DAM\_LMP_h^m$ = the *day-ahead market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *delivery point* 'm' in *settlement hour* 'h'.

3.1.17 $DAM\_LMP_h^c$ = the *day-ahead market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h'.

3.1.18 $DAM\_LMP_h^s$ = the *day-ahead market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at steam turbine *resource delivery point* 's' in *settlement hour* 'h'.

3.1.19 $DAM\_LMP_h^i$ = the *day-ahead market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *intertie metering point* 'i' in *settlement hour* 'h'.

3.1.20 $DAM\_LMP_h^{vz}$ = the *day-ahead market virtual zonal price* for *energy* (in $/MWh and up to 2 decimal places) at *virtual transaction zone* 'vz' in *settlement hour* 'h'.

3.1.21 $DAM\_PEC_h^i$ = the external congestion component (in $/MWh and up to 2 decimal places) of the *day-ahead market locational marginal price* at *intertie metering point* 'i' in *settlement hour* 'h'.

3.1.22 $DAM\_PNISL_h^i$ = the net interchange scheduling limit component (in $/MWh and up to 2 decimal places) of the *day-ahead market locational marginal price* at *intertie metering point* 'i' in *settlement hour* 'h'.

3.2 The *IESO* shall, for each of the three types "r" of *class r reserves*, determine the following *day-ahead market operating reserve market prices* and scheduled *operating reserve* quantities from the set of results from the *day-ahead market calculation engine*, unless otherwise specified, and provide them directly to the *settlement process*:

3.2.1 $DAM\_QSOR_{r,k,h}^m$=scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h', where r1, r2, and r3 are all applicable.

3.2.2 $DAM\_QSOR^{i}_{r,k,h}$= scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' described in the *day-ahead schedule*, where only r2 and r3 are applicable.

3.2.3 $DAM\_QSOR^{c}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h' described in the *day-ahead schedule,* where r1, r2, and r3 are all applicable.

3.2.4 $DAM\_QSOR^{p}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h' described in the *day-ahead schedule,* where r1, r2, and r3 are all applicable.

3.2.5 $DAM\_QSOR^{s}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h' described in the *day-ahead schedule,* where r1, r2, and r3 are all applicable.

3.2.6 $DAM\_QSOR^{i,p1}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h', as scheduled by Pass 1: Market Commitment and Market Power Mitigation*,* where r1, r2, and r3 are all applicable.

3.2.7 $DAM\_QSOR^{i,p2}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h', as scheduled by Pass 2: Reliability Scheduling and Commitment*,* where r1, r2, and r3 are all applicable.

3.2.8 $DAM\_PROR^{m}_{r,h}$ = the *day-ahead market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at *delivery point* 'm' in *settlement hour* 'h', where r1, r2, and r3 are all applicable.

3.2.9 $DAM\_PROR^{c}_{r,h}$ = the *day-ahead market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h', where r1, r2, and r3 are all applicable.

3.2.10 $DAM\_PROR^{s}_{r,h}$ = the *day-ahead market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at steam turbine *resource delivery point* 's' in *settlement hour* 'h', where r1, r2, and r3 are all applicable.

3.2.11 $DAM\_PROR^{i}_{r,h}$ = the *day-ahead market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at *intertie metering point* 'i' in *settlement hour* 'h', where only r2 and r3 are applicable.

3.3 The *IESO* shall provide the following *dispatch data* directly to the *settlement process*:

3.3.1 $DAM\_BE^{m}_{k,h}$ = *energy offers* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.2 $DAM\_BE^{i}_{k,h}$ = *energy offers* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2.

3.3.3 $DAM\_BE^{p}_{k,h}$ = *energy offers* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *pseudo-unit delivery point* 'p' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place)are in column 2, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.4 $DAM\_BE\_SU^{m}_{k,h}$ = *start-up offer* submitted in the *day-ahead market* (in $/start and up to 2 decimal places) for the first *settlement hour* 'h' of the *day-ahead operational commitment* at *delivery point* 'm' for *market participant* 'k', as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.5 $DAM\_BE\_SU^{p}_{k,h}$ = *start-up offer* submitted in the *day-ahead market* (in $/start and up to 2 decimal places) for the first *settlement hour* 'h' of the *day-ahead operational commitment* at *pseudo-unit delivery point* 'p' for *market participant* 'k', as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.6 $DAM\_BE\_SU^{m}_{k,f}$ = *start-up offer* submitted in the *day-ahead market* (in $/start and up to 2 decimal places) at *delivery point* 'm' for *market participant* 'k' committed by the *day-ahead market calculation engine* for the *day-ahead operational commitment* that bridges with the *pre-dispatch operational* *commitment* that *generator failure* 'f' occurred in, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.7 $DAM\_BE\_SU^{p}_{k,f}$ = *start-up offer* submitted in the *day-ahead market* (in $/start and up to 2 decimal places) at *pseudo-unit delivery point* 'p' for *market participant* 'k' committed by the *day-ahead market calculation engine* for the *day-ahead operational commitment* that bridges with the *pre-dispatch operational commitment* that the combustion turbine *resource generator failure* 'f' occurred in, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.8 $DAM\_BE\_SNL^{m}_{k,h}$ = *speed no-load offer* submitted in the *day-ahead market* (in $/start and up to 2 decimal places), subject to pro-rata reduction based on $N^{m}_{k,h}$, for *settlement hour* 'h' at *delivery point* 'm' for *market participant* 'k', as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5, where:

$N^{m}_{k,h}$ = the number of 5-minute *metering intervals* that *market participant* 'k' was injecting *energy* at *delivery point* 'm' within the *settlement hour* 'h'.

3.3.9 $DAM\_BE\_SNL^{p}_{k,h}$ = *speed no-load offer* submitted in the *day-ahead market* (in $/start and up to 2 decimal places) for *settlement hour* 'h' at *pseudo-unit delivery point* 'p' for *market participant* 'k', as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.10 $DAM\_BL^{m}_{k,h}$ = *energy bids* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places)are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2.

3.3.11 $DAM\_BL^{i}_{k,h}$ = *energy bids* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2.

3.3.12 $DAM\_HDR\_BL^{m}_{k,h}$ = *energy bids* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at physical *hourly demand response resource* 'm' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2.

3.3.13 $DAM\_BOR^{m}_{r,k,h}$ = *class r reserve offers* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2, where r1, r2, and r3 are all applicable, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.14 $DAM\_BOR^{i}_{r,k,h}$ = *Class r reserve offers* submitted in the *day-ahead market*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2, where only r2 and r3 are applicable.

3.3.15 $DAM\_BOR^{p}_{r,k,h}$ = *Class r reserve offers* submitted in the *day-ahead market* by *market participant* 'k' for *pseudo-unit delivery point* 'p' for *settlement hour* 'h', represented as an M-by-2 matrix (where M is M^{p}_{k}) of *price-quantity pairs* arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2, where r1, r2, and r3 are all applicable, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5.

3.3.16 MLP^{m}_{k} = *minimum loading point* (in MW and up to 1 decimal place) for a *resource* at *delivery point* 'm' for *market participant* 'k'.

3.3.17 MLP^{c}_{k} = *minimum loading point* (in MW and up to 1 decimal place) for a combustion turbine *resource* at combustion turbine *resource delivery point* 'c' for *market participant* 'k'.

3.3.18 MLP^{s}_{k} = *minimum loading point* (in MW and up to 1 decimal place) for a steam turbine *resource* at steam turbine *resource delivery point* 's' for *market participant* 'k'.

3.3.19 MLP^{p}_{k} = *minimum loading point* (in MW and up to 1 decimal place) for a *pseudo-unit* at *pseudo-unit delivery point* 'p' for *market participant* 'k'.

3.4 The *IESO* shall determine the following *day-ahead market* data in accordance with the following formulations, and provide them directly to the *settlement process*:

3.4.1 $DAM\_EOP^{m}_{k,h}$ = the *day-ahead market* economic operating point of *energy* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.2 $DAM\_EOP^{i}_{k,h}$= the *day-ahead market* economic operating point of *energy* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.3 $DAM\_EOP^{p}_{k,h}$= the *day-ahead market* economic operating point of *energy* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.4 $DAM\_EOP^{c}_{k,h}$= the *day-ahead market* economic operating point of *energy* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.5 $DAM\_OR\_EOP^{i}_{r,k,h}$= the *day-ahead market* economic operating point of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h', where only r2 and r3 are applicable, and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.6 $DAM\_OR\_EOP^{s}_{r,k,h}$= the *day-ahead market* economic operating point of *class r reserve* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.7 $DAM\_OR\_EOP^{c}_{r,k,h}$= the *day-ahead market* economic operating point of *class r reserve* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' for *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.8 $DAM\_OR\_EOP^{m}_{r,k,h}$= the *day-ahead market* economic operating point of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.9 $DAM\_OR\_EOP^{p}_{r,k,h}$ = the *day-ahead market* economic operating point of *class r reserve* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.2.6.

3.4.10 $DAM\_DIPC^{c}_{k,h}$ = the *day-ahead market energy* price curve for a *non-quick start resource* for *market participant* 'k' at combustion turbine *resource* *delivery point* 'c' in *settlement hour* 'h', and determined in accordance with Appendix 9.3.

3.4.11 $DAM\_DIPC^{s}_{k,h}$ = the *day-ahead market energy* price curve for a *non-quick start resource*, for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', and determined in accordance with Appendix 9.3.

3.4.12 $DAM\_DIGQ^{s}_{k,h}$ = the portion of the *day-ahead market schedule* quantity of *energy* scheduled for injection for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', and determined in accordance with Appendix 9.3.

3.4.13 $DAM\_EOP\_DIGQ^{s}_{k,h}$ = the *day-ahead market* economic operating point of the portion of the *day-ahead market schedule* quantity of *energy* scheduled for injection for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', and determined in accordance with Appendix 9.3.

3.4.14 $DAM\_OR\_DIPC^{c}_{r,k,h}$ = the *day-ahead market class r reserve* price curve for a *non-quick start resource* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' during *settlement hour* 'h', and determined in accordance with Appendix 9.3.

3.4.15 $DAM\_OR\_DIPC^{s}_{r,k,h}$= the *day-ahead market class r reserve* price curve for a *non-quick start resource* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *settlement hour* 'h', and determined in accordance with Appendix 9.3.

3.4.16 $DAM\_STP\_QSI^{p}_{k,h}$ = the steam turbine *resource* portion of the *day-ahead schedule* of *energy* for injection (in MWh and up to 1 decimal place) for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h', and derived as the difference between $DAM\_QSI^{p}_{k,h}$ and $DAM\_QSI^{c}_{k,h}$.

4 Pre-Dispatch Variables, Data and Information

4.1 The *IESO* shall determine the following pre-dispatch *energy market prices* and scheduled *energy* quantities from the last valid set of results from the *pre-dispatch calculation engine,* unless otherwise specified*,* and provide them directly to the *settlement process*:

4.1.1 $PD\_QSI^{i}_{k,h}$ = pre-dispatch quantity of *energy* scheduled for injection (in MWh and up to 1 decimal place) by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h' by pre-dispatch run 'pd1'.

4.1.2 $PD\_QSI_{k,h}^{m,pdm}$ = pre-dispatch quantity of *energy* scheduled for injection (in MWh and up to 1 decimal place) by *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' for pre-dispatch run 'pdm'.

4.1.3 $PD\_QSI_{k,h}^{p,pdm}$ = *pre-dispatch schedule* quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by pre-dispatch run 'pdm' for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h'.

4.1.4 $PD\_QSI_{k,h}^{c,pdm}$ = *pre-dispatch schedule* quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by pre-dispatch run 'pdm' for *market participant* 'k' at combustion turbine *resource delivery point* 'p' in *settlement hour* 'h'.

4.1.5 $PD\_QSW_{k,h}^{i}$ = pre-dispatch quantity of *energy* scheduled for withdrawal (in MWh and up to 1 decimal place) by *market participant* 'k' at *intertie metering point* 'i' in *settlement hour* 'h'.

4.1.6 $PD\_LMP_{h}^{m,pd1}$=*pre-dispatch locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *delivery point* 'm' in *settlement hour* 'h' for pre-dispatch run 'pd1'.

4.1.7 $PD\_LMP_{h}^{m,pdm}$= *pre-dispatch locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *delivery point* 'm' in *settlement hour* 'h' for pre-dispatch run 'pdm'.

4.1.8 $PD\_LMP_{h}^{c,pd1}$ = pre-dispatch *locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h' for pre-dispatch run 'pd1'.

4.1.9 $PD\_LMP_{h}^{c,pdm}$ = pre-dispatch *locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h' for pre-dispatch run 'pdm'.

4.1.10 $PD\_LMP_{h}^{s,pdm}$ = pre-dispatch *locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at steam turbine *resource delivery point* 's' in *settlement hour* 'h' for pre-dispatch run 'pdm'.

4.1.11 $PD\_LMP_{h}^{i}$ = pre-dispatch *locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *intertie metering point* 'i' in *settlement hour* 'h'.

4.1.12 $PD\_IBP_{h}^{i}$ = the pre-dispatch *intertie border price* for *energy* (in $/MWh and up to 2 decimal places) at *intertie metering point* 'i' in *settlement hour* 'h'.

4.2 The *IESO* shall provide directly to the *settlement process*:

4.2.1 $PD\_BE_{k,h}^{m,pdm}$ = *energy offer* submitted in the *pre-dispatch process*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in a given pre-dispatch run 'pdm', arranged in ascending order by the *offered* price in each price-quantity pair where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2.

4.2.2 $PD\_BE_{k,h}^{p,pdm}$ = *energy offer* submitted in pre-dispatch run 'pdm' by *market participant* 'k' at *pseudo-unit delivery point* 'p' for *settlement hour* 'h', represented as an M-by-2 matrix (where M is M_{k}^{p}) of *price-quantity pairs* arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2.

4.2.3 $PD\_BE\_SU_{k,h}^{m}$ = *start-up offer* submitted in the *pre-dispatch process* (in $/start and up to 2 decimal places) for the first *settlement hour* 'h' of the *pre-dispatch operational commitment* at *delivery point* 'm' for *market participant* 'k'.

4.2.4 $PD\_BE\_SU_{k,h}^{p}$ = *start-up offer* submitted in the *pre-dispatch process* (in $/start and up to 2 decimal places) for the first *settlement hour* 'h' of the *pre-dispatch operational commitment* at *pseudo-unit* 'p' for *market participant* 'k'.

4.2.5 $PD\_BE\_SU_{k,f}^{p,pdm}$= *start-up offer* submitted in the *pre-dispatch process* (in $/start and up to 2 decimal places) at *pseudo-unit* 'p' for *market participant* 'k' for the first *settlement hour* 'h' of the *pre-dispatch operational commitment* committed by the *pre-dispatch calculation engine* in pre-dispatch run 'pdm' that the *generator failure* 'f' occurred in.

4.2.6 $PD\_BE\_SU_{k,f}^{m,pdm}$= *start-up offer* submitted in the *pre-dispatch process* (in $/start and up to 2 decimal places) at *delivery point* 'm' for *market participant* 'k' committed by the *pre-dispatch calculation engine* in pre-dispatch run 'pdm' that the *generator failure* 'f' occurred in.

4.2.7 $PD\_BE\_SNL_{k,h}^{m}$ = *speed no-load offer* submitted in the *pre-dispatch process* (in $ and up to 2 decimal places) for *settlement hour* 'h' at *delivery point* 'm' for *market participant* 'k'.

4.2.8 $PD\_BE\_SNL_{k,h}^{p}$ = *speed no-load offer* submitted in the *pre-dispatch process* (in $ and up to 2 decimal places) for *settlement hour* 'h' at *pseudo-unit delivery point* 'p' for *market participant* 'k'.

4.2.9 $PD\_BE\_SNL_{k,h}^{m,pdm}$ = *speed no-load offer* submitted in pre-dispatch run 'pdm' (in $ and up to 2 decimal places) for *settlement hour* 'h' at *delivery point* 'm' for *market participant* 'k'.

4.2.10 $PD\_BE\_SNL_{k,h}^{p,pdm}$ = *speed no-load offer* submitted in pre-dispatch run 'pdm' (in $ and up to 2 decimal places) for *settlement hour* 'h' at *pseudo-unit delivery point* 'p' for *market participant* 'k'.

4.3 The *IESO* shall determine the following pre-dispatch data in accordance with the following formulations, and provide them directly to the *settlement process*:

4.3.1 $PD\_STP\_QSI_{k,h}^{p,pdm}$ = the steam turbine *resource* portion of the *pre-dispatch schedule* of *energy* for injection (in MWh and up to 1 decimal place) from pre-dispatch run 'pdm' for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h', and derived as the difference between $PD\_QSI_{k,h}^{p,pdm}$ and $PD\_QSI_{k,h}^{c,pdm}$.

4.3.2 $PD\_DIPC_{k,h}^{c,t}$ = *generator failure* charge – guarantee cost component *energy* price curve of a *GOG-eligible resource* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', and determined in accordance with Appendix 9.3.

4.3.3 $PD\_DIPC_{k,h}^{s,t}$ = *generator failure* charge – guarantee cost component *energy* price curve of a *GOG-eligible resource* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', and determined in accordance with Appendix 9.3.

4.3.4 $PD\_DIGQ_{k,h}^{s,t}$ = the *generator failure* charge – guarantee cost component portion of the *pre-dispatch schedule* quantity of *energy* of a *GOG-eligible resource* scheduled for injection for *market participant* 'k' at *steam turbine resource* 's' during *metering interval* 't' of *settlement hour* 'h', and determined in accordance with Appendix 9.3.

5 Real-Time Market Variables, Data and Information

5.1 The *IESO* shall determine the following *real-time market energy market prices* from the set of results from the *real-time calculation engine*, unless otherwise specified, and scheduled *energy* quantities from the *real-time schedules* and provide them directly to the *settlement process*:

5.1.1 $RT\_QSI_{k,h}^{m,t}$ = quantity of *energy* scheduled for injection (in MWh and up to 1 decimal place) in the *real-time market* by *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'.

5.1.2 $RT\_QSI_{k,h}^{c,t}$ = quantity of *energy* scheduled for injection (in MWh and up to 1 decimal place) in the *real-time market* by *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h'.

5.1.3 $RT\_QSI_{k,h}^{p}$ = quantity of *energy* (in MWh and up to 1 decimal place) scheduled for injection by *market participant* 'k' at *pseudo-unit delivery point* 'p' in *settlement hour* 'h'.

5.1.4 $RT\_QSW_{k,h}^{m,t}$ = quantity of *energy* scheduled for withdrawal (in MWh and up to 1 decimal place) in the *real-time market* by *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'.

5.1.5 $ST\_Portion\_INT_{k,h,d}^{p,t}$ = the real-time steam turbine *resource* portion (in %) of the *energy* calculated by the *real-time calculation engine* as being attributed to the steam turbine *resource* in *metering interval* 't' of *settlement hour* 'h' for *market participant* 'k' at *pseudo-unit delivery point* 'p' in operating region 'd1'.

5.1.6 $SQEW_{k,h}^{i,t}$ = quantity of *energy* scheduled for withdrawal (in MWh and up to 1 decimal place) in the *real-time market* by *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', as described in the *interchange schedule*.

5.1.7 $SQEI_{k,h}^{i,t}$ = quantity of *energy* scheduled for injection (in MWh and up to 1 decimal place) in the *real-time market* by *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', as described in the *interchange schedule*.

5.1.8 $RT\_LMP_{h}^{m,t}$ = the *real-time market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'.

5.1.9 $RT\_LMP_{h}^{z}$ = the *real-time market Ontario zonal price* for *energy* (in $/MWh and up to 2 decimal places) at electrical zone 'z' in *settlement hour* 'h', where the relevant electrical zone is Ontario.

5.1.10 $RT\_LMP_{h}^{vz,t}$ = the *real-time market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *virtual transaction zone* 'vz' in *metering interval* 't' of *settlement hour* 'h'.

5.1.11 $RT\_LMP_h^{d,t}$ = the *real-time market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *hourly demand response resource* 'd' in *metering interval* 't' of *settlement hour* 'h'.

5.1.12 $RT\_LMP_h^{c,t}$ = the *real-time market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h'.

5.1.13 $RT\_LMP_h^{s,t}$ = the *real-time market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h'.

5.1.14 $RT\_LMP_h^{i,t}$ = the *real-time market locational marginal price* for *energy* (in $/MWh and up to 2 decimal places) at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.

5.1.15 $RT\_PEC_h^{i,t}$ = the *real-time market* price of external congestion component (in $/MWh and up to 2 decimal places) of the *locational marginal price* at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.

5.1.16 $RT\_PNISL_h^{i,t}$ = the *real-time market* price of the net interchange scheduling limit component (in $/MWh and up to 2 decimal places) of the *locational marginal price* at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.

5.1.17 $RT\_IBP_h^{i,t}$ = the *real-time market intertie border price* for *energy* (in $/MWh and up to 2 decimal places) at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.

5.2 The *IESO* shall provide the following *dispatch data* directly to the *settlement process*:

5.2.1 $BE_{k,h}^{m,t}$ = *energy offers* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *delivery point* 'm' for *market participant* 'k' for *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5A.

5.2.2 $BE_{k,h}^{i,t}$ = *energy offers* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *intertie metering point* 'i' for *market participant* 'k' for *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices ‘P’ (in $ and up to 2 decimal places) are in column 1 and *offered* quantities ‘Q’ (in MWh and up to 1 decimal place) are in column 2.

5.2.3 $BE_{k,h}^{p,t}$ = *energy offers* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *pseudo-unit delivery point* ‘p’ for *market participant* ‘k’ for *metering interval* ‘t’ of *settlement hour* ‘h’, arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices ‘P’ (in $ and up to 2 decimal places) are in column 1 and *offered* quantities ‘Q’ (in MWh and up to 1 decimal place) are in column 2, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5A.

5.2.4 $BL_{k,h}^{m,t}$ = *energy bids* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *delivery point* ‘m’ for *market participant* ‘k’ for *metering interval* ‘t’ of *settlement hour* ‘h’, arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices ‘P’ (in $ and up to 2 decimal places) are in column 1 and *offered* quantities ‘Q’ (in MWh and up to 1 decimal place) are in column 2.

5.2.5 $BL_{k,h}^{i,t}$ = *energy bids* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *intertie metering point* ‘i’ for *market participant* ‘k’ for *metering interval* ‘t’ of *settlement hour* ‘h’, arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices ‘P’ (in $ and up to 2 decimal places) are in column 1 and *offered* quantities ‘Q’ (in MWh and up to 1 decimal place) are in column 2.

5.2.6 $BOR_{r,k,h}^{m,t}$ = *class r reserve offers* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *delivery point* ‘m’ for *market participant* ‘k’ for *metering interval* ‘t’ of *settlement hour* ‘h’, arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices ‘P’ (in $ and up to 2 decimal places) are in column 1 and *offered* quantities ‘Q’ (in MWh and up to 1 decimal place) are in column 2, where r1, r2, and r3 are all applicable, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5A.

5.2.7 $BOR_{r,k,h}^{i,t}$ = *class r reserve offers* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *intertie metering point* ‘i’ for *market participant* ‘k’ for *metering interval* ‘t’ of *settlement hour* ‘h’, arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices ‘P’ (in $ and up to 2 decimal places) are in column 1 and *offered* quantities ‘Q’ (in MWh and up to 1 decimal place) are in column 2, where only r2 and r3 are applicable.

5.2.8 $BOR_{r,k,h}^{p,t}$ = *class r reserve offers* submitted in the *real-time market*, represented as an N-by-2 matrix of *price-quantity pairs* at *pseudo-unit* *delivery point* 'p' for *market participant* 'k' for *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' (in $ and up to 2 decimal places) are in column 1 and *offered* quantities 'Q' (in MWh and up to 1 decimal place) are in column 2, where r1, r2, and r3 are all applicable, as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5A.

5.2.9 $RT\_GOG\_SU^{m}_{k,h}$ = *start-up offer* submitted in the *real-time market* (in $/start and up to 2 decimal places) for the real-time *generator offer* guarantee *settlement amount*, at *delivery point* 'm' for *market participant* 'k' in *settlement hour* 'h', as may be replaced by the *IESO* pursuant to MR Ch.7 App.7.5A.

5.3 The *IESO* shall, for each of the three types "r" of *class r reserves,* determine the following *real-time market operating reserve market prices* from the set of results from the *real-time calculation engine*, unless otherwise specified, and scheduled *operating reserve* quantities from the *real-time schedules* and provide them directly to the *settlement process*:

5.3.1 $RT\_PROR^{m,t}_{r,h}$ = the *real-time market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.2 $RT\_PROR^{c,t}_{r,h}$ = the *real-time market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.3 $RT\_PROR^{s,t}_{r,h}$ = the *real-time market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.4 $RT\_PROR^{i,t}_{r,h}$ = the *real-time market locational marginal price* (in $/MWh and up to 2 decimal places) of *class r reserve* at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', where only r2 and r3 are applicable.

5.3.5 $RT\_QSOR^{m,t}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* in the *real-time market* at *delivery point* 'm' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.6 $RT\_QSOR^{c,t}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* in the *real-time market* at combustion turbine *resource delivery point* 'm' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.7 $RT\_QSOR^{s,t}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* in the *real-time market* at steam turbine *resource delivery point* 's' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.8 $RT\_QSOR^{p,t}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* in the *real-time market* at *pseudo-unit delivery point* 'p' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable.

5.3.9 $RT\_QSOR^{i,t}_{r,k,h}$ = scheduled quantity (in MWh and up to 1 decimal place) of *class r reserve* in the *real-time market* at *intertie metering point* 'i' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h' as described in the *interchange schedule*, where only r2 and r3 are applicable.

5.4 The *IESO* shall determine the following *real-time market* data in accordance with the following formulations, and provide them directly to the *settlement process*:

5.4.1 $RT\_LC\_EOP^{m,t}_{k,h}$ = the *real-time market* lost cost economic operating point of *energy* for *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.2 $RT\_LC\_EOP^{i,t}_{k,h}$ = the *real-time market* lost cost economic operating point of *energy* for *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.3 $RT\_LC\_EOP^{p,t}_{k,h}$ = the *real-time market* lost cost economic operating point of *energy* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.4 $RT\_LC\_EOP^{c,t}_{k,h}$ = the *real-time market* lost cost economic operating point of *energy* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.5 $RT\_LOC\_EOP_{k,h}^{m,t}$ = the *real-time market* lost opportunity cost economic operating point of *energy* for *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.6 $RT\_LOC\_EOP_{k,h}^{p,t}$ = the *real-time market* lost opportunity cost economic operating point of *energy* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.7 $RT\_LOC\_EOP_{k,h}^{i,t}$ = the *real-time market* lost opportunity cost economic operating point of *energy* for *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.8 $RT\_LOC\_EOP_{k,h}^{c,t}$ = the *real-time market* lost opportunity cost economic operating point of *energy* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.8 $RT\_OR\_LC\_EOP_{r,k,h}^{m,t}$ = the *real-time market* lost cost economic operating point of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.9 $RT\_OR\_LC\_EOP_{r,k,h}^{p,t}$ = the *real-time market* lost cost economic operating point of *class r reserve* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.10 $RT\_OR\_LC\_EOP_{r,k,h}^{i,t}$ = the *real-time market* lost cost economic operating point of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', where only r2 and r3 are applicable, and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.11 $RT\_OR\_LC\_EOP_{r,k,h}^{c,t}$ = the *real-time market* lost cost economic operating point of *class r reserve* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.12 $RT\_OR\_LC\_EOP_{r,k,h}^{s,t}$ = the *real-time market* lost cost economic operating point of *class r reserve* for *market participant* 'k' at steam turbine *resource delivery* *point* 's' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.3.5.

5.4.13 $RT\_OR\_LOC\_EOP_{r,k,h}^{m,t}$ = the *real-time market* lost opportunity cost economic operating point of *class r reserve* for *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.14 $RT\_OR\_LOC\_EOP_{r,k,h}^{i,t}$ = the *real-time market* lost opportunity cost economic operating point of *class r reserve* for *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', where only r2 and r3 are applicable, and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.15 $RT\_OR\_LOC\_EOP_{r,k,h}^{c,t}$ = the *real-time market* lost opportunity cost economic operating point of *class r reserve* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.16 $RT\_OR\_LOC\_EOP_{r,k,h}^{s,t}$ = the *real-time market* lost opportunity cost economic operating point of *class r reserve* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', where r1, r2, and r3 are all applicable, and determined in accordance with MR Ch.7 App.7.8 s.4.5.

5.4.17 $RT\_STP\_QSI_{k,h}^{p,t}$ = the steam turbine *resource* portion of the *real-time schedule* of *energy* for injection (in MWh and up to 1 decimal place) for *market participant* 'k' at *pseudo-unit delivery point* 'p' in *metering interval* 't' of *settlement hour* 'h', and derived as the difference between $RT\_QSI_{k,h}^{p,t}$ and $RT\_QSI_{k,h}^{c,t}$.

5.4.18 $RT\_STP\_QSOR_{r,k,h}^{p,t}$ = the steam turbine *resource* portion of the *real-time schedule* of *class r reserve* (in MWh and up to 1 decimal place) for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', and derived as the difference between $RT\_QSOR_{r,k,h}^{p,t}$ and $RT\_QSOR_{r,k,h}^{c,t}$.

5.4.19 $PB\_IM_{h}^{t}$ = the price bias adjustment factor (in up to 2 decimal places) for import transactions in effect for *metering interval* 't' of *settlement hour* 'h', as *published* by the *IESO* in accordance with MR Ch.9 s.3.7.2.

5.4.20 $PB\_EX_{h}^{t}$ = the price bias adjustment factor (in up to 2 decimal places) for export transactions in effect for *metering interval* 't' of *settlement hour* 'h', as *published* by the *IESO* in accordance with MR Ch.9 s.3.7.2.

5.4.21 $RT\_DIPC_{k,h}^{c,t}$ = the *real-time market energy* price curve for a *non-quick start resource* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.22 $RT\_DIPC_{k,h}^{s,t}$ = the *real-time market energy* price curve for a *non-quick start resource* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.23 $RT\_CMT\_DIPC_{k,h}^{s,t}$ = the *real-time market energy* price curve of a *non-quick start resource* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.24 $RT\_QSI\_DIGQ_{k,h}^{s,t}$ = the portion of the *real-time schedule* quantity of *energy* scheduled for injection for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.25 $RT\_CMT\_DIGQ_{k,h}^{s,t}$ = the portion of the *real-time schedule* quantity of *energy* scheduled for injection that is eligible for the real-time *generator offer* guarantee *settlement amount* for the steam turbine *resource* that is associated with the *pseudo-unit* that was operationally constrained by the *pre-dispatch calculation engine* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.26 $RT\_LC\_EOP\_DIGQ_{k,h}^{s,t}$ = the portion of the steam turbine *resource*'s $RT\_LC\_EOP_{k,h}^{p,t}$ that is eligible for the real-time make-whole payment *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.27 $RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t}$ = the portion of the steam turbine *resource*'s $RT\_LOC\_EOP_{k,h}^{p,t}$ that is eligible for the real-time make-whole payment *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.28 $RT\_OR\_DIPC^{c,t}_{r,k,h}$ = *real-time market class r reserve* price curve for a *non-quick start resource* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

5.4.29 $RT\_OR\_DIPC^{s,t}_{r,k,h}$ = the *real-time market class r reserve* price curve for a *non-quick start resource* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h' as determined in accordance with Appendix 9.3.

5.4.30 $RT\_OR\_CMT\_DIPC^{s,t}_{r,k,h}$ = the *real-time market class r reserve* price curve of a steam turbine *resource* that is associated with the *pseudo-unit* that was operationally constrained by the *pre-dispatch calculation engine* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h' as determined in accordance with Appendix 9.3.

5.4.31 $RT\_OR\_CMT\_DIGQ^{s,t}_{r,k,h}$ = the portion of the *real-time schedule* quantity of *class r reserve* scheduled for injection that is eligible for the real-time *generator offer* guarantee *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with Appendix 9.3.

6 Physical Bilateral Contract Variables, Data and Information

6.1 *Physical bilateral contract quantities* shall be determined for each *settlement hour* by the *IESO* using *physical bilateral contract data* submitted by *selling market participant*s and, where so required by the nature of the *physical bilateral contract data*, operating results. The *IESO* shall divide each hourly *physical bilateral contract quantity* into equal *physical bilateral contract quantities* if determination of *settlement amounts* requires quantities for each *metering interval* of each *settlement hour*. The *IESO* shall provide the following variables and data directly to the *settlement process*:

6.1.1 $DAM\_BCQ^{m}_{s,k,h}$ = *physical bilateral contract quantity* of *energy* in the *day-ahead market* (in MWh) bought by *buying market participant* 'k' from *selling market participant* 's' at *delivery point* 'm' in *settlement hour* 'h'.

6.1.2 $DAM\_BCQ^{m}_{k,b,h}$ = *physical bilateral contract quantity* of *energy* in the *day-ahead market* (in MWh) sold by *selling market participant* 'k' to *buying market participant* 'b' at *delivery point* 'm' in *settlement hour* 'h'.

6.1.3 $DAM\_BCQ^{i}_{s,k,h}$ = *physical bilateral contract quantity* of *energy* in the *day-ahead market* (in MWh) bought by *buying market participant* 'k' from *selling market participant* 's' at *intertie metering point* 'i' in *settlement hour* 'h'.

6.1.4 $DAM\_BCQ^{i}_{k,b,h}$ = *physical bilateral contract quantity* of *energy* in the *day-ahead market* (in MWh) sold by *selling market participant* 'k' to *buying market participant* 'b' at *intertie metering point* 'i' in *settlement hour* 'h'.

6.1.5 $BCQ^{m,t}_{s,k,h}$ = *physical bilateral contract quantity* of *energy* in the *real-time market* (in MWh) bought by *buying market participant* 'k' from *selling market participant* 's' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'.

6.1.6 $BCQ^{m,t}_{k,b,h}$ = *physical bilateral contract quantity* of *energy* in the *real-time market* (in MWh) sold by *selling market participant* 'k' to *buying market participant* 'b' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'.

6.1.7 $BCQ^{i,t}_{s,k,h}$ = *physical bilateral contract quantity* of *energy* in the *real-time market* (in MWh) bought by *buying market participant* 'k' from *selling market participant* 's' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.

6.1.8 $BCQ^{i,t}_{k,b,h}$ = *physical bilateral contract quantity* of *energy* in the *real-time market* (in MWh) sold by *selling market participant* 'k' to *buying market participant* 'b' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'.

6.1.9 $RQ^{m,i,t}_{k,h}$ = the net sum of any *day-ahead market* and *real-time market physical bilateral contract quantities* of *energy*, indicated in all relevant *physical bilateral contract data* in which the transfer of the *hourly uplift settlement amount* has been agreed to between the *selling market participant* and the *buying market participant*, for *market participant* 'k' at *delivery point* 'm' and *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h', and derived as follows:

$$RQ^{m,i,t}_{k,h} = \left[\sum_{B} \frac{DAM\_BCQ^{m,i}_{k,b,h}}{12} - \sum_{S} \frac{DAM\_BCQ^{m,i}_{s,k,h}}{12} + \sum_{B} BCQ^{m,i,t}_{k,b,h} - \sum_{S} BCQ^{m,i,t}_{s,k,h}\right]$$

7 Transmission Rights Variables, Data and Information

7.1 The *IESO* shall provide the following *TR* data directly to the *settlement process*:

7.1.1 $QTR^{iz,jz}_{k,h}$ = quantity of *transmission rights* (in MW and whole numbers) assigned to *market participant* 'k' for transmission from injection *TR zone* 'iz' to withdrawal *TR zone* 'jz' for *settlement hour* 'h'.

8 Allocated Quantities

8.1 The *IESO* shall determine the following allocated physical quantities for each *market participant* for each primary *registered wholesale meter* and each *intertie metering point* using *metering data*, operating results and *interchange schedule* data. If physical quantities are provided only for each *settlement hour* (as they may be for *interchange schedules*, *non-dispatchable loads, non-dispatchable generation resources*, and *self-scheduling electricity storage facilities*), the *IESO* shall, if necessary for *settlement* purposes, determine the interval amounts defined below by dividing the hourly amounts into twelve equal interval amounts. If physical quantities are provided only for each *metering interval,* the *IESO* shall, if for *settlement* purposes the *IESO* is comparing hourly and interval data, determine the hourly amounts defined below by multiplying the interval amounts by twelve:

8.1.1 $AQEI_{k,h}^{m,t}$ = allocated quantity (in MWh and up to 3 decimal places) of *energy* injected by *market participant* 'k' at primary *registered wholesale meter* 'm' in *metering interval* 't' of *settlement hour* 'h'.

8.1.2 $AQEI_{k,h}^{c,t}$ = allocated quantity (in MWh and up to 3 decimal places) of *energy* injected by *market participant* 'k' at combustion turbine *resource* primary *registered wholesale meter* 'c' in *metering interval* 't' of *settlement hour* 'h'.

8.1.3 $AQEI_{k,h}^{s,t}$ = allocated quantity (in MWh and up to 3 decimal places) of *energy* injected by *market participant* 'k' at steam turbine *resource* primary *registered wholesale meter* 's' in *metering interval* 't' of *settlement hour* 'h'.

8.1.4 $AQEW_{k,h}^{m,t}$ = allocated quantity (in MWh and up to 3 decimal places) of *energy* withdrawn by *market participant* 'k' at primary *registered wholesale meter* 'm' in *metering interval* 't' of *settlement hour* 'h'.

8.1.5 $AQOR_{r,k,h}^{m,t}$ = allocated quantity (in MW) of *class r reserve* for *market participant* 'k' at primary *registered wholesale meter* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'.

8.1.6 $GSSR\_AQEW_{k,h}^{m,t}$ = qualified allocated quantity (in MWh) of *energy* withdrawn by *market participant* 'k' at *registered wholesale meter* 'm' in *metering interval* 't' of *settlement hour* 'h' by an eligible *generation resource*.

9 Market Power Mitigation

9.1 The *IESO* shall determine the following market power mitigation data in accordance with Appendix 9.4 and provide them directly to the *settlement process*:

9.1.1 $EMFC\_DAM\_BE_{k,h}^{m}$ = enhanced mitigated for conduct *offer* for *energy* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.2 $EMFC\_DAM\_BOR_{r,k,h}^{m}$ = enhanced mitigated for conduct *offer* for *class r reserve* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.3 $EMFC\_DAM\_BE\_SU_{k,h}^{m}$ = enhanced mitigated for conduct *start-up offer* in the *day-ahead market* for the *thermal state* indicated in the *dispatch data* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.4 $EMFC\_DAM\_SNL_{k,h}^{m}$ = enhanced mitigated for conduct *speed no-load offer* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.5 $EMFC\_RT\_BE_{k,h}^{m}$ = enhanced mitigated for conduct *offer* for *energy* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.6 $EMFC\_RT\_BOR_{r,k,h}^{m}$ = enhanced mitigated for conduct *offer* for *class r reserve* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.7 $EMFC\_RT\_SU_{k,h}^{m}$ = enhanced mitigated for conduct *start-up offer* in the *real-time market* for the *thermal state* determined in accordance with section 2.12.2 for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.8 $EMFC\_RT\_SNL_{k,h}^{m}$ = enhanced mitigated for conduct *speed-no-load offer* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h'.

9.1.9 $DAM\_RLL_{k,h}^{m}$ = is the *day-ahead market energy offer reference level value* based on the *resource's* lower cost profile for *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', as set by the *IESO* pursuant to MR. Ch. 7 s. 22.5.8.

9.1.10 $DAM\_RLH_{k,h}^{m}$ is the *day-ahead market energy offer reference level value* based on the *resource's* higher cost profile for *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', as set by the *IESO* pursuant to MR. Ch. 7 s. 22.5.8.

9.1.11 $RT\_RLL_{k,h}^{m}$ is the *real-time market energy offer reference level value* based on the *resource's* lower cost profile for *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', as set by the *IESO* pursuant to MR. Ch. 7 s. 22.5.8.

9.1.12 $RT\_RLH_{k,h}^{m}$ is the *real-time market energy offer reference level value* based on the *resource's* higher cost profile for *market participant* 'k' at *delivery point* 'm' of *settlement hour* 'h', as set by the *IESO* pursuant to MR. Ch. 7 s. 22.5.8.

10 Mathematical Functions

10.1 The *IESO* shall utilize the following mathematical functions as directed in this MR Ch.9:

10.1.1 The following is the operating profit function:

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an N-by-2 matrix (B) of *price-quantity pairs*:

$$\mathrm{OP(P,Q,B)} = \mathrm{P} \cdot \mathrm{Q} - \sum_{n=1}^{s^*} \mathrm{P_n} \cdot (\mathrm{Q_n} - \mathrm{Q_{n-1}}) - (\mathrm{Q} - \mathrm{Q_{s^*}}) \cdot \mathrm{P_{s^*+1}}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$\mathrm{OP(P,Q,B)} = \mathrm{P} \cdot \mathrm{Q} - \sum_{n=1}^{s^*} [\mathrm{B}[n,1] \cdot (\mathrm{B}[n,2] - \mathrm{B}[n-1,2])] - [(\mathrm{Q} - \mathrm{B}[s^*,2]) \cdot \mathrm{B}[s^*+1,1]]$$

Where:

(a) s* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$; and
(b) Q_0=0

10.1.2 In MR Ch.9 and its appendices any function within an equation that is structured as OP(x,y,z) where x, y, and z are variables or equations, shall be a reference to the operating profit function specified in this section 10.1, where x is P, y is Q and z is B.

11 Capacity Auction

11.1 The *IESO* shall provide the following *capacity auction* information directly to the *settlement process*:

11.1.1 $CACP^{z}$ = the *capacity auction clearing price* (in $/MW per day) for the relevant *trading day* in electrical zone 'z'.

11.1.2 $CACP^{z}_{h}$ = the *capacity auction clearing price* for *settlement hour* 'h' (in $/MW per hour) within the *availability window* in electrical zone 'z', determined by taking the *capacity auction clearing price* for the applicable *obligation period* and electrical zone and dividing by the number of *settlement hours* within the *availability window* of all *trading days* within the *obligation period.*

11.1.3 $CAEO^{m}_{k,h}$ = the quantity of *auction capacity* for *settlement hour* 'h' (in MW) made available by *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* of the *availability window* determined as the lesser of the *resource's energy offers* submitted in the *day-ahead market*, *pre-dispatch process*, and *real-time market*, as applicable.

11.1.4 $CARC_{k}^{m}$ = the quantity of *energy* (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant* 'k' at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual;*

11.1.5 $CBOC^{m}_{k}$ = the buy-out capacity is an amount (in MW) by which the *capacity obligation* for the *obligation period* for a *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' is being reduced as per the *capacity market participant's* election pursuant to MR Ch.9 s.4.13.9.

11.1.6 $CCO^{m}_{k,h}$ = the *capacity obligation* (in MW) for the *obligation period* per *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* 'h', as may be adjusted pursuant to the *market rules*.

11.1.7 $CICAP^{m}_{k}$ = the *cleared ICAP* (in MW) for *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, as determined in accordance with the applicable *market manual*.

11.1.8 $CNPF_{tm}$ = for a given *energy market billing period* 'tm' within the relevant *obligation period*, the non-performance factor as listed in the applicable *market manual*.

11.1.9 $DREBQ^{m}_{k,h}$ = the quantity (in MW) of *auction capacity* made available by an *hourly demand response resource* or *capacity dispatchable load resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' of the *availability window*, determined as the lesser of the *resource's energy bids* submitted in the *day-ahead market*, *pre-dispatch process*, and *real-time market*, as applicable, and where such value exceeds the $CARC_{k}^{m}$ for the *resource* in the relevant *energy market billing period*, the $DREBQ^{m}_{k,h}$ shall equal such $CARC_{k}^{m}$.

11.1.10 $DRSQty^{m}_{k,h}$ = the quantity of *energy* (in MW) scheduled for withdrawal in the *real-time market* by *market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' of the *availability window*, as described in all *real-time schedules* for such *settlement hour.*

11.1.11 $HDRBP^{m}_{k,h}$ = the price component (in $) of the *energy bid* submitted in the *real-time market* for *hourly demand response resource* by *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' within the *availability window.*

11.1.12 $HDRDC^{m}_{k,h}$= the delivered capacity (in MWh) by *hourly demand response resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' within the *activation window* of the applicable test activation, calculated as follows:

$$\mathrm{Min}(\mathrm{Curtailed\ MW}^{m}{}_{k,h}\,, \sum_{t=1}^{12}(\frac{\mathrm{Min}(\mathrm{TBQ}^{m}{}_{k,h}, \mathrm{CARC}_{k^{m}}, \mathrm{CCO}^{m}{}_{k,\mathrm{h}})) - DQSW_{k,h}^{m,t}}{12}))$$

Where:

(a) "Curtailed $MW^{m}_{k,h}$" is the difference (in MWh) between baseline value, calculated in accordance with the applicable *market manual*, and actual consumption measurement data by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as calculated in accordance with the applicable *market manual*.

(b) "$TBQ^{m}_{k,h}$" is the offered quantity of *energy* (in MW) contained in the last lamination of the *price quantity pair* of the *energy bid* submitted in the *real-time market* by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h'.

11.1.13 HDRTAPR = the out of market test activation rate (in $/MWh), as set out in the applicable *market manual.*

11.1.14 $OCMW^{i}_{k}$ = the *over committed capacity* (in MW) of a *generator-backed capacity import resource* for *capacity market participant* 'k' at *intertie metering point* 'i', as determined by the *IESO* in accordance with MR. Ch.9 s.4.13.7.1.

11.1.15 RAC^{m}_{k} = the available capacity (in MW) of a *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, and is determined in accordance with the following:

(a) For *capacity dispatchable load resources* and *hourly demand response resources*:

$$RAC^{m}_{k} = MIN(DREBQ^{m}_{k,h}, (1.15 * CCO^{m}_{k,h}), CICAP^{m}_{k}, CARC_{k}^{m})$$

Where:

(i) $CARC_{k}^{m}$ is only applicable to virtual *hourly demand response resources*

(b) For *capacity generation resources*, *system-backed capacity import resources*, *generator-backed capacity import resources* and *capacity storage resources*:

$$RAC^{m}_{k} = MIN(CAEO^{m}_{h,k}, (1.15 * CCO^{m}_{k,h}), CICAP^{m}_{k})$$

Appendix 9.3 – Pseudo-Unit Translation

1.1 Introduction/General

1.1.1 In this Appendix 9.3, the following variables have the following meanings:

1.1.1.1 M_k^p = the maximum number of *price-quantity pairs* in an *energy offer* or *operating reserve offer,* as the case may be, that may be submitted by *market participant* 'k' in the *day-ahead market*, *pre-dispatch process*, and *real-time market* at *pseudo-unit delivery point* 'p'. For *energy offers* it is set equal to 20 divided by the number of combustion turbine *resource*s and rounded down to the nearest whole number. For *operating reserve offers* it is set equal to 5*;* and

1.1.1.2 N_k^s = the number of combustion turbine *resource delivery points* registered as associated with steam turbine *resource delivery point* 's' for *market participant* 'k'.

1.2 Day-Ahead Market – Energy

1.2.1 The *IESO* shall determine the following *day-ahead market* data in accordance with the following formulations*,* and provide them directly to the *settlement process*:

Intermediate Variables

1.2.1.1 $DAM\_ORRQ_{k,d}^p$ = the *day-ahead market* operating region range quantity, which is the *pseudo-unit* operating region quantity of *energy* (in MW) calculated by the *day-ahead market calculation engine* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in operating region 'd', where 'd1', 'd2', and 'd3' are all applicable.

1.2.1.2 $DAM\_CRRQ_k^p$ = the *day-ahead market* collapsed region range quantity, which is the portion of the *pseudo-unit* operating region quantity of *energy* (in MW) calculated by the *day-ahead market calculation engine* at *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1' and *dispatchable* operating region 'd2' before any de-ratings are applied for *market participant* 'k', and is derived as follows:

$$DAM\_CRRQ_k^p = DAM\_ORRQ_{k,d1}^p + DAM\_ORRQ_{k,d2}^p$$

1.2.1.3 $DAM\_MRRQ^{p}_{k,h}$ = the *day-ahead market minimum loading point* region range quantity (in MW), which is the portion of the greater of the $DAM\_QSI^{p}_{k,h}$ and $DAM\_EOP^{p}_{k,h}$ associated with *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1' for *pseudo-unit delivery point* 'p' for *market participant* 'k' in *settlement hour* 'h', and is derived as follows:

$$DAM\_MRRQ^{p}_{k,h} = Min\left(DAM\_ORRQ^{p}_{k,d1}, Max\left(DAM\_QSI^{p}_{k,h}, DAM\_EOP^{p}_{k,h}\right)\right)$$

1.2.1.4 $DAM\_DRRQ^{p}_{k,h}$ = the *day-ahead market dispatchable* region range quantity (in MW), which is the portion of the greater of the $DAM_QSI^{c}_{k,h}$and $DAM\_EOP^{c}_{k,h}$ associated with *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1' and *dispatchable* operating region 'd2' for *market participant* 'k' in *settlement hour* 'h', and is derived as follows:

$$DAM\_DRRQ^{p}_{k,h} = Min\left(DAM\_CRRQ^{p}_{k}, DAM\_MRRQ^{p}_{k,h} + \frac{Max\left(0, Max\left(DAM\_QSI^{c}_{k,h}, DAM\_EOP^{c}_{k,h}\right) - MLP^{c}_{k}\right)}{\left(1 - ST\_Portion^{p}_{k,d2}\right)}\right)$$

Where:

a. 'c' is the combustion turbine *resource delivery point* associated with *pseudo-unit delivery point* 'p'.

1.2.1.5 $DAM\_DFRRQ^{p}_{k,h}$ = the *day-ahead market* duct firing region range quantity (in MW), which is the portion of the greater of the $DAM\_QSI^{p}_{k,h}$ and $DAM\_EOP^{p}_{k,h}$ associated with *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1', *dispatchable* operating region 'd2', and duct firing operating region 'd3' of the *pseudo-unit* for *market participant* 'k' in *settlement hour* 'h', and is derived as follows:

$$DAM\_DFRRQ^{p}_{k,h} = Min\left(DAM\_ORRQ^{p}_{k,d1} + DAM\_ORRQ^{p}_{k,d2} + DAM\_ORRQ^{p}_{k,d3}, Max\left(Max\left(DAM\_QSI^{p}_{k,h}, DAM\_EOP^{p}_{k,h}\right) + DAM\_CRRQ^{p}_{k} - DAM\_DRRQ^{p}_{k,h}, DAM\_CRRQ^{p}_{k}\right)\right)$$

1.2.1.6 $DAM\_ST\_Q^{p}_{k,h}$ = an M-by-1 matrix (where M is M^{p}_{k}) of steam turbine *resource* quantity values (in MW), calculated from the $DAM\_BE^{p}_{k,h}$ and

$ST\_Portion_{k,d}^{p}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *settlement hour* 'h', and is derived as follows:

Scenario	Domain	$DAM\_ST\_Q_{k,h}^{p}$
1	$0 < DAM\_BE[i,2]_{k,h}^{p} \leq DAM\_MRRQ_{k,h}^{p}$	$DAM\_BE[i,2]_{k,h}^{p} \times ST\_Portion_{k,d1}^{p}$
2	$DAM\_MRRQ_{k,h}^{p} < DAM\_BE[i,2]_{k,h}^{p} \leq DAM\_DRRQ_{k,h}^{p}$	$DAM\_MRRQ_{k,h}^{p} \times ST\_Portion_{k,d1}^{p} + (DAM\_BE[i,2]_{k,h}^{p} - DAM\_MRRQ_{k,h}^{p}) \times ST\_Portion_{k,d2}^{p}$
3	$DAM\_DRRQ_{k,h}^{p} < DAM\_BE[i,2]_{k,h}^{p} \leq CRRQ_{k}^{p}$	$DAM\_MRRQ_{k,h}^{p} \times ST\_Portion_{k,d1}^{p} + (DAM\_DRRQ_{k,h}^{p} - DAM\_MRRQ_{k,h}^{p}) \times ST\_Portion_{k,d2}^{p}$
4	$CRRQ_{k}^{p} < DAM\_BE[i,2]_{k,h}^{p} \leq DAM\_DFRRQ_{k,h}^{p}$	$DAM\_MRRQ_{k,h}^{p} \times ST\_Portion_{k,d1}^{p} + (DAM\_DRRQ_{k,h}^{p} - DAM\_MRRQ_{k,h}^{p}) \times ST\_Portion_{k,d2}^{p} + (DAM\_BE[i,2]_{k,h}^{p} - CRRQ_{k}^{p}) \times ST\_Portion_{k,d3}^{p}$
5	$DAM\_DFRRQ_{k,h}^{p} < DAM\_BE[i,2]_{k,h}^{p}$	$DAM\_MRRQ_{k,h}^{p} \times ST\_Portion_{k,d1}^{p} + (DAM\_DRRQ_{k,h}^{p} - DAM\_MRRQ_{k,h}^{p}) \times ST\_Portion_{k,d2}^{p} + (DAM\_DFRRQ_{k,h}^{p} - CRRQ_{k}^{p}) \times ST\_Portion_{k,d3}^{p}$

or simplified as:

$$
\begin{aligned}
DAM\_ST\_Q[i]_{k,h}^{p} \\
&= Min(DAM\_MRRQ_{k,h}^{p}, DAM\_BE[i,2]_{k,h}^{p}) \times ST\_Portion_{k,d1}^{p} \\
&+ Max(0, Min(DAM\_DRRQ_{k,h}^{p}, DAM\_BE[i,2]_{k,h}^{p}) \\
&- DAM\_MRRQ_{k,h}^{p}) \times ST\_Portion_{k,d2}^{p} \\
&+ Max(0, Min(DAM\_DFRRQ_{k,h}^{p}, DAM\_BE[i,2]_{k,h}^{p}) - DAM\_CRRQ_{k}^{p}) \\
&\times ST\_Portion_{k,d3}^{p}
\end{aligned}
$$

1.2.1.7 $DAM\_ST\_PC_{k,h}^{p}$ = an M-by-2 matrix (where M is M_{k}^{p}) of *price-quantity pairs* representing the incremental quantity of *energy* at each price for each *pseudo-unit*, calculated from the price component of $DAM\_BE_{k,h}^{p}$ and the quantity component of $DAM\_ST\_Q_{k,h}^{p}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix	=	Price [Row 'i', Column 1)	Quantity [Row 'i', Column 2]
$DAM\_ST\_PC^{p}_{k,h}$	Row i = 1	$DAM\_BE[i,1]^{p}_{k,h}$	0
	Row i ≥ 2	$DAM\_BE[i,1]^{p}_{k,h}$	$DAM\_ST\_Q[i]^{p}_{k,h} - DAM\_ST\_Q[i-1]^{p}_{k,h}$

1.2.1.8 $DAM\_ST\_PC^{s}_{k,h}$ = a Y-by-2 matrix (where $Y \leq \sum_{p=1}^{N} M^{p}_{k}$) of *price-quantity pairs* calculated from the price component and the quantity component from all the calculated $DAM\_ST\_PC^{p}_{k,h}$ for *market participant* 'k' associated with steam turbine *resource delivery point* 's' during *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DAM\_ST\_PC^{s}_{k,h}$	Rows i=1 to m1, j=1 to m1	$DAM\_ST\_PC[j,1]^{p1}_{k,h}$	$DAM\_ST\_PC[j,2]^{p1}_{k,h}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$DAM\_ST\_PC[j,1]^{p2}_{k,h}$	$DAM\_ST\_PC[j,2]^{p2}_{k,h}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$DAM\_ST\_PC[j,1]^{p3}_{k,h}$	$DAM\_ST\_PC[j,2]^{p3}_{k,h}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$DAM\_ST\_PC[j,1]^{p4}_{k,h}$	$DAM\_ST\_PC[j,2]^{p4}_{k,h}$

Where:

a. For a *pseudo-unit* to be included in the $DAM\_ST\_PC^{s}_{k,h}$ matrix, for the relevant *settlement hour*:

   i. it must not have *offered* in the *day-ahead market* in *single cycle mode*; and

   ii. the associated combustion turbine *resource* must have received a *day-ahead schedule* greater than or equal to its *minimum loading point.*

b. $DAM\_ST\_PC^{s}_{k,h}$ matrix will be modified in the following order:

   i. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair*;

   ii. any *price-quantity pairs* with a zero quantity shall be removed from the $DAM\_ST\_PC^{s}_{k,h}$ matrix;

iii. the *price-quantity pairs* shall be sorted by increasing price; and

iv. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The inserted *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2.

c. m1 is the number of rows in $DAM\_ST\_PC^{p}_{k,h}$ from *PSU1.*

d. m2 is the number of rows in $DAM\_ST\_PC^{p}_{k,h}$ from *PSU2.*

e. m3 is the number of rows in $DAM\_ST\_PC^{p}_{k,h}$ from *PSU3.*

f. m4 is the number of rows in $DAM\_ST\_PC^{p}_{k,h}$ from *PSU4.*

DIPC

1.2.1.9 $DAM\_DIPC^{s}_{k,h}$= the *day-ahead market energy* price curve for a *non-quick start resource*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, and where 'i' is the current row of the matrix of *price-quantity pairs,* and is derived as follows:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DAM\_DIPC^{s}_{k,h}$	Row i	$DAM\_ST\_PC[i,1]^{s}_{k,h}$	$\sum_{j=1}^{i} DAM\_ST\_PC[j,2]^{s}_{k,h}$

1.2.1.10 $DAM\_DIPC^{c}_{k,h}$= the *day-ahead market energy* price curve for a *non-quick start resource*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, and where 'i' is the current row of the matrix of *price-quantity pairs,* and is derived as follows:

Scenario	Domain	CT Quantity
1	$0 < DAM\_BE[i,2]^p_{k,h} \leq DAM\_MRRQ^p_{k,h}$	$DAM\_BE[i,2]^p_{k,h} \times (1 - ST\_Portion^p_{k,d1})$
2	$DAM\_MRRQ^p_{k,h} < DAM\_BE[i,2]^p_{k,h} \leq DAM\_DRRQ^p_{k,h}$	$DAM\_MRRQ^p_{k,h} \times (1 - ST\_Portion^p_{k,d1}) + (DAM\_BE[i,2]^p_{k,h} - DAM\_MRRQ^p_{k,h}) \times (1 - ST\_Portion^p_{k,d2})$
3	$DAM\_DRRQ^p_{k,h} < DAM\_BE[i,2]^p_{k,h}$	$DAM\_MRRQ^p_{k,h} \times (1 - ST\_Portion^p_{k,d1}) + (DAM\_DRRQ^p_{k,h} - DAM\_MRRQ^p_{k,h}) \times (1 - ST\_Portion^p_{k,d2})$

or simplified as:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DAM\_DIPC^c_{k,h}$	Row i	$DAM\_BE[i,1]^p_{k,h}$	$Min(DAM\_BE[i,2]^p_{k,h}, DAM\_DRRQ^p_{k,h}) - [Min(DAM\_MRRQ^p_{k,h}, DAM\_BE[i,2]^p_{k,h}) \times ST\_Portion^p_{k,d1} + Max(0, Min(DAM\_DRRQ^p_{k,h}, DAM\_BE[i,2]^p_{k,h}) - DAM\_MRRQ^p_{k,h}) \times ST\_Portion^p_{k,d2}]$

Where:

a. Any *price-quantity pairs* in the $DAM\_DIPC^c_{k,h}$ price curve matrix that have the same quantity value as a prior quantity value in the price curve matrix shall have their price component and quantity component set to zero.

DIGQ

1.2.1.11 $DAM\_DIGQ^s_{k,h}$= the portion of the *day-ahead schedule* quantity of *energy* (in MW) scheduled for injection for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', and is derived as follows:

$$DAM\_QSI\_DIGQ^s_{k,h} = \sum_{p=1}^{N} DAM\_STP\_QSI^p_{k,h}$$

Where:

a. N is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' that for the relevant *settlement hour*.

i. did not *offer* in the *day-ahead market* in *single cycle mode*; and

ii. had a *day-ahead schedule* greater than or equal to its *minimum loading point*.

1.2.1.12 $DAM\_EOP\_DIGQ^{s}_{k,h}$= the *day-ahead market* economic operating point of the portion of the *day-ahead schedule* quantity of *energy* scheduled for injection for *market participant* 'k' at steam turbine *resource delivery point* 's' in *settlement hour* 'h', and is derived as follows:

$$DAM\_EOP\_DIGQ^{s}_{k,h} = \sum\nolimits_{p=1}^{N} \left[DAM\_EOP^{p}_{k,h} - DAM\_EOP^{c}_{k,h}\right]$$

Where:

a. N is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' that for the relevant *settlement hour* 'h':

i. did not *offer* in the *day-ahead market* in *single cycle mode*; and

ii. had a *day-ahead schedule* greater than or equal to its *minimum loading point*.

1.3 Day-Ahead Market – Operating Reserve

1.3.1 The *IESO* shall determine the following *day-ahead market* data in accordance with the following*,* and provide them directly to the *settlement process:*

1.3.1.1 $OR\_DAM\_DRRQ^{p}_{r,k,h}$ = the *day-ahead market dispatchable* region range quantity for *operating reserve* (in MW), which is the portion of the greater of the $DAM\_QSOR^{c}_{r,k,h}$ and $DAM\_OR\_EOP^{c}_{r,k,h}$ associated with *pseudo-unit delivery point* 'p' that is in the *dispatchable* operating region 'd2' for *market participant* 'k' in *settlement hour* 'h', and is derived as follows:

$$OR\_DAM\_DRRQ^{p}_{r,k,h} = \frac{Max\left(DAM\_QSOR^{c}_{r,k,h}, DAM\_OR\_EOP^{c}_{r,k,h}\right)}{\left(1 - ST\_Portion^{p}_{k,d2}\right)}$$

Where:

a. 'c' is the combustion turbine *resource delivery point* associated with *pseudo-unit delivery point* 'p'

1.3.1.2 $OR\_DAM\_DFRRQ^{p}_{r,k,h}$ = the *day-ahead market* duct-firing region range quantity for *operating reserve* (in MW), which is the portion of the greater of the $DAM\_QSOR^{p}_{r,k,h}$ and $DAM\_OR\_EOP^{p}_{r,k,h}$ associated with *pseudo-unit delivery point* 'p' that is in the *dispatchable* operating region 'd2' and duct firing operating region 'd3' for *market participant* 'k' in *settlement hour* 'h', and is derived as follows:

$$OR\_DAM\_DFRRQ^{p}_{r,k,h} = Max\left(OR\_DAM\_DRRQ^{p}_{r,k,h}, Max\left(DAM\_QSOR^{p}_{r,k,h}, DAM\_OR\_EOP^{p}_{r,k,h}\right)\right)$$

1.3.1.3 $DAM\_OR\_ST\_Q^{p}_{r,k,h}$ = an M-by-1 matrix (where M is M^{p}_{k}) of steam turbine *resource* quantity values (in MW) calculated from the $DAM\_BOR^{p}_{r,k,h}$ and the $ST\_Portion^{p}_{k,d}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *settlement hour* 'h', and is derived as follows:

$$DAM\_ST\_Q^{p}_{r,k,h} = Min\left(OR\_DAM\_DRRQ^{p}_{r,k,h}, DAM\_BOR[i,2]^{p}_{r,k,h}\right) \times ST\_Portion^{p}_{k,d2} + Max\left[0, Min\left(OR\_DAM\_DFRRQ^{p}_{k,r,h}, DAM\_BOR[i,2]^{p}_{r,k,h}\right) - OR\_DAM\_DRRQ^{p}_{r,k,h}\right] \times ST\_Portion^{p}_{k,d3}$$

1.3.1.4 $DAM\_OR\_ST\_PC^{p}_{r,k,h}$ = an M-by-2 matrix (where M is M^{p}_{k}) of *price-quantity pairs*, calculated from the price component of $DAM\_BOR^{p}_{r,k,h}$ and the quantity component of $DAM\_ST\_Q^{p}_{r,k,h}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DAM\_OR\_ST\_PC^{p}_{r,k,h}$	Row $i = 1$	$DAM\_BOR[i,1]^{p}_{r,k,h}$	0
	Row $i \geq 2$	$DAM\_BOR[i,1]^{p}_{r,k,h}$	$DAM\_OR\_ST\_Q[i]^{p}_{r,k,h} - DAM\_ST\_Q[i-1]^{p}_{r,k,h}$

1.3.1.5 $DAM\_OR\_ST\_PC^{s}_{r,k,h}$ = a Y-by-2 matrix (where Y ≤ $\Sigma^{N}_{p=1}$ (M^{p}_{k})) of *price-quantity pairs*, calculated from the price component and the quantity component from all the calculated $DAM\_OR\_ST\_PC^{p}_{r,k,h}$ for *market* *participant* 'k', associated with steam turbine *resource delivery point* 's' during *settlement hour* 'h', and is derived as follows:

DAM PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 2]	Quantity [Row 'i', Column 2]
$DAM\_OR\_ST\_PC^{s}_{r,k,h}$	Rows i=1 to m1, j=1 to m1	$DAM\_OR\_ST\_PC[j,1]^{p1}_{r,k,h}$	$DAM\_OR\_ST\_PC[j,2]^{p1}_{r,k,h}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$DAM\_OR\_ST\_PC[j,1]^{p2}_{r,k,h}$	$DAM\_OR\_ST\_PC[j,2]^{p2}_{r,k,h}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$DAM\_OR\_ST\_PC[j,1]^{p3}_{r,k,h}$	$DAM\_OR\_ST\_PC[j,2]^{p3}_{r,k,h}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$DAM\_OR\_ST\_PC[j,1]^{p4}_{r,k,h}$	$DAM\_OR\_ST\_PC[j,2]^{p4}_{r,k,h}$

Where:

a. For a *pseudo-unit* to be included in the $DAM\_OR\_ST\_PC^{s}_{r,k,h}$ matrix, for the relevant *settlement hour,* it must have received a *day-ahead schedule* greater than or equal to its *minimum loading point*.

b. the *price-quantity pairs* shall be sorted by increasing price;

c. $DAM\_OR\_ST\_PC^{s}_{r,k,h}$ matrix will be modified in the following order:

   i. the *price-quantity pairs* shall be sorted by increasing price;

   ii. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair;*

   iii. any *price-quantity pairs* with a zero quantity shall be removed from the $DAM\_OR\_ST\_PC^{s}_{r,k,h}$ matrix; and

   iv. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The inserted *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2;

d. m1 is the number of rows in $DAM\_OR\_ST\_PC^{p}_{r,k,h}$ from *PSU1*.

e. m2 is the number of rows in $DAM\_OR\_ST\_PC^{p}_{r,k,h}$ from *PSU2*.

f. m3 is the number of rows in $DAM\_OR\_ST\_PC^{p}_{r,k,h}$ from *PSU3*.

g. m4 is the number of rows in $DAM\_OR\_ST\_PC^{p}_{r,k,h}$ from *PSU4*.

DIPC

1.3.1.6 $DAM\_OR\_DIPC^{s}_{r,k,h}$= the *day-ahead market class r reserve* price curve for a *non-quick start resource*, represented as an X-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, where r1, r2, and r3 are all applicable, and is derived as follows:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DAM\_OR\_DIPC^{s}_{r,k,h}$	Row i	$DAM\_OR\_ST\_PC[i,1]^{s}_{r,k,h}$	$\sum_{j=1}^{i} DAM\_OR\_ST\_PC[j,2]^{s}_{r,k,h}$

Where:

a. any *price-quantity pairs* in the $DAM\_OR\_DIPC^{s}_{r,k,h}$ price curve matrix that have the same quantity value as a prior quantity value in the price curve matrix shall have their price component and quantity component set to zero.

1.3.1.7 $DAM\_OR\_DIPC^{c}_{r,k,h}$= the *day-ahead market class r reserve* price curve for a *non-quick start resource*, represented as an X-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' during *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, where r1, r2, and r3 are all applicable, and is derived as follows:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$DAM\_OR\_DIPC^{c}_{r,k,h}$	Row i	$DAM\_BOR[i,1]^{p}_{r,k,h}$	$Min\left(DAM\_BOR[i,2]^{p}_{r,k,h}, OR\_DAM\_DRRQ^{p}_{r,k,h}\right) \times \left(1 - ST\_Portion^{p}_{k,d2}\right)$

Where:

a. any *price-quantity pairs* in the $DAM\_OR\_DIPC^{c}_{r,k,h}$ price curve matrix that have the same quantity value as a prior quantity value in the price curve matrix shall have their price component and quantity component set to zero.

1.4 Pre-Dispatch – Energy

1.4.1 The *IESO* shall determine the following *pre-dispatch process* data in accordance with the following, and provide them directly to the *settlement process:*

Intermediate Variables

1.4.1.1 $PD\_MRRQ_{k,h}^{p,t}$= the pre-dispatch *minimum loading point* region range quantity (in MW), which is the portion of the $PD\_QSI_{k,h}^{p,pdm}$ associated with *pseudo-unit delivery point* 'p' in the *minimum loading point* operating region 'd1' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$PD\_MRRQ_{k,h}^{p,t} = Min\left(ORRQ_{k,d1}^{p}, PD\_QSI_{k,h}^{p,pdm}\right)$$

Where:

a. $PD\_MRRQ_{k,h}^{p,t}$ is only calculated for *pseudo-units* whose associated combustion turbine *resource* was determined to have experienced a *generator failure*.

1.4.1.2 $PD\_DRRQ_{k,h}^{p,t}$= the pre-dispatch *dispatchable* region range quantity (in MW), which is the portion of the $PD\_QSI_{k,h}^{p,pdm}$ associated with *pseudo-unit delivery point* 'p' in the *minimum loading point* operating region 'd1' and *dispatchable* operating region 'd2' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', and derived as follows:

$$PD\_DRRQ_{k,h}^{p,t} = Min\left(CRRQ_{k}^{p}, PD\_MRRQ_{k,h}^{p,t} + \frac{Max\left(PD\_QSI_{k,h}^{c,pdm} - MLP_{k}^{c}, 0\right)}{\left(1 - ST\_Portion_{k,d2}^{p}\right)}\right)$$

Where:

a. 'c' is the combustion turbine *resource delivery point* associated with *pseudo-unit delivery point* 'p'; and

b. $PD\_DRRQ_{k,h}^{p,t}$ is only calculated for *pseudo-units* whose associated combustion turbine *resource* was determined to have experienced a *generator failure*.

1.4.1.3 $PD\_DFRRQ_{k,h}^{p,t}$ = the pre-dispatch duct firing region range quantity (in MW), which is the portion of the $PD\_QSI_{k,h}^{p,pdm}$ associated with *pseudo-unit* *delivery point* 'p' that is in the *minimum loading point* operating region 'd1', *dispatchable* operating region 'd2', and duct firing operating region 'd3' of the *pseudo-unit* for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', and derived as follows:

$$PD\_DFRRQ_{k,h}^{p,t} = Min\Big(ORRQ_{k,d1}^{p} + ORRQ_{k,d2}^{p} + ORRQ_{k,d3}^{p}, Max\big(PD\_QSI_{k,h}^{p,pdm} + CRRQ_{k}^{p} - PD\_DRRQ_{k,h}^{p,t}, CRRQ_{k}^{p}\big)\Big)$$

Where:

a. $PD\_DFRRQ_{k,h}^{p,t}$ is only calculated for *pseudo-units* whose associated combustion turbine *resource* was determined to have experienced a *generator failure*.

1.4.1.4 $PD\_ST\_Q_{k,h}^{p,t}$= an M-by-1 matrix (where M is M_{k}^{p}) of steam turbine *resource* quantity values (in MW) calculated from the $PD\_BE_{k,h}^{p,pdm}$ and $ST\_Portion_{k,d}^{p}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *metering interval* 't' of *settlement hour* 'h', and derived as follows:

Scenario	Domain	$PD\_ST\_Q_{k,h}^{p,t}$
1	$0 < PD\_BE[i,2]_{k,h}^{p,pdm} \leq PD\_MRRQ_{k,h}^{p,t}$	$PD\_BE[i,2]_{k,h}^{p,pdm} \times ST\_Portion_{k,d1}^{p}$
2	$PD\_MRRQ_{k,h}^{p,t} < PD\_BE[i,2]_{k,h}^{p,pdm} \leq PD\_DRRQ_{k,h}^{p,t}$	$PD\_MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,d1}^{p} + \big(PD\_BE[i,2]_{k,h}^{p,pdm} - PD\_MRRQ_{k,h}^{p,t}\big) \times ST\_Portion_{k,d2}^{p}$
3	$PD\_DRRQ_{k,h}^{p,t} < PD\_BE[i,2]_{k,h}^{p,pdm} \leq CRRQ_{k}^{p}$	$PD\_MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,d1}^{p} + \big(PD\_DRRQ_{k,h}^{p,t} - PD\_MRRQ_{k,h}^{p,t}\big) \times ST\_Portion_{k,d2}^{p}$
4	$CRRQ_{k}^{p} < PD\_BE[i,2]_{k,h}^{p,pdm} \leq PD\_DFRRQ_{k,h}^{p,t}$	$PD\_MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,d1}^{p} + \big(PD\_DRRQ_{k,h}^{p,t} - PD\_MRRQ_{k,h}^{p,t}\big) \times ST\_Portion_{k,d2}^{p} + \big(PD\_BE[i,2]_{k,h}^{p,pdm} - CRRQ_{k}^{p}\big) \times ST\_Portion_{k,d3}^{p}$
5	$PD\_DFRRQ_{k,h}^{p,t} < PD\_BE[i,2]_{k,h}^{p,pdm}$	$PD\_MRRQ_{k,h}^{p,t} \times ST\_Portion_{k,d1}^{p} + \big(PD\_DRRQ_{k,h}^{p,t} - PD\_MRRQ_{k,h}^{p,t}\big) \times ST\_Portion_{k,d2}^{p} + \big(PD\_DFRRQ_{k,h}^{p,t} - CRRQ_{k}^{p}\big) \times ST\_Portion_{k,d3}^{p}$

or simplified as:

$$PD\_ST\_Q_{k,h}^{p,t} = Min\left(PD\_MRRQ_{k,h}^{p,t}, PD\_BE[i,2]_{k,h}^{p,pdm}\right) \times ST\_Portion_{k,d1}^{p} + Max\left(0, Min\left(PD\_DRRQ_{k,h}^{p,t}, PD\_BE[i,2]_{k,h}^{p,pdm}\right) - PD\_MRRQ_{k,h}^{p,t}\right) \times ST\_Portion_{k,d2}^{p} + Max\left(0, Min\left(PD\_DFRRQ_{k,h}^{p,t}, PD\_BE[i,2]_{k,h}^{p,pdm}\right) - CRRQ_{k}^{p}\right) \times ST\_Portion_{k,d3}^{p}$$

1.4.1.5 $PD\_ST\_PC_{k,h}^{p,t}$ = an M-by-2 matrix (where M is M_k^p) of *price-quantity pairs,* calculated from the price component of $PD\_BE_{k,h}^{p,pdm}$ and quantity component of the $PD\_ST\_Q_{k,h}^{p,t}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix	=	Price [Row 'i', Column 1)	Quantity [Row 'i', Column 2]
$PD\_ST\_PC_{k,h}^{p,t}$	Row i = 1	$PD\_BE[i,1]_{k,h}^{p,pdm}$	0
	Row i ≥ 2	$PD\_BE[i,1]_{k,h}^{p,pdm}$	$PD\_ST\_Q[i]_{k,h}^{p,t} - PD\_ST\_Q[i-1]_{k,h}^{p,t}$

1.4.1.6 $PD\_S\_ST\_PC_{k,h}^{s,t}$ = a Y-by-2 matrix (where $Y \leq \sum_{p=1}^{N} M_k^p$) of *price-quantity pairs,* calculated from the price component and the quantity component from all calculated $PD\_ST\_PC_{k,h}^{p,t}$ for *market participant* 'k' associated with steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$PD\_S\_ST\_PC_{k,h}^{s,t}$	Rows i=1 to m1, j=1 to m1	$PD\_ST\_PC[j,1]_{k,h}^{p1,t}$	$PD\_ST\_PC[j,2]_{k,h}^{p1,t}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$PD\_ST\_PC[j,1]_{k,h}^{p2,t}$	$PD\_ST\_PC[j,2]_{k,h}^{p2,t}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$PD\_ST\_PC[j,1]_{k,h}^{p3,t}$	$PD\_ST\_PC[j,2]_{k,h}^{p3,t}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$PD\_ST\_PC[j,1]_{k,h}^{p4,t}$	$PD\_ST\_PC[j,2]_{k,h}^{p4,t}$

Where:

a. $PD\_S\_ST\_PC_{k,h}^{s,t}$ matrix will be modified in the following order:

i. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair*;

ii. any *price-quantity pairs* with a zero quantity shall be removed from the $PD\_S\_ST\_PC_{k,h}^{s,t}$ matrix;

iii. the *price-quantity pairs* shall be sorted by increasing price; and

iv. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The inserted *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2.

b. m1 is the number of rows in $PD\_ST\_PC_{k,h}^{p,t}$ from *PSU1.*

c. m2 is the number of rows in $PD\_ST\_PC_{k,h}^{p,t}$ from *PSU2.*

d. m3 is the number of rows in $PD\_ST\_PC_{k,h}^{p,t}$ from *PSU3.*

e. m4 is the number of rows in $PD\_ST\_PC_{k,h}^{p,t}$ from *PSU4.*

DIPC

1.4.1.7 $PD\_DIPC_{k,h}^{s,t}$= *generator failure* charge – guarantee cost component *energy* price curve of a *GOG-eligible resource*, represented as a N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and the *offered* quantities 'Q' are in column 2, and is derived as follows:

Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$PD\_DIPC_{k,h}^{s,t}$	Row i	$PD\_S\_ST\_PC[i,1]_{k,h}^{s,t}$	$\sum_{j=1}^{i} PD\_S\_ST\_PC[j,2]_{k,h}^{s,t}$

Where:

a. the $PD\_DIPC_{k,h}^{s,t}$ price curve matrix shall only be constructed for each combustion turbine *resource* determined to have experienced a *generator failure*.

1.4.1.8 $PD\_DIPC_{k,h}^{c,t}$ = *generator failure* charge – guarantee cost component *energy* price curve of a *GOG-eligible resource*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and the *offered* quantities 'Q' are in column 2, and is derived as follows:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$PD\_DIPC_{k,h}^{c,t}$	Row i	$PD\_BE[i,1]_{k,h}^{p,pdm}$	$Min(PD\_BE[i,2]_{k,h}^{p,pdm}, PD\_DRRQ_{k,h}^{p,t}) - [Min(PD\_MRRQ_{k,h}^{p,t}, PD\_BE[i,2]_{k,h}^{p,pdm}) \times ST\_Portion_{k,d1}^{p} + Max(0, Min(PD\_DRRQ_{k,h}^{p,t}, PD\_BE[i,2]_{k,h}^{p,pdm}) - PD\_MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,d2}^{p}]$

Where:

a. any *price-quantity pairs* in the $PD\_DIPC_{k,h}^{c,t}$ price curve matrix that have the same quantity value as a prior quantity value in the price curve matrix shall have their price component and quantity component set to zero; and

b. the $PD\_DIPC_{k,h}^{c,t}$ price curve matrix shall only be constructed for each combustion turbine *resource* determined to have experienced a *generator failure*.

DIGQ

1.4.1.9 $PD\_DIGQ_{k,h}^{s,t}$ = the *generator failure* charge – guarantee cost component portion of the *pre-dispatch schedule* quantity of *energy* of a *GOG-eligible resource* scheduled for injection for *market participant* 'k' at *steam turbine resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$PD\_DIGQ_{k,h}^{s,t} = \sum_{p=1}^{F} PD\_STP\_QSI_{k,h}^{p,pdm}$$

Where:

a. the $PD\_DIGQ_{k,h}^{s,t}$ price curve matrix shall only be constructed for each combustion turbine *resource* determined to have experienced a *generator failure*.

b. 'F' is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' associated with the combustion turbine *resources* determined to have experienced a *generator failure*.

1.5 Real-Time Market – Energy

1.5.1 The *IESO* shall determine the following *real-time market* data in accordance with the following, and provide them directly to the *settlement process*:

Intermediate Variables

1.5.1.1 $RT\_ORRQ_{k,d}^{p}$ = the *real-time market* operating region range quantity (in MW), which is the *pseudo-unit* operating region quantity of *energy* calculated by the *real-time calculation engine* for *market participant* 'k' at *pseudo-unit delivery point* 'p' in operating region 'd', where 'd1', 'd2' and 'd3' are all applicable.

1.5.1.2 $RT\_CRRQ_{k}^{p}$= the *real-time market* collapsed region range quantity (in MW), which is the portion of the *pseudo-unit* operating region quantity of *energy* calculated by the *real-time calculation engine* at *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1' and *dispatchable* operating region 'd2' before any de-ratings are applied for *market participant* 'k', and is derived as follows:

$$RT\_CRRQ_{k}^{p} = RT\_ORRQ_{k,d1}^{p} + RT\_ORRQ_{k,d2}^{p}$$

1.5.1.3 $RT\_MRRQ_{k,h}^{p,t}$ = the *real-time market minimum loading point* region range quantity (in MW), which is the portion of the greater of the $RT\_QSI_{k,h}^{p,t}$ and $RT\_LC\_EOP_{k,h}^{p,t}$ associated with *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$RT\_MRRQ_{k,h}^{p,t} = Min\left(RT\_ORRQ_{k,d1}^{p,t}, Max\left(RT\_LC\_EOP_{k,h}^{p,t}, RT\_QSI_{k,h}^{p,t}\right)\right)$$

1.5.1.4 $RT\_DRRQ_{k,h}^{p,t}$ = the *real-time market dispatchable* region range quantity (in MW), which is the portion of the greater of the $RT\_QSI_{k,h}^{c,t}$ and $RT\_LC\_EOP_{k,h}^{c,t}$ associated with *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1' and *dispatchable* operating region 'd2' for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$RT\_DRRQ_{k,h}^{p,t} = Min\left(RT\_CRRQ_{k}^{p}, RT\_MRRQ_{k,h}^{p,t} + \frac{Max\left(0, Max\left(RT\_LC\_EOP_{k,h}^{c,t}, RT\_QSI_{k,h}^{c,t}\right) - MLP_{k}^{c}\right)}{\left(1 - ST\_Portion_{k,h,d2}^{p,t}\right)}\right)$$

Where:

a. 'c' is the combustion turbine *resource delivery point* associated with *pseudo-unit delivery point* 'p'

1.5.1.5 $RT\_DFRRQ_{k,h}^{p,t}$ = the *real-time market* duct firing region range quantity (in MW), which is the portion of the greater of the $RT\_QSI_{k,h}^{p,t}$ and $RT\_LC\_EOP_{k,h}^{p,t}$ associated with *pseudo-unit delivery point* 'p' that is in the *minimum loading point* operating region 'd1', *dispatchable* operating region 'd2', and duct firing operating region 'd3', plus any quantity of *energy* associated with a combustion turbine *resource* derate on the *pseudo-unit* for *market participant* 'k' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$RT\_DFRRQ_{k,h}^{p,t} = Min\Big(RT\_ORRQ_{k,d1}^{p} + RT\_ORRQ_{k,d2}^{p} + RT\_ORRQ_{k,d3}^{p}, Max\big(Max\big(RT\_LC\_EOP_{k,h}^{p,t}, RT\_QSI_{k,h}^{p,t}\big) + RT\_CRRQ_{k}^{p} - RT\_DRRQ_{k,h}^{p,t}, RT\_CRRQ_{k}^{p}\big)\Big)$$

1.5.1.6 $RT\_ST\_Q_{k,h}^{p,t}$ = An M-by-1 matrix (where M is M_{k}^{p}) of steam turbine *resource* quantity values (in MW) calculated from the $BE_{k,h}^{p}$ and $ST\_Portion_{k,h,d}^{p,t}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *metering interval* 't' of *settlement hour* 'h', and derived as follows:

$$RT\_ST\_Q_{k,h}^{p,t} = Min\big(RT\_MRRQ_{k,h}^{p,t}, BE[i,2]_{k,h}^{p}\big) \times ST\_Portion\_INT_{k,h,d1}^{p,t} + Max\big(0, Min\big(RT\_DRRQ_{k,h}^{p,t}, BE[i,2]_{k,h}^{p}\big) - RT\_MRRQ_{k,h}^{p,t}\big) \times ST\_Portion_{k,h,d2}^{p,t} + Max\big(0, Min\big(RT\_DFRRQ_{k,h}^{p,t}, BE[i,2]_{k,h}^{p}\big) - RT\_CRRQ_{k}^{p}\big) \times ST\_Portion_{k,h,d3}^{p,t}$$

1.5.1.7 $RT\_ST\_PC_{k,h}^{p,t}$ = An M-by-2 matrix (where M is M_{k}^{p}) of *price-quantity pairs* representing the incremental quantity of *energy* at each price for each *pseudo-unit*, calculated from the price component of $BE_{k,h}^{p}$ and the quantity component of $RT\_ST\_Q_{k,h}^{p,t}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix	=	Price [Row 'i', Column 1)	Quantity [Row 'i', Column 2]
$RT\_ST\_PC_{k,h}^{p,t}$	Row i = 1	$BE[i,1]_{k,h}^{p}$	0
	Row i ≥ 2	$BE[i,1]_{k,h}^{p}$	$RT\_ST\_Q[i]_{k,h}^{p,t} - RT\_ST\_Q[i-1]_{k,h}^{p,t}$

1.5.1.8 $RT\_ST\_PC_{k,h}^{s,t}$ = A Y-by-2 matrix (where $Y \leq \sum_{p=1}^{N} M_{k}^{p}$) of *price-quantity pairs,* calculated from the price component and the quantity component from all calculated $RT\_ST\_PC^{p,t}_{k,h}$ for *market participant* 'k' associated with steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_ST\_PC^{s,t}_{k,h}$	Rows i=1 to m1, j=1 to m1	$RT\_ST\_PC[j,1]^{p1,t}_{k,h}$	$RT\_ST\_PC[j,2]^{p1,t}_{k,h}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$RT\_ST\_PC[j,1]^{p2,t}_{k,h}$	$RT\_ST\_PC[j,2]^{p2,t}_{k,h}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$RT\_ST\_PC[j,1]^{p3,t}_{k,h}$	$RT\_ST\_PC[j,2]^{p3,t}_{k,h}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$RT\_ST\_PC[j,1]^{p4,t}_{k,h}$	$RT\_ST\_PC[j,2]^{p4,t}_{k,h}$

Where:

a. For a *pseudo-unit* to be included in the $RT\_ST\_PC^{s,t}_{k,h}$ matrix, for the relevant *metering interval*:

   i. it must not have *offered* in the *real-time market* in *single cycle mode*; and

   ii. the associated combustion turbine *resource* received a *real-time schedule* greater than or equal to its *minimum loading point;*

b. $RT_ST_PC^{s,t}_{k,h}$matrix will be modified in the following order:

   i. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair*;

   ii. any *price-quantity pairs* with a zero quantity shall be removed from the $RT_ST_PC^{s,t}_{k,h}$matrix;

   iii. the *price-quantity pairs* shall be sorted by increasing price; and

   iv. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The inserted *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2.

c. m1 is the number of rows in $RT\_ST\_PC^{p,t}_{k,h}$ from *PSU1.*

d. m2 is the number of rows in $RT\_ST\_PC_{k,h}^{p,t}$ from *PSU2.*

e. m3 is the number of rows in $RT_ST_PC_{k,h}^{p,t}$from *PSU3.*

f. m4 is the number of rows in $RT_ST_PC_{k,h}^{p,t}$from *PSU4.*

1.5.1.9 $RT\_CMT\_ST\_PC_{k,h}^{s,t}$= A Y-by-2 matrix (where $Y \leq \sum_{p=1}^{N} M_{k,h}^{p,t}$) of *price-quantity pairs*, calculated from the price component and quantity component from all calculated $RT\_ST\_PC_{k,h}^{p,t}$ for *market participant* 'k' associated with steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_CMT\_ST\_PC_{k,h}^{s,t}$	Rows i=1 to m1, j=1 to m1	$RT\_ST\_PC[j,1]_{k,h}^{p1,t}$	$RT\_ST\_PC[j,2]_{k,h}^{p1,t}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$RT\_ST\_PC[j,1]_{k,h}^{p2,t}$	$RT\_ST\_PC[j,2]_{k,h}^{p2,t}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$RT\_ST\_PC[j,1]_{k,h}^{p3,t}$	$RT\_ST\_PC[j,2]_{k,h}^{p3,t}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$RT\_ST\_PC[j,1]_{k,h}^{p4,t}$	$RT\_ST\_PC[j,2]_{k,h}^{p4,t}$

Where:

a. For a *pseudo-unit* to be included in the $RT\_CMT\_ST\_PC_{k,h}^{s,t}$ matrix, for the relevant *metering interval*:

   i. it must be operationally constrained greater than or equal to its *minimum loading point* by the *pre-dispatch calculation engine;*

   ii. it must not have *offered* in the *real-time market* in *single cycle mode*; and

   iii. the associated combustion turbine *resource* must have received a *real-time schedule* greater than or equal to its *minimum loading point*.

b. $RT_CMT_ST_PC_{k,h}^{s,t}$matrix will be modified in the following order:

i. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair*;

ii. any *price-quantity pairs* with a zero quantity shall be removed from the $RT_CMT_ST_PC_{k,h}^{s,t}$matrix;

iii. the *price-quantity pairs* shall be sorted by increasing price; and

iv. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2.

c. m1 is the number of rows in $RT\_ST\_PC_{k,h}^{p,t}$ from PSU1.

d. m2 is the number of rows in $RT\_ST\_PC_{k,h}^{p,t}$ from PSU2.

e. m3 is the number of rows in $RT\_ST\_PC_{k,h}^{p,t}$ from PSU3.

f. m4 is the number of rows in $RT\_ST\_PC_{k,h}^{p,t}$ from PSU4.

DIPC

1.5.1.10 $RT\_DIPC_{k,h}^{s,t}$ = the *real-time market energy* price curve for a *non-quick start resource*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, and is derived as follows:

Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_DIPC_{k,h}^{s,t}$	Row i	$RT\_CMT\_ST\_PC[i,1]_{k,h}^{s,t}$	$\sum_{j=1}^{i} RT\_CMT\_ST\_PC[j,2]_{k,h}^{s,t}$

1.5.1.11 $RT\_CMT\_DIPC_{k,h}^{s,t}$ = the *real-time market energy* price curve of a *non-quick start resource*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, and is derived as follows:

Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_CMT\_DIPC_{k,h}^{s,t}$	Row i	$RT\_CMT\_ST\_PC[i,1]_{k,h}^{s,t}$	$\sum_{j=1}^{i} RT\_CMT\_ST\_PC[j,2]_{k,h}^{s,t}$

1.5.1.12 $RT\_DIPC_{k,h}^{c,t}$ = the *real-time market energy* price curve for a *non-quick start resource*, represented as an N-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' in *metering interval* 't' of *settlement hour* 'h', arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities 'Q' are in column 2, and is derived as follows:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_DIPC_{k,h}^{c,t}$	Row i	$BE[i,1]_{k,h}^{p}$	$Min(BE[i,2]_{k,h}^{p}, RT\_DRRQ_{k,h}^{p,t}) - [Min(RT\_MRRQ_{k,h}^{p,t}, BE[i,2]_{k,h}^{p}) \times ST\_Portion\_INT_{k,h,d1}^{p,t} + Max(0, Min(RT\_DRRQ_{k,h}^{p,t}, BE[i,2]_{k,h}^{p}) - RT\_MRRQ_{k,h}^{p,t}) \times ST\_Portion_{k,h,d2}^{p,t}]$

Where:

a. any *price-quantity pairs* in the $RT\_DIPC_{k,h}^{c,t}$ price curve matrix that have the same quantity value as a prior quantity value in the price curve matrix shall have their price component and quantity component set to zero.

DIGQ

1.5.1.13 $RT\_QSI\_DIGQ_{k,h}^{s,t}$ = the portion of the *real-time schedule* quantity of *energy* scheduled for injection for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$RT\_QSI\_DIGQ_{k,h}^{s,t} = \sum_{p=1}^{N} RT\_STP\_QSI_{k,h}^{p,t}$$

Where:

a. 'N' is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' that for the relevant *metering interval* 't' of *settlement hour* ''h':

   i. are operating in combined cycle mode; and

   ii. whose associated combustion turbine *resource* has a *real-time schedule* greater than or equal to its *minimum loading point.*

1.5.1.14 $RT\_CMT\_DIGQ_{k,h}^{s,t}$= the portion of the *real-time schedule* quantity of *energy* scheduled for injection that is eligible for the real-time *generator offer* guarantee *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$RT\_CMT\_DIGQ_{k,h}^{s,t} = \sum_{p=1}^{N} RT\_STP\_QSI_{k,h}^{p,t}$$

Where:

a. 'N' is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' that for the relevant *metering interval* 't' of *settlement hour* 'h':

   i. are operating in combined cycle mode;

   ii. were operationally constrained greater than or equal to its *minimum loading point* by the *pre-dispatch calculation engine;* and

   iii. whose associated combustion turbine *resource* must have received a *real-time schedule* greater than or equal to its *minimum loading point*.

1.5.1.15 $RT\_LC\_EOP\_DIGQ_{k,h}^{s,t}$ = the portion of the steam turbine *resource's* $RT\_LC\_EOP_{k,h}^{p,t}$ that is eligible for the real-time make-whole payment *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', and derived as follows:

$$RT\_LC\_EOP\_DIGQ_{k,h}^{s,t} = \sum_{p=1}^{N} \left[RT\_LC\_EOP_{k,h}^{p,t} - RT\_LC\_EOP_{k,h}^{c,t}\right]$$

Where:

a. 'N' is the set of all *pseudo-units* associated with *steam turbine resource delivery point* 's' that for the relevant *metering interval*:

i. are operating in combined cycle mode; and

ii. whose associated combustion turbine *resource* has received a *real-time schedule* greater than or equal to its *minimum loading point*.

1.5.1.16 $RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t}$ = the portion of the steam turbine *resource's* $RT\_LOC\_EOP_{k,h}^{p,t}$ that is eligible for the real-time make-whole payment *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', and derived as follows:

$$RT\_LOC\_EOP\_DIGQ_{k,h}^{s,t} = \sum_{p=1}^{N} \left[RT\_LOC\_EOP_{k,h}^{p,t} - RT\_LOC\_EOP_{k,h}^{c,t}\right]$$

Where:

a. 'N' is the set of all *pseudo-units* associated with *steam turbine resource delivery point* 's' that for the relevant *metering interval* 't' in *settlement hour* 'h':

i. are operating in combined cycle mode; and

ii. whose associated combustion turbine *resource* received a *real-time schedule* greater than or equal to its *minimum loading point*.

1.6 Real-Time Market – Operating Reserve

1.6.1 The *IESO* shall determine the following *real-time market* data in accordance with the following, and provide them directly to the *settlement process:*

Intermediate Variables

1.6.1.1 $OR\_RT\_DRRQ_{r,k,h}^{p,t}$ = the *real-time market dispatchable* region range quantity for *operating reserve* (in MW), which is the portion of the greater of the $RT\_QSOR_{r,k,h}^{c,t}$ and $RT\_OR\_LC\_EOP_{r,k,h}^{c,t}$, associated with *pseudo-unit delivery point* 'p' that is in the *dispatchable* operating region 'd2' for *market participant* 'k' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$OR\_RT\_DRRQ_{k,h,r}^{p,t} = \frac{Max\left(RT\_QSOR_{r,k,h}^{c,t}, RT\_OR\_LC\_EOP_{r,k,h}^{c,t}\right)}{\left(1 - ST\_Portion_{k,h,d2}^{p,t}\right)}$$

Where:

a. 'c' is the combustion turbine *resource delivery point* associated with *pseudo-unit delivery point* 'p'

1.6.1.2 $OR\_RT\_DFRRQ^{p,t}_{r,k,h}$ = the *real-time market* duct-firing region range quantity for *operating reserve* (in MW), which is the portion of the greater of the $RT\_QSOR^{p,t}_{r,k,h}$ and $RT\_OR\_LC\_EOP^{p,t}_{r,k,h}$ associated with *pseudo-unit delivery point* 'p', that is in the *dispatchable* operating region 'd2' and duct firing operating region 'd3' for *market participant* 'k' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$OR\_RT\_DFRRQ^{p,t}_{r,k,h} = Max\left(OR\_RT\_DRRQ^{p,t}_{r,k,h}, Max\left(RT\_QSOR^{p,t}_{r,k,h}, RT\_OR\_LC\_EOP^{p,t}_{r,k,h}\right)\right)$$

1.6.1.3 $RT\_OR\_ST\_Q^{p,t}_{r,k,h}$ = An M-by-1 matrix (where M is M^p_k) of steam turbine *resource* quantity values (in MW) calculated from the $BOR^p_{r,k,h}$, $ST\_Portion^{p,t}_{k,h,d2}$, and $ST\_Portion^{p,t}_{k,h,d3}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$\begin{aligned} RT\_OR\_ST\_Q^{p,t}_{r,k,h} &= Min\left(RT\_OR\_DRRQ^p_{r,k,h}, BOR[i,2]^p_{r,k,h}\right) \times ST\_Portion^p_{k,d2} \\ &+ Max\left[0, Min\left(RT\_OR\_DFRRQ^p_{k,r,h}, BOR[i,2]^p_{r,k,h}\right) \right. \\ &\left. - RT\_OR\_DRRQ^p_{r,k,h}\right] \times ST\_Portion^p_{k,d3} \end{aligned}$$

1.6.1.4 $RT\_OR\_ST\_PC^{p,t}_{r,k,h}$ = An M-by-2 matrix (where M is M^p_k) of *price-quantity pairs*, calculated from the price component of $BOR^p_{r,k,h}$ and the quantity component of $RT\_OR\_ST\_Q^{p,t}_{r,k,h}$ for *market participant* 'k' at *pseudo-unit delivery point* 'p' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix	=	Price [Row 'i', Column 1)	Quantity [Row 'i', Column 2]
$RT\_OR\_ST\_PC^{p,t}_{r,k,h}$	Row i = 1	$BOR[i,1]^p_{r,k,h}$	0
	Row i ≥ 2	$BOR[i,1]^p_{r,k,h}$	$RT\_OR\_ST\_Q[i]^{p,t}_{r,k,h} - RT\_OR\_ST\_Q[i-1]^{p,t}_{r,k,h}$

1.6.1.5 $RT\_OR\_ST\_PC^{s,t}_{r,k,h}$ = A Y-by-2 matrix (where $Y \leq \sum_{p=1}^{N} M^p_k$) of *price-quantity pairs*, calculated from the price component and quantity component from all the calculated $RT\_OR\_ST\_PC^{p,t}_{r,k,h}$ for *market participant* 'k' at steam turbine *resource delivery point* 's' for during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_OR\_ST\_PC_{k,r,h}^{s,t}$	Rows i=1 to m1, j=1 to m1	$RT\_OR\_ST\_PC[j,1]_{k,r,h}^{p1,t}$	$RT\_OR\_ST\_PC[j,2]_{k,r,h}^{p1,t}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$RT\_OR\_ST\_PC[j,1]_{k,r,h}^{p2,t}$	$RT\_OR\_ST\_PC[j,2]_{k,r,h}^{p2,t}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$RT\_OR\_ST\_PC[j,1]_{k,r,h}^{p3,t}$	$RT\_OR\_ST\_PC[j,2]_{k,r,h}^{p3,t}$
	Rows i=(m3+1) to (m1+m2+m3+m4), j=1 to m4	$RT\_OR\_ST\_PC[j,1]_{k,r,h}^{p4,t}$	$RT\_OR\_ST\_PC[j,2]_{k,r,h}^{p4,t}$

Where:

a. For a *pseudo-unit* to be included in the $RT\_OR\_ST\_PC_{r,k,h}^{s,t}$ matrix, it must have received a *real-time schedule* for *energy* greater than or equal to its *minimum loading point* for the relevant *metering interval.*

b. the *price-quantity pairs* shall be sorted by increasing price;

c. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair;*

d. any *price-quantity pairs* with a zero quantity shall be removed from the $RT_OR_ST_PC_{k,h}^{s,t}$matrix;

e. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2;

f. m1 is the number of rows in $RT_OR_ST_PC_{r,k,h}^{s,t}$from PSU1.

g. m2 is the number of rows in $RT_OR_ST_PC_{r,k,h}^{s,t}$from PSU2.

h. m3 is the number of rows in $RT_OR_ST_PC_{r,k,h}^{s,t}$from PSU3.

i. m4 is the number of rows in $RT_OR_ST_PC_{r,k,h}^{s,t}$from PSU4.

1.6.1.6 $RT\_OR\_CMT\_ST\_PC_{r,k,h}^{s,t}$ = A Y-by-2 matrix (where $Y \leq \sum_{p=1}^{N} M_k^p$) of *price-quantity pairs*, calculated from the price component and the quantity component from all calculated $RT\_OR\_ST\_PC^{p,t}_{k,r,h}$ for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

PQ Pair Matrix (assuming 4 included *PSUs*)	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$	Rows i=1 to m1, j=1 to m1	$RT\_OR\_CMT\_ST\_PC[j,1]^{p1,t}_{r,k,h}$	$RT\_OR\_CMT\_ST\_PC[j,2]^{p1,t}_{r,k,h}$
	Rows i=(m1+1) to (m1+m2), j=1 to m2	$RT\_OR\_CMT\_ST\_PC[j,1]^{p2,t}_{r,k,h}$	$RT\_OR\_CMT\_ST\_PC[j,2]^{p2,t}_{r,k,h}$
	Rows i=(m2+1) to (m1+m2+m3), j=1 to m3	$RT\_OR\_CMT\_ST\_PC[j,1]^{p3,t}_{r,k,h}$	$RT\_OR\_CMT\_ST\_PC[j,2]^{p3,t}_{r,k,h}$
	Rows i=(m3+1) to (m1+m2+m3+ m4), j=1 to m4	$RT\_OR\_CMT\_ST\_PC[j,1]^{p4,t}_{r,k,h}$	$RT\_OR\_CMT\_ST\_PC[j,2]^{p4,t}_{r,k,h}$

Where:

a. For a *pseudo-unit* to be included in the $RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$ matrix, for the relevant *metering interval* 't' of *settlement hour* 'h':

   i. it must not have *offered* in the *real-time market* in *single cycle mode*;

   ii. the associated combustion turbine *resource* must have received a *real-time schedule* for *energy* greater than or equal to its *minimum loading point;* and

   iii. it must be operationally constrained greater than or equal to its *minimum loading point* by the *pre-dispatch calculation engine*.

b. the *price-quantity pairs* shall be sorted by increasing price;

c. any *price-quantity pairs* with the same price shall have their quantities aggregated into a single *price-quantity pair;*

d. any *price-quantity pairs* with a zero quantity shall be removed from the $RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$ matrix;

e. a new first row will be added and a *price-quantity pair* will be inserted into the first row. The *price-quantity pair* will have a quantity value of zero and its price value will be equal to the price value of the *price-quantity pair* in the new row 2;

f. m1 is the number of rows in $RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$ from PSU1.

g. m2 is the number of rows in $RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$ from PSU2.

h. m3 is the number of rows in $RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$ from PSU3.

i. m4 is the number of rows in $RT\_OR\_CMT\_ST\_PC^{s,t}_{r,k,h}$ from PSU4.

DIPC

1.6.1.7 $RT\_OR\_DIPC^{c,t}_{r,k,h}$ = *real-time market class r reserve* price curve for a *non-quick start resource*, represented as an X-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at combustion turbine *resource delivery point* 'c' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities are in column 2, and is derived as follows:

Derived Interval Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row i, Column 2]
$RT\_OR\_DIPC^{c,t}_{k,r,h}$	Row i	$BOR[i,1]^{p}_{k,r,h}$	$Min\left(BOR[i,2]^{p}_{r,k,h}, RT\_OR\_DRRQ^{p,t}_{r,k,h}\right) \times \left(1 - ST\_Portion^{p,t}_{k,h,d2}\right)$

Where:

a. Any *price-quantity pairs* in the $RT\_OR\_DIPC^{c,t}_{r,k,h}$ price curve matrix that have the same quantity value as a prior quantity value in the price curve matrix shall have their price component and quantity component set to zero.

1.6.1.8 $RT\_OR\_DIPC^{s,t}_{r,k,h}$ = the *real-time market class r reserve* price curve for a *non-quick start resource*, represented as an X-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities are in column 2, and is derived as follows:

Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_OR\_DIPC_{r,k,h}^{s,t}$	Row i	$RT\_OR\_ST\_PC[i,1]_{r,k,h}^{s,t}$	$\sum_{j=1}^{i} RT\_OR\_ST\_PC[j,2]_{r,k,h}^{s,t}$

1.6.1.9 $RT\_OR\_CMT\_DIPC_{r,k,h}^{s,t}$ = the *real-time market class r reserve* price curves of a *non-quick start resource*, represented as an X-by-2 matrix of *price-quantity pairs* for *market participant* 'k' at steam turbine *resource delivery point* 's' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the *offered* price in each *price-quantity pair* where *offered* prices 'P' are in column 1 and *offered* quantities are in column 2, and is derived as follows:

Price Curve Matrix	=	Price [Row 'i', Column 1]	Quantity [Row 'i', Column 2]
$RT\_OR\_CMT\_DIPC_{r,k,h}^{s,t}$	Row i	$RT\_OR\_CMT\_ST\_PC[i,1]_{r,k,h}^{s,t}$	$\sum_{j=1}^{i} RT\_OR\_CMT\_ST\_PC[j,2]_{r,k,h}^{s,t}$

DIGQ

1.6.1.10 $RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}$ = the portion of the *real-time schedule* quantity of *class r reserve* scheduled for injection that is eligible for the *real-time generator offer* guarantee *settlement amount* for *market participant* 'k' at steam turbine *resource delivery point* 's' in *metering interval* 't' of *settlement hour* 'h', and is derived as follows:

$$RT\_OR\_CMT\_DIGQ_{k,r,h}^{s,t} = \sum_{p=1}^{N} RT\_STP\_QSOR_{r,k,h}^{p,t}$$

Where:

a. 'N' is the set of all *pseudo-units* associated with steam turbine *resource delivery point* 's' that, for the relevant *metering interval* 't' of *settlement hour* 'h':

   i. are operating in combined cycle mode;

   ii. were operationally constrained greater than or equal to its *minimum loading point* by the *pre-dispatch calculation engine;* and

   iii. whose associated combustion turbine *resource* must have received a *real-time schedule* greater than or equal to its *minimum loading point*.

Appendix 9.4 – Settlement Mitigation

1 Introduction

1.1 Interpretation

1.1.1 In this Appendix 9.4:

1.1.1.1 the applicable *thermal state* for a *start-up offer* shall be the *thermal state* assigned to the *resource* at the time of the *start-up notice* in accordance with MR Ch.7 App.7.5A s.8.6.3.8 for the relevant *settlement hour*. Notwithstanding the foregoing, the applicable *thermal state* for all *settlement hours* within a *day-ahead commitment period* or a *real-time market commitment period*, as the case may be, shall be the *thermal state* of the first *settlement hour* of the *day-ahead commitment period* or *real-time market commitment period*, as the case may be, as determined at the time of the *start-up notice* in accordance with MR Ch.7 App.7.5A s.8.6.3.8;

1.1.1.2 notwithstanding sections 2.1 and 3.1, if an as-*offered financial dispatch data parameter* for an *offer* is less than its corresponding *reference level value,* the *reference level value offer* for the relevant variable defined in section 2.1 or 3.1, as the case may be, shall be the value of the as-*offered financial dispatch data parameter;* and

1.1.1.3 The following lists the conduct tests in order of their restrictiveness, from most restrictive to least restrictive, for the purpose of determining which conduct test applies for a specific *settlement hour*:

a. the local market power mitigation process for *operating reserve* set out in section 2.4.12 for the *day-ahead market* and section 3.4.12 for the *real-time market;*

b. the *reliability* conditions conduct test for *energy* set out in sections 2.4.10 and 2.4.11 for the *day-ahead market* and sections 3.4.10 and 3.4.11 for the *real-time market;*

c. the global market power mitigation process conduct test for *operating reserve* set out in section 2.4.13 for the *day-ahead market* and section 3.4.13 for the *real-time market;*

d. the *narrow constrained area* conduct test for *energy* set out in sections 2.4.2 and 2.4.3 for the *day-ahead market* and sections 3.4.2 and 3.4.3 for the *real-time market;*

e. the *dynamic constrained area* conduct test for *energy* set out in sections 2.4.4 and 2.4.5 for the *day-ahead market* and sections 3.4.4 and 3.4.5 for the *real-time market;*

f. the broad constrained area conduct test for *energy* set out in sections 2.4.6 and 2.4.7 for the *day-ahead market* and sections 3.4.6 and 3.4.7 for the *real-time market;* and

g. the global market power mitigation process conduct test for *energy* set out in sections 2.4.8 and 2.4.9 for the *day-ahead market* and sections 3.4.8 and 3.4.9 for the *real-time market.*

2 Day-Ahead Market Mitigation

2.1 Variables

2.1.1 In section 2, the following variables shall have the following meanings:

2.1.1.1 $A_{k,h}^{GTMLP}$ is the as-*offered* set of *offer* laminations for *energy* quantities greater than the *offer* lamination that includes the *minimum loading point* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

2.1.1.2 $A_{k,h}^{LTMLP}$ is the as-*offered* set of *offer* laminations for *energy* quantities up to and including the *offer* lamination that includes the *minimum loading point* in the *day-ahead market* for a *GOG-eligible resource* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

2.1.1.3 $A_{r,k,h}^{m}$ is the as-*offered* set of *offer* laminations for *class r reserve* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', where r1, r2, and r3 are all applicable;

2.1.1.4 $PGTMLP_{k,h,a}^{m}$ designates the price for the quantity of *energy* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in association with *offer* lamination $a \in A_{k,h}^{GTMLP}$;

2.1.1.5 $PDG_{r,k,h,a}^{m}$ designates the price for the quantity of *class r reserve* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in association with *offer* lamination $a \in A_{r,k,h}^{m}$, where r1, r2, and r3 are all applicable;

2.1.1.6 $SUDG^{m}_{k,h}$ is the as-*offered start-up offer* in the *day-ahead market* for the *thermal state* indicated in the *dispatch data* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

2.1.1.7 $SNL^{m}_{k,h}$ is the as-*offered speed no-load offer* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

2.1.1.8 $PLTMLP^{m}_{k,h,a}$ designates the price for the maximum quantity of *energy* up to and including the *minimum loading point* that may be scheduled in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in association with *offer* lamination $a \in A^{LTMLP}_{k,h}$;

2.1.1.9 $A'^{GTMLP,m}_{k,h}$ is the set of *reference level value* laminations for *energy* quantities greater than the *offer* lamination that includes the *minimum loading point* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

2.1.1.10 $A'^{LTMLP,m}_{k,h}$ is the set of *reference level value* laminations for *energy* quantities up to and including the *offer* lamination that includes the *minimum loading point* in the *day-ahead market* for a *GOG-eligible resource* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

2.1.1.11 $A'^{m}_{r,k,h}$ is the set of *reference level value* laminations for *class r reserve* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', where r1, r2, and r3 are all applicable;

2.1.1.12 $PGTMLPRef^{m}_{k,h,a'}$ designates the *reference level value* for *energy offer* lamination $a' \in A'^{GTMLP,m}_{k,h}$ for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h', as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.2.1.2;

Where:

a. If the relevant *resource* is a *non-committable resource* and is primarily fueled by biomass, natural gas or oil, then for each contiguous period of its *day-ahead market schedule*:

   i. the applicable *reference level value* for the initial *settlement hours* of such contiguous *day-ahead market schedule*, equal to the duration of the *resource's minimum run-time*, will be the *resource's* primary *energy offer reference level value*; and

ii. the applicable *reference level value* for all other *settlement hours* of such contiguous *day-ahead market schedule* will be the *resource's* secondary *energy offer reference level value*.

2.1.1.13 $PDGRef^{m}_{r,k,h,a'}$ designates the *reference level value* for *class r reserve offer* lamination $a' \in A'^{m}_{r,k,h}$ for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h', where r1, r2, and r3 are all applicable;

2.1.1.14 $SUDGRef^{m}_{k,h}$ designates the *reference level value* for the *start-up offer* in the *day-ahead market* for the same *thermal state* as $SUDG^{m}_{k,h'}$ for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h', as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.2.1.2;

2.1.1.15 $SNLRef^{m}_{k,h}$ designates the *reference level value* for the *speed no-load offer* in the *day-ahead market* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.2.1.2;

2.1.1.16 $PLTMLPRef^{m}_{k,h,a'}$ designates the *reference level value* for the *energy* up to and including the *minimum loading point reference level* lamination $a' \in A'^{LTMLP,m}_{k,h}$ of the *offer* for *market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.2.1.2;

2.2 Constrained Area Conditions

2.2.1 The *IESO* shall apply the conditions set out in this section 2.2 to determine whether and which conduct tests set out in section 2.4 apply.

2.2.2 In regards to *energy*:

Constrained Area Condition Test for a Narrow Constrained Area

2.2.2.1 Where the conditions set out in MR Ch.7 App.7.5 s.10.4.1.1.1 are true, or any *resource* meets the conditions outlined in ss.2.3.2.2 or 2.3.2.3, the *IESO* shall apply the *narrow constrained area* conduct test set out in sections 2.4.2 and 2.4.3;

Constrained Area Condition Test for a Dynamic Constrained Area

2.2.2.2 Where the conditions set out in MR Ch.7 App.7.5 s.10.4.1.1.2 are true, or any *resource* meets the conditions outlined in ss.2.3.3.2 or 2.3.3.3, the *IESO* shall apply the *dynamic constrained area* conduct test set out in sections 2.4.4 and 2.4.5;

Constrained Area Condition Test for a Broad Constrained Area

2.2.2.3 Where the conditions set out in MR Ch.7 App.7.5 s.10.4.2.1 are true, or any *resource* meets the conditions outlined in ss.2.3.4.2 or 2.3.4.3, the *IESO* shall apply the broad constrained area conduct test set out in sections 2.4.6 and 2.4.7;

Constrained Area Condition Test for Global Market Power Mitigation for Energy

2.2.2.4 Where the conditions set out in MR Ch.7 App.7.5 s.10.5.1 are true, or any *resource* meets the conditions outlined in ss.2.3.5.2, the *IESO* shall apply the global market power mitigation process conduct test set out in sections 2.4.8 and 2.4.9; and

Constrained Area Condition Test for Reliability

2.2.2.5 Notwithstanding the foregoing, the *IESO* shall apply the *reliability* conditions conduct test set out in sections 2.4.10 and 2.4.11 where any of the conditions set out in the applicable *market manual* are true.

2.2.3 In regards to *operating reserve*:

Constrained Area Condition Test for Local Market Power Mitigation for Operating Reserve

2.2.3.1 Where the conditions set out in MR Ch.7 App.7.5 s.10.6.1 are true, or any *resource* meets the conditions outlined in s.2.3.7(b), the *IESO* shall apply the local market power mitigation process conduct test set out in section 2.4.12; and

Constrained Area Condition Test for Global Market Power Mitigation for Operating Reserve

2.2.3.2 Where the conditions set out in MR Ch.7 App.7.5 s.10.7.1 are true, or any *resource* meets the conditions outlined in ss.2.3.8(b), the *IESO* shall apply the global market power mitigation process conduct test set out in sections 2.4.13.

2.3 Applicable Resources

2.3.1 The *IESO* shall apply the conduct tests described in section 2.4 for transactions scheduled in the *day-ahead market* to the *resources* identified in this section 2.3.

Constrained Area Condition Test for a Narrow Constrained Area

2.3.2 Subject to section 2.3.9, in regards to the conduct test for local market power mitigation process in a *narrow constrained area* in the *energy market* outlined in sections 2.4.2 and 2.4.3, the *IESO* shall apply such conduct tests to the following *resources*:

2.3.2.1 All *resources* that have a *day-ahead schedule* for *energy* and are identified as having met the *narrow constrained area* condition in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5 s.10.8.1;

2.3.2.2 Any *GOG-eligible resource* that is part of the *narrow constrained area,* that received a *day-ahead operational commitment,* and where any binding constraint from the same *narrow constrained area* causes an increase in the congestion component of the *resource's day-ahead market locational marginal price;*

2.3.2.3 Any *GOG-eligible resource* that is part of the *narrow constrained area* and received a *day-ahead operational commitment,* such *resource* has a *generator* sensitivity factor that is less than -0.02 on an active constraint that is a *narrow constrained area* constraint, and such constraint would have been binding or would have been violated but for the *day-ahead operational commitment* received by the *resource* except for when the difference between the flow and constraint value is less than or equal to 10MW.

Constrained Area Condition Test for a Dynamic Constrained Area

2.3.3 Subject to section 2.3.9, in regards to the conduct test for local market power mitigation process in a *dynamic constrained area* in the *energy market* outlined in sections 2.4.4 and 2.4.5, the *IESO* shall apply such conduct tests to the following *resources*:

2.3.3.1 All *resources* that have a *day-ahead schedule* for *energy* and are identified as having met the *dynamic constrained area* condition in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5 s.10.8.1;

2.3.3.2 Any *GOG-eligible resource* that is part of the *dynamic constrained area,* that received a *day-ahead operational commitment,* and where any binding constraint from the same *dynamic constrained area* causes an increase in the congestion component of the *resource's day-ahead market locational marginal price*; and

2.3.3.3 Any *GOG-eligible resource* that is part of the *dynamic constrained area* and received a *day-ahead operational commitment,* such *resource* has a *generator* sensitivity factor that is less than -0.02 on an active constraint that is a *dynamic constrained area* constraint, and such constraint would have been binding or would have been violated but for the *day-ahead* *operational commitment* received by the *resource* except for when the difference between the flow and constraint value is less than or equal to 10MW.

Constrained Area Condition Test for a Broad Constrained Area

2.3.4 Subject to section 2.3.9, in regards to the conduct test for local market power mitigation process in a broad constrained area in the *energy market* outlined in sections 2.4.6 and 2.4.7, the *IESO* shall apply such conduct tests to the following *resources*:

2.3.4.1 All *resources* that have a *day-ahead schedule* for *energy* and are identified as having met the broad constrained area condition in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5 s.10.8.1;

2.3.4.2 Any *GOG-eligible resource* that received a *day-ahead operational commitment* and where any binding constraint that was not a *narrow constrained area* or a *dynamic constrained area* binding constraint causes an increase in the congestion component of the *resource's day-ahead market locational marginal price*; and

2.3.4.3 Any *GOG-eligible resource* that received a *day-ahead operational commitment,* such *resource* has a *generator* sensitivity factor that is less than -0.02 on an active constraint that is not a *narrow constrained area* or a *dynamic constrained area* constraint, and such constraint would have been binding or would have been violated but for the *day-ahead operational commitment* received by the *resource* except for when the difference between the flow and constraint value is less than or equal to 10MW.

Constrained Area Condition Test for Global Market Power Mitigation for Energy

2.3.5 Subject to section 2.3.9, in regards to the global market power mitigation process in the *energy market* outlined in sections 2.4.8 and 2.4.9, the *IESO* shall apply such conduct tests to the following *resources*:

2.3.5.1 All *resources* that have a *day-ahead schedule* for *energy* and are identified as having met the global market power mitigation conditions for *energy* in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5 s.10.8.1; and

2.3.5.2 Any *GOG-eligible resource* that received a *day-ahead operational commitment* from Pass 2: Reliability Scheduling and Commitment pass of the *day-ahead market calculation engine.*

Constrained Area Condition Test for Reliability

2.3.6 Subject to section 2.3.9, in regards to the conduct test for local market power mitigation process due to *reliability* constraints in the *energy market* outlined in sections 2.4.10 and 2.4.11, the *IESO* shall apply such conduct tests to any *resource* that was subject to a constraint identified pursuant to section 2.2.2.5.

Constrained Area Condition Test for Local Market Power Mitigation for Operating Reserve

2.3.7 Subject to section 2.3.9, in regards to the local market power mitigation process in the *operating reserve market* outlined in section 2.4.12, the *IESO* shall apply such conduct tests to the following *resources*:

2.3.7.1 all *resources* that have a *day-ahead schedule* for *operating reserve* and are identified as having met the local power mitigation conditions for *operating reserve* in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5 s.10.8.1; and

2.3.7.2 all *resources* that meet the condition outlined in MR Ch.7 App7.5 s. 10.6.1.3.

Constrained Area Condition Test for Global Market Power Mitigation for Operating Reserve

2.3.8 Subject to section 2.3.9, in regards to the global market power mitigation process in the *operating reserve market* outlined in section 2.4.13, the *IESO* shall apply such conduct tests to the following *resources:*

2.3.8.1 all *resources* that have a *day-ahead schedule* for *operating reserve* and are identified as having met the global power mitigation conditions for *operating reserve* in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5 s.10.8.1; and

2.3.8.2 all *resources* that meet the condition outlined in section MR Ch.7 App7.5 s. 10.7.3.

2.3.9 Notwithstanding the foregoing*, non-committable resources* may only be subject to the conduct tests described in sections 2.4.2, 2.4.4, 2.4.6, 2.4.8, and 2.4.10. For greater certainty, *GOG-eligible resources* may, depending on the outcome of this section 2.3, be subject to any conduct test set out in section 2.4.

2.4 Conduct Test

2.4.1 Subject to section 2.4.14, the *IESO* shall apply the conduct tests as set out in this section 2.4. For the purpose of the conduct tests set out in this section 2.4:

2.4.1.1 where a *resource* has not submitted a *minimum loading point,* the applicable *minimum loading point* is deemed to be zero MW, and all *offer laminations* for such *resource* will be considered to be above the *energy offer* lamination that includes its *minimum loading point;*

2.4.1.2 the maximum quantity of the *offer laminations* that form part of $EMFC\_DAM\_BE_{k,h}^{m}$ will be equal to the maximum quantity of the *resource's* submitted *offer laminations*; and

2.4.1.3 $EMFC\_DAM\_BE_{k,h}^{m}$ shall not exceed 20 laminations for a *resource* that is not a *pseudo-unit* or the number of laminations specified in MR. Ch.7 s.3.5.5.6 for a *resource* that is a *pseudo-unit*. Where the outcome of the conduct test set out in this section 2.4 would otherwise violate this requirement, the IESO shall:

(i) for conduct tests applicable to laminations that are above the *energy offer* lamination that includes its *minimum loading point,* delete the laminations in order from the highest price to the lowest price, except maintaining the lamination with the highest price, until the number of laminations is equal to the maximum number of laminations permitted; and

(ii) for conduct tests applicable to laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point,* replace all laminations with one lamination where the price is equal to the highest price lamination of the relevant *reference level* and the quantity is equal to the submitted *minimum loading point.*

Local Market Power Mitigation Process in a Narrow Constrained Area for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

2.4.2 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.1 to the *resources* identified in section 2.3.2. For each *settlement hour* 'h' that qualified to be tested under section 2.2.2.1 and for each such *resource* the *IESO* shall:

2.4.2.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination 'a':

For all $a \in A_{k,h}^{GTLMP,m}$, if

i. $PGTMLP_{k,h,a}^{m} > 25$; and

ii. $PTMLPG_{k,h,a}^{m} > min((PGTMLPRef_{k,h,a'}^{m} + abs(PGTMLPRef_{k,h,a'}^{m}) \times 0.5), PGTMLPRef_{k,h,a'}^{m} + 25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$.

Local Market Power Mitigation Process in a Narrow Constrained Area for Energy Offers up to and Including the Offer Lamination That Includes Minimum Loading Point

2.4.3 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.1 to the *resources* identified in section 2.3.2. For each *settlement hour* 'h' within a *day-ahead commitment period* that contains a *settlement hour* that qualified to be tested under section 2.2.2.1 and for each such *resource* the *IESO* shall:

2.4.3.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. *a resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination 'a':

For all a ∈ $A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\left((PLTMLPRef_{k,h,a'}^{m} + abs(PLTMLPRef_{k,h,a'}^{m}) \times 0.5), PLTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $DAM\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

2.4.3.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > (SUDGRef_{k,h}^{m} + abs(SUDGRef_{k,h}^{m}) \times 0.25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

2.4.3.3 Evaluate speed *no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > \left(SNLRef_{k,h}^{m} + abs\left(SNLRef_{k,h}^{m}\right) \times 0.25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Local Market Power Mitigation Process in a Dynamic Constrained Area for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

2.4.4 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.2 to the *resources* identified in section 2.3.3. For each *settlement hour* 'h´that qualified to be tested under section 2.2.2.2 and for each such *resource* the *IESO* shall:

2.4.4.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination 'a':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m}$ > 25; and

ii. $PGTMLP_{k,h,a}^{m} > min\left(\left(PGTMLPRef_{k,h,a'}^{m} + abs\left(PGTMLPRef_{k,h,a'}^{m}\right) \times 0.5\right), PGTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

Local Market Power Mitigation Process in a Dynamic Constrained Area for Energy Offers up to and Including the Offer Lamination That Includes Minimum Loading Point

2.4.5 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.2 to the *resources* identified in section 2.3.3. For each *settlement hour* 'h' within a *day-ahead commitment period* that contains a *settlement hour* that qualified to be tested under section 2.2.2.2 and for each such *resource* the *IESO* shall:

2.4.5.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\left(\left(PLTMLPRef_{k,h,a'}^{m} + abs\left(PLTMLPRef_{k,h,a'}^{m}\right) \times 0.5\right), PLTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $DAM\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

2.4.5.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 0.25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

2.4.5.3 Evaluate speed *no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{h.k}^{m} > (SNLRef_{h.k}^{m} + abs(SNLRef_{h.k}^{m}) \times 0.25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Local Market Power Mitigation Process in a Broad Constrained Area for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

2.4.6 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.3 to the *resources* identified in section 2.3.4. For each *settlement hour* 'h' that qualified to be tested under section 2.2.2.3 and for each such *resource* the *IESO* shall:

2.4.6.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m} > 25$; and

ii. $PGTMLP_{k,h,a}^{m} > min\left(\left(PGTMLPRef_{k,h,a'}^{m} + abs\left(PGTMLPRef_{k,h,a'}^{m}\right) \times 3\right), PGTMLPRef_{k,h,a'}^{m} + 100\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$

Local Market Power Mitigation Process in a Broad Constrained Area for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

2.4.7 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.3 to the *resources* identified in section 2.3.4. For each *settlement hour* 'h' within a *day-ahead commitment period* that contains a *settlement hour* that qualified to be tested under section 2.2.2.3 and for each such *resource* the *IESO* shall:

2.4.7.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\,((PLTMLPRef_{k,h,a'}^{m} + abs(PLTMLPRef_{k,h,a'}^{m}) \times 3), PLTMLPRef_{k,h,a'}^{m} + 100)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $DAM\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

2.4.7.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > (SUDGRef_{k,h}^{m} + abs(SUDGRef_{k,h}^{m}) \times 1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

2.4.7.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs(SNLRef_{k,h}^{m}) \times 1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Global Market Power Mitigation Process for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

2.4.8 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.4 to the *resources* identified in section 2.3.5. For each *settlement hour* 'h' that qualified to be tested under section 2.2.2.4 and for each such *resource* the *IESO* shall:

2.4.8.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m}$ > 25; and

ii. $PGTMLP_{k,h,a}^{m} > min\left(\left(PGTMLPRef_{k,h,a'}^{m} + abs\left(PGTMLPRef_{k,h,a'}^{m}\right) \times 3\right), PGTMLPRef_{k,h,a'}^{m} + 100\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

Global Market Power Mitigation Process for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

2.4.9 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.4 to the *resources* identified in section 2.3.5. For each *settlement hour* 'h' within a *day-ahead commitment period* that contains a *settlement hour* that qualified to be tested under section 2.2.2.4 and for each such *resource* the *IESO* shall:

2.4.9.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m}$ > 25; and

ii. $PLTMLP_{k,h,a}^{m} > min\ ((PLTMLPRef_{k,h,a'}^{m} + abs(PLTMLPRef_{k,h,a'}^{m}) \times 3),\ PLTMLPRef_{k,h,a'}^{m} + 100)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $DAM\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

2.4.9.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 1\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU^{m}_{k,h}$ shall equal $SUDGRef^{m}_{k,h}$; and

2.4.9.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL^{m}_{k,h} > SNLRef^{m}_{k,h} + abs(SNLRef^{m}_{k,h}) \times 1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL^{m}_{k,h}$ shall equal $SNLRef^{m}_{k,h}$.

Local Market Power Mitigation Process Due to Reliability Constraints for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

2.4.10 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.5 to the *resources* identified in section 2.3.6. For each *settlement hour* 'h' that qualified to be tested under section 2.2.2.5 and for each such *resource* the *IESO* shall:

2.4.10.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A^{GTMLP,m}_{k,h}$, if

i. $PGTMLP^{m}_{k,h,a} > 25$; and

ii. $PGTMLP^{m}_{k.h.a} > \min\Big(\big(PGTMLPRef^{m}_{k.h.a'} + abs\big(PGTMLPRef^{m}_{k,h,a'}\big) \times 0.1\big), PGTMLPRef^{m}_{k,h,a'} + 25\Big)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE^{m}_{k,h}$ shall equal $PLTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{LTMLP,m}_{k,h}$ and $PGTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{GTMLP,m}_{k,h}$;

Local Market Power Mitigation Process Due to Reliability Constraints for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

2.4.11 The *IESO* shall apply the following conduct test in the circumstances outlined in section 2.2.2.5 to the *resources* identified in section 2.3.6. For each *settlement hour* 'h' within a *day-ahead commitment period* that contains a *settlement hour* that qualified to be tested under section 2.2.2.5 and for each such *resource* the *IESO* shall:

2.4.11.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m}$ > 25; and

ii. $PLTMLP_{k,h,a}^{m} > min\ ((PLTMLPRef_{k,h,a'}^{m} + abs(PLTMLPRef_{k,h,a'}^{m}) \times 0.1),\ PLTMLPRef_{k,h,a'}^{m} + 25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $DAM\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

2.4.11.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs\left(SNLRef_{k,h}^{m}\right) \times 0.1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

2.4.11.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{h.k}^{m} > SNLRef_{h.k}^{m} + abs(SNLRef_{h.k}^{m}) \times 0.1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL^{m}_{k,h}$ shall equal $SNLRef^{m}_{h.k}$.

Local Market Power Mitigation Process in the Operating Reserve Market

2.4.12 The *IESO shall* apply the following conduct test in the circumstances outlined in 2.2.3.1 to the *resources* identified in section 2.3.7. For each *settlement hour* 'h' that qualified to be tested under section 2.2.3.1 and for each such *resource* the *IESO* shall:

2.4.12.1 Evaluate *offers* for *operating reserve* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *class r reserve* for any *offer* lamination '*a*':

For all $a \in A^{m}_{r,k,h}$, if

i. $PDG^{m}_{r,k,h,a} > 5$; and

ii. $PDG^{m}_{r,k,h,a} > \min\left(\left(PDGRef^{m}_{r,k,h,a'} + abs\left(PDGRef^{m}_{r,k,h,a'}\right) \times 0.1\right), PDGRef^{m}_{r,k,h,a'} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BOR^{m}_{r,k,h}$ shall equal $PDGRef^{m}_{r,k,h,a'}$ for all *offer* lamination $a \in A^{m}_{r,k,h}$ for the *class r reserve* for which it failed the test;

2.4.12.2 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A^{LTMLP,m}_{k,h}$, if

i. $PLTMLP^{m}_{k,h,a} > 25$; and

ii. $PLTMLP^{m}_{k.h.a} > min\ ((PLTMLPRef^{m}_{k.h.a'} + abs(PLTMLPRef^{m}_{k,h,a'}) \times 0.1),\ PLTMLPRef^{m}_{k,h,a'} + 25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE^{m}_{k,h}$ shall equal $PLTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{LTMLP,m}_{k,h}$ and $DAM\_BE^{m}_{k,h}$ for all *offer* laminations $a \in A^{GTMLP,m}_{k,h}$;

2.4.12.3 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 0.1\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

2.4.12.4 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{h.k}^{m} > SNLRef_{h.k}^{m} + abs(SNLRef_{h.k}^{m}) \times 0.1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Global Market Power Mitigation Process in the Operating Reserve Market

2.4.13 The *IESO shall* apply the following conduct test in the circumstances outlined in section 2.2.3.2 to the *resources* identified in section 2.3.8. For each *settlement hour* 'h' that qualified to be tested under section 2.2.3.2 and for each such *resource* the *IESO* shall:

2.4.13.1 Evaluate *offers* for *operating reserve* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *class r reserve* for any *offer* lamination '*a*':

For all $a \in A_{r,k,h}^{m}$, if

i. $PDG_{r,k,h,a}^{m} > 5$; and

ii. $PDG_{r,k,h,a}^{m} > \min\left(\left(PDGRef_{r,k,h,a'}^{m} + abs\left(PDGRef_{r,k,h,a'}^{m}\right) \times 0.5\right), PDGRef_{r,k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BOR_{r,k,h}^{m}$ shall equal $PDGRef_{r,k,h,a'}^{m}$ for all *offer* lamination $a \in A_{r,k,h}^{m}$ for the *class r reserve* for which it failed the test;

2.4.13.2 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\left((PLTMLPRef_{k,h,a'}^{m} + abs(PLTMLPRef_{k,h,a'}^{m}) \times 0.5), PLTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $DAM\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

2.4.13.3 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 0.25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

2.4.13.4 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs\left(SNLRef_{k,h}^{m}\right) \times 0.25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_DAM\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

2.4.14 If multiple conduct tests set out in section 2.4 apply in regards to the same *settlement hour*, then the *IESO* shall apply the following:

2.4.14.1 where multiple conduct tests for *energy* greater than *minimum loading point* apply in regards to the same *settlement hour,* the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour*;

2.4.14.2 where multiple conduct tests for *energy* up to and including *minimum loading point* apply in regards to the same *settlement hour*, the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to all *settlement hours* within the *day-ahead commitment period* that contains such *settlement hour;*

2.4.14.3 where both a conduct test for *energy* up to and including *minimum loading point* and *energy* greater than *minimum loading point* apply with respect to the same *settlement hour,*

a. the greater than *minimum loading point* conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour;* and

b. if the *resource* does not fail such greater than *minimum loading point* conduct test, the up to and including *minimum loading point* conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour.*

2.4.14.4 where multiple conduct tests for *operating reserve offers* apply in regards to the same *settlement hour,* the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour*;

2.4.14.5 where multiple conduct tests for *start-up offer* or *speed no-load offers*, as the case may be, apply in regards to the same *settlement hour*, the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to all *settlement hours* within the *day-ahead commitment period* that contains such *settlement hour.*

3 Real-Time Mitigation

3.1 Variables

3.1.1 In section 3, the following variables shall have the following meanings:

3.1.1.1 $A_{k,h}^{GTMLP,m}$ is the as-*offered* set of *offer* laminations for *energy* quantities greater than the *offer* lamination that includes the *minimum loading point* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

3.1.1.2 $A_{k,h}^{LTMLP,m}$ is the as-*offered* set of *offer* laminations for *energy* quantities up to and including the *offer* lamination that includes the *minimum loading point* in the *real-time market* for a *GOG-eligible resource* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

3.1.1.3 $A_{r,k,h}^{m}$ is the as-*offered* set of *offer* laminations for *class r reserve* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', where r1, r2, and r3 are all applicable;

3.1.1.4 $PGTMLP_{k,h,a}^{m}$ designates the price for the quantity of *energy* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in association with *offer a* ∈ $A^{GTMLP,m}{}_{k,h}$;

3.1.1.5 $PDG_{r,k,h,a}^{m}$ designates the price for the quantity of *class r reserve* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in association with *offer* lamination $a \in A_{r,k,h}^{m}$, where r1, r2, and r3 are all applicable;

3.1.1.6 $PLTMLP_{k,h,a}^{m}$ designates the price for the maximum quantity of *energy* up to and including the *minimum loading point* that may be scheduled in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' in association with *offer* lamination *a* ∈ $A^{LTMLP,m}{}_{k,h}$;

3.1.1.7 $SUDG_{k,h}^{m}$ is the as-*offered start-up offer* in the *real-time market* for the *thermal state* determined in accordance with section 1.1.1 for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

3.1.1.8 $SNL_{k,h}^{m}$ is the as-*offered speed no-load offer* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

3.1.1.9 $A'^{GTMLP,m}_{k,h}$ is the set of *reference level value* laminations for *energy* quantities greater than the *offer* lamination that includes the *minimum* *loading point* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

3.1.1.10 $A'^{LTMLP,m}_{k,h}$ is the set of *reference level value* laminations for *energy* quantities up to and including the *offer* lamination that includes the *minimum loading point in the real-time market* for a *GOG-eligible resource* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h';

3.1.1.11 $A'^{m}_{r,k,h}$ is the set of *reference level value* laminations for *class r reserve* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', where r1, r2, and r3 are all applicable;

3.1.1.12 $PGTMLPRef^{m}_{k,h,a'}$ designates the *reference level value* for *energy offer* lamination a' ∈ $A'^{GTMLP,m}_{k,h}$ for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.3.1.2;

Where:

a. if the relevant *resource* is a *non-committable resource* and is primarily fueled by biomass, natural gas or oil, then for each contiguous period of its *real-time market schedule*:

   i. the applicable *reference level value* for the initial *settlement hours* of such contiguous *real-time schedule*, equal to the duration of the *resource's minimum run-time*, will be the *resource's* primary *energy offer reference level value*; and

   ii. the applicable *reference level value* for all other *settlement hours* of such contiguous *real-time schedule* will be the *resource's* secondary *energy offer reference level value*.

3.1.1.13 $PDGRef^{m}_{r,k,h,a'}$ designates the *reference level value* for *class r reserve offer* lamination $a' \in A'^{m}_{r,k,h}$ for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', where r1, r2, and r3 are all applicable;

3.1.1.14 $SUDGRef^{m}_{k,h}$ designates the *reference level value* for the *start-up offer* in the *real-time market* for the same *thermal state* as $SUDG^{m}_{k,h'}$ for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.3.1.2;

3.1.1.15 $SNLRef^{m}_{k,h}$ designates the *reference level value* for the *speed no-load offer* in the *real-time market* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.3.1.2;

3.1.1.16 $PLTMLPRef^{m}_{k,h,a'}$ designates the *reference level value* for the *energy* up to and including the *minimum loading point reference level* lamination $a' \in A'^{LTMLP,m}_{k,h}$ of the *offer* for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' as may be adjusted by the *IESO* pursuant to MR Ch.9 s.5.3.1.2.

3.2 Constrained Area Conditions

3.2.1 The *IESO* shall apply the conditions set out in this section 3.2 to determine whether and which conducts tests set out in section 3.4 apply:

3.2.2 In regards to *energy*,

Constrained Area Condition Test for a Narrow Constrained Area

3.2.2.1 The *IESO* shall apply:

a. the *narrow constrained area* conduct test set out in section 3.4.2 when at least one transmission constraint for a *narrow constrained area* is binding in the 'pd1' pre-dispatch run; and

b. the *narrow constrained area* conduct test set out in section 3.4.3 when at least one transmission constraint for a *narrow constrained area* is binding in the 'pdi' pre-dispatch run or any *resource* meets the conditions outlined in 3.3.2.3 or 3.3.2.4.

Constrained Area Condition Test for a Dynamic Constrained Area

3.2.2.2 The *IESO* shall apply:

a. the *dynamic constrained area* conduct test set out in section 3.4.4, when at least one transmission constraint for a *dynamic constrained area* is binding in the 'pd1' pre-dispatch run; and

b. the *dynamic constrained area* conduct test set out in section 3.4.5, when at least one transmission constraint for a *dynamic constrained area* is binding in the 'pdi' pre-dispatch run or any *resource* meets the conditions outlined in 3.3.3.3 or 3.3.3.4.

Constrained Area Condition Test for a Broad Constrained Area

3.2.2.3 The *IESO* shall apply:

a. the broad constrained area conduct test set out in section 3.4.6 when the congestion component of the *locational marginal price* of a *resource* is greater than $25/MWh in the 'pd1' pre-dispatch run; and

b. the broad constrained area conduct test set out in section 3.4.7 when the congestion component of the *locational marginal price* of a *resource* is greater than $25/MWh in the 'pdi' pre-dispatch run or any *resource* meets the conditions outlined in 3.3.4.2 or 3.3.4.3.

Constrained Area Condition Test for Global Market Power Mitigation for Energy

3.2.2.4 The *IESO* shall apply:

a. the global market power mitigation conduct test set out in section 3.4.8 when the following circumstances are true in the 'pd1' pre-dispatch run, as applicable:

i. the *intertie border prices* at the *global market power reference intertie zones* are greater than $100/MWh for the relevant *settlement hour*; and

ii. at least one of the following conditions is met:

a) import congestion component of the *locational marginal price* from the relevant pre-dispatch run is less than zero on all of the *global market power reference intertie zones* for both of the two *settlement hours* immediately following the relevant *settlement hour*, or

b) the net *interchange schedule* limit is binding for imports, represented by a negative backward net *interchange schedule* limit shadow price for incremental imports for both of the two *settlement hours* immediately following the relevant *settlement hour.*

b. the global market power mitigation conduct test set out in section 3.4.9 when the following circumstance are true within two hours of the 'pdi' pre-dispatch run, as applicable:

i. the the *intertie border prices* at the *global market power reference intertie zones* are greater than $100/MWh for the relevant *settlement hour*; and

ii. at least one of the following conditions is met:

a) import congestion component of the *locational marginal price* from the relevant pre-dispatch run is less than zero on all of the *global market power reference intertie zones* for both of the two *settlement hours* immediately following the relevant *settlement hour*, or

b) the net interchange schedule limit is binding for imports, represented by a negative backward net interchange schedule limit shadow price for incremental imports for both of the two *settlement hours* immediately following the relevant *settlement hour.*

c. the global market power mitigation conduct test set out in section 3.4.9 when any *resource* meets the conditions outlined in 3.3.5.2 or 3.3.5.3.

Constrained Area Condition Test for Reliability

3.2.2.5 Notwithstanding the foregoing, the *IESO* shall apply the *reliability* conditions conduct tests set out in section 3.4.10 and 3.4.11 where any of the conditions set out in the applicable *market manual* are true.

3.2.3 In regards to *operating reserve*:

Constrained Area Condition Test for Local Market Power Mitigation for Operating Reserve

3.2.3.1 The *IESO* shall apply the local market power mitigation process conduct test set out in section 3.4.12 if a reserve area has a non-zero minimum requirement in the 'pd1' pre-dispatch run or the 'pdi' pre-dispatch run or any *resource* meets the condition outlined in 3.3.7(b).

Constrained Area Condition Test for Global Market Power Mitigation for Operating Reserve

3.2.3.2 The *IESO* shall apply the global market power mitigation process conduct test set out in section 3.4.13 when a *locational marginal price* for any class of *operating reserve* is greater than $15/MW in the 'pd1' pre-dispatch run or the 'pdi' pre-dispatch run or any *resource* meets the conditions outlined in 3.3.8.2, 3.3.8.3, or 3.3.8.4.

3.3 Applicable Resources

3.3.1 The *IESO* shall apply the conduct tests described in section 3.4 for transactions scheduled in the *real time market* to the *resources* identified in this section 3.3.

Constrained Area Condition Test for a Narrow Constrained Area

3.3.2 Subject to section 3.3.9, in regards to the conduct test for local market power mitigation process in a *narrow constrained area* in the *energy market* outlined in sections 3.4.2 and 3.4.3, the *IESO* shall apply the conduct tests to the following *resources*:

3.3.2.1 Any *non-committable resources* located in the *narrow constrained area* that had at least one binding constraint in the 'pd1' pre-dispatch run;

3.3.2.2 Any *GOG-eligible resources* located in the *narrow constrained area* that had at least one binding constraint in the 'pdi' pre-dispatch run;

3.3.2.3 Any *GOG-eligible resource* that is part of the *narrow constrained area,* that received a *pre-dispatch operational commitment* in the 'pdi' pre-dispatch run, and where any binding constraint from the same *narrow constrained area* causes an increase in the congestion component of the *resource's real-time market locational marginal price*; and

3.3.2.4 Any *GOG-eligible resource* that is part of the *narrow constrained area* and received a *pre-dispatch operational commitment* in the 'pdi' pre-dispatch run, such *resource* has a generator sensitivity factor that is less than -0.02 on an active constraint that is a *narrow constrained area*, and such constraint would have been binding or would have been violated but for the *pre-dispatch operational commitment* received by the *resource* except for when the difference between the flow and constraint value is less than or equal to 10MW.

Constrained Area Condition Test for a Dynamic Constrained Area

3.3.3 Subject to section 3.3.9, in regards to the conduct test for local market power mitigation process in a *dynamic constrained area* in the *energy market* outlined in sections 3.4.4 and 3.4.5 the *IESO* shall apply the conduct tests to the following *resources:*

3.3.3.1 Any *non-committable resources* located in the *dynamic constrained area* that had at least one binding constraint in the 'pd1' pre-dispatch run;

3.3.3.2 Any *GOG-eligible resources* located in the *dynamic constrained area* that had at least one binding constraint in the 'pdi' pre-dispatch run;

3.3.3.3 Any *GOG-eligible resource* that is part of the *dynamic constrained area,* that received a *pre-dispatch operational commitment,* and where any binding constraint from the same *dynamic constrained area* causes an increase in the congestion component of the *resource's real-time market locational marginal price*; and

3.3.3.4 Any *GOG-eligible resource* that is part of the *dynamic constrained area* and received a *pre-dispatch operational commitment,* such *resource* has a generator sensitivity factor that is less than -0.02 on an active constraint that is a *dynamic constrained area*, and such constraint would have been binding or would have been violated but for the *pre-dispatch operational commitment* received by the *resource* except for when the difference between the flow and constraint value is less than or equal to 10MW.

Constrained Area Condition Test for a Broad Constrained Area

3.3.4 Subject to section 3.3.9, in regards to the conduct test for local market power mitigation process in a broad constrained area in the *energy market* outlined in section 3.4.6 and 3.4.7, the *IESO* shall apply such conduct tests to the following *resources*:

3.3.4.1 All *resources* that have a *real time market schedule* for *energy* and are identified as having met the broad constrained area condition in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5A s.10.8.1;

3.3.4.2 Any *GOG-eligible resource* that received a *pre-dispatch operational commitment* in the 'pdi' pre-dispatch run and where any binding constraint that was not a *narrow constrained area* or a *dynamic constrained area* binding constraint causes an increase in the congestion component of the *resource's real-time market locational marginal price*; and

3.3.4.3 Any *GOG-eligible resource* that received a *pre-dispatch operational commitment* in the 'pdi' pre-dispatch run, such *resource* has a generator sensitivity factor that is less than -0.02 on an active constraint that is not a *narrow constrained area* or a *dynamic constrained area* constraint, and such constraint would have been binding or would have been violated but for the *pre-dispatch operational commitment* received by the *resource* except for when the difference between the flow and constraint value is less than or equal to 10MW.

Constrained Area Condition Test for Global Market Power Mitigation for Energy

3.3.5 Subject to section 3.3.9, in regards to the global market power mitigation process in the *energy market* outlined in section 3.4.8 and 3.4.9, the *IESO* shall apply such conduct tests to the following *resources*:

3.3.5.1 All *resources* that have a *real- time market* s*chedule* for *energy* and are identified as having met the global market power mitigation condition for *energy* in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5A s.10.8.1;

3.3.5.2 any *GOG-eligible resource* that received a *pre-dispatch operational commitment* for *energy*; and

3.3.5.3 any *GOG-eligible resource* that, either as permitted in accordance with MR Ch.7 ss.3.3.4B, 3.3.8, 3.3.9.2, 3.3.11 and 21.6 or as approved by the *IESO* in accordance with MR Ch.7 s.3.3.6, a new *energy offer* within the *real-time market mandatory window;*

Constrained Area Condition Test for Reliability

3.3.6 Subject to section 3.3.9, in regards to the conduct test for local market power mitigation process due to *reliability* constraints in the *energy market* outlined in section 3.4.10 and 3.4.11, the *IESO* shall apply such conduct tests to any *resource* that was subject to a constraint identified pursuant to section 3.2.2.5.

Constrained Area Condition Test for Local Market Power Mitigation for Operating Reserve

3.3.7 Subject to section 3.3.9, in regards to the local market power mitigation process in the *operating reserve market* outlined in section 3.4.12, the *IESO* shall apply such conduct tests to the following *resources:*

3.3.7.1 all *resources* that have a *real-time market schedule* for *operating reserve* and are identified as having met the local market power mitigation condition for *operating reserve* in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5A s.10.8.1; and

3.3.7.2 all *resources* that meet the condition outlined in MR Ch.7 App7.5 s.10.6.2.

Constrained Area Condition Test for Global Market Power Mitigation for Operating Reserve

3.3.8 Subject to section 3.3.9, in regards to the global market power mitigation process in the *operating reserve market* outlined in section 3.4.13, the *IESO* shall apply such conduct tests to the following *resources*:

3.3.8.1 All *resources* that have a *real-time market schedule* for *operating reserve* and are identified as having met the global market power mitigation condition for *operating reserve* in the Outputs of the Constrained Area Conditions Test produced in accordance with MR Ch.7 App.7.5A s.10.8.1;

3.3.8.2 Any *GOG-eligible resource* that has a *real-time schedule* for *operating reserve*;

3.3.8.3 all *resources* that meet the condition outlined in MR Ch.7 App7.5 s. 10.7.3; and

3.3.8.4 Any *resource* that, either as permitted in accordance with MR Ch.7 ss.3.3.4B, 3.3.8, 3.3.9.2, 3.3.11 and 21.6 or as approved by the *IESO* in accordance with MR Ch.7 s.3.3.6, a new *operating reserve offer* within the *real-time market mandatory window*.

3.3.9 Notwithstanding the foregoing*, non-committable resources* may only be subject to the conduct tests described in sections 3.4.2, 3.4.4, 3.4.6, 3.4.8, and 3.4.10. For greater certainty, *GOG-eligible resources* may, depending on the outcome of this section 3.3, be subject to any conduct test set out in section 3.4.

3.4 Conduct Test

3.4.1 Subject to section 3.4.14, the *IESO* shall apply the conduct tests as set out in this section 3.4. For the purpose of the conduct tests set out in this section 3.4:

3.4.1.1 where a *resource* has not submitted a *minimum loading point,* the applicable *minimum loading point* is deemed to be zero MW, and all *offer laminations* for such *resource* will be considered to be above the *energy offer* lamination that includes its *minimum loading point;*

3.4.1.2 the maximum quantity of the *offer laminations* that form part of $EMFC\_RT\_BE_{k,h}^{m}$ will be equal to the maximum quantity of the *resource's* submitted *offer laminations*; and

3.4.1.3 $EMFC\_RT\_BE_{k,h}^{m}$ shall not exceed 20 laminations for a *resource* that is not a *pseudo-unit* or the number of laminations specified in MR. Ch.7 s.3.5.5.6 for a *resource* that is a *pseudo-unit*. Where the outcome of the conduct test set out in this section 3.4 would otherwise violate this requirement, the *IESO* shall:

(i) for conduct tests applicable to laminations that are above the *energy offer* lamination that includes its *minimum loading point,* delete the laminations in order from the highest price to the lowest price, except maintaining the lamination with the highest price, until the number of laminations is equal to the maximum number of laminations permitted; and

(ii) for conduct tests applicable to laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point,* replace all laminations with one lamination where the price is equal to the highest price lamination of the relevant *reference level* and the quantity is equal to the submitted *minimum loading point.*

Local Market Power Mitigation Process in a Narrow Constrained Area for Energy Offers Greater than the Offer Lamination That Includes Minimum Loading Point

3.4.2 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.1(a) to the *resources* identified in section 3.3.2. For each *settlement hour* 'h' that qualified to be tested under section 3.2.2.1(a) and for each such *resource* the *IESO* shall:

3.4.2.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m} > 25$; and

ii. $PGTMLP_{k,h,a}^{m} > min((PGTMLPRef_{k,h,a'}^{m} + abs(PGTMLPRef_{k,h,a'}^{m}) \times 0.5), PGTMLPRef_{k,h,a'}^{m} + 25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

Local Market Power Mitigation Process in a Narrow Constrained Area for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

3.4.3 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.1(b) to the *resources* identified in ss.3.3.2.2 to 3.3.2.4. For each *settlement hour* 'h' within a *real-time commitment period* and/or *real-time reliability commitment period* that contains a *settlement hour* that qualified to be tested under section 3.2.2.1(b) and for each such *resource* the *IESO* shall:

3.4.3.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\left(\left(PLTMLPRef_{k,h,a'}^{m} + abs\left(PLTMLPRef_{k,h,a'}^{m}\right) \times 0.5\right), PLTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $RT\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

3.4.3.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 0.25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

3.4.3.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > \left(SNLRef_{k,h}^{m} + abs\left(SNLRef_{k,h}^{m}\right) \times 0.25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Local Market Power Mitigation Process in a Dynamic Constrained Area for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

3.4.4 the *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.2(a) to the *resources* identified in section 3.3.3. For each *settlement hour* 'h' that qualified to be tested under section 3.2.2.2(a) and for each such *resource* the *IESO* shall:

3.4.4.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m}$ > 25; and

ii. $PGTMLP_{k,h,a}^{m} > min\left(\left(PGTMLPRef_{k,h,a'}^{m} + abs\left(PGTMLPRef_{k,h,a'}^{m}\right) \times 0.5\right), PGTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

Local Market Power Mitigation Process in a Dynamic Constrained Area for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

3.4.5 the *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.2(b) to the *resources* identified in ss.3.3.3.2 to 3.3.3.4. For each *settlement hour* 'h' within a *real-time commitment period* and/or *real-time reliability commitment period* that contains a *settlement hour* that qualified to be tested under section 3.2.2.2(b) and for each such *resource* the *IESO* shall:

3.4.5.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m}$> 25; and

ii. $PLTMLP_{k,h,a}^{m} > min\left(\left(PLTMLPRef_{k,h,a'}^{m} + abs\left(PLTMLPRef_{k,h,a'}^{m}\right) \times 0.5\right), PLTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $RT\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

3.4.5.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > (SUDGRef_{k,h}^{m} + abs(SUDGRef_{k,h}^{m}) \times 0.25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

3.4.5.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs(SNLRef_{k,h}^{m}) \times 0.25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Local Market Power Mitigation Process in a Broad Constrained Area for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

3.4.6 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.3(a) to the *resources* identified in section 3.3.4. For each *settlement hour* 'h' that qualified to be tested under section 3.2.2.3(a) and for each such *resource* the *IESO* shall:

3.4.6.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m}$ > 25; and

ii. $PGTMLP_{k,h,a}^{m} > min\ ((PGTMLPRef_{k,h,a'}^{m} + abs(PGTMLPRef_{k,h,a'}^{m}) \times 3), PGTMLPRef_{k,h,a'}^{m} + 100$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal

$PLTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{LTMLP,m}_{k,h}$ and $PGTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{GTMLP,m}_{k,h}$;

Local Market Power Mitigation Process in a Broad Constrained Area for Energy Offers up to and Including the Offer Lamination That Includes Minimum Loading Point

3.4.7 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.3(b) to the *resources* identified in sections 3.3.4.2 or 3.3.4.3. For each *settlement hour* 'h' within a *real-time commitment period* and/or *real-time reliability commitment period* that contains a *settlement hour* that qualified to be tested under section 3.2.2.3(b) and for each such *resource* the *IESO* shall:

3.4.7.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A^{GTMLP,m}_{k,h}$, if

i. $PLTMLP^{m}_{k,h,a} > 25$; and

ii. $PLTMLP^{m}_{k,h,a} > min\left(\left(PLTMLPRef^{m}_{k,h,a'} + abs\left(PLTMLPRef^{m}_{k,h,a'}\right) \times 3\right), PLTMLPRef^{m}_{k,h,a'} + 100\right.$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE^{m}_{k,h}$ shall equal $PLTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{LTMLP,m}_{k,h}$ and $RT\_BE^{m}_{k,h}$ for all *offer* laminations $a \in A^{GTMLP,m}_{k,h}$;

3.4.7.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG^{m}_{k,h} > \left(SUDGRef^{m}_{k,h} + abs\left(SUDGRef^{m}_{k,h}\right) \times 1\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU^{m}_{k,h}$ shall equal $SUDGRef^{m}_{k,h}$; and

3.4.7.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > (SNLRef_{k,h}^{m} + abs(SNLRef_{k,h}^{m}) \times 1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Global Market Power Mitigation Process for Energy Offers Greater Than the Offer Lamination That Includes Minimum Loading Point

3.4.8 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.4(a) to the *resources* identified in section 3.3.5. For each *settlement hour* 'h' that qualified to be tested under section 3.2.2.4(a) and for each such *resource* the *IESO* shall:

3.4.8.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m} > 25$; and

ii. $PGTMLP_{k,h,a}^{m} > min\left(\left(PGTMLPRef_{k,h,a'}^{m} + abs\left(PGTMLPRef_{k,h,a'}^{m}\right) \times 3\right), PGTMLPRef_{k,h,a'}^{m} + 100\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

Global Market Power Mitigation Process for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

3.4.9 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.4(b) or 3.2.2.4(c) to the *resources* identified in ss.3.3.5.2 or 3.3.5.3. For each *settlement hour* 'h' within a *real-time commitment period* and/or *real-time reliability commitment period* that contains a *settlement hour* that qualified to be tested under section 3.2.2.4(b) or 3.2.2.4(c) and for each such *resource* the *IESO* shall:

3.4.9.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\left(\left(PLTMLPRef_{k,h,a'}^{m} + abs\left(PLTMLPRef_{k,h,a'}^{m}\right) \times 3\right), PLTMLPRef_{k,h,a'}^{m} + 100\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $RT\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

3.4.9.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 1\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

3.4.9.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs\left(SNLRef_{k,h}^{m}\right) \times 1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Local Market Power Mitigation Process due to Reliability Constraints for Energy Offers Greater than the Offer Lamination That Includes Minimum Loading Point

3.4.10 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.5 to the *resources* identified in section 3.3.6. For each *settlement hour* 'h' that qualified to be tested under section 3.2.2.5 and for each such *resource* the *IESO* shall:

3.4.10.1 Evaluate *energy offer* laminations that are above the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{GTMLP,m}$, if

i. $PGTMLP_{k,h,a}^{m} > 25$; and

ii. $PGTMLP_{k,h,a}^{m} > min\left(\left(PGTMLPRef_{k,h,a'}^{m} + abs\left(PGTMLPRef_{k,h,a'}^{m}\right) \times 0.1\right), PGTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal $PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $PGTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

Local Market Power Mitigation Process Due to Reliability Constraints for Energy Offers Up to and Including the Offer Lamination That Includes Minimum Loading Point

3.4.11 The *IESO* shall apply the following conduct test in the circumstances outlined in section 3.2.2.5 to the *resources* identified in section 3.3.6. For each *settlement hour* 'h' within a *real-time commitment period* and/or *real-time reliability commitment period* that contains a *settlement hour* that qualified to be tested under section 3.2.2.5 and for each such *resource* the *IESO* shall:

3.4.11.1 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A_{k,h}^{LTMLP,m}$, if

i. $PLTMLP_{k,h,a}^{m} > 25$; and

ii. $PLTMLP_{k,h,a}^{m} > min\left(\left(PLTMLPRef_{k,h,a'}^{m} + abs\left(PLTMLPRef_{k,h,a'}^{m}\right) \times 0.1\right), PLTMLPRef_{k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE_{k,h}^{m}$ shall equal

$PLTMLPRef_{k,h,a'}^{m}$ for all *offer* laminations $a \in A_{k,h}^{LTMLP,m}$ and $RT\_BE_{k,h}^{m}$ for all *offer* laminations $a \in A_{k,h}^{GTMLP,m}$;

3.4.11.2 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG_{k,h}^{m} > \left(SUDGRef_{k,h}^{m} + abs\left(SUDGRef_{k,h}^{m}\right) \times 0.1\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU_{k,h}^{m}$ m shall equal $SUDGRef_{k,h}^{m}$; and

3.4.11.3 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs\left(SNLRef_{k,h}^{m}\right) \times 0.1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

Local Market Power Mitigation Process in the Operating Reserve Market

3.4.12 The *IESO shall* apply the following conduct test in the circumstances outlined in section 3.2.3.1 to the *resources* identified in section 3.3.7. For each *settlement hour* 'h' that qualified to be tested under section 3.2.3.1 and for each such *resource* the *IESO* shall:

3.4.12.1 Evaluate *offers* for *operating reserve* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *class r reserve* for any *offer* lamination '*a*':

For all $a \in A_{r,k,h}^{m}$, if

i. $PDG_{r,k,h,a}^{m} > 5$; and

ii. $PDG_{r,k,h,a}^{m} > \min\left(\left(PDGRef_{r,k,h,a'}^{m} + abs\left(PDGRef_{r,k,h,a'}^{m}\right) \times 0.1\right), PDGRef_{r,k,h,a'}^{m} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BOR^{m}_{r,k,h}$ shall equal $PDGRef^{m}_{r,k,h,a'}$ for all *offer* lamination $a \in A^{m}_{r,k,h}$ for the *class r reserve* for which it failed the test;

3.4.12.2 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A^{LTMLP,m}_{k,h}$, if

i. $PLTMLP^{m}_{k,h,a} > 25$; and

ii. $PLTMLP^{m}_{k,h,a} > min\left((PLTMLPRef^{m}_{k,h,a'} + abs(PLTMLPRef^{m}_{k,h,a'}) \times 0.1), PLTMLPRef^{m}_{k,h,a'} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE^{m}_{k,h}$ shall equal $PLTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{LTMLP,m}_{k,h}$ and $RT\_BE^{m}_{k,h}$ for all *offer* laminations $a \in A^{GTMLP,m}_{k,h}$;

3.4.12.3 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG^{m}_{k,h} > \left(SUDGRef^{m}_{k,h} + abs\left(SUDGRef^{m}_{k,h}\right) \times 0.1\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU^{m}_{k,h}$ shall equal $SUDGRef^{m}_{k,h}$; and

3.4.12.4 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SNL^{m}_{k,h} > SNLRef^{m}_{k,h} + abs\left(SNLRef^{m}_{k,h}\right) \times 0.1)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL^{m}_{k,h}$ shall equal $SNLRef^{m}_{k,h}$.

Global Market Power Mitigation Process in the Operating Reserve Market

3.4.13 The *IESO shall* apply the following conduct test in the circumstances outlined in section 3.2.3.2 to the *resources* identified in section 3.3.8. For each *settlement hour* 'h' that qualified to be tested under section 3.2.3.2 and for each such *resource* the *IESO* shall:

3.4.13.1 Evaluate *offers* for *operating reserve* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *class r reserve* for any *offer* lamination '*a*':

For all $a \in A^{m}_{r,k,h}$, if

i. $PDG^{m}_{r,k,h,a} > 5$; and

ii. $PDG^{m}_{r,k,h,a} > \min\left(\left(PDGRef^{m}_{r,k,h,a'} + abs\left(PDGRef^{m}_{r,k,h,a'}\right) \times 0.5\right), PDGRef^{m}_{r,k,h,a'} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BOR^{m}_{r,k,h}$ shall equal $PDGRef^{m}_{r,k,h,a'}$ for all *offer* lamination $a \in A^{m}_{r,k,h}$ for the *class r reserve* for which it failed the test;

3.4.13.2 Evaluate *energy offer* laminations that are up to and including the *energy offer* lamination that includes its *minimum loading point* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if the following is true for any *offer* lamination '*a*':

For all $a \in A^{LTMLP,m}_{k,h}$, if

i. $PLTMLP^{m}_{k,h,a} > 25$; and

ii. $PLTMLP^{m}_{k,h,a} > min\left(\left(PLTMLPRef^{m}_{k,h,a'} + abs(PLTMLPRef^{m}_{k,h,a'}) \times 0.5\right), PLTMLPRef^{m}_{k,h,a'} + 25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_BE^{m}_{k,h}$ shall equal $PLTMLPRef^{m}_{k,h,a'}$ for all *offer* laminations $a \in A^{LTMLP,m}_{k,h}$ and $RT\_BE^{m}_{k,h}$ for all *offer* laminations $a \in A^{GTMLP,m}_{k,h}$;

3.4.13.3 Evaluate *start-up offers* as follows:

a. a *resource* at *delivery point* 'm' fails the conduct test for *settlement hour* 'h' if $SUDG^{m}_{k,h} > \left(SUDGRef^{m}_{k,h} + abs\left(SUDGRef^{m}_{k,h}\right) \times 0.25\right)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SU_{k,h}^{m}$ shall equal $SUDGRef_{k,h}^{m}$; and

3.4.13.4 Evaluate *speed no-load offers* as follows:

a. a *resource* at *delivery point* ‘m’ fails the conduct test for *settlement hour* ‘h’ if $SNL_{k,h}^{m} > SNLRef_{k,h}^{m} + abs(SNLRef_{k,h}^{m}) \times 0.25)$

b. where such *resource* fails the conduct test and for the *settlement hour* that failed the conduct test, $EMFC\_RT\_SNL_{k,h}^{m}$ shall equal $SNLRef_{k,h}^{m}$.

3.4.14 If multiple conduct tests set out in section 3.4 apply in regards to the same *settlement hour*, then the *IESO* shall apply the following:

a. where multiple conduct tests for *energy* greater than *minimum loading point* apply in regards to the same *settlement hour,* the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour*;

b. where multiple conduct tests for *energy* up to and including *minimum loading point* apply in regards to the same *settlement hour*, the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to all *settlement hours* within the *real-time commitment period* and/or *real-time reliability commitment period* that contains such *settlement hour;*

c. where both a conduct test for *energy* up to and including *minimum loading point* and *energy* greater than *minimum loading point* apply with respect to the same *settlement hour,*

i. the greater than *minimum loading point* conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour;* and

ii. if the *resource* does not fail such greater than *minimum loading point* conduct test, the up to and including *minimum loading point* conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour.*

d. where multiple conduct tests for *operating reserve offers* apply in regards to the same *settlement hour,* the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to such *settlement hour*;

e. where multiple conduct tests for *start-up offer* or *speed no-load offers*, as the case may be, apply in regards to the same *settlement hour*, the conduct test with the most restrictive threshold, as determined in accordance with section 1.1.1.3*,* shall apply to all *settlement hours* within the *real-time commitment period* and/or *real-time reliability commitment period* that contains such *settlement hour.*

RUL-23

Renewed Market Rules

Chapter 0.10

Transmission Service and Planning

Renewed Market Rules – Chapter 0.10: Transmission Service and Planning

0.10

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

1. Introduction

1.1 Objectives of this Chapter and Interpretation

1.1.1 This Chapter of the *market rules* sets forth the terms and conditions under which the *IESO* will administer the collection and distribution of *transmission services charges* for transactions that use the *IESO-controlled grid* for the transmission of *energy* and *ancillary services*.

1.1.2 The *market rules* in this Chapter and MR Ch.7 are intended to satisfy the requirements of section 27 of the *Electricity Act, 1998* that the conveyance of electricity into, through or out of the *IESO-controlled grid* shall be pursuant to the *market rules*.

1.1.3 This Chapter sets forth procedures that the *IESO* and *market participants* will use to assess the *reliability* of the *IESO-controlled grid*.

1.1.4 For the purpose of giving effect to the collection and *settlement* of *transmission services charges* contemplated in this Chapter 10, all references in MR Ch.9 s.6, other than MR Ch.9 s.6.2 to a *market participant* shall be deemed to include a reference to a *transmission customer*.

1.1.5 For the purpose of giving effect to the collection and *settlement* of *transmission services charges* contemplated in this Chapter 10, all references in MR Ch.6 to a *metered market participant* shall be deemed to include a reference to a *transmission customer*.

2. Transmission Services

2.1 Classes of Service

2.1.1 The *IESO* shall administer the collection and distribution of *transmission services charges* for the various classes of *transmission service* as required by this Chapter and in accordance with the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*.

2.2 Billing and Payment for Service

Billing Procedure

2.2.1 The *IESO* shall include a line item on each *invoice* issued in respect of an *energy market billing period* pursuant to MR Ch.9 to each *transmission customer* that is required to pay for a *transmission service* with respect to which the *IESO* is required to collect charges in accordance with this Chapter, which shall cover the charges for *transmission services* during that *energy market billing period*. The charges for *transmission service* in such *invoice* shall be paid by the *transmission customer* on the *market participant payment date* associated with the *invoice* at the same time and in the same manner as required for the payment of *invoices* under MR Ch.9.

Reimbursement of Transmitters

2.2.2 The *IESO* shall include a line item on each *invoice* issued in respect of an *energy market billing period* pursuant to MR Ch.9 to each *transmitter* that is entitled to payment for a *transmission service* with respect to which the *IESO* is required to collect charges in accordance with this Chapter. Such line item shall, subject to section 2.2.2A, reflect an amount equal to that portion of the charges for *transmission services*, as invoiced to *transmission customers* pursuant to section 2.2.1, relating to that *transmitter's transmission system*. On each *IESO payment date* in respect of each applicable *energy market billing period*, the *IESO* shall remit any amount owing pursuant to such *invoice* to each applicable *transmitter* by *electronic funds transfer* in the manner provided in MR Ch.9 and in accordance with the applicable rate order issued by the *OEB* to the *transmitter*.

2.2.2A Notwithstanding any other provision of these *market rules*, the *IESO* shall not be required to make payment to a *transmitter* in respect of charges for *transmission services* relating to that *transmitter's transmission system* that have been *invoiced* to a *transmission customer* that is not a *market participant* until such time as the *IESO* has received payment from such *transmission customer* for such charges. Where such a *transmission customer* fails to pay such an *invoice*, the *IESO* shall not be required to take any action other than notifying the applicable *transmitter* of the default in payment.

Customer Default

2.2.3 Without limiting the generality of MR Ch.3 s.6.3.1.1, failure by a *market participant* to make payment to the *IESO* in respect of *transmission service* by the due date as described in section 2.2.1 constitutes an *event of default* in respect of that *market participant* pursuant to MR Ch.3 s.6 of and shall be dealt with by the *IESO* accordingly.

Collection Obligation

2.2.3A The *IESO* shall not be required to collect charges for *transmission service* from any *transmission customer* in respect of the *transmission system* of a given *transmitter* unless the information or documentation referred to:

2.2.3A.1 in section 3.1.3, 5.1.3 or 6.1.3; or

2.2.3A.2 where section 6A.1.2 applies, in that section, as may be applicable, relating to that *transmission customer* has been provided.

2.3 Arranging for Transmission Service and Dispatch

2.3.1 *Energy* and *ancillary service* transactions, including import and export transactions, using the *IESO-controlled grid* shall be arranged with the *IESO* using the *offer*, *bid*, *self-scheduling*, *contracted ancillary services* and other procedures set forth in MR Ch.7.

2.3.2 *Energy* and *ancillary service* transactions, including import and export transactions, using the *IESO-controlled grid* shall be subject to *dispatch* by the *IESO*:

2.3.2.1 in accordance with the procedures for *dispatching generation resources*, *electricity storage resources*, *dispatchable loads* and *boundary entity resources*, based on the *offers*, *bids*, *self-schedules*, and forecasts of *intermittent generation* submitted by *market participants* pursuant to MR Ch.7 or in accordance with the terms of applicable *contracted ancillary services* contracts; and

2.3.2.2 in circumstances where the *IESO* determines that *curtailment* is necessary to protect the *reliability* of the *IESO-controlled grid* or the *integrated power system* or to ensure the safety of any person, prevent the damage of equipment, or to prevent the violation of any *applicable law* pursuant to MR Ch.5.

3. Network Service

3.1 Network Service

3.1.1 [Intentionally left blank]

3.1.2 The *IESO* shall collect charges for *network service* from each *transmission customer*:

3.1.2.1 [Intentionally left blank]

3.1.2.2 [Intentionally left blank]

3.1.2.3 [Intentionally left blank]

3.1.2.4 that is identified by an applicable *transmitter* pursuant to section 3.1.3.1 as being required by the applicable rate order issued by the *OEB* to pay for *network service*; and

3.1.2.5 in respect of which the necessary *meter point* documentation has been provided by the *transmission customer's metering service provider* pursuant to MR Ch.6 App.6.5 s. 1.3A.

3.1.3 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and to whom the *OEB* has issued a rate order shall:

3.1.3.1 provide to the *IESO*, and update as required, a list of those *transmission customers* that, pursuant to the terms of the rate order issued to the *transmitter* by the *OEB*, are required to pay charges in respect of *network service* relating to such *transmission system*; and

3.1.3.2 for each *transmission customer* identified in the list referred to in section 3.1.3.1, provide to the *IESO*, as required under any agreement between the *IESO* and the *transmitter*, written confirmation of its approval of that portion of the *meter point* documentation specified in such agreement and of any updates thereto prepared in accordance with MR Ch.6 App.6.5 s.1.3 for each transmission *delivery point*, as described in the applicable transmission rate schedule approved by the *OEB*, for such *transmission customer;* and

3.1.3.3 annually review the list of *transmission customers* provided to the *IESO* in accordance with section 3.1.3.1 and the information provided pursuant to section 3.1.3.2 and promptly notify the *IESO* of any errors within such list or information.

3.1.4 The *IESO* shall notify each *transmitter* providing the list referred to in section 3.1.3.1 as to the identity of those *transmission customers* who have:

3.1.4.1 not been registered with the *IESO* as a *market participant*; or

3.1.4.2 otherwise ceased to be a *market participant*.

3.2 Arranging for Network Service

3.2.1 [Intentionally left blank]

3.2.2 [Intentionally left blank]

3.2.3 No *transmission customer* shall commence to obtain *network service* until the relevant *transmitter* and the *transmission customer* have completed the installation of all equipment required to connect the *transmission customer* to, or otherwise provide access to, the *IESO-controlled grid*, as specified in MR Ch.4, and the applicable *connection point*, other than an *interconnection*, or *embedded connection point* has, where required by these *market rules*, a *metering installation* that complies with the requirements of MR Ch.6.

3.3 Maintaining Network Service

3.3.1 [Intentionally left blank]

3.3.2 To the extent that a *transmission customer* desires to add a new *delivery point* for *network service*, the *transmission customer* shall provide the *IESO* with as much advance notice as practicable of such addition. No *transmission customer* shall establish a new *delivery point* until *connection facilities* at the new delivery point have been completed and satisfy the requirements of MR Ch.4.

3.4 Rates and Charges for Network Service

3.4.1 The rates and charges, if any, for *network service* to be applied to the *transmission customers* identified in a list provided to the *IESO* pursuant to section 3.1.3.1 shall be as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

3.5 [Intentionally left blank]

3.6 Responsibilities of Market Participants Utilising Network Service

3.6.1 Each *transmission customer* that is a *market participant* utilising *network service* shall plan, construct, operate and maintain its system, *facilities* and equipment in accordance with MR Ch.4 and MR Ch.5.

3.7 [Intentionally left blank]

3.8 Import Transactions

3.8.1 The *IESO-controlled grid* shall be available for the transmission of *energy* and *ancillary services* into the *IESO control area* from a neighbouring *transmission system*. Charges for *network service* shall not be applicable to a *market participant* in respect of the use of the *IESO-controlled grid* for such transmission. The *IESO* shall determine the available transmission capability at each *interconnection* with a neighbouring *transmission system* for imports into the *IESO control area* and shall manage congestion over such *interconnections* in accordance with MR Ch.7 s.3A.1.4.

3.9 [Intentionally left blank]

4. Export Transmission Service

4.1 Availability of Export Transmission Service

4.1.1 The *IESO-controlled grid* shall be available for the transmission of *energy* out of the *IESO control area* into a neighbouring *transmission system*. Charges for *network service* shall not be applicable to a *market participant* in respect of the use of the *IESO-controlled grid* for such transmission. The *IESO* shall determine the available transmission capability at each *interconnection* with a neighbouring *transmission system* for exports out of the *IESO control area* and shall manage congestion over such *interconnections* in accordance with MR Ch.7 s.3A.1.4.

4.1.2 The *IESO* shall collect charges for *export transmission service* from each *transmission customer* that uses the *IESO-controlled grid* for the transmission of *energy* out of the *IESO control area*.

4.2 [Intentionally left blank]

4.3 Arranging for Export Transmission Service

4.3.1 To arrange for *export transmission service*, a *transmission customer* desiring such service shall be a *market participant* and shall register to use a *boundary entity resource* to which the *export transmission service* will relate. A *transmission customer* that is a *market participant* may obtain *export transmission service* once it has registered to use the *boundary entity resource*.

4.4 Responsibility for Third-Party Arrangements

4.4.1 Each *transmission customer* obtaining *export transmission service* shall be responsible for any arrangements with other *control areas* or third parties that are necessary to deliver *energy* from the *IESO-controlled grid* to the *transmission customer's delivery point* outside the *IESO-controlled grid*.

4.5 Rates and Charges for Export Transmission Service

4.5.1 The rates and charges, if any, for *export transmission service* to be applied to the *transmission customers* referred to in section 4.1.2 shall be as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

5. Line Connection Service

5.1.1 The *IESO* shall collect charges for l*ine connection service* from each *transmission customer*:

5.1.1.1 that is identified by an applicable *transmitter* pursuant to section 5.1.3.1 as being required by an applicable rate order issued by the *OEB* to pay for *line connection service*; and

5.1.1.2 in respect of which the necessary *meter point* documentation has been provided by the *transmission customer's metering service provider* pursuant to MR Ch.6 App.6.5 s.1.3A.

The rates and charges, if any, for *line connection service* to be applied to such *transmission customer* shall be as established by the *OEB* from time to time under the *Ontario Energy Board Act, 1998*.

5.1.2 [Intentionally left blank]

5.1.3 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and to whom the *OEB* has issued a rate order shall:

5.1.3.1 provide to the *IESO*, and update as required, a list of those *transmission customers* that, pursuant to the terms of the rate order issued to the *transmitter* by the *OEB*, are required to pay charges in respect of *line connection service* relating to such *transmission system*;

5.1.3.2 for each *transmission customer* identified in the list referred to in section 5.1.3.1, provide to the *IESO*, as required under any agreement between the *IESO* and the *transmitter*, written confirmation of its approval of that portion of the *meter point* documentation specified in such agreement and of any updates thereto prepared in accordance with MR Ch.6 App 6.5 s.1.3 for each transmission *delivery point*, as described in the applicable transmission rate schedule approved by the *OEB*, for such *transmission customer*; and

5.1.3.3 annually review the list of *transmission customers* provided to the *IESO* in accordance with section 5.1.3.1 and the information provided pursuant to section 5.1.3.2 and promptly notify the *IESO* of any errors within such list or information.

5.1.4 The *IESO* shall notify each *transmitter* providing the list referred to in section 5.1.3.1 as to the identity of those *transmission customers* who have:

5.1.4.1 not been registered with the *IESO* as a *market participant*; or

5.1.4.2 otherwise ceased to be a *market participant*.

6. Transformation Connection Service

6.1.1 The *IESO* shall collect charges for *transformation connection service* from each *transmission customer*:

6.1.1.1 that is identified by an applicable *transmitter* pursuant to section 6.1.3.1 as being required by an applicable rate order issued by the *OEB* to pay for *transformation connection service*; and

6.1.1.2 in respect of which the necessary *meter point* documentation has been provided by the *transmission customer's metering service provider* pursuant to MR Ch.6 App.6.5 s.1.3A.

The rates and charges, if any, for *transformation connection service* to be applied to such *transmission customer* shall be as established by the *OEB* from time to time under the *Ontario Energy Board Act, 1998*.

6.1.2 [Intentionally left blank]

6.1.3 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and to whom the *OEB* has issued a rate order shall:

6.1.3.1 provide to the *IESO*, and update as required, a list of those *transmission customers* that, pursuant to the terms of the rate order issued by the *OEB*, are required to pay charges in respect of *transformation connection service* relating to such *transmission system*;

6.1.3.2 for each *transmission customer* identified in the list referred to in section 6.1.3.1, provide to the *IESO*, as required under any agreement between the *IESO* and the *transmitter*, written confirmation of its approval of that portion of the *meter point* documentation specified in such agreement and of any updates thereto prepared in accordance with MR Ch.6 App.6.5 s.1.3 for each transmission *delivery point*, as described in the applicable transmission rate schedule approved by the *OEB*, for such *transmission customer*; and

6.1.3.3 annually review the list of *transmission customers* provided to the IESO in accordance with section 6.1.3.1 and the information provided pursuant to section 6.1.3.2 and promptly notify the IESO of any errors within such list or information.

6.1.4 The *IESO* shall notify each *transmitter* providing the list referred to in section 6.1.3.1 as to the identity of those *transmission customers* who have:

6.1.4.1 not been registered with the *IESO* as a *market participant*; or

6.1.4.2 otherwise ceased to be a *market participant*.

6A. Other Transmission Service

6A.1.1 The *IESO* shall, where required by the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*, collect charges for any *transmission service* other than one referred to in sections 3, 4, 5 and 6 from each *transmission customer* that is required by such rate order to pay for such *transmission service* and, where section 6A.1.2 applies:

6A.1.1.1 that has been identified in the list referred to in section 6A.1.2.1; and

6A.1.1.2 in respect of which the information referred to in section 6A.1.2.2 has been provided.

The rates and charges for such *transmission service* shall be as established by the *OEB* from time to time under the *Ontario Energy Board Act, 1998.*

6A.1.2 At the request of the *IESO*, each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* shall provide to the *IESO*, and shall update as required:

6A.1.2.1 a list of those *transmission customers* that, pursuant to the terms of a rate order issued by the *OEB*, are required to pay charges in respect of any *transmission service* referred to in section 6A.1.1 relating to such *transmission system*; and

6A.1.2.2 such other information as the *IESO* may reasonably require in respect of such *transmission customer*, including but not limited to any confirmation that may be required from the *transmitter* under any agreement between it and the *IESO*, so as to enable the *IESO* to perform any necessary calculations for the charges referred to in section 6A.1.2.1 in a manner consistent with the rate order referred to in that section.

6A.1.3 The *IESO* shall notify each *transmitter* providing the list referred to in section 6A.1.2.1 as to the identity of those *transmission customers* who have:

6A.1.3.1 not been registered with the *IESO* as a *market participant*; or

6A.1.3.2 otherwise ceased to be a *market participant*.

6A.1.4 Each *transmitter* whom has provided a list of *transmission customers* and/or other information as may be reasonably required by the *IESO* in accordance with section 6A.1.2 shall annually review such list and information and promptly notify the *IESO* of any errors within such list or information.

6B. Liability

6B.1.1 The *IESO* shall be entitled to and shall rely on the list of *transmission customers* provided pursuant to section 3.1.3.1, 5.1.3.1, 6.1.3.1 or 6A.1.2.1 and on the *meter point* documentation or other information provided pursuant to section 3.1.2.2, 5.1.1.2, 6.1.1.2 or 6A.1.1.2, regardless of whether any portion of such *meter point* documentation has been confirmed by the applicable *transmitter*, for the purpose of the collection and distribution of charges for a *transmission service* and, notwithstanding section 13 of Chapter 1:

6B.1.1.1 the *IESO* shall not be liable to any person in respect of the collection from a *transmission customer* of, or the failure to collect from that *transmission customer*, charges in respect of a *transmission service* by reason of the erroneous identification, inclusion or exclusion of that person on or from such list or by reason of any inaccuracies in such *meter point* documentation or other information; and

6B.1.1.2 the applicable *transmitter* providing the *IESO* with such list or other information shall indemnify and hold harmless the *IESO* in respect of any and all claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation or collection by the *IESO* of charges in respect of a *transmission service* by reason of the erroneous identification, inclusion or exclusion of a person on or from such list or by reason of any inaccuracies in such other information or *meter point* documentation pertaining to any of its *transmission customers*,

provided that nothing in this section 6B.1.1 shall be construed as affecting the liability of the *IESO* in respect of the manner of calculation of charges for a *transmission service* collected from a person that is properly identified or included on such list and in respect of which such *meter point* documentation or other information is accurate.

6B.1.2 Notwithstanding section 13.4.1 of Chapter 1, the liability and indemnification provisions of section 6B.1.1 shall apply to any agreement between the *IESO* and a *transmitter* pursuant to sections 3.1.3, 5.1.3, 6.1.3, or 6A.1.2.2.

6C. Correction of Errors in Lists

6C.1.1 The *IESO* shall promptly notify the applicable *transmitter* upon becoming aware that a *transmission customer* may be erroneously identified, included or excluded on or from a list of *transmission customers* provided by such *transmitter* pursuant to section 3.1.3.1, 5.1.3.1, 6.1.3.1 or 6A.1.2.1. Where applicable, the *transmitter* shall promptly update the list accordingly.

6C.1.2 Subject to section 6C.1.4, the *IESO* shall use reasonable efforts to adjust the applicable *settlement statement* of a *transmission customer* that:

6C.1.2.1 has been charged or that has failed to be charged for a *transmission service* by reason of the erroneous identification, inclusion or exclusion of that *transmission customer* on or from a list of *transmission customers* provided by the applicable *transmitter* pursuant to section 3.1.3.1, 5.1.3.1, 6.1.3.1 or 6A.1.2.1; or

6C.1.2.2 has been incorrectly charged for a *transmission service* by reason of any inaccuracies in the *meter point* documentation or other information referred to in section 3.1.3.2, 5.1.3.2, 6.1.3.2 or 6A.1.2.2.

6C.1.3 Subject to section 6C.1.4, where the *IESO*:

6C.1.3.1 charges a *transmission customer* for *transmission service* pursuant to section 6C.1.2.1, the *IESO* shall include such charge on the applicable *invoice* issued to the *transmission customer* in accordance with section 2.2.1 and shall, subject to section 2.2.2A, include as a credit on the applicable *invoice* submitted to each applicable *transmitter* an amount equal to that portion of the charges for *transmission services*, as charged to *transmission customers*, relating to that *transmitter's transmission system* in accordance with section 2.2.2;

6C.1.3.2 credits a *transmission customer* for charges for *transmission service* for which it should not have been charged pursuant to section 6C.1.2.1 the *IESO* shall include such credit on the applicable *invoice* issued to the *transmission customer* in accordance with section 2.2.1 and shall include as a debit on the applicable *invoice* submitted to each applicable *transmitter* an amount equal to that portion of the charges for *transmission services*, as credited to *transmission customers*, relating to that *transmitter's transmission system* in accordance with section 2.2.2; or

6C.1.3.3 corrects the amount charged for a *transmission service* pursuant to section 6C.1.2.2, the *IESO* shall include an amount equal to such correction as a credit or debit, as the case may be, on the applicable *invoice* issued to the *transmission customer* in accordance with section 2.2.1 and shall include as a credit or debit, as the case may be, on the applicable *invoice* submitted to each applicable *transmitter* an amount equal to such correction, as credited or debited to *transmission customers*, relating to that *transmitter's transmission system* in accordance with section 2.2.2.

6C.1.4 The *IESO* shall not take any action or make any correction under section 6C in regards to any *settlement amount* if a limitation period applicable to such *settlement amount* prescribed in *applicable law* has lapsed. Additionally, where a *transmitter* fails to conduct a review, in accordance with sections 3.1.3.3, 5.1.3.3, 6.1.3.3, or 6A.1.4, as the case may be, the *IESO* shall not take any action or make any correction under section 6C in regards to any *settlement amount* pertaining to the information which the *transmitter* failed to review that arose prior to the date on which the *transmitter* failed to conduct the applicable review.

6C.1.5 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6C.1.2, the *market participant* may pursue their disagreement through the dispute resolution process outlined in MR Ch.3 s.2.

7. [Intentionally left blank – section deleted]

8. Information Requirements

8.1 [Intentionally left blank – section deleted]

8.2 [Intentionally left blank – section deleted]

8.3 [Intentionally left blank – section deleted]

8.4 [Intentionally left blank – section deleted]

8.5 [Intentionally left blank – section deleted]

8.6 [Intentionally left blank – section deleted]

8.7 Retirements

8.7.1 [Intentionally left blank – section deleted]

8.7.2 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* shall provide to the *IESO* not less than six months' advance notice of the commencement of planned retirements of transmission *facilities*, including notification of any plans the *transmitter* may have to construct replacement *facilities* for those being retired. If the *IESO* believes that a planned retirement of transmission *facilities* may have an adverse effect on the *reliability* of the *IESO-controlled grid*, or on the efficient operation of the *IESO-administered markets*, the

IESO may request that the *transmitter* not retire the *facility*. If the *IESO* and a *transmitter* disagree regarding the retirement of a transmission *facility*, or with respect to the *transmitter's* plans to replace such a *facility*, the matter may, subject to *licence* of the *IESO* or of the *transmitter* or to the provisions of the applicable *operating agreement,* be submitted for resolution using the dispute resolution procedures set forth in MR Ch.3 s. 2.

8.8 Transmitter Data Access

8.8.1 Each *transmitter* for which the *IESO* administers the collection and distribution of *transmission services charges* for the various classes of *transmission service* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998* and whose *transmission system* forms part of the *IESO-controlled grid* shall, where applicable, have access to the following *confidential information* related to each type of *transmission services charge* in a manner and form specified by the *IESO*:

8.8.1.1 *energy* readings that reside in the *metering database* pursuant to MR Ch.6 s.10.1.5.3which have been loss adjusted and totalized to their respective *delivery points* defined for the purposes of *transmission services charges* as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*;

8.8.1.2 *interchange schedule data* used in the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*;

8.8.1.3 the coincident or non-coincident peak *demand* quantity for each transmission *delivery point* to the extent that such quantities are relevant to the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*;

8.8.1.4 the peak *demand* quantity applicable to the *transmitter's transmission system* or the *IESO-controlled grid* as the case may be, to the extent that such quantities are relevant to the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*; and

8.8.1.5 the *transmission services charges* payable by each *transmission customer* to the transmitter at each *delivery point* defined for the purposes of *transmission services charges* or *intertie metering point* to the extent that such data is relevant to the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

8.8.2 The *transmitter* to whom the disclosure of information described in section 8.8.1 is made shall use the *confidential information* so disclosed solely for the purposes of collecting and administering those *transmission services charges* and shall use all reasonable efforts to protect the confidentiality of such *confidential information*, including but not confined to adherence of any code, licence condition, order by the *OEB* or applicable law regarding the separation of the *transmitter's* commercial activities and information with respect to any other affiliated entities as may be defined in said code, licence condition, order, or applicable law.

8.8.3 Notwithstanding MR Ch.1 s.13, the applicable *transmitter* receiving the *confidential information* referred to in section 8.8.1 shall indemnify and hold harmless the *IESO* in respect of any and all claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the subsequent use of such information by, the *transmitter*.

9. [Intentionally left blank – section deleted]

RUL-24

Renewed Market Rules

Chapter 0.11

Definitions

Connecting Today.
Powering Tomorrow.

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Table of Contents

Introduction

A.1.1 This Chapter is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for operation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect prior to the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation; or

A.1.4.4 affect an investigation, proceeding or remedy in respect of:

(a) a right, privilege, obligation or liability described in subsection A.1.4.2; or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5 An investigation, proceeding or remedy pertaining to any matter described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

Definitions

In the market rules:

actual exposure means, the estimated net amount payable by or owing to a *market participant* at any given time, calculated by the *IESO* for a *market participant* pursuant to MR Ch.2 ss.5.5, 5C.3, or 5D.2;

adequacy means the ability of the *electricity system* to supply electrical demand and *energy* requirements at all times, taking into account *outages*;

adjustment period allocation refers to a means of allocating post-final adjustments to *settlement amounts.* This allocation is based on *market participant* activity in the *energy market* during the event that is the subject of the originating *settlement* adjustment;

administrative price means a price established by the *IESO* in the circumstances referred to and in accordance with MR Ch.7 s.8.4A;

advance approval means *IESO* approval of a *planned outage* before the scheduled start date of the *planned outage*. *Advance approval* includes *quarterly advance approval, weekly advance approval, three-day advance approval* and *one-day advance approval*;

advanced pre-dispatch operational commitment means a minimum scheduling constraint advancement established by the *IESO* to a *GOG-eligible resource's minimum loading point,* that applies for a duration of at least one hour in advance of an existing *day-ahead operational commitment* or *stand-alone pre-dispatch operational commitment* based on the *binding pre-dispatch advisory schedule,* during the applicable hours specified by the *IESO* pursuant to MR Ch.7 s.5.8.2.5;

affiliate, with respect to a corporation, has the meaning ascribed thereto in the *Business Corporations Act* (Ontario);

alternative intertie reference level value means the *intertie reference level value* determined by the *IESO* pursuant to MR Ch.7 s.22.19.4;

alternative reference quantity value means the *reference quantity value* determined by the *IESO* pursuant to MR Ch.7 s.22.15.21;

amend, in relation to the *market rules*, means any change to the *market rules*, whether by amendment, alteration, addition or deletion;

amendment submission has the meaning ascribed thereto in MR Ch.3 s.4.2.4;

ancillary service means services necessary to maintain the *reliability* of the *IESO-controlled grid*, including, but not limited to, *regulation*, *black start capability*, *voltage control*, reactive power, *operating reserve* and any other such services established by the *market rules*;

ancillary service provider means a person who provides an *ancillary service*;

applicable law means all laws, regulations, other statutory instruments and rules and other documents of a legislative nature which apply to the *IESO* or to *market participants*, and all orders of a government, governmental body, authority or agency having jurisdiction over the *IESO* or a *market participant* including, but not limited to, any *licence* issued to the *IESO* or a *market participant*;

applicant has the meaning ascribed thereto in MR Ch.3 s.2.5.1;

application for authorization to participate means the form *published* by the *IESO* and by which a person may apply for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

<u>Arbitration Act, 1991</u> means the Arbitration Act, 1991, S.O. 1991, c. 17;

arbitrator means a qualified person appointed pursuant to MR Ch.3 s.2.7 to arbitrate a dispute;

area control error or *ACE* means the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias;

attended means regularly staffed on a twenty-four hours a day, seven days a week basis;

auction capacity means an amount in megawatts of electricity available to be provided to the *IESO-controlled grid*, by *capacity market participants* in association with a *capacity auction*;

auction period means, with respect to a *capacity auction,* the length of time commencing with the opening of the window during which the *IESO* receives *capacity auction offers*, and finishing at the time at which the *IESO publishes* auction results;

authority centre means, in respect of a *facility*, an *attended* location at which indirect operational control of the *facility* is effected;

automatic generation control or *AGC* means the process that automatically adjusts the output from a *generation resource* or an *electricity storage resource* that is providing *regulation;*

automatic voltage regulation or *AVR* means the process that automatically adjusts the reactive output of a *generation unit, electricity storage unit,* or synchronous condenser to maintain the *unit* terminal voltage within a pre-determined range;

availability declaration envelope means the most recent maximum quantity of *energy* included in a *bid* or *offer* submitted in the *day-ahead market* under MR Ch.7 s.3.1.11, as issued by the *IESO* under MR Ch.7 s.4.8.1;

availability de-rating factor means, in respect of an *obligation period*, a value which is assigned to a *capacity auction resource*, as determined in accordance with the applicable *market manual*;

availability window means the hours in an *obligation period* during which *capacity auction resources* are required to be available to provide *auction capacity*;

basecase means a model of electrical components of the *IESO-controlled grid* and *neighbouring electricity systems.* Such components may include but are not limited to transformers, *generation facilities, electricity storage facilities,* and transmission lines, and includes the steady-state, dynamic and short circuit attributes of each component where applicable;

BES exception applicant means (i) a *market participant* who owns *IESO controlled-grid* elements or *facilities* who applies to the *IESO* for a *BES exception*; or (ii) a *connection applicant* who applies to the *IESO* for a *BES exception*;

BES exception request means an application for the approval, amendment, termination, or transfer of a *BES exception* pursuant to MR Ch.5 s.3.2B;

bid means a statement of the quantities and prices of a commodity that a buyer is willing to purchase in the *day-ahead market*, the *real-time market* or the *procurement markets* and includes *dispatch data* parameters that are submitted in accordance with MR Ch.7 s.3;

bidding limit means, in respect of a given *TR participant*, the amount calculated by the *IESO* for that *TR participant* in accordance with MR Ch.8 s.3.14.1;

billing period means, in respect of the purchase or sale of *TRs* in a round of a *TR auction,* a period of a *trading week,* in respect of the *day-ahead market*, the *real-time market* and the *settlement* of amounts owing to *TR holders* under MR Ch.9 s.3.8.1, a period of a calendar month;

binding pre-dispatch advisory schedule means those *dispatch hours* of the *pre-dispatch schedule* for a *GOG-eligible resource* (i) that are the initial set of contiguous *dispatch hours* greater than or equal to its *minimum loading point* excluding the hours scheduled for the *ramp up energy to minimum loading point,* and (ii) that are the basis for a *start-up notice* for a *stand-alone pre-dispatch operational commitment* or *advanced pre-dispatch operational commitment*;

black start capability means the capability of a *generation facility* to start without an outside electrical supply so as to be used to energize a defined portion of the *IESO-controlled grid*;

boundary entity means the set of *boundary entity resources* associated with an *intertie zone;*

boundary entity resource means a construct existing within the *IESO's* systems that facilitates *intertie* flow between the *IESO-controlled grid* and an *intertie zone*;

bulk electric system exception or *BES exception* is an exception from compliance with the requirements of *NERC reliability standards* relating to elements or *facilities* connected to the *IESO controlled-grid* in accordance with the Ontario-adapted *NERC* procedure for processing *BES exceptions;*

business day means any day other than a Saturday, a Sunday or a holiday as defined in section 88 of the *Legislation Act* and, where expressed by reference to the jurisdiction of a *market participant* other that the Province of Ontario, means any day other than a Saturday, a Sunday or a day on which banks are authorized or required to be closed in the jurisdiction of that *market participant*;

buying market participant means a *market participant* that is purchasing *energy* under a *physical bilateral contract*;

called capacity export means an *energy* export from the *IESO control area* that is supported by the capacity of a *generation resource* or the capacity for injection of an *electricity storage resource* within the *IESO control area* that has committed its capacity, or a portion thereof, to an external *control area* and that capacity has been called by the external *control area operator* in accordance with MR Ch.7 s.20.3;

Canadian prime interest rate means the base lending rate that the bank where the *IESO settlement clearing account* is maintained charges for commercial loans to its best and most creditworthy commercial customers;

capacity auction means an auction operated by the *IESO* to acquire *auction capacity;*

capacity auction capacity test means a test which is used to evaluate a capacity auction resource on their ability to provide *capacity*, as specified in the applicable *market manual*;

capacity auction clearing price means the price at which *a capacity auction* clears for an *obligation period* and is expressed in $/MW-day;

capacity auction commitment period means the period of time for each *capacity auction* over which it secures *capacity*. It consists of two *obligation periods;*

capacity auction deposit means the deposit required to be made by a *capacity auction participant* in accordance with MR Ch.7 s.18, as a condition of participating in a *capacity auction;*

capacity auction dispatch test means a test conducted by the *IESO* in which *capacity auction resources* are evaluated on their ability to successfully respond to *dispatch instructions* as specified in the applicable *market manual*;

capacity auction eligible generation resource means a *generation resource* that is a *non-committed resource,* associated with a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as *dispatchable* with the *IESO* prior to the *obligation period* in accordance with the timelines specified in the applicable *market manual*;

capacity auction eligible storage resource means an *electricity storage resource* that is a *non-committed resource* associated with a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as *dispatchable* with the *IESO* prior to the *obligation period* in accordance with the timelines specified in the applicable *market manual*;

capacity auction offer means an *offer(s)* from a *capacity auction participant*, in the form of a *price-quantity pair(s)*, to provide *auction capacity* through a *capacity auction resource* for an applicable *obligation period*, reflecting the amount of *auction capacity* that the *capacity auction participant* can reliably and responsibly provide if received as a *capacity obligation*, and which *offer* amount is no greater than the *capacity auction participant's unforced capacity;*

capacity auction participant means a person that is authorized to participate in a *capacity auction* and submit *capacity auction offers*;

capacity auction reference price represents the price at which resources would be incentivized to enter the market and recover the necessary costs to make their capacity available, recognizing their revenue opportunities and avoided costs in the *energy market*. The reference price is directly associated with the *target capacity* as another key reference point in the demand curve;

capacity auction resource means a *resource* specified in MR Ch.7 s.19.1.2 and is utilized by a *capacity auction participant* to satisfy a *capacity obligation*;

capacity auction zonal constraints means the minimum or maximum amount of *auction capacity*, or virtual *demand response capacity* that a *capacity auction* seeks to secure for a specific electrical zone or group of electrical zones as detailed by the *IESO* in each pre-auction report;

capacity dispatchable load resource means a *dispatchable load* that has received a *capacity obligation* in a given *capacity auction* in accordance with the applicable *market manual*;

capacity export agreement means an agreement between the *IESO* and a *control area operator* regarding the management of *called capacity exports*, and which may include but is not limited to *interconnection agreements*;

capacity export request means a request submitted to the *IESO* by a *market participant* for approval to commit the Ontario-based capacity of a *generation resource* or the injection capacity of an *electricity storage resource* to an external *control area* in accordance with MR Ch.7 s.20.1;

capacity generation resource means a *capacity auction eligible generation resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual*;

capacity import call means an *energy* import from an external *control area* that is supported by the capacity of a *generation unit* or the capacity for injection of an *electricity storage unit* within the external *control area* that has committed its capacity, or a portion thereof, to the *IESO control area* and that capacity has been called by the *IESO* in accordance with MR Ch.7 s.19.9 or 19.9B;

capacity market participant means a *capacity auction participant* that has registered with the *IESO* as a *capacity market participant,* and who satisfies requirements contemplated in MR Ch.7s.18;

capacity obligation means the amount of *cleared UCAP* that a *capacity market participant* is required to provide from a particular *capacity auction resource* during each hour of the *availability window* of an *obligation period*;

capacity prudential support means the collateral provided by a *market participant* with a *capacity obligation in* accordance with the requirements contemplated in MR Ch.2 s.5B;

capacity prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of satisfying a *capacity obligation*;

capacity qualification request means a request submitted to the *IESO* by a *capacity auction participant* which includes the *installed capacity* and all other applicable information, using the forms specified by the *IESO*, for the determination of the *unforced capacity* of a *capacity auction resource* in the capacity qualification process specified in the applicable *market manual*;

capacity storage resource means a *capacity auction eligible storage resource* with a *capacity obligation* received in a given *capacity auction,* in accordance with the applicable *market manual;*

capacity transferee means a *capacity auction participant* who is willing to accept all or a portion of a *capacity obligation* from a *capacity transferor.* A *capacity transferee* may be the same *capacity auction participant* as the *capacity transferor;*

capacity transferor means a *capacity auction participant* who intends to transfer all or a portion of its *capacity obligation* received through a *capacity auction* to a *capacity transferee.* A *capacity transferor* may be the same *capacity auction participant* as the *capacity transferee;*

cascade group means one or more *forebays* in a river system;

certified black start facility means a *generation facility* contracted in accordance with MR Ch.9 s.4.2.2 that, to the satisfaction of the *IESO* acting reasonably, has complied with and continues to comply with equipment and staffing configurations, training and maintenance programs and inspection and testing regime as set out in the *market rules* or the *Ontario power system restoration plan*, and from which the *IESO* may direct the delivery of power without assistance from the electrical system;

charge type means the identifier designating an item on an *invoice* or a *settlement statement*;

class r reserve means *operating reserve* of class r, where r = 1 denotes synchronized *ten-minute operating reserve,* r = 2 denotes non-synchronized *ten-minute operating reserve,* and r = 3 denotes *thirty-minute operating reserve*;

cleared ICAP means, in respect of a *capacity auction resource*, an amount in megawatts of electricity, as determined in accordance with MR.Ch.7 s.18.8.2 and adjusted for any applicable *capacity obligation* buy-outs or *capacity obligation* transfers;

cleared UCAP means an amount in megawatts of electricity that a *capacity auction resource* cleared in a given *capacity auction* and adjusted for any applicable *capacity obligation* buy-outs, *capacity obligation* transfers, or in-period *cleared UCAP* adjustments;

close of banking business means 3:00 p.m. on the day the relevant bank is open for business;

cogeneration facility means a *generation facility* that produces both electric *energy* and either steam or other forms of useful energy (such as heat), which are used for industrial, commercial, heating, or cooling purposes, and qualifies for treatment as a Class 43.1 facility or has qualified as a Class 34 facility under the Income Tax Act, R.S.C. 1985, c.1;

combined cycle plant means a group of *generation resources* associated with a *generation facility* in which *energy* is generated by one or more *generation units* that are combustion turbines and by one *generation unit* that is a steam turbine for which steam is supplied by recovery of waste heat from one or more of the combustion turbines or by an independent injection of heat from duct firing;

commissioning electricity storage facility means an *electricity storage facility* located within the *IESO control area* that is either (i) newly constructed or (ii) significantly redesigned or rebuilt and is designated by the *IESO* as a *commissioning electricity storage facility* and, in either case, that has not yet completed the commissioning tests referred to in MR Ch.7 s.2.2D.4.2;

commissioning generation facility means a *generation facility* located within the *IESO control area* that is either (i) newly constructed or (ii) significantly redesigned or rebuilt and is designated by the *IESO* as a *commissioning generation facility* and, in either case, that has not yet completed the commissioning tests referred to in MR Ch.7 s.2.2A.4.2;

commitment cost parameters means *start-up offer*, *speed no-load offer*, and the portion of an *energy offer* up to and including the *minimum loading point*;

confidential information means (i) information which has been supplied by the disclosing person in confidence implicitly or explicitly, where disclosure could reasonably be expected to: (a) prejudice significantly the competitive position of the disclosing person; (b) interfere significantly with the contractual or other negotiations of the disclosing person or another person; (c) result in undue loss or gain to the disclosing person or another person; (d) compromise the efficiency of the *IESO-administered markets*; (e) result in the disclosing person being in breach of a bona fide confidentiality agreement to which the information is subject; or (f) in the opinion of the *IESO*, pose a potential security threat to the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions; and (ii) information that, pursuant to the *market rules* or *applicable law*, the *IESO* or a *market participant* cannot disclose or make available to one or more persons;

confidentiality classification means a classification referred to in MR Ch.3 s.5.4.1;

connect means to form a physical link to or with the *IESO-controlled grid* through a *connection facility*;

connected facility means a *facility connected* to the *IESO-controlled grid*;

connected wholesale customer means a *wholesale customer*, other than a *distributor*, that is directly *connected* to the *IESO-controlled grid*;

connection agreement means an agreement entered into between a *transmitter* and a *market participant* governing the terms and conditions pursuant to which the *market participant* is *connected* to the *transmitter's transmission system*;

connection applicant means any of: (i) a *market participant* or person that applies to the *IESO* for approval of a new *connection* to the *IESO-controlled grid* or for approval of the modification of an existing *connection* to the *IESO-controlled grid*, or (ii) a *distributor* in whose *distribution system* a *market participant* or person is or intends to be connected as an *embedded generator* or *embedded electricity storage participant* whose *facility* is or will be rated greater than 10 MW, that seeks to establish a new or modify an existing connection pursuant to MR Ch.4 s.6.1.6;

connection assessment means a study conducted by the *IESO* pursuant to MR Ch.4 s.6.1.5 to assess the impact of a new *connection* to the *IESO-controlled grid* or of the modification of an existing *connection* to the *IESO-controlled grid* on the *reliability* of the *integrated power system*;

connection charge means a charge for recovering costs associated with connection to a *transmission system*;

connection facility means a *facility* and equipment that allow a person to become *connected* to the *IESO-controlled grid* and includes, in the case of a *distributor*, distribution assets owned by a person other than the *distributor* that have been deemed by the *OEB* to be transmission assets;

connection point means a point of connection between the *IESO-controlled grid* and a *generation facility, electricity storage facility,* or *load facility*, or the point at which a neighbouring *transmission system* is connected to the *IESO-controlled grid*;

connection-related reliability information means any information provided or requested pursuant to MR Ch.7 s.2.2.5 and/or MR Ch.4 s.6.1.6;

connection request means a request submitted by a *market participant* or a *connection applicant* to a *transmitter* for *connection* to the *IESO-controlled grid*;

connection station service is *station service* associated with transformers, capacitors, switchgear, protection systems and control systems that *connect generation facilities*, *electricity storage facilities, load facilities* or distribution *facilities* to the *IESO-controlled grid*;

conservative operating state means the state described in MR Ch.5 s.2.5;

consumer means a person who uses, for the person’s own consumption, electricity that the person did not generate;

contingency event means the unexpected failure of a single component or multiple components connected to the *electricity system*;

contracted ancillary services means *ancillary services*, other than *operating reserve*, procured by the *IESO* by contract rather than in the *real-time markets* in accordance with MR Ch.7 ss.9.2 to 9.5;

contributor outage means an *outage* of a *demand response contributor* where its energy consumption is less than 1% of its peak consumption measured in the prior three months, excluding any *outages* related to *generation units*;

control area means an area on an electricity system where supply and demand are kept in balance through *dispatch* by the *control area operator*;

control area operator means the person responsible for the *secure* operation of a *control area*, and includes independent system operators and regional transmission organizations in other jurisdictions;

control centre means, in respect of a *facility* or group of *facilities,* an *attended location* where signals and instructions for controlling the associated *resources* are received from an *authority centre* or the *IESO*, and transferred directly to the *facilities* for implementation;

costs of the arbitration means the fees and expenses of an *arbitrator* and any other costs and expenses related to the arbitration of a dispute under MR Ch.3 s.2, other than the legal costs and expenses of the parties to the dispute and of any intervenor;

costs of the mediation means the fees and expenses of a *mediator* and any other costs and expenses related to the mediation of a dispute under MR Ch.3 s.2, other than the legal costs and expenses of the parties to the dispute and of any person permitted by the *mediator* to attend a mediation session pursuant to MR Ch.3 s.2.6.6;

current period adjustment means an adjustment that is effected against amounts owing or payable in respect of transactions reflected in a *settlement statement* issued for the *billing period* or *trading day* during which the *current period adjustment* is effected regardless of the *billing period* or *trading day* during which the *preliminary settlement statement* to which the adjustment relates occurred;

curtailment means the involuntary curtailment of consumption by *non-dispatchable loads* or *price responsive loads* as a result of insufficient *generation capacity* or *electricity storage capacity*, of a limitation in the capacity of a *transmission system* or of actions taken by the *IESO* pursuant to MR Ch.5 to maintain the *reliability* of the *IESO-controlled grid* or of the *electricity system*;

day-ahead commitment period means the set of contiguous *settlement hours* described in MR Ch.9 s.4.4.1.1(c);

day-ahead market or *DAM* means a daily, *IESO-administered market* that creates financially binding obligations for a *dispatch day* on the day prior to the relevant *dispatch day*;

day-ahead market calculation engine means an algorithm that consists of three passes, where each pass executes one or more optimization problems solved by the *IESO* to determine schedules and prices in accordance with MR Ch.7 App.7.5 to meet the needs of the *day-ahead market*;

day-ahead market expiration means the earliest time at which the *IESO publishes* and issues *day-ahead market* results in accordance with MR Ch.7 ss.4.7.2 and 4.8.1 or when the *IESO* declares a *day-ahead market* failure in accordance with MR Ch.7 s.4.3.2;

day-ahead market external congestion rent means, in respect of an *intertie zone* and a *settlement hour*, the total *day-ahead market* external congestion collected by the *IESO* for all *boundary entity resources*, determined as the *day-ahead market* quantity of *energy* scheduled for withdrawal minus the *day-ahead market* quantity of *energy* scheduled for injection, multiplied by the *day-ahead market* price of external congestion ($DAM\_PEC_h^i$) as defined in MR Ch.9 App.9.2;

day-ahead market restricted window means the period of time commencing at 10:00 EPT on the day prior to the relevant *dispatch day* until *day-ahead market expiration;*

day-ahead market submission window means the period of time commencing at 06:00 EPT and ending at 10:00 EPT on the day prior to the relevant *dispatch day;*

day-ahead operational commitment means a minimum scheduling constraint established by the *IESO* to a *GOG-eligible resource's minimum loading point* based on the *day-ahead schedule* to respect the *resource's minimum generation block run-time* during the hours specified by the *IESO* pursuant to MR Ch.7 s.4.8.1.4;

day-ahead operational schedule means the hours in a *GOG-eligible resource's day-ahead schedule* that are greater than or equal to the *minimum loading point* excluding the hours scheduled for the *ramp up energy to minimum loading point*;

day-ahead schedule means the hourly schedule for the 24-hour period of the next *dispatch day* as determined by the *DAM calculation engine* during the *day-ahead market*;

data collection system means a means of extracting *metering data* from a *metering installation* and transferring such *metering data* into a remote *metering database*;

data logger means a device designed to be capable of reading and holding data until that data is collected;

default amount means a dollar amount by which a *market participant* has defaulted upon its obligations to *settle* with the *IESO* and shall, for purposes of the imposition of a *default levy,* be calculated in accordance with MR Ch.2 s.8.3.1 or 8.5.1;

default interest means interest at the *default interest rate*;

default interest rate means the interest rate calculated as the *Canadian prime interest rate* plus 2%;

default levy means a levy imposed by the *IESO* on *non-defaulting market participants* in accordance with MR Ch.2 s.8;

default protection amount means a component of the *maximum net exposure* that represents the dollar estimate of the additional debt that a *market participant* could accumulate in the *real-time market* or *day-ahead market* between the time that a *market participant* commits an *event of default* and the time a *market participant* could be removed from the *real-time market* or *day-ahead market*, determined from time to time by the *IESO* for a *market participant* in accordance with MR Ch.2 s.5.3.8 or s.5C.1.7;

defaulting market participant means a *market participant* that is in default of payment in respect of monies owing to the *IESO* under the *market rules*;

defined meter point means (a) in respect of a *facility connected* to the *IESO-controlled grid* by a *connection facility* that is a radial line designated by the *IESO* for such purpose, the point at a voltage above 50 kV at which the designated radial line is *connected* to (i) the high voltage bus of the *facility*, or (ii) the *facility*, if there is no such high voltage bus; (b) in respect of a *facility connected* to the *IESO-controlled grid* by a *connection facility* other than one referred to in (a), the point at a voltage above 50 kV at which the *connection facility* is *connected* to the *IESO-controlled grid*; and (c) in respect of an *embedded market participant*, the point at which the *embedded market participant's facility* is connected to the *distribution system* within which it is *embedded*;

delivery point means a uniquely identified reference point determined in accordance with MR Ch.9 s.2.5 and used for *settlement* purposes in the *day-ahead market* and *real-time market*, other than in respect of transactions involving the transmission of *energy* or *ancillary services* into or out of the *IESO-controlled grid* from a neighbouring *transmission system*;

demand means the rate at which electric *energy* is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time;

demand response bid price threshold means the price which a *demand response energy bid* shall exceed in the *real-time market* in accordance with the applicable *market manual*;

demand response capacity means the quantity of load reduction provided by *dispatchable loads* and/or *hourly demand response resources*;

demand response contributor means *load equipment* that is associated with an *hourly demand response resource* and is used to satisfy in whole or a portion of a *capacity obligation. Demand response contributors* are registered by *capacity market participants* as part of the contributor management process detailed in the applicable *market manual*;

demand response energy bid means a *bid* in the *day-ahead market,* and a *bid* in the *real-time market* that is greater than the *demand response bid price threshold*, except during the *capacity auction capacity test* testing window, and less than the *MMCP,* by a *capacity market participant* entered for either a *capacity dispatchable load resource* or an *hourly demand response resource* to fulfill a *capacity obligation* availability requirement;

demand response resource means, in a *capacity auction,* either an *hourly demand response resource* or a *capacity dispatchable load resource*;

disaster recovery plan means the plan for maintaining *IESO settlement* functions in the event of a disaster;

disconnect means to separate *facilities* or equipment from the *IESO-controlled grid*, a *transmission system,* a *distribution system* or from a host *market participant*, as the case may be, and, in the case of a *distributor* that is *connected* to the *IESO-controlled grid* by distribution assets owned by a person other than the *distributor* that have been deemed by the *OEB* to be transmission assets, to separate the *distributor* from those assets;

disconnection order means an order issued by the *IESO* to any one of, or a combination of, a *transmitter,* a *distributor* or other *market participant*, directing such *transmitter, distributor* or other *market participant*, as applicable, to *disconnect facilities* or equipment specified within such order;

dispatch means the process by which the *IESO* directs the real-time operation of a *resource* to cause a specified amount of electric *energy* or *ancillary service* to be provided to or taken off the *electricity system*;

dispatch centre means, in respect of a *facility* or group of *facilities,* an *attended location* at which employees have the authority and capability to *dispatch* the associated *resources* based on the *dispatch instructions* received from the *IESO;*

dispatch data means the *offers*, *bids*, *self-schedules* or forecasts of *intermittent generation resources* required to be submitted to the *IESO* in accordance with MR Ch.7 and used by the *IESO* to determine schedules, physical operations and *market prices;*

dispatch day means a period from midnight EST to the following midnight EST;

dispatch hour means a one-hour period within a *dispatch day*;

dispatch instructions means in respect of a *resource* other than a *boundary entity resource*, a physical operating instruction issued by the *IESO* either in the *real-time dispatch process* or in those *dispatch intervals* when *administrative prices* were applied pursuant to MR Ch.7 s.8.4A or the *IESO-administered markets* are suspended pursuant to MR Ch.7 s.13, and, in respect of a *boundary entity resource*, the *interchange schedule* pertaining to it;

dispatch interval means a five-minute interval within a *dispatch hour*;

dispatch scheduling error means an error made by the *IESO* in the (i) *day-ahead market*; or (ii) *real-time dispatch process*, that is identified after the results of the *day-ahead market* or *real-time dispatch process,* as the case may be, have been *published* or issued*,* in circumstances where these *market rules, market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules* do not admit of any deviation or departure from the *day-ahead market* or *real-time dispatch process*;

dispatch workstation means the communication equipment that is required to be installed and maintained in accordance with MR Ch.2 App.2.2 for the purposes referred to in MR Ch.2 App.2.2 s.1.3.1;

dispatchable means being subject to *dispatch*;

dispatchable load means a *load resource* which is subject to *dispatch* by the *IESO* and whose level is selected or set based on the price of *energy* in the *day-ahead market* or *real-time market,* and, for greater certainty, excludes *hourly demand response resources*;

dispute outcome means the outcome of a dispute resolution process that requires adjustments to one or more *settlement statements,* whether arising from good faith negotiations, mediations, or an *arbitrator's* order;

dispute resolution panel means the panel of the same name established by the *IESO* pursuant to the *Governance and Structure By-law*;

distribute, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

distribution system means a system for *distributing* electricity, and includes any structures, equipment or other things used for that purpose;

distributor means a person who owns or operates a *distribution system*;

duct firing 10-minute operating reserve capability means the ability of a *pseudo-unit* to be scheduled to provide synchronized or non-synchronized *ten-minute operating reserve* in the duct firing region;

dynamic constrained area or *DCA* means a *potential constrained area* designated as a *dynamic constrained area* pursuant to MR Ch.7 s.22.10.3;

economic withholding means submitting *financial dispatch data parameters* or *non-financial dispatch data parameters* outside a *resource's reference level values* by more than the applicable threshold;

elapsed time to dispatch means the minimum amount of time, in minutes, between the time at which a start-up sequence is initiated for a *generation resource* or an *electricity storage* *resource* and the time at which it becomes *dispatchable,* including by reaching its *minimum loading point*, as registered by a *market participant* in accordance with MR Ch.7 s.2.2.6K;

electrical island has the meaning provided in the *NPCC* Glossary of Terms, as may be amended from time to time;

Electricity Act, 1998 means the *Electricity Act*, *1998*, S.O. 1998, c. 15, Schedule A;

Electricity and Gas Inspection Act means the Electricity and Gas Inspection Act, R.S.C. 1985, c. E-4;

electricity storage capacity means the maximum power that an *electricity storage unit* or *electricity storage facility* can supply, usually expressed in megawatts (MWs);

electricity storage energy rating means the maximum amount of stored *energy* of an *electricity storage unit* or *electricity storage facility*, usually expressed in megawatt hours (MWhs);

electricity storage facility means a *facility* that is comprised of one or more *electricity storage units* and includes any structures, equipment or other things to support the functioning of its *electricity storage units;*

electricity storage facility size means the greater of the absolute values of the maximum injection and maximum withdrawal capabilities of the *electricity storage facility* expressed in either megawatts (MWs) or megavolt amperes (MVAs);

electricity storage participant means a person who owns or operates an *electricity storage facility*;

electricity storage resource means a *resource* modelled to represent one or more *electricity storage units*;

electricity storage station service means *station service* associated with an *electricity storage facility* that is comprised of one or more *electricity storage units* each of which is associated with a *resource,* including a *resource* that is aggregated in accordance with MR Ch.7 s.2.3;

electricity storage unit means the equipment used for the sole purpose of withdrawing electricity from the *electricity system*, storing that electricity, and re-injecting it, or a portion thereof, into the *electricity system*;

electricity storage unit size means the greater of the absolute values of the maximum injection and maximum withdrawal capabilities of the *electricity storage unit* expressed in either megawatts (MWs) or megavolt amperes (MVAs);

electricity system means the *integrated power system* and all *facilities* registered with the *IESO* in accordance with MR Ch.7 s.2 that are connected to that system;

electronic funds transfer means the transfer of funds between bank accounts by electronic means;

electronic information system means the internet or the real-time communication network that is used for the exchange of information referred to in MR Ch.2 App.2.2 s.1.4.1 via the *participation workstation*;

embedded connection point means the point of connection between a *facility* and a *distribution system*;

embedded electricity storage facility means an *electricity storage facility* within the *IESO control area* and is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded electricity storage participant means an *electricity storage participant* whose *electricity storage facility* is within the *IESO control area* and is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system;*

embedded generator means a *generator* whose *generation facility* is within the *IESO control area* and is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system* and *embedded generation facility* shall be interpreted accordingly;

embedded load consumer means a person that owns or operates an *embedded load facility*;

embedded load facility means a *load facility* within the *IESO control area* that is not directly *connected* to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded market participant means a *market participant* whose *facility* is within the *IESO control area* and is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded registered wholesale meter (RWM) means a *registered wholesale meter* that is not a *primary registered wholesale meter* and that measures flows that are also part of the flows measured by a *primary registered wholesale meter*;

emergency means any abnormal system condition that requires remedial action to prevent or limit loss of a *transmission system* or generation supply that could adversely affect the *reliability* of the *electricity system*;

emergency energy means *energy* acquired by the *IESO* from another *control area* or provided by the *IESO* to another *control area* in order to maintain the *reliability* of the *IESO-controlled grid* or of a *transmission system* within such other *control area*;

emergency operating state means the state described in MR Ch.5 s.2.3;

emergency preparedness plan means a plan prepared by the *IESO* or required to be prepared by a *market participant* and submitted to the *IESO* in accordance with MR Ch.5 s.11.2.1;

energy means, in respect of the *market rules* other than MR Ch.5 or MR Ch.6, real *energy* only and may, in respect of MR Ch.5 or MR Ch.6, mean both real *energy* and reactive *energy* if the context so requires;

energy bid intertie reference level means an *intertie reference level* for an *energy bid;*

energy limited resource means a *dispatchable generation resource* or *dispatchable electricity storage resource* with a *maximum daily energy limit* for the applicable *dispatch day*;

energy offer intertie reference level means an *intertie reference level* for an *energy offer*;

energy offer reference level means a *reference level* for an *energy offer*;

energy market means the *day-ahead market* and *real-time market* for *energy* administered by the *IESO* pursuant to MR Ch.7, in which *energy offers* and *energy bids* are cleared and a *market price* for *energy* is determined;

energy per ramp hour means the average amount of *energy,* in MWh, that a *generation resource* is expected to produce in each hour that is part of the *ramp hours to minimum loading point*;

energy per ramp hour reference level means a *reference level* for a *resource's energy per ramp hour*;

energy ramp rate reference level means a *reference level* for a *resource's* ramp rate for *energy;*

energy trader means a *market participant* authorized by the *IESO* to participate in the *energy market* by importing, exporting, and wheeling *energy* or *operating reserve*;

enhanced combined cycle facility means a *generation facility* associated with one or more *combined cycle plants* in which the steam utilized to generate electricity in one or more of the steam turbines is supplemented by recovery of waste heat from an independent industrial process/processes such as waste heat from the gas turbine exhaust of a natural gas compressor station, and qualifies for treatment as a Class 43.1 facility or has qualified as a Class 34 facility under the Income Tax Act, R.S.C. 1985, c.1.;

estimated market prices means the price forecasts developed by the *IESO* for the purposes of determining *market participant maximum net exposures* and *prudential support obligations*;

event of default means an event referred to in MR Ch.3 s.6.3.1;

exemption means an exclusion from one or more specific obligations or standards which are or may be imposed on the *exemption applicant* or in respect of the *exemption applicant's facilities,* equipment or *resources* pursuant to the *market rules*, *market manuals* or from any standard, policy or procedure established by the *IESO* pursuant to the *market rules*;

exemption applicant means the *IESO* or a person, including a *market participant*, who submits an application for an *exemption*;

exemption application means the material submitted by the *exemption applicant* pursuant to the practice and procedure established by the *IESO Board* for the processing of an *exemption*;

existing support has the meaning ascribed thereto in MR Ch.2 s.5.2.5;

export transmission service means the *transmission service* relating to the use of the *IESO-controlled grid* for the transmission of *energy* out of the *IESO control area* into a neighbouring *transmission system* and in respect of which charges are required to be collected by the *IESO* pursuant to MR Ch.10 s.4;

extended pre-dispatch operational commitment means a minimum scheduling constraint extension established by the *IESO* to a *GOG-eligible resource's minimum loading point* for a duration of one hour immediately following an existing *day-ahead operational commitment*, *stand-alone pre-dispatch operational commitment* or a previous *extended pre-dispatch operational commitment,* based on a *pre-dispatch schedule,* during the hours specified by the *IESO* pursuant to MR Ch.7 s.5.8.2.2;

facility means a *generation facility*, a *load facility,* an *electricity storage facility,* a *connection facility,* a *transmission system*, or a *distribution system,* located within the *IESO control area*, or any other equipment that is a component or part of the *electricity system*;

federal metering requirements means all requirements relating to *meters* and to *metering installations* imposed by or under the authority of an Act of Parliament;

final recalculated settlement statement means the *recalculated settlement statement* issued by the *IESO* in accordance with either section 6.3.6(b) or section 6.3.17(g) of Chapter 9;

final settlement statement means the *IESO's* final statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase of *transmission rights* in the *TR market*, the *IESO*'s final statement of the payments to be made by a *TR holder* with respect to a given *TR auction* or the final statement of the payments to be made to a *TR holder* with respect to a given *billing period*;

financial dispatch data parameters means a subset of *dispatch data* that are represented as financial values and for which the *IESO* must determine *reference levels*;

flexible nuclear generation means the component of a nuclear *generation resource* that has flexibility for reductions due to the operation of condenser steam discharge valves, and is made available at the sole discretion of the *flexible nuclear generator* to manoeuvre without requiring the *resource* to shut down under normal operations, while respecting safety, technical, equipment, environmental and regulatory restrictions;

flexible nuclear generator means a *generator* whose *generation resource* has a component classified as *flexible nuclear generation*;

forbidden region means an operating range between the applicable lower limit and upper limit within which a hydroelectric *generation resource* cannot maintain steady operation without causing equipment damage. A hydroelectric *generation resource* may have more than one *forbidden region*;

force majeure event means, in relation to a person, any event or circumstance, or combination of events or circumstances, (i) that is beyond the reasonable control of the person; (ii) that adversely affects the performance by the person of its obligations under these *market rules*; and (iii) the adverse effects of which could not have been foreseen and prevented, overcome, remedied or mitigated in whole or in part by the person through the exercise of diligence and reasonable care, and includes, but is not limited to, acts of war (whether declared or undeclared), invasion, armed conflict or act of a foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or act of terrorism; strikes, lockouts, restrictive work practices or other labour disturbances; unlawful arrests or restraints by governments or governmental, administrative or regulatory agencies or authorities; orders, regulations or restrictions imposed by governments or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the person of a permit, licence or other authorization or of any *applicable law*; and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or accumulation of snow or ice or lack of water arising from weather or environmental problems; provided however, for greater certainty, that (i) the lack, insufficiency or non-availability of funds shall not constitute a *force majeure event*, (ii) an act of the *IESO* effected in accordance with the *market rules* or with the provisions of any form, policy, guideline or other document referred to in MR Ch.1 s.7.7 shall not constitute a *force majeure event* in respect of a *market participant*, and (iii) an act of a *market participant* effected in accordance with the *market rules* or with the provisions of any form, policy, guideline or other document referred to in MR Ch.1 s.7.7 shall not constitute a *force majeure event* in respect of the *IESO*;

forced outage means an unanticipated intentional or automatic removal from service of equipment or the temporary de-rating of, restriction of use or reduction in performance of equipment;

forebay means a body of water within a *cascade group* upon which one or more hydroelectric *generation resources* that have the same *registered market participant* may be registered;

forecasting entity means the entity or entities contracted by the *IESO* to provide forecasting services relating to *variable generation*;

forward period means the period of time beginning three (3) *business days* following a *capacity auction*, to the commencement of an *obligation period*;

funds transfer process means the process by which funds are transferred between the respective bank accounts of the *IESO*, *market participants* and *transmitters*;

generation capacity means the maximum power that a *generation unit*, generation station or other electrical apparatus can supply, usually expressed in megawatts;

generation facility means a *facility* for generating electricity or providing *ancillary services*, other than *ancillary services* provided by a *transmitter* or *distributor* through the operation of a *transmission* or *distribution system*, and may be composed of one or more *generation units* including any structures, equipment or other things used for that purpose;

generation resource means a *resource* modelled to represent one or more *generation units*;

generation station service means *station service* associated with a *generation facility* that is comprised of one or more *generation units* each of which is associated with a *resource,* including a *resource* that is aggregated in accordance with MR Ch.7 s.2.3;

generation unit means the principal equipment at a *generation facility* used to generate electricity, together with all internally related equipment essential to its functioning as a single unit distinguishable from other *generation units*;

generator means a person who owns or operates a *generation facility*;

generator failure means the occurrence of a failure determined in accordance with MR Ch.9 s.4.10.4 or s.4.10.7, for a *GOG-eligible resource* that is not a *pseudo-unit* or a *GOG-eligible resource* that is a *pseudo-unit,* respectively;

generator-backed capacity auction eligible import resource means one or more *generator-backed import contributors.* No portion of the capacity that is being offered into the *IESO capacity auction* may be *over committed capacity;*

generator-backed capacity import resource means a *generator-backed capacity auction eligible import resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual;*

generator-backed import contributor means an existing in-service generation facility or electricity storage facility associated with a *generator-backed capacity auction eligible import resource*, and which is located in a neighbouring *control area* that has an agreement with the *IESO* to allow for the trade of capacity, is able to qualify capacity in accordance with the applicable *market manual*, has been in operation for at least one year prior to the *capacity* *auction,* is a resource type that is currently enabled to participate in the *IESO's capacity auction,* and is able to transmit energy from the generation facility or the electricity storage facility to the Ontario border;

generator offer guarantee eligible resource or *GOG-eligible resource* means a *dispatchable non-quick start resource:*

(i) with a registered *elapsed time to dispatch* greater than one hour;

(ii) with a registered *minimum loading point* greater than 0 MW;

(iii) with a registered *minimum generation block run-time* greater than one hour; and

(iv) its primary or secondary fuel source is not uranium;

global market power reference intertie zone means an *intertie zone* designated pursuant to MR Ch.7 s.22.11.1;

good utility practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, *reliability*, safety and expedition. *Good utility practice* is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

Governance and Structure By-law means the by-law of the *IESO* made pursuant to subsection 22(2) of the *Electricity Act, 1998*;

gross MW as related to active power output from an *electricity storage unit*, *generation unit*, or *facility*, is the total amount of active power produced by such unit or *facility* as measured at the unit's terminal or as measured as a sum of active power produced by the *facility*'s individual units;

gross MX as related to reactive power output from an *electricity storage unit*, *generation unit*, or *facility*, is the total amount of reactive power produced by such unit or *facility* as measured at the unit's terminal or as measured as a sum of reactive power produced by the *facility*'s individual units;

high priority path facility means a voice communication facility that meets the requirements of MR Ch.2 App.2.2 s.1.1.7;

high-risk operating state means the state described in MR Ch.5 s.2.4;

hourly demand response resource means the *capacity auction resource* type that has received a *capacity obligation* in a given *capacity auction* and is used by a *capacity market participant* to satisfy a *capacity obligation* on an hourly basis and is activated by the *IESO* in accordance with MR Ch.7 s.19.4*;*

hourly must run means the quantity, in MWh, below which a *dispatchable* hydroelectric *generation resource* is incapable of responding to *dispatch instructions* due to specific must run conditions which could reasonably be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*;

hourly uplift means the uplift payments that are determined for each hour based on *real-time market* and *day-ahead market* results in that hour;

IESO or the *Independent Electricity System Operator* means the Independent Electricity System Operator, which is the continuation of the Independent Electricity Market Operator established under Part II of the *Electricity Act, 1998*;

IESO adjustment account means the *settlement account* operated by the *IESO* which is used for adjustments in *settlement* payments after a preliminary market *settlement* has been made;

IESO-administered markets means the markets established by the *market rules*;

IESO administration charge means the charge imposed by the *IESO* on *market participants* for the purpose of recovery by the *IESO* of its administration costs;

IESO Board means the Board of Directors of the *IESO*;

IESO catalogue of reliability-related information means the catalogue described in MR Ch.5 s.14.1.3;

IESO control area means that area, including the *IESO-controlled grid*, with respect to which the *IESO* is the *control area operator*;

IESO-controlled grid means the *transmission systems* with respect to which, pursuant to *operating agreements*, the *IESO* has authority to direct operations;

IESO-controlled grid model means the model capable of being used by the *day-ahead market calculation engine,* the *pre-dispatch calculation engine*, or the *real-time calculation engine* and described in MR Ch.7 s.3A.1.3;

IESO payment date means the date on which the *IESO* is to make *settlement* payments to *market participants*;

IESO prepayment account means the *settlement account* operated by the *IESO* to hold payments by *market participants* prior to the relevant *market participant payment date* to which such payments relate;

IESO settlement clearing account means the *settlement account* operated by the *IESO* for holding market *settlement* payments made to the *IESO*;

IESO Settlement Schedule & Payments Calendar or SSPC means the *IESO*'s calendar of dates for providing *settlement* information to *market participants* and of dates on which *settlement* payments must be made by and to the *IESO*;

information confidentiality catalogue means the applicable *market manual* listing information and its *confidentiality classification* determined pursuant to MR Ch.3 s.5;

installed capacity or *ICAP* means the amount, in MW, of electricity submitted by a *capacity auction participant*, in accordance with the applicable *market manual*, during the *IESO*'s capacity qualification process that reflects a *capacity auction resource's* maximum seasonal generation capability, load reduction capability, or import capability;

instance of intertie economic withholding means a *dispatch day* for which at least one of a *market participant's bids* or *offers* on a *boundary entity resource* failed a conduct test and associated impact test used to assess *intertie economic withholding* in an uncompetitive *intertie zone* in either the *day-ahead market* or *real-time market;*

instance of physical withholding means a *dispatch day* for which at least one of a *market participant's offers* for a *resource* failed a conduct test and associated impact test used to assess *physical withholding* in either the *day-ahead market* or *real-time market*;

instrument transformer means an iron cored device that isolates a *meter* from the primary voltage while passing a correct value of the primary measured quantity to the *meter*;

integrated power system means the *IESO-controlled grid* and the structures, equipment and other things that connect the *IESO-controlled grid* with *transmission systems* and *distribution systems* in Ontario and *transmission systems* outside Ontario;

interchange schedule means the scheduled *intertie* flow between the *IESO-controlled grid* and a neighbouring *control area*, determined by the *IESO* in accordance with MR Ch.7 s.6.1.3;

interchange schedule data means data pertaining to *interchange schedules*;

interconnected systems means two or more individual *transmission systems* that have one or more *interties*;

interconnected transmitter means a *transmitter* whose transmission facilities are outside the Ontario *control area* and has entered into an *interconnection agreement* with the *IESO;*

interconnection agreement means an agreement between the *IESO* and another *control area operator, security coordinator* or *interconnected transmitter* regarding the operation of an *interconnection* with the *IESO-controlled grid*;

interconnection means a connection between the *IESO-controlled grid* and a *transmission system* outside the *IESO control area* that have one or more interconnecting *interties*;

intermittent generation resource means a *generation resource* that generates on an intermittent basis as a result of factors beyond the control of the *generator* unless limited by *dispatch,* and excludes a *variable generation resource*;

intertie means a transmission line which forms part of an *interconnection*;

intertie border price or *IBP* means, in respect of an *intertie zone*, the *locational marginal price* of *energy* or *operating reserve* minus the *intertie congestion price,* determined in the *real-time market* or *day-ahead market* in accordance with the provisions of MR Ch.7 or the *administrative price*, where applicable;

intertie congestion price or *(ICP)* means in respect of an *intertie zone*, the portion of the *locational marginal price* that consists of the cumulative congestion costs resulting from the binding import or export transmission limits that affect transactions scheduled at such an *intertie zone*, including any net interchange scheduling limit congestion costs, as determined in the *real-time market* or *day-ahead market* in accordance with the provisions of MR Ch.7 or the *administrative price*, where applicable;

intertie economic withholding means submitting *offers* or *bids* on a *boundary entity resource* that are outside a *boundary entity resource's intertie reference level values* by more than the applicable threshold;

intertie metering point means a point within an *intertie zone*, at which the *IESO* obtains *interchange schedule data* for the purposes of the *settlement process*;

intertie reference level means an *IESO*-determined formula to calculate an *intertie reference level value*;

intertie reference level value means an *IESO*-determined estimate of a *dispatch data* parameter that a *market participant* would have submitted for a *boundary entity resource* if such *boundary entity resource* were subject to *unrestricted competition*;

intertie zone means a market region designated by the *IESO* which is connected to the *IESO-controlled grid* by an *intertie*;

invoice means an invoice from the *IESO* to a *market participant* which sets forth a *settlement amount*;

lead time means the amount of time, in hours, required for a *generation resource* to complete its start-up procedures and reach its *minimum loading point* from the applicable *thermal state*;

lead time reference level means a *reference level* for a *resource's lead time;*

legacy market rules means the baseline of *market rules* and *market manuals* in effect immediately prior to *the market transition,* but excluding the *renewed market rules;*

licence means a licence issued by the Ontario Energy Board pursuant to the *Ontario Energy Board Act, 1998*;

line connection service means the *transmission service* relating to the use of the line connection assets of a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and in respect of which charges are required to be collected by the *IESO* pursuant to MR Ch.10 s.5.1.1;

linked forebay means a *forebay* that is upstream or downstream from another *forebay* in the same *cascade group*, and that has a *time lag* relationship and *MWh ratio* with the other *forebay*;

linked wheeling through transaction means a set of import and export *energy* transactions scheduled in the *day-ahead market* or the *real-time market* for *boundary entity resources*, that have been linked by the relevant *market participant* pursuant to MR Ch.7 s.3.5.19.2;

load equipment means equipment within a *load facility* that draws electrical *energy* from the *integrated power system*;

load facility means a *facility* that draws electrical *energy* from the *integrated power system*;

load resource means a *resource* modelled to represent one or more sets of *load equipment*;

load serving breaker means a device, or sequence of devices, which provide a single path for *energy* to flow between a *connection facility* and a *load facility*;

local area has the meaning ascribed thereto in MR Ch.5 s.5.4.1;

locational marginal price or *LMP* means, in respect of a *delivery point, intertie metering point*, or other relevant location, the price of *energy* or *operating reserve* determined in the *real-time market* or in the *day-ahead market* in accordance with the provisions of MR Ch.7, or an *administrative price*, where applicable. For greater certainty, the *locational marginal price* for *intertie* transactions includes both the *intertie border price* and the *intertie congestion price*;

long-term auction means a *TR auction* conducted by the *IESO* for the purchase of *long-term transmission rights* and that may also include the purchase of *short-term transmission rights*;

long-term transmission right means a *transmission right* that is valid for a period of one year;

lower energy limit means the lowest energy amount to which an *electricity storage unit* can be consistently discharged without damage beyond expected degradation from normal use;

main island means, in the event of a network split, the island with the largest number of *IESO-controlled grid* buses;

main/alternate metering installation means a *metering installation* comprised of two *revenue meters* measuring the same electrical quantities;

major dispatchable load facility means a *load facility* associated with a *dispatchable load* that is rated at 100 MVA or higher; that comprises sets of *load equipment* that are associated with *dispatchable loads,* the ratings of which in the aggregate equals or exceeds 100 MVA; or that is re-classified as a *major dispatchable load facility* pursuant to MR Ch.2 App.2.2 s.1.5.1 or MR Ch.4 s.7.8.1;

major electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 100 MVA or higher; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 100 MVA; or that is re-classified as a *major electricity storage facility* pursuant to MR Ch.2 App.2.2 s.1.5.1A or MR Ch.4 s.7.8.2A;

major generation facility means a *generation facility* that includes a *generation unit* associated with a *resource* that provides *regulation*; that includes a *generation unit* that is rated at 100 MVA or higher; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 100 MVA; or that is re-classified as a *major generation facility* pursuant to MR Ch.2 App.2.2 s.1.5.1or or MR Ch.4 s.7.8.1;

margin call means a notice given by the *IESO* to a *market participant* pursuant to MR Ch.2 ss.5.4.2, 5C.2.2, or 5D.3.2 indicating that the *actual exposure* of that *market participant* equals or exceeds its *trading limit*;

market assessment unit means the entity established by the *IESO* pursuant to MR Ch.3 s.3.2.1;

market commencement date means the date on which the *real-time market* commences operation;

market control entity means a person or entity disclosed by a *market participant* to the *IESO* pursuant to MR Ch.7 s.22.9.2 of the *market rules*;

market control entity for physical withholding means the *market control entity* that a *market participant* has designated pursuant to MR Ch.7 ss 22.9.3-22.9.7 of the *market rules;*

market creditor means a person, including a *market participant*, that is owed monies by the *IESO* as a result of sales made or contracts existing in the *IESO-administered markets*;

market debtor means a person, including a *market participant*, that owes monies to the *IESO* as a result of purchases made or contracts existing in the *IESO-administered markets*;

market manual means a *published* document that is entitled as such and that prescribes procedures, standards and other requirements to be followed, met or performed by *market participants,* the *IESO* and other persons in fulfilling their respective obligations under the *market rules*;

market monitoring unit means the entity that monitors the markets administered by a *control area operator* or *security coordinator;*

market operations means the operation of all or part of the *IESO-administered markets;*

market participant means a person who is authorized by the *market rules* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* and includes a person that has received conditional authorization under MR Ch.2 s.4;

market participant payment date means the date on which *market participants* are to make *settlement* payments to the *IESO*;

market participant settlement account means an account designated by the particular *market participant* as the account from and into which *settlement* payments are made;

market price means the price of *energy* or *operating reserve* determined in the *real-time market,* in the *day-ahead market,* or the price of *auction capacity* determined in the *capacity auction* in accordance with the provisions of MR Ch.7, or an *administrative price*, where applicable;

market rules means rules made under section 32 of the *Electricity Act, 1998*;

market surveillance panel means the panel of the same name continued as a panel of the *OEB* in accordance with subsection 4.3.1(1) of the *Ontario Energy Board Act, 1998*;

market transition means the process of enabling the *IESO* to administer the *IESO-administered markets* and *dispatch* the *IESO-controlled grid* as a single-schedule system with *locational marginal prices*, commencing on a date specified by the *IESO* pursuant to MR Ch.7 s.13.2.4.5 and ending on the *market transition completion;*

market transition completion means the date specified by the *IESO* pursuant to MR Ch.7 s13.2A.8 of the *market rules;*

market transition error means an error during a *market transition* determined by the *IESO* based on the criteria in MR Ch.7 s.13.2A.7 of the *market rules;*

maximum continuous rating means the gross or net maximum electrical output (in megawatts) which a *generation unit* or generating station is currently capable of producing continuously. This may include seasonal effects or other "long-term" deratings;

maximum daily energy limit means (i) for a *dispatchable generation resource* that is a *non-quick start resource* and is not a nuclear *generation resource,* a maximum quantity of *energy* in MWh that may be scheduled for a *resource* within a *dispatch day* at or above its *minimum loading point* excluding the hours scheduled for the *ramp up energy to minimum loading point* or (ii) for any other *resource*, a maximum quantity of *energy* in MWh that may be scheduled for a *resource* within a *dispatch day;*

maximum daily trading limit means the maximum quantity a *virtual trader* may *bid* or *offer* in a given *trading day*, and is the absolute value in MWh submitted by a *virtual trader* in accordance with MR Ch.2 s.5C.1, used by the *IESO* to calculate a *virtual trader's minimum trading limit, default protection amount*, and the *bid/offer* quantity limit for *dispatch data* submissions in accordance with MR Ch.7 s.3.10.1.3;

maximum market clearing price or *MMCP* means the maximum price that a *market participant* may be charged or paid for *energy*;

maximum number of starts per day means the number of times that a *resource* can be started within a *dispatch day*;

maximum number of starts per day reference level means a reference level for a resource's maximum numbers of starts per day;

maximum net exposure means a component of the *prudential support obligation* that reflects the *IESO's* estimate of the net amount a *market participant* will owe to the *IESO* calculated from time to time by the *IESO* for a *market participant* in accordance with MR Ch.2 s.5.3 or s.5C.1;

maximum operating reserve price or *MORP* means the maximum price that can be determined or paid to a *market participant* for *operating reserve*;

mediator means a qualified person appointed pursuant to MR Ch.3 s 2.6 to mediate a dispute;

meter means a device that measures and records active *energy*, reactive *energy* or both and shall be deemed to include the *data logger* but to exclude the *instrument transformers*;

meter point means, in respect of a *load facility* and of a *generation facility* or *electricity storage facility* that is injecting, with respect to which the current transformers are located on the output side of the *generation facility* or *electricity storage facility*, the physical location of the current transformers used to measure power flow and, in respect of a *generation facility* or an *electricity storage facility* with respect to which the current transformers are located on the grounded side of the *generation facility*, or the *electricity storage facility* the physical location of the voltage transformers;

metered market participant means, in respect of a *registered wholesale meter*, the *market participant* designated as the *metered market participant* for the *resource(s)* associated with that *registered wholesale meter* in accordance with MR Ch.9;

metering data means electrical quantities measured and recorded by a *metering installation*;

metering database means an information system established and maintained by the *IESO* in accordance with MR Ch.6 for the purpose of storing *metering data*;

metering installation means any apparatus, including but not limited to a *registered wholesale meter* used to measure electrical quantities and includes the communication system by which *metering data* is transferred to the relevant telecommunications network through which *metering data* is transferred to the communication interface of the *metering database*;

metering interval means the five-minute period over which *metering data* is collected;

metering registry means the information system established and maintained by the *IESO* in accordance with MR Ch.6;

metering service provider means a person that provides, installs, commissions, registers, maintains, repairs, replaces, inspects and tests *metering installations*;

minimum daily energy limit means the minimum amount of *energy*, in MWh, that must be scheduled within a *dispatch day* for a hydroelectric *generation resource*;

minimum generation block down-time means, for each *thermal state,* the minimum time, in hours, between the time a *generation resource* was last at its *minimum loading point* before de-synchronization and the time the *generation resource* reaches its *minimum loading point* again after synchronization;

minimum generation block down-time reference level means a *reference level* for a *resource's minimum generation block down-time;*

minimum generation block run-time means the number of hours that a *generation resource* must be operating at *minimum loading point*, in accordance with its technical requirements;

minimum generation block run-time reference level means a *reference level* for a *resource's minimum generation block run-time;*

minimum hourly output means the minimum amount of *energy*, in MWh, that must be scheduled for a hydroelectric *generation resource* within a *dispatch hour* if scheduled above 0 MWh*;*

minimum loading point means the minimum output of *energy* that can be produced by a *generation resource* under stable conditions without ignition support, in accordance with the technical requirements of the associated *facility*;

minimum loading point reference level means a *reference level* for a *resource's minimum loading point;*

minimum run-time means the number of hours required for the *generation resource* to ramp from a cold start to *minimum loading point* plus *minimum generation block run-time,* in accordance with technical requirements of the associated *facility*;

minimum shut-down time means the minimum time in hours between shutdown and start-up of a *generation resource*. This is measured from the time of de-synchronization from the *IESO-controlled grid* to the time of re-synchronization on start-up;

minimum trading limit means the dollar amount determined from time to time by the *IESO* in accordance with MR Ch.2 s.5.3.4 or s.5C.1.5, that represents the lowest possible *trading limit* that may be calculated by the *IESO* for a *market participant* as permitted by the *market rules*;

Minister means the Minister of Energy or such member of the Executive Council that may be assigned the administration of the *Electricity Act, 1998* under the *Executive Council Act, 1990*;

minor amendment, in respect of the *market rules*, means an *amendment* to the *market rules* to correct a typographical or grammatical error, or to effect a change of a non-material procedural nature;

minor dispatchable load facility means a *load facility* associated with a *dispatchable load* that is rated at 1 MVA or higher but less than 20 MVA; that comprises sets of *load equipment* that are associated with *dispatchable loads* the ratings of which in the aggregate equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor dispatchable load facility* pursuant to MR Ch.2 App.2.2 s.1.5.2 or MR Ch.4 s.7.8.2;

minor electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 1 MVA or higher but less than 20 MVA; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor electricity storage facility* pursuant to MR Ch.2 App.2.2 s.1.5.1A or s.1.5.2A or MR Ch.4 s.7.8.2A or s.7.8.2B;

minor generation facility means a *generation facility* that includes a *generation unit* that is rated at 1 MVA or higher but less than 20 MVA; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor generation facility* pursuant to MR Ch.2 App.2.2 s.1.5.1 or s.1.5.2 or MR Ch.4 s.7.8.1 or s.7.8.2;

monthly confirmation notice means the notice provided by the *IESO* to each *market participant* containing a summary of the *market participant's settlement* payments made during a calendar month and of the payments outstanding for that calendar month;

MWh ratio means the proportional amount of *energy* that must be scheduled on the *resources* registered on the downstream *linked forebay* after the *time lag* has elapsed for every MWh of *energy* scheduled on the *resources* registered on the upstream *linked forebay;*

narrow constrained area or *NCA* means a *potential constrained area* designated as a *NCA* pursuant to MR Ch.7 s.22.10.2;

neighbouring electricity system means a system comprising generation, transmission and load facilities that is connected to the *electricity system* via one or more *interconnections*;

NERC means the North American Electric Reliability Corporation;

NERC confidentiality agreement means an agreement required to be executed between *NERC* and all *security coordinators* and, where applicable, *control area operators* and *interconnected transmitters* which ensures that required data is available and that the confidentiality of such data is protected and disclosed only to those responsible for maintaining the operational security of electricity supply in North America;

net MW as related to active power output from an *electricity storage unit*, *generation unit*, or *facility* is equal to the applicable unit or *facility*'s *gross MW* output less the applicable unit or *facility station service* MW load and MW losses to the *defined meter point* for that applicable unit or *facility;*

net MX as related to reactive power output from an *electricity storage unit*, *generation unit*, or *facility* is equal to the applicable unit or *facility*'s *gross MX* output less the applicable unit or *facility station service* MX load and MX losses to the *defined meter point* for that applicable unit or *facility;*

net transaction dollar amount means an amount calculated in accordance with MR Ch.2 s.8.6.1.1;

network service means the *transmission service* relating to the use of the *IESO-controlled grid* for the transmission of *energy* and *ancillary services*, other than in respect of transactions to which *export transmission service* relates, and in respect of which charges are required to be collected by the *IESO* pursuant to MR Ch.10 s.3;

no margin call option means the option wherein a *market participant* elects, pursuant to MR Ch.2 s.5.6.4, to not be subject to *margin calls*;

non-committable resource means a *dispatchable generation resource* that is not a *GOG-eligible resource, dispatchable load*, or a *dispatchable electricity storage resource*;

non-committed resource means the *resource* for a *facility* that is neither in whole or in part rate-regulated, contracted to the *IESO*, contracted to the *OEFC*, or obligated as a resource backed capacity export to another jurisdiction during the entire duration of a given *obligation period*;

non-defaulting market participant means, for purposes of the imposition of the *default levy*, every *market participant* other than the *defaulting market participant* whose default in payment has triggered the imposition of the *default levy*;

non-dispatchable generation resource means a *generation resource* within the *IESO control area* that is a *self-scheduling generation resource* or *intermittent generation resource;*

non-dispatchable load means a *load resource*, within the *IESO control area*, that is not *dispatchable* and whose level is not selected or set by the *IESO* based on the price of *energy* in the *day-ahead market* or *real-time market*;

non-financial dispatch data parameters means a subset of *dispatch data* that are not represented as financial values and for which the *IESO* must determine *reference levels*;

non-quick start resource means a *generation resource* or an *electricity storage resource* whose electrical *energy* output cannot be provided to the *IESO-controlled grid* within five minutes of the *IESO's* request when its equipment is not synchronized to the *IESO-controlled grid*;

normal operating state means the state described in MR Ch.5 s.2.2;

normal priority path facility means a voice communication facility that meets the requirements of MR Ch.2 App.2.2 s. 1.1.8;

notice of default levy means a notice issued by the *IESO* to a *non-defaulting market participant* in accordance with MR Ch.2 s.8.2.3 or 8.4.1;

notice of disagreement means a notice provided by a *market participant* in accordance with MR Ch.9 s.6.8 to the *IESO* in regard to a disagreement over a *settlement statement*;

notice of dispute has the meaning ascribed thereto in MR Ch.3 s.2.5.1;

notice of intent to suspend means a notice issued by the *IESO* to a *market participant* under MR Ch.3 s.6.3.3.1;

notice of intention means a notice issued by the *IESO* to a *market participant* under MR Ch.3 s.6.2B.2;

notice to elect shall be in such form as may be established by the *IESO* and means a written notice provided by the *market participant* to the *IESO* under MR Ch.3 s.6.2B.7;

NPCC means the Northeast Power Coordinating Council;

OEB or *Ontario Energy Board* means the Ontario Energy Board continued pursuant to section 4 of the *Ontario Energy Board Act, 1998*;

OEFC means the Ontario Electricity Finance Corporation established under Part V of the *Electricity Act, 1998;*

obligation period means the period of time for which a *capacity market participant* is required to fulfill its *capacity obligation* through the *energy market;*

offer means a statement of the quantities and prices of a commodity that a seller is willing to provide in the *day-ahead market, real-time market,* the *procurement markets*, or the *capacity auction* and includes *dispatch data* parameters that are submitted in accordance with MR Ch.7 s.3;

one-day advance approval means *IESO* approval of a *planned outage* of equipment no later than 8:00 EST on the *business day* prior to the scheduled start date of the *planned outage*;

Ontario electricity emergency plan means the plan describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *integrated power system*;

Ontario Energy Board Act, 1998 means the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B;

OPA or *Ontario Power Authority* means the Ontario Power Authority established under Part II.1 of the *Electricity Act, 1998*;

Ontario power system restoration plan means the detailed plan indicating how to re-energize the *IESO-controlled grid* or part of it in case the *IESO-controlled grid* or part of it collapses;

Ontario zonal price means the price of *energy* in Ontario, prior to any adjustments made as a result of the load forecast deviation adjustment, applicable to *non-dispatchable loads*, as determined in the *real-time market* or in the *day-ahead market* in accordance with the provisions of MR Ch.7, or an *administrative price*, where applicable;

operating agreement means an agreement between the *IESO* and a *transmitter* which gives the *IESO* the authority to direct operations of the *transmitter's transmission system*, as contemplated in subsection 6(1)(b) of the *Electricity Act, 1998* and in subsection 70(2)(k) of the *Ontario Energy Board Act, 1998*;

operating deviation means the deviation described in MR Ch.9 s.3.9 between the performance of a *resource* and the performance required of that *resource* for the provision of *operating reserve*;

operating reserve means *generation capacity, electricity storage capacity* or load reduction capacity which can be called upon on short notice by the *IESO* to replace scheduled *energy* supply which is unavailable as a result of an unexpected *outage* or to augment scheduled *energy* as a result of unexpected *demand* or other contingencies;

operating reserve market means a *physical market* in which *offers* to supply each class of *operating reserve* are cleared consistent with the *energy offers* and *energy bids*;

operating reserve offer intertie reference level means an *intertie reference level* for an *offer* to provide *operating reserve*;

operating reserve offer reference level means a *reference level* for an *offer* to provide *operating reserve*;

operating reserve ramp rate reference level means a *reference level* for a *resource's* ramp rate for *operating reserve;*

operating result means the physical quantity or quantities measured or estimated by the *IESO* as delivered by a *resource* during the actual operation of the *electricity system*;

outage means the removal of equipment from service, unavailability for connection of equipment or temporary derating, restriction of use, or reduction in performance of equipment for any reason including, but not limited to, to permit the performance of inspections, tests or repairs on equipment, and shall include a *planned outage*, a *forced outage* and an automatic *outage*;

over committed capacity means capacity has been contracted to or otherwise obligated to be provided to the *IESO*, the *OEFC*, or another *control area operator* at any time during a given *obligation period* where the same capacity is included in a *cleared ICAP* held by a *capacity market participant* participating with a *generator-backed capacity import resource;*

participation agreement means the agreement required to be executed between the *IESO* and each *market participant* pursuant to MR Ch.2 s.1.2.2.3 and pursuant to which the *IESO* and the *market participant* agree, among other matters, to be bound by the *market rules*;

participant technical reference manual means the document entitled "Participant Technical Reference Manual" and *published* by the *IESO*;

participant workstation means the communication equipment that is required to be maintained by *market participants* in accordance with MR Ch.2 App. 2.2 for the purposes referred to in MR Ch.2 App.2.2 s.1.4.1;

payment date means the date upon which payment is due;

per-start means the act of achieving synchronization to the *IESO-controlled grid*, ramping to the *minimum loading point* and operating at the *minimum loading point* until the end of the *minimum generation block run-time*;

performance adjustment factor means a value assigned to a *capacity auction resource* based on its historical performance during a *capacity auction capacity test* activation in the relevant summer or winter *obligation period* and is calculated in accordance with the process set out in the applicable *market manual*;

period of steady operation means a predefined number of intervals (0, 1, or 2) for which a *non-quick start resource* that is a *generation resource* must maintain steady operation before changing direction of its *energy* output (either increasing or decreasing). Such a *resource* is considered to be in steady operation if the magnitude of change between *dispatch instructions* for the last two *dispatch intervals* is less than 0.1 multiplied by its ramp rate capability between the two *dispatch intervals*;

phasor measurement unit or *PMU* is a device used to measure *synchrophasor* data. It can be a dedicated device, a protective relay or other device that is capable of providing *synchrophasor* data;

physical bilateral contract means an agreement between two parties, neither of which is the *IESO*, to trade a specified quantity of electricity at prices determined by the parties to the agreement, and pursuant to which the parties provide for the use of the *IESO settlement process* to account for *physical bilateral contract data*;

physical bilateral contract data means the data concerning a *physical bilateral contract* that a *selling market participant* provides to the *IESO* for purposes of *settlement*;

physical bilateral contract quantity means a quantity of *energy*, in MWh, that a *selling market participant* is selling to a *buying market participant* at a specified location and in a specified hour;

physical market means a *day-ahead market*, *real-time market* and/or a *procurement market* administered by the *IESO* pursuant to MR Ch.7;

physical service means the service of providing *energy* or *ancillary services*;

physical transaction means (i) a transaction in the *IESO-administered markets* that creates a financial obligation in the *day-ahead market* and a balancing obligation in the *real-time market* with a capability to fulfill the balancing obligation by delivery or consumption of *physical services* in the *real-time market*; or (ii) a transaction in the *IESO-administered markets* based on delivery or consumption of *physical services* in the *real-time market;*

physical withholding means submitting *offer* quantities of *energy* or *operating reserve* less than a *resource*'s *reference quantity value* by more than the applicable threshold;

PJM means the Pennsylvania, New Jersey, Maryland Interconnection;

planned capability factor means the ratio of the *energy* which could have been delivered by a generating station with planned *generation unit* limitations in effect, to the *energy*, over the same period of time, that could have been delivered if the generating station had operated at its *maximum continuous rating*;

planned outage means an *outage* which is planned and intentional;

potential constrained area means an electrical area of the *IESO-controlled grid* that can be created when a single or multiple transmission constraints bind, leaving a reduced set of *resources* that can meet the load behind the transmission constraints;

pre-dispatch calculation engine means an algorithm that consists of a sequence of optimization problems solved by the *IESO* to determine *pre-dispatch schedules* and prices over the pre-dispatch look-ahead period in accordance with MR Ch.7 to meet the needs of the pre-dispatch timeframe;

pre-dispatch operational commitment means (i) a *stand-alone pre dispatch operational commitment;* (ii) an *advancement pre-dispatch operational commitment*; or (iii) an *extension pre-dispatch operational commitment;*

pre-dispatch process means the process described in MR Ch.7 s.5, used to establish *pre-dispatch schedules* and prices in the *real-time market*;

pre-dispatch schedule means an hourly schedule for the remaining hours of a *dispatch day* and may include all hours of the next *dispatch day* as determined by the *pre-dispatch calculation engine*;

pre-existing facility or equipment means a *facility* or equipment (i) that was or was part of a *facility* that was in existence on, and in respect of which a *licence* has been issued prior to, or on, the date of coming into force of MR Ch.4 (April 17, 2000); or was in service on the date of coming into force of MR Ch.4 (April 17, 2000); and (ii) in respect of which an *exemption* has been applied for or granted relating to any of the following standards or obligations: (a) the technical requirements set out in MR Ch.2 App.2.2 relating to voice communication, monitoring and control but not those relating to the *participant workstation* or *dispatch workstation*; (b) the technical requirements set out in MR Ch.5 s.12 relating to communications; and (c) the grid *connection* and data monitoring requirements set out in MR Ch.4 other than the requirements set forth in MR Ch.4 ss.6.1.5 to 6.1.21;

preliminary settlement statement means the *IESO's* preliminary statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase of *transmission rights* in the *TR market*, the *IESO*'s preliminary statement of the payments to be made by a *TR holder* with respect to a given *TR auction* or the preliminary statement of the payments to be made to a *TR holder* with respect to a given *billing period*;

preliminary view means a statement from the *IESO* of the *reference levels* and *reference quantities* that the *IESO* intends to register for a *resource;*

price-quantity pair means a price and an associated quantity that define a "step" in an *offer* or *bid* curve;

price responsive load means a *load resource* for which the *registered market participant* is authorized to submit *bids* for *energy* into the *day-ahead market* but for which the *load resource* is not *dispatchable* and whose level is not selected or set by the *IESO* based on the price of *energy* in the *real-time market*;

primary registered wholesale meter or *primary RWM* means an *registered wholesale meter* that measures *meter data* regarding flows directly into or from the *IESO-controlled grid*;

procurement market means any one of the markets operated by the *IESO*, pursuant to MR Ch.7, for contracted *ancillary services*, including *regulation, voltage control services* and *reactive support services* and *black-start capability*, and for *reliability must-run contracts*;

prudential support means the collateral posted with the *IESO* to secure the financial obligations of a *market participant,* in the forms set forth in MR Ch.2 s.5.7 or s.5C.5;

prudential support obligation means an amount of *prudential support* owed to the *IESO* equal to a *market participant's maximum net exposure* less any allowable reductions calculated in accordance with MR Ch.2 s.5.8 or s.5C.6;

pseudo-unit means a *dispatchable generation resource* associated with a *combined cycle plant* that is modeled based on a gas-to-steam relationship between one combustion turbine *generation resource* and a share of one steam turbine *generation resource* at the same *combined cycle plant*;

publish means, in respect of a document or information, to place that document or information on the *IESO's* web site, and publication shall be interpreted accordingly;

quarterly advance approval means *IESO* approval of a *planned outage* of equipment no later than the end of the month that is one month prior to the start of a six-month period, starting with the next calendar quarter, in which the *planned outage* is scheduled to start;

quick start resource means a *generation resource* or an *electricity storage resource* whose electrical *energy* output can be provided to the *IESO-controlled grid* within five minutes of the *IESO's* request when its equipment is not synchronized to the *IESO-controlled grid*;

radial intertie means a transmission line or lines which form part of the *IESO-controlled grid* and that: (a) connect an isolated portion of the *IESO control area* to an adjacent *control area;* or (b) connect the *IESO control area* to an isolated portion of an adjacent *control area,* in either case where the connected portion cannot, in accordance with an *operating agreement* or an *interconnection agreement,* be simultaneously connected to either another portion of one such *control area* or to a third *control area*;

ramp hours to minimum loading point means the number of hours required for a *generation resource* to ramp up from synchronization to its *minimum loading point* as described in MR Ch.7 s.3.5.33;

ramp hours to minimum loading point reference level means a *reference level* for a *resource's ramp hours to minimum loading point*;

ramp-up energy to minimum loading point means the amount of *energy,* in MWh, a *generation resource* is expected to inject in each hour from the time of synchronization to the time it reaches its *minimum loading point* as described in MR Ch.7 s.3.5.33;

reactive support service means a service provided by a *market participant* so as to allow the *IESO* to maintain the reactive power levels around the *IESO-controlled grid*;

real-time calculation engine means an algorithm that consists of a sequence of optimization problems solved by the *IESO* to determine *real-time schedules* and prices for the *dispatch interval* and the subsequent ten *dispatch intervals* in accordance with MR Ch.7 to meet the needs of the *real-time market*;

real-time commitment period means the set of contiguous *settlement hours* described in MR Ch.9 s.4.5.1.1(c);

real-time dispatch process is the process described in MR Ch.7 ss.7.1, 7.2, 7.3, and 7.4, when applied (i) while the *IESO-controlled grid* is in a *normal operating state;* and (ii) at a time other than when *market operations* have been suspended or *administrative prices* have been implemented;

real-time market or *RTM* means any one of the markets operated by the *IESO* for *energy* or *operating reserve* pursuant to MR Ch.7, other than the *day-ahead market*;

real-time market mandatory window means the period of time on a *dispatch day* that begins following the *real-time market unrestricted window* and that ends 10 minutes before the *dispatch hour*, or in the case of a *boundary entity resource*, that ends an hour and 10 minutes before the *dispatch hour*;

real-time market restricted window means the period of time that begins upon *day-ahead market expiration* and that ends upon the completion of the *dispatch day*;

real-time market unrestricted window means the period of time that begins upon *day-ahead market expiration* and that ends two hours prior to the *dispatch hour;*

real-time reliability commitment period means the set of contiguous *settlement hours* described in MR Ch.9, s.4.5.1.1(d);

real-time schedule means:

(i) in respect of a *dispatchable generation resource*, a *dispatchable electricity storage resource*, or a *dispatchable load resource*, a *dispatch* schedule for a *dispatch interval* as determined by the *real-time calculation engine*;

(ii) in respect of a *boundary entity resource*, an *interchange schedule*;

(iii) in respect of an *hourly demand response resource*, a schedule to reduce energy withdrawals as determined by the relevant *pre-dispatch schedule*; or

(iv) in respect of a *non-dispatchable generation resource* or *self-scheduling electricity storage resource* that intends to inject *energy*, a schedule as determined by the *real-time calculation engine* and includes for purposes of the *settlement process*, any modifications made thereto in accordance with the *market rules*;

recalculated settlement statement means the *IESO's* recalculated statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase and sale of *transmission rights* in the *TR market*, the *IESO*'s recalculated statement of the payments to be made by or to a *TR holder* with respect to a given *TR auction* or the recalculated statement of the payments to be made by or to a *TR holder* with respect to a given *billing period*;

record of review means the document issued by the *IESO* to a *restoration participant* pursuant to MR Ch.5 s.11.4.1;

reference bus means the bus designated by the *IESO* in accordance with MR Ch.7 App.7.5 s.5.2, MR Ch.7 App.7.5A s.5.2 or MR Ch.7 App 7.6 s.5.2 for the purpose of determining the components of *locational marginal price*;

reference level means an *IESO*-determined formula to calculate a *reference level value*;

reference level value means an *IESO*-determined estimate of a *dispatch data* parameter that a *resource* would have submitted if it were subject to *unrestricted competition*;

reference quantity means an *IESO*-determined formula to calculate a *reference quantity value*;

reference quantity value means an *IESO*-determined estimate for the quantity of *energy* or *operating reserve* that a *market participant* would have submitted for a *resource* if it were subject to *unrestricted competition*;

registered market participant means a *market participant* that is registered with the *IESO* to submit *dispatch data* with respect to a *resource*;

registered wholesale meter or *RWM* means a *meter* that meets the criteria specified in MR Ch.6 and that is registered with the *IESO.* References to a *registered wholesale meter* or *RWM* within MR Ch.9 also include *meters* in *metering installations* whose registration has expired but the *IESO* determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*;

regulation means the service required to control power system frequency and maintain the balance between load and generation;

release notification means in respect of a *variable generator* that is a *registered market participant,* a notification issued by the *IESO* providing that *energy* may be supplied from the *variable generation resource* to the *IESO-controlled grid* as ambient fuel conditions allow until a *dispatch instruction* is sent;

reliability means, in respect of electricity service, the ability to deliver electricity within *reliability standards* and in the amount desired and means, in respect of the *electricity system*, the *IESO-controlled grid*, the *integrated power system* or a *transmission system,* the ability of the *electricity system*, the *IESO-controlled grid,* the *integrated power system* or that *transmission system* to operate within *reliability standards* in an *adequate* and secure manner;

reliability commitment means a minimum scheduling constraint established manually by the *IESO* to at least a *GOG-eligible resource*'s *minimum loading point* in order to maintain the *reliable* operation of the *IESO-controlled grid*, as determined by the *IESO;*

reliability must-run contract means a contract between the *IESO* and a *registered market participant* or prospective *registered market participant* for a *resource* that is or will be a *generation resource*, an *electricity storage resource,* a *dispatchable load resource* or a *boundary entity resource*, which allows the *IESO* to call on that *registered market participant's* or prospective *registered market participant's resource* in order to maintain *reliability* of the *IESO-controlled grid*;

reliability must-run resources means the *resources* described in MR Ch.5 s.4.8.1; these may also be referred to as *must-run resources*;

reliability standards means the criteria and standards, including an amendment to a standard or criterion, relating to the *reliable* operation of the *integrated power system* established by a *standards authority*, and declared in force subject to MR Ch.5 ss.1.2.6 and 1.2.7, together with those set forth in these *market rules* or otherwise established by the *IESO* in accordance with these *market rules* and which has not otherwise been stayed or revoked and referred back to the *IESO* for further consideration by the *Ontario Energy Board*;

remaining duration of service means the remaining time it is expected that an *electricity storage resource* can continue injecting, or withdrawing, until it reaches its *lower energy limit,* or *upper energy limit*, respectively, assuming the *electricity storage resource* continues operating at its quantity *offered* or *bid*;

remedial action schemes or *RAS* means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system *reliability*. The term special protection system or SPS shall have the same meaning;

renewed market rules refers to a set of *market rules* and *market manuals,* the purpose and scope of which are described in MR Ch 0.1 - 0.11, s.A.1;

request for connection assessment means a request for the approval of a new *connection* to the *IESO-controlled grid* or of the modification of an existing *connection* to the *IESO-controlled grid* made pursuant to MR Ch.4 s. 6.1.6;

request for segregation means a request from a *registered market participant* for approval to operate its *resource* in a *segregated mode of operation*;

reserve target means the minimum required MWs of any class of reserve required to satisfy reserve requirements;

reserve loading point means the minimum level of *energy* output, in MWs, required for a *generation resource* or an injecting *electricity storage resource* to provide its maximum *offered* amount of a given class of *operating reserve;*

resource means an *IESO*-modelled representation of one or more *generation units, electricity storage units,* or sets of *load equipment*, existing within the *IESO's systems*, which is used for the secure operations of the *IESO control area*, or to participate in the *IESO-administrated markets*; or a *boundary entity resource*; or *virtual zonal resource*;

respondent means a person against whom a complaint is made in a *notice of dispute*, a *response* or a response to a crossclaim;

response has the meaning ascribed thereto in MR Ch.3 s. 2.5.4;

response to the notice of intention shall be in such form as may be established by the *IESO* and means a notice provided by the *market participant* under MR Ch.3 s. 6.2B.3;

restoration participant means a *market participant* who has been identified by the *IESO* as having equipment or *facilities* that: (i) are directly *connected* to the *IESO-controlled grid* and (ii) affect the restoration process as set out in the *Ontario power system restoration plan*;

restoration participant attachment means the attachment to the *Ontario power system restoration plan* required to be prepared by a *restoration participant* and submitted to the *IESO* in accordance with MR Ch.5 s. 11.3.5;

retail, with respect to electricity, means (a) to sell or offer to sell electricity to a consumer; (b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity; or (c) to act or offer to act as an agent or broker for a *consumer* with respect to the sale or offering for sale of electricity;

retailer means a person who *retails* electricity;

revenue meter means a *meter* that is the designated source of *metering data* to be used by the *IESO* for *settlement* purposes in accordance with the *VEE process*;

review notice has the meaning ascribed thereto in MR Ch.3 s. 4.4.2;

reviewable decision means a decision of the *IESO* referred to in MR Ch.6 ss.2.1.2, 4.4.3, 5.1.12, 5.3.9 or 6.1.5 and MR Ch.5 ss.3.2A.1, 3.2A.5.3, 3.2A.10, 3.2B.5.3, 3.2B.7 or 3.2B.10;

RSS commencement date means May 1, 2023, which is the date on which *market rule amendment* MR-00475-R00 came into effect;

second contingency loss means an unexpected loss of a second component from the *electricity system* after the first component is already lost;

secretary means the secretary of the *dispute resolution panel* appointed pursuant to the *Governance and Structure By-law*;

security means the ability of the *electricity system,* the *IESO-controlled grid*, the *integrated power* system or a *transmission system* to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of equipment or components;

security coordinator, in respect of the *IESO-controlled grid*, means the *IESO* and, in respect of another *transmission system*, means the person responsible for coordinating the security of that *transmission system* with that of other *transmission systems*;

security limits include operating *electricity system* stability limits and thermal ratings;

segregated mode of operation means an electrical configuration where a portion of the *IESO-controlled grid* is used to *connect* a *generation facility* associated with one or more *generation resources* to a neighbouring *control area* using a *radial intertie* for the purposes of delivering electricity or *physical services* to such *control area*;

self-assessed trading limit means, the dollar amount submitted to the *IESO* by a *market participant* in accordance with MR Ch.2 s.5.3.2, for the purposes of calculating its *trading limit*;

self-schedule means an hourly schedule specified by a *self-scheduling generation resource* or a *self-scheduling electricity storage resource,* and *self-scheduling* has an analogous meaning;

self-scheduling electricity storage resource means an *electricity storage resource* that is not *dispatchable* except for the provision of *regulation* services in respect of which it shall follow *dispatch instructions,* and when it intends to withdraw *energy* is authorized to submit *bids* for *energy* into the *day-ahead market;*

self-scheduling electricity storage facility means an *electricity storage facility* comprised of one or more *electricity storage units* that are each exclusively associated with a *self-scheduling electricity storage resource*;

self-scheduling generation facility means a *generation facility* comprised of one or more *generation units* that are each exclusively associated with a *self-scheduling generation resource*;

self-scheduling generation resource means a *generation resource* that can operate independently of *dispatch instructions* from the *IESO*;

selling market participant means a *market participant* who is selling *energy* under a *physical bilateral contract*;

settlement means the process of transferring payments from those who are required to make payment to those who are required to be paid under the *market rules*;

settlement account means a bank account held by the *IESO*, a *market participant* or a *transmitter* pursuant to the *settlement* rules set forth in MR Ch.8 and MR Ch.9;

settlement amount means any amount of money to be paid by or to a *market participant,* determined in accordance with MR Ch.9;

settlement floor price means the minimum price that a *market participant* may be charged or paid for *energy*;

settlement hour means a period of one hour which corresponds to a particular *dispatch hour* for which *metering data* determined in accordance with MR Ch.6 and *market prices* for the *physical market* for services calculated pursuant to MR Ch.7 are to be used to calculate the *settlement* debits and credits of *market participants*;

settlement process means any process administered by the *IESO* to effect *settlement*;

settlement statement means a *preliminary settlement statement*, a *final settlement statement*, and/or a *recalculated settlement statement*;

short-term auction means a *TR auction* conducted by the *IESO* for the purchase of *short-term transmission rights*;

short-run marginal benefit means a financial benefit that accrues to a *market participant* with respect to a *boundary entity resource* that only accrues if that *boundary entity resource* exports *energy* and does not accrue otherwise;

short-run marginal cost means a financial cost incurred by a *market participant* with respect to its *resource* that is only incurred if that *resource* provides *energy* or *operating reserve* and is not incurred otherwise;

short-term transmission right means a *transmission right* that is valid for a period of one month;

significant dispatchable load facility means a *load facility* that is associated with a *dispatchable load* that is rated at 20 MVA or higher but less than 100 MVA; that comprises *sets of load equipment* that are associated with *dispatchable loads,* the ratings of which in the aggregate equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant dispatchable load facility* pursuant to MR Ch.2 App.2.2. s.1.5.1 or s.1.5.2 or MR Ch.4 s.7.8.1 or s.7.8.2;

significant electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 20 MVA or higher but less than 100 MVA; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant electricity storage facility* pursuant to MR Ch.2 App.2.2 s.1.5.1A or s.1.5.2A or MR Ch.4 s.7.8.2A or s.7.8.2B;

significant generation facility means a *generation facility* that includes a *generation unit* that is rated at 20 MVA or higher but less than 100 MVA; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant generation facility* pursuant to MR Ch.2 App.2.2. s.1.5.1 or s.1.5.2 or MR Ch.4 s.7.8.1 or s.7.8.2;

simulated as-offered energy locational marginal price means, for a given *resource,* the *energy locational marginal price* produced by simulating the *day-ahead market* or *real-time market,* as applicable, using the inputs used by the relevant calculation engines for the *dispatch day*;

simulated as-offered operating reserve locational marginal price means, for a given *resource*, the *operating reserve locational marginal price* produced by simulating the *day-ahead market* or *real-time market,* as applicable, using the inputs used by the relevant calculation engines for the *dispatch day*;

simulated intertie reference level energy location marginal price means the *energy locational marginal price* at an uncompetitive *intertie zone* produced by simulating the *day-ahead market* or *real-time market,* as applicable;

simulated intertie reference level operating reserve location marginal price means the *operating reserve locational marginal price* at an uncompetitive *intertie zone* produced by simulating the *day-ahead market* or *real-time market,* as applicable;

simulated reference quantity energy locational marginal price means, for a given *resource*, the *energy locational marginal price* produced by simulating the *day-ahead market* or *real-time market,* as applicable, using the inputs used by the relevant calculation engines and the applicable *reference quantities* and *reference levels* for the *dispatch day*;

simulated reference quantity operating reserve locational marginal price means, for a given *resource,* the *operating reserve locational marginal price* produced by simulating the *day-ahead market* or *real-time market,* as applicable, using the inputs used by the relevant calculation engines and the applicable *reference quantities* and *reference levels* for the *dispatch day*;

single cycle mode means the mode of operating a *pseudo-unit* without the steam turbine *generation unit(s)*;

single metering installation means a *metering installation* comprised of one *revenue meter*;

small distributor means, a *distributor* with a projected *energy* consumption less than or equal to 0.25% of projected total system *energy* on an annual basis as determined by the *IESO* in accordance with the applicable *market manual*;

small electricity storage facility means an *electricity storage facility* that is comprised solely of an *electricity storage unit* with an *electricity storage unit size* rated at less than 1 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which is less than 1 MVA or that is re-classified as a *small electricity storage facility* pursuant to MR Ch.2 App.2.2 s.1.5.2A or MR Ch.4 s.7.8.2B;

small generation facility means a *generation facility* that is comprised solely of a *generation unit* rated at less than 1 MVA or of *generation units* the ratings of which in the aggregate is less than 1 MVA or that is re-classified as a *small generation facility* pursuant to MR Ch.2 App.2.2 s.1.5.2 or MR Ch.4 s.7.8.2;

speed no-load offer means the hourly dollar amount offered by the *registered market participant* to maintain a *generation resource* synchronized with zero net *energy* injected into the *IESO-controlled grid*;

speed no-load offer reference level means a *reference level* for a *speed no-load offer;*

SSPC means the *IESO* Settlement Schedule & Payments Calendar;

standards authority means *NERC, NPCC*, any successors thereof, and any other agency or body that approves standards or criteria applicable both in and outside Ontario relating to the *reliability* of *transmission systems*;

stand-alone pre-dispatch operational commitment means a minimum scheduling constraint established by the *IESO* to a *GOG-eligible resource's minimum loading point* based on the *binding pre-dispatch advisory schedule* to respect the *resource's minimum generation block run-time* during the applicable hours specified by the *IESO* pursuant to MR Ch.7 s.5.8.2.4;

standing dispatch data means the initial *dispatch data* that is submitted on a *resource* for one or more *dispatch hours* of future *dispatch days*, as specified by a *registered market participant;*

start indication value means the minimum quantity of *energy,* in MW, that a *resource* must be scheduled to determine whether it has used one or more of the submitted *maximum number of starts per day*;

start-up notice means the notification issued to a *GOG-eligible resource* in accordance with MR Ch.7 s.10.1 containing the *GOG-eligible resource's* start time, synchronization time, and time to reach the *minimum loading point*;

start-up offer is the dollar amount *offered* by the *registered market participant* to bring an off-line *resource* to its *minimum loading point* based on the *resource's thermal state*;

start-up offer reference level means a *reference level* for a *start-up offer*;

start-up time means the time in hours required to bring a *generation resource* or *electricity storage resource* on line. This is measured from the time of receiving a request to start the *generation unit* or *electricity storage unit* associated with that *resource* to the time of synchronization;

state of charge means the percentage of which an *electricity storage unit* is charged relative to the maximum registered *electricity storage energy rating* of the *electricity storage unit;*

station service means *energy* withdrawn from the *IESO-controlled grid* to power the on-site maintenance and operation of transmission *facilities*, *generation facilities, electricity storage facilities* and *connection facilities* located within the *IESO control area* but excludes *energy* consumed in association with activities which could be ceased or moved to other locations without impeding the normal and safe operation of the *facility* in question;

Statutory Powers Procedure Act means the *Statutory Powers Procedure Act,* R.S.O. 1990, c.S.22;

steam turbine percentage share means the percentage of the total steam turbine *generation unit* capacity that is allocated to an associated *pseudo-unit*;

supervisory control and data acquisition or *SCADA* is a computer system for gathering and analyzing real time data;

suspended market participant means a *market participant* that is the subject of a *suspension order*;

suspension order means an order issued pursuant to MR Ch.3 s.6.3A suspending all or part of the rights of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

synchrophasor is a phasor representing the fundamental of an AC signal whose magnitude is the root mean square (RMS) value of the fundamental amplitude and angle is the difference between the signal fundamental angle and the phase angle of a cosine at the nominal signal frequency that is synchronized to the Coordinated Universal Time (UTC) time;

system-backed capacity auction eligible import resource means a *capacity auction resource* associated with a *boundary entity resource* that is available to qualify capacity that a neighbouring *control area operator* is willing to allocate to Ontario, if a *capacity obligation* is secured, for the duration of the applicable *obligation period*, which capacity would be deemed to be supplied from the entire system of the neighbouring *control area.* The allocated capacity must not otherwise be - in whole or in part - contracted to or otherwise obligated to be provided to the *IESO*, the *OEFC*, or another *control area operator* during the entire duration of a given *obligation period*;

system-backed capacity import resource means a *system-backed capacity auction eligible import resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual;*

target capacity means the amount of *auction capacity* which the *IESO* seeks to acquire through *a capacity auction*;

technical feasibility exception or *TFE* is a temporary exception from compliance with certain requirements of *NERC reliability standards* relating to critical infrastructure in accordance with Ontario-adapted *NERC* procedures for processing *TFEs*;

technical panel means the panel of the same name established pursuant to the *Governance and Structure By-law*;

ten-minute operating reserve or *10-minute operating reserve* means those *operating reserves* required to respond fully within ten minutes of being called upon by the *IESO*;

terminated market participant means a market participant that is the subject of a termination order; *termination order* means an order issued pursuant to MR Ch.3 s.6.4 terminating the rights of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

TFE applicant means (i) a *market participant* who applies to the *IESO* for a *technical feasibility exception* ; or (ii) a person applying to become a *market participant* who applies to the *IESO* for a *technical feasibility exception*; or (iii) the *IESO*, in the event the *IESO* requires a *technical feasibility exception*;

TFE application means an application for the approval, amendment, termination, or transfer of a *TFE* pursuant to MR Ch.5 s.3.2A;

thermal state means the state of a *dispatchable generation resource,* other than a *quick start resource* or a nuclear *generation resource,* that is either a hot, warm or cold state, as the case may be, relative to the last *dispatch hour* at which the *resource* was at its *minimum loading point;*

thirty-minute operating reserve or *30-minute operating reserve* means those *operating reserves* required to respond fully within thirty minutes of being called upon by the *IESO*;

three-day advance approval means *IESO* approval of a *planned outage* of equipment no later than 16:00 EST on the third *business day* prior to the scheduled start date of the *planned outage;*

time lag means an amount of time less than 24 hours that it takes for the water discharged from an upstream *linked forebay* to reach a downstream *linked forebay*;

tieline means a transmission line which forms part of an *interconnection;* see *intertie*;

TR auction means an auction conducted by the *IESO* for the purchase of *transmission rights*;

TR bid means a statement of the quantities and prices at which a buyer is willing to purchase *transmission rights* in a *TR auction*;

TR bidder means a person that submits a *TR bid* to purchase a *transmission right* in a *TR auction*;

TR clearing account means the *settlement account* or fund established by the *IESO* and described in MR Ch.8 s.3.18.1;

TR holder means, in respect of a given *transmission right*, the *TR participant* recognized by the *IESO,* in accordance with MR Ch.8 s.3.3.1 or s.3.9.5, as the *TR participant* that has the right to receive all *settlement amounts* under the *transmission right* or, in the case of a *long-term transmission right*, the right to receive all *settlement amounts* relating to one or more periods of one month under the *long-term transmission right*;

TR lamination means a price and an associated quantity that define a "step" in a *TR bid*;

TR market means the market operated by the *IESO* for *transmission rights* pursuant to MR Ch.8 s.3;

TR market clearing price means, in respect of a given *transmission right*, the market clearing price for the *transmission right* established in accordance with MR Ch.8 s.3.15;

TR market deposit means the deposit required to be made by a *TR participant* pursuant to MR Ch.8 s.3.8.2 as a condition of being a *TR bidder* in a *TR auction*;

TR participant means a person that has been authorized by the *IESO* to participate in the *TR market* in accordance with MR Ch.8 s3.8;

TR zone means the *IESO control area* or an *intertie zone* in respect of which the *IESO* calculates prices for *energy* for *settlement* purposes in the *day-ahead market*;

trading day means a period from midnight EST to the following midnight EST within a *billing period*;

trading limit means the dollar amount representing the maximum amount of *actual exposure* that a *market participant* may accumulate before being issued a *margin call* from the *IESO*, determined from time to time by the *IESO* in accordance with MR Ch.2 ss.5.3.5, 5.3.6, 5C.1.5, or 5D.2.2;

trading week means seven consecutive *trading days* commencing on and including a Sunday;

transformation connection service means the *transmission service* relating to the use of the transformation connection assets of a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and in respect of which charges are required to be collected by the *IESO* pursuant to MR Ch.10 s.6.1.1;

transmission customer means a person, including but not limited to a *market participant*, that is required to pay for one or more *transmission services* pursuant to the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*;

transmission right or *TR* means a contractual right to receive a *settlement amount* determined in the manner described in MR Ch.8 s.3.4;

transmission service means any one or more of *network service*, *export transmission service*, *line connection service*, *transformation connection service* and such other service as may be approved by the *OEB* and in respect of which charges are required to be collected by the *IESO* pursuant to MR Ch.10 s.6A.1.1;

transmission services charges means all charges administered by the *IESO* to recover the costs of *transmission services*;

transmission services settlement account means a *settlement account* operated by a *transmitter* for the purpose of receiving payment of *transmission services charges* from the *IESO*;

transmission station service means *station service* associated with transformers, capacitors, switchgear, protection systems and control systems that are part of a transmission *facility* and that do not *connect generation facilities*, *electricity storage facilities, load facilities* or *distribution facilities* to the *IESO-controlled grid*;

transmission system means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

transmission tariff means a tariff fixed or authorized by the *Ontario Energy Board* in a rate order issued pursuant to the *Ontario Energy Board Act, 1998* with respect to the provision of *transmission services*;

transmission transfer capabilities means the measure, in terms of electric power expressed in megawatts, of the ability of *interconnected* electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines or paths between those areas under specified system conditions;

transmitter means a person who owns or operates a *transmission system*;

unattended means not *attended*;

unrestricted competition means a counterfactual market absent any conditions that would require testing for market power pursuant to the *market rules*;

unforced capacity or *UCAP* means the maximum amount, in MW, that a *capacity auction participant* is able to *offer* for a *capacity auction resource* for an applicable *obligation period*, as calculated pursuant to MR Ch.7 s.18.2A.1;

upper energy limit means the highest energy amount to which an *electricity storage unit* can be consistently charged without damage beyond expected degradation from normal use;

urgent amendment, in relation to the market *rules*, means an *amendment* to the *market rules* made in accordance with section 34 of the *Electricity Act, 1998* on an urgent basis for any of the purposes noted in subsection 34(1) of the *Electricity Act, 1998*;

urgent rule amendment committee means the committee referred to in the *Governance and Structure By-law* and established by the Board of Directors of the *IESO* under the authority of the *Governance and Structure By-law* for the purpose of making *urgent amendments* to the *market rules*;

variable generation means all *energy* that is supplied by a *variable generation resource;*

variable generation forecast quantity means an *energy* quantity submitted by the *registered market participant* in the *day-ahead market* for a *dispatchable generation resource* that is classified as *variable generation* to be used instead of the *IESO's* centralized forecast quantity for that *resource*;

variable generation resource means a *generation resource* associated with a *generation facility* with a fuel type of wind or solar photovoltaic that (i) has an installed capacity of 5MW or greater, or (ii) that is directly *connected* to the *IESO-controlled grid;*

variable generator means a *generator* associated with a *variable generation resource;*

VEE process means the process described in MR Ch.9 and used to validate, estimate and edit raw *metering data* to produce final *metering data* or to replicate missing *metering data*;

VEE standard means that part of the *market manual* pertaining to *metering* entitled *Validating, Estimating, and Editing – Requirements for Validating, Estimating, and Editing Of Revenue Metering Data in the IESO-Administered Market*;

virtual trader means a *market participant* authorized to conduct *virtual transactions;*

virtual transaction means a transaction in the *IESO-administered markets* in the form described in MR Ch.7 s.3.4.1.8, that creates a financial obligation to settle against the difference between the *day-ahead market virtual zonal price* and the *real-time market virtual zonal price*, without a corresponding injection or withdrawal of *energy* in the *real-time market*;

virtual transaction zone means a region internal to the *IESO control area* designated by the *IESO* for the purpose of conducting *virtual transactions*;

virtual zonal price means, in respect of a *virtual transaction zone*, the price of *energy* determined in the in the *day-ahead market* or *real-time market* in accordance with the provisions of MR Ch.7;

virtual zonal resource means a construct existing within the *IESO's* systems that corresponds to a *virtual transaction zone,* that facilitates *virtual transactions*;

voltage control service means a service provided by a *market participant* so as to allow the *IESO* to maintain the voltage around the *IESO-controlled grid*;

voltage reduction capability means the capability to reduce demand by lowering a customer's voltage. Within the *IESO-administered markets*, this capability is specifically defined as being able to reduce *distribution* or secondary voltages by 3% and 5%, and having the controlling authority to be able to effect that voltage reduction within five minutes of receipt of the direction from the *IESO* to do so;

weekly advance approval means *IESO* approval of a *planned outage* of equipment no later than 16:00 EST on the second Friday prior to the start of the week, starting Monday, in which the *planned outage* is scheduled to start;

wholesale consumer means a person who purchases electricity or *ancillary services* in the *IESO-administered markets* or directly from another person;

wholesale customer means a *market participant* who takes supply from the *IESO-controlled grid* for its own consumption or for sale;

wholesale seller means a person who sells electricity or *ancillary services* through the *IESO-administered markets* or directly to another person;