Market Rule Amendment Proposal Form

Part 1 - Market Rule Information

Identification No.:	MR-00456-R00
Subject:	Market Renewal Program – Market Settlements, Market Billing and Funds Administration
Title:	Market Renewal Program – Market Settlements, Market Billing and Funds Administration
Nature of Proposal:	☒ Alteration ☒ Deletion ☒ Addition
Chapter:	Chapter 9
Appendix:	
Sections:	Chapter 9, Sections 1, 2, 3, 4, 5 and 6
Sub-sections proposed for amending:	
Current Market Rules Baseline:	

Part 2 - Proposal History

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review	December 1, 2022
2.0	Draft following Stakeholder Review Period	April 24, 2023
3.0	Draft for Technical Panel Review	May 2, 2023
4.0	Submitted for Technical Panel Provisional Vote	June 6, 2023
5.0	Provisionally Recommended by Technical Panel; Submitted for IESO Board Review	June 13, 2023
6.0	Re-Published for Stakeholder Review and Comment	January 29, 2024

Approved Amendment Publication Date:

Approved Amendment Effective Date:

Part 3 - Explanation for Proposed Amendment

Provide a brief description that includes some or all of the following points:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to codify the Market Renewal Program's (MRP's) market settlements framework.

The proposed amendments to Chapter 9 of the market rules include the following:

- Consequential amendments to section 1 – Introductory Rules and section 2 – Settlement Data Collection and Management. These changes include references to the day-ahead market, general clean-up, revised market rule section numbering conventions, and reference to new variables, data, mathematical functions and information;
- Extensive rewrites of section 3 – Hourly Settlement Amounts and section 4 – Non-Hourly Settlement Amounts;
- New section 5 – Market Power Mitigation – Settlements which specifies the settlement mitigation process applicable to specific settlement amounts and adding new settlement amounts related to market power mitigation processes;
- Consequential amendments to section 6 – Settlement Statements to be inclusive of the day-ahead market, and other amendments to incorporate the new suite of MRP defined terms.

This proposal is based on input from various stakeholder engagement initiatives for the Market Renewal Program.

Further information on MRP can be found on the IESO's Market Renewal webpage.

Background

Please refer to MRP backgrounder in MR-00450-R00.

Discussion

The accompanying Settlements "Summary of Market Settlements, Metering, and Market Billing and Funds Administration" reader's guide provides a summary of the market rule amendments made to Chapter 9 of the market rules.

Supplemental information on certain sections in Chapter 9 which explicitly cross reference to the "applicable market manual" is provided below:

- MR Ch.9 s.3.4.3.2 specifies for the purpose of determining the day-ahead market make-whole payment settlement amount, the IESO shall adjust any bid price associated with a dispatchable load, price responsive load, dispatchable electricity storage resource that is ~~withdrawing~~registered to withdraw, or a boundary entity resource that is withdrawing that is less than two price components determined in accordance with the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts specifies that the relevant price used in this adjustment process is -$125/MWh for exporters and -$15/MWh for the other types of resources.

- MR Ch.9 s.3.4.13.1(a), (b), s3.4.13.3(c) and s3.4.13.5.2(c) defines "Attained Max Starts" and "Not Attained Max Starts" for hydroelectric generation resources, in the calculation of the day-ahead market make-whole payment, as requiring the determination of the number of starts of the relevant resource as determined by the IESO in accordance with the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts provides further details in regards to determining the number of starts.

- MR Ch.9 s.3.5.2(h), 3.5.8.1 and s.3.5.8.2 refers to boundary entity resources for export transactions and reason codes as set out in the applicable market manual, for purposes of calculating the real-time make-whole payment settlement amount. Market Manual 4.3 - Real- Time Scheduling of the Physical Markets provides details on the applicable reason codes.

- MR Ch.9 s.3.5.4.4 and 3.5.4.9(a) specify that dispatchable load resources and dispatchable electricity storage resources that are ~~withdrawing~~registered to withdraw, shall be ineligible for ELOC (a component of the real-time make-whole payment settlement amount) under certain ramping scenarios as described in the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts provides further details on those ramping scenarios.

- MR Ch.9 s.3.5.4.9.1(b) specifies that dispatchable load resources and dispatchable electricity storage resources that are ~~withdrawing~~registered to withdraw, shall be eligible for ELOC (a component of the real-time make-whole payment settlement amount) when the metering interval is part of an activation for operating reserves as specified in the applicable Market Manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts further specifies the conditions for the activation of operating reserve for resources to be eligible for ELOC.

- MR Ch.9 s.3.5.5.2 specifies for the purpose of determining the real-time make-whole payment settlement amount, the IESO shall adjust any bid price associated with a dispatchable load, price responsive load, dispatchable electricity storage resource that is ~~withdrawing~~registered to withdraw, or a boundary entity resource that is withdrawing that is less than two price components determined in accordance with the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts specifies that the relevant price used in this adjustment process is -$125/MWh for exporters and -$15/MWh for the other types of resources.

- MR Ch.9 s.3.6.5.2(f) specifies that for purposes of calculating the real-time intertie offer guarantee, that the offset quantity of energy of an eligible import transaction scheduled in the real-time market shall be subject to the offsetting process conducted in accordance with the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts describes the steps in determining IOG_Offset MWs, with illustrations of this process in Appendix D of the market manual.

- MR Ch.9 s.3.7.2 specifies that the IESO shall, when calculating real-time intertie failure charges, determine any price bias adjustment factors in accordance with the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts, Appendix C provides the methodology to calculate the price bias adjustment factors.

- MR Ch.9 s.4.6.2.2, s.4.6.7.2 and s.4.6.12.2 specify, that for purposes of calculating the real-time ramp-down settlement amount, that energy offers shall be determined in accordance with the applicable market manual. These sections further specify an adjustment by a ramp-down factor, as specified in the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts details the method of determining energy offers when calculating the real-time ramp-down settlement amount, and further specifies that the applicable ramp-down factor is 1.3.

- MR Ch.9 s.4.10.1(a) and (b) specify that the relevant metering intervals for calculating the generator failure charge is as determined in accordance with the applicable market manual. Similarly, MR Ch.9 s.4.10.9(a) specifies the same as it relates to steam turbines associated with a pseudo-unit. Market Manual 5.5: IESO-Administered Markets Settlement Amounts details specific failure events and the corresponding metering intervals used in calculating the generator failure charge.

- MR Ch.9 s.4.11.1.3 specifies that market participants submitting a claim for the fuel cost compensation credit settlement amount, must submit such claim in accordance with the process specified in the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts details the required process via Online IESO via completion of the "Fuel Cost Compensation" form.

- MR Ch.9 s.4.14.14 specifies that 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, any compensation for capacity market participants paid in that energy market billing period by the IESO, and any funds borrowed by the IESO and any associated interest costs incurred in the preceding energy market billing period. Market Manual 5.5: IESO-Administered Markets Settlement Amounts will be updated to include further details at a future date once market rule amendments for capacity auction enhancements are complete.

- MR Ch.9 s.4.14.15 specifies that the IESO shall distribute to market participants, in the manner specified in the applicable market manual, any adjustments to capacity market participant payments pursuant to section 4.13. Market Manual 5.5: IESO-Administered Markets Settlement Amounts will be updated to include further details at a future date once market rule amendments for capacity auction enhancements are complete.

- MR Ch.9 s.5.1.5a specifies that 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 MR Ch.9 App 9.4, as the case may be, for the settlement hour determined in accordance with the applicable market manual. Market Manual 5.5: IESO-Administered Markets Settlement Amounts sets out the relevant settlement hour for the purpose of this determination.

- MR Ch.9 s.5.4.1.1(b) and s.5.4.1.2(b) specifies that the variable PM_PW_{mcepw} is the persistence multiplier as determined in accordance with the applicable market manual. Market Manual 14.1 provides further details on the determination of the persistence multiplier with example scenarios.

Part 4 - Proposed Amendment

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* ~~with other *control areas*~~, 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 ~~3.1.9~~ 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 ~~*facilities*~~*resources* are ~~connected to~~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 ~~*facilities*~~*resources* are ~~*connected* to~~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 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* ~~*unit*~~*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* ~~*units*~~*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* ~~*units*~~*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* ~~*unit*~~*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* ~~*units*~~*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* ~~*units*~~*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 ~~location~~*delivery point* of a *generation* ~~*unit* which is part of~~*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 uplift *settlement amounts*, or both, accruing at the ~~location~~*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 uplift *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 ~~location~~*delivery point* of an *electricity storage* ~~*unit* which is part of~~*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 ~~location~~*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* ~~*facilities*~~*resources* shall be recorded by ~~*registered wholesale meters*~~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 ~~registered~~ *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 ~~a~~ given *registered wholesale* ~~*meter*~~*meters* shall be determined by the *IESO* by:

2.5.1.1 adjusting the *metering data* from ~~that~~those *registered wholesale* ~~*meter*~~*meters* in accordance with MR Ch.6 s.4.2.3; and

2.5.1.2 summing the *metering data* from ~~that~~those *registered wholesale* ~~*meter*~~*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 ~~that~~those *registered wholesale* ~~*meter*~~*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.*

~~2.5.2.1 the *registered wholesale meter*; or~~

~~2.5.2.2 the *registered wholesale meter* or *registered wholesale meters* associated with the *facility*,~~

~~as the case may be.~~

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 practicable after 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 Appendix9.2.

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 *real-time market Ontario zonal price* and a load forecast deviation charge of 0.

Note: Existing Section 3 has been deleted in its entirety and replaced with new section 3 – Hourly Settlement Amounts

Note: New Section 3 – Hourly Settlement Amounts (sections 3.1 to 3.10) has been shown without track changes for ease of review.

3 Hourly Settlement Amounts (New)

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 ~~withdrawing~~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 ~~withdrawing~~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*:

$$HPTSA\_PBC\{1\}_{k,h} = \sum^{M}\left[DAM\_LMP_h^m \; x \left(\sum_S DAM\_BCQ_{s,k,h}^m - \sum_B DAM\_BCQ_{k,b,h}^m\right) + DAM\_LMP_h^i \; x \left(\sum_S DAM\_BCQ_{s,k,h}^i - \sum_B DAM\_BCQ_{k,b,h}^i\right)\right]$$

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 ~~a~~an *energy trader* participating with a *boundary entity resource:*

$$HPTSA\{1\}_{k,h} = \sum^{M}\left[\left(DAM\_QSI^{m}_{k,h} - DAM\_QSW^{m}_{k,h}\right) x\ DAM\_LMP^{m}_{h} + \left(DAM\_QSI^{i}_{k,h} - DAM\_QSW^{i}_{k,h}\right) x\ DAM\_LMP^{i}_{h}\right]$$

3.1.4 For all *delivery points* 'm' associated with a *price responsive load* or a *self-scheduling electricity storage resource* that is ~~withdrawing~~registered to withdraw:

$$HPTSA\{1\}\_PRL\_SSW_{k,h} = -1\ x \left[\sum^{M1}\left(DAM\_QSW^{m}_{k,h} \times DAM\_LMP^{m}_{h}\right) + \sum^{M2}\left(DAM\_QSW^{m}_{k,h} \times DAM\_LMP^{m}_{h}\right)\right]$$

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*:

$$HPTSA\{2\}\_PBC_{k,h} = \sum^{M,T} RT\_LMP^{m,t}_{h}\ x \left(\sum_{S} BCQ^{m,t}_{s,k,h} - \sum_{B} BCQ^{m,t}_{k,b,h}\right) + \sum^{M,T} RT\_LMP^{i,t}_{h}\ x \left(\sum_{S} BCQ^{i,t}_{s,k,h} - \sum_{B} BCQ^{i,t}_{k,b,h}\right)$$

Where:

a. If the location specified pursuant to MR Ch.8 s.2.2.1 relates to a *non-dispatchable load*, the $RT\_LMP^{m,t}_{h}$ shall be replaced with the $DAM\_LMP^{z}_{h}$.

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*:

$$HPTSA\{2\}_{k,h} = \sum^{M,T} RT\_LMP^{m,t}_{h}\ x \frac{\left(\left(AQEI^{m,t}_{k,h} - DAM\_QSI^{m}_{k,h}\right) - \left(AQEW^{m,t}_{k,h} - DAM\_QSW^{m}_{k,h}\right)\right)}{12} + RT\_LMP^{i,t}_{h}\ x \frac{\left(\left(SQEI^{i,t}_{k,h} - DAM\_QSI^{i}_{k,h}\right) - \left(SQEW^{i,t}_{k,h} - DAM\_QSW^{i}_{k,h}\right)\right)}{12}$$

3.1.7 For all *delivery points* 'm' associated with a *price responsive load* or a *self-scheduling electricity storage resource* that is ~~withdrawing~~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':

$$HVTSA\{1\}_{k,h} = \sum^{V} \left(DAM\_QVSI_{k,h}^{v} - DAM\_QVSW_{k,h}^{v}\right) \times DAM\_LMP_{h}^{vz}$$

Hourly Virtual Transaction Settlement Amount – Real-Time Balancing Settlement

3.1.9 For all *virtual zonal resources* 'v':

$$HVTSA\{2\}_{k,h} = -1\ x \sum^{V,T} \left(DAM\_QVSI_{k,h}^{v} - DAM\_QVSW_{k,h}^{v}\right)/12\ x\ RT\_LMP_{h}^{vz,t}$$

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*:

$$HORSA\{2\}_{k,h} = \sum_{R}^{M,T} \left\{RT\_PROR_{r,h}^{m,t}\ x \left(RT\_QSOR_{r,k,h}^{m,t} - DAM\_QSOR_{r,k,h}^{m}\right) + RT\_PROR_{r,h}^{i,t}\ x \left(RT\_QSOR_{r,k,h}^{i,t} - DAM\_QSOR_{r,k,h}^{i}\right)\right\}$$

3.2 Hourly Physical Transaction Settlement Amount – Non-Dispatchable ~~Resources~~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:

$$HPTSA\_NDL_{k,h} = -1 \text{ x } (DAM\_LMP_h^z + LFDC_h) \text{ x } \sum\nolimits^T (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t})$$

Where:

a. '$LFDC_h$' is the load forecast deviation charge for *settlement hour* 'h' determined in accordance with section 3.2.3.

3.2.3 The *IESO* shall determine the load forecast deviation charge for all *non-dispatchable loads* ("$LFDC_h$") for each *settlement hour* 'h' in accordance with the following:

$$LFDC_h = \frac{Real\_Time\ Purchase\ Cost\_Benefit_h + DAM\ Volume\ Factor\ Cost\_Benefit_h}{\sum_{K,h}^{M,T}(AQEW - AQEI)_{k,h}^{m,t}}$$

Where:

a. $Real\_Time\ Purchase\ Cost\_Benefit = \sum_{K,h}^{M,T}[RT\_LMP_h^{m,t} \text{ x } (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t} - DAM\_QSW_{k,h}^{m})/12] - \sum_{K,h}^{M2,T}[RT\_LMP_h^{d,t} \text{ x } DAM\_QSW_{k,h}^{d}/12]$;

b. $DAM\ Volume\ Factor\ Cost\_Benefit = DAM\_LMP_h^z \text{ x } [\sum_{K,h}^{M,T}(DAM\_QSW_{k,h}^{m} - AQEW_{k,h}^{m,t} + AQEI_{k,h}^{m,t})/12] + \sum_{K}^{M2}[DAM\_LMP_h^z \text{ x } DAM\_QSW_{k,h}^{d}]$

~~3.2.4 The hourly *physical transaction settlement amount* for *non-dispatchable generation resources* and *self-scheduling electricity storage resources* that are injecting shall be calculated for each *settlement hour* 'h' and disbursed to the *market participants* of such *resources* in accordance with section 3.2.4.1.~~

~~3.2.4.1 For all *delivery points* 'm' associated with a *non-dispatchable generation resource* and *self-scheduling electricity storage resources* that are injecting, the hourly *physical transaction settlement amount* for *non-dispatchable generation resources* applicable to *market participant* 'k' in *settlement hour* 'h' ("HPTSA_NDG$_{k,h}$") is calculated as follows:~~

$$HPTSA\_NDG_{k,h} = RT\_LMP_h^{m,t}\ x\ (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t})$$

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 activated 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. $Min\,(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i})$ 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 *settlement 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. $DAM\_BCOR_{k,h}^{m}$ is the *operating reserve* component of the *day-ahead market* balancing credit *settlement amount* and is calculated as follows:

$$DAM\_BCOR_{k,h}^{m} = \sum^{R,T} Max\left(0, RT\_PROR_{r,h}^{m,t} - DAM\_PROR_{r,h}^{m}\right) \times Max\left(0, DAM\_QSOR_{r,k,h}^{m} - RT\_QSOR_{r,k,h}^{m,t}\right)/12$$

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:

$$DAM\_BC_{k,h}^{i} = DAM\_BCE_{k,h}^{i} + DAM\_BCOR_{k,h}^{i}$$

Where:

a. for an import transaction, $DAM\_BCE_{k,h}^{i}$ is the *energy* component of the *day-ahead market* balancing credit s*ettlement amount* and calculated as follows:

$$DAM\_BCE_{k,h}^{i} = MAX\{0, \sum^{T} OP(RT\_LMP_{h}^{i,t}, Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSI_{k,h}^{i}), BE_{k,h}^{i,t}) - OP(RT\_LMP_{h}^{i,t}, SQEI_{k,h}^{i,t}, BE_{k,h}^{i,t})\} /12$$

b. for an export transaction, $DAM\_BCE_{k,h}^{i}$ is the *energy* component of the *day-ahead market* balancing credit s*ettlement amount* and calculated as follows:

$$DAM\_BCE_{k,h}^{i} = -1 \times MIN\{0, \sum^{T} OP(RT\_LMP_{h}^{i,t}, Min(RT\_LOC\_EOP_{k,h}^{i,t}, DAM\_QSW_{k,h}^{i}), BL_{k,h}^{i,t}) - OP(RT\_LMP_{h}^{i,t}, SQEW_{k,h}^{i,t}, BL_{k,h}^{i,t})\}/12$$

c. $DAM\_BCOR_{k,h}^{i}$ is the *operating reserve* component of the *day-ahead market* balancing credit s*ettlement amount* and calculated as follows:

$$DAM\_BCOR_{k,h}^{i} = \sum^{R} MAX\{0, \sum^{T} OP(RT\_PROR_{r,h,}^{i,t}, Min(RT\_OR\_LOC\_EOP_{r,k,h}^{i,t}, DAM\_QSOR_{r,k,h}^{i}), BOR_{r,k,h}^{i,t}) - OP(RT\_PROR_{r,h}^{i,t}, RT\_QSOR_{r,k,h}^{i,t}, BOR_{r,k,h}^{i,t})\}/12$$

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 *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 *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 *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 *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 ~~withdrawing~~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 ~~injecting, or~~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 ~~withdrawing, or~~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 *non-quick start resource* for a *settlement hour* where the *non-quick start resource* has a *day-ahead schedule* less than its *minimum loading point*;

3.4.4.2 a *called capacity export* that the external *control area operator* called for a *generation resource* or *dispatchable electricity storage resource*:

a. prior to the *generation resource* or *dispatchable electricity storage resource*, as the case may be, receiving a *day-ahead schedule*; or

b. after the *generation resource* or *dispatchable electricity storage resource*, as the case may be, receives a *day-ahead schedule* 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;

3.4.4.3 an *energy trader* participating with a *boundary entity resource* during any *settlement hours* 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* or an *hourly must run* binding constraint;

3.4.4.5 *dispatchable loads* and *dispatchable electricity storage resources* that are ~~withdrawing~~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;* ~~and~~

3.4.4.6 combustion ~~turbines~~turbine *generation units* or steam ~~turbines~~turbine *generation units* that are not operating as a *pseudo-unit* for *settlement hours* in which they have a ~~binding~~minimum constraint applied for combined cycle ~~physical unit constraint~~operation consistent with combustion turbine commitment; and

3.4.4.7 *dispatchable electricity storage resources* for such *settlement hours* 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 ~~do not share *forebays*~~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 such *resource* is equal to its *minimum daily energy limit;* or

3.4.5.2 hydroelectric *generation resources* that ~~share a *forebay*~~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 ~~share~~are registered to a *forebay* is equal to the *minimum daily energy limit* of ~~the shared~~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 ~~Associated with~~ a Pseudo-Unit and Dispatchable Storage

3.4.7 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* that is ~~injecting~~registered to inject or a *dispatchable generation resource* that is not ~~associated with~~ 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:

$$DAM\_MWP_{k,h}^{m} = Max\left[0, DAM\_COMP1_{k,h}^{m} + DAM\_COMP2_{k,h}^{m}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{m} = -1 \times \left[OP\left(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right)\right]$

b. $DAM\_COMP2_{k,h}^{m} = -1 \times \sum_{R}\left[OP\left(DAM\_PROR_{r,h}^{m}, DAM\_QSOR_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m}\right) - OP\left(DAM\_PROR_{r,h}^{m}, DAM\_OR\_EOP_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m}\right)\right]$

Day-Ahead Market Make-Whole Payment for Dispatchable Loads and Dispatchable Storage

3.4.8 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* that is ~~withdrawing~~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

3.4.9 For a *delivery point* 'm' associated with a *self-scheduling electricity storage resource* that is ~~withdrawing~~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:

$$DAM\_MWP^{m}_{k,h} = Max\left[0, DAM\_COMP1^{m}_{k,h}\right]$$

Where:

a. $DAM\_COMP1^{m}_{k,h} = OP\left(DAM\_LMP^{m}_{h}, DAM\_QSW^{m}_{k,h}, DAM\_BL^{m}_{k,h}\right) - OP\left(DAM\_LMP^{m}_{h}, DAM\_EOP^{m}_{k,h}, DAM\_BL^{m}_{k,h}\right)$

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 ~~that is registered as~~ 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:

$$DAM\_MWP_{k,h}^{i} = Max\left[0, DAM\_COMP1_{k,h}^{i} + DAM\_COMP2_{k,h}^{i}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{i} = -1 \times \left[OP\left(DAM\_LMP_{h}^{i}, DAM\_QSI_{k,h}^{i}, DAM\_BE_{k,h}^{i}\right) - OP\left(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BE_{k,h}^{i}\right)\right]$

b. $DAM\_COMP2_{k,h}^{i} = -1\ x\ \sum_{R}\left[OP\left(DAM\_PROR_{r,h}^{i}, DAM\_QSOR_{r,k,h}^{i}, DAM\_BOR_{r,k,h}^{i}\right) - OP\left(DAM\_PROR_{r,h}^{i}, DAM\_OR\_EOP_{r,k,h}^{i}, DAM\_BOR_{r,k,h}^{i}\right)\right]$

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 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 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 a hydroelectric *generation resource* has not submitted a *maximum number of starts per day;*

3.4.13.2 where applicable, $FROP^{m}_{k,h}$ shall be determined as follows:

a. If $DAM\_QSI^{m}_{k,h}$ is not equal to $FR\_UL^{m,f}_{k}$, or the *resource* does not have a *forbidden region*,

$$FROP^{m}_{k,h} = 0$$

b. Otherwise,

$$FROP_{k,h}^{m} = OP\left(DAM\_LMP_{h}^{m}, FR\_UL_{k}^{m,f}, DAM\_BE_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, Max\left(DAM\_EOP_{k,h}^{m}, FR\_LL_{k}^{m,f}\right), DAM\_BE_{k,h}^{m}\right)$$

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 ~~binding~~ *reliability* constraint, then for such *settlement hours* with a ~~binding~~ *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:

$$DAM\_MWP_{k,h}^{m} = Max\left[0, DAM\_COMP1_{k,h}^{m} + DAM\_COMP2_{k,h}^{m}\right]$$

Where:

i. $DAM\_COMP1_{k.h}^{m} = (-1) \times \left[OP\left(DAM\_LMP_{h}^{m}, DAM\_QSI_{k.h}^{m}, DAM\_BE_{k.h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right) - FROP_{k,h}^{m}\right]$

ii. $FROP_{k.h}^{m}$ is determined in accordance with the formulation outlined in section 3.4.13.2.

iii. $DAM\_COMP2_{k.h}^{m} = -1 \times \sum_{R}\left[OP\left(DAM\_PROR_{r.h}^{m}, DAM\_QSOR_{r.k.h}^{m}, DAM\_BOR_{r.k.h}^{m}\right) - OP\left(DAM\_PROR_{r,h}^{m}, DAM\_OR\_EOP_{r,k,h}^{m}, DAM\_BOR_{r,k,h}^{m}\right)\right]$

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:

$$DAM\_MWP_{k,s}^{m} = Max\left[0, DAM\_COMP1_{k,s}^{m} + DAM\_COMP2_{k,s}^{m}\right]$$

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. $DAM\_COMP1_{k,s}^{m} = (-1) \times \left\{\left[\sum_{Hp} OP\left(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right) - FROP_{k,h}^{m}\right] + \left[\sum_{Hn} OP\left(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right) - OP\left(DAM\_LMP_{h}^{m}, DAM\_EOP_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right) - FROP_{k,h}^{m}\right]\right\}$

And where:

i. 'Hp' is the set of all *settlement hours* within start 's' where $OP\left(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right)$ is positive, excluding those *settlement hours* in which the *resource* has a ~~binding~~ *reliability* constraint;

ii. 'Hn' is the set of all *settlement hours* within start 's' where $OP\left(DAM\_LMP_{h}^{m}, DAM\_QSI_{k,h}^{m}, DAM\_BE_{k,h}^{m}\right)$ 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 ~~binding~~ *reliability* constraint or a binding constraint referred to in section 3.4.2.3; 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-head schedule* with *settlement hours* with a ~~binding~~ *reliability* constraint, then for such *settlement hours* with a ~~binding~~ *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 ~~Associated with a~~That Are Pseudo-~~unit~~Units

Combustion Turbine

3.4.14 For a *delivery point* 'c' for a combustion turbine *generation unit* 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. $DAM\_COMP2^{c}_{k,h} = -1 \times \sum_{R}\left[OP\left(DAM\_PROR^{c}_{r,h}, DAM\_QSOR^{c}_{r,k,h}, DAM\_OR\_DIPC^{c}_{r,k,h}\right) - OP\left(DAM\_PROR^{c}_{r,h}, DAM\_OR\_EOP^{c}_{r,k,h}, DAM\_OR\_DIPC^{c}_{r,k,h}\right)\right]$

Steam Turbine

3.4.15 For a *delivery point* 's' for a steam turbine *generation unit* 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. ~~a *boundary entity resource*~~an import or export transaction during any *settlement hours* in which the ~~*boundary entity resource*~~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;*

d. a *non-quick start resource* that is not ~~associated with~~ a *pseudo-unit*, for any *settlement hour* in which its *real-time schedule* is less than its *minimum loading point*;

e. a combustion turbine *generation unit* associated with a *pseudo-unit,* for any *settlement hour* in which its *real-time schedule* is less than its *minimum loading point;*

f. a steam turbine *generation unit* associated with a *pseudo-unit,* for any *settlement hour* where none of the combustion ~~turbines~~turbine *generation unit*s associated with the steam turbine *generation unit* 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*; ~~or~~

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* ~~run~~*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 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 ~~withdrawing~~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 ~~turbines~~turbine *generation units* or steam ~~turbines~~turbine *generation units* that are registered as a *pseudo-unit* but not operating as a *pseudo-unit* for *metering intervals* in which they have a ~~binding~~minimum constraint applied for combined cycle ~~physical unit constraint~~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 ~~share a~~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 ~~binding~~ *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 ~~share a~~are registered to the same *forebay* is less than or equal to the *minimum daily energy limit* of ~~the shared~~such *forebay;* or

iii. that ~~do~~are not ~~share a~~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 ~~binding~~ *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 ~~withdrawing~~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; and

3.5.4.9 Subject to section 3.5.4.9.1, *dispatchable loads* and *dispatchable electricity storage resources* that are ~~withdrawing~~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.*

3.5.4.9.1 Notwithstanding section 3.5.4.9, *dispatchable loads* and *dispatchable electricity storage resources* that are ~~withdrawing~~registered to withdraw shall be eligible for ELOC in the circumstances described in section 3.5.4.9 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 ~~injecting, or~~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 ~~withdrawing, or~~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 ~~Associated with a~~ Pseudo-~~Unit~~Units and Dispatchable Storage

3.5.6 For a *delivery point* 'm' associated with a *dispatchable electricity storage resource* that is ~~injecting~~registered to inject or a *dispatchable generation resource* that is not ~~associated with~~ a *pseudo-unit*, the real-time make-whole payment *settlement amount* is calculated as follows:

$$RT\_MWP^{m}_{k,h} = \sum^{T} Max\left(0, RT\_ELC^{m,t}_{k,h} + RT\_OLC^{m,t}_{k,h}\right) + Max\left(0, RT\_ELOC^{m,t}_{k,h} + RT\_OLOC^{m,t}_{k,h}\right)$$

Where:

a. $RT\_ELC^{m,t}_{k,h}$ is calculated in accordance with section 3.5.6.1;

b. $RT\_OLC^{m,t}_{k,h} = \sum_{R}\{-1 \times \left[OP\left(RT\_PROR^{m,t}_{r,h}, Max(DAM\_QSOR^{m}_{r,k,h}, RT\_QSOR^{m,t}_{r,k,h}), BOR^{m,t}_{r,k,h}\right) - OP\left(RT\_PROR^{m,t}_{r,h}, Max(RT\_OR\_LC\_EOP^{m,t}_{r,k,h}, DAM\_QSOR^{m}_{r,k,h}), BOR^{m,t}_{r,k,h}\right)\right]/12\}$

c. $RT\_ELOC^{m,t}_{k,h}$ is calculated in accordance with section 3.5.6.2;

d. $RT\_OLOC^{m,t}_{k,h} = \sum_{R}\left[\{OP\left(RT\_PROR^{m,t}_{r,h}, RT\_OR\_LOC\_EOP^{m,t}_{r,k,h}, BOR^{m,t}_{r,k,h}\right) - Max\left[0, OP\left(RT\_PROR^{m,t}_{r,h}, RT\_QSOR^{m,t}_{r,k,h}, BOR^{m,t}_{r,k,h}\right)\right]\}/12\right]$

Where:

i. if the *offer* price of $BOR^{m,t}_{r,k,h}$ is greater than $RT\_PROR^{m,t}_{r,h}$, the *IESO* shall revise the *offer* price of $BOR^{m,t}_{r,k,h}$ to be equal to $RT\_PROR^{m,t}_{r,h}$.

3.5.6.1 The *IESO* shall calculate $RT\_ELC^{m,t}_{k,h}$ as follows:

$$RT\_ELC^{m,t}_{k,h} = -1\ x\ \left[\!\left[\left[OP\left(RT\_LMP^{m,t}_{h}, Max(DAM\_QSI^{m}_{k,h}, Min(RT\_QSI^{m,t}_{k,h}, AQEI^{m,t}_{k,h})), BE^{m,t}_{k,h}\right) - OP\left(RT\_LMP^{m,t}_{h}, Max(RT\_LC\_EOP^{m,t}_{k,h}, DAM\_QSI^{m}_{k,h}), BE^{m,t}_{k,h}\right)\right] - RT\_FROP\_LC^{m,t}_{k,h}\right]\!\right] /12$$

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:

$$\begin{aligned} &RT\_FROP\_LC_{k,h}^{m,t} \\ &= \; OP\left(RT\_LMP_{h}^{m,t}, Max(DAM\_QSI_{k,h}^{m}, Min(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})), BE_{k,h}^{m,t}\right) \\ &- \; OP\left(RT\_LMP_{h}^{m,t}, Max(FR\_LL_{k,h}^{m,t,f}, DAM\_QSI_{k,h}^{m}, RT\_LC\_EOP_{k,h}^{m,t}), BE_{k,h}^{m,t}\right) \end{aligned}$$

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:

$$\begin{aligned} RT\_ELOC_{k,h}^{m,t} = \; &\{OP\left(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) \\ &- \; Max\left[0, OP\left(RT\_LMP_{h}^{m,t}, Max(RT\_QSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}\right)\right] \\ &- RT\_FROP\_LOC_{k,h}^{m,t}\}/12 \end{aligned}$$

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 and $RT\_QSI_{k,h}^{m,t}$ is less than FR_UL, then:

$$RT\_FROP\_LOC_{k,h}^{m,t} = OP\left(RT\_LMP_h^{m,t}, Min(FR\_UL_{k,h}^{m,t,f}, RT\_LOC\_EOP_{k,h}^{m,t}), BE_{k,h}^{m,t}\right) - Max\left[0, OP\left(RT\_LMP_h^{m,t}, Max(RT\_QSI_{k,h}^{m,t,f}, AQEI_{k,h}^{m,t}), BE_{k,h}^{m,t}\right)\right]$$

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:

$$RT\_MWP_{k,h}^{m} = \sum^{T} Max(0, RT\_ELC_{k,h}^{m,t} + RT\_OLC_{k,h}^{m,t}) + Max(0, RT\_ELOC_{k,h}^{m,t} + RT\_OLOC_{k,h}^{m,t})$$

Where:

~~$RT\_ELC_{k,h}^{m,t} = Max\{0, OP(RT\_LMP_{h}^{m,t}, Min(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t}) - OP(RT\_LMP_{h}^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSW_{k,h}^{m}), BL_{k,h}^{m,t})\}/12$~~

a. $RT\_ELC_{k,h}^{m,t} = [OP(RT\_LMP_{h}^{m,t}, Max(DAM\_QSW_{k,h}^{m}, Min(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t})), BL_{k,h}^{m,t}) - OP(RT\_LMP_{h}^{m,t}, Max(RT\_LC\_EOP_{k,h}^{m,t}, DAM\_QSW_{k,h}^{m}), BL_{k,h}^{m,t})]/12$

b. $RT\_OLC_{k,h}^{m,t} = \sum_{R}\{-1 \times [OP(RT\_PROR_{r,h}^{m,t}, Max(DAM\_QSOR_{r,k,h}^{m}, RT\_QSOR_{r,k,h}^{m,t}), BOR_{r,k,h}^{m,t}) - OP(RT\_PROR_{r,h}^{m,t}, Max(RT\_OR\_LC\_EOP_{r,k,h}^{m,t}, DAM\_QSOR_{r,k,h}^{m}), BOR_{r,k,h}^{m,t})]/12\}$

~~$RT\_ELOC_{k,h}^{m,t} = -1 \times \{OP(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BL_{k,h}^{m,t}) - Max[0, OP(RT\_LMP_{h}^{m,t}, Max(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t})]\}/12$~~

c. $RT\_ELOC_{k,h}^{m,t} = -1 \times \{OP(RT\_LMP_{h}^{m,t}, RT\_LOC\_EOP_{k,h}^{m,t}, BL_{k,h}^{m,t}) - OP(RT\_LMP_{h}^{m,t}, Max(RT\_QSW_{k,h}^{m,t}, AQEW_{k,h}^{m,t}), BL_{k,h}^{m,t})\}/12$

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. $RT\_OLOC_{k,h}^{m,t} = \sum_{R}[\{OP(RT\_PROR_{r,h}^{m,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}) - Max[0, OP(RT\_PROR_{r,h}^{m,t}, RT\_QSOR_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t})]\}/12]$

And 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 $RT\_PROR_{r,h}^{m,t}$.

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 ~~Associated with a~~That Are Pseudo-~~Unit~~Units

Combustion turbine

3.5.9 For a *delivery point* 'c' for a combustion turbine *generation unit* of a *dispatchable generation resource* ~~associated with~~that is a *pseudo-unit*, the real-time make-whole payment *settlement amount* is calculated as follows:

$$RT\_MWP_{k,h}^{c} = \sum^{T} Max\left(0, RT\_ELC_{k,h}^{c,t} + RT\_OLC_{k,h}^{c,t}\right) + Max\left(0, RT\_ELOC_{k,h}^{c,t} + RT\_OLOC_{k,h}^{c,t}\right)$$

Where:

a. $RT\_ELC_{k,h}^{c,t} = (-1) \times \left[OP\left(RT\_LMP_{h}^{c,t}, Max(DAM\_QSI_{k,h}^{c}, Min\left(RT\_QSI_{k,h}^{c,t}, AQEI_{k,h}^{c,t}\right)), RT\_DIPC_{k,h}^{c,t}\right) - OP\left(RT\_LMP_{h}^{c,t}, Max\left(RT\_LC\_EOP_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}\right), RT\_DIPC_{k,h}^{c,t}\right)\right]/12$

b. $RT\_OLC_{k,h}^{c,t} = \sum_{R}\left[(-1) \times \left\{OP\left(RT\_PROR_{r,h}^{c,t}, Max(DAM\_QSOR_{r,k,h}^{c}, RT\_QSOR_{r,k,h}^{c,t}), RT\_OR\_DIPC_{r,k,h}^{c,t}\right) - OP\left(RT\_PROR_{r,h}^{c,t}, Max(RT\_OR\_LC\_EOP_{r,k,h}^{c,t}, DAM\_QSOR_{r,k,h}^{c}), RT\_OR\_DIPC_{r,k,h}^{c,t}\right)\right\}/12\right]$

And where:

i. If the *offer* price in the $RT\_OR\_DIPC_{r,k,h}^{c,t}$ *offer* curve is greater than $RT\_PROR_{r,h}^{c,t}$ for the same *class r reserve*, the *IESO* shall revise the *offer* price of $RT\_OR\_DIPC_{r,k,h}^{c,t}$ to be equal to $RT\_PROR_{r,h}^{c,t}$.

c. $RT\_ELOC_{k,h}^{c,t} = \left\{OP\left(RT\_LMP_{h}^{c,t}, RT\_LOC\_EOP_{k,h}^{c,t}, RT\_DIPC_{k,h}^{c,t}\right) - Max\left[0, OP\left(RT\_LMP_{h}^{c,t}, Max\left(RT\_QSI_{k,h}^{c,t}, AQEI_{k,h}^{c,t}\right), RT\_DIPC_{k,h}^{c,t}\right)\right]\right\}/12$

And where:

i. If the *offer* price in the $RT\_DIPC_{k,h}^{c,t}$ *offer* curve is greater than $RT\_LMP_{h}^{c,t}$, the *IESO* shall revise the *offer* price of $RT\_DIPC_{k,h}^{c,t}$ to be equal to $RT\_LMP_{h}^{c,t}$

d. $RT\_OLOC_{k,h}^{c,t} = \sum_{R}\left[OP\left(RT\_PROR_{r,h}^{c,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{c,t}, RT\_OR\_DIPC_{r,k,h}^{c,t}\right) - Max\left[0, OP\left(RT\_PROR_{r,h}^{c,t}, RT\_QSOR_{r,k,h}^{c,t}, RT\_OR\_DIPC_{r,k,h}^{c,t}\right)\right]\right]/12$

And where:

i. If the *offer* price in the $RT\_OR\_DIPC_{r,k,h}^{c,t}$ *offer* curve is greater than $RT\_PROR_{r,h}^{c,t}$ for the same *class r reserve*, the *IESO* shall revise the *offer* price of $RT\_OR\_DIPC_{r,k,h}^{c,t}$ to be equal to $RT\_PROR_{r,h}^{c,t}$.

Steam turbine

3.5.10 For a *delivery point* 's' for a steam turbine *generation unit* of a *dispatchable generation resource* ~~associated with~~that is a *pseudo-unit* where at least one of the combustion ~~turbines~~turbine *generation units* 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. $RT\_ELC_{k,h}^{s,t} = (-1) \times \left[OP\left(RT\_LMP_{h}^{s,t}, Max(DAM\_DIGQ_{k,h}^{s}, Min(RT\_QSI\_DIGQ_{k,h}^{s,t}, AQEI_{k,h}^{s,t})), RT\_DIPC_{k,h}^{s,t}\right) - OP\left(RT\_LMP_{h}^{s,t}, Max\left(RT\_LC\_EOP\_DIGQ_{k,h}^{s,t}, DAM\_DIGQ_{k,h}^{s}\right), RT\_DIPC_{k,h}^{s,t}\right)\right]/12$

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~~t_0' is ~~the set of all~~ *metering* ~~*intervals*~~*interval* 't' in *settlement hour* 'h' when none of the combustion ~~turbines~~turbine *generation units* associated with the steam turbine *generation unit* 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. '~~T₁~~t_1' is ~~the set of all~~ *metering* ~~*intervals*~~*interval* 't' in *settlement hour* 'h' when (1) at least one combustion turbine *generation unit* associated with the steam turbine *generation unit* has a *real-time schedule* greater than or equal to its *minimum loading point*; and (2) at least one of the combustion ~~turbines~~turbine *generation units* associated with the steam turbine *generation unit* 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. $RT\_OLOC_{k,h}^{s} = \sum_R[\{OP(RT\_PROR_{r,h}^{s,t}, RT\_OR\_LOC\_EOP_{r,k,h}^{s,t}, RT\_OR\_DIPC_{r,k,h}^{s,t}) - Max[0, OP(RT\_PROR_{r,h}^{s,t}, RT\_QSOR_{r,k,h}^{s,t}, RT\_OR\_DIPC_{r,k,h}^{s,t})]\}/12]$

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 ~~*market participants* of~~*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:

$$RT\_IOG^{i}_{k,h} = Max\left[Potential\_IOG^{i}_{k,h} - IOG\_Offset^{i}_{k,h}, 0\right]$$

Where:

a. $IOG\_Offset^{i}_{k,h}$ 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. $Potential\_IOG^{i}_{k,h} = (-1) \times Min\left[0, \sum^{T} OP\left(RT\_LMP^{i,t}_{h}, SQEI^{i,t}_{k,h}, BE^{i,t}_{k,h}\right) - \sum^{T} OP\left(RT\_LMP^{i,t}_{h}, Min\left[SQEI^{i,t}_{k,h}, DAM\_QSI^{i}_{k,h}\right], BE^{i,t}_{k,h}\right)\right]/12$

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' ("$IOG\_Offset^{i}_{k,h}$") is determined by the following equation:

$$IOG\_Offset^{i}_{k,h} = OFFSET\_MW^{i}_{k,h} \times IOG\_RATE^{i}_{k,h}$$

Where:

a. $IOG\_RATE^{i}_{k,h} = \frac{Potential\_IOG^{i}_{k,h}}{\left(\sum^{T} SQEI^{i,t}_{k,h} - DAM\_QSI^{i}_{k,h}\right)/12}$

b. $IOG\_RATE^{i}_{k,h}$ shall be zero if $DAM\_QSI^{i}_{k,h}$ is greater than or equal to $SQEI^{i}_{k,h}$; and

c. $OFFSET\_MW^{i}_{k,h}$ 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* ($OFFSET\_MW^{i}_{k,h}$) shall be:

3.6.5.1 determined for each eligible *energy* import transaction scheduled in the *real-time market* with a $IOG\_Rate^{i}_{k,h}$ that is greater than $0/MW. For greater certainty, those eligible *energy* import transaction scheduled in the *real-time market* with an $IOG\_Rate^{i}_{k,h}$ 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 $OFFSET\_MW^{i}_{k,h}$ value for each eligible *energy* import transaction scheduled in the *real-time market* with a non-zero $IOG\_Rate^{i}_{k,h}$, 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 $OFFSET\_MW_{k,h}^{i}$ 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 $IOG\_Rate_{k,h}^{i}$, from those with the lowest $IOG\_Rate_{k,h}^{i}$ to those with the highest $IOG\_Rate_{k,h}^{i}$. Once $OFFSET\_MW_{k,h}^{i}$ 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 ~~*market participants* for~~ *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' ($RT\_EXFC^{i}_{k,h}$) shall be determined as follows:

$$RT\_EXFC^{i}_{k,h} = \sum^{T} \Big[(-1) \times Min\Big(Max\big(0, \big(PD\_IBP^{i}_{h} - PB\_EX^{t}_{h} - RT\_IBP^{i,t}_{h}\big) \times RT\_ESD^{i,t}_{k,h}\big), Max\big(0,\ PD\_IBP^{i}_{h} \times RT\_ESD^{i,t}_{k,h}\big)\Big) - Max\big(0, \big(RT\_PEC^{i,t}_{h} + RT\_PNISL^{i,t}_{h}\big) \times RT\_ESD^{i,t}_{k,h}\big)\Big] / 12$$

Where:

(a) $RT\_ESD^{i,t}_{k,h}$ 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:

$$RT\_ESD^{i,t}_{k,h} = Max\big(PD\_QSW^{i}_{k,h} - Max\big(DAM\_QSW^{i}_{k,h}, SQEW^{i,t}_{k,h}\big), 0\big)$$

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' ($DAM\_IMFC^{i}_{k,h}$) shall be determined as follows:

$$DAM\_IMFC^{i}_{k,h} = \sum^{T} Min\left(0, \big(RT\_PEC^{i,t}_{h} + RT\_PNISL^{i,t}_{h}\big) \times DAM\_ISD^{i,t}_{k,h} / 12\right)$$

Where:

(a) $DAM\_ISD^{i,t}_{k,h}$ 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:

$$DAM\_ISD^{i,t}_{k,h} = Max\big(Min\big(DAM\_QSI^{i}_{k,h}, PD\_QSI^{i}_{k,h}\big) - SQEI^{i,t}_{k,h}, 0\big)$$

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' ($DAM\_EXFC^{i}_{k,h}$) shall be determined as follows:

$$DAM\_EXFC^{i}_{k,h} = \sum^{T} (-1) \times Max\left(0, \left(RT\_PEC^{i,t}_{h} + RT\_PNISL^{i,t}_{h}\right) \times DAM\_ESD^{i,t}_{k,h}/12\right)$$

Where:

c. $DAM\_ESD^{i,t}_{k,h}$ 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:

$$DAM\_ESD^{i,t}_{k,h} = Max\left(Min\left(DAM\_QSW^{i}_{k,h}, PD\_QSW^{i}_{k,h}\right) - SQEW^{i,t}_{k,h}, 0\right)$$

3.8 Hourly Settlement Amounts for Transmission Rights

3.8.1 The ~~TR~~*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:

$$TRSC_{k,h} = Max\left[0, QTR^{i,j}_{k,h} \times DAM\_PEC^{i}_{h}\right]$$

3.8.1.2 if the withdrawal *TR zone* of the *transmission right* is in the *IESO control area*, determined by the following equation:

$$TRSC_{k,h} = Max\left[0, -1 \times QTR^{i,j}_{k,h} \times DAM\_PEC^{j}_{h}\right]$$

Where:

a. 'j' is the *registered wholesale meter* or *intertie metering points* associated with the withdrawal *TR zone*;

b. 'i' is the *registered wholesale meter* or *intertie metering points* associated with the injection *TR zone;*

c. $DAM\_PEC^{i}_{h}$ is the *day-ahead market* external congestion price for *energy* in injection *TR zone* 'i' in *settlement hour* 'h'; and

d. $DAM\_PEC^{j}_{h}$ is the *day-ahead market* external congestion price for *energy* in withdrawal *TR zone* 'j' 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 ~~TR~~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,

$$ORSSD_{k,r,h} = \sum_{m,t}[ORESF^{m,t}_{k,r,h} \times \sum_{T,H}(ORRSC^{m,T}_{k,r,H})\,]$$; or

3.9.2.2 in all other cases,

$$ORSSD_{k,r,h} = \sum_{m,t}[ORESF^{m,t}_{k,r,h} \times \sum_{T,H}(ORRSC^{m,T}_{k,r,H})\ /2]$$

Where:

a. $ORESF^{m,t}_{k,r,h}$ is calculated in accordance with section 3.9.3;

b. $ORRSC^{m,T}_{k,r,H}$ is calculated in accordance with section 3.9.4;

c. 't' is all *metering intervals* in *settlement hour* 'h' in which $ORESF^{m,t}_{k,r,h}$ 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' ("$ORESF^{m,t}_{k,r,h}$") 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* ~~injecting~~registered to inject *energy*:

$$ORESF^{m,t}_{k,r,h} = Max\,[(SE^{m,t}_{k,h} - AQEI^{m,t}_{k,h})/SE^{m,t}_{k,h}, 0]$$

3.9.3.2 where *operating reserve* is provided from a *dispatchable load* or from an *electricity storage resource* ~~withdrawing~~registered to withdraw *energy*:

$$ORESF^{m,t}_{k,r,h} = Max\,[(AQEW^{m,t}_{k,h} - SE^{m,t}_{k,h})/AQEW^{m,t}_{k,h}, 0]$$

3.9.3.3 in either of the above cases, $ORESF^{m,t}_{k,r,h}$ 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. $ORESF^{m,t}_{k,r,h}$ 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. 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 *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 *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, $TAOR^{m,t}_{k,h}$, $TAOR\_CT^{c,t}_{k,h}$, and $TAOR\_ST^{s,t}_{k,h}$ will be calculated as follows:

a. For a *dispatchable electricity storage resource* or a non-aggregated *dispatchable generation resource,* the total accessible *operating reserve* is calculated as follows:

$$TAOR^{m,t}_{k,h} = Max\left(0, MAX\_CAP^{m,t}_{k,h} - AQEI^{m,t}_{k,h}\right)$$

Where:

i. $MAX\_CAP_{k,h}^{m,t}$ is the maximum limit used in determining the *real-time schedule* in the *dispatch scheduling* and pricing process.

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. $MC_{k,h}^{m,t}$ the minimum consumption level, equal to the quantity in the *price-quantity pair* where the *bid* price is the *maximum market clearing price.*

c. For a combustion turbine *generation unit* associated with a *pseudo unit*, the total accessible *operating reserve* is calculated as follows:

i. If the combustion turbine *generation unit* 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 *generation unit* 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 *generation unit* associated with a *pseudo unit*, the total accessible *operating reserve* is calculated as follows:

$$TAOR\_ST_{k,h}^{s,t} = Max\left[0, \left(\sum\nolimits_{D}^{P1} RT\_ORRQ_{k,d}^{p}\right) - \left(\sum\nolimits^{C1} MAX\_CAP_{k,h}^{c,t}\right) - AQEI_{k,h}^{s,t}\right]$$

Where:

i. 'P1' is the set of the *resource's pseudo-units* 'p' where the associated combustion turbine *generation unit* 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 *generation units* 'c' associated with the steam turbine *generation unit* and the combustion turbine *generation unit* that 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*; 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. $\sum_R RT\_QSOR_{r,k,h}^{m,t} > 0$; and

ii. $\sum_R RT\_QSOR_{r,k,h}^{m,t} > TAOR_{k,h}^{m,t}$

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. $\sum_R RT\_QSOR_{r,k,h}^{m,t} > 0$; and

ii. $\sum_R RT\_QSOR_{r,k,h}^{m,t} > TAOR_{k,h}^{m,t}$

Operating Reserve Non-Accessibility Charge for Dispatchable Loads and Non-Aggregated 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*:

$$ORSCB_{r1,k,h}^{m,t} = Min\left[0, \left(TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right) \times RT\_PROR_{r1,h}^{m,t}\right]$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB_{r2,k,h}^{m,t} = Min\left\{0, \left[Max\left(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}\right) - AQOR_{r2,k,h}^{m,t}\right] \times RT\_PROR_{r2,h}^{m,t}\right\}$$

c. For *thirty-minute operating reserve*:

$$ORSCB_{r3,k,h}^{m,t} = Min\{0, [Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}) - RT\_QSOR_{r3,k,h}^{m,t}] \times RT\_PROR_{r3,h}^{m,t}\}$$

Operating Reserve Non-Accessibility Charge for Aggregated Generation Resources Non-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:

$$ORIA_{r1,k,h}^{m,t} = Min(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t})$$

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:

$$ORIA_{r2,k,h}^{m,t} = Min[0, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}) - RT\_QSOR_{r2,k,h}^{m,t}]$$

iv. $ORIA_{r3,k,h}^{m,t}$ is the amount of inaccessible *thirty-minute operating reserve*, and determined in accordance with the following:

v. $ORIA_{r3,k,h}^{m,t} = Min[0, Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}) - RT\_QSOR_{r3,k,h}^{m,t}]$

vi. $ORSCB_{k,h}^{M,t}$ 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:

$$ORSCB_{k,h}^{M,t} = Min\left[0, \sum_{R}^{M} (NORD_{r,k,h}^{m,t} \times RT\_PROR_{r,k,h}^{m,t})\right]$$

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*:

$$NORD_{r1,k,h}^{m,t} = Min(RT\_QSOR_{r1,k,h}^{m,t}, TAOR_{r1,k,h}^{m,t}) + REAH_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}$$

ii. For non-synchronized *ten-minute operating reserve*:

$$NORD_{r2,k,h}^{m,t} = Min[(RT\_QSOR_{r2,k,h}^{m,t}, Max(0, TAOR_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t})] + REAH_{r2,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}$$

iii. For *thirty-minute operating reserve*:

$$NORD_{r3,k,h}^{m,t} = Min[RT\_QSOR_{r3,k,h}^{m,t}, Max(0, TAOR_{r1,k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t})] + REAH_{r2,k,h}^{m,t} - RT\_QSOR_{r3,k,h}^{m,t}$$

Where:

ii. $REAH^{m,t}_{r,k,h}$ is the allocated excess available headroom for the relevant *dispatchable generation resources*, and is calculated as follows for each type of *class r reserve*:

$$REAH^{m,t}_{r,k,h} = TREAH^{M,t}_{r,k,h} \times \frac{EAH^{m,t}_{k,h}}{\sum^{M} EAH^{m,t}_{k,h}}$$

ii. $EAH^{m,t}_{k,h}$ is the total amount of excess available headroom for the relevant *delivery point* 'm', and is calculated as follows:

$$EAH^{m,t}_{k,h} = Max\left(0, TAOR^{m,t}_{k,h} - \sum_{R} RT\_QSOR^{\,m,t}_{r,k,h}\right)$$

iii. $TREAH^{M,t}_{r,k,h}$ is the total reallocated excess available headroom for the aggregated *dispatchable generation resources*. When $\sum^{M} EAH^{m,t}_{k,h}$ is equal to zero, then $TREAH^{M,t}_{r,k,h}$ will also equal zero, and when $\sum^{M} EAH^{m,t}_{k,h}$ is less 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:

$$TREAH^{M,t}_{r1,k,h} = Min\left(\sum^{M} EAH^{m,t}_{k,h}, (-1) \times \sum^{M} ORIA^{m,t}_{r1,k,h}\right)$$

b. $TREAH^{M,t}_{r2,k,h}$ is the total reallocated excess available headroom for non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$TREAH^{M,t}_{r2,k,h} = Min\left[\left(\sum^{M} EAH^{m,t}_{k,h}\right) - TREAH^{M,t}_{r1,k,h}, (-1) \times \sum^{M} ORIA^{m,t}_{r2,k,h}\right]$$

c. $TREAH^{M,t}_{r3,k,h}$ is the total reallocated excess available headroom for *thirty-minute operating reserve*, and determined in accordance with the following:

$$TREAH^{M,t}_{r3,k,h} = Min\left[\left(\sum^{M} EAH^{m,t}_{k,h}\right) - TREAH^{M,t}_{r1,k,h} - TREAH^{M,t}_{r2,k,h}, (-1) \times \sum^{M} ORIA^{m,t}_{r3,k,h}\right]$$

Operating Reserve Non-Accessibility Charge for Generation Resources That Are Pseudo-Units

Combustion Turbine Generation Unit

3.10.11 The *operating reserve* non-accessibility charge *settlement amount* shall be calculated and collected from the combustion turbine *generation unit* of a non-aggregated *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. $\sum_R RT\_QSOR_{r,k,h}^{c,t} > 0$; and

b. $\sum_R RT\_QSOR_{r,k,h}^{c,t} > TAOR\_CT_{k,h}^{c,t}$

3.10.12 For each combustion turbine *generation unit 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*:

$$ORSCB_{r1,k,h}^{c,t} = ORSCB_{k,h}^{M,t} \times \frac{\sum_R ORIA_{r1,k,h}^{c,t}}{\sum_R^M \left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB_{r2,k,h}^{c,t} = ORSCB_{k,h}^{M,t} \times \frac{\sum_R ORIA_{r2,k,h}^{c,t}}{\sum_R^M \left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$

c. For *thirty-minute operating reserve*:

$$ORSCB_{r3,k,h}^{c,t} = ORSCB_{k,h}^{M,t} \times \frac{\sum_R ORIA_{r3,k,h}^{c,t}}{\sum_R^M \left(ORIA_{r,k,h}^{c,t} + ORIA_{r,k,h}^{s,t}\right)}$$

Where:

i. 'M' is the set of all *delivery points* 'c' and 's' of the aggregated group of *dispatchable generation resources;*

ii. $ORIA_{r1,k,h}^{c,t}$ is the amount of inaccessible synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$ORIA_{r1,k,h}^{c,t} = Min\left(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}\right)$$

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 Generation Unit

3.10.13 The *operating reserve* non-accessibility charge *settlement amount* shall be calculated and collected from the steam turbine *generation unit* of a non-aggregated *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 *generation unit 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*:

$$ORSCB^{s,t}_{r1,k,h} = ORSCB^{M,t}_{k,h} \times \frac{\sum_R ORIA^{s,t}_{r1,k,h}}{\sum_R^M \left(ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h}\right)}$$

b. For non-synchronized *ten-minute operating reserve*:

$$ORSCB^{s,t}_{r2,k,h} = ORSCB^{M,t}_{k,h} \times \frac{\sum_R ORIA^{s,t}_{r2,k,h}}{\sum_R^M \left(ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h}\right)}$$

c. For *thirty-minute operating reserve*:

$$ORSCB^{s,t}_{r3,k,h} = ORSCB^{M,t}_{k,h} \times \frac{\sum_R ORIA^{s,t}_{r3,k,h}}{\sum_R^M \left(ORIA^{c,t}_{r,k,h} + ORIA^{s,t}_{r,k,h}\right)}$$

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. $NORD_{r,k,h}^{c,t}$ is the net *operating reserve* deviation for a combustion turbine *generation unit*, and is calculated as follows for each type of *class r reserve*:

i. For synchronized *ten-minute operating reserve*:

$$NORD_{r1,k,h}^{c,t} = Min(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{r1,k,h}^{c,t}) + REAH_{r1,k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}$$

ii. For non-synchronized *ten-minute operating reserve*:

$$NORD_{r2,k,h}^{c,t} = Min[(RT\_QSOR_{r2,k,h}^{c,t}, Max(0, TAOR\_CT_{r1,k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t})] + REAH_{r2,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}$$

iii. For *thirty-minute operating reserve*:

$$NORD_{r3,k,h}^{c,t} = Min[RT\_QSOR_{r3,k,h}^{c,t}, Max(0, TAOR\_CT_{r1,k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t})] + REAH_{r2,k,h}^{c,t} - RT\_QSOR_{r3,k,h}^{c,t}$$

Where:

i. $REAH_{r,k,h}^{c,t}$ is the allocated excess available headroom for the relevant *dispatchable generation resources,* and is calculated as follows for each type of *class r reserve*:

$$REAH_{r,k,h}^{c,t} = TREAH_{r,k,h}^{M,t} \times \frac{EAH_{k,h}^{c,t}}{\sum^{M}\left(EAH_{k,h}^{c,t} + EAH_{k,h}^{s,t}\right)}$$

ii. $EAH_{k,h}^{c,t}$ is the total amount of excess available headroom for the relevant combustion turbine *generation unit delivery point* 'c', and is calculated as follows:

$$EAH_{k,h}^{c,t} = Max\left(0, TAOR\_CT_{k,h}^{c,t} - \sum\nolimits_{R} RT\_QSOR\,_{r,k,h}^{c,t}\right)$$

c. $NORD_{r,k,h}^{s,t}$ is the net *operating reserve* deviation for a steam turbine *generation unit*, and is calculated as follows for each type of *class r reserve*:

i. For synchronized *ten-minute operating reserve*:

$$NORD_{r1,k,h}^{s,t} = Min(RT\_QSOR_{r1,k,h}^{s,t}, TAOR\_CT_{r1,k,h}^{s,t}) + REAH_{r1,k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}$$

ii. For non-synchronized *ten-minute operating reserve*:

$$NORD^{s,t}_{r2,k,h} = Min[(RT\_QSOR^{s,t}_{r2,k,h}, Max(0, TAOR\_CT^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r1,k,h})] + REAH^{s,t}_{r2,k,h} - RT\_QSOR^{s,t}_{r2,k,h}$$

iii. For *thirty-minute operating reserve*:

$$NORD^{s,t}_{r3,k,h} = Min[RT\_QSOR^{s,t}_{r3,k,h}, Max(0, TAOR\_CT^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h})] + REAH^{s,t}_{r2,k,h} - RT\_QSOR^{s,t}_{r3,k,h}$$

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 *generation unit delivery point* 's', and is calculated as follows:

$$EAH^{s,t}_{k,h} = Max\left(0, TAOR\_ST^{s,t}_{k,h} - \sum_{R} RT\_QSOR^{s,t}_{r,k,h}\right)$$

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 less 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:

$$TREAH^{M,t}_{r1,k,h} = Min\left(\sum^{M}\left(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}\right), (-1) \times \sum^{M}\left(ORIA^{s,t}_{r1,k,h} + ORIA^{s,t}_{r1,k,h}\right)\right)$$

b. $TREAH^{M,t}_{r2,k,h}$ is the total reallocated excess available headroom for non-synchronized *ten-minute operating reserve*, and determined in accordance with the following:

$$TREAH^{M,t}_{r2,k,h} = Min\left[\left(\sum^{M}\left(EAH^{c,t}_{k,h} + EAH^{s,t}_{k,h}\right)\right) - TREAH^{M,t}_{r1,k,h}, (-1) \times \sum^{M}\left(ORIA^{c,t}_{r2,k,h} + ORIA^{s,t}_{r2,k,h}\right)\right]$$

c. $TREAH^{M,t}_{r3,k,h}$ 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 and 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:

$$RT\_MWP\_RC^{m}_{k,h} = \sum^{T}\left(RT\_OLCRC^{m,t}_{k,h} + RT\_OLOCRC^{m,t}_{k,h}\right)$$

Where:

a. The *operating reserve* non-accessibility lost cost reversal, $RT\_OLCRC^{m,t}_{k,h}$, is calculated in accordance with section 3.10.18.

b. The *operating reserve* non-accessibility lost opportunity cost reversal, $RT\_OLOCRC^{m,t}_{k,h}$, is calculated in accordance with section 3.10.19.

3.10.18 The *operating reserve* lost cost component reversal charge, $RT\_OLCRC^{m,t}_{k,h}$, is calculated as follows:

$$RT\_OLCRC^{m,t}_{k,h} = Min\left[0, Max\left(-1\ x\left(RT\_ELC^{m,t}_{k,h} + RT\_OLC^{m,t}_{k,h}\right), \sum_{R} OLC\_CB^{m,t}_{r,k,h}\right)\right]$$

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, $RT\_OLOCRC_{k,h}^{m}$, is calculated as follows:

$$RT\_OLOCRC_{k,h}^{m,t} = Min\left[0, Max\left(-1\,x\left(RT\_ELOC_{k,h}^{m,t} + RT\_OLOC_{k,h}^{m,t}\right), \sum_{R} OLOC\_CB_{r,k,h}^{m,t}\right)\right]$$

Where:

a. For synchronized *ten-minute operating reserve*:

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, $OLOC\_CB_{r1,k,h}^{m,t} = 0$

b. 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, $OLOC\_CB_{r2,k,h}^{m,t} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{m,t}$ 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 Generation Resources That Are Pseudo-Units

Combustion Turbine Generation Unit

3.10.20 For a *delivery point* 'c' for a combustion turbine *generation unit* 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:

$$RT\_MWP\_CB^{c}_{k,h} = \sum^{T} (RT\_OLCRC^{c,t}_{k,h} + RT\_OLOC\_RC^{c,t}_{k,h})$$

Where:

a. The *operating reserve* non-accessibility lost cost reversal, $RT\_OLCRC^{c}_{k,h}$, is calculated in accordance with section 3.10.21.

b. The *operating reserve* non-accessibility lost opportunity cost reversal, $RT\_OLOCRC^{c}_{k,h}$, is calculated in accordance with section 3.10.22.

3.10.21 The *operating reserve* lost cost component reversal charge, $RT\_OLCRC^{c}_{k,h}$, is calculated as follows:

$$RT\_OLCRC^{c,t}_{k,h} = Min\Big[0, Max\Big(-1\ x\ \big(RT\_ELC^{c,t}_{k,h} + RT\_OLC^{c,t}_{k,h}\big), \textstyle\sum_{R} OLC\_CB^{c,t}_{r,k,h}\Big)\Big]$$

Where:

a. For synchronized *ten-minute operating reserve*:

i. if $TAOR\_CT^{c,t}_{k,h} < RT\_QSOR^{c,t}_{r1,k,h}$ and if $RT\_OR\_LC\_EOP^{c,t}_{r1,k,h} < RT\_QSOR^{c,t}_{r1,k,h}$ then:

$$OLC\_CB^{c,t}_{r1,k,h} = \{OP\big(RT\_PROR^{c,t}_{r1,h}, Max(DAM\_QSOR^{c,t}_{r1,k,h}, RT\_QSOR^{c,t}_{r1,k,h}), BOR^{c,t}_{r1,k,h}\big) - OP\big[RT\_PROR^{c,t}_{r1,h}, Max\big(TAOR\_CT^{c,t}_{k,h}, RT\_OR\_LC\_EOP^{c,t}_{r1,k,h}, DAM\_QSOR^{c,t}_{r1,k,h}\big), BOR^{c,t}_{r1,k,h}\big] / 12$$

ii. Otherwise, $OLC\_CB^{c,t}_{r1,k,h} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_QSOR_{r2,k,h}^{c,t}$ and if $RT\_OR\_LC\_EOP_{r2,k,h}^{c,t} < RT\_QSOR_{r2,k,h}^{c,t}$, then:

$$OLC\_CB_{r2,k,h}^{c,t} = \{OP\left(RT\_PROR_{r2,h}^{c,t}, Max(DAM\_QSOR_{r2,k,h}^{c,t}, RT\_QSOR_{r2,k,h}^{c,t}), BOR_{r2,k,h}^{c,t}\right) - OP\left[RT\_PROR_{r2,h}^{c,t}, Max\left(TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}, RT\_OR\_LC\_EOP_{r2,k,h}^{c,t}, DAM\_QSOR_{r2,k,h}^{c,t}\right), BOR_{r2,k,h}^{c,t}\right]/12$$

ii. Otherwise, $OLC\_CB_{r2,k,h}^{c,t} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$ and if $RT\_OR\_LC\_EOP_{r3,k,h}^{c,t} < RT\_QSOR_{r3,k,h}^{c,t}$, then:

$$OLC\_CB_{r3,k,h}^{c,t} = \{OP\left(RT\_PROR_{r3,h}^{c,t}, Max(DAM\_QSOR_{r3,k,h}^{c,t}, RT\_QSOR_{r3,k,h}^{c,t}), BOR_{r3,k,h}^{c,t}\right) - OP\left[RT\_PROR_{r3,h}^{c,t}, Max\left(TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}, RT\_OR\_LC\_EOP_{r3,k,h}^{c,t}, DAM\_QSOR_{r3,k,h}^{c,t}\right), BOR_{r3,k,h}^{c,t}\right]/12$$

ii. Otherwise, $OLC\_CB_{r3,k,h}^{c,t} = 0$

3.10.22 The *operating reserve* lost opportunity cost component reversal charge, $RT\_OLOCRC_{k,h}^{c}$, is calculated as follows:

$$RT\_OLOCRC_{k,h}^{c,t} = Min\left[0, Max\left(-1\ x\left(RT\_ELOC_{k,h}^{c,t} + RT\_OLOC_{k,h}^{c,t}\right), \sum_{R} OLOC\_CB_{r,k,h}^{c,t}\right)\right]$$

Where:

a. 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:

$$OLOC\_CB_{r1,k,h}^{c,t} = (-1) \times \{OP(RT\_PROR_{r1,h}^{c,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{c,t}, BOR_{r1,k,h}^{c,t}) - OP[RT\_PROR_{r1,h}^{c,t}, Max(RT\_QSOR_{r1,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}), BOR_{r1,k,h}^{c,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r1,k,h}^{c,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}$ and if $RT\_QSOR_{r2,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}$, then:

$$OLOC\_CB_{r2,k,h}^{c,t} = (-1) \times \{OP(RT\_PROR_{r2,h}^{c,t}, RT\_OR\_LOC\_EOP_{r2,k,h}^{c,t}, BOR_{r2,k,h}^{c,t}) - OP[RT\_PROR_{r2,h}^{c,t}, Max(RT\_QSOR_{r2,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}), BOR_{r2,k,h}^{c,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r2,k,h}^{c,t} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}$ and if $RT\_QSOR_{r3,k,h}^{c,t} < RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}$, then:

$$OLOC\_CB_{r3,k,h}^{c,t} = (-1) \times \{OP(RT\_PROR_{r3,h}^{c,t}, RT\_OR\_LOC\_EOP_{r3,k,h}^{c,t}, BOR_{r3,k,h}^{c,t}) - OP[RT\_PROR_{r3,h}^{c,t}, Max(RT\_QSOR_{r3,k,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}), BOR_{r3,k,h}^{c,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r3,k,h}^{c,t} = 0$

Steam Turbine Generation Unit

3.10.23 For a *delivery point* 's' for a steam turbine *generation unit* 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:

$$RT\_MWP\_CB_{k,h}^{s} = \sum^{T} (RT\_OLCRC_{k,h}^{s,t} + RT\_OLOC\_RC_{k,h}^{s,t})$$

Where:

a. The *operating reserve* non-accessibility lost cost reversal, $RT\_OLCRC^{s}_{k,h}$, is calculated in accordance with section 3.10.24.

b. The *operating reserve* non-accessibility lost opportunity cost reversal, $RT\_OLOCRC^{s}_{k,h}$, is calculated in accordance with section 3.10.25.

3.10.24 The *operating reserve* lost cost component reversal charge, $RT\_OLCRC^{s}_{k,h}$, is calculated as follows:

$$RT\_OLCRC^{s,t}_{k,h} = Min\left[0, Max\left(-1\ x\ \left(RT\_ELC^{s,t}_{k,h} + RT\_OLC^{s,t}_{k,h}\right), \sum_{R} OLC\_CB^{s,t}_{r,k,h}\right)\right]$$

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:

$$OLC\_CB^{s,t}_{r1,k,h} = \{OP\left(RT\_PROR^{s,t}_{r1,h}, Max(DAM\_QSOR^{s,t}_{r1,k,h}, RT\_QSOR^{s,t}_{r1,k,h}), BOR^{s,t}_{r1,k,h}\right) - OP\left[RT\_PROR^{s,t}_{r1,h}, Max\left(TAOR\_ST^{s,t}_{k,h}, RT\_OR\_LC\_EOP^{s,t}_{r1,k,h}, DAM\_QSOR^{s,t}_{r1,k,h}\right), BOR^{s,t}_{r1,k,h}\right] /12$$

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:

$$OLC\_CB^{s,t}_{r2,k,h} = \{OP\left(RT\_PROR^{s,t}_{r2,h}, Max(DAM\_QSOR^{s,t}_{r2,k,h}, RT\_QSOR^{s,t}_{r2,k,h}), BOR^{s,t}_{r2,k,h}\right) - OP\left[RT\_PROR^{s,t}_{r2,h}, Max\left(TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h}, RT\_OR\_LC\_EOP^{s,t}_{r2,k,h}, DAM\_QSOR^{s,t}_{r2,k,h}\right), BOR^{s,t}_{r2,k,h}\right]/12$$

ii. Otherwise, $OLC\_CB^{s,t}_{r2,k,h} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t} < RT\_QSOR_{r3,k,h}^{s,t}$ and if $RT\_OR\_LC\_EOP_{r3,k,h}^{s,t} < RT\_QSOR_{r3,k,h}^{s,t}$, then:

$$OLC\_CB_{r3,k,h}^{s,t} = \{OP(RT\_PROR_{r3,h}^{s,t}, Max(DAM\_QSOR_{r3,k,h}^{s,t}, RT\_QSOR_{r3,k,h}^{s,t}), BOR_{r3,k,h}^{s,t}) - OP[RT\_PROR_{r3,h}^{s,t}, Max(TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}, RT\_OR\_LC\_EOP_{r3,k,h}^{s,t}, DAM\_QSOR_{r3,k,h}^{s,t}), BOR_{r3,k,h}^{s,t}]/12$$

ii. Otherwise, $OLC\_CB_{r3,k,h}^{s,t} = 0$

3.10.25 The *operating reserve* lost opportunity cost component reversal charge, $RT\_OLOCRC_{k,h}^{s}$, is calculated as follows:

$$RT\_OLOCRC_{k,h}^{s,t} = Min\left[0, Max\left(-1\ x\left(RT\_ELOC_{k,h}^{s,t} + RT\_OLOC_{k,h}^{c,t}\right), \sum_{R} OLOC\_CB_{r,k,h}^{s,t}\right)\right]$$

Where:

a. 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 $RT\_QSOR_{r1,k,h}^{s,t} < RT\_OR\_LOC\_EOP_{r1,k,h}^{s,t}$ then:

$$OLOC\_CB_{r1,k,h}^{s,t} = (-1) \times \{OP(RT\_PROR_{r1,h}^{s,t}, RT\_OR\_LOC\_EOP_{r1,k,h}^{s,t}, BOR_{r1,k,h}^{s,t}) - OP[RT\_PROR_{r1,h}^{s,t}, Max(RT\_QSOR_{r1,k,h}^{s,t}, TAOR\_ST_{k,h}^{s,t}), BOR_{r1,k,h}^{s,t}]\}/12$$

ii. Otherwise, $OLOC\_CB_{r1,k,h}^{s,t} = 0$

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b. For non-synchronized *ten-minute operating reserve*:

i. if $TAOR\_ST^{s,t}_{k.h} - RT\_QSOR^{s,t}_{r1.k.h} < RT\_OR\_LOC\_EOP^{s,t}_{r2.k.h}$ and if $RT\_QSOR^{s,t}_{r2,k,h} < RT\_OR\_LOC\_EOP^{s,t}_{r2,k,h}$, then:

$$OLOC\_CB^{s,t}_{r2,k,h} = (-1) \times \{OP(RT\_PROR^{s,t}_{r2,h}, RT\_OR\_LOC\_EOP^{s,t}_{r2,k,h}, BOR^{s,t}_{r2,k,h}) - OP[RT\_PROR^{s,t}_{r2,h}, Max(RT\_QSOR^{s,t}_{r2,k,h}, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h}), BOR^{s,t}_{r2,k,h}]\}/12$$

ii. Otherwise, $OLOC\_CB^{s,t}_{r2,k,h} = 0$

c. For *thirty-minute operating reserve*:

i. if $TAOR\_ST^{s,t}_{k.h} - RT\_QSOR^{s,t}_{r1.k.h} - RT\_QSOR^{s,t}_{r2.k.h} < RT\_OR\_LOC\_EOP^{s,t}_{r3.k.h}$ and if $RT\_QSOR^{s,t}_{r3.k.h} < RT\_OR\_LOC\_EOP^{s,t}_{r3.k.h}$, then:

$$OLOC\_CB^{s,t}_{r3,k,h} = (-1) \times \{OP(RT\_PROR^{s,t}_{r3,h}, RT\_OR\_LOC\_EOP^{s,t}_{r3,k,h}, BOR^{s,t}_{r3,k,h}) - OP[RT\_PROR^{s,t}_{r3,h}, Max(RT\_QSOR^{s,t}_{r3,k,h}, TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h}), BOR^{s,t}_{r3,k,h}]\}/12$$

ii. Otherwise, $OLOC\_CB^{s,t}_{r3,k,h} = 0$

Real-Time Generator Offer Guarantee Clawback for Dispatchable Generation Resources That Are Not Pseudo-Units

3.10.26 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 *generator offer* guarantee *clawback settlement amount* ($RT\_GOG\_CB^m_{k,h}$) is calculated as follows:

$$RT\_GOG\_CB^m_k = Max\left\{(-1)xRT\_GOG^m_k, Min[0, \sum_R^{T1}[ORSCB\_REV^{m,t}_{r,k,h} + COMP2\_CB^{m,t}_{r,k,h} - ORIA\_AMT^{m,t}_{r,k,h}] - \sum^{T1} RT\_MWP\_CB^{m,t}_{k,h}\right\}$$

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.

iii. $ORSCB\_REV^{m,t}_{r,k,h}$ = (-1) x $ORSCB^{m,t}_{r,k,h}$

iv. $COMP2\_CB_{r,k,h}^{m,t}$ is calculated in accordance with section 3.10.27.

v. $ORIA\_AMT_{r,k,h}^{m,t}$ 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:

$$COMP2\_CB_{r1,k,h}^{m,t} = \{OP[RT\_PROR_{r1,h}^{m,t}, RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r1,k,h}^{m,t}] - OP(RT\_PROR_{r1,h}^{m,t}, TAOR_{k,h}^{m,t}, BOR_{r1,k,h}^{m,t})\}/12$$

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:

$$COMP2\_CB_{r2,k,h}^{m,t} = \{OP[RT\_PROR_{r2,h}^{m,t}, RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r2,k,h}^{m,t}] - OP(RT\_PROR_{r2,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t}, BOR_{r2,k,h}^{m,t})\}/12$$

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:

$$COMP2\_CB_{r3,k,h}^{m,t} = \{OP[RT\_PROR_{r3,h}^{m,t}, RT\_QSOR_{r3,k,h}^{m,t}, BOR_{r3,k,h}^{m,t}] - OP(RT\_PROR_{r3,h}^{m,t}, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}, BOR_{r3,k,h}^{m,t})/12$$

ii. Otherwise, $COMP2\_CB_{r3,k,h}^{m,t} = 0$

3.10.28 The revenue earned for non-accessible *operating reserve*, $ORIA\_AMT_{r,k,h}^{m,t}$, 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:

$$ORIA\_AMT_{r1,k,h}^{m,t} = [RT\_PROR_{r1,h}^{m,t} \times (RT\_QSOR_{r1,k,h}^{m,t} - TAOR_{k,h}^{m,t})]/12$$

ii. Otherwise, $ORIA\_AMT_{r1,k,h}^{m,t} = 0$

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:

$$ORIA\_AMT_{r2,k,h}^{m,t} = \left[RT\_PROR_{r2,h}^{m,t} \times \left(RT\_QSOR_{r2,k,h}^{m,t} - Max(0, TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t})\right)\right] / 12$$

ii. Otherwise, $ORIA\_AMT_{r2,k,h}^{m,t} = 0$

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:

$$ORIA\_AMT_{r3,k,h}^{m,t} = \left[RT\_PROR_{r3,h}^{m,t} \times \left(RT\_QSOR_{r3,k,h}^{m,t} - TAOR_{k,h}^{m,t} - RT\_QSOR_{r1,k,h}^{m,t} - RT\_QSOR_{r2,k,h}^{m,t}\right)\right]/12$$

ii. Otherwise, $ORIA\_AMT_{r3,k,h}^{m,t} = 0$

Real-Time Generator Offer Guarantee Clawback for Dispatchable Generation Resources That Are Pseudo-Units

Steam Turbine Generation Unit

3.10.29 For a *delivery point* 's' associated with a steam turbine *generation unit* associated with a *pseudo-unit*, the real-time *generator offer* guarantee *clawback settlement amount* ($RT\_GOG\_CB^{s}_{k,h}$) is calculated as follows:

$$RT\_GOG\_CB_k^s = Max\left\{(-1)xRT\_GOG_k^s, Min[0, \sum_R^{T1}[ORSCB\_REV_{r,k,h}^{s,t} + COMP2\_CB_{r,k,h}^{s,t} - ORIA\_AMT_{r,k,h}^{s,t}] - \sum^{T1} RT\_MWP\_CB_{k,h}^{s,t}\right\}$$

Where:

a. 'T1' is the set of all *metering intervals* 't' beginning from the first *metering interval* that the steam turbine *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 steam turbine *generation unit* is at *minimum loading point* within such *real-time commitment period* or a *real-time reliability commitment period*, as applicable.

$$RT\_GOG\_ORSCB_{k,h}^{s,t} = ORSCB_{k,h}^{s,t} \times \frac{\sum_R OR\_RT\_GOG\_DIGQ_{r,k,h}^{s,t}}{\sum_R RT\_QSOR_{r,k,h}^{s,t}}$$

b. $COMP2\_CB_{r,k,h}^{s,t}$ is calculated in accordance with section 3.10.30

c. $ORIA\_AMT_{r,k,h}^{s,t}$ is calculated in accordance with section 3.10.31

d. 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:

$$RT\_GOG\_TAOR\_ST_{k,h}^{s,t} = TAOR\_ST_{k,h}^{s,t} \times \frac{\sum_R OR\_RT\_GOG\_DIGQ_{r,k,h}^{s,t}}{\sum_R RT\_QSOR_{r,k,h}^{s,t}}$$

3.10.30 $COMP2\_CB_{r,k,h}^{s,t}$ is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} < RT\_QSOR_{r1,k,h}^{s,t}$, then:

$$COMP2\_CB_{r1,k,h}^{s,t} = \{OP[RT\_PROR_{r1,h}^{s,t}, RT\_QSOR_{r1,k,h}^{s,t}, BOR_{r1,k,h}^{s,t}] - OP(RT\_PROR_{r1,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t}, BOR_{r1,k,h}^{s,t})\}/12$$

ii. Otherwise, $COMP2\_CB_{r1,k,h}^{s,t} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} < RT\_QSOR_{r2,k,h}^{s,t}$, then:

$$COMP2\_CB_{r2,k,h}^{s,t} = \{OP[RT\_PROR_{r2,h}^{s,t}, RT\_QSOR_{r2,k,h}^{s,t}, BOR_{r2,k,h}^{s,t}] - OP(RT\_PROR_{r2,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t}, BOR_{r2,k,h}^{s,t})\}/12$$

ii. Otherwise, $COMP2\_CB_{r2,k,h}^{s,t} = 0$

c. For *thirty-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST_{k.h}^{s,t} - RT\_QSOR_{r1.k.h}^{s,t} - RT\_QSOR_{r2.k.h}^{s,t} < RT\_QSOR_{r3,k,h}^{s,t}$, then:

$$COMP2\_CB_{r3,k,h}^{s,t} = \{OP[RT\_PROR_{r3,h}^{s,t}, RT\_QSOR_{r3,k,h}^{s,t}, BOR_{r3,k,h}^{s,t}] - OP(RT\_PROR_{r3,h}^{s,t}, RT\_GOG\_TAOR\_ST_{k,h}^{s,t} - RT\_QSOR_{r1,k,h}^{s,t} - RT\_QSOR_{r2,k,h}^{s,t}, BOR_{r3,k,h}^{s,t})/12$$

ii. Otherwise, $COMP2\_CB_{r3,k,h}^{s,t} = 0$

3.10.31 The revenue earned for non-accessible *operating reserve*, $ORIA\_AMT^{s,t}_{r,k,h}$, is calculated as follows:

a. For synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST^{s,t}_{k,h} < RT\_QSOR^{s,t}_{r1,k,h}$, then:

$$ORIA\_AMT^{s,t}_{r1,k,h} = \left[RT\_PROR^{s,t}_{r1,h} \times \left(RT\_QSOR^{s,t}_{r1,k,h} - RT\_GOG\_TAOR\_ST^{s,t}_{k,h}\right)\right]/12$$

ii. Otherwise, $ORIA\_AMT^{s,t}_{r1,k,h} = 0$

b. For non-synchronized *ten-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} < RT\_QSOR^{s,t}_{r2,k,h}$, then:

$$ORIA\_AMT^{s,t}_{r2,k,h} = \left[RT\_PROR^{s,t}_{r2,h} \times \left(RT\_QSOR^{s,t}_{r2,k,h} - Max(0, RT\_GOG\_TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h})\right)\right]/12$$

ii. Otherwise, $ORIA\_AMT^{s,t}_{r2,k,h} = 0$

c. For *thirty-minute operating reserve*:

i. If $RT\_GOG\_TAOR\_ST^{s,t}_{k.h} - RT\_QSOR^{s,t}_{r1.k.h} - RT\_QSOR^{s,t}_{r2.k.h} < RT\_QSOR^{s,t}_{r3,k,h}$, then:

$$ORIA\_AMT^{s,t}_{r3,k,h} = \left[RT\_PROR^{s,t}_{r3,h} \times \left(RT\_QSOR^{s,t}_{r3,k,h} - RT\_GOG\_TAOR\_ST^{s,t}_{k,h} - RT\_QSOR^{s,t}_{r1,k,h} - RT\_QSOR^{s,t}_{r2,k,h}\right)\right]/12$$

ii. Otherwise, $ORIA\_AMT^{s,t}_{r3,k,h} = 0$

Combustion Turbine Generation Unit

3.10.32 For a *delivery point* 'c' associated with a combustion turbine *generation unit* associated with 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:

$$RT\_GOG\_CB^{c}_{k} = Max\left\{(-1)xRT\_GOG^{c}_{k}, Min[0, \sum_{R}^{T1}\left[ORSCB\_REV^{c,t}_{r,k,h} + COMP2\_CB^{c,t}_{r,k,h} - ORIA\_AMT^{c,t}_{r,k,h}\right] - \sum^{T1} RT\_MWP\_CB^{c,t}_{k,h}\right\}$$

Where:

a. 'T1' is the set of all *metering intervals* 't' beginning from the first *metering interval* that the combustion turbine *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 combustion turbine *generation unit* is at *minimum loading point* within such *real-time commitment period* or a *real-time reliability commitment period*, as applicable.

b. $ORSCB\_REV_{r,k,h}^{c,t}$ = (-1) x $ORSCB_{r,k,h}^{c,t}$

c. $COMP2\_CB_{r,k,h}^{c,t}$ is calculated in accordance with section 3.10.33.

d. $ORIA\_AMT_{r,k,h}^{c,t}$ is calculated in accordance with section 3.10.34.

3.10.33 $COMP2\_CB_{r,k,h}^{c,t}$ 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:

$$COMP2\_CB_{r1,k,h}^{c,t} = \{OP[RT\_PROR_{r1,h}^{c,t}, RT\_QSOR_{r1,k,h}^{c,t}, BOR_{r1,k,h}^{c,t}] - OP(RT\_PROR_{r1,h}^{c,t}, TAOR\_CT_{k,h}^{c,t}, BOR_{r1,k,h}^{c,t})\}/12$$

ii. Otherwise, $COMP2\_CB_{r1,k,h}^{c,t} = 0$

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:

$$COMP2\_CB_{r2,k,h}^{c,t} = \{OP[RT\_PROR_{r2,h}^{c,t}, RT\_QSOR_{r2,k,h}^{c,t}, BOR_{r2,k,h}^{c,t}] - OP(RT\_PROR_{r2,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}, BOR_{r2,k,h}^{c,t})\}/12$$

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:

$$COMP2\_CB_{r3,k,h}^{c,t} = \{OP[RT\_PROR_{r3,h}^{c,t}, RT\_QSOR_{r3,k,h}^{c,t}, BOR_{r3,k,h}^{c,t}] - OP(RT\_PROR_{r3,h}^{c,t}, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t}, BOR_{r3,k,h}^{c,t})/12$$

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:

$$ORIA\_AMT_{r1,k,h}^{c,t} = [RT\_PROR_{r1,h}^{c,t} \times (RT\_QSOR_{r1,k,h}^{c,t} - TAOR\_CT_{k,h}^{c,t})]/12$$

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:

$$ORIA\_AMT_{r2,k,h}^{c,t} = [RT\_PROR_{r2,h}^{c,t} \times (RT\_QSOR_{r2,k,h}^{c,t} - Max(0, TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t}))]/12$$

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:

$$ORIA\_AMT_{r3,k,h}^{c,t} = [RT\_PROR_{r3,h}^{c,t} \times (RT\_QSOR_{r3,k,h}^{c,t} - TAOR\_CT_{k,h}^{c,t} - RT\_QSOR_{r1,k,h}^{c,t} - RT\_QSOR_{r2,k,h}^{c,t})]/12$$

ii. Otherwise, $ORIA\_AMT_{r3,k,h}^{c,t} = 0$

~~3.10~~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:

$$HUSA_h = \sum_K \left(HORSA\{1\}_{k,h} + HORSA\{2\}_{k,h} + DAM\_BC_{k,h} + RT\_MWP_{k,h} + RT\_IOG_{k,h} + RT\_NISLR_h\right) - \sum_K \left(\sum_R ORSSD_{r,k,h} + RT\_IMFC_{k,h} + RT\_EXFC_{k,h} + GFC\_MPC_{k,h} + RT\_RLSC_{k,h} + DAM\_RLSC_{k,h}\right)$$

$$HUSA_h = \sum_K \left(HORSA\{1\}_{k,h} + HORSA\{2\}_{k,h} + DAM\_BC_{k,h} + RT\_MWP_{k,h} + RT\_IOG_{k,h} + RT\_NISLR_h\right) - \sum_K \left(\sum_R ORSSD_{r,k,h} + \sum_R ORSCB_{r,k,h} + RT\_IMFC_{k,h} + RT\_EXFC_{k,h} + GFC\_MPC_{k,h} + RT\_RLSC_{k,h} + DAM\_RLSC_{k,h}\right)$$

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. 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';

i. $GFC\_MPC_{k,h}$ 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';

j. $RT\_RLSC_{k,h}$ 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';

k. $DAM\_RLSC_{k,h}$ 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'; and

l. $ORSSD_{r,k,h}$ 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'.

~~l.~~m. $ORSCB_{r,k,h}$ 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*.4.2.5Subject 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.*

Note: New Sections 4.4 to 4.8 have been shown without track changes for ease of review.

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 ~~-1~~0" refers to the day the *day-ahead market calculation engine* runs to set the *day-ahead schedule* for Day ~~0~~1;

b. "Day ~~0~~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 ~~0~~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 ~~-1~~0 at the time the *day-ahead market calculation engine* determines the *day-ahead schedule* for Day ~~0~~1;

b. the *GOG-eligible resource* has completed its scheduled *minimum generation block run-time* in Day ~~-1~~0 and has a *day-ahead operational schedule* in the first *settlement hour* of Day ~~0~~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 ~~0~~1.

Day-Ahead Market Generator Offer Guarantee for Non-Pseudo Units

Formulations

Variant #1

4.4.3 If a *GOG-eligible resource* ~~not associated with~~that is 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 ~~0~~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':

$$DAM\_GOG_k^m = Max[0, DAM\_GOG\_COMP1_k^m + DAM\_GOG\_COMP2_k^m + DAM\_GOG\_COMP4_{k,h}^m - DAM\_GOG\_COMP5_k^m]$$

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 ~~associated with~~ a *pseudo-unit* (1) has a *pre-dispatch operational commitment* or a *day-ahead operational commitment* in the last *settlement hour* of Day ~~-1~~0 at the time the *day-ahead market calculation engine* determined the *day-ahead schedule* for Day ~~0~~1; and (2) is scheduled to complete its *minimum generation block run-time* in Day ~~0~~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 ~~associated with~~ 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 ~~0~~1; (2) has either a *day-ahead operational commitment* or *pre-dispatch operational commitment* in the last *settlement hour* of Day ~~-1~~0 at the time the *day-ahead market calculation engine* determines the *day-ahead schedule* for Day ~~0~~1; and (3) completed its *minimum generation block run-time* in the last *settlement hour* of Day ~~-1~~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 ~~0~~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 ~~associated with~~ a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP1_k^m$ as follows:

$$DAM\_GOG\_COMP1_k^m = \sum^{H}\left[-1\,x\,\left(OP(DAM\_LMP_h^m, DAM\_QSI_{k,h}^m, DAM\_BE_{k,h}^m)\right) + (DAM\_BE\_SNL_{k,h}^m\,x\,N_{k,h}^m/12)\right] - \sum^{RH}\left[DAM\_LMP_h^m\,x\,DAM\_QSI_{k,h}^m\right]$$

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 *generation unit* or steam turbine *generation unit* is registered as a *pseudo-unit* but is not operating as a *pseudo-unit* and has a ~~binding~~minimum constraint applied for combined cycle ~~physical unit constraint~~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 ~~associated with~~ 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~~ associated with~~ 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 ~~-1~~0;

b. 'MLP_k^m' is the *minimum loading point* of the *GOG-eligible resource* for Day ~~-1~~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~~ associated with~~ 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:

$$DAM\_GOG\_COMP4^{m}_{k,h} = DAM\_BE\_SU^{m}_{k,h} - (DAM\_BE\_SU^{m}_{k,h} \times N\_INT\ /12)$$

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,

$$DAM\_GOG\_COMP4^{m}_{k,h} = 0$$

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* ~~required, in order to maintain the *reliability* of the *IESO-controlled grid*,~~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 ~~associated with~~ a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP5^{m}_{k}$ as follows:

$$DAM\_GOG\_COMP5^{m}_{k} = \sum^{H} DAM\_MWP^{m}_{k,h}$$

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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit* meets any of the following conditions:

4.4.12.1 The combustion turbine *generation unit* has:

a. A *day-ahead operational schedule* to start in Day ~~0~~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 *generation unit* *delivery point* 'c':

$$DAM\_GOG_k^c = Max\Big[0, DAM\_GOG\_COMP1_k^c + DAM\_GOG\_COMP2_k^c + DAM\_GOG\_COMP4_{k,h}^c - DAM\_GOG\_COMP5_k^c\Big]$$

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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit* has either a *day-ahead operational commitment* or *pre-dispatch operational commitment* for the last *settlement hour* of Day ~~-1~~0 and is scheduled to complete its *minimum generation block run-time* in the first *settlement hour* of Day ~~0~~1, the *day-ahead market generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *generation unit* *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 *generation unit* of a *GOG-eligible resource* ~~associated with~~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 ~~0~~1; (2) has either a *day-ahead operational commitment* or a *pre-dispatch operational commitment* for the last *settlement hour* of Day ~~-1~~0 at the time the *day-ahead market calculation engine* determines the *day-ahead schedule* for Day ~~0~~1; and (3) has completed its *minimum* *generation block run-time* when the *day-ahead operational commitment* in the first *settlement hour* of Day ~~0~~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 ~~0~~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 *generation unit* of a *GOG-eligible resource* ~~associated with~~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's~~turbine *generation unit*'s relevant *day-ahead commitment period*;

b. 'RH' is the set of contiguous *settlement hours* that the combustion turbine *generation unit* has a *day-ahead schedule* for the ramp-up period, scheduled greater than zero but less than the combustion ~~turbine's~~turbine *generation unit's* *minimum loading point;*

c. 'p' is the *pseudo-unit* associated with combustion turbine *generation unit* *delivery point* 'c'; and

d. '$N_{k,h}^{c}$' is the number of *metering intervals* in the *settlement hour* 'h' during which combustion turbine *generation unit* *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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP2_{k}^{c}$ as follows:

$$DAM\_GOG\_COMP2_{k}^{c} = \sum^{R}\sum^{H}\left[(-1) \times OP\left(DAM\_PROR_{r,h}^{c}, DAM\_QSOR_{r,k,h}^{c}, DAM\_OR\_DIPC_{r,k,h}^{c}\right)\right]$$

Where:

a. 'H' is the set of *settlement hours* within the combustion ~~turbine's~~turbine *generation unit'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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP3_{k}^{c}$ as follows:

$$DAM\_GOG\_COMP3_{k}^{c} = \sum^{H}\left[(-1)x\ OP\left(DAM\_LMP_{h}^{c}, MLP_{k}^{c}, DAM\_DIPC_{k,h}^{c}\right) + DAM\_BE\_SNL_{k,h}^{p} \times \frac{N_{k,h}^{c}}{12} \times \left(1 - ST\_Portion_{k,d1}^{p}\right)\right]$$

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 ~~-1~~0;

b. 'p' is the *pseudo-unit* associated with combustion turbine *generation unit* *delivery point* 'c';

c. 'MLP_{k}^{c}' is the *minimum loading point* of the combustion turbine *generation unit* associated with combustion turbine *generation unit* *delivery point* 'c'; and

d. '$N^{c}_{k,h}$' is the number of *metering intervals* in the *settlement hour* 'h' during which combustion turbine *generation unit* *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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP4^{c}_{k,h}$ in accordance with the following:

4.4.18.1 Subject to section 4.4.19, if the combustion turbine *generation unit* 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 *generation unit* 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 *generation unit* 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 *generation unit* 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 *generation unit* 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 *generation unit* after the commencement of its *day-ahead operational commitment*, then the combustion turbine *generation unit* 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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP5_k^c$ as follows:

$$DAM\_GOG\_COMP5_k^c = \sum^{H} DAM\_MWP_{k,h}^c$$

Where:

a. 'H' is the set of *settlement hours* within the combustion ~~turbine's~~turbine *generation unit*'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 *generation unit* associated with a *GOG-eligible resource* ~~associated with~~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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP1_k^s$ as follows:

$$\begin{aligned} DAM\_GOG\_COMP1_k^s &= \sum^{H} \Bigg[(-1) \times OP(DAM\_LMP_h^s, DAM\_DIGQ_{k,h}^s, DAM\_DIPC_{k,h}^s) \\ &+ \sum_{p=1}^{M} \left(DAM\_BE\_SNL_{k,h}^p \times \frac{N_{k,h}^p}{12} \times ST\_Portion_{k,d1}^p \right)\Bigg] \\ &- \sum_{\square}^{RH} [DAM\_LMP_h^s \times DAM\_QSI_{k,h}^s] \end{aligned}$$

Where:

a. 'H' is the set of all *settlement hours* within the steam ~~turbine's~~turbine *generation unit*'s *day-ahead commitment period* when at least one of the *pseudo-units* associated with the steam turbine *generation unit* 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 *generation unit 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's~~turbine *generation unit*'s *day-ahead operational commitment* when all of the *pseudo-units* associated with the steam turbine *generation unit* are scheduled less than their *minimum loading point*; and

d. '$N_{k,h}^{p}$' is the number of *metering intervals* in the *settlement hour* 'h' during which the combustion turbine *generation unit* 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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP2_k^s$ as follows:

$$DAM\_GOG\_COMP2_k^s = \sum^{R}\sum^{H}\left[(-1) \times OP\left(DAM\_PROR_{r,h}^s, DAM\_QSOR_{r,k,h}^s, DAM\_OR\_DIPC_{r,k,h}^s\right)\right]$$

Where:

a. 'H' is the set of all *settlement hours* within the steam ~~turbine's~~turbine *generation unit*'s *day-ahead commitment period* when at least one of the *pseudo-units* associated with the steam turbine *generation unit* 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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP3_k^s$ as follows:

$$DAM\_GOG\_COMP3_{k}^{s} = \sum^{V}\sum^{MHR_p}\left[(-1)\times OP\left(DAM\_LMP_{h}^{s}, MLP_{k}^{s}, DAM\_DIPC_{k,h}^{s}\right) + DAM\_BE\_SNL_{k,h}^{p}\times\frac{N_{k,h}^{p}}{12}\times ST\_Portion_{k,d1}^{p}\right]$$

Where:

a. 'V' is the set of all *pseudo-units* 'p' associated with steam turbine *generation unit* *delivery point* 's' whose associated combustion turbine *generation unit* has a variant #2 (section 4.4.13) *day-ahead operational commitment* that overlaps with the steam turbine *generation unit* *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 ~~-1~~0 for *pseudo-unit* 'p' associated with the steam turbine *generation unit*;

c. 'MLP_k^s' is the *minimum loading point* of steam turbine *generation unit*, associated with *pseudo-unit* 'p', for *market participant* 'k'; and

d. '$N_{k,h}^{p}$' is the number of *metering intervals* in the *settlement hour* 'h' during which the combustion turbine *generation unit* 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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit,* the *IESO* shall calculate $DAM\_GOG\_COMP4_{k,h}^{s}$ as follows:

$$DAM\_GOG\_COMP4_{k,h}^{s} = \sum_{c=1}^{C}\sum_{x=1}^{X_c}\left[DAM\_GOG\_COMP4_{k,x}^{c}\times\frac{ST\_Portion_{k,d1}^{p}}{\left(1-ST\_Portion_{k,d1}^{p}\right)}\right]$$

Where:

a. 'C' is the set of all combustion turbine *generation unit* *delivery points* 'c' associated with steam turbine *generation unit* *delivery point* 's'; ~~and~~

b. $DAM\_GOG\_COMP4_{k,x}^{c}$ is determined in accordance with section 4.4.18 for combustion turbine *generation unit delivery point* 'c' for *market participant* 'k' for *day-ahead commitment period 'x';* and

~~b.~~c. 'X_c' is the set of all *day-ahead commitment periods* 'x' for combustion turbine *generation unit* *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's~~turbine *generation unit*'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 *generation unit* of a *GOG-eligible resource* ~~associated with~~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's~~turbine *generation unit*'s *day-ahead commitment period* when at least one of the *pseudo-units* associated with steam turbine *generation unit* *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 ~~-1~~0" refers to the day before Day ~~0~~1;

b. "Day ~~0~~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 ~~0~~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 ~~0~~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 ~~0~~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,* unless:

a. such *settlement hour* is economically scheduled in the latest *pre-dispatch schedule* issued at the time of the *start-up notice*; and

b. the constraint resulting from such request is not binding in the *real-time market;* or

iv. the steam turbine *generation unit* 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 *generation unit*, 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~~ associated with~~ a *pseudo-unit*:

a. injects into the *IESO-controlled grid* in Day ~~0~~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~~ associated with~~ a *pseudo-unit* has a *pre-dispatch operational commitment* in the first *settlement hour* of Day ~~0~~1 where such *pre-dispatch operational commitment* requires the *resource* to complete its *minimum generation block run-time* that began in Day ~~-1~~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*:

$$RT\_GOG_k^m = Max\big[0,\ RT\_GOG\_COMP1_k^m + RT\_GOG\_COMP2_k^m - RT\_GOG\_COMP3_{k,h}^m - RT\_GOG\_COMP5_{k,h}^m\big]$$

Where:

a. $RT\_GOG\_COMP1_{k,h}^m$, $RT\_GOG\_COMP2_k^m$, $RT\_GOG\_COMP3_{k,h}^m$, 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~~ associated with~~ a *pseudo-unit*:

a. has a *pre-dispatch operational commitment* in the first *settlement hour* of Day ~~0~~1 where such *pre-dispatch operational commitment* requires the *resource* to operate continuously from Day ~~-1~~0 after completing its *minimum generation block-run time* in Day ~~-1~~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~~ associated with~~ a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP1_{k,h}^m$ as follows:

$$\begin{aligned} RT\_GOG\_COMP1_k^m &\\ = \sum^{T1} \Bigg[&(-1) \\ &\times Max\left(OP\left(RT\_LMP_h^{m,t}, RT\_QSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(RT\_LMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) \\ &+ \frac{PD\_BE\_SNL_{k,h}^m}{12}\Bigg] - \sum^{T0}\left[RT\_LMP_h^{m,t} \times AQEI_{k,h}^{m,t}\right] \\ &+ \sum^{RH}\left[DAM\_LMP_h^m\ x\ DAM\_QSI_{k,h}^m/12\right] \end{aligned}$$

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 *generation unit* or steam turbine *generation unit* is registered as a *pseudo-unit* but is not operating as a *pseudo-unit* and has a ~~binding~~minimum constraint applied for combined cycle ~~physical unit constraint~~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~~ associated with~~ a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP2_{k,h}^{m}$ as follows:

$$RT\_GOG\_COMP2_k^m = (-1) \times \sum_R^{T1} OP\left(RT\_PROR_{r,h}^{m,t}, RT\_QSOR_{r,k,h}^{m,t}, BOR_{r,k,h}^{m,t}\right)$$

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~~ associated with~~ a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP3_{k,h}^{m}$ as follows:

$$RT\_GOG\_COMP3_k^m = \sum^{T2} [(-1)\, x \left(OP(RT\_LMP_h^{m,t}, MLP_k^m, BE_{k,h}^{m,t})\right) + \frac{PD\_BE\_SNL_{k,h}^m}{12}]$$

Where:

a. 'T2' is the set of contiguous *metering intervals* 't' beginning with the first *metering interval* of Day ~~0~~1 and ending with the *metering interval* in Day ~~0~~1 in which the *resource* completes its *minimum generation block run-time* that began in Day ~~-1~~0; and

b. 'MLP_k^m' is the *minimum loading point* of the *resource* for Day ~~0~~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 ~~associated with~~ a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP4^{m}_{k,h}$ 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

$$RT\_GOG\_COMP4^{m}_{k} = RT\_GOG\_SU^{m}_{k,h}$$

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

$$RT\_GOG\_COMP4^{m}_{k} = RT\_GOG\_SU^{m}_{k,h} - (RT\_GOG\_SU^{m}_{k,h} \times N\_INT\ /12)$$

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,

$$RT\_GOG\_COMP4^{m}_{k} = 0$$

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:

$$RT\_GOG\_SU^{m}_{k,h} = PD\_BE\_SU^{m}_{k,h}$$

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:

$$RT\_GOG\_SU^{m}_{k,h} = Max\left(0, PD\_BE\_SU^{m}_{k,h} - DAM\_BE\_SU^{m}_{k,h}\right)$$

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 ~~associated with~~ a *pseudo-unit,* the *IESO* shall calculate $RT\_GOG\_COMP5_{k,h}^{m}$ as follows:

$$RT\_GOG\_COMP5_{k}^{m} = \sum\nolimits^{T1} RT\_MWP_{k,h}^{m}$$

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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit:*

a. injects into the *IESO-controlled grid* in Day ~~0~~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 *generation unit 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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit* has a *pre-dispatch operational commitment* in the first *settlement hour* of Day ~~0~~1 where such *pre-dispatch operational commitment* requires the *resource* to complete its *minimum generation block run-time* that began in Day ~~-1~~0, the real-time *generator offer* guarantee *settlement amount* is calculated as follows for combustion turbine *generation unit* *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 *generation unit* of a *GOG-eligible resource* ~~associated with~~that is a *pseudo-unit:*

a. has a *pre-dispatch operational commitment* in the first *settlement hour* of Day ~~0~~1 where such *pre-dispatch operational commitment* requires the *resource* to operate continuously from Day ~~-1~~0 after completing its *minimum generation block-run time* in Day ~~-1~~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 *generation unit* *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 *generation unit*, the *IESO* shall calculate $RT\_GOG\_COMP1_k^c$ as follows:

$$RT\_GOG\_COMP1_k^c = \sum^{T1}\Bigg[(-1) \times \mathrm{Max}\Big(OP\big(RT\_LMP_h^{c,t}, RT\_QSI_{k,h}^{c,t}, RT\cancel{\_CMT}\_DIPC_{k,h}^{c,t}\big), OP\big(RT\_LMP_h^{c,t}, AQEI_{k,h}^{c,t}, RT\cancel{\_CMT}\_DIPC_{k,h}^{c,t}\big)\Big) + \frac{PD\_BE\_SNL_{k,h}^{p}}{12} \times (1 - ST\_Portion_{k,d1}^{p})\Bigg] - \sum^{T0}\big(RT\_LMP_h^{c,t} \times AQEI_{k,h}^{c,t}\big) + \sum^{RH}\big[DAM\_LMP_h^c \times DAM\_QSI_{k,h}^c/12\big]$$

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 *generation unit*;

b. 'p' is the *pseudo-unit* associated with combustion turbine *generation unit delivery point* 'c';

c. 'T0' is the set of all *metering intervals* 't' between the time when the combustion turbine *generation unit* is synchronized and injecting *energy* into the *IESO-controlled grid* and the time when the combustion turbine *generation unit* 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 *generation unit* received a *pre-dispatch operational commitment* while operating in combined cycle mode but, due to a failure or *outage* at the associated steam turbine *generation unit*, operates in single cycle mode, then the applicable $\cancel{RT\_CMT\_DIPC_{k,h}^{c,t}}RT\_DIPC_{k,h}^{c,t}$ 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 *generation unit*, the *IESO* shall calculate $RT\_GOG\_COMP2_k^c$ as follows:

$$RT\_GOG\_COMP2_k^c = \sum_R^{T1} [(-1) \times OP(RT\_PROR_{r,h}^{c,t}, RT\_QSOR_{r,k,h}^{c,t}, RT\_OR\_\cancel{CMT}\_DIPC_{r,k,h}^{c,t})]$$

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 *generation unit*.

Component #3 - applicable to for Variant # 2

4.5.17 In determining the real-time *generator offer* guarantee *settlement amount* for a combustion turbine *generation unit*, the *IESO* shall calculate $RT\_GOG\_COMP3_k^c$ as follows:

$$RT\_GOG\_COMP3_k^c = \sum^{T2} \left[(-1) \times \left(OP\left(RT\_LMP_h^{c,t}, MLP_k^c, RT\_\cancel{CMT}\_DIPC_{k,h}^{c,t}\right)\right) + \frac{PD\_BE\_SNL_{k,h}^p}{12} \times (1 - ST\_Portion_{k,d1}^p) \right]$$

Where:

a. 'T2' is the set of contiguous *metering intervals* 't' beginning with the first *metering interval* of Day ~~0~~1 and ending with the *metering interval* in Day ~~0~~1 in which the *resource* completes its *minimum generation block run-time* that began in Day ~~-1~~0;

b. 'MLP_k^c' is the *minimum loading point* of the combustion turbine *generation unit* associated with combustion turbine *generation unit delivery point* 'c'; and

c. 'p' is the *pseudo-unit* associated with combustion turbine *generation unit 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 *generation unit*, 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 *generation unit* achieved its *minimum loading point* within the first six *metering intervals* of the start of the *pre-dispatch operational commitment*, then:

$$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right)$$

ii. If the combustion turbine *generation unit* 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:

$$RT\_GOG\_COMP4_k^c = PD\_BE\_SU_{k,h}^p \times \left(1 - ST\_Portion_{k,d1}^p\right) \times \left(1 - \frac{N\_INT_k^c}{12}\right)$$

Where:

a. '$N\_INT^c_k$' is the number of *metering intervals* after the first six *metering intervals* that the combustion turbine *generation unit* 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 *generation unit* 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 *generation unit* 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 *generation unit* 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 *generation unit* 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 *generation unit* to de-synchronize from the *IESO-controlled grid* after the commencement of its *pre-dispatch operational commitment*, then the combustion turbine *generation unit* 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 *generation unit*, 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 *generation unit.*

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 *generation unit* associated with a *GOG-eligible resource* ~~associated with~~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 *generation unit*, 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's~~turbine *generation unit'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 *generation unit 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 *generation unit 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 *generation unit* 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's~~turbine *generation unit's real-time commitment period* when: (i) the steam turbine *generation unit* 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 *generation unit*, the *IESO* shall calculate $RT\_GOG\_COMP2_k^s$ as follows:

$$RT\_GOG\_COMP2_k^s = \sum_R^{T1}\left[(-1) \times OP\left(RT\_PROR_{r,h}^{s,t}, RT\_OR\_CMT\_DIGQ_{r,k,h}^{s,t}, RT\_OR\_CMT\_DIPC_{r,k,h}^{s,t}\right)\right]$$

Where:

a. 'T1' is the set of all *metering intervals* 't' in the steam ~~turbine's~~turbine *generation unit'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 *generation unit*, 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 *generation unit delivery point* 's' that have a *real-time schedule* in the first *settlement hour* of Day ~~0~~1 to complete its *minimum generation block run-time* as part of a *pre-dispatch operational commitment* that began in Day ~~-1~~0 and forms part of the steam ~~turbine's~~turbine *generation unit'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 ~~0~~1 to complete its *minimum generation block run-time;* and (ii) the combustion turbine *generation unit* 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 ~~0~~1.

Component #4

4.5.25 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *generation unit*, 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 *generation unit delivery points* 'c' associated with steam turbine *generation unit delivery point* 's';

b. $RT\_GOG\_COMP4_{k,x}^{c}$ is determined in accordance with section 4.5.18 for combustion turbine *generation unit 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 *generation unit* 'c' during the steam ~~turbine's~~turbine *generation unit's real-time commitment period*.

Component #5

4.5.26 In determining the real-time *generator offer* guarantee *settlement amount* for a steam turbine *generation unit*, 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's~~turbine *generation unit'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 ~~associated with~~ 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* where the *GOG-eligible resource* that is not ~~associated with~~ 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 ~~associated with~~ 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 ~~associated with~~ 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 *generation unit delivery point* 'c' ("$RT\_RDSA_k^c$") shall be calculated and disbursed to the *market participant* for a *GOG-eligible resource* ~~associated with~~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* ~~associated with a~~that is 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

4.6.8.2 where the *GOG-eligible resource* ~~associated with~~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* ~~associated with~~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* ~~associated with~~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 *generation unit* *delivery point* 's' ("$RT\_RDSA_k^s$") shall be calculated and disbursed to the *market participant* for a *GOG-eligible resource* ~~associated with~~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* ~~associated with~~that is 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

4.6.13.2 where the *GOG-eligible resource* ~~associated with~~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* ~~associated with~~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:

$$RT\_RDSA_k^s = Max\left(0, \sum^T \left[(-1) \times OP\left(DAM\_LMP_h^s, AQEI_{k,h}^{s,t}, RT\_DIPC_{k,h}^{s,t}\right) - Max\left(0, (-1) \times OP\left(DAM\_LMP_h^s, AQEI_{k,h}^{s,t}, DAM\_DIPC_{k,h}^s\right)\right)\right]\right)$$

4.6.15 For a *GOG-eligible resource* ~~associated with~~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:

$$RT\_RDSA_k^s = Max\left(0, \sum^T\left[(-1) \times OP\left(RT\_LMP_h^{s,t}, AQEI_{k,h}^{s,t}, RT\_DIPC_{k,h}^{s,t}\right)\right]\right)$$

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:

$$
\begin{aligned}
\text{CRLR} = {} & \sum\nolimits_{K,H}^{M0} \Big[\big(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}\big)\ x\ DAM\_LMP_{h}^{m} \\
& + \sum\nolimits^{T} \Big(\big(AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}\big) \\
& - \big(DAM\_QSW_{k,h}^{m} - DAM\_QSI_{k,h}^{m}\big) \Big)\ x\ RT\_LMP_{h}^{m,t}/12 \Big] \\
& + \sum\nolimits_{K,H}^{V} \Big[\big(DAM\_QVSW_{k,h}^{v} \\
& - DAM\_QVSI_{k,h}^{v}\big)\ x \sum\nolimits^{T} \big(DAM\_LMP_{h}^{vz} - RT\_LMP_{h}^{vz,t}\big) \Big] \\
& + \sum\nolimits_{K,H}^{M1} \Big[\big(DAM\_LMP_{h}^{z} + LFDC_{h}\big)\ x \sum\nolimits^{T} AQEW_{k,h}^{m,t} \Big] \\
& + \sum\nolimits_{K,H}^{I} \Big[\big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)\ x\ DAM\_LMP_{h}^{i} \\
& + \sum\nolimits^{T} \Big(\big(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\big) \\
& - \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big) \Big)\ x\ RT\_LMP_{h}^{i,t}/12 \Big] \\
& - \sum\nolimits_{K,H}^{I} \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)\ x\ DAM\_PEC_{h}^{i} \\
& - \sum\nolimits_{K,H}^{I} \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big)\ x\ DAM\_PNISL_{h}^{i} \\
& - \sum\nolimits_{K,H}^{I,T} \Big(\big(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\big) - \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big) \Big) \\
& \times\ RT\_PEC_{h}^{i,t}/12 \\
& - \sum\nolimits_{K,H}^{I,T} \Big(\big(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\big) - \big(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\big) \Big) \\
& \times\ RT\_PNISL_{h}^{i,t}/12
\end{aligned}
$$

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:

$$ICLR_k = CRLR \times \sum\nolimits_{H}^{M,T} AQEW_{k,h}^{m,t} / \sum\nolimits_{K,H}^{M,T} AQEW_{k,h}^{m,t}$$

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 *non-dispatchable loads*, *dispatchable loads, price responsive loads,* 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:

$$DAM\_NISLR = \sum_{K,H}^{I} \left[\left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right) x\ DAM\_PNISL_{h}^{i}\right]$$

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:

$$DAM\_NISLU_k = DAM\_NISLR\ x \left[\sum_{H}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right) / \sum_{K,H}^{M,T}\left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

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:

$$RT\_NISLR_h = \sum_{K}^{I,T}\left(\left(SQEW_{k,h}^{i,t} - SQEI_{k,h}^{i,t}\right) - \left(DAM\_QSW_{k,h}^{i} - DAM\_QSI_{k,h}^{i}\right)\right) \times RT\_PNISL_{h}^{i,t}/12$$

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 services 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.

Note: New Sections 4.10 to 4.11 have been shown without track changes for ease of review.

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 *generation unit delivery point* 'c', or steam turbine *generation unit delivery point* 's', as applicable, of the relevant *generator failure*~~;~~, determined in accordance with the applicable *market manual*; and

~~a.~~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 *generation unit delivery point* 'c', or steam turbine *generation unit delivery point* 's', as applicable, ~~in *settlement hour* 'h' of~~within ~~the relevant *generator failure* *metering intervals* 'T1', determined in accordance with the applicable *market manual*; and~~.

~~b. 'T1' is the set of all contiguous *metering intervals* at *delivery point* 'm' of the relevant *generator failure,* determined in accordance with the applicable *market manual*.~~

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 ~~associated with~~ 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~~ associated with~~ 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 the *market participant* provides less than four hours of advance notice of a given *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:

$$GFC\_MPC_{k,h}^{m} = \sum^{T} Min\left[0, -1 \times \left(Min\left(RT\_LMP_{h}^{m,t}, PD\_LMP_{h}^{m,pd1}\right) - PD\_LMP_{h}^{m,pdm}\right) \times Max\left(0, PD\_QSI_{k,h}^{m,pdm} - Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}\right)\right)\right]/12$$

Non-Pseudo-Unit – Guarantee Cost Component

4.10.6 For a *GOG-eligible resource* that is not~~ associated with~~ 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:

$$GFC\_GCC_{k,f}^{m} = -1 \times Max\left[0, PD\_SU\_Ratio_{k,f}^{m} \times SU\_INCR_{k,f}^{m} + \sum^{T1} \frac{PD\_BE\_SNL_{k,h}^{m,pdm}}{12} - \sum^{T1} OP\left(PD\_LMP_{h}^{m,pdm}, PD\_QSI_{k,h}^{m,pdm}, PD\_BE^{m,pdm}\right)/12\right] \times M1$$

Where:

a. 'M1' is the prorating factor based on the quantity of *energy* that the *resource* failed to deliver and calculated as follows:

$$M1 = \left[1 - \frac{\sum^{T1} Min\left(PD\_QSI_{k,h}^{m,pdm}, Max\left(AQEI_{k,h}^{m,t}, DAM\_QSI_{k,h}^{m}\right)\right)}{\left(\sum^{T1} PD\_QSI_{k,h}^{m,pdm}\right)}\right]$$

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:

$$SU\_INCR_{k,f}^{m} = Max\left(0, PD\_BE\_SU_{k,f}^{m,pdm} - DAM\_BE\_SU_{k,f}^{m}\right)$$

c. if the *pre-dispatch operational commitment* violated by the *generator failure* 'f' is an *extended pre-dispatch operational commitment*, then:

$$SU\_INCR_{k,f}^{m} = 0$$

d. Otherwise:

$$SU\_INCR_{k,f}^{m} = PD\_BE\_SU_{k,f}^{m,pdm}$$

e. $PD\_SU\_Ratio_{k,f}^{m}$ 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:

$$PD\_SU\_Ratio_{k,f}^{m} = \text{Min}\left(1, \frac{MLP\_INJ_{k,f}^{m}}{PD\_MGBRT_{k,f}^{m}}\right)$$

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* ~~associated with~~that is a *pseudo-unit,* a *generator failure* will have occurred in the following circumstances:

a. for a combustion turbine *generation unit* associated with a *pseudo-unit*, if at any time during a *settlement hour* where:

   i. the combustion turbine *generation unit* fails to achieve its *minimum loading point* by the start of the *pre-dispatch operational commitment* of its associated *pseudo-unit*;

   ii. the combustion turbine *generation unit* 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

   iii. 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*;*

b. for a steam turbine *generation unit* associated with a *pseudo-unit*, if:

   i. one or more of the combustion ~~turbines~~turbine *generation units* associated with the steam turbine *generation unit*:

      a. fails to achieve its *minimum loading point* by the start of the *pre-dispatch operational commitment* of its associated *pseudo-unit*; or

      b. 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

   ii. one or more of the *pseudo-units* associated with the steam turbine *generation unit* 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 *generation unit* 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 generation unit *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*, $GFC\_MPC_{k,h}^{c}$ shall be determined as follows:

$$GFC\_MPC_{k,h}^{c} = \sum^{T} Min\left[0, (-1) \times \left(Min\left(RT\_LMP_{h}^{c,t}, PD\_LMP_{h}^{c,pd1}\right) - PD\_LMP_{h}^{c,pdm}\right) \times Max\left(PD\_QSI_{k,h}^{c,pdm} - Max\left(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}\right), 0\right)\right]/12$$

4.10.9 For a steam turbine generation unit 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 generation unit *delivery point* 's' for each *settlement hour* 'h' within the *generator failure* ($GFC\_MPC_{k,h}^{s}$) in accordance with the following:

$$GFC\_MPC_{k,h}^{s} = \sum^{T} GFC\_MPC_{k,h}^{s,t}$$

Where:

~~a. 'T' is the set of all *metering intervals* at steam turbine *delivery point* 's' in *settlement hour* 'h' of the relevant *generator failure*, determined in accordance with the applicable *market manual*;~~

~~b.~~a. If the *market participant* provides less than four hours of advance notice of the *generator failure* or fails to provide such notice, $GFC\_MPC_{k,h}^{s,t}$ shall be determined as follows:

$$GFC\_MPC_{k,h}^{s,t} = (-1) \times Max\left(RT\_LMP_{h}^{s,t} - Min\{c \in CT_{F} | PD\_LMP_{h}^{s,pdm}\}, 0\right) \times Max\left(\sum^{M_t}\left[RT\_STP\_QSI_{k,h}^{p,t}\right] + \sum^{N_t}\left[PD\_STP\_QSI_{k,h}^{p,pdm}\right] - AQEI_{k,h}^{s,t}, 0\right)/12$$

~~c.~~b. If the *market participant* provides four hours or greater advance notice of the *generator failure*, $GFC\_MPC_{k,h}^{s,t}$ shall be determined as follows:

$$GFC\_MPC_{k,h}^{s,t} = (-1) \times Max\left(Min\left(RT\_LMP_h^{s,t}, PD\_LMP_h^{s,pd1}\right) - Min\{c \in CT_F | PD\_LMP_h^{s,pdm}\}, 0\right) \times Max\left(\sum^{M_t}\left[RT\_STP\_QSI_{k,h}^{p,t}\right] + \sum^{N_t}\left[PD\_STP\_QSI_{k,h}^{p,pdm}\right] - AQEI_{k,h}^{s,t}, 0\right)/12$$

Where:

i. 'CT_F' is the set of all combustion ~~turbines~~turbine *generation units* associated with steam turbine *generation unit* *delivery point* 's' having a combustion turbine *generation unit* 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 *generation unit* *delivery point* 's' whose associated combustion turbine *generation unit* does not have a combustion turbine *generation unit* 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 *generation unit* *delivery point* 's' whose associated combustion turbine *generation unit* has a combustion turbine *generation unit* 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 *generation unit* 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 *generation unit* *delivery point* 'c' for each *generator failure* 'f' that occurs ($GFC\_GCC_{k,f}^{c}$) in accordance with the following and the operating profit function described in section 10 of Appendix 9.2:

$$
\begin{aligned}
GFC\_GCC_{k,f}^{c} = (-1) \\
&\times Max\left[0, PD\_SU\_Ratio_{k,f}^{c} \times SU\_INCR_{k,f}^{p,pdm} \times \left(1 - ST\_Portion_{k,d1}^{p}\right)\right. \\
&+ \sum^{T1}\left(\frac{PD\_BE\_SNL_{k,h}^{p,pdm}}{12} \times \left(1 - ST\_Portion_{k,d1}^{p}\right)\right. \\
&\left.\left. - \frac{OP\left(PD\_LMP_{h}^{c,pdm}, PD\_QSI_{k,h}^{c,pdm}, PD\_DIPC_{k,h}^{c,t}\right)}{12}\right)\right] \times M1
\end{aligned}
$$

Where:

a. 'M1' is the prorating factor based on the quantity of *energy* that the *resource* failed to deliver and calculated as follows:

$$
M1 = \left[1 - \frac{\sum^{T1} Min\left(PD\_QSI_{k,h}^{c,pdm}, Max\left(AQEI_{k,h}^{c,t}, DAM\_QSI_{k,h}^{c}\right)\right)}{\left(\sum^{T1} PD\_QSI_{k,h}^{c,pdm}\right)}\right]
$$

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:

$$
SU\_INCR_{k,f}^{p,pdm} = Max\left(0, PD\_BE\_SU_{k,f}^{p,pdm} - DAM\_BE\_SU_{k,f}^{p}\right)
$$

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 ~~prorated factor~~prorating factor for *market participant* 'k' at combustion turbine *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 *generation unit 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 *generation unit 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 *generation unit* 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 *generation unit 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:

$$\begin{aligned} GFC\_GCC_{k}^{s} &= (-1) \\ &\times Max\Bigg[0, \sum^{F}\left(PD\_SU\_Ratio_{k,f}^{c} \times SU\_INCR_{k,f}^{p,pdm} \times ST\_Portion_{k,d1}^{p}\right) \\ &+ \sum^{T1}\sum^{CT_f}\left(\frac{PD\_BE\_SNL_{k,h}^{p,pdm}}{12} \times ST\_Portion_{k,d1}^{p}\right) \\ &- \sum^{T1}\left(OP\left[Min\{c \in CT_F | PD\_LMP_{h}^{s,pdm}\}, PD\_DIGQ_{k,h}^{s,t}, PD\_DIPC_{k,h}^{s,t}\right]/12\right)\Bigg] \times M1 \end{aligned}$$

Where:

a. 'M1' is the prorating factor based on the quantity of *energy* that the *resource* failed to deliver and calculated as follows:

$$M1 = \left[1 - \frac{\sum^{T1} Min\left(\sum^{N_t}\left[PD\_STP\_QSI_{k,h}^{p,pdm}\right], Max\left(AQEI_{k,h}^{s,t} - \sum^{M_t}\left(RT\_STP\_QSI_{k,h}^{p,t}\right), \sum^{N_t} DAM\_STP\_QSI_{k,h}^{p}\right)\right)}{\sum^{T1}\sum^{N_t}\left[PD\_STP\_QSI_{k,h}^{p,pdm}\right]}\right]$$

b. If the combustion ~~turbine's~~turbine *generation unit'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 ~~prorated *start-up offer*~~prorating factor for *market participant* 'k' at combustion turbine *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 ~~turbines~~turbine *generation units* associated with steam turbine *generation unit delivery point* 's' having a combustion turbine *generation unit* failure interval during *metering interval* 't';

b. 'M_t' is the set of all *pseudo-units* associated with steam turbine *generation unit delivery point* 's' whose associated combustion turbine *generation unit* does not have a combustion turbine *generation unit* 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 *generation unit delivery point* 's' whose associated combustion turbine *generation unit* has a combustion turbine *generation unit* failure interval or are operating in *single cycle mode* during *metering interval* 't';

d. 'F' is the set of all combustion turbine *generation unit* or steam turbine *generation unit* failures 'f' occurring during the period 'T1';

e. $MLP\_INJ^{c}_{k,f}$ has the same meaning as section 4.10.10(e)(ii)(a); and

f. $PD\_MGBRT^{c}_{k,f}$ 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* ~~in accordance~~for ~~with~~ 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

~~**Note: This provision has been left blank and the updated MRP provisions will be provided in a future batch once anticipated market rule amendments related to capacity auctions is complete and the baseline is settled.**~~

Capacity Obligation Availability Payment~~s~~

4.13.1~~4.7J.1~~ The *capacity* ~~*auction*~~*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*.

~~4.7J.2 [Intentionally left blank – section deleted]~~

Capacity Obligation Availability Charge~~s~~

4.13.2~~4.7J.2~~ The *capacity* *obligation*~~*auction*~~ 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~~4.7J.2.1~~ In regards to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*, the *capacity* *obligation*~~*auction*~~ availability charge *settlement amount* shall be calculated for each *trading day* for which it receives a standby notice and 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* ~~*commitment process*~~*market* and maintain such *energy bid* through the *real-time~~ energy~~* market. The *capacity obligation~~auction~~* 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~~commitment process~~* or failed to maintain such *energy bid* through the *real-time~~ energy~~ market*, $DREBQ^{m}_{k,h} = 0$;

c. In regards 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~~commitment process~~* 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* or *capacity dispatchable load resource*, as the case may be.

4.13.2.24~~4.7J.2.1B~~ 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~~auction~~* 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~~commitment process~~* and maintain such *energy offer* in accordance with the applicable *market manual*. The *capacity obligation~~auction~~* 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~~commitment process~~* or failed to maintain such *energy offer* in accordance with the applicable *market manual* for *settlement hour* 'h', $CAEO^{m}_{\cancel{h,}k,h} = 0$;

c. If the *energy offer* submitted in the *day-ahead market~~commitment process~~* for *settlement hour* 'h' is not equal to the *energy offer* submitted in the *pre-dispatch process*~~hour~~ for the same *settlement hour*, $CAEO^{m}_{\cancel{h,}k,h}$ 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 $CAEO^{m}_{\cancel{h,}k,h}$ 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~~s~~

4.13.3~~4.7J.2.2~~ Subject to ~~section~~ MR Ch.7 ss.19.4.5 and 7.5.3 ~~of Chapter 7~~, the *capacity obligation~~auction~~* 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 ~~or~~ 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 ~~4.7J.2.2.1~~ 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~~4.7J.2.2.1~~ A commercial ~~or~~ 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~~AQEW~~, 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 ~~3.1.10~~11 of Appendix 9.2.

Capacity Obligation Administration Charge~~s~~

4.13.4~~4.7J.2.3~~ The *capacity obligation~~auction~~* 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~~auction~~* availability payment *settlement amount*, calculated in accordance with section ~~4.7J.1~~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~~s~~

4.13.5~~4.7J.2.4~~ The *capacity obligation~~auction~~* 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~~auction~~ 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~~auction~~* availability payment *settlement amount*, calculated in accordance with section ~~4.7J.1~~4.13.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

~~4.7J.2.5 [Intentionally left blank – section deleted]~~

~~4.7J.2.6 [Intentionally left blank – section deleted]~~

Capacity Obligation Capacity Import Call Failure Charge~~s~~

4.13.6~~4.7J.2.7~~ Subject to ~~section~~ MR Ch.7 s.7.5.8A ~~of Chapter 7~~, the *capacity obligation*~~*auction*~~ 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*~~*auction*~~ availability payment *settlement amount*, calculated in accordance with section ~~4.7J.1~~ 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~~s~~

4.13.7~~4.7J.2.8~~ 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~~4.7J.2.8.1~~ 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~~4.7J.2.9~~ 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:

$$CAIPA^m_k = (-1 \times Max (0, (CAAP^m_k \times (UCAP\ Adjustment) + \Sigma^H CAAC^m_{k,h}))$$

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 ~~4.7J.1~~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 ~~4.7J.1~~ 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 ~~section~~ MR Ch.7 s. 19.4.18 ~~of Chapter 7~~, then the UCAP Adjustment shall equal 100%.

Capacity Obligation Buy-Out Charge~~s~~

4.13.9~~4.7J.3~~ 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 *commitment period*.

~~(b) 'tm' is the *energy market billing period* that corresponds to the *relevant settlement hour*.~~

Measurement Data Audit

4.13.10~~4.7J.4~~ 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~~4.7J.5~~ Subject to section ~~4.7J.5.3~~ 4.13.11.3, the *IESO* shall calculate and disburse a *capacity* *obligation*~~*auction*~~ *dispatch test* payment *settlement amount* or *capacity* *obligation*~~*auction*~~ 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~~4.7J.5.1~~ in regards to *capacity auction dispatch tests*, the c*apacity* *obligation*~~*auction*~~ *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:

$$CATAP^m_{k,h} = HDRTAPR \text{ X } HDRDC^m_{k,h}$$

4.13.11.2~~4.7J.5.2~~ in regards to *emergency operating state* activation, the *capacity* *obligation*~~*auction*~~ *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:

$$CAEOP^m_{k,h} = Max(0, HDRBP^m_{k,h} – Max(0, ~~HOEP_h~~ DAM\_LMP^z_h)) X HDRDC^m_{k,h}$$

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:

$$CAEOP^m_{k,h} = Max(0, HDRBP^m_{k,h} – Max(0,RT\_LMP^m_{k,h})) X HDRDC^m_{k,h}$$

4.13.11.4~~4.7J.5.3~~ 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~~auction~~* test activation payment *settlement amount* or a *capacity obligation~~auction~~ emergency operating state* activation payment *settlement amount* for such *settlement hour*.

Capacity Obligation Availability Charges True-Up Payment

4.13.12~~4.7J.6~~ 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 ~~4.7J.2.1 or 4.7J.2.1A~~ 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 ~~capacity market participant offered an amount of capacity~~ in excess of the *capacity obligation* of ~~its~~ the relevant *capacity auction resource* for at least one *settlement hour* within the *availability window* of the applicable *obligation period*. The *capacity obligation~~auction~~* availability charge true-up *settlement amount* shall be calculated as follows*:*

$$CAACT^m_k = (Min ((-1) x \Sigma^{TM} ((\Sigma^D CAAC^m_k) + UCAP\ Adjustment\ x\ CAAP^m_k + CAIPA^m_k), \Sigma^H Max (0,(RAC_k – CCO_{k,h}) x CACP_h x CNPF_{tm}))$$

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 ~~4.7J.2.1~~ 4.13.2.1;

b. 'UCAP Adjustment' is a de-rate (in %) determined in accordance with section 4.13.8~~based on the *hourly demand response resource's* delivered performance during a *capacity auction capacity test* performed during the relevan *obligation period*, as determined in accordance with the applicable *market manual*~~;

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 ~~4.7J.1~~4.13.~~1~~;

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 ~~4.7J.2.9~~ 4.13.8;

e. 'D' is the set of all *trading days* within the relevant *energy market billing period*;

~~'tm' is the *energy market billing period* associated with *settlement hour* 'h' within the relevant *obligation period*~~

f. ~~g.~~ TM' is the set of all *energy market billing periods* within the relevant *obligation period;* and

g. ~~h.~~'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~~4.7J.7~~ 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:

$$CACT^{m}_{k} = -1 \times \text{Min}\left(0, \left(\Sigma_{H} TD_{C,k,h}^{m} + \Sigma_{H} TD_{P,k,h}^{m}\right)\right)$$

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:

a. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. ~~4.7J.2.1, 4.7J.2.1A, 4.7J.2.3, 4.7J.2.4, 4.7J.2.7, 4.7J.2.8, and 4.7J.2.9~~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:

a. 'P' is the set of the *settlement amounts* applied in accordance with MR Ch.9 ss. ~~4.7J.1 and 4.7J.6~~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~~4.7J.8~~ The *capacity* *obligation*~~*auction*~~ 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*~~*auction*~~ uplift *settlement amount* shall be determined in accordance with sections ~~4.7J.8.1 and 4.7J.8.2~~ 4.13.14.1 and 4.13.14.2. In calculating the *capacity* *obligation*~~*auction*~~ uplift *settlement amount* in this section ~~4.7J.8~~ 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~~4.7J.8.1~~ 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*~~*auction*~~ uplift *settlement amount* for such load facility shall be calculated as follows:

$$CAU^m_k = \Sigma_{H,M} (TD_{C,k,h}{}^m \text{ x } \cancel{*} PDF_k)$$

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. ~~4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7~~ 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~~4.7J.8.2~~ 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*~~*auction*~~ uplift *settlement amount* shall for such load facility shall be calculated in accordance with the following:

a. for Fort Frances Power Corporation Distribution Inc.:

$$CAU^{m}_{k} = (\Sigma_{H,M}\, TD_{C,k,h}^{m} - TD_{C1350,k,h}^{m}) \times M\cancel{AX}ax((\Sigma_{H}^{M,T}\, AQEW_{k,h}^{m,t} + EGEI_{k} - EEQ),0) / \text{Class B Load}$$

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.~~ 4.7J.1, 4.7J.2, 47J., 47J.5, 4.7J.6, and 4.7J.7~~ 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~~ 4.7J.8.1~~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*:

$$CAU^{m}_{k} = (\Sigma_{H,M}\, TD_{C,k,h}^{m} - TD_{C1350,k,h}^{m}) \times \cancel{MAX}Max((\Sigma_{H}^{M,T}\, AQEW_{k,h}^{m,t} + EGEI_{k} - GA\_AQEW_{g,k,h,M}^{m,t} - PGS_{h,M}),0) / \text{Class B Load}$$

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 ~~4.7J.8.1~~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*.

Note: New Section 4.14 – Non-Hourly Uplifts has been shown without track changes for ease of review.

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:

$$GFC\_GCCU_k = -1\ x \sum_{K,F}^{M} GFC\_GCC_{k,f}^{m} \times \left[\sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})\right]$$

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* ("$RT\_GOG_{k,h}^{m}$") shall be determined as follows:

$$RT\_GOGU_k = -1\ x \sum_{K,H}^{M,T} RT\_GOG_{k,h}^{m} \times \left[\sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})\right]$$

$$RT\_GOGU_k = -1\ x \sum_{K,H}^{M,T} \left(RT\_GOG_{k,h}^{m} + RT\_GOG\_CB_{k,h}^{m}\right) \times \left[\sum_{H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)\right]$$

Where:

a. $RT\_GOG_{k,h}^{m}$ 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';* ~~and~~

b. 'M' is the set of all *delivery points* 'm' and *intertie metering points* 'i'; and

~~b.~~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:

$$DAM\_UPL_k = -1\ x \left(\sum_{H}^{M} \left(DAM\_MWP_{k,h}^{m} + DAM\_GOG_{k}^{m}\right) - DAM\_P2\_PMT\right) \times \sum_{H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right) / \sum_{K,H}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right)$$

Where:

a. $DAM\_MWP_{k,h}^{m}$ 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. $DAM\_GOG_{k}^{m}$ 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:

$$V\_DRSU_k = DAM\_P2\_PMT \times \sum_{H}^{V} DAM\_QVSI_{k,h}^{v} / \left(\sum_{K,H}^{V} DAM\_QVSI_{k,h}^{v} + DAM\_NDL\_OF\right)$$

Where:

a. 'DAM_P2_PMT' is as calculated in accordance with section 4.14.5;

b. 'V' is the set of all *delivery points* 'v' for *virtual zonal resources*; and

c. 'DAM_NDL_OF' is the total quantity of *energy* that was over-forecasted in the *day-ahead market* for *non-dispatchable loads,* as determined by the *IESO* as follows:

$$DAM\_NDL\_OF = \sum_{H,K}^{M} Max(DAM\_QSW_{k,h}^{m} + DAM\_HDR\_QSW_{k,h}^{m1} - AQEW_{k,h}^{m,t}, 0)$$

Where:

i. '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

ii. 'm1' is the set of all *delivery points* 'm' for physical *hourly demand response resources*.

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~~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 ($Imp\_DAM\_MWP_{k,h}^{i,p2}$) as follows:

$$Imp\_DAM\_MWP_{k,h}^{i,p2} = Max\left[0, DAM\_COMP1_{k,h}^{i} + DAM\_COMP2_{k,h}^{i}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{i} = -1\ x\ [OP(DAM\_LMP_{h}^{i}, DAM\_QSI_{k,h}^{i,p2}, DAM\_BE_{kh}^{i}$ $OP(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BE_{kh}^{i}\ )]$

b. $DAM\_COMP2_{k,h}^{i} =$ $-1\ x \sum_{R}[OP(DAM\_PROR_{r,h}^{i}, DAM\_QSOR_{r,k,h}^{i,p2}, DAM\_BOR_{r,k,h}^{i}\ ) -$ $OP(DAM\_PROR_{r,h}^{i}, DAM\_EOP_{r,k,h}^{i}, DAM\_BOR_{r,k,h}^{i})]$

$$Imp\_DAM\_MWP_{k,h}^{i,p2} = Max\left[0, DAM\_COMP1_{k,h}^{i} + DAM\_COMP2_{k,h}^{i}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{i} = -1 \times [OP(DAM\_LMP_{h}^{i}, DAM\_QSI_{k,h}^{i,p2}, DAM\_BE_{kh}^{i}\ ) -$ $OP(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BE_{kh}^{i}\ )]$

b. $DAM\_COMP2_{k,h}^{i} = -1\ \times$ $\sum_{R}[OP(DAM\_PROR_{r,h}^{i}, DAM\_QSOR_{r,k,h}^{i,p2}, DAM\_BOR_{r,k,h}^{i}\ ) -$ $OP(DAM\_PROR_{r,h}^{i}, DAM\_OR\_EOP_{r,k,h}^{i}, DAM\_BOR_{r,k,h}^{i})]$

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 ($Imp\_DAM\_MWP_{k,h}^{i,p1}$) as follows:

$$Imp\_DAM\_MWP_{k,h}^{i,p1} = Max\left[0, DAM\_COMP1_{k,h}^{i} + DAM\_COMP2_{k,h}^{i}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{i} = -1\ x\ [OP(DAM\_LMP_{h}^{i}, DAM\_QSI_{k,h}^{i,p1}, DAM\_BE_{kh}^{i}\ ) -$ $OP(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BE_{kh}^{i}\ )]$

b. $DAM\_COMP2_{k,h}^{i} =$ $-1\ x \sum_{R}[OP(DAM\_PROR_{r,h}^{i}, DAM\_QSOR_{r,k,h}^{i,p1}, DAM\_BOR_{r,k,h}^{i}\ ) -$ $OP(DAM\_PROR_{r,h}^{i}, DAM\_EOP_{r,k,h}^{i}, DAM\_BOR_{r,k,h}^{i})]$

$$Imp\_DAM\_MWP_{k,h}^{i,p1} = Max\left[0, DAM\_COMP1_{k,h}^{i} + DAM\_COMP2_{k,h}^{i}\right]$$

Where:

a. $DAM\_COMP1_{k,h}^{i} = -1\ \times [OP(DAM\_LMP_{h}^{i}, DAM\_QSI_{k,h}^{i,p1}, DAM\_BE_{kh}^{i}\ ) -$ $OP(DAM\_LMP_{h}^{i}, DAM\_EOP_{k,h}^{i}, DAM\_BE_{kh}^{i}\ )]$

b. $DAM\_COMP2_{k,h}^{i} = -1\ \times$ $\sum_{R}[OP(DAM\_PROR_{r,h}^{i}, DAM\_QSOR_{r,k,h}^{i,p1}, DAM\_BOR_{r,k,h}^{i}\ ) -$ $OP(DAM\_PROR_{r,h}^{i}, DAM\_OR\_EOP_{r,k,h}^{i}, DAM\_BOR_{r,k,h}^{i})]$

$$Imp\_DAM\_MWP^{i,p1}_{k,h} = Max\left[0, DAM\_COMP1^{i}_{k,h} + DAM\_COMP2^{i}_{k,h}\right]$$

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:

$$FCCU_k = -1 \times \sum_{K}^{M} FCC^{m}_{k} \times \sum_{H}^{M,T} (AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h}) / \sum_{K,H}^{M,T} (AQEW^{m,t}_{k,h} + SQEW^{i,t}_{k,h})$$

Where:

a. FCC^{m}_{k} 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~~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 *economic withholding settlement* charge 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 mitigation for *economic withholding* on uncompetitive interties *settlement amount,* in accordance with section 5.9. The ex-post mitigation *economic withholding settlement* charge uplift *settlement amount* for *market participant* 'k' for the relevant *energy market billing period* ("$\mathrm{EXP\_EWSCU}_k$") shall be determined as follows:

$$EXP\_EWSCU_k = \sum_K^M (EXP\_EWSC_k^i)\ \mathrm{x}\ \sum_H^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t})$$

Where:

a. $EXP\_EWSC_k^i$ is the mitigation for *economic withholding* on uncompetitive interties *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:

$$RTRDSAU_k = -1\ x \sum_{K}^{M,T} RT\_RDSA_k^m \times \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \,/\, \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right) \right]$$

$$RT\_RDSAU_k = -1\ \times \sum_{K}^{M,T} RT\_RDSA_k^m \times \left[\sum^{M,T} (AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}) \,/\, \sum_{K}^{M,T} \left(AQEW_{k,h}^{m,t} + SQEW_{k,h}^{i,t}\right) \right]$$

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*, recover from *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, 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; and

i. Section 4.12.1.

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.

Note: Existing section 5 – Market Power Mitigation: section 5.1 is being deleted in its entirety and replaced by new section 5 under the same title.

New section 5 has been shown without track changes for ease of review.

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 $DAM\_SNL^{m}_{k,h}$;

e. $EMFC\_RT\_BE^{m}_{k,h}$ shall replace $RT\_BE^{m}_{k,h}$;

f. $EMFC\_RT\_BOR^{m}_{r,k,h}$ shall replace $RT\_BOR^{m}_{r,k,h}$;

g. $EMFC\_RT\_SU^{m}_{k,h}$ shall replace $RT\_SU^{m}_{k,h}$; and

h. $EMFC\_RT\_SNL^{m}_{k,h}$ shall replace $RT\_SNL^{m}_{k,h}$;

i. 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 ~~withdrawing~~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 ~~injecting~~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:

$$DAM\_RLSC_{k,h}^{m} = -1 \times DAM\_QSI_{k,h}^{m} \times (DAM\_LMP_{h}^{m} - DAM\_PLCP_{k,h}^{m}) \times PM\_RLSC_{mcepw}$$

$$DAM\_RLSC_{k,h}^{m} = -1 \times DAM\_QSI_{k,h}^{m} \times (DAM\_LMP_{h}^{m} - DAM\_PLCP_{k,h}^{m}) \cancel{\times PM\_RLSC_{mcepw}}$$

~~Where~~

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 $DAM\_QSI_{k,h}^{m} \leq Q_n$~~; and~~.

~~b. PM_RLSC_{mcepw} is the persistence multiplier for *market control entity for physical withholding* 'mcepw' of the relevant *resource* for the relevant *settlement hour,* determined as the number of *trading days* in which any *resource* associated with the *market control entity for physical withholding* is subject to a *day-ahead market reference level settlement* charge *settlement amount* or a *real-time market reference level settlement* charge *settlement amount* within the last 18 months, up to a maximum of 3.~~

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*; ~~and~~or

~~5.2.1.1.4~~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 ~~injecting~~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:

$$RT\_RLSC_{k,h}^{m} = -1 \times \sum^{T} (RT\_QSI_{k,h}^{m,t} \times (RT\_LMP_{h}^{m,t} - RT\_PLCP_{k,h}^{m}) \times PM\_RLSC_{mcepw})$$

$$RT\_RLSC_{k,h}^{m} = -1 \times \sum^{T} (RT\_QSI_{k,h}^{m,t} \times (RT\_LMP_{h}^{m,t} - RT\_PLCP_{k,h}^{m}) \cancel{\times PM\_RLSC_{mcepw}})$$

~~Where~~

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 $RT\_QSI_{k,h}^{m} \leq Q_n$~~; and~~.

~~b. PM_RLSC_{mcepw} is the persistence multiplier for *market control entity for physical withholding* 'mcepw' of the relevant *resource* for the relevant *settlement hour,* determined as the number of *trading days* in which any *resource* associated with the *market control entity for physical withholding* is subject to a *day-ahead market reference level settlement* charge *settlement amount* or a *real-time market reference*~~

~~*level settlement* charge *settlement amount* within the last 18 months, up to a maximum of 3.~~

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 $RT\_PHCP_{k,h}^{m} >= RT\_LMP_{h}^{m,t}$;

a. Where:

$RT\_PHCP_{k,h}{}^{m}$ is the price component P_n of N-by-2 matrix $(\mathrm{RT\_RLH}_{\mathrm{k,h}}^{\mathrm{m}})$ 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;* ~~and~~or

~~5.3.1.1.4~~ 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 each *trading day* for which the *IESO* issues a second notice of *physical withholding* pursuant to MR Ch.7 s.22.15.~~26~~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 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. $DAM\_PW_{k,h}^{m} = 1.5 \times \left(MWhs\ Failed_{k,h}^{m}\right) \times \left(DAM\_LMP_{k,h}^{m}\right)$

c. $DAM\_PW_{k,h}^{m} = 1.5 \times \left(MWhs\ Failed_{k,h}^{m}\right) \times \left(DAM\_LMP_{\cancel{k,}h}^{m}\right)$

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 ~~*alternate*~~*alternative reference quantity value*, as the case may be, of the *resource* associated with the *offer*.

d. $RT\_PW_{k,h}^{m} = 1.5 \times \sum^{T}\left(MWhs\ Failed_{k,h}^{m,t}\right) \times \left(RT\_LMP_{k,h}^{m,t}\right)$

d. $RT\_PW_{k,h}^{m} = 1.5 \times \sum^{T}\left(MWhs\ Failed_{k,h}^{m,t}\right) \times \left(RT\_LMP_{\cancel{k,}h}^{m,t}\right)$

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

  ~~a.~~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*.

5.4.1.2 The *IESO* shall determine $PW\_OR_{k}^{m}$ as follows:

$$PW\_OR_{k}^{m} = \sum^{H} Max\left(DAM\_PW_{k,h}^{m}, RT\_PW_{k,h}^{m}\right) \times PM\_PW_{mce}$$

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_{mce} is the persistence multiplier applicable to the relevant *trading day* for the *market control entity for physical withholding 'mce'* for the applicable *resource* designated, as determined in accordance with the applicable *market manual*;

c. $DAM\_PW^{m}_{k,h} = 1.5 \times \sum_{R}(MWs\ Failed^{m}_{r,k,h} \times DAM\_PROR^{m}_{r,h})$

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. '$MWs\ Failed^{m}_{r,k,h}$' is the quantity of *class r reserve* (in MWs) for *market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', ~~as~~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

~~a.~~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*.

d. $RT\_PW^{m}_{k,h} = 1.5 \times \sum^{T}_{R}(MWs\ Failed^{m,t}_{r,k,h} \times RT\_PROR^{m,t}_{r,h})$

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

~~a.~~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*.

5.5 Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties

5.5.1 The ex-post mitigation for *economic withholding* on uncompetitive interties *settlement amount* for *energy* and *operating reserve* shall be calculated for each *trading day* for which the *IESO* issues a second notice of *economic withholding* pursuant to MR Ch.7 s.22.19.8*.* The mitigation for *economic withholding* on uncompetitive *interties 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* ("$EXP\_EWSC_k^i$") as follows:

$$EXP\_EWSC_k^i = -1 \text{ x } (EW\_E_k^i + EW\_MWP_k^i + EW\_OR_k^i)$$

Where:

a. $EW\_E_k^i$ is determined in accordance with section 5.5.1.1;

b. $EW\_MWP_k^i$ is determined in accordance with section 5.5.1.2; and

c. $EW\_OR_k^i$ is determined in accordance with section 5.5.1.3.

5.5.1.1 The *IESO* shall determine $EW\_E_k^i$ as follows:

$$EW\_E_k^i = \sum^{H} Max(DAM\_EWUI_{k,h}^i, RT\_EWUI_{k,h}^i)$$

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 the *day-ahead market,* the *real-time market,* or both;

b. $DAM\_EWUI_{k,h}^i = (MWhs\ Failed_{k,h}^i) \times DAM\_LMP_{k,h}^i$

b. $DAM\_EWUI_{k,h}^i = (MWhs\ Failed_{k,h}^i) \times DAM\_LMP_{\cancel{k,}h}^i$

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. '$MWhs\ Failed^{i}_{k,h}$' is the quantity of *energy* (in MWhs) for *market participant* 'k' at *intertie metering point* 'i' for *settlement hour* 'h', ~~as~~

a. if the *IESO* is assessing *intertie economic withholding* in only the *real-time market*, it is deemed to be zero; and

~~a.~~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. $RT\_EWUI^{i}_{k,h} = \sum^{T}\left(MWhs\ Failed^{i,t}_{k,h}\right) \times \left(RT\_LMP^{i,t}_{k,h}\right)$

c. $RT\_EWUI^{i}_{k,h} = \sum^{T}\left(MWhs\ Failed^{i,t}_{k,h}\right) \times \left(RT\_LMP^{i,t}_{\cancel{k,}h}\right)$

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 *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~~

a. if the *IESO* is assessing *intertie economic withholding* in only the *day-ahead market*, it is deemed to be zero; and

~~a.~~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 $EW\_MWP^{i}_{k}$ as follows:

$$EW\_MWP^{i}_{k} = \sum^{H}\left(DAM\_MWP^{i}_{k,h} - IRL\_DAM\_MWP^{i}_{k,h}\right) + \left(RT\_MWP^{i}_{k,h} - IRL\_RT\_MWP^{i}_{k,h}\right) + \left(RT\_IOG^{i}_{k,h} - IRL\_RT\_IOG^{i}_{k,h}\right)$$

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~~

a. if the *IESO* is assessing *intertie economic withholding* in only the *real-time market*, it is deemed to be zero; and

~~a.~~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~~

a. if the *IESO* is assessing *intertie economic withholding* in only the *day-ahead market*, it is deemed to be zero; and

~~a.~~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 six *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 six *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 ~~equal to the aggregate of~~determined in accordance with the following:

6.3.29.1 In regards to amount referred to in section 6.4.2.1, the amount 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 In regards to amount referred to in section 6.4.2.2, the amount 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.8s. 4.16.1 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 ~~or sale~~ 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 ~~or sale~~ 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 c*urrent 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 6.3.27 or 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 participant*s 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:

d. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or

e. 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. MR Ch.3 s.6.3

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:

c. payment default by one or more *market participants* in the *day-ahead market* and *real-time* market; or

d. 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. $TRCAD_L =(\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAR$

ii. $TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAR$

iii. TRCAR = the total dollar value of TR shortfall recovery from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period.*

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.