PUBLIC

Detailed Design

Market Renewal Program: Energy

Day-Ahead Market Calculation Engine

Detailed Design

Issue 2.0

This document provides a detailed overview of the processes related to the Day-Ahead Market Calculation Engine that will be implemented for the Energy work stream of the Market Renewal Program, including related market rules and procedural requirements.

DES-23

Disclaimer

This document provides an overview of the proposed detailed design for the Ontario Market Renewal Program (MRP) and must be read in the context of the related MRP detailed design documents. As such, the narratives included in this document are subject to on-going revision. The posting of this design document is made exclusively for the convenience of *market participants* and other interested parties.

The information contained in this design document and related detailed design documents shall not be relied upon as a basis for any commitment, expectation, interpretation and/or design decision made by any *market participant* or other interested party.

The *market rules*, *market manuals*, *applicable laws*, and other related documents will govern the future market.

Document Change History

Issue	Reason for Issue	Date
1.0	First publication for external stakeholder review.	July 27, 2020
2.0	Second publication after consideration of external stakeholder feedback.	January 28, 2021

Related Documents

Document ID	Document Title
DES-13	MRP High-level Design: Single Schedule Market
DES-14	MRP High-level Design: Day-Ahead Market
DES-15	MRP High-level Design: Enhanced Real-Time Unit Commitment
DES-16	MRP Detailed Design: Overview
DES-17	MRP Detailed Design: Authorization and Participation
DES-18	MRP Detailed Design: Prudential Security
DES-19	MRP Detailed Design: Facility Registration
DES-20	MRP Detailed Design: Revenue Meter Registration
DES-21	MRP Detailed Design: Offers, Bids and Data Inputs
DES-22	MRP Detailed Design: Grid and Market Operations Integration
DES-23	MRP Detailed Design: Day-Ahead Market Calculation Engine
DES-24	MRP Detailed Design: Pre-Dispatch Calculation Engine
DES-25	MRP Detailed Design: Real-Time Calculation Engine
DES-26	MRP Detailed Design: Market Power Mitigation
DES-27	MRP Detailed Design: Publishing and Reporting Market Information
DES-28	MRP Detailed Design: Market Settlement
DES-29	MRP Detailed Design: Market Billing and Funds Administration

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Table of Changes

This detailed design document has been updated since version 1. For more detailed information about these changes, refer to the “MRP Energy Detailed Design - Version 2.0 Updates” document.

1. Introduction

1.1. Purpose

This document is a section of the Market Renewal Program (MRP) detailed design document series specific to the Energy work stream. This document provides the details of the business design and the requirements for *market rules*, market-facing and internal procedures, and the data flow required to support the Day-Ahead Market (DAM) Calculation Engine processes as related to the introduction of the future day-ahead market and the *real-time market*. This design document will aid in the coordinated development of business processes, *market rules* and supporting systems.

As illustrated in Figure 1-, this document is an integral part of the MRP detailed design document series and will provide the design basis for the development of the governing documents and the design documents.

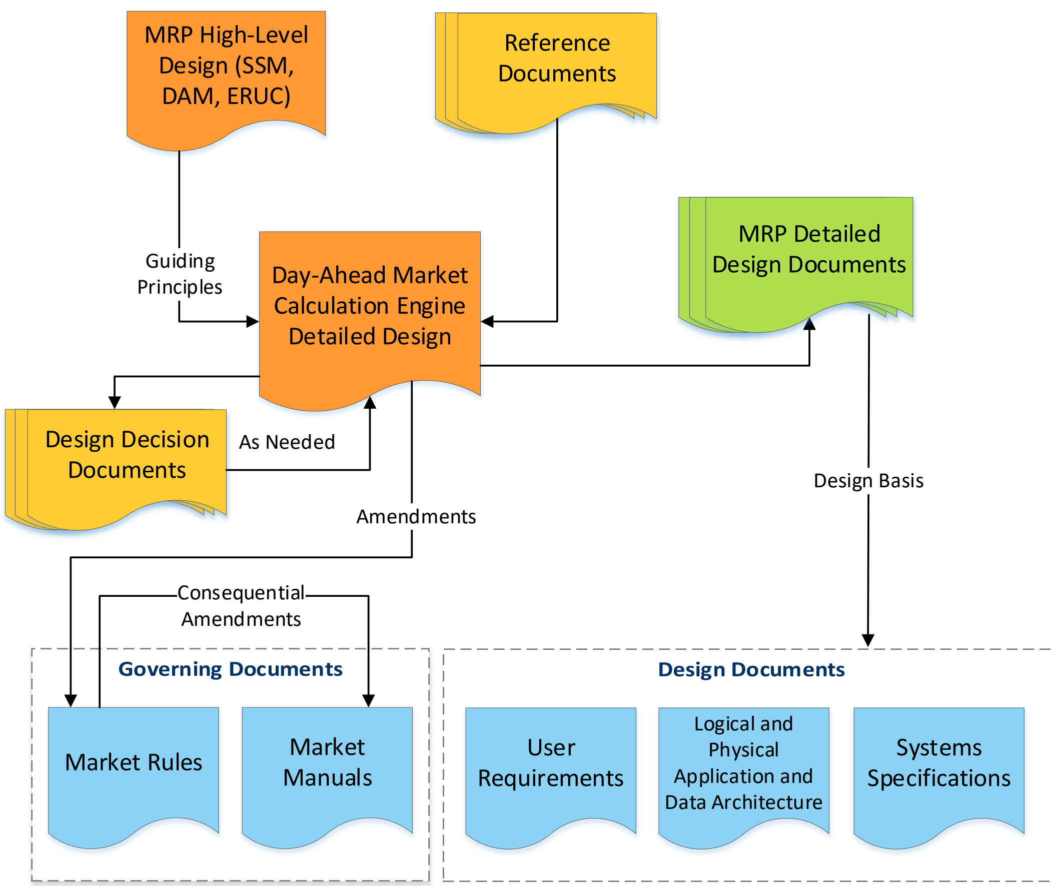

Figure 1-1: Detailed Design Document Relationships

1.2. Scope

This document describes the DAM calculation engine requirements for the future day-ahead market and *real-time market*, in terms of:

- detailed functional design;
- supporting *market rules* requirements;
- supporting procedural requirements; and
- business process and information flow requirements.

Various portions of this document make reference to current business practices, rules, procedures and processes of the DAM calculation engine. However, this document is not meant as a restatement of the existing design of the *Independent Electricity System Operator* (*IESO*) process. Rather this document focuses on existing components only to the extent that they might be used in the current or amended form in support of the future day-ahead market and *real-time market*.

1.3. Who Should Use This Document

This document is a public document for use by the MRP project team, pertinent *IESO* departments and external stakeholders. Portions of this document that are only pertinent to *IESO* internal processes and procedures may not be incorporated into the public version.

1.4. Assumptions and Limitations

Assumptions:

While this document makes references to specific parameters that might be used in the DAM calculation engine, this document does not impart any assumptions as to what the value of those parameters might ultimately be. The setting of such parameters will be a matter of *IESO* policy to be determined at a later date under the amended authority of the *market rules*.

Limitations:

The business process design presented in Sections 2 and Section 6 of this document provides a logical breakdown of the various sub-processes described in the detailed business design presented in Section 3. However, factors such as existing and future system boundaries and system capabilities may alter the ultimate design of these sub-processes.

1.5. Conventions

The standard conventions followed for this document are as follows:

- Title case is used to highlight process or component names; and

- Italics are used to highlight *market rule* terms that are defined in Chapter 11 of the *market rules*.

1.6. Roles and Responsibilities

This document does not set any specific roles or responsibilities. This document is intended to provide the design basis for development of the documentation associated with the *IESO* Project Lifecycle that will be produced in conjunction with the MRP.

1.7. How This Document Is Organized

This document is organized as follows:

- **Section 2** of this document briefly describes the *IESO's* current day-ahead calculation engine and the difference between that engine and the future DAM calculation engine.
- **Section 3** of this document provides a detailed description of the functional design inferred from sections relevant to the DAM calculation engine in the high-level designs for the Single Schedule Market (SSM), the Day-Ahead Market (DAM) and an Enhanced Real-time Unit Commitment (ERUC).
- **Section 4** of this document describes how the DAM calculation engine processes will be enabled under the authority of the *market rules* in terms of existing rule provisions, amended rule provisions and additional rule provisions that will need to be developed.
- **Section 5** of this document describes the requirements of the DAM calculation engine processes for a system of market-facing manuals and internal procedures in terms of existing procedures, amended procedures and additional procedures that will need to be developed.
- **Section 6** of this document provides an overview of the arrangement of *IESO* processes supporting the overall DAM calculation engine processes described in Section 3. This section also outlines the logical boundaries and interfaces of the various sub-processes related to the DAM calculation engine in terms of existing processes, amended processes and additional processes that will need to be developed.

– End of Section –

2. Summary of the Current and Future State

2.1. The Calculation Engine in Today's Day-Ahead Commitment Process

The *IESO* implemented the Day-Ahead Commitment Process (DACP) to address *reliability* issues exacerbated by *energy* imports that failed to materialize in real time and the difficulty in forecasting the next day's available capacity and *energy* supply. The DACP was later enhanced to use a dedicated calculation engine – the Day-Ahead Calculation Engine (DACE). The DACE optimizes *energy* and *operating reserve* schedules to maximize the gains from trade for the 24 hours of the next *dispatch day*.

The DACP provides *reliability* guarantees and incentives that enable:

- a dependable view of the available capacity and *energy* supply and anticipated *demand* for the next *dispatch day*;
- day-ahead scheduling of imports providing more certainty that *energy* will be delivered in real time;
- day-ahead operational commitment of non-quick start (NQS) *generation units* for all hours in which the unit was scheduled to at least its *minimum loading point* by the DACE for the next *dispatch day*; and
- lowered risk associated with day-ahead operational commitment for *generators* and day-ahead scheduling of imports. This is facilitated by providing a day-ahead production cost guarantee (DA-PCG) for commitment costs of eligible *generators* as well as an *intertie offer* guarantee (IOG) that guarantees the *offered* cost for eligible imports. These guarantees protect suppliers against the risk that such costs may not be recovered through *real-time market* revenues.

The DACE is a core component of the DACP and realizes its goals through:

- a *security*-constrained unit commitment that performs a least-cost optimization of *start-up costs*, *speed no-load costs* and *energy* costs through the use of three part *offers* for committable *generation facilities*;
- a *security*-constrained economic *dispatch* for the least-cost optimization of *energy* and *operating reserve;*
- inclusion of imports, exports, and wheeling through transactions; and
- a *pseudo unit* (PSU) model for combined cycle *facilities* to provide improved scheduling of these *generation facilities*.

The DACE receives inputs from *market participants* and the *IESO.* The DACE requires *dispatch data* submitted by dispatchable *generation facilities*, *dispatchable loads* and *hourly demand response resources* that provides a declaration of the maximum capability of these resources for the next *dispatch day*. Schedules and forecasts submitted by *self-scheduling* and *intermittent generation facilities* are also required. NQS *generation units* also submit daily generator data (DGD) and three-part *offers* for each committable generation resource. DGD includes *minimum loading point*, *minimum generation block run time*, and *minimum generation block down-time* values. Three-part *offers* consist of *start-up cost*, *speed no-load cost* and incremental *energy* cost data. *Dispatch data,* if submitted for imports, exports, and wheeling through transactions, is also processed by the DACE.

The DACE produces a set of results in the form of advisory schedules, day-ahead shadow prices and binding operational commitments for DA-PCG eligible NQS *generation units.* The day-ahead shadow prices are advisory and are not used for *settlement*. These results are provided in the form of the following reports:

- Private reports provide the *energy* and *operating reserve* schedules for each hour produced by the DACE for each dispatchable *generation unit*. These schedules are advisory and intended for the use of each *market participant*.
- Private day-ahead commitment reports provide the list of *market participant* resources for which each *generation unit* will be scheduled to at least the unit's *minimum loading point.* These commitments are applied as constraints in subsequent *pre-dispatch schedules* through to the real-time *dispatch hour*.
- Public reports of day-ahead shadow prices for *energy* and *operating reserve* produced at selected nodes within and external to Ontario. These prices are informational and intended for use by *market participants* when planning in the day-ahead. These prices are not used for *settlement*.

The DACE uses the inputs from *market participants* and the *IESO* to execute its three passes. In addition to these inputs, Pass 2 and Pass 3 of the DACE also use the outputs from the previous passes as inputs. Each pass has a specific purpose:

- Pass 1 – the Commitment Pass: determines the initial set of commitments for NQS *generation facilities* and imports required to satisfy the average forecast *demand* for the next day.
- Pass 2 – the Reliability Pass: checks if the resources committed by Pass 1 are sufficient to satisfy the peak forecast *demand*. Pass 2 then commits additional resources if required.
- Pass 3 – the Scheduling Pass: uses the commitments made in Pass 1 and Pass 2 to determine the day-ahead advisory schedules of all dispatchable resources, including NQS *generation facilities*, imports, *quick start generation facilities*, *dispatchable loads,* exports, and *hourly demand response* resources to meet the average forecast *demand*.

The three passes of the DACE are conducted with consideration of resource and system constraints. These constraints include the recognition of each resource's ramping capabilities and system constraints, which include *operating reserve* requirements and transmission limits needed to maintain the *security* of the *IESO-controlled grid*.

Figure 2-1 provides a high-level overview of the current DACP and DACE scheduling and commitment processes.

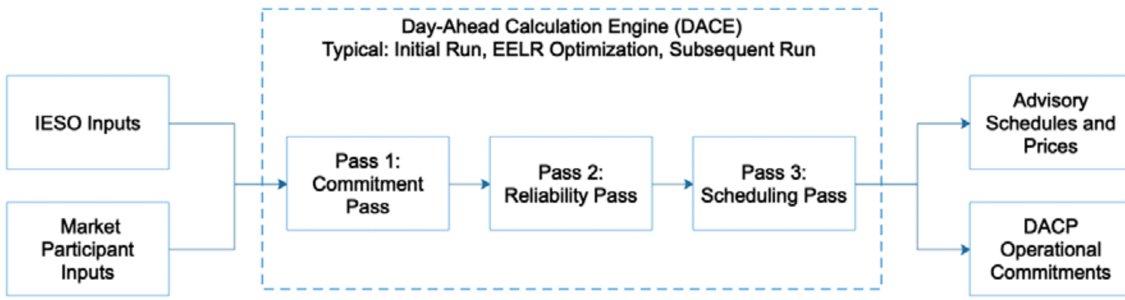

Figure 2-1: Current DACP and DACE Processes

2.1.1. Scheduling of DACE Runs

The DACP normally consists of two runs of the DACE – an initial run and an eligible *energy* limited resources (EELR) run. The EELR optimization run provides the opportunity for *market participants* with eligible hydroelectric resources to assess the results of the initial run to see if the DACE has scheduled the daily *energy* limit for hydroelectric *generation facilities* in an infeasible way. This second run provides for re-submittal of EELR *offers* during an EELR re-submission window (normally from 11:30 to 12:30 EST) to help resolve potential *reliability* problems due to infeasible schedules.

After the initial and EELR optimization runs have completed, a subsequent DACE run may be initiated if changing systems conditions that are known at the end of the EELR optimization run will impact the next *dispatch day.* A subsequent DACE run might also be required if the results of the previous DACE runs show a capacity or *energy* shortfall. This subsequent run will use new or revised *dispatch data* submitted after the close of the DACP submission window (normally 10:00 EST) that has been accepted and approved by the *IESO*.

Figure 2-2 illustrates the timeline for the Day-Ahead Commitment Process and multiple DACE runs.

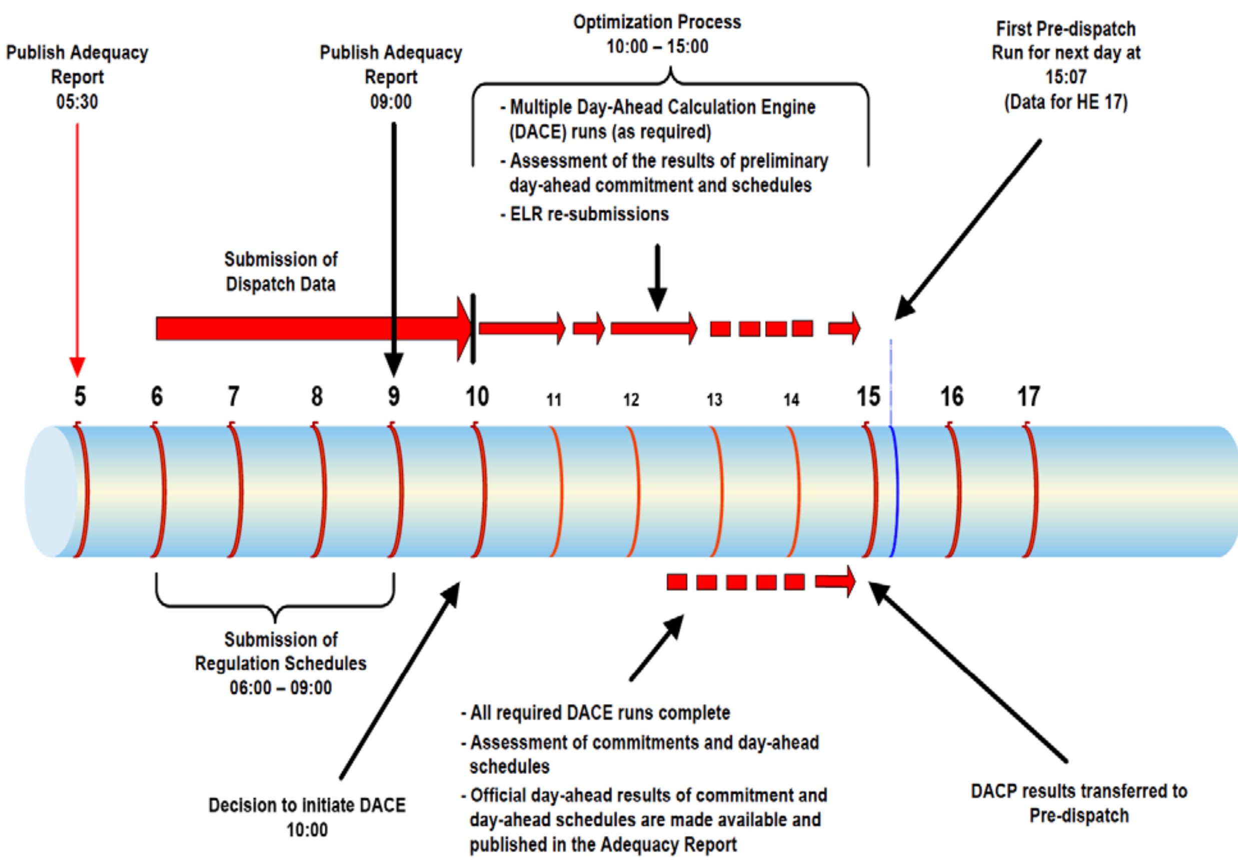

Figure 2-2: Timeline of the Current Day-Ahead Commitment Process

Currently, the DACP provides operational commitments and production cost guarantees for eligible NQS *generation units.* It also provides day-ahead *intertie offer* guarantees (IOGs) to eligible imports. These guarantees help ensure a dependable capacity and *energy* supply to meet the forecast *demand* for the next *dispatch day.* With the exception of the guarantees, the advisory schedules and shadow prices that are outputs of the DACE are not an *energy market* mechanism and are not used for the *settlement* of the *IESO-administered market*.

2.2. The Calculation Engine in the Future Day-Ahead Market

In the future *energy market*, the DAM calculation engine will constitute the core component of the day-ahead market providing both an *energy* and *operating reserve* market and the necessary mechanism for *reliability*. The DACP and the DACE will be retired. The future DAM calculation engine will be similar to the current DACE in overall structure. However, there are some important differences between the two, which are described below.

As with the DACE, the DAM calculation engine will use inputs from *market participants* and the *IESO*. The set of inputs for the DAM calculation engine will include new inputs from *market participants* that recognize additional operational characteristics of *generation facilities*.

Some examples of new inputs include those that can be submitted for hydroelectric resources to specify dependencies between different hydroelectric resources on a cascade river system as well as the minimum level of output to which a hydroelectric resource can be scheduled. For NQS *generation units*, new inputs specifying the number of hours it takes for a resource to reach *minimum loading point* (MLP) and the *energy* injected for each of these hours can be submitted.

The existing data submission constructs of three part *offers* and daily generator data (DGD) will be retired and replaced by the submission of hourly and daily *dispatch data* parameters providing the data submission structure for these new inputs.

New *IESO* data inputs will also be utilized by the DAM calculation engine. Examples of these new data inputs include an enhanced network model providing pricing locations for all *delivery points* associated with dispatchable *generation facilities*, *dispatchable loads*, non-dispatchable *generation facilities*, *non-dispatchable loads* and price responsive loads. New pricing locations will also be established for virtual transaction zonal trading entities. *Demand* forecasts will be produced as the sum of four separate area *demand* forecasts to better reflect localized weather conditions and consumption patterns for each area.

For a detailed description of the changes to the *IESO* and *market participant* inputs, refer to the Offers, Bids and Data Inputs detailed design document.

Consistent with the DACE, the DAM calculation engine will maximize the gains from trade while maintaining the *security* of the *IESO-controlled grid*. The DAM calculation engine will evaluate schedules against the operating *security limits* (OSLs) and thermal ratings of equipment. Instead of the static marginal loss factors currently used by the DACE, the DAM calculation engine will calculate and use dynamic marginal loss factors in each hour for the purposes of determining schedules, commitments and locational marginal prices (LMPs).

Similar to the DACE, the DAM calculation engine will involve three passes and is designed to achieve the same *reliability*-based scheduling outcome as the DACE. Recognizing that the DAM calculation engine is facilitating a financially binding day-ahead market, it will produce LMPs that will be used for *settlement*. When system constraints create the conditions for the potential exercise of market power, the first pass will also include steps that facilitate ex-ante Market Power Mitigation.

The operational commitments produced by the DAM calculation engine for NQS *generation units* will differ from those produced by the DACE. The DAM commitments will be for the *generation unit's* minimum generation block as defined by the *minimum loading point* and the duration of the *minimum generation block run-time* for that *generation unit.*

The DAM calculation engine performs three passes.

2.2.1. Pass 1 – Market Commitment and Market Power Mitigation

This pass will use *market participant* and *IESO* inputs as well as resource and system constraints to determine a set of resource schedules and NQS *generation unit* commitments. These schedules and commitments will be calculated to meet the *IESO's* average hourly forecast *demand* and the *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports.

Pass 1 will assess whether conditions have been met related to transmission congestion that could limit competition. If such conditions exist Pass 1 will perform the tests related to the ex-ante Market Power Mitigation process. The schedules, commitments and prices produced by Pass 1 will be used as inputs into Pass 2.

The following provides a description of the steps that comprise Pass 1.

- As-Offered Scheduling: Determines an initial set of schedules for all *market participants* as well as commitments for eligible NQS resources*.* It uses as-offered *dispatch data* from *market participants, IESO* data inputs and all resource and system constraints to perform a unit commitment and economic *dispatch* that maximizes the gains from trade. The *IESO* data inputs includes the constraint violation penalty curves required to meet the *IESO's reliability* requirements.
- As-Offered Pricing: Determines an initial set of prices that account for all resource and system constraints. It uses the same as-offered *dispatch data* from *market participants* and the set of *IESO* inputs from As-Offered Scheduling with one exception. Instead of the constraint violation penalty curves for *reliability*, As-Offered Pricing uses the constraint violation penalty curves that are relevant for pricing. It also performs an economic *dispatch* to maximize the gains from trade and applies the principle for price-setting eligibility[1] which take into account the resource schedules and commitments determined in As-Offered Scheduling. The prices produced are not used for *settlement*. They are used as inputs to Pass 2 Reliability Scheduling and Commitment, and may be used as inputs to the ex-ante Market Power Mitigation conduct and price impact tests, if necessary.

[1] The marginal price at each location is set by the *offer* or *bid* that is able to supply the next increment of *demand* at that locale. Resources are able to meet that *demand* when they can be scheduled without restriction due to a system constraint or an operational constraint of a resource.

- Constrained Area Conditions Test: The initiation of the ex-ante Market Power Mitigation process is based on specific conditions corresponding to the constrained area to which a resource belongs. When an area is constrained from being supplied by additional resources, competition is reduced and this creates the potential for the exercise of market power. The constrained area conditions test will use the results of As-Offered Pricing to determine if the conduct test of the ex-ante Market Power Mitigation process needs to be initiated. For more information regarding the different types of constrained areas, refer to the Market Power Mitigation detailed design document.
- Conduct Test (if necessary): If conditions related to the restriction of competition are met, the conduct test will determine if financial *dispatch data* parameter values submitted by a *market participant* for a resource differ from its reference levels by more than the relevant conduct threshold. If one or more *dispatch data* parameter values for any resource fails the conduct test, then Reference Level Scheduling and Reference Level Pricing will occur to facilitate the price impact test. If no financial *dispatch data* parameter values fail the conduct test, then no further steps in the ex-ante Market Power Mitigation process are necessary.
- Reference Level Scheduling (if necessary): Uses nearly all of the same inputs and produces the same outputs as As-Offered Scheduling. The exception is that any *dispatch data* parameter value that failed the conduct test will be replaced by the reference level value for that *dispatch data* parameter.
- Reference Level Pricing (if necessary): Uses nearly all of the same inputs and produces the same outputs as As-Offered Pricing. However, there are two differences. One difference is that *dispatch data* parameter values that failed the conduct test will be replaced by the reference level value for that *dispatch data* parameter. The other difference is that the commitments and resource schedules that are inputs to this step will come from Reference Level Scheduling.
- Price Impact Test (if necessary): Compares the prices from As-Offered Pricing to those from Reference Level Pricing. The price impact test is failed if one or more prices in As-Offered Pricing is greater than the corresponding price from Reference Level Pricing by a specified impact threshold. If the price impact test is failed, then Mitigated Scheduling and Mitigated Pricing will occur. If the price impact test does not fail, then no further steps in the Market Power Mitigation process are necessary and the commitments and prices produced by As-Offered Scheduling and As-Offered Pricing will be used as inputs to Pass 2.
- Mitigated Scheduling (if necessary): Uses nearly all of the same inputs and produces the same outputs as As-Offered Scheduling. The exception is that when the price impact test failed, each *dispatch data* parameter value that

also failed the conduct test is substituted with the applicable reference level value for that *dispatch data* parameter.

- Mitigated Pricing (if necessary): Uses nearly all of the same inputs and produces the same outputs as the As-Offered Pricing. However, there are two differences. The first difference is that if the price impact test fails, *dispatch data* parameter values that also failed the conduct test will be replaced by the reference level value for that *dispatch data* parameter. The second difference is that the commitments and resource schedules that are inputs to this step will come from Mitigated Scheduling.
Similar to As-Offered Pricing, the prices produced by Mitigated Pricing are not used for *settlement*. They are used as inputs to Pass 2: Reliability Scheduling and Commitment in lieu of the output of As-Offered Scheduling and As-Offered Pricing.

Either the commitments and prices produced by As-Offered Scheduling and As-Offered Pricing or the commitments and prices produced by Mitigated Scheduling and Mitigated Pricing will be used as inputs to Pass 2.

- If conditions are such that the potential to exercise market power does not exist, the conduct test will not be conducted and the commitments and prices of As-Offered Scheduling and As-Offered Pricing will be used as inputs to Pass 2.
- If the Market Power Mitigation Conduct Test and Price Impact Test fail, the commitments and prices of Mitigated Scheduling and Mitigated Pricing will be used as inputs to Pass 2.

2.2.2. Pass 2 – Reliability Scheduling and Commitment

Similar to Pass 2 of the DACE, Pass 2 of the DAM calculation engine will assess if the NQS *generation units* committed by Pass 1 are sufficient to satisfy the peak forecast *demand*. It does this by utilizing primarily the same set of *market participant* and *IESO* inputs used in As-Offered Scheduling, or if the price impact test fails, the reference level *dispatch data* used in Mitigated Scheduling. However, there are some important differences between the inputs used in Pass 1 and those used by Pass 2. These differences are necessary to make sure that the *IESO* will have adequate supply available to meet peak *demand* in each hour.

The inputs for this pass include the *IESO's* centralized forecasts of supply from variable *generation facilities* and forecasts of *demand* for all *non-dispatchable loads* (including price-responsive loads and no *bid dispatchable loads*[2]) and exclude

[2] In Pass 2, the quantity for no bid *dispatchable loads* will be set to the forecast MW quantity for the *load facility* as described in section 3.13. The DAM calculation engine will not calculate a schedule for a no bid *dispatchable load* in Passes 1 and 3. Comparably, the quantity for a *bid* submitted for a *dispatchable load* at the *maximum market clearing price* will be set to the *bid* quantity in all passes.

virtual *bids* and virtual *offers*. Commitments for NQS resources cannot be revoked or reduced between Pass 1 and Pass 2. Import schedules will not decrease and export schedules will not increase from those produced by Pass 1.

Pass 2 uses the inputs described above to conduct a unit commitment and economic *dispatch*, considering all resource and system constraints, to minimize the cost of additional commitments. To do this, Pass 2 will evaluate whether it can meet peak forecast *demand* and *operating reserve* requirements using *energy* and *operating reserve* from resources that were committed or available to be scheduled in Pass 1. If *demand* cannot be met with the available *energy* and *operating reserve* from the set of available resources from Pass 1, then additional NQS resources may be committed.

All NQS commitments that were input into, or created as a result of Pass 2, along with the schedules of imports and exports, will then be used as inputs into Pass 3.

2.2.3. Pass 3 – Day-Ahead Market Scheduling and Pricing

Pass 3 will use the same set of *market participant* and *IESO* inputs used in Pass 1. It will also use the NQS commitment decisions determined in Pass 1 and Pass 2 to produce a set of financially binding schedules, *settlement*-ready LMPs and operational commitments.

- Day-Ahead Market Scheduling: Determines the financially binding DAM schedules for all supply and load resources. These schedules will include the commitments for NQS *generation units* determined in Pass 1 and Pass 2. Import schedules will not decrease and export schedules will not increase from those determined in Pass 2. Day-Ahead Market Scheduling uses the same set of *market participant* and *IESO* inputs used in As-Offered Scheduling, or if the price impact test had failed, the reference level *dispatch data* used in Mitigated Scheduling. This includes the constraint violation penalty curves for meeting the *IESO's reliability* requirements. Day-Ahead Market Scheduling uses these inputs to perform an economic *dispatch* that maximizes the gains from trade. All resource and system constraints are considered.

  Day-Ahead Market Scheduling will also produce the *energy* scheduled for withdrawal at the *delivery points* for all *non-dispatchable loads*. These schedules will be used for the *settlement* calculation of the forecast deviation price adjustment used for the *settlement* of the adjusted quantity of *energy* withdrawn (AQEW) by *non-dispatchable loads* in real time. Standby notices for *hourly demand response* resources when these *demand* response resources may be needed will also be produced.

- Day-Ahead Market Pricing: Determines a set of *settlement*-ready LMPs that account for all resource and system constraints. Day-Ahead Market Pricing uses the same set of *market participant* and *IESO* inputs used in As-Offered

Pricing, or, if applicable the reference level *dispatch data* used in Mitigated Pricing. This includes using the constraint violation penalty curves that are relevant for pricing. Day-Ahead Market Pricing then performs an economic *dispatch* that maximizes the gains from trade by evaluating these inputs, the commitments from Pass 1 and Pass 2 and certain resource schedules determined by Day-Ahead Market Scheduling, to apply the principle for price-setting eligibility.

The resulting LMPs will be used for the *settlement* of *energy* and *operating reserve markets*. Consistent with the current *real-time market*, the DAM prices for *settlement* of *energy* and *operating reserve* in the future day-ahead market will be no greater than $2,000/MWh and $2,000/MW respectively. *Energy* and *operating reserve* prices will be no less than -$100/MWh and $0/MW respectively. Day-Ahead Market Pricing will use the *settlement*-ready LMPs to produce the DAM Ontario Zonal Price that will be used for the *settlement* of the AQEW by *non-dispatchable loads.* Day-Ahead Market Pricing will also produce the zonal prices for the *settlement* of virtual transactions.

The schedules and LMPs produced by the DAM calculation engine are utilized by the *settlement* process to determine *settlement* outcomes. For more information on how the DAM schedules and DAM LMPs pertain to *settlement* outcomes, refer to the Market Settlement detailed design document.

Finally, the Publishing and Reporting Market Information process will produce a number of public, *market participant* confidential and internal *IESO* reports on the *pre-dispatch day* resulting from the DAM calculation engine. Refer to the Publishing and Reporting Market Information detailed design document for details.

Figure 2-3 provides a high-level overview of the future DAM calculation engine processes. Section 3 and Section 6 of this document describe the various inputs and outputs of each pass in detail.

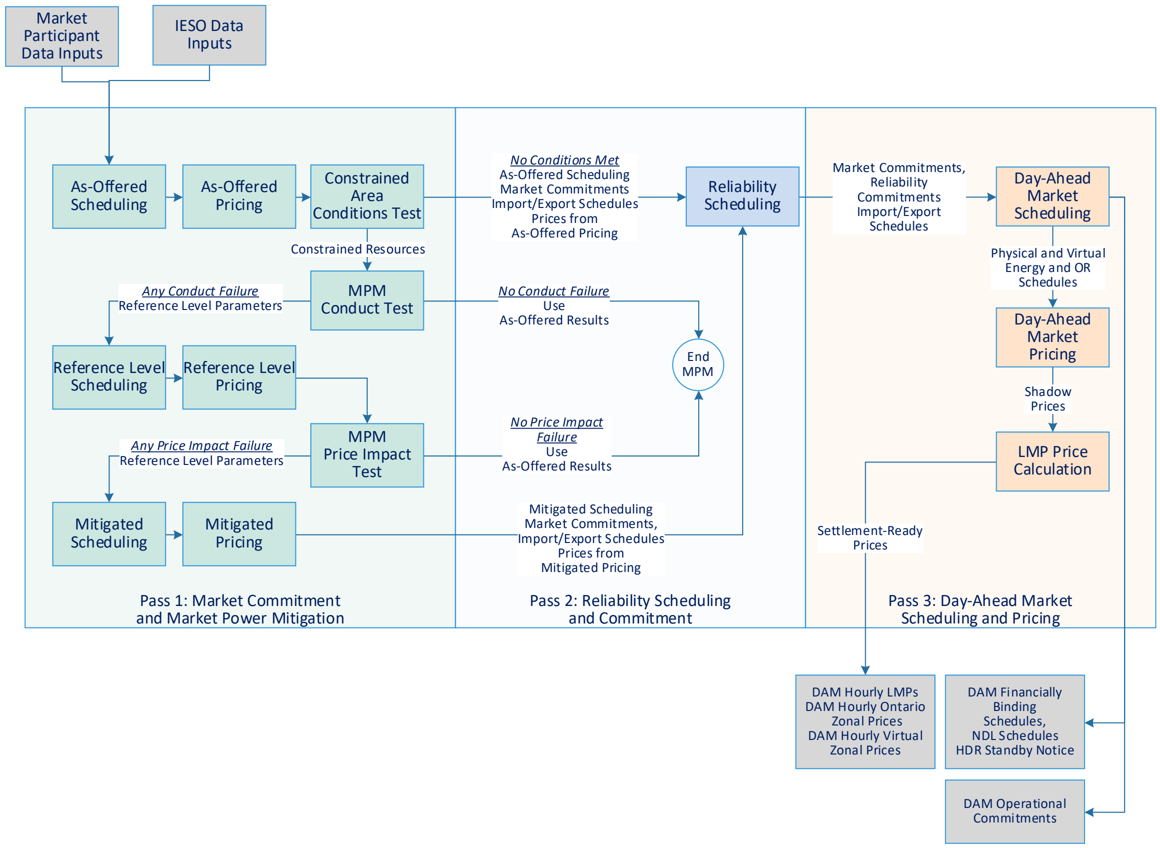

Figure 2-3: Future DAM Calculation Engine Processes

2.2.4. Scheduling of the DAM Calculation Engine Run

The DAM calculation engine execution will be completed in a single run and will occur in eastern prevailing time (EPT). This differs from the multiple runs of the DACE and the scheduling of the DACP in eastern standard time (EST) year-round. The DAM submission window, the DAM calculation engine run, and the *publishing* of the day-ahead *market schedules* and prices will all occur in EPT as standard time and day-light savings time alternate through each year. *Pre-dispatch scheduling* activities and *real-time dispatch* will continue in EST year-round in the future *energy markets*.

Figure 2-4: provides an overview of the day-ahead market scheduling timelines and the relationship to subsequent pre-dispatch activities.

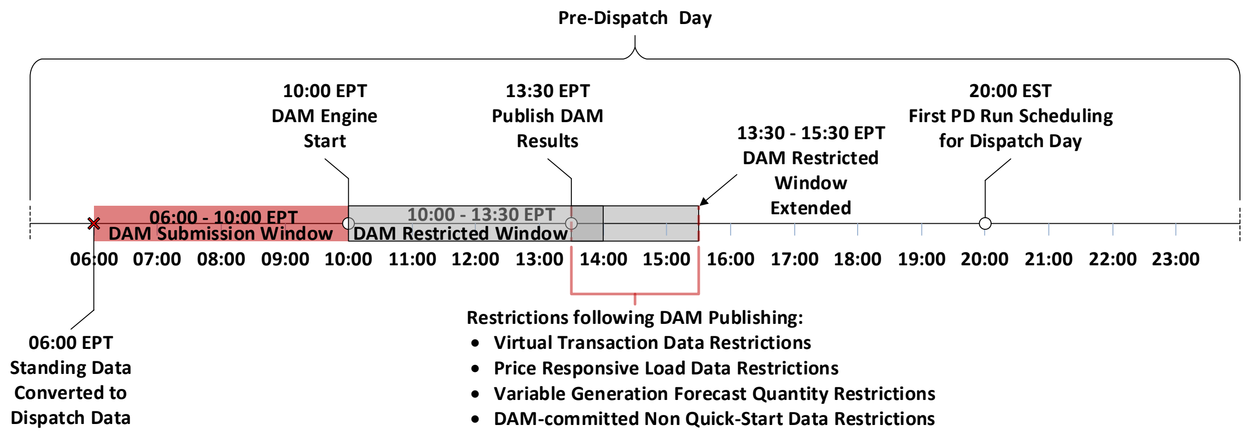

Figure 2-4: Day-Ahead Scheduling Process Timelines

Similar to the DACE, the DAM calculation engine will begin its optimization of input data for its three passes at the close of the DAM submission window. The single run of the DAM calculation engine will occur during the DAM restricted window. Normal *publishing* of DAM schedules, commitments, and prices for the next *dispatch day* will occur at 13:30 EPT. For more information on the timing of the DAM submission window, refer to the Grid and Market Operations Integration detailed design document.

– End of Section –

3. Detailed Functional Design

3.1. Structure of this Section

For the purposes of this document, schedules and prices for a 'resource' refer to schedules and prices for a resource within a *generation* or *dispatchable load facility* for a *registered market participant*.

The design of the DAM calculation engine will be described in terms of:

- Objectives
- DAM Calculation Engine Functions
- Inputs into the DAM Calculation Engine
- Initialization
- Pass 1: Market Commitment and Market Power Mitigation
    - As-Offered Scheduling
    - As-Offered Pricing
    - Constrained Area Conditions Test
    - Conduct Test
    - Reference Level Scheduling
    - Reference Level Pricing
    - Price Impact Test
    - Mitigated Scheduling
    - Mitigated Pricing
- Pass 2: Reliability Scheduling and Commitment
    - Reliability Scheduling
- Pass 3: DAM Scheduling and Pricing
    - DAM Scheduling
    - DAM Pricing
- Security Assessment Function
- Pricing Formulas
- Data Generation for Settlement Mitigation
- The Pseudo-Unit Model
- Determination of the Non-Dispatchable Load Forecast

3.2. Objectives

The objective of this detailed functional design is to define the DAM calculation engine functions in terms of the scheduling and pricing algorithms used to maximize the gains from trade for *energy* and *operating reserve* while providing for the necessary *reliability* and *security* of the *IESO-controlled grid*. This design also defines the DAM calculation engine functions that are required for the ex-ante Market Power Mitigation process.

The high-level designs for MRP identify several objectives for the day-ahead market and the *real-time market*. These objectives, when achieved, will provide the following improvements to the overall *IESO-administered markets*:

- Producing financially binding day-ahead *market schedules* and prices for participating resources. These will provide an improved level of financial and operational certainty to *market participants* and to the *IESO*;
- Providing nodal and zonal prices that are closely aligned to *demand* and system conditions anticipated in real-time. These will provide more accurate pricing signals and result in improved incentives for *market participants* to submit *offers* at marginal cost;
- Encouraging greater participation from imports and exports in the day-ahead timeframe. This will increase the accuracy of day-ahead schedules with respect to expected real-time conditions; and
- Generating outputs that will be used in the commitment process so that day-ahead schedules are accounted for in the pre-dispatch timeframe.

3.3. DAM Calculation Engine Functions

As described in Section 2, the day-ahead market (DAM) will be driven by a DAM calculation engine composed of three passes, each with a distinct role in creating financially binding DAM schedules and LMPs. In Pass 1, a scheduling algorithm will calculate hourly commitment statuses and resource schedules to meet average hourly *demand* while a pricing algorithm will calculate an initial set of hourly LMPs. Pass 2 will perform only the scheduling algorithm to calculate hourly commitment statuses and resource schedules required to meet the peak hourly *demand*. In Pass 3, the scheduling algorithm will fix the hourly commitment statuses to those determined in Pass 1 and Pass 2 and calculate resource schedules while the pricing algorithm will calculate hourly LMPs.

The scheduling algorithm will calculate hourly commitment statuses and resource schedules by performing a *security*-constrained unit commitment and economic *dispatch.* This will be achieved by performing multiple iterations between an optimization function and a *security* assessment function.

The multiple iterations will be carried out as follows:

1. The optimization function will determine commitment status decisions and the optimal economic scheduling of committed resources. To do this, the optimization function will consider inputs from *market participants* and the *IESO*, and also take into account all resource and system constraints.
2. Each time the optimization function determines resource schedules, the *security* assessment function will assess the *security* of the resulting constrained *dispatch* by considering transmission and operating limits. If the *security* assessment function identifies limit violations, an updated *security* constraint set will be provided to the optimization function, and another iteration will be performed.
3. The scheduling algorithm will conclude when the *security* assessment function does not identify any additional *security* limits for the optimization function to enforce.

The commitment statuses determine the eligibility of a resource for economic scheduling within the scheduling algorithm and the corresponding pricing algorithm. For each hour of the next *dispatch day*, the commitment status of a resource will either be “committed” or “not committed”, and the following will apply:

- If the resource is committed, then it will be scheduled to at least its MLP and will be eligible for economic scheduling above its MLP.
- If the resource is not committed, it will not be eligible for economic scheduling. It will receive a zero schedule, unless it is an hour where ramp *energy* to MLP is scheduled.

A non-dispatchable resource or quick-start resource will always be committed in each hour when it has been *offered* because such resources do not have commitment costs and have an MLP of zero. The commitment status of an eligible NQS resource for any given hour will be determined by the scheduling algorithm. For NQS resources, the commitment status from one pass will be considered in determining the commitment status in subsequent passes. The final commitment statuses will be used to derive operational commitments.

The pricing algorithm will primarily use the same set of *market participant* inputs, *IESO* inputs and resource and system constraints as the scheduling algorithm. It will use the commitment statuses and certain resource schedules from the scheduling algorithm to determine LMPs by performing a *security*-constrained economic *dispatch.* Similar to the scheduling algorithm, the pricing algorithm will perform multiple iterations between an optimization function and a *security* assessment function. The pricing algorithm will use the same *security* assessment function that is used in the scheduling algorithm.

However, the optimization function will be modified to:

- enforce the unit commitment statuses determined in the scheduling algorithm;
- use the constraint violation penalty curves for market pricing; and
- allow an *offer* or *bid* lamination to set price in accordance with the price setting eligibility principle, which will be applied after taking the scheduling algorithm results into account.

The DAM calculation engine will use the *security* assessment function in the scheduling and pricing algorithms to perform the following calculations and analyses, and provide inputs to the subsequent optimization function iteration.

1. Base case power flow: A base case (also known as pre-contingency) power flow will be prepared and solved for each hour. The base case solution will use the resource schedules produced by the optimization function along with planned transmission outages, load distribution factors and settings and parameters such as normal breaker/switch statuses, transformer tap positions, and desired voltages associated with the network model.

2. Pre-contingency security assessment: Continuous thermal limits for all monitored equipment and OSLs will be assessed using the base case solution for pre-contingency limit violations. Violated limits will be linearized and incorporated as constraints for use by the subsequent iteration of the optimization function.

3. Loss calculation: The base case solution will be used to calculate the marginal loss factors and loss adjustment that will be used in the *energy* balance constraint of the optimization function.

4. Contingency analysis: A linear power flow will be used to simulate all valid contingencies, calculate post-contingency flows and check for limited-time (i.e. emergency) thermal limit violations. Violated limits will be linearized and incorporated as constraints for use by the subsequent iteration of the optimization function.

Marginal loss factors and sensitivity factors are also required to calculate prices for *energy*.

The inputs to the DAM calculation engine are described in Section 3.4. Section 3.5 describes the initialization processes that the DAM calculation engine will perform before the execution of the three passes. Outputs from a certain pass that are used as inputs in a later pass are specified at the outset of the latter pass's description.

Mathematical formulations of the optimization function for the scheduling algorithm and pricing algorithm, if applicable, of each pass are provided in Section 3.6 through Section 3.8. A description of the *security* assessment function common to the scheduling and pricing algorithms in all passes is provided in Section 3.9.

3.4. Inputs into the DAM Calculation Engine

The DAM calculation engine requires inputs for its different functions. These functions are the optimization function, the ex-ante Market Power Mitigation process and the *security* assessment function. The inputs for each function and their notations are described in the following sections.

For more information on the nomenclature used for the variables and the mathematical symbols used in the notations, refer to Appendix D.

3.4.1. Inputs into the Optimization Function

The optimization function requires:

- *market participant* inputs;
- inputs provided by the *IESO*; and
- the *security* constraint sets, marginal loss factors and loss adjustment provided by the *security* assessment function.

The optimization function for a certain scheduling or pricing algorithm may also require the results of a preceding scheduling or pricing algorithm execution as inputs. In these cases, such inputs will be specified at the outset of the specific optimization function formulation.

3.4.1.1 Fundamental Sets and Location Identifiers

For the purpose of describing the DAM calculation engine processes and the constraints used by these processes, each internal resource whose *bids* and *offers* are considered by the optimization function will be identified by a unique bus, where:

- B shall designate the set of buses within Ontario, corresponding to *bids* and *offers* at locations on the *IESO-controlled grid*.

If more than one internal resource is connected to the *IESO-controlled grid* at the same electrical location, they will be considered to be at separate buses for the purposes of the optimization function.

Imports scheduled from and exports scheduled to each of the *intertie zones* will be modelled in the DAM calculation engine as though they are occurring at a proxy location. Imports shall be modelled as though they are generation emanating from sources at the proxy location, and *exports* shall be modelled as though they are load occurring at sinks at the proxy location. The *IESO* shall define a number of source and sink buses in the *intertie zones* to be used by imports and exports. The electrical location of these source and sink buses will be identical for all *intertie* transactions at the same proxy location. However, transactions at the same proxy location but specified as occurring at different *intertie zones*, subject to phase shifter operation, will be modelled as flowing across independent paths.

Each import *offer* will be identified by a unique *intertie zone* source bus and each export *bid* will be identified by a unique *intertie zone* sink bus, where:

- A shall designate the set of all *intertie zones*;
- D shall designate the set of buses outside Ontario, corresponding to *bids* and *offers* at *intertie zones*;
- $DX \subseteq D$ shall designate the subset of buses outside Ontario that correspond to *bids* to export;
- $DI \subseteq D$ shall designate the subset of buses outside Ontario that correspond to *offers* to import;
- $D_a \subseteq D$ shall designate the set of all buses outside Ontario in *intertie zone* $a \in A$;
- $DX_a \subseteq D_a$ shall designate the subset of buses outside Ontario that correspond to *bids* to export in *intertie zone* $a \in A$; and
- $DI_a \subseteq D_a$ shall designate the subset of buses outside Ontario that correspond to *offers* to import in *intertie zone* $a \in A$.

Virtual transaction *offers* and *bids* for *energy* are made at a specific virtual transaction zonal trading entity, where:

- M shall designate the set of virtual transaction zonal trading entities within Ontario;
- V shall designate the set of virtual transaction *bids* to buy *energy* and virtual transaction *offers* to sell *energy*;
- $VB \subseteq V$ shall designate the set of virtual transaction *bids*;
- $VO \subseteq V$ shall designate the set of virtual transaction *offers;*
- $V_m \subseteq V$ shall designate the set of virtual transaction *bids* and virtual transaction *offers* at virtual transaction zonal trading entity $m \in M$;
- $VB_m \subseteq V_m$ shall designate the set of virtual transaction *bids* at virtual transaction zonal trading entity $m \in M$; and
- $VO_m \subseteq V_m$ shall designate the set of virtual transaction *offers* at virtual transaction zonal trading entity $m \in M$.

Assume B, D and V are pairwise disjoint (i.e. no two sets have any elements in common). The optimization function evaluates *bids* and *offers* for $b \in B \cup D \cup V$.

3.4.1.2 Load Inputs

Load inputs can belong to one of the following categories:

- *Demand* forecasts prepared by the *IESO*;

- *Dispatch data* for price responsive loads;
- *Dispatch data* for *dispatchable loads*;
- *Dispatch data* for *hourly demand response* resources. This includes both physical *hourly demand response* resources for which a *registered wholesale meter* and *delivery point* has been defined, as well as virtual *hourly demand response* resources aggregated within various zones in the *distribution system*;
- Virtual transaction *bids* for *energy;* and
- *Bids* to export *energy*.

Internal load buses of a specific resource type will be denoted as follows:

- $B^{PRL} \subseteq B$ shall designate the set of buses identifying price responsive loads;
- $B^{DL} \subseteq B$ shall designate the set of buses identifying *dispatchable loads*; and
- $B^{HDR} \subseteq B$ shall designate the set of buses identifying *hourly demand response* resources.

Bid for *energy* laminations and *offer* for *operating reserve* laminations at a load bus will be denoted as follows:

- $J_{h,b}^{E}$ shall designate the set of *bid* for *energy* laminations for $b \in B \cup DX \cup VB$ for hour $h \in \{1,..,24\}$;
- $J_{h,b}^{10S}$ shall designate the set of synchronized *ten-minute operating reserve offer* laminations at bus $b \in B \cup DX$ for hour $h \in \{1,..,24\}$;
- $J_{h,b}^{10N}$ shall designate the set of non-synchronized *ten-minute operating reserve offer* laminations at bus $b \in B \cup DX$ for hour $h \in \{1,..,24\}$; and
- $J_{h,b}^{30R}$ shall designate the set of *thirty-minute operating reserve offer* laminations at bus $b \in B \cup DX$ for hour $h \in \{1,..,24\}$; .

Demand Forecasts

The *IESO* shall prepare hourly average *demand* forecasts and hourly peak *demand* forecasts that are representative of transmission losses and forecast consumption of all *load facilities* and *hourly demand response* resources for each of the *IESO's demand* forecast areas[3] and for each *dispatch hour* of the *dispatch day*. Before the optimization function uses these forecasts, they will be adjusted as described in Section 3.13 to arrive at a non-dispatchable *demand* forecast, a quantity that is representative of load that is considered non-dispatchable and is inclusive of losses.

[3] In the future day-ahead market the *IESO* will produce the existing province-wide *demand* forecast as the sum of separate *demand* forecasts for four *demand* forecast areas. For more information on demand forecasts, refer to the Offers, Bids and Data Inputs detailed design document.

The hourly average forecast will be used in Pass 1 and Pass 3 and the hourly peak forecast will be used in Pass 2, where:

- AFL_h shall designate the hourly average non-dispatchable *demand* forecast for hour $h \in \{1,..,24\}$;; and
- PFL_h shall designate the hourly peak non-dispatchable *demand* forecast for hour $h \in \{1,..,24\}$;.

The distribution of forecasted load to load locations within each forecast area for the purposes of *security* analysis is performed within the *security* assessment function. See Section 3.9.1.3 for more detail.

Dispatch Data for Price Responsive Loads

Registered market participants representing price responsive loads may submit a *bid* to consume *energy* with at most 20 *price-quantity pairs* corresponding to 19 laminations. Table 3-1 lists the parameters for *dispatch data* submitted for a price responsive load identified by bus $b \in B^{PRL}$.

Table 3-1: Parameters for Dispatch Data Submitted for Price Responsive Loads

Parameter	Description
$QPRL_{h,b,j}$	shall designate an incremental quantity of *energy* consumption that may be scheduled in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$.
$PPRL_{h,b,j}$	shall designate the *bid* price to consume an incremental quantity of *energy* in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$. The *bid* price indicates the highest price at which the price responsive load is willing to consume the corresponding incremental quantity of *energy*.
$QPRLFIRM_{h,b}$	shall designate the quantity of *energy* that is *bid* at $MMCP$ in hour $h \in \{1,..,24\}$.

Dispatch Data for Dispatchable Loads

Registered market participants representing *dispatchable loads* may submit a *bid* to consume *energy*, *offers* to provide *operating reserve* and affiliated ramp rates. At most 20 *price-quantity pairs* corresponding to 19 laminations may be submitted in the *bid* to consume *energy*. At most five *price-quantity pairs* corresponding to four laminations may be submitted for each class of *operating reserve* the *dispatchable load* is qualified to provide. The non-dispatchable portion of a *dispatchable load*, i.e. the quantity of *energy* that is *bid* at $MMCP$, must always be scheduled.

Table 3-2 lists the parameters for *dispatch data* submitted for a *dispatchable load* identified by bus $b \in B^{DL}$.

Table 3-2: Parameters for Dispatch Data Submitted for Dispatchable Loads

Parameter	Description
$QDL_{h,b,j}$	shall designate an incremental quantity of *energy* consumption that may be scheduled in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^{E}_{h,b}$.
$PDL_{h,b,j}$	shall designate the *bid* price to consume an incremental quantity of *energy* in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^{E}_{h,b}$. The *bid* price indicates the lowest *energy* price at which the *dispatchable load* prefers to forgo *energy* consumption.
$Q10SDL_{h,b,j}$	shall designate the synchronized *ten-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$.
$P10SDL_{h,b,j}$	shall designate the price of being scheduled to provide synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$.
$Q10NDL_{h,b,j}$	shall designate the non-synchronized *ten-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$.
$P10NDL_{h,b,j}$	shall designate the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$.
$Q30RDL_{h,b,j}$	shall designate the *thirty-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$.
$P30RDL_{h,b,j}$	shall designate the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$.
$ORRDL_{b}$	shall designate the *operating reserve* ramp rate in MW per minute for reductions in load consumption.
$URRDL_{b}$	shall designate the maximum rate in MW per minute at which the *dispatchable load* can increase its amount of *energy* consumption.
$DRRDL_{b}$	shall designate the maximum rate in MW per minute at which the *dispatchable load* can decrease its amount of *energy* consumption.
$QDLFIRM_{h,b}$	shall designate the quantity of *energy* that is *bid* at $MMCP$ in hour $h \in \{1,..,24\}$.

As detailed in the Offers, Bids and Data Inputs detailed design document, *registered market participants* representing *dispatchable loads* may submit up to five sets of MW quantity, ramp up rate and ramp down rate values for *energy* for each *dispatch hour*. The DAM calculation engine will evaluate the same *energy* ramp rates for each hour in the *dispatch day*. The *energy* ramp rates used will correspond to the submitted *energy* ramp rates for the first hour in which the *market participant* has submitted an *energy bid*. Similarly, the DAM calculation engine will evaluate the same *operating reserve* ramp rate for each hour in the *dispatch day*.

The DAM calculation engine passes will respect the *energy* ramping constraints determined by the submitted MW quantity (up to five), ramp up rate and ramp down rate value sets. The optimization function formulations provided in this document assume one ramp up rate and one ramp down rate apply across the entire operating range of a *dispatchable load*. For more information, see the *energy* ramping constraints in Section 3.6.1.5.

Dispatch Data for Hourly Demand Response Resources

An *hourly demand response* resource may submit an *energy bid* and affiliated ramp rates. If the resource is an aggregator, its *bid* will be identified with a proxy bus. The electrical location of this proxy bus depends only on the zone in which the *hourly demand response* resource has submitted a *bid*. Table 3-3 lists the parameters for *dispatch data* submitted for an *hourly demand response* resource identified by bus $b \in B^{HDR}$.

Table 3-3: Parameters for Dispatch Data Submitted for Hourly Demand Response Resources

Parameter	Description
$QHDR_{h,b,j}$	shall designate an incremental quantity of reduction in *energy* consumption that may be scheduled in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$.
$PHDR_{h,b,j}$	shall designate the *bid* price to incrementally reduce *energy* consumption in hour $h \in \{1,..,24\}$ in association with *bid* lamination $j \in J^E_{h,b}$. The *bid* price indicates the lowest *energy* price at which the resource prefers to forgo *energy* consumption.
$URRHDR_b$	shall designate the maximum rate in MW per minute at which the *hourly demand response* resource can decrease its amount of *energy* consumption.

Parameter	Description
$DRRHDR_b$	shall designate the maximum rate in MW per minute at which the *hourly demand response* resource can increase its amount of *energy* consumption.

Virtual Transaction Bids for Energy

Each virtual transaction *bid* for *energy* consists of a minimum of two and a maximum of 20 *price-quantity pairs* representing 19 *energy* laminations. Virtual transaction *price-quantity pairs* will allow *market participants* to submit different hourly prices and associated quantities of *energy* they desire to sell or buy at a particular virtual transaction zonal trading entity. This is a new *dispatch data* parameter that is described in further detail in the Offers, Bids and Data Inputs detailed design document.

Table 3-4 lists the parameters for *dispatch data* submitted for a virtual transaction *bid* for *energy* $v \in VB$.

Table 3-4: Parameters for Dispatch Data Submitted for Virtual Bids to Buy

Parameter	Description
$QVB_{h,v,j}$	shall designate a quantity of *energy* that may be scheduled in hour $h \in \{1,...,24\}$ in association with *bid* lamination $j \in J^E_{h,v}$.
$PVB_{h,v,j}$	shall designate the *bid* price for an incremental quantity of *energy* in hour $h \in \{1,...,24\}$ in association with *bid* lamination $j \in J^E_{h,v}$. The *bid* price indicates the highest price at which the virtual transaction is willing to be scheduled.

Bids to Export Energy

Each *bid* to export designates the amount of *energy* that the *registered market participant* wishes to schedule for export at a given price to an *intertie zone* and *boundary entity* proxy location. Except for Quebec, exports to other jurisdictions cannot be scheduled over individual *interties*. Several *intertie zones* are defined for Quebec so that exports may be scheduled over individual *interties* between Quebec and Ontario.

Registered market participants may submit *bids* to export *energy* along with *offers* to provide *operating reserve*. A maximum of 20 *price-quantity pairs* corresponding to 19 laminations may be submitted in a *bid* to export *energy*. A maximum of five *price-quantity pairs* corresponding to four laminations may be submitted for each class of *operating reserve* the exporter is qualified to provide. Table 3-5 lists the parameters for *dispatch data* submitted for a *bid* to export at an *intertie zone* sink bus $d \in DX$.

Table 3-5: Parameters for Dispatch Data Submitted for Export Bids

Parameter	Description
$QXL_{h,d,j}$	shall designate the maximum quantity of *energy* for which the export to bus d in hour $h \in \{1,...,24\}$ may be scheduled in association with *bid* lamination $j \in J^{E}_{h,d}$.
$PXL_{h,d,j}$	shall designate the *bid* price of the exporter at bus d for an incremental quantity of *energy* in hour $h \in \{1,...,24\}$ in association with *bid* lamination $j \in J^{E}_{h,d}$. The *bid* price indicates the highest price at which the exporter is willing to be scheduled.
$Q10NXL_{h,d,j}$	shall designate the non-synchronized *ten-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,...,24\}$ in association with *offer* lamination $j \in J^{10N}_{h,d}$.
$P10NXL_{h,d,j}$	shall designate the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,...,24\}$ in association with *offer* lamination $j \in J^{10N}_{h,d}$.
$Q30RXL_{h,d,j}$	shall designate the *thirty-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,...,24\}$ in association with *offer* lamination $j \in J^{30R}_{h,d}$.
$P30RXL_{h,d,j}$	shall designate the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,...,24\}$ in association with *offer* lamination $j \in J^{30R}_{h,d}$

If an export *bid* lamination's price is equal to the *maximum market clearing price* ($MMCP$), a price of $8 \cdot MMCP$ will be used in the optimization function for the scheduling algorithm and a price of $MMCP$ will be used in the optimization function for the pricing algorithm.

Export Bids in Wheeling Through Transactions

A wheeling through transaction will consist of an individual *bid* to export *energy* to an *intertie zone* and an individual *offer* to import *energy* from another *intertie zone* in the same hour. Both the export *bid* and the import *offer* will be linked using the same North American Electric Reliability Corporation (*NERC*) tag identifiers. The DAM calculation engine will ensure that the export *bid* and import *offer* of the wheeling through transaction receive equal schedules. Wheeling through transactions are not eligible to provide *operating reserve*. For each hour $h \in \{1,...,24\}$:

- $L_h \subseteq DX \times DI$ shall designate the set of linked *intertie zone* sink and source buses corresponding to wheeling through transactions. Here L_h is a set with elements of the form (dx, di) where $dx \in DX$ and $di \in DI$.

3.4.1.3 Supply Inputs

Supply inputs can belong to one of the following categories:

- *Dispatch data* for *self-scheduling generation facilities*, *transitional scheduling generators* and *intermittent generators*, known as non-dispatchable *generation facilities*;
- *Dispatch data* for dispatchable *generation facilities*;
- Virtual transaction *offers* for *energy*; and
- *Offers* to import *energy* and provide *operating reserve*.

Internal supply buses of a specific resource type will be denoted as follows:

- $B^{NDG} \subseteq B$ shall designate the set of buses identifying non-dispatchable generation resources; and
- $B^{DG} \subseteq B$ shall designate the set of buses identifying dispatchable generation resources. Dispatchable generation resources can be further categorized by resource type as described in the Dispatch Data for Dispatchable Generation Facilities sub-section.

Offer for *energy* laminations and *offer* for *operating reserve* laminations at a supply bus will be denoted as follows:

- $K^{E}_{h,b}$ shall designate the set of *offer* for *energy* laminations for $b \in B \cup DI \cup VO$ for hour $h \in \{1,..,24\}$;
- $K^{10S}_{h,b}$ shall designate the set of synchronized *ten-minute operating reserve offer* laminations at bus $b \in B \cup DI$ for hour $h \in \{1,..,24\}$;
- $K^{10N}_{h,b}$ shall designate the set of non-synchronized *ten-minute operating reserve offer* laminations at bus $b \in B \cup DI$ for hour $h \in \{1,..,24\}$; and
- $K^{30R}_{h,b}$ shall designate the set of *thirty-minute operating reserve offer* laminations at bus $b \in B \cup DI$ for hour $h \in \{1,..,24\}$.

Dispatch Data for Non-Dispatchable Generation Facilities

The DAM calculation engine takes into account the forecast output from non-dispatchable generation resources. The *registered market participants* of *self-scheduling generation facilities*, *transitional scheduling generators* and *intermittent generators* will provide *dispatch data* on forecast production and the lowest price at which they wish to be scheduled. The forecast production and price will be treated as an *offer* for *energy* with a single lamination. Table 3-6 lists the parameters for *dispatch data* submitted for a non-dispatchable generation resource identified by bus $b \in B^{NDG}$.

Table 3-6: Parameters for Dispatch Data Submitted for Non-Dispatchable Generation

Parameter	Description
$QNDG_{h,b,k}$	shall designate the incremental quantity of *energy* generation that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,b}$.
$PNDG_{h,b,k}$	shall designate the *offered energy* price for incremental generation in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,b}$. The *offered* price indicates the lowest price at which the non-dispatchable generation resource is willing to be scheduled.

Dispatch Data for Dispatchable Generation Facilities

Registered market participants representing dispatchable *generation facilities* may submit *offers* to supply *energy*, *offers* to provide *operating reserve*, and other affiliated *dispatch data*. A maximum of 20 *price-quantity pairs* corresponding to 19 laminations may be submitted in the *offer* to produce *energy*. A maximum of five *price-quantity pairs* corresponding to four laminations may be submitted for each class of *operating reserve* a resource is qualified to provide. The other *dispatch data* that may be submitted depend on the *facility* type. For example, NQS *generation facilities* may provide an *offered* value of starting a resource, operating that resource at its *minimum loading point,* and increasing output above the *minimum loading point*.

The following inputs are common to all dispatchable *generation facilities*. Table 3-7 lists the parameters for *dispatch data* submitted for a dispatchable generation resource identified by bus $b \in B^{DG}$.

Table 3-7: Parameters for Dispatch Data Submitted for Dispatchable Generation

Parameter	Description
$MinQDG_b$	shall designate the *minimum loading point*, which is the minimum MW output that a resource must maintain to remain stable without the support of ignition and therefore the minimum amount of *energy* the resource must be scheduled to produce in any hour it is committed by the DAM calculation engine
$QDG_{h,b,k}$	shall designate an incremental quantity of *energy* (above and beyond the *minimum loading point*) that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,b}$.

Parameter	Description
$PDG_{h,b,k}$	shall designate the *offered energy* price for incremental generation in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{E}_{h,b}$. The *offered* price indicates the lowest *energy* price at which the resource is willing to be scheduled.
$Q10SDG_{h,b,k}$	shall designate the *offered* quantity of synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10S}_{h,b}$.
$P10SDG_{h,b,k}$	shall designate the *offered* price of being scheduled to provide synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10S}_{h,b}$.
$Q10NDG_{h,b,k}$	shall designate the *offered* quantity of non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10N}_{h,b}$.
$P10NDG_{h,b,k}$	shall designate the *offered* price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{10N}_{h,b}$
$Q30RDG_{h,b,k}$	shall designate the *offered* quantity of *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{30R}_{h,b}$
$P30RDG_{h,b,k}$	shall designate the *offered* price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{30R}_{h,b}$.
$ORRDG_{b}$	shall designate the maximum *operating reserve* ramp rate in MW per minute.
$URRDG_{b}$	shall designate the maximum rate in MW per minute at which the resource can increase the amount of *energy* it supplies (ramp rate up).
$DRRDG_{b}$	shall designate the maximum rate in MW per minute at which the resource can decrease the amount of *energy* it supplies (ramp rate down).
$RLP30R_{h,b}$	shall designate the reserve loading point for *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ indicating the minimum output level at which the resource can provide its full *thirty-minute operating reserve* amount.
$RLP10S_{h,b}$	shall designate the reserve loading point for synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ indicating the

Parameter	Description
	minimum output level at which the resource can provide its full synchronized *ten-minute operating reserve* amount.

As detailed in the Offers, Bids, and Data Inputs detailed design document, *registered market participants* representing dispatchable *generation facilities* may submit up to five sets of MW quantity, ramp up rate and ramp down rate values for *energy* for each *dispatch hour*. The DAM calculation engine will evaluate the same *energy* ramp rates for each hour in the *dispatch day*. The *energy* ramp rates used will correspond to the submitted *energy* ramp rates for the first hour in which the *market participant* has submitted an *energy offer*. Similarly, the DAM calculation engine will evaluate the same *operating reserve* ramp rate for each hour in the *dispatch day*.

The DAM calculation engine passes will respect the *energy* ramping constraints determined by the submitted MW quantity (up to five), ramp up rate and ramp down rate value sets. The optimization function formulations provided in this document assume one ramp up rate and one ramp down rate apply across the entire dispatchable range of a dispatchable generation resource. For more information, see the *energy* ramping constraints in Section 3.6.1.5.

Committed resources, which are scheduled to operate at or above their *minimum loading point*, may be scheduled for all types of *operating reserve*. Uncommitted resources will not be scheduled for any type of *operating reserve*. Quick start resources will have a *minimum loading point* ($MinQDG_b$) of zero. These resources will be considered committed for all 24 hours. See Section 3.3 for more information.

In addition to the above inputs which are common to all dispatchable generation resources, the DAM calculation engine will evaluate additional inputs for the following generation resource types to further enable representation of their operating characteristics:

- NQS resources: start-up offer, minimum generation costs, *minimum generation block run time*, *minimum generation block down time*, *maximum number of starts per day* and ramp up *energy* to MLP profile;
- PSU resources: steam turbine share of MLP region, steam turbine share of dispatchable region, ramp up *energy* to MLP profile for the combustion turbine and steam turbine, indication of whether the PSU can provide *ten-minute operating reserve* while scheduled in its duct firing region;
- Variable generation resources: *variable generation* forecast quantity, *IESO's* centralized *variable generation* forecast;
- *Energy*-limited resources: maximum daily *energy* limit; and

- Hydroelectric resources: *forbidden regions*, minimum daily *energy* limit, minimum hourly output, hourly must run, *maximum number of starts per day*, linked resources, time lag and MWh ratio.

Buses identifying resources of these types will be denoted as follows:

- $B^{NQS} \subseteq B^{DG}$ shall designate the subset of buses identifying NQS resources;
- $B^{PSU} \subseteq B^{NQS}$ shall designate the subset of buses identifying PSU resources;
- $B^{VG} \subseteq B^{DG}$ shall designate the subset of buses identifying *variable generation* resources;
- $B^{ELR} \subseteq B^{DG}$ shall designate the subset of buses identifying *energy*-limited resources; and
- $B^{HE} \subseteq B^{DG}$ shall designate the subset of buses identifying hydroelectric resources.

A resource may belong to more than one of the above sets. For example, a hydroelectric resource may be *energy*-limited.

The following sections provide further detail on the notations that will be used to represent the operational characteristics that are specific to each generation resource type.

NQS Resources

Table 3-8 lists the parameters for *dispatch data* submitted for an NQS resource identified by bus $b \in B^{NQS}$.

Table 3-8: Parameters for Dispatch Data Submitted for NQS Resources

Parameter	Description
$MGODG_{h,b}$	shall designate the *offered* minimum generation cost to operate at *minimum loading point* in hour $h \in \{1,...,24\}$. This parameter is calculated based on the speed no-load offer and *energy* laminations up to the resource's *minimum loading point* submitted by the *market participant*.
$SUDG_{h,b}$	shall designate the start-up offer to start, synchronize and reach MLP in hour $h \in \{1,...,24\}$.
$MGBRTDG_b$	shall designate the *minimum generation block run-time* – the shortest period (in hours) the resource must be scheduled to operate to at least its *minimum loading point* if its *offer* to generate is accepted.
$MGBDTDG_b$	shall designate the *minimum generation block down-time* – the shortest period (in hours) between the end of one hour the resource is scheduled to operate at or above its *minimum loading*

Parameter	Description
	point and the beginning of the next hour the resource is scheduled to operate at or above its *minimum loading point*. The value of this parameter will be equal to the value for MGBDT in the hot thermal state
$MaxStartsDG_b$	shall designate the maximum number of times an NQS resource can be scheduled to start within a *dispatch day*.
$RampHrs_b$	shall designate the number of hours it takes the resource to ramp from 0 to its *minimum loading point*.
$RampE_{b,w}$	shall designate the quantity of *energy* injected w hours before the resource reaches its *minimum loading point* for $w \in \{1,..,RampHrs_b\}$.
$SNL_{h,b}$	shall designate the speed no-load offer, which is the cost required to operate in a synchronized status while injecting no *energy* to the *IESO-controlled grid* in hour $h \in \{1,..,24\}$.
$K_{h,b}^{LTMLP}$	shall designate the set of *energy offer* laminations for quantities up to the *minimum loading point* in hour $h \in \{1,..,24\}$.
$QLTMLP_{h,b,k}$	shall designate an incremental quantity of *energy* generation (up to the *minimum loading point*) that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{LTMLP}$.
$PLTMLP_{h,b,k}$	shall designate the *offered energy* price for incremental generation in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{LTMLP}$.

As described in the Offers, Bids and Data Inputs detailed design document, *the* start-up offer, and ramp up *energy* to MLP inputs will correspond to those for the thermal state selected by the *registered market participant* for the purposes of DAM scheduling.

The minimum generation cost for an NQS resource indicates the cost of operating the resource at its *minimum loading point* in a specific hour. Although this cost is not submitted directly by the *registered market participant*, it can be calculated from the speed no-load offer and *energy* laminations up to the resource's *minimum loading point*. For an NQS resource identified by bus $b \in B^{NQS}$, the minimum generation cost in hour $h \in \{1,..,24\}$ can be calculated as follows:

$$MGODG_{h,b} = SNL_{h,b} + \sum_{k \in K_{h,b}^{LTMLP}} PLTMLP_{h,b,k} \cdot QLTMLP_{h,b,k}.$$

For the purposes of market power mitigation, the component speed no-load and *energy* laminations up to the resource's *minimum loading point* will be compared against their respective reference levels separately. Within the optimization function of the DAM calculation engine, the minimum generation cost as derived from these *offered* parameters will be evaluated as a whole in determining a commitment decision.

PSU Resources

For combined cycle *facilities* that have elected and are eligible to be represented as a *pseudo-unit* resource, additional inputs are required to reflect the physical unit loading as a function of the *pseudo-unit* schedules. For more information, see Section 3.12. Table 3-9 lists the parameters for *dispatch data* submitted for a PSU resource identified by bus $b \in B^{PSU}$.

Table 3-9: Parameters for Dispatch Data Submitted for PSU Resources

Parameter	Description
$K_{h,b}^{DR} \subseteq K_{h,b}^{E}$	shall designate the *energy offer* laminations corresponding to the dispatchable region of the *pseudo-unit* in hour $h \in \{1,..,24\}$.
$K_{h,b}^{DF} \subseteq K_{h,b}^{E}$	shall designate the *energy offer* laminations corresponding to the duct firing region of the *pseudo-unit* in hour $h \in \{1,..,24\}$.
$STShareMLP_b$	shall designate the steam turbine share of the MLP region.
$STShareDR_b$	shall designate the steam turbine share of the dispatchable region.
$RampCT_{b,w}$	shall designate the quantity of *energy* injected w hours before the resource reaches its *minimum loading point* that is attributed to the combustion turbine for $w \in \{1,..,RampHrs_b\}$.
$RampST_{b,w}$	shall designate the quantity of *energy* injected w hours before the resource reaches its *minimum loading point* that is attributed to the steam turbine for $w \in \{1,..,RampHrs_b\}$.

To calculate the loading on a specific steam turbine, the combined cycle *facility* must identify the PSU resources sharing a steam turbine, where:

- PST shall designate the set of steam turbines being *offered* as part of a PSU; and
- $B_p^{ST} \subseteq B^{PSU}$ shall designate the subset of buses identifying PSU resources with a share of steam turbine $p \in PST$.

At the time of registration, a combined cycle *facility* will indicate using a flag that a PSU resource may not provide *ten-minute operating reserve* from its duct firing region, where:

- $B^{NO10DF} \subseteq B^{PSU}$ shall designate the subset of buses identifying a PSU resource that cannot provide *ten-minute operating reserve* from its duct firing region.

Variable Generation Resources

For each *registered facility* supplying *variable generation*, the *IESO* will continue to produce an hourly production forecast for all hours of the next day. This forecast is provided by a *forecasting entity* and is based on meteorological and technical data provided from *variable generation* resources. For each hour of the next day, *variable generation* resources participating in the DAM will have the option of submitting their own forecast or electing the *IESO* forecast as *dispatch data*. The DAM calculation engine will use an alternative *variable generation* forecast that utilizes the *market participant* forecast for the hours with a submitted value and the *IESO's* centralized *variable generation* forecast for the hours a value has not been submitted by the *market participant*. This alternative forecast will be used in Pass 1 and Pass 3. For Pass 2, the *IESO* forecast will be used for all hours as it represents the *IESO's* view of expected *variable generation* output when assessing *reliability*.

For the *variable generation* resource identified by bus $b \in B^{VG}$ and hour $h \in \{1,..,24\}$:

- $FG_{h,b}$ shall designate the *IESO*'s centralized forecast; and
- $AFG_{h,b}$ shall designate the alternative forecast which is either the *market participant*-submitted forecast or the *IESO*'s centralized forecast.

Energy-Limited Resources

Energy-limited resources constitute a subset of generation resources that may be limited in the amount of *energy* they can provide during each *dispatch day*. For the *energy*-limited resource identified by bus $b \in B^{ELR}$:

- $MaxDEL_b$ shall designate the daily limit on the amount of *energy* that the resource may be scheduled to generate over the course of the *dispatch day*. This limit does not apply to a shared hydroelectric resource.

To improve the ability of the DAM calculation engine to find a feasible solution, it will be allowed to violate the *MaxDEL* constraints at a cost. See Section 3.4.1.4 for details.

Hydroelectric Resources

Hydroelectric resources may optionally submit additional *dispatch data* reflecting their operating characteristics. For resources choosing not to submit some or all of these *dispatch data*, the corresponding constraints will not need to be enforced by the DAM calculation engine. Table 3-10 lists the parameters for *dispatch data* submitted for a hydroelectric resource identified by bus $b \in B^{HE}$.

Table 3-10: Parameters for Dispatch Data Submitted for Hydroelectric Resources

Parameter	Description
$MinHMR_{h,b}$	shall designate the hourly must-run value, which is the minimum amount of *energy* that the resource is required to produce in hour $h \in \{1,..,24\}$ to prevent the resource from operating in a manner that, as a dispatch instruction, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*. This minimum amount will be scheduled regardless of whether the resource would be scheduled to operate based on its *offer* price. Hourly must-run is a new hourly *dispatch data* parameter. For more details on this parameter, refer to the Offers, Bids and Data Inputs detailed design document.
$MinHO_{h,b}$	shall designate the minimum hourly output, which is the amount of *energy* that the resource is required to produce in hour $h \in, \{1,..,24\}$, if scheduled to operate, to prevent the resource from operating in a manner that, as a dispatch instruction, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*. Minimum hourly output will be a new hourly *dispatch data* parameter. For more details on this parameter, refer to the Offers, Bids and Data Inputs detailed design document.
$MinDEL_b$	shall designate the minimum amount of *energy* that the resource that is not a shared hydroelectric resource must be scheduled to generate within the *dispatch day* to prevent the resource from operating in a manner that, as a dispatch instruction, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*.
$MaxStartsHE_b$	shall designate the maximum number of times the hydroelectric resource can be scheduled to start within a *dispatch day*.
$StartMW_{b,i}$ for $i \in \{1,..,NStartMW_b\}$	shall designate the MW quantities for measuring unit starts; one unit start is counted between hours h and $(h+1)$ if the schedule increases from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$. Start indication value will be a new optional registration parameter that represents the minimum quantity of *energy* a

Parameter	Description
	resource must be scheduled to determine whether the *generation units* associated with resource have used up one or more of their *maximum number of starts per day*. For more details on this parameter, refer to the Facility Registration detailed design document.
$(ForL_{b,i}, ForU_{b,i})$ for $i \in \{1,..,NFor_b\}$	shall designate the lower and upper limits of the resource's *forbidden regions* indicating that the resource cannot be scheduled strictly between $ForL_{b,i}$ and $ForU_{b,i}$ for all $i \in \{1,..,NFor_b\}$. *Forbidden regions* will be a new daily *dispatch data* parameter used to represent one or more operating ranges, in MW, within which a hydroelectric *generation unit* cannot maintain steady state operation without causing equipment damage. For more details on this parameter, refer to the Offers, Bids and Data Inputs detailed design document.

Market participants may register two or more hydroelectric resources as having a shared daily *energy* limit when these resources are collectively limited in the amount of *energy* they can or must provide during each day. Table 3-11 lists the parameters for *dispatch data* submitted for hydroelectric resources with shared *energy* limit.

Table 3-11: Parameters for Dispatch Data Submitted for Hydroelectric Resources – Shared Energy Limit

Parameter	Description
SHE	shall designate the set indexing the sets of hydroelectric resources with a shared daily *energy* limit. Shared daily *energy* limit will be a new registration parameter that will indicate whether one or more resources registered by the same *market participant* draw water from the same forebay. For more details on this parameter, refer to the Facility Registration detailed design document.
$B_s^{HE} \subseteq B^{HE}$	shall designate the subset of buses identifying hydroelectric resources in set $s \in SHE$.
$MaxSDEL_s$	shall designate the maximum daily *energy* limit shared by all hydroelectric resources in set $s \in SHE$. Maximum daily *energy* limit is an existing parameter that has been enhanced so that *registered market participants* will also be able to submit a single Max DEL value for two or more

Parameter	Description
	dispatchable hydroelectric *generation unit* resource types that are registered as sharing the same forebay. For more details on this parameter, refer to the Offers, Bids and Data Inputs detailed design document.
$MinSDEL_s$	shall designate the minimum amount of *energy* that all hydroelectric resources in set $s \in SHE$ must be collectively scheduled to generate within a *dispatch day* to prevent the resources from operating in a manner that, as a dispatch instruction, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*. Minimum daily *energy* limit will be a new *dispatch data* parameter that represents the minimum amount of *energy*, in MWh, that a set of *generation units* must be scheduled to supply within a *dispatch day.* For more details on this parameter, refer to the Offers, Bids and Data Inputs detailed design document.

Multiple hydroelectric resources owned by the same *registered market participant* and located on a cascade river system may provide linkage inputs. These inputs are used to represent physical operating characteristics where *energy* produced by one or more upstream resources requires a proportional amount of *energy* to be produced by one or more downstream resources after a period of time to prevent the downstream resource from operating in a manner that, as a dispatch instruction, reasonably could be expected to endanger the safety of any person, damage equipment or violate any *applicable law*.

To calculate the *energy* produced by linked hydroelectric resources, the upstream and downstream resources located on cascade river systems must be identified, where:

- $\wp(B^{HE})$ shall designate the power set (the set of all subsets) of the set B^{HE}.
- $B^{HE}_{up} \subseteq \wp(B^{HE})$ shall designate the set of buses identifying all hydroelectric resources on the upstream of cascade river systems.
- $B^{HE}_{dn} \subseteq \wp(B^{HE})$ shall designate the set of buses identifying all hydroelectric resources on the downstream of cascade river systems.

Linked resources, time lag and MWh ratio will be three new daily *dispatch data* parameters used to represent the *energy* production and time lag relationship between generation resources on a hydroelectric cascade river system. For more information on this parameter, refer to the Offer, Bids and Data Inputs detailed design document. Table 3-12 lists the parameters for *dispatch data* submitted for linked hydroelectric resources.

Table 3-12: Parameters for Dispatch Data Submitted for Linked Hydroelectric Resources

Parameter	Description
$LNK \subseteq \wp(B^{HE}) \times \wp(B^{HE})$	shall designate the set of linked hydroelectric resources. Here LNK is a set with elements of the form (b_1, b_2) where $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$.
$Lag_{b_1,b_2} \in \{0,..,23\}$	shall designate the time lag in hours between upstream hydroelectric resources $b_1 \in B_{up}^{HE}$ and downstream hydroelectric resources $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK$.
$MWhRatio_{b_1,b_2}$	shall designate the MWh ratio between upstream hydroelectric resources $b_1 \in B_{up}^{HE}$ and downstream hydroelectric resources $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK$. For every MWh scheduled at buses b_1 in a given hour, $MWhRatio_{b_1,b_2}$ must be scheduled at buses b_2 exactly Lag_{b_1,b_2} hours later.

To improve the ability of the DAM calculation engine to find a feasible solution, it will be allowed to violate certain hydroelectric constraints at a cost. See Section 3.4.1.4 for details.

Virtual Transaction Offers for Energy

Each virtual transaction *offer* for *energy* consists of a minimum of two and maximum of 20 *price-quantity pairs* representing 19 *energy* laminations. Virtual transaction *price-quantity pairs* will allow *market participants* to submit different hourly prices and associated quantities of *energy* they desire to sell or buy at a particular virtual transaction zonal trading entity. This is a new *dispatch data* parameter that is described in further detail in the Offers, Bids and Data Inputs detailed design document.

Table 3-13 lists the parameters for *dispatch data* submitted for a virtual transaction *offer* for *energy* $v \in VO$.

Table 3-13: Parameters for Dispatch Data Submitted for Virtual Offer to Sell

Parameter	Description
$QVO_{h,v,k}$	shall designate a quantity of *energy* that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,v}^{E}$.

Parameter	Description
$PVO_{h,v,k}$	shall designate the *offered* price for an incremental quantity of *energy* in hour $h \in \{1,...,24\}$ in association with *offer* lamination $k \in K^{E}_{h,v}$. The *offered* price indicates the lowest price at which the virtual transaction is willing to be scheduled.

Offers to Import Energy

Each *offer* to import designates the amount of *energy* that the *registered market participant* is willing to schedule at a given price for an *intertie zone* and *boundary entity* proxy location. Except for Quebec, imports to other jurisdictions cannot be scheduled over individual *interties*. Several *intertie zones* are defined for Quebec so that imports may be scheduled over individual *interties* between Quebec and Ontario.

Market participants may submit *offers* to import *energy* along with *offers* to provide *operating reserve*. A maximum of 20 *price-quantity pairs* corresponding to 19 laminations may be submitted in the *offer* to import *energy*. A maximum of five *price-quantity pairs* corresponding to four laminations may be submitted for each class of *operating reserve* the importer is qualified to provide. Table 3-14 lists the parameters for *dispatch data* submitted for an *intertie zone* source bus $d \in DI$.

Table 3-14: Parameters for Dispatch Data Submitted for Import Offers

Parameter	Description
$QIG_{h,d,k}$	shall designate the maximum quantity of *energy* for which an import from bus d in hour $h \in \{1,...,24\}$ may be scheduled in association with *offer* lamination $k \in K^{E}_{h,d}$.
$PIG_{h,d,k}$	shall designate the *offered* price of the importer at bus d for an incremental quantity of *energy* in hour $h \in \{1,...,24\}$ in association with *offer* lamination $k \in K^{E}_{h,d}$. The *offered* price indicates the lowest price at which the importer is willing to be scheduled.
$Q10NIG_{h,d,k}$	shall designate the non-synchronized *ten-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,...,24\}$ in association with *offer* lamination $k \in K^{10N}_{h,d}$.
$P10NIG_{h,d,k}$	shall designate the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,...,24\}$ in association with *offer* lamination $k \in K^{10N}_{h,d}$.
$Q30RIG_{h,d,k}$	shall designate the *thirty-minute operating reserve* quantity that may be scheduled in hour $h \in \{1,...,24\}$ in association with *offer* lamination $k \in K^{30R}_{h,d}$.

Parameter	Description
$P30RIG_{h,d,k}$	shall designate the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K^{30R}_{h,d}$.

Import Offers in Wheeling Through Transactions

As mentioned in Section 3.4.1.2, wheeling through transactions will consist of an individual *bid* to export *energy* to an *intertie zone* and an individual *offer* to import *energy* from another *intertie zone* in the same hour. Both the export *bid* and the import *offer* will be linked using the same NERC tag identifiers. The DAM calculation engine will ensure that the export *bid* and the import *offer* of the wheeling through transaction receive equal schedules. Wheeling through transactions are not eligible to provide *operating reserve*. For each hour $h \in \{1,..,24\}$:

- $L_h \subseteq DX \times DI$ shall designate the set of linked *intertie zone* sink and source buses corresponding to wheeling through transactions. Here L_h is a set with elements of the form (dx, di) where $dx \in DX$ and $di \in DI$.

3.4.1.4 Additional IESO Data Inputs

This section describes the additional inputs that the *IESO* will provide to the DAM calculation engine to enable system *reliability* when a solution is determined.

Operating Reserve Requirements

The *IESO* will input minimum *operating reserve* requirements for each hour. *Operating reserve* requirements will include minimum requirements for the total amount of synchronized *ten-minute operating reserve*, the total amount of *ten-minute operating reserve* and the total amount of *thirty-minute operating reserve*. For each hour $h \in \{1,..,24\}$:

- $TOT10S_h$ shall designate the synchronized *ten-minute operating reserve* requirement;
- $TOT10R_h$ shall designate the *ten-minute operating reserve* requirement; and
- $TOT30R_h$ shall designate the *thirty-minute operating reserve* requirement, which may also include an increase to account for the flexibility *operating reserve* requirement.

In addition, the *IESO* will define a number of regions within Ontario that will have their own regional *operating reserve* minimum requirements and maximum restrictions. Each region shall consist of a set of buses at which *operating reserve* scheduled may be used to satisfy the minimum requirement for that region and is limited by the maximum restriction for that region, where:

- $ORREG$ shall designate the set of regions for which regional *operating reserve* limits have been defined;
- $B_r^{REG} \subseteq B$ shall designate the set of internal buses in *operating reserve* region $r \in ORREG$;
- $D_r^{REG} \subseteq D$ shall designate the set of *intertie zone* buses in *operating reserve* region $r \in ORREG$;
- $REGMin10R_{h,r}$ shall designate the minimum requirement for total *ten-minute operating reserve* in region $r \in ORREG$ in hour $h \in \{1,..,24\}$[4];
- $REGMin30R_{h,r}$ shall designate the minimum requirement for *thirty-minute operating reserve* in region $r \in ORREG$ in hour $h \in \{1,..,24\}$[5];
- $REGMax10R_{h,r}$ shall designate the maximum amount of total *ten-minute operating reserve* that may be provided in region $r \in ORREG$ in hour $h \in \{1,..,24\}$; and
- $REGMax30R_{h,r}$ shall designate the maximum amount of *thirty-minute operating reserve* that may be provided in region $r \in ORREG$ in hour $h \in \{1,..,24\}$.

Intertie Limits

The *IESO* will establish *intertie* limits based on its assessment of the amount of *energy* and *operating reserve* that can be imported into Ontario, or the amount of *energy* that can be exported from Ontario during the upcoming day. These limits will belong to one of the following two categories:

- Flow limits:
- Import limit: Limits on the sum of the total net scheduled inflow of *energy* (imports minus exports) into Ontario from one or more *intertie zones* and scheduled *operating reserve* from one or more *intertie zones* in each hour.
  - Export limit: Limits on the total net scheduled outflow of *energy* (exports minus imports) from Ontario into one or more *intertie zones* in each hour.
  - Net interchange scheduling limit (NISL): Limit on the change in total scheduled *energy* flows over all the *interties* between Ontario and the *intertie* zones from hour-to-hour.

Flow Limits

The *IESO* will define flow limit constraints by specifying the flow limit, the *intertie* zones contributing to the constraint and the contribution of each *intertie* zone to

[4] These minimum limits could be set at zero.

[5] These minimum limits could be set at zero.

the constraint. Let Z_{Sch} contain all the import and export flow constraints that the *IESO* has defined. For each such constraint $z \in Z_{Sch}$:

- $EnCoeff_{a,z}$ shall designate the coefficient for calculating the contribution of scheduled *energy* flows and *operating reserve* inflows for *intertie* zone $a \in A$. A coefficient of $+1$ will describe flows into Ontario while a coefficient of -1 will describe flows out of Ontario; and
- $MaxExtSch_{h,z}$ shall designate the maximum flow limit in hour $h \in \{1,..,24\}$.

Net Interchange Scheduling Limits

The net interchange scheduling limit constraint limits time-step to time-step changes in net interchange. For $h \in \{1,..,24\}$:

- $ExtDSC_h$ shall designate the maximum decrease in net flows over all *interties* from hour $(h\text{-}1)$ to hour h; and
- $ExtUSC_h$ shall designate the maximum increase in net flows over all *interties* from hour $(h\text{-}1)$ to hour h.

Hour-to-hour increases in net interchange from all the *intertie zones* should not exceed $ExtUSC_h$, and hour-to-hour decreases in net interchange from all *intertie zones* should not exceed $ExtDSC_h$.

Resource Minimum and Maximum Constraints

Dispatchable Load

The minimum and maximum consumption of a *dispatchable load* may be limited for the following reasons:

- Reliability constraints: a constraint imposed as a result of a control action may limit the minimum or maximum consumption of a *dispatchable load*.

The DAM calculation engine will accordingly enforce minimum and maximum constraints on the consumption of a *dispatchable load*. For hour $h \in \{1,..,24\}$:

- $MinDL_{h,b}$ shall designate the most restrictive of the above minimum consumption limits for the *dispatchable load* at bus $b \in B^{DL}$; and
- $MaxDL_{h,b}$ shall designate the most restrictive of the above maximum consumption limits for the *dispatchable load* at bus $b \in B^{DL}$.

Non-Dispatchable and Dispatchable Generation Resources

The minimum and maximum output of an internal generation resource may be limited for the following reasons:

- *Reliability* constraints: The *IESO* will identify resources that must operate for *reliability* purposes. The *IESO* may, as required, place minimum or maximum constraints on these resources to support *reliability must-run contracts*, *reactive support service* contracts or other *reliability* needs, to enable the reliable operation of the system.

- *Regulation*: The *IESO* will continue to enter into contracts with certain dispatchable *generation facilities* to provide *regulation*. Such *generation facilities* must submit DAM *offers.* Resources providing *automatic generation control* (*AGC*) will be flagged as must-commit in all hours in which they are designated as *AGC* providers. A resource providing AGC will be scheduled to at least the more restrictive of its minimum AGC limit and its *minimum loading point* plus the designated AGC range. It will be scheduled to at most the more restrictive of its maximum AGC limit and its maximum *offered energy* quantity minus the designated AGC range. *Generation facilities* nominated to provide *AGC* are not allowed to *offer operating reserve* into the DAM.
- Outages and De-ratings: *Outages* or de-ratings from the *IESO's* Outage Coordination and Scheduling System (OCSS) limit a generation resource's maximum output.

The DAM calculation engine will accordingly enforce minimum and maximum constraints on the output of an internal generation resource. For hour $h \in \{1,..,24\}$:

- $MinNDG_{h,b}$ shall designate the most restrictive of the above minimum output limits for the non-dispatchable generation resource at bus $b \in B^{NDG}$;
- $MaxNDG_{h,b}$ shall designate the most restrictive of the above maximum output limits for the non-dispatchable generation resource at bus $b \in B^{NDG}$;
- $MinDG_{h,b}$ shall designate the most restrictive of the above minimum output limits for the dispatchable generation resource at bus $b \in B^{DG}$; and
- $MaxDG_{h,b}$ shall designate the most restrictive of the above maximum output limits for the dispatchable generation resource at bus $b \in B^{DG}$.

PSU Resources

Within the optimization function of the DAM calculation engine, most minimum and maximum limits on the output of a PSU resource will be enforced in the same way minimum and maximum limits on the output of other dispatchable generation resources are enforced. However, the minimum and maximum limits may be inputs to the DAM calculation engine on a physical unit basis and then converted to a constraint on the corresponding PSU resources before the execution of the DAM calculation engine passes. Such minimum and maximum limits for the PSU resource at bus $b \in B^{PSU}$ for hours $h \in \{1,..,24\}$ will be represented by $MinDG_{h,b}$ and $MaxDG_{h,b}$ as described above. The logic to perform the conversion of physical unit limitations to PSU limitations is described in Section 3.12.3

Special logic will apply when a de-rate is submitted on the combustion turbine. To model this logic, the dispatchable and duct firing capacity of the PSU resource will be calculated as described in Section 3.12.2. For hour $h \in \{1,..,24\}$ and for the PSU resource at bus $b \in B^{PSU}$:

- $MaxMLP_{h,b}$ shall designate the maximum output limit in hour h for the MLP region;
- $MaxDR_{h,b}$ shall designate the maximum output limit in hour h for the dispatchable region; and
- $MaxDF_{h,b}$ shall designate the maximum output limit in hour h for the duct firing region.

Inadvertent Payback

The *intertie* transactions that correspond to inadvertent payback transactions will be identified and such transactions must receive a schedule equal to the specified quantity. For hour $h \in \{1,..24\}$:

- $DX_h^{INP} \subseteq DX$ shall designate the *intertie zone* sink buses corresponding to inadvertent payback transactions for hour h; and
- $DI_h^{INP} \subseteq DI$ shall designate the *intertie zone* source buses corresponding to inadvertent payback transactions for hour h.

Constraint Violation Penalties

In some situations, the DAM calculation engine might be unable to resolve all system constraints. For example, the DAM calculation engine would fail to produce a solution when insufficient generation is *offered* to meet the forecast *demand* unless the engine is permitted to serve only a portion of the forecast *demand*. To ensure the DAM calculation engine can always find a feasible solution, it will be allowed to violate certain system constraints at a cost.[6] This will be achieved via constraint violation penalty curves which establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints. The constraint violation penalty curves used by the scheduling algorithm to produce constrained schedules may differ from the constraint violation penalty curves used by the pricing algorithm to calculate *market prices* in order to produce *settlement*-ready prices.

The constraints described below will include constraint violation variables with affiliated penalty price terms appearing in the objective function. The number of violation variables required for the scheduling algorithm and pricing algorithm may differ depending on the number of segments in the applicable constraint violation penalty curve. For notational purposes, the scheduling and pricing penalty curves for each constraint will be assumed to have the same number of segments and any

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[6] Under such conditions, system *reliability* will be maintained by *IESO* control actions.

segments that are not required will be assigned a quantity of zero. The notation for the affiliated prices and quantities is described below.

The *energy* balance constraint may be violated for both reasons of under generation and over generation.

For hour $h \in \{1,..,24\}$:

- $(PLdViolSch_{h,i}, QLdViolSch_{h,i})$ for $i \in \{1,..,N_{LdViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under generation used for scheduling to meet the *IESO*'s *reliability* requirements;
- $(PLdViolPrc_{h,i}, QLdViolPrc_{h,i})$ for $i \in \{1,..,N_{LdViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under generation used for calculating *market prices*;
- $(PGenViolSch_{h,i}, QGenViolSch_{h,i})$ for $i \in \{1,..,N_{GenViol_h}\}$ shall designate the price-quantity segments of the penalty curve for over generation used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(PGenViolPrc_{h,i}, QGenViolPrc_{h,i})$ for $i \in \{1,..,N_{GenViol_h}\}$ shall designate the price-quantity segments of the penalty curve for over generation used for calculating *market prices*.

The synchronized *ten-minute operating reserve* constraint may be violated to allow a shortfall. For hour $h \in \{1,..,24\}$:

- $(P10SViolSch_{h,i}, Q10SViolSch_{h,i})$ for $i \in \{1,..,N_{10SViol_h}\}$ shall designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(P10SViolPrc_{h,i}, Q10SViolPrc_{h,i})$ for $i \in \{1,..,N_{10SViol_h}\}$ shall designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used for calculating *market prices*.

The total *ten-minute operating reserve* constraint may be violated to allow a shortfall. For hour $h \in \{1,..,24\}$:

- $(P10RViolSch_{h,i}, Q10RViolSch_{h,i})$ for $i \in \{1,..,N_{10RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(P10RViolPrc_{h,i}, Q10RViolPrc_{h,i})$ for $i \in \{1,..,N_{10RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used for calculating *market prices*.

The *thirty-minute operating reserve* constraint may be violated to allow a shortfall. For hour $h \in \{1,..,24\}$:

- $(P30RViolSch_{h,i}, Q30RViolSch_{h,i})$ for $i \in \{1,..,N_{30RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(P30RViolPrc_{h,i}, Q30RViolPrc_{h,i})$ for $i \in \{1,..,N_{30RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used for calculating *market prices*.

Area minimum and maximum *operating reserve* requirements may be violated. For hour $h \in \{1,..,24\}$:

- $(PREG10RViolSch_{h,i}, QREG10RViolSch_{h,i})$ for $i \in \{1,..,N_{REG10RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used for scheduling to meet the *IESO*'s *reliability* requirements;
- $(PREG10RViolPrc_{h,i}, QREG10RViolPrc_{h,i})$ for $i \in \{1,..,N_{REG10RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used for calculating *market prices*;
- $(PREG30RViolSch_{h,i}, QREG30RViolSch_{h,i})$ for $i \in \{1,..,N_{REG30RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used for scheduling to meet the *IESO*'s *reliability* requirements;
- $(PREG30RViolPrc_{h,i}, QREG30RViolPrc_{h,i})$ for $i \in \{1,..,N_{REG30RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used for calculating *market prices*;
- $(PXREG10RViolSch_{h,i}, QXREG10RViolSch_{h,i})$ for $i \in \{1,..,N_{XREG10RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used for scheduling to meet the *IESO*'s *reliability* requirements;
- $(PXREG10RViolPrc_{h,i}, QXREG10RViolPrc_{h,i})$ for $i \in \{1,..,N_{XREG10RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used for calculating *market prices*;
- $(PXREG30RViolSch_{h,i}, QXREG30RViolSch_{h,i})$ for $i \in \{1,..,N_{XREG30RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(PXREG30RViolPrc_{h,i}, QXREG30RViolPrc_{h,i})$ for $i \in \{1,..,N_{XREG30RViol_h}\}$ shall designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used for calculating *market prices*.

Pre-contingency and post-contingency internal transmission limits may be violated. As described in Section 3.4.3, transmission constraints may be identified for any *facility* (or group of *facilities*) within Ontario. The set of *facilities* (or groups of *facilities*) for which transmission constraints may be identified shall be designated by F. For hour $h \in \{1,..,24\}$:

- $(PPreITLViolSch_{f,h,i}, QPreITLViolSch_{f,h,i})$ for $i \in \{1,..,N_{PreITLViol_{f,h}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used for scheduling to meet the *IESO*'s *reliability* requirements;

- $(PPreITLViolPrc_{f,h,i}, QPreITLViolPrc_{f,h,i})$ for $i \in \{1,..,N_{PreITLViol_{f,h}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used for calculating *market prices*. As described in the Offers, Bids and Data Inputs detailed design document, the quantity will be based on a percentage of the applicable transmission *security limit*. As the percentage and limit do not depend on the optimization function decisions, the quantity can be precomputed and treated as fixed within the DAM calculation engine optimization function;

- $(PITLViolSch_{c,f,h,i}, QITLViolSch_{c,f,h,i})$ for $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used for scheduling to meet the *IESO*'s *reliability* requirements; and

- $(PITLViolPrc_{c,f,h,i}, QITLViolPrc_{c,f,h,i})$ for $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used for calculating *market prices*. Similar to pre-contingency limits, the penalty curve quantities are based on a percentage of the applicable transmission *security limit* and are fixed within the DAM calculation engine optimization function.

Intertie scheduling limits may be violated. For hour $h \in \{1,..,24\}$:

- $(PPreXTLViolSch_{z,h,i}, QPreXTLViolSch_{z,h,i})$ for $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the flow limit specified by $z \in Z_{Sch}$ used for scheduling to meet the *IESO*'s *reliability* requirements;

- $(PPreXTLViolPrc_{z,h,i}, QPreXTLViolPrc_{z,h,i})$ for $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the flow limit specified by $z \in Z_{Sch}$ used for calculating *market prices*;

- $(PNIUViolSch_{h,i}, QNIUViolSch_{h,i})$ for $i \in \{1,..,N_{NIUViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange increase constraint between hours (h-1) and h used for scheduling to meet the *IESO*'s *reliability* requirements;

- ($PNIUViolPrc_{h,i}$,$QNIUViolPrc_{h,i}$) for $i \in \{1,..,N_{NIUViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange increase constraint between hours (h-1) and h used for calculating *market prices*;
- ($PNIDViolSch_{h,i}$,$QNIDViolSch_{h,i}$) for $i \in \{1,..,N_{NIDViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange decrease constraint between hours (h-1) and h used for scheduling to meet the *IESO*'s *reliability* requirements; and
- ($PNIDViolPrc_{h,i}$,$QNIDViolPrc_{h,i}$) for $i \in \{1,..,N_{NIDViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the hour h net interchange decrease constraint between hours (h-1) and h used for calculating *market prices*.

Maximum and minimum daily *energy* limits for individual resources and shared maximum and minimum daily *energy* limits may be violated. For hour $h \in \{1,..,24\}$:

- ($PMaxDelViolSch_{h,i}$,$QMaxDelViolSch_{h,i}$) for $i \in \{1,..,N_{MaxDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding a resource's maximum daily *energy* limit used for scheduling to meet the *IESO*'s *reliability* requirements;
- ($PMaxDelViolPrc_{h,i}$,$QMaxDelViolPrc_{h,i}$) for $i \in \{1,..,N_{MaxDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding a resource's maximum daily *energy* limit used for calculating *market prices*;
- ($PMinDelViolSch_{h,i}$,$QMinDelViolSch_{h,i}$) for $i \in \{1,..,N_{MinDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under-scheduling a resource's minimum daily *energy* limit used for scheduling to meet the *IESO*'s *reliability* requirements;
- ($PMinDelViolPrc_{h,i}$,$QMinDelViolPrc_{h,i}$) for $i \in \{1,..,N_{MinDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under-scheduling a resource's minimum daily *energy* limit used for calculating *market prices*;
- ($PSMaxDelViolSch_{h,i}$,$QSMaxDelViolSch_{h,i}$) for $i \in \{1,..,N_{SMaxDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding a shared maximum daily *energy* limit used for scheduling to meet the *IESO*'s *reliability* requirements;

- $(PSMaxDelViolPrc_{h,i}, QSMaxDelViolPrc_{h,i})$ for $i \in \{1,..,N_{MaxDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for exceeding a shared maximum daily *energy* limit used for calculating *market prices*;
- $(PSMinDelViolSch_{h,i}, QSMinDelViolSch_{h,i})$ for $i \in \{1,..,N_{SMinDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under-scheduling a shared minimum daily *energy* limit used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(PSMinDelViolPrc_{h,i}, QSMinDelViolPrc_{h,i})$ for $i \in \{1,..,N_{SMinDelViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under-scheduling a shared minimum daily *energy* limit used for calculating *market prices*.

The downstream resource of a hydroelectric linkage may be violated for both reasons of under generation and over generation. For hour $h \in \{1,..,24\}$:

- $(POGenLnkViolSch_{h,i}, QOGenLnkViolSch_{h,i})$ for $i \in \{1,..,N_{OGenLnkViol_h}\}$ shall designate the price-quantity segments of the penalty curve for over generation on a downstream resource used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(PUGenLnkViolSch_{h,i}, QUGenLnkViolSch_{h,i})$ for $i \in \{1,..,N_{UGenLnkViol_h}\}$ shall designate the price-quantity segments of the penalty curve for under generation on a downstream resource used for scheduling to meet the *IESO*'s *reliability* requirements.

Tie-Breaking

When there exist two or more equivalent *bids* or *offers* for *energy* or *offers* for *operating reserve* that do not create differences in the optimization, tie-breaking rules will be used by the DAM calculation engine. Two tie-breaking methods will be used.

The first tie-breaking method pertains to only *variable generation* resources and its application is facilitated by pre-processing *variable generation offers* within the initialization processes of the DAM calculation engine. The intent of this method is to break ties when two or more *energy offers* from *variable generation* resources are such that there is no difference in the cost to the market of using either *offer*. In such instances, the schedules for these *offers* shall be determined using the daily *dispatch* order for *variable generation*, where:

- $NumVG$ shall designate the number of *variable generation* resources in the daily *dispatch* order; and
- $TBM_b \in \{1,..,NumVG\}$ shall designate the tie-breaking modifier for the *variable generation* resource at bus $b \in B^{VG}$.

The second tie-breaking method pertains to all *bids* and *offers* for *energy* and *offers* for *operating reserve* and is applied using a quadratic penalty within the optimization function of the DAM calculation engine. The intent of this method is to break ties when two or more *bids* or *offers* are such that there is no difference in the cost to the market of using either *bid/offer*. In such instances, the schedules for these *bids* or *offers* shall be pro-rated based on the amount of *energy offered* and available at the corresponding price. No additional input to the DAM calculation engine is required to perform this pro-rata tie-breaking.

3.4.1.5 Initial Scheduling Assumptions

The DAM calculation engine will use data specifying the initial schedules and commitment of resources for the hour preceding the first hour of the next *dispatch day*. This data is described in the following sections.

Initial Schedules

By default, initial schedules will be based on the hour ending 24 schedules of the most recent pre-dispatch run. For notational convenience, the initial resources schedules will be denoted using the scheduling variables in Section 3.6.1.2 with the hour set to 0. For example, $SDG_{0,b,k}$ shall denote the initial schedule of the dispatchable generation resource at bus $b \in B^{DG}$ affiliated with *offer* lamination $k \in K^{E}_{0,b}$.

Initial Commitment Status and Number of Hours in Operation

The presence of an operational constraint in the last hour of the previous day will determine if a resource is to be considered in operation in the first hour of the day and if any remaining *minimum generation block run-time* for the resource must be respected. The DAM calculation engine will not need to consider start-up *offers* for resources that are expected to be running as a result of an operational constraint if it decides to schedule them to operate during the first hour of the day.

The *IESO* will have the capability to change this default information to reflect any operational changes (*outages*, unplanned unit starts). For bus $b \in B^{DG}$:

- $ODG_{0,b}$ shall designate the commitment status for the resource at bus b at the end of the previous day; and
- $InitOperHrs_b$ shall designate the number of consecutive hours at the end of the previous day for which the resource at bus b was scheduled to operate. It shall be set to zero for resources that are not considered to be in operation at the end of the preceding day.

Initial Net Interchange Schedule

The DAM calculation engine requires the initial net *interchange schedule*. This value is the difference between all imports to Ontario and all exports from Ontario, in the last hour of the previous day. By default, this value will be based on the most recent pre-dispatch run. For notational convenience, this value will be inferred from the initial resources schedules for imports and exports using the scheduling variables in Section 3.6.1.2 with the hour set to 0.

3.4.1.6 Inputs Provided by the Security Assessment Function

Transmission inputs to the optimization function are calculated by the *security* assessment function based on information prepared by the *IESO* to enable the DAM calculation engine to evaluate the *security* of the *IESO-controlled grid.*

Transmission Constraints

A set of linearized transmission constraints will be provided by the *security* assessment function. Operating *security limits* and thermal limits for both pre-contingency and post-contingency conditions will be considered, where:

- F shall designate the set of *facilities* (or groups of *facilities*) in Ontario for which transmission constraints may be identified; and
- C shall designate the set of contingency conditions that are considered in the *security* assessment function.

For each hour $h \in \{1,...,24\}$, if the pre-contingency limit on *facility* $f \in F$ is violated, the *security* assessment function will calculate a linearization of the constraint in the optimization function scheduling variables and provide the affiliated coefficients and limit. Let $F_h \subseteq F$ designate the set of *facilities* whose pre-contingency limit was violated in hour h of a preceding *security* assessment function iteration. For a *facility* $f \in F_h$:

- $PreConSF_{h,f,b}$ shall designate the pre-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during hour h under pre-contingency conditions;
- $VPreConSF_{h,f,m}$ shall designate the pre-contingency sensitivity factor for virtual transaction zonal trading entity $m \in M$ indicating the effect of scheduled *energy* at m to flows on *facility* $f \in F_h$ in hour h under pre-contingency conditions; and
- $AdjNormMaxFlow_{h,f}$ shall designate the corresponding limit indicating the maximum flow allowed on *facility* f in hour h under pre-contingency conditions.

For each hour $h \in \{1,...,24\}$ and contingency $c \in C$, if the post-contingency limit on *facility* $f \in F$ is violated, the *security* assessment function will calculate a linearization of the constraint in the optimization function scheduling variables and provide the affiliated coefficients and limit.

Let $F_{h,c} \subseteq F$ designate the set of *facilities* whose post-contingency limit for contingency c was violated in hour h of a preceding *security* assessment function iteration. For a *facility* $f \in F_{h,c}$:

- $SF_{h,c,f,b}$ shall designate the post-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during hour h under post-contingency conditions for contingency c;
- $VSF_{h,c,f,m}$ shall designate the post-contingency sensitivity factor for virtual transaction zonal trading entity $m \in M$ indicating the effect of scheduled *energy* at m to flows on *facility* $f \in F_{h,c}$ in hour h under post-contingency conditions for contingency c; and
- $AdjEmMaxFlow_{h,c,f}$ shall designate the corresponding limit indicating the maximum flow allowed on *facility* f in hour h under post-contingency conditions for contingency c.

Transmission Losses

Losses will be modelled in the DAM calculation engine using marginal loss factors and a loss adjustment. As described in Section 3.9.2.3, the marginal loss factors for each hour will be calculated using a base case power flow from the *security* assessment function based on the schedules determined for that hour by the optimization function.

Therefore, the marginal loss factors will be calculated dynamically and can be different in distinct hours, where:

- $MglLoss_{h,b}$ shall designate a marginal loss factor and shall reflect the marginal impact on transmission losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at resource bus $b \in B \cup D$ in hour $h \in \{1,..,24\}$. When determining marginal loss factors, the impact of local branches (e.g. load step-down transformers) between the resource bus and the resource *connection point* to the *IESO-controlled grid* will be excluded;
- $VMglLoss_{h,m}$ shall designate the marginal loss factor for virtual transaction zonal trading entity $m \in M$ in hour $h \in \{1,..,24\}$; and
- $LossAdj_h$ shall designate any adjustment needed for hour $h \in \{1,..,24\}$ to correct for any discrepancy between Ontario total system losses calculated using a base case power flow from the *security* assessment function and linearized losses that would be calculated using the marginal loss factors.

A discrepancy may arise because a linear equation based on marginal loss factors is used to represent losses, but losses are not a linear function of load. The adjustment required may be positive or negative and depends on the location of the *reference bus.* For the purposes of the optimization function formulation, the convention will be that a positive value for the loss adjustment term reflects the need for less generation to cover losses.

3.4.2. Inputs into the Ex-Ante Market Power Mitigation Process

Inputs to the ex-ante Market Power Mitigation process will include inputs to the constrained area conditions test, conduct test and price impact test.

3.4.2.1 Condition Testing Inputs

The ex-ante Market Power Mitigation process will apply to areas of restricted competition within the *IESO-controlled grid*. The constrained area to which a resource belongs is a reflection of the extent to which competition is restricted for that resource. The *IESO* will apply conduct tests using conduct thresholds specific to the constrained area that meets the conditions.

Constrained Area Designations

Depending on how frequently the transmission constraints bind in an area, that area will be classified as one of the following: narrow constrained area (NCA), dynamic constrained area (DCA) or broad constrained area (BCA).

A list of NCAs and DCAs, along with *facilities* leading to the formation of, and resources located in, an NCA or a DCA, will be provided as inputs to the DAM calculation engine, where:

- NCA shall designate the set of narrow constrained areas;
- DCA shall designate the set of dynamic constrained areas;
- $F_n^{NCA} \subseteq F$ shall designate the set of transmission *facilities* whose pre-contingency transmission limit is expected to be binding, resulting in an NCA n;
- $F_d^{DCA} \subseteq F$ shall designate the set of transmission *facilities* whose pre-contingency transmission limit is expected to be binding, resulting in a DCA d;
- $B_n^{NCA} \subseteq B$ shall designate the set of buses identifying resources in NCA, n, that could potentially meet the conditions for Market Power Mitigation testing; and
- $B_d^{DCA} \subseteq B$ shall designate the set of buses identifying resources in DCA, d, that could potentially meet the conditions for Market Power Mitigation testing.

BCAs will be determined for each hour within the DAM calculation engine according to the evaluated grid configuration, where:

- $BCACondThresh$ shall designate the threshold for the congestion component of a resource's LMP, above which the resource will meet the BCA condition.

Conditions to test for global market power in the *energy* and *operating reserve* markets will be determined for each hour within the DAM calculation engine and will consider the following inputs:

- $IBPThresh$ shall designate the *intertie* border price (IBP) threshold;
- $D^{GMPRef} \subseteq D$ shall designate the set of Global Market Power Reference Interties, and proxy locations associated with those *interties*; and
- $ORGCondThresh$ shall designate the threshold for a resource's *operating reserve* LMP, above which the resource will meet the Global Market Power (*Operating reserve*) condition.

3.4.2.2 Conduct Test Inputs

If the conditions for ex-ante market power mitigation are met, the identified set of resources will be subject to a conduct test. The *IESO* will use reference levels and conduct thresholds to test for the potential for the exercise of market power.

Reference Levels

Reference levels will be the *IESO*'s estimate of the competitive *offer* of a resource. For the purposes of the DAM calculation engine, there will be reference levels for the following *offered* values:

- $PDGRef_{h,b,k}$ shall designate the *energy offer* reference level for lamination $k \in K^E_{h,b}$ of the *offer* from the resource at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;
- $P10SDGRef_{h,b,k}$ shall designate the synchronized *ten-minute operating reserve offer* reference level for lamination $k \in K^{10S}_{h,b}$ of the *offer* from the resource at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;
- $P10NDGRef_{h,b,k}$ shall designate the non-synchronized *ten-minute operating reserve offer* reference level for lamination $k \in K^{10N}_{h,b}$ of the *offer* from the resource at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;
- $P30RDGRef_{h,b,k}$ shall designate the *thirty-minute operating reserve offer* reference level for lamination $k \in K^{30R}_{h,b}$ of the *offer* from the resource at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$;
- $SUDGRef_{h,b}$ shall designate the start-up offer reference level for the resource at bus $b \in B^{NQS}$ in hour $h \in \{1,..,24\}$;
- $SNLRef_{h,b}$ shall designate the speed no-load offer reference level for the resource at bus $b \in B^{NQS}$ in hour $h \in \{1,..,24\}$; and
- $PLTMLPRef_{h,b,k}$ shall designate the *energy offer* for the *energy* to MLP reference level for lamination $k \in K^{LTMLP}_{h,b}$ of the *offer* from the resource at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$.

Conduct Thresholds

Conduct thresholds will be used in conjunction with reference levels to determine if resources that are tested for economic withholding have failed the conduct test. Conduct thresholds will be provided for every *dispatch data* parameter for which there exists a reference level, and will vary by constrained zone designation. For the purposes of the DAM calculation engine, the following conduct thresholds will be provided, where:

- $CTEnThresh1^{NCA}$ shall designate the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the NCA conduct test;
- $CTEnThresh2^{NCA}$ shall designate the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the NCA conduct test;
- $CTSUThresh^{NCA}$ shall designate the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the NCA conduct test;
- $CTSNLThresh^{NCA}$ shall designate the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the NCA conduct test;
- $CTEnThresh1^{DCA}$ shall designate the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the DCA conduct test;
- $CTEnThresh2^{DCA}$ shall designate the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the DCA conduct test;
- $CTSUThresh^{DCA}$ shall designate the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the DCA conduct test;
- $CTSNLThresh^{DCA}$ shall designate the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the DCA conduct test;
- $CTEnThresh1^{BCA}$ shall designate the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the BCA conduct test;
- $CTEnThresh2^{BCA}$ shall designate the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the BCA conduct test;
- $CTSUThresh^{BCA}$ shall designate the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the BCA conduct test;

- $CTSNLThresh^{BCA}$ shall designate the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the BCA conduct test;
- $CTEnThresh1^{GMP}$ shall designate the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test;
- $CTEnThresh2^{GMP}$ shall designate the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test;
- $CTSUThresh^{GMP}$ shall designate the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test;
- $CTSNLThresh^{GMP}$ shall designate the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test;
- $CTORThresh1^{ORL}$ shall designate the *operating reserve offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test;
- $CTORThresh2^{ORL}$ shall designate the *operating reserve offer* conduct threshold, pertaining to allowable $/MW increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test;
- $CTEnThresh1^{ORL}$ shall designate the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test;
- $CTEnThresh2^{ORL}$ shall designate the *energy offer* for the *energy* to MLP conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test;
- $CTSUThresh^{ORL}$ shall designate the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test;
- $CTSNLThresh^{ORL}$ shall designate the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test;

- $CTORThresh1^{ORG}$ shall designate the *operating reserve offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test;
- $CTORThresh2^{ORG}$ shall designate the *operating reserve offer* conduct threshold, pertaining to allowable $/MW increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test;
- $CTEnThresh1^{ORG}$ shall designate the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test;
- $CTEnThresh2^{ORG}$ shall designate the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test;
- $CTSUThresh^{ORG}$ shall designate the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test; and
- $CTSNLThresh^{ORG}$ shall designate the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test.

For more details on the conduct thresholds that the *IESO* will use, refer to Appendix E in this document.

Other Inputs

Other inputs required for the DAM calculation engine to perform the conduct test include:

- $CTEnMinOffer$ shall designate the minimum *energy offer* value for the *offer* lamination to be included in the conduct test. *Energy offer* laminations below this value are excluded from the conduct test; and
- $CTORMinOffer$ shall designate the minimum *operating reserve offer* value for the *offer* lamination to be included in the conduct test. *Operating reserve offer* laminations below this value are excluded from the conduct test.

3.4.2.3 Price Impact Test Inputs

Resources with *dispatch data* parameters that fail the conduct test will be tested ex-ante for potential price impact.

Price Impact Thresholds

Impact thresholds will be used to determine whether *market participant offers* have a significant enough effect on *energy* or *operating reserve* prices to warrant intervention. Impact thresholds will be provided to the DAM calculation engine for *energy* and *operating reserve* LMPs, and will vary for each constrained zone designation.

For the purposes of the DAM calculation engine, the following price impact thresholds will be provided:

- $ITThresh1^{NCA}$ shall designate the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the NCA price impact test;
- $ITThresh2^{NCA}$ shall designate the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the NCA price impact test;
- $ITThresh1^{DCA}$ shall designate the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the DCA price impact test;
- $ITThresh2^{DCA}$ shall designate the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the DCA price impact test;
- $ITThresh1^{BCA}$ shall designate the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the BCA price impact test;
- $ITThresh2^{BCA}$ shall designate the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the BCA price impact test;
- $ITThresh1^{GMP}$ shall designate the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (*Energy*) price impact test;
- $ITThresh2^{GMP}$ shall designate the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (*Energy*) price impact test;
- $ITThresh1^{ORG}$ shall designate the price impact threshold, pertaining to allowable percent increase in the *operating reserve* LMP from As-Offered

Pricing above the *operating reserve* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (OR) price impact test; and

- $ITThresh2^{ORG}$ shall designate the price impact threshold, pertaining to allowable $/MW increase in the *operating reserve* LMP from As-Offered Pricing above the *operating reserve* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (OR) price impact test.

For more details on the conduct thresholds that the *IESO* will use, refer to Appendix E in this document.

3.4.3. Inputs into the Security Assessment Function

Similar to the DACE, the DAM calculation engine *security* assessment function will continue to use the outputs of the optimization function, *security limits* and the network model to perform *security* analysis of the *IESO-controlled grid*. Section 3.9.1 provides further details on how these inputs are used by the *security* assessment function in each of the three passes.

3.4.3.1 Inputs Provided by the Optimization Function

The optimization function will provide the *security* assessment function with schedules for load and supply resources (withdrawals and injections), which will be represented at their corresponding electrical buses in the network model.

3.4.3.2 Security Limits

The *security* assessment function will continue to apply a set of equations, known as operating *security* limits (OSLs). OSLs help ensure that power flows remain within NERC and NPCC *reliability* criteria both pre-contingency and following contingency events. The *security* assessment function will also continue to use pre-contingency and post-contingency thermal ratings to help ensure that DAM schedules result in transmission flows that respect the thermal limits.

3.4.3.3 Network Model

The *security* assessment function will continue to use data related to the power system model, load distribution factors, contingencies and monitored equipment.

3.5. Initialization

Before the execution of its three passes, the DAM calculation engine will perform any necessary initialization processes. These processes include selecting a reference bus, determining islanding conditions, applying the *variable generation* resource tie-breaking logic and pre-processing maximum generation constraints that apply to *pseudo-units*.

3.5.1. Reference Bus

The optimization function will use a fixed *reference bus* as a starting point to determine all LMPs. By default, this *reference bus* will be the Richview Transformer Station. If the *reference bus* is out of service, then an alternative station will be chosen as per the prevailing system conditions.

3.5.2. Islanding

In the case of a network split, only the island with the largest number of *IESO-controlled grid* buses will be considered, and the following rules will apply:

- Resources, imports and exports that are not in the largest island will be assumed to neither inject nor withdraw and therefore will be disregarded by the optimization function;
- The load forecasts used by the optimization function will only include *demand* forecast areas in the largest island; and
- If necessary, the *reference bus* will be updated to a bus within the largest island.

For any nodes outside the largest island, prices will be determined as per the methodology detailed in Section 3.10.3.

3.5.3. Variable Generation Resource Tie-Breaking

As described in the Tie-Breaking sub-section in Section 3.4.1.4, *variable generation* resource *energy offer* prices will be modified prior to the engine passes for the purposes of tie-breaking. For each hour $h \in \{1,..,24\}$, each *variable generation* resource bus $b \in B^{VG}$ and each *offer* lamination $k \in K^{E}_{h,b}$, the *offer* price $PDG_{h,b,k}$ shall be updated to $PDG_{h,b,k} - \left(\frac{TBM_b}{NumVG}\right)\rho$ where ρ is a small nominal value of order 10^{-4}.

3.5.4. Pseudo-Unit Maximum Constraints

For a combined cycle *facility* that has elected to be represented as a *pseudo-unit*, any maximum generation constraint applied to a corresponding physical unit will be pre-processed to determine an appropriate constraint for the PSU resource. The logic for determining the appropriate constraints is described in Section 3.12.3.

3.6. Pass 1: Market Commitment and Market Power Mitigation

Pass 1 will use *market participant* and *IESO* inputs along with resource and system constraints to determine a set of resource schedules and commitments. These schedules and commitments are calculated to meet the *IESO's* average non-dispatchable forecast *demand* and the *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports. Pass 1 will also determine LMPs consistent with these scheduling and commitment decisions.

Pass 1 will assess whether conditions related to transmission congestion have been met. If such conditions exist, then Pass 1 will perform the steps related to the ex-ante Market Power Mitigation process. If the ex-ante Market Power Mitigation process is performed and the price impact test is failed, then the schedules, commitments and LMPs comprising the Pass 1 outputs will reflect the corresponding results of the ex-ante Market Power Mitigation process. That is, the Pass 1 outputs will reflect the results of performing Mitigated Scheduling and Mitigated Pricing which use reference level *dispatch data* for specific inputs identified by the ex-ante Market Power Mitigation process.

3.6.1. As-Offered Scheduling

As-Offered Scheduling will perform a *security*-constrained unit commitment and economic *dispatch* to meet the *IESO*'s average non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. As-Offered Scheduling will also evaluate *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and *bids* to export *energy*.

As-Offered Scheduling will use *bids* and *offers* submitted by *market participants* to maximize the gains from trade. The gains from trade is the difference between the total price of *bids* that are scheduled and the total price of *offers* that are scheduled. The optimization is subject to the resource constraints accompanying those *bids* and *offers*, and system constraints imposed by the *IESO* to maintain *reliability*.

As-Offered Scheduling will determine commitment statuses and initial schedules based on the inputs described in Section 3.4. These commitments will serve as inputs into As-Offered Pricing. The schedules produced will not be financially binding.

The following sections describe the formulation of the optimization function for As-Offered Scheduling.

3.6.1.1 Inputs

All applicable inputs identified in Section 3.4.1 will be evaluated.

3.6.1.2 Variables and Objective Function

The DAM calculation engine will solve for the following variables:

- $SPRL_{h,b,j}$ shall represent the amount of price responsive load scheduled at bus $b \in B^{PRL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$;
- $SDL_{h,b,j}$ shall represent the amount of *dispatchable load* scheduled at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$;
- $S10SDL_{h,b,j}$ shall represent the amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10S}_{h,b}$;
- $S10NDL_{h,b,j}$ shall represent the amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10N}_{h,b}$;
- $S30RDL_{h,b,j}$ shall represent the amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{30R}_{h,b}$;
- $SHDR_{h,b,j}$ shall represent the amount of *hourly demand response* reduction scheduled at bus $b \in B^{HDR}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$;
- $SVB_{h,v,j}$ shall represent the amount of virtual *bid* $v \in VB$ scheduled in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,v}$;
- $SXL_{h,d,j}$ shall represent the amount of exports scheduled to *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,d}$;
- $S10NXL_{h,d,j}$ shall represent the amount of non-synchronized *ten-minute operating reserve* scheduled from *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10N}_{h,d}$;
- $S30RXL_{h,d,j}$ shall represent the amount of *thirty-minute operating reserve* scheduled from *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{30R}_{h,d}$;
- $SNDG_{h,b,k}$ shall represent the amount of non-dispatchable generation scheduled at bus $b \in B^{NDG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,b}$;
- $SDG_{h,b,k}$ shall represent the amount of dispatchable generation scheduled at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,b}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled;

- $ODG_{h,b}$ shall represent whether the dispatchable generation resource at bus $b \in B^{DG}$ has been scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$;
- $IDG_{h,b}$ shall represent whether the dispatchable generation resource at bus $b \in B^{DG}$ has been scheduled to start (reach its *minimum loading point*) in hour $h \in \{1,..,24\}$;
- $S10SDG_{h,b,k}$ shall represent the amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$;
- $S10NDG_{h,b,k}$ shall represent the amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$;
- $S30RDG_{h,b,k}$ shall represent the amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,b}$;
- $SCT_{h,b}$ shall represent the schedule of the combustion turbine associated with the PSU resource at bus $b \in B^{PSU}$ in hour $h \in \{1,..,24\}$;
- $SST_{h,p}$ shall represent the schedule of steam turbine $p \in PST$ in hour $h \in \{1,..,24\}$;
- $O10R_{h,b}$ shall represent whether the PSU resource at bus $b \in B^{NO10DF}$ has been scheduled for *ten-minute operating reserve* in hour $h \in \{1,..,24\}$;
- $OHO_{h,b}$ shall represent whether the hydroelectric resource at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$;
- $OFR_{h,b,i}$ for $i \in \{1,..,NFor_b\}$ shall represent whether the hydroelectric resource at bus $b \in B^{HE}$ has been scheduled at or below $ForL_{b,i}$, or, at or above $ForU_{b,i}$ in hour $h \in \{1,..,24\}$;
- $IHE_{h,b,i}$ shall represent whether the hydroelectric resource at bus $b \in B^{HE}$ registered a start between hours $(h\text{-}1)$ and $h \in \{1,..,24\}$ as a result of its schedule increasing from below $StartMW_{b,i}$ to at or above $StartMW_{b,i}$ for $i \in \{1,..,NStartMW_b\}$;
- $SVO_{h,v,k}$ shall represent the amount of virtual *offer* $v \in VO$ scheduled in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,v}$;
- $SIG_{h,d,k}$ shall represent the amount of imports from *intertie zone* source bus $d \in DI$ scheduled in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,d}$;
- $S10NIG_{h,d,k}$ shall represent the amount of non-synchronized *ten-minute operating reserve* scheduled from *intertie zone* source bus $d \in DI$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,d}$;

- $S30RIG_{h,d,k}$ shall represent the amount of *thirty-minute operating reserve* scheduled from *intertie zone* source bus $d \in DI$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,d}$;
- TB_h shall represent any adjustment to the objective function to facilitate pro-rata tie-breaking in hour $h \in \{1,..,24\}$, as described in Section 3.4.1.4 and this section; and
- $ViolCost_h$ shall represent the cost incurred in order to avoid having the schedules for hour $h \in \{1,..,24\}$ violate certain constraints, as described in Section 3.4.1.4 and this section.

To maximize the gains from trade, the objective function in As-Offered Scheduling will maximize the value of the following expression:

$$\sum_{h=1,..,24} \begin{pmatrix} ObjPRL_h + ObjDL_h - ObjHDR_h + ObjVB_h + ObjXL_h - ObjNDG_h \\ - ObjDG_h - ObjVO_h - ObjIG_h - TB_h - ViolCost_h \end{pmatrix}$$

where:

$$ObjPRL_h = \sum_{b \in B^{PRL}} \left(\sum_{j \in J^E_{h,b}} SPRL_{h,b,j} \cdot PPRL_{h,b,j} \right)$$

$$ObjDL_h = \sum_{b \in B^{DL}} \begin{pmatrix} \sum_{j \in J^E_{h,b}} SDL_{h,b,j} \cdot PDL_{h,b,j} - \sum_{j \in J^{10S}_{h,b}} S10SDL_{h,b,j} \cdot P10SDL_{h,b,j} - \\ \sum_{j \in J^{10N}_{h,b}} S10NDL_{h,b,j} \cdot P10NDL_{h,b,j} - \sum_{j \in J^{30R}_{h,b}} S30RDL_{h,b,j} \cdot P30RDL_{h,b,j} \end{pmatrix}$$

$$ObjHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J^E_{h,b}} SHDR_{h,b,j} \cdot PHDR_{h,b,j} \right)$$

$$ObjVB_h = \sum_{v \in VB} \left(\sum_{j \in J^E_{h,v}} SVB_{h,v,j} \cdot PVB_{h,v,j} \right)$$

$$ObjXL_h = \sum_{d \in DX} \begin{pmatrix} \sum_{j \in J^E_{h,d}} SXL_{h,d,j} \cdot PXL_{h,d,j} - \sum_{j \in J^{10N}_{h,d}} S10NXL_{h,d,j} \cdot P10NXL_{h,d,j} \\ - \sum_{j \in J^{30R}_{h,d}} S30RXL_{h,d,j} \cdot P30RXL_{h,d,j} \end{pmatrix}$$

$$ObjNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K^E_{h,b}} SNDG_{h,b,k} \cdot PNDG_{h,b,k} \right)$$

$$ObjDG_h = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \cdot PDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \cdot P10SDG_{h,b,k} + \\ \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \cdot P10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \cdot P30RDG_{h,b,k} \end{array} \right) + \sum_{b \in B^{NQS}} \left(ODG_{h,b} \cdot MGODG_{h,b} + IDG_{h,b} \cdot SUDG_{h,b} \right)$$

$$ObjVO_h = \sum_{v \in VO} \left(\sum_{k \in K_{h,v}^{E}} SVO_{h,v,k} \cdot PVO_{h,v,k} \right)$$

$$ObjIG_h = \sum_{d \in DI} \left(\begin{array}{c} \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \cdot PIG_{h,d,k} + \sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \cdot P10NIG_{h,d,k} \\ + \sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \cdot P30RIG_{h,d,k} \end{array} \right)$$

The tie-breaking term - TB_h - is obtained by adding a term for each *bid* or *offer* lamination. For each lamination, this term is the product of a small penalty cost and the quantity of the lamination scheduled. The penalty cost is calculated by multiplying a base penalty cost of $TBPen$ by the amount of the lamination scheduled and then dividing by the maximum amount that could have been scheduled. When this penalty cost is multiplied by the amount scheduled from that lamination, a quadratic function that increases as the amount scheduled increases is obtained. This effectively increases the *bid* or *offer* price by zero if nothing is scheduled from the lamination, but by $TBPen$ if the maximum amount that could have been scheduled is scheduled. This slight price gradient, which is smaller than the minimum step size of *bid* or *offer* prices, will ensure that two otherwise tied laminations will be scheduled to the point where their modified costs are identical, effectively achieving a pro-rated result.

$ViolCost_h$ calculates the total constraint violation cost and depends on the constraint violation variables. The constraint violation variables for hour $h \in \{1,..,24\}$ are:

- $SLdViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{LdViol_h}\}$ of the penalty curve for the *energy* balance constraint (allowing under-generation).
- $SGenViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{GenViol_h}\}$ of the penalty curve for the *energy* balance constraint (allowing over-generation).
- $S10SViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{10SViol_h}\}$ of the penalty curve for the synchronized *ten-minute operating reserve* requirement.
- $S10RViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{10RViol_h}\}$ of the penalty curve for the total *ten-minute operating reserve* requirement.

- $S30RViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{30RViol_h}\}$ of the penalty curve for the *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement.
- $SREG10RViol_{r,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{REG10RViol_h}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* minimum requirement in region $r \in ORREG$.
- $SREG30RViol_{r,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{REG30RViol_h}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* minimum requirement in region $r \in ORREG$.
- $SXREG10RViol_{r,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{XREG10RViol_h}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* maximum restriction in region $r \in ORREG$.
- $SXREG30RViol_{r,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{XREG30RViol_h}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* maximum restriction in region $r \in ORREG$.
- $SPreITLViol_{f,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{PreITLViol_{f,h}}\}$ of the penalty curve for violating the pre-contingency transmission limit for *facility* $f \in F$.
- $SITLViol_{c,f,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$ of the penalty curve for violating the post-contingency transmission limit for *facility* $f \in F$ and contingency $c \in C$.
- $SPreXTLViol_{z,h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$ of the penalty curve for violating the import/export limit affiliated with *intertie* limit constraint $z \in Z_{Sch}$.
- $SNIUViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{NIUViol_h}\}$ of the penalty curve for exceeding the net interchange increase limit between hours $(h$-1) and h.
- $SNIDViol_{h,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{NIDViol_h}\}$ of the penalty curve for exceeding the net interchange decrease limit between hours $(h$-1) and h.
- $SMaxDelViol_{h,b,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{MaxDelViol_h}\}$ of the penalty curve for exceeding the maximum daily *energy* limit constraint for a resource at bus $b \in B^{ELR}$.
- $SMinDelViol_{h,b,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{MinDelViol_h}\}$ of the penalty curve for violating the minimum daily *energy* limit constraint for a resource at bus $b \in B^{HE}$.

- $SSMaxDelViol_{h,s,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{SMaxDelViol_h}\}$ of the penalty curve for exceeding the shared maximum daily *energy* limit constraint for hydroelectric resources in set $s \in SHE$.
- $SSMinDelViol_{h,s,i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{SMinDelViol_h}\}$ of the penalty curve for violating the shared minimum daily *energy* limit constraint for hydroelectric resources in set $s \in SHE$.
- $SOGenLnkViol_{h,(b_1,b_2),i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{OGenLnkViol_h}\}$ of the penalty curve for violating the linked hydroelectric resources constraint by over-generating the downstream resource, for $(b_1,b_2) \in LNK$ such that $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$.
- $SUGenLnkViol_{h,(b_1,b_2),i}$ is the violation variable affiliated with segment $i \in \{1,..,N_{UGenLnkViol_h}\}$ of the penalty curve for violating the linked hydroelectric resources constraint by under-generating the downstream resource, for $(b_1,b_2) \in LNK$ such that $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$.

From these variables, the violation cost is computed as follows:

$$
\begin{aligned}
ViolCost_h = & \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \cdot PLdViolSch_{h,i} - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} \cdot PGenViolSch_{h,i} \\
& + \sum_{i=1..N_{10SViol_h}} S10SViol_{h,i} \cdot P10SViolSch_{h,i} \\
& + \sum_{i=1..N_{10RViol_h}} S10RViol_{h,i} \cdot P10RViolSch_{h,i} \\
& + \sum_{i=1..N_{30RViol_h}} S30RViol_{h,i} \cdot P30RViolSch_{h,i} \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG10RViol_h}} SREG10RViol_{r,h,i} \cdot PREG10RViolSch_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG30RViol_h}} SREG30RViol_{r,h,i} \cdot PREG30RViolSch_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG10RViol_h}} SXREG10RViol_{r,h,i} \cdot PXREG10RViolSch_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG30RViol_h}} SXREG30RViol_{r,h,i} \cdot PXREG30RViolSch_{h,i} \right) \\
& + \sum_{f \in F_h} \left(\sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} \cdot PPreITLViolSch_{f,h,i} \right) \\
& + \sum_{c \in C} \sum_{f \in F_{h,c}} \left(\sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \cdot PITLViolSch_{c,f,h,i} \right) \\
& + \sum_{z \in Z_{Sch}} \left(\sum_{i=1..N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} \cdot PPreXTLViolSch_{z,h,i} \right) \\
& + \sum_{i=1..N_{NIUViol_h}} SNIUViol_{h,i} \cdot PNIUViolSch_{h,i} \\
& + \sum_{i=1..N_{NIDViol_h}} SNIDViol_{h,i} \cdot PNIDViolSch_{h,i} \\
& + \sum_{b \in B^{ELR}} \left(\sum_{i=1..N_{MaxDelViol_h}} SMaxDelViol_{h,b,i} \cdot PMaxDelViolSch_{h,b,i} \right) \\
& + \sum_{b \in B^{HE}} \left(\sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i} \cdot PMinDelViolSch_{h,b,i} \right)
\end{aligned}
$$

$$+\sum_{s\in\text{SHE}}\left(\sum_{i=1..N_{SMaxDelViol_h}} SSMaxDelViol_{h,s,i}\cdot PSMaxDelViolSch_{h,s,i}\right)$$

$$+\sum_{s\in\text{SHE}}\left(\sum_{i=1..N_{SMinDelViol_h}} SSMinDelViol_{h,s,i}\cdot PSMinDelViolSch_{h,s,i}\right)$$

$$+\sum_{(b_1,b_2)\in LNK}\left(\sum_{i=1..N_{OGenLnkViol_h}} SOGenLnkViol_{h,(b_1,b_2),i}\cdot PSOGenLnkViolSch_{\text{h},(b_1,b_2),i}\right)$$

$$+\sum_{(b_1,b_2)\in LNK}\left(\sum_{i=1..N_{UGenLnkViol_h}} SUGenLnkViol_{h,(b_1,b_2),i}\cdot PSUGenLnkViolSch_{\text{h},(b_1,b_2),i}\right).$$

This maximization will be subject to the constraints described in the next sections.

3.6.1.3 Constraints Overview

The constraints that apply to the optimization can be divided into three categories:

1. Single hour constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *dispatch data* submitted by *registered market participants*;
2. Inter-hour and multi-hour constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *dispatch data* submitted by *registered market participants*, and
3. Constraints to ensure that those schedules do not violate the *reliability* inputs established by the *IESO*.

3.6.1.4 Bid/Offer Constraints Applying to Single Hours

Scheduling Variable Bounds and Commitment Status Variables

As described in Section 3.3, a dispatchable generation resource is said to be committed in a specific hour if it is scheduled at or above its *minimum loading point* in that hour. A Boolean variable $ODG_{h,b}$ indicates whether the resource at bus $b \in B^{DG}$ is committed in hour $h \in \{1,..,24\}$. A value of zero indicates that a resource is not committed, while a value of one indicates that it is committed. Therefore, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$ODG_{h,b} \in \{0,1\}.$$

Reliability must-run resources will be considered committed for all must-run hours. Regulating units will be considered committed for all the hours that they are regulating. As described in Section 3.3, a dispatchable generation resource with zero commitment cost (i.e., its *minimum loading point*, start-up offer, speed no-load offer, minimum *generation block run-time* and *minimum generation block down time* are zero) will be considered committed for all hours. If the dispatchable generation resource at bus $b \in B^{DG}$ is considered committed according to these rules in hour $h \in \{1,..,24\}$, then:

$$ODG_{h,b}=1.$$

No schedule can be negative, nor can any schedule exceed the quantity *offered* for the respective market (*energy* and *operating reserve*). Therefore, for all hours $h \in \{1,..,24\}$:

$0 \le SPRL_{h,b,j} \le QPRL_{h,b,j}$ for all $b \in B^{PRL}$, $j \in J^{E}_{h,b}$;

$0 \le SDL_{h,b,j} \le QDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{E}_{h,b}$;

$0 \le S10SDL_{h,b,j} \le Q10SDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{10S}_{h,b}$;

$0 \le S10NDL_{h,b,j} \le Q10NDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{10N}_{h,b}$;

$0 \le S30RDL_{h,b,j} \le Q30RDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{30R}_{h,b}$;

$0 \le SHDR_{h,b,j} \le QHDR_{h,b,j}$ for all $b \in B^{HDR}$, $j \in J^{E}_{h,b}$;

$0 \le SVB_{h,v,j} \le QVB_{h,v,j}$ for all $v \in VB$, $j \in J^{E}_{h,v}$;

$0 \le SXL_{h,d,j} \le QXL_{h,d,j}$ for all $d \in DX$, $j \in J^{E}_{h,d}$;

$0 \le S10NXL_{h,d,j} \le Q10NXL_{h,d,j}$ for all $d \in DX$, $j \in J^{10N}_{h,d}$;

$0 \le S30RXL_{h,d,j} \le Q30RXL_{h,d,j}$ for all $d \in DX$, $j \in J^{30R}_{h,d}$;

$0 \le SNDG_{h,b,k} \le QNDG_{h,b,k}$ for all $b \in B^{NDG}$, $k \in K^{E}_{h,b}$;

$0 \le SVO_{h,v,k} \le QVO_{h,v,k}$ for all $v \in VO$, $k \in K^{E}_{h,v}$;

$0 \le SIG_{h,d,k} \le QIG_{h,d,k}$ for all $d \in DI$, $k \in K^{E}_{h,d}$;

$0 \le S10NIG_{h,d,k} \le Q10NIG_{h,d,k}$ for all $d \in DI$, $k \in K^{10N}_{h,d}$; and

$0 \le S30RIG_{h,d,k} \le Q30RIG_{h,d,k}$ for all $d \in DI$, $k \in K^{30R}_{h,d}$.

In addition to restrictions on their schedules similar to those above, the schedules for dispatchable generation resources must be consistent with their commitment status. Dispatchable *generation* resources can be scheduled to produce *energy* and *operating reserve* only if their commitment status variable is equal to 1. Therefore, for all hours $h \in \{1,..,24\}$:

$0 \le SDG_{h,b,k} \le ODG_{h,b} \cdot QDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{E}_{h,b}$;

$0 \le S10SDG_{h,b,k} \le ODG_{h,b} \cdot Q10SDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{10S}_{h,b}$;

$0 \le S10NDG_{h,b,k} \le ODG_{h,b} \cdot Q10NDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{10N}_{h,b}$; and

$0 \le S30RDG_{h,b,k} \le ODG_{h,b} \cdot Q30RDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{30R}_{h,b}$.

Resource Minimums and Maximums

The schedule of an internal resource may be limited as detailed in Resource Minimum and Maximum Constraints within Section 3.4.1.4.

Price Responsive Load

The non-dispatchable portion of a price responsive load must always be scheduled. Therefore, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{PRL}$:

$$\sum_{j \in J^{E}_{h,b}} SPRL_{h,b,j} \ge QPRLFIRM_{h,b}.$$

Dispatchable Load

A constraint is required to limit *dispatchable loads* within their minimum and maximum consumption for an hour. Therefore, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$MinDL_{h,b} \le \sum_{j \in J^{E}_{h,b}} SDL_{h,b,j} \le MaxDL_{h,b}.$$

The non-dispatchable portion of a *dispatchable load* must always be scheduled. Therefore, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J^{E}_{h,b}} SDL_{h,b,j} \ge QDLFIRM_{h,b}.$$

Non-Dispatchable Generation Resources

A constraint is required to limit non-dispatchable generation resources within their minimum and maximum output for an hour. Therefore, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{NDG}$:

$$MinNDG_{h,b} \le \sum_{k \in K^{E}_{h,b}} SNDG_{h,b,k} \le MaxNDG_{h,b}.$$

Dispatchable Generation Resources

A constraint is required to limit dispatchable generation resources within their minimum and maximum output for an hour. The maximum output of a dispatchable *variable generation* resource will additionally be limited by its forecast.

For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$, let

$$AdjMaxDG_{h,b} = \begin{cases} min(MaxDG_{h,b}, AFG_{h,b}) & if\ b \in B^{VG} \\ MaxDG_{h,b} & otherwise \end{cases}$$

and

$$AdjMinDG_{h,b} = min(MinDG_{h,b}, AdjMaxDG_{h,b}).$$

Then, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{h,b} \leq MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq AdjMaxDG_{h,b}.$$

If the commitment status of the resource is fixed to 1 (i.e. $ODG_{h,b} = 1$) and if this is inconsistent with the adjusted minimum and maximum constraints (i.e. $MinQDG_b > AdjMaxDG_{h,b}$), then the commitment status will be relaxed. If the total *offered* quantity does not exceed the minimum ($MinQDG_b + \sum_{k \in K^E_{h,b}} QDG_{h,b,k} < AdjMinDG_{h,b}$) then the resource will receive a schedule of zero.

Maximum constraints are also applied to an NQS resource ramping to its *minimum loading point*. A resource will not be scheduled to reach MLP in a given hour if the resource's ramp up *energy* to MLP profile cannot be accommodated in a preceding hour due to a maximum constraint.

Inadvertent Payback

A constraint is required to schedule inadvertent payback transactions. For all hours $h \in \{1,..,24\}$ and all *intertie zone* sink buses corresponding to an inadvertent payback transaction $d \in DX^{INP}_h$:

$$\sum_{j \in J^E_{h,d}} SXL_{h,d,j} = \sum_{j \in J^E_{h,d}} QXL_{h,d,j}.$$

For all hours $h \in \{1,..,24\}$ and all *intertie zone* source buses corresponding to an inadvertent payback transaction $d \in DI^{INP}_h$:

$$\sum_{k \in K^E_{h,d}} SIG_{h,d,k} = \sum_{k \in K^E_{h,d}} QIG_{h,d,k}.$$

Operating Reserve Scheduling

Dispatchable Load

The total *operating reserve* (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load less the non-dispatchable portion. Lastly, it cannot exceed the remaining portion of its capacity that is dispatchable after considering minimum load consumption constraints. These conditions can be enforced by the following constraints for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq 30 \cdot ORRDL_b;$$

$$\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq \sum_{j\in J_{h,b}^{E}} SDL_{h,b,j} - QDLFIRM_{h,b};$$

and

$$\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq \sum_{j\in J_{h,b}^{E}} SDL_{h,b,j} - MinDL_{h,b}.$$

The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j} \leq 10 \cdot ORRDL_b.$$

Exports

The total *operating reserve* (10-minute non-synchronized and 30-minute) from an hourly export cannot exceed the total scheduled export. This condition can be enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all *intertie zone* sink buses $d \in DX$:

$$\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j} + \sum_{j\in J_{h,d}^{30R}} S30RXL_{h,d,j} \leq \sum_{j\in J_{h,d}^{E}} SXL_{h,d,j}.$$

Dispatchable Generation Resources

The total *operating reserve* (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed dispatchable generation resource cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). Lastly, it cannot exceed its unscheduled capacity. These conditions can be enforced by the following constraints for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq 30 \cdot ORRDG_b;$$

$$\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \sum_{k\in K_{h,b}^{E}} (QDG_{h,b,k} - SDG_{h,b,k});$$

and

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq AdjMaxDG_{h,b} - \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} - MinQDG_b.$$

The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a dispatchable generation resource is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \leq 10 \cdot ORRDG_b.$$

The amount of synchronized *ten-minute operating reserve* that a dispatchable generation resource is scheduled to provide is limited by its synchronized 10-minute reserve loading point. This condition can be enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$ with $RLP10S_{h,b} > 0$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \leq \left(MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \right) \cdot \left(\frac{1}{RLP10S_{h,b}} \right) \cdot \left(min \left\{ 10 \cdot ORRDG_b, \sum_{k \in K_{h,b}^{10S}} Q10SDG_{h,b,k} \right\} \right).$$

The amount of *thirty-minute operating reserve* that a dispatchable generation resource is scheduled to provide is limited by its 30-minute reserve loading point. This condition can be enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$ with $RLP30R_{h,b} > 0$:

$$\sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \left(MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \right) \cdot \left(\frac{1}{RLP30R_{h,b}} \right) \cdot \left(min \left\{ 30 \cdot ORRDG_b, \sum_{k \in K_{h,b}^{30R}} Q30RDG_{h,b,k} \right\} \right).$$

Imports

The total *operating reserve* (10-minute non-synchronized and 30-minute) from an hourly import cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). This condition can be enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all *intertie zone* source buses $d \in DI$:

$$\sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} + \sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \le \sum_{k \in K_{h,d}^{E}} (QIG_{h,d,k} - SIG_{h,d,k}).$$

PSU Resources

De-rates

De-rates are enforced on the operating region to which they apply as described in Section 3.12.2. These constraints apply to both *energy* and *operating reserve* schedules. For all hours $h \in \{1,..,24\}$ and PSU resource buses $b \in B^{PSU}$:

$$MinQDG_b \cdot ODG_{h,b} \le MaxMLP_{h,b},$$

$$\sum_{k \in K_{h,b}^{DR}} SDG_{h,b,k} \le MaxDR_{h,b},$$

$$\sum_{k \in K_{h,b}^{DF}} SDG_{h,b,k} \le MaxDF_{h,b},$$

and

$$\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \le MaxDR_{h,b} + MaxDF_{h,b}.$$

Translation Between PU and PSU Schedules

Physical unit schedules will be calculated from the *pseudo-unit* schedules using the PSU model and sharing percentages.

For all hours $h \in \{1,..,24\}$ and PSU resource buses $b \in B^{PSU}$:

$$SCT_{h,b} = (1 - STShareMLP_b) \cdot MinQDG_b \cdot ODG_{h,b} + (1 - STShareDR_b) \cdot \left(\sum_{k \in K_{h,b}^{DR}} SDG_{h,b,k} \right),$$

and for all hours $h \in \{1,..,24\}$ and steam turbines $p \in PST$:

$$SST_{h,p} = \sum_{b \in B_p^{ST}} \left(\begin{array}{c} STShareMLP_b \cdot MinQDG_b \cdot ODG_{h,b} + \\ STShareDR_b \cdot \left(\sum_{k \in K_{h,b}^{DR}} SDG_{h,b,k} \right) + \sum_{k \in K_{h,b}^{DF}} SDG_{h,b,k} \end{array} \right).$$

Transmission constraint sensitivity factors and loss factors are provided on a physical unit basis. Accordingly, the combustion turbine and steam turbine schedules will be used in the *energy* balance constraint and the transmission constraints described in Section 3.6.1.6.

For the purposes of such constraints, the combustion turbine schedule for the PSU resource at bus $b \in B^{PSU}$ in hour $h \in \{1,..,24\}$ will be equal to:

- $SCT_{h,b}$ if the PSU resource is scheduled at or above MLP;
- $RampCT_{b,w}$ if the resource is schedule to reach MLP in hour $(h + w)$ for $w \in \{1,..,RampHrs_b\}$; or
- 0 otherwise.

For the purposes of such constraints, the steam turbine schedule for $p \in PST$ will be equal to $SST_{h,p}$ plus any contribution from PSU resources $b \in B_p^{ST}$ ramping to MLP as given by $RampST_{b,w}$ for a resource scheduled to reach MLP in hour $(h + w)$ for $w \in \{1,..,RampHrs_b\}$.

The DAM calculation engine will evaluate effective sensitivity and loss factors as a function of the unit loading as determined above. For the purposes of the formulations, the *energy* balance and transmission constraints expressed in this document assume that a PSU's effective sensitivity and loss factors are constant across its operating range.

Duct Firing Operating Reserve Limitations

For a PSU resource that cannot provide *ten-minute operating reserve* from its duct firing region, constraints are required to limit the resource from being scheduled in its duct firing region whenever the resource is scheduled for *ten-minute operating reserve.* For all hours $h \in \{1,..,24\}$ and PSU resource buses $b \in B^{NO10DF}$:

$$O10R_{h,b} \in \{0,1\},$$

and

$$\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \le MaxDR_{h,b} + (1 - O10R_{h,b}) \cdot MaxDF_{h,b}$$

For all hours $h \in \{1,..,24\}$, PSU resource buses $b \in B^{NO10DF}$, and laminations $k \in K_{h,b}^{10S}$:

$$S10SDG_{h,b,k} \le O10R_{h,b} \cdot Q10SDG_{h,b,k}.$$

For all hours $h \in \{1,..,24\}$, PSU resource buses $b \in B^{NO10DF}$, and laminations $k \in K_{h,b}^{10N}$:

$$S10NDG_{h,b,k} \le O10R_{h,b} \cdot Q10NDG_{h,b,k}.$$

Hydroelectric Resources

A hydroelectric resource must be scheduled for its hourly must-run amount. For all hours $h \in \{1,..,24\}$ and hydroelectric resource buses $b \in B^{HE}$:

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq MinHMR_{h,b}.$$

Either a hydroelectric resource must be scheduled to 0 or its minimum hourly output must be respected. For all hours $h \in \{1,..,24\}$ and all hydroelectric resources buses $b \in B^{HE}$:

$$OHO_{h,b} \in \{0,1\};$$

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq MinHO_{h,b} \cdot OHO_{h,b};$$

and for all $k \in K_{h,b}^E$:

$$0 \leq SDG_{h,b,k} \leq OHO_{h,b} \cdot QDG_{h,b,k}.$$

A hydroelectric resource cannot be scheduled within its *forbidden regions*. For all hours $h \in \{1,..,24\}$, all hydroelectric resource buses $b \in B^{HE}$ and all $i \in \{1,..,NFor_b\}$:

$$OFR_{h,b,i} \in \{0,1\};$$

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \leq OFR_{h,b,i} \cdot ForL_{b,i} + (1 - OFR_{h,b,i}) \cdot \left(MinQDG_b + \sum_{k \in K_{h,b}^E} QDG_{h,b,k} \right);$$

and

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq (1 - OFR_{h,b,i}) \cdot ForU_{b,i}.$$

Wheeling Through Transactions

In the case of wheeling through transactions, the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore, for all hours $h \in \{1,..,24\}$ and all linked *intertie zone* sink and source buses $(dx,di) \in L_h$:

$$\sum_{j \in J_{h,dx}^E} SXL_{h,dx,j} = \sum_{k \in K_{h,di}^E} SIG_{h,di,k}.$$

3.6.1.5 Bid/Offer Inter-Hour/Multi-Hour Constraints

Energy Ramping

In the following ramping constraints, a single ramp up rate and a single ramp down rate ($URRDG_b$ and $DRRDG_b$ for dispatchable generation resources, $URRDL_b$ and $DRRDL_b$ for *dispatchable loads*) are used. That is, the ramp rates are considered to be constant over the full operating range of the dispatchable generation resource or *dispatchable load*. However, the DAM calculation engine will respect the ramping restrictions determined by the (up to five) *offered* MW quantity, ramp up rate and ramp down rate value sets.

In all ramping constraints, the schedules for “hour 0” are obtained from the initial scheduling assumptions. For all hours $h \in \{1,..,24\}$ the ramping rates in all ramping constraints must be adjusted to allow the resource to:

- Ramp down from its lower limit in hour $(h\text{-}1)$ to its upper limit in hour h.
- Ramp up from its upper limit in hour $(h\text{-}1)$ to its lower limit in hour h.

This will allow a solution to be obtained when changes to the upper and lower limits between hours are beyond the ramping capability of the resources.

Dispatchable Load

Energy schedules for a *dispatchable load* cannot vary by more than an hour’s ramping capability for that resource. This is enforced by the following constraint for all hours $h \in \{1,..,24\}$ and buses $b \in B^{DL}$:

$$\sum_{j \in J^E_{h-1,b}} SDL_{h-1,b,j} - 60 \cdot DRRDL_b \leq \sum_{j \in J^E_{h,b}} SDL_{h,b,j} \leq \sum_{j \in J^E_{h-1,b}} SDL_{h-1,b,j} + 60 \cdot URRDL_b.$$

Hourly Demand Response Resources

Energy schedules for an *hourly demand response* resource cannot vary by more than an hour’s ramping capability for that resource. This is enforced by the following constraint for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{HDR}$:

$$\sum_{j \in J^E_{h-1,b}} (QHDR_{h-1,b,j} - SHDR_{h-1,b,j}) - 60 \cdot URRHDR_b \leq \sum_{j \in J^E_{h,b}} (QHDR_{h,b,j} - SHDR_{h,b,j})$$
$$\leq \sum_{j \in J^E_{h-1,b}} (QHDR_{h-1,b,j} - SHDR_{h-1,b,j}) + 60 \cdot DRRHDR_b.$$

Dispatchable Generation Resources

Energy schedules for each dispatchable generation resource cannot vary by more than an hour’s ramping capability for that resource. The following three-part constraint handles ramping for a resource when it is committed. The constraint covers incremental change above the resource's *minimum loading point* (MLP) in the hours where:

- The resource first reaches MLP (Start Up);
- The resource stays on at or above MLP (Continued On); and
- The last hour the resource is scheduled at or above MLP before being scheduled off (Shut Down).

Only the "Continued On" constraint applies to quick-start resources because they are always committed.

For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

1. Start Up Scenario ($ODG_{h,b} = 1, ODG_{h\text{-}1,b} = 0$):

$$0 \leq \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq 30 \cdot URRDG_b$$

2. Continued On Scenario ($ODG_{h,b} = 1, ODG_{h\text{-}1,b} = 1$)

$$\sum_{k \in K^E_{h-1,b}} SDG_{h-1,b,k} - 60 \cdot DRRDG_b \leq \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq \sum_{k \in K^E_{h-1,b}} SDG_{h-1,b,k} + 60 \cdot URRDG_b$$

3. Shut Down Scenario ($ODG_{h,b} = 1, ODG_{h+1,b} = 0$):

$$0 \leq \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq 30 \cdot DRRDG_b$$

In hours where NQS resources are ramping up to MLP, *energy* will be scheduled using the submitted ramp up *energy* to MLP profile. This is described in the equation for injections at a dispatchable generation resource bus in Section 3.6.1.6. In hours where NQS resources are ramping down from MLP, no *energy* will be scheduled.

Operating Reserve Ramping

Dispatchable Loads

In addition to *energy* ramping limitations, the total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to decrease load consumption.

For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} + \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} + \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \leq \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} - \sum_{j \in J_{h-1,b}^{E}} SDL_{h-1,b,j} + 60 \cdot DRRDL_b.$$

Dispatchable Generation Resources

In addition to *energy* ramping limitations, the total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed dispatchable generation resource cannot exceed its ramp capability to increase generation.

For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \leq \sum_{k \in K_{h-1,b}^{E}} SDG_{h-1,b,k} - \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + 60 \cdot URRDG_b;$$

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq [(h-n) \cdot 60 + 30] \cdot URRDG_b \cdot ODG_{h,b}$$

where n is the hour of the last start before or in hour h; and

$$\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \leq [(m-h) \cdot 60 + 30] \cdot DRRDG_b \cdot ODG_{h,b}$$

where m is the hour of the last shutdown in or after hour h.

NQS Resources

Schedules for NQS resources must observe minimum generation block run times, minimum generation block down times and *maximum number of starts per day*.

At the beginning of the day, a resource's previous day schedule is evaluated to determine any remaining *minimum generation block run time* constraints to enforce and determine the commitment status of the resource in hour 0. If $0 < InitOperHrs_b < MGBRTDG_b$, then the resource at bus $b \in B^{NQS}$ has yet to complete its *minimum generation block run time*, and:

$$ODG_{1,b}, ODG_{2,b}, \ldots, ODG_{min(24, MGBRTDG_b\text{-}InitOperHrs_b),b} = 1.$$

During the day, if $ODG_{h\text{-}1,b} = 0$, $ODG_{h,b} = 1$, and $MGBRTDG_b > 1$ for hour $h \in \{1,..,24\}$, then the resource at bus $b \in B^{NQS}$ has been scheduled to start up during hour h. It must be scheduled to remain in operation until it has completed its *minimum generation block run time* or to the end of the day. Therefore:

$$ODG_{h+1,b}, ODG_{h+2,b}, \ldots, ODG_{min(24, h + MGBRTDG_b\text{-}1),b} = 1.$$

During the day, if $ODG_{h\text{-}1,b} = 1$, $ODG_{h,b} = 0$, and $MGBDTDG_b > 1$ for hour $h \in \{1,..,24\}$, then the resource at bus $b \in B^{NQS}$ has been scheduled to shut down during hour h. It must be scheduled to remain off until it has completed its *minimum generation block down time* or to the end of the day. Therefore:

$$ODG_{h+1,b}, ODG_{h+2,b}, \ldots, ODG_{min(24, h + MGBDTDG_b\text{-}1),b} = 0.$$

A Boolean variable $IDG_{h,b}$ indicates that the NQS resource at bus $b \in B^{NQS}$ is scheduled to reach its *minimum loading point* in hour $h \in \{1,..,24\}$ after being scheduled below its *minimum loading point* in the preceding hour. A value of zero indicates that a resource is not scheduled to reach its *minimum loading point*, while a value of one indicates that it is scheduled to reach its *minimum loading point*.

Therefore, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{NQS}$:

$$IDG_{h,b} = \begin{cases} 1 & if\ ODG_{h-1,b} = 0\ and\ ODG_{h,b} = 1 \\ 0 & otherwise. \end{cases}$$

To ensure that NQS resources are not scheduled to be cycled on and off more than their specified maximum number in a day, the following constraint is defined for all buses $b \in B^{NQS}$:

$$\sum_{h=1..24} IDG_{h,b} \le MaxStartsDG_b.$$

Energy-Limited Resources

E*nergy*-limited resources cannot be scheduled to provide more *energy* than they have indicated they are capable of providing. The submitted *energy* limit both limits the total amount of *energy* scheduled over the course of a *dispatch day* and prevents *operating reserve* schedules which, if activated, would result in an exceedance of the submitted daily *energy* limit. A violation variable is provided for this constraint to improve the ability of the DAM calculation engine to find a solution. Given these factors, for all buses $b \in B^{ELR}$ where an *energy*-limited resource is located and all hours $H \in \{1,..,24\}$:

$$\sum_{h=1..H}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K^E_{h,b}}SDG_{h,b,k}\right)$$
$$+10ORConv\left(\sum_{k\in K^{10S}_{H,b}}S10SDG_{H,b,k}+\sum_{k\in K^{10N}_{H,b}}S10NDG_{H,b,k}\right)$$
$$+30ORConv\left(\sum_{k\in K^{30R}_{H,b}}S30RDG_{H,b,k}\right)-\sum_{i=1..N_{MaxDelViol_H}}SMaxDelViol_{H,b,i}$$
$$\leq MaxDEL_b.$$

The factors $10ORConv$ and $30ORConv$ are applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* for *energy*-limited resources to convert MW into MWh.

Hydroelectric Resources

A hydroelectric resource must be scheduled for at least its minimum daily *energy*. A violation variable is provided for this constraint to improve the ability of the DAM calculation engine to find a solution. For all hydroelectric resource buses $b \in B^{HE}$:

$$\sum_{h=1..24}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}}SDG_{h,b,k}+\sum_{i=1..N_{MinDelViol_h}}SMinDelViol_{h,b,i}\right)\geq MinDEL_b.$$

A Boolean variable $IHE_{h,b,i}$ indicates that a start for the hydroelectric resource at bus $b\in B^{HE}$ was counted in hour $h\in\{1,..24\}$ as a result of the resource schedule increasing from below its i-th start indication value to at or above its i-th start indication for $i\in\{1,..,NStartMW_b\}$. A value of zero indicates that a start was not counted, while a value of one indicates that a start was counted.

Therefore, for all hours $h\in\{1,..,24\}$, buses $b\in B^{HE}$ and start indication values $i\in\{1,..,NStartMW_b\}$:

$$IHE_{h,b,i}=\begin{cases}1 \quad if\left(ODG_{h-1,b}\cdot MinQDG_b+\sum_{k\in K^E_{h-1,b}}SDG_{h-1,b,k}<StartMW_{b,i}\right)\\ \qquad and\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K^E_{h,b}}SDG_{h,b,k}\geq StartMW_{b,i}\right)\\ 0 \quad otherwise.\end{cases}$$

To ensure that hydroelectric resources are not scheduled to be started more times than permitted by their *maximum number of starts per day* value, the following constraint is defined for all buses $b\in B^{HE}$:

$$\sum_{h=1..24}\left(\sum_{i=1..NStartMW_b} IHE_{h,b,i}\right) \leq MaxStartsHE_b.$$

The schedules for hydroelectric resources must respect shared maximum daily *energy* limits. A violation variable is provided for this constraint to improve the ability of the DAM calculation engine to find a solution. For all sets $s \in SHE$ and all hours $H \in \{1,..,24\}$:

$$\sum_{h=1..H}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b + \sum_{k\in K_{h,b}^E} SDG_{h,b,k}\right)\right) + \sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}} S10SDG_{H,b,k} + \sum_{k\in K_{H,b}^{10N}} S10NDG_{H,b,k}\right) + 30ORConv\left(\sum_{k\in K_{H,b}^{30R}} S30RDG_{H,b,k}\right)\right) - \sum_{i=1..N_{SMaxDelViol_H}} SSMaxDelViol_{H,s,i} \leq MaxSDEL_s.$$

As for a single resource with a daily *energy* limit, the factors $10ORConv$ and $30ORConv$ are applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserve* for *energy*-limited resources to convert MW into MWh.

The schedules for hydroelectric resources must respect shared minimum daily *energy* limits. A violation variable is provided for this constraint to improve the ability of the DAM calculation engine to find a solution. For all sets $s \in SHE$:

$$\sum_{h=1..24}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b + \sum_{k\in K_{h,b}^E} SDG_{h,b,k}\right) + \sum_{i=1..N_{SMinDelViol_h}} SSMinDelViol_{h,s,i}\right) \geq MinSDEL_s.$$

For linked hydroelectric resources, *energy* scheduled at the upstream resource in one hour will result in a proportional amount of *energy* being scheduled at the linked downstream resource in the hour determined by the time lag. Violation variables for both over and under generation at the downstream resource are provided for this constraint to improve the ability of the DAM calculation engine to find a solution.

For all linked hydroelectric resources between upstream resources $b_1 \in B_{up}^{HE}$ and downstream resources $b_2 \in B_{dn}^{HE}$ for $(b_1,b_2) \in LNK$ and hours $h \in \{1,..,24\}$ such that $h + Lag_{b_1,b_2} \leq 24$:

$$\sum_{b_2 \in B_{dn}^{HE}} \left(ODG_{h+Lag_{b_1,b_2},b_2} \cdot MinQDG_{b_2} + \sum_{k \in K_{b_2,h+Lag_{b_1,b_2}}^{E}} SDG_{k,h+Lag_{b_1,b_2},b_2} \right) - \sum_{i=1..N_{OGenLnkViol_{h+Lag_{b_1,b_2}}}} SOGenLnkViol_{h+Lag_{b_1,b_2},(b_1,b_2),i} + \sum_{i=1..N_{UGenLnkViol_{h+Lag_{b_1,b_2}}}} SUGenLnkViol_{h+Lag_{b_1,b_2},(b_1,b_2),i} = MWhRatio_{b_1,b_2} \cdot \sum_{b_1 \in B_{up}^{HE}} \left(ODG_{h,b_1} \cdot MinQDG_{b_1} + \sum_{k \in K_{b_1,h}^{E}} SDG_{k,h,b_1} \right)$$

3.6.1.6 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

Energy Balance

For each hour of the DAM, the total amount of *energy* scheduled on supply resources, including scheduled imports and scheduled virtual *offers* must be equal to the forecast *demand*, *energy* scheduled on load resources, including scheduled exports and scheduled virtual *bids*. This constraint will also account for transmission losses and is described further in terms of its constituent parts.

Define the total amount of withdrawals scheduled at load bus $b \in B$ in hour $h \in \{1,..,24\}$, $With_{h,b}$, as either:

- the price responsive load scheduled at bus b if $b \in B^{PRL}$; or
- all *dispatchable load* scheduled at bus b if $b \in B^{DL}$; or
- the *hourly demand response* quantity *bid* at bus b, net the amount of reduction scheduled if $b \in B^{HDR}$

so that

$$With_{h,b} = \begin{cases} \sum_{j \in J_{h,b}^{E}} SPRL_{h,b,j} & if\ b \in B^{PRL} \\ \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} & if\ b \in B^{DL} \\ \sum_{j \in J_{h,b}^{E}} (QHDR_{h,b,j} - SHDR_{h,b,j}) & if\ b \in B^{HDR} \end{cases}.$$

Define the net withdrawal from virtual transaction zonal trading entity $m \in M$ in hour $h \in \{1,..,24\}$, $VWith_{h,m}$, as all scheduled virtual transaction *bids* for *energy* less scheduled virtual *offers* for *energy.* Thus,

$$VWith_{h,m} = \left(\sum_{v \in VB_m} \sum_{j \in J^E_{h,v}} SVB_{h,v,j} \right) - \left(\sum_{v \in VO_m} \sum_{k \in K^E_{h,v}} SVO_{h,v,k} \right).$$

Define the total amount of withdrawals scheduled at *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$, $With_{h,d}$, as the exports from Ontario to the *intertie zone* sink bus. Thus,

$$With_{h,d} = \sum_{j \in J^E_{h,d}} SXL_{h,d,j}.$$

Define the total amount of injections scheduled at internal generation resource bus $b \in B$ in hour $h \in \{1,..,24\}$, $Inj_{h,b}$, as the sum of:

- either
    - non-dispatchable generation scheduled at that bus if $b \in B^{NDG}$; or
    - dispatchable generation scheduled at that bus if $b \in B^{DG}$; and
- ramp up to *energy* to *minimum loading point* if $b \in B^{NQS}$.

Let

$$OfferInj_{h,b} = \begin{cases} \sum_{k \in K^E_{h,b}} SNDG_{h,b,k} & if\ b \in B^{NDG} \\ ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} & if\ b \in B^{DG} \end{cases}$$

and

$$RampInj_{h,b} = \begin{cases} \sum_{w=1..min(RampHrs_b, 24-h)} RampE_{b,w} \cdot IDG_{h+w,b} & if\ b \in B^{NQS} \\ 0 & otherwise \end{cases}$$

so that

$$Inj_{h,b} = OfferInj_{h,b} + RampInj_{h,b}.$$

Define the total amount of injections scheduled at *intertie zone* source bus $d \in DI$ in hour $h \in \{1,..,24\}$, $Inj_{h,d}$, as the imports into Ontario from that *intertie zone* source bus. Thus

$$Inj_{h,d} = \sum_{k \in K^E_{h,d}} SIG_{h,d,k}.$$

Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the *demand* constraint violation will be subtracted from the total load or generation to ensure that the DAM calculation engine will always produce a solution. The resulting *energy* balance constraint for hour $h \in \{1,..,24\}$ is

$$\begin{aligned} AFL_h + \sum_{b \in B^{PRL} \cup B^{DL} \cup B^{HDR}} & (1 + MglLoss_{h,b}) \cdot With_{h,b} \\ & + \sum_{m \in M} (1 + VMglLoss_{h,m}) \cdot VWith_{h,m} \\ & + \sum_{d \in DX} (1 + MglLoss_{h,d}) \cdot With_{h,d} \\ & - \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \\ & = \sum_{b \in B^{NDG} \cup B^{DG}} (1 + MglLoss_{h,b}) \cdot Inj_{h,b} \\ & + \sum_{d \in DI} (1 + MglLoss_{h,d}) \cdot Inj_{h,d} \\ & - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} + LossAdj_h. \end{aligned}$$

Operating Reserve Requirements

Sufficient *operating reserve* must be scheduled to meet system-wide requirements for synchronized *ten-minute operating reserve*, total *ten-minute operating reserve,* and *thirty-minute operating reserve* plus, when applicable, flexibility *operating reserve*. All applicable regional minimum requirements and maximum restrictions for *operating reserve* must also be respected. Constraint violation penalty curves will be used to impose a penalty cost for not meeting the *IESO*'s system-wide *operating reserve* requirements, not meeting a regional minimum requirement, or not adhering to a regional maximum restriction. The *IESO* will therefore meet its full *operating reserve* requirements unless the cost of doing so would be higher than the applicable penalty cost. Therefore, the following constraints are required for each hour $h \in \{1,..24\}$:

$$\begin{aligned} \sum_{b \in B^{DL}} \left(\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \right) + \sum_{i=1..N_{10SViol_h}} S10SViol_{h,i} \\ \geq TOT10S_h; \end{aligned}$$

$$\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)$$
$$+\sum_{d\in DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)$$
$$+\sum_{d\in DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)+\sum_{i=1..N_{10RViol_h}} S10RViol_{h,i}\ \geq\ TOT10R_h;$$

and

$$\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)$$
$$+\sum_{d\in DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)$$
$$+\sum_{d\in DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)+\sum_{b\in B^{DL}}\left(\sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,j}\right)$$
$$+\sum_{d\in DX}\left(\sum_{j\in J_{h,d}^{30R}} S30RXL_{h,d,j}\right)+\sum_{b\in B^{DG}}\left(\sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k}\right)$$
$$+\sum_{d\in DI}\left(\sum_{k\in K_{h,d}^{30R}} S30RIG_{h,d,k}\right)+\sum_{i=1..N_{30RViol_h}} S30RViol_{h,i}\ \geq\ TOT30R_h.$$

The following constraints are required for each hour $h \in \{1,..24\}$ and each region $r \in ORREG$:

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$+\sum_{i=1..N_{REG10RViol_h}} SREG10RViol_{r,h,i}\ \geq\ REGMin10R_{h,r};$$

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$-\sum_{i=1..N_{XREG10RViol_h}} SXREG10RViol_{r,h,i}\le\ REGMax10R_{h,r};$$

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10S}} S10SDL_{h,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10S}} S10SDG_{h,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{10N}} S10NDL_{h,b,j}\right)+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{10N}} S10NXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{10N}} S10NDG_{h,b,k}\right)+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{10N}} S10NIG_{h,d,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{h,b}^{30R}} S30RDL_{h,b,j}\right)+\sum_{d\in D_r^{REG}\cap DX}\left(\sum_{j\in J_{h,d}^{30R}} S30RXL_{h,d,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{h,b}^{30R}} S30RDG_{h,b,k}\right)+\sum_{d\in D_r^{REG}\cap DI}\left(\sum_{k\in K_{h,d}^{30R}} S30RIG_{h,d,k}\right)$$
$$+\sum_{i=1..N_{REG30RViol_h}} SREG30RViol_{r,h,i}\ \ge\ REGMin30R_{h,r};$$

and

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \right) + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \right) + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,k} \right) + \sum_{d \in D_r^{REG} \cap DX} \left(\sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \right)$$
$$+ \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \right) + \sum_{d \in D_r^{REG} \cap DI} \left(\sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \right)$$
$$- \sum_{i=1..N_{XREG30RViol_h}} SXREG30RViol_{r,h,i} \leq REGMax30R_{h,r}.$$

IESO Internal Transmission Limits

The *IESO* must ensure that the set of DAM schedules produced would not violate any *security limits* in either the pre-contingency state or after any contingency. To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus as developed for the *energy* balance constraint will be used.

The *security* assessment function of the DAM calculation engine will linearize violated pre-contingency transmission limits on *facilities* within Ontario. For all hours $h \in \{1,..,24\}$ and *facilities* $f \in F_h$, the linearized constraints will take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG}} PreConSF_{h,f,b} \cdot Inj_{h,b} - \sum_{b \in B^{PRL} \cup B^{DL} \cup B^{HDR}} PreConSF_{h,f,b} \cdot With_{h,b}$$
$$- \sum_{m \in M} VPreConSF_{h,f,m} \cdot VWith_{h,m} + \sum_{d \in DI} PreConSF_{h,f,d} \cdot Inj_{h,d}$$
$$- \sum_{d \in DX} PreConSF_{h,f,d} \cdot With_{h,d} - \sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i}$$
$$\leq AdjNormMaxFlow_{h,f}.$$

Similarly, for all hours $h \in \{1,..,24\}$, contingencies $c \in C$, and *facilities* $f \in F_{h,c}$, the linearized constraints will take the form:

$$\sum_{b \in B^{NDG} \cup B^{DG}} SF_{h,c,f,b} \cdot Inj_{h,b} - \sum_{b \in B^{PRL} \cup B^{DL} \cup B^{HDR}} SF_{h,c,f,b} \cdot With_{h,b} - \sum_{m \in M} VSF_{h,c,f,m} \cdot VWith_{h,m} + \sum_{d \in DI} SF_{h,c,f,d} \cdot Inj_{h,d} - \sum_{d \in DX} SF_{h,c,f,d} \cdot With_{h,d} - \sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \le AdjEmMaxFlow_{h,c,f.}$$

Intertie Limits

The *IESO* must ensure that the set of DAM schedules produced would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. In each hour, the net amount of *energy* scheduled to flow over each *intertie* and the amount of scheduled *operating reserve* that would be delivered across the *intertie* must be calculated. For each flow limit constraint, these *energy* and *operating reserve* quantities (if applicable) will be summed over all affected *interties* and the result will be compared to the limit associated with that constraint. Therefore, for all hours $h \in \{1,..,24\}$ and all constraints $z \in Z_{Sch}$:

$$\sum_{a \in A:\, EnCoeff_{a,z} \neq 0} \left[\begin{array}{c} EnCoeff_{a,z} \left(\sum_{d \in DI_a} \sum_{k \in K^{E}_{h,d}} SIG_{h,d,k} - \sum_{d \in DX_a} \sum_{j \in J^{E}_{h,d}} SXL_{h,d,j} \right) \\ +0.5 \cdot (EnCoeff_{a,z} + 1) \left(\begin{array}{c} \sum_{d \in DI_a} \left(\sum_{k \in K^{10N}_{h,d}} S10NIG_{h,d,k} + \sum_{k \in K^{30R}_{h,d}} S30RIG_{h,d,k} \right) + \\ \sum_{d \in DX_a} \left(\sum_{j \in J^{10N}_{h,d}} S10NXL_{h,d,j} + \sum_{j \in J^{30R}_{h,d}} S30RXL_{h,d,j} \right) \end{array} \right) \end{array} \right] - \sum_{i=1..N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} \le MaxExtSch_{h,z}.$$

To model an *intertie* as out-of-service, the *intertie* transmission limits will be set to zero and all import *offers*, export *bids* and *operating reserve offers* will receive a zero schedule.

Changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour to obtain the net *interchange schedule* for the hour, and:

- It cannot exceed the net *interchange schedule* for the previous hour plus the maximum permitted hourly increase.
- It cannot be less than the net *interchange schedule* for the previous hour minus the maximum permitted hourly decrease.

Violation variables are provided for both the up and down ramp limits to ensure that the DAM calculation engine will always find a solution. Therefore, for all hours $h \in \{1,..,24\}$:

$$\sum_{d\in DI}\sum_{k\in K_{h-1,d}^{E}} SIG_{h-1,d,k} - \sum_{d\in DX}\sum_{j\in J_{h-1,d}^{E}} SXL_{h-1,d,j} - ExtDSC_h - \sum_{i=1..N_{NIDViol_h}} SNIDViol_{h,i}$$
$$\leq \sum_{d\in DI}\sum_{k\in K_{h,d}^{E}} SIG_{h,d,k} - \sum_{d\in DX}\sum_{j\in J_{h,d}^{E}} SXL_{h,d,j}$$
$$\leq \sum_{d\in DI}\sum_{k\in K_{h-1,d}^{E}} SIG_{h-1,d,k} - \sum_{d\in DX}\sum_{j\in J_{h-1,d}^{E}} SXL_{h-1,d,j} + ExtUSC_h$$
$$+ \sum_{i=1..N_{NIUViol_h}} SNIUViol_{h,i}.$$

Penalty Price Variable Bounds

The following constraints restrict the penalty price variables to the ranges determined by the penalty price curves. For all hours $h \in \{1,..,24\}$:

$0 \leq SLdViol_{h,i} \leq QLdViolSch_{h,i}$ for all $i \in \{1,..,N_{LdViol_h}\}$;

$0 \leq SGenViol_{h,i} \leq QGenViolSch_{h,i}$ for all $i \in \{1,..,N_{GenViol_h}\}$;

$0 \leq S10SViol_{h,i} \leq Q10SViolSch_{h,i}$ for all $i \in \{1,..,N_{10SViol_h}\}$;

$0 \leq S10RViol_{h,i} \leq Q10RViolSch_{h,i}$ for all $i \in \{1,..,N_{10RViol_h}\}$;

$0 \leq S30RViol_{h,i} \leq Q30RViolSch_{h,i}$ for all $i \in \{1,..,N_{30RViol_h}\}$;

$0 \leq SREG10RViol_{r,h,i} \leq QREG10RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG10RViol_h}\}$;

$0 \leq SREG30RViol_{r,h,i} \leq QREG30RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG30RViol_h}\}$;

$0 \leq SXREG10RViol_{r,h,i} \leq QXREG10RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG10RViol_h}\}$;

$0 \leq SXREG30RViol_{r,h,i} \leq QXREG30RViolSch_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG30RViol_h}\}$;

$0 \leq SPreITLViol_{f,h,i} \leq QPreITLViolSch_{f,h,i}$ for all $f \in F_h$, $i \in \{1,..,N_{PreITLViol_{f,h}}\}$;

$0 \leq SITLViol_{c,f,h,i} \leq QITLViolSch_{c,f,h,i}$ for all $c \in C, f \in F_{h,c}$, $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$;

$0 \leq SPreXTLViol_{z,h,i} \leq QPreXTLViolSch_{z,h,i}$ for all $z \in Z_{Sch}$, $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$;

$0 \leq SNIUViol_{h,i} \leq QNIUViolSch_{h,i}$ for all $i \in \{1,..,N_{NIUViol_h}\}$;

$0 \leq SNIDViol_{h,i} \leq QNIDViolSch_{h,i}$ for all $i \in \{1,..,N_{NIDViol_h}\}$;

$0 \leq SMaxDelViol_{h,b,i} \leq QMaxDelViolSch_{h,b,i}$ for all $b \in B^{ELR}$, $i \in \{1,..,N_{MaxDelViol_h}\}$;

$0 \leq SMinDelViol_{h,b,i} \leq QMinDelViolSch_{h,b,i}$ for all $b \in B^{HE}$, $i \in \{1,..,N_{MinDelViol_h}\}$;

$0 \leq SSMaxDelViol_{h,s,i} \leq QSMaxDelViolSch_{h,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMaxDelViol_h}\}$;

$0 \leq SSMinDelViol_{h,s,i} \leq QSMinDelViolSch_{h,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMinDelViol_h}\}$;

$0 \leq SOGenLnkViol_{h,(b_1,b_2),i} \leq QOGenLnkViol_{h,(b_1,b_2),i}$ for all $(b_1,b_2) \in LNK$, $i \in \{1,..,N_{OGenLnkViol_h}\}$; and

$0 \leq SUGenLnkViol_{h,(b_1,b_2),i} \leq QUGenLnkViol_{h,(b_1,b_2),i}$ for all $(b_1,b_2) \in LNK$, $i \in \{1,..,N_{UGenLnkViol_h}\}$.

3.6.1.7 Outputs

As-Offered Scheduling will produce schedules and unit commitment statuses for all resources.

For each variable SXX, SXX^{AOS} shall designate the value determined in As-Offered Scheduling. For example, $SDL^{AOS}_{h,b,j}$ shall designate the schedule computed for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$. As another example, $OHO^{AOS}_{h,b}$ shall designate whether the hydroelectric resource at bus $b \in B^{HE}$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

In particular, the unit commitment statuses and affiliated start-up decision determined in As-Offered Scheduling will be denoted as follows:

- $ODG^{AOS}_{h,b} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$; and
- $IDG^{AOS}_{h,b} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled to start (reach its *minimum loading point*) in hour $h \in \{1,..,24\}$.

The DAM calculation engine will record all such values for informational purposes. Internal resource schedules are provided to *market participants* at a 0.1 MW granularity. *Intertie* schedules are provided at a 1 MW granularity.

3.6.2. As-Offered Pricing

As-Offered Pricing will perform a *security*-constrained economic *dispatch* to meet the *IESO*'s average non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. As-Offered Pricing will also evaluate *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and *bids* to export *energy*. As-Offered Pricing will use the commitment statuses and resource schedules determined in As-Offered Scheduling to calculate prices in accordance with the principle for price-setting eligibility.

As-Offered Pricing will use *bids* and *offers* submitted by *market participants* to maximize the gains from trade. Like As-Offered Scheduling, the optimization is subject to the resource constraints accompanying those *bids* and *offers*, and system constraints enforced by the *IESO* to maintain *reliability*. However, the objective function and constraints will reflect the set of constraint violation penalty curves for market pricing.

As-Offered Pricing will determine a set of prices based upon the inputs described in Section 3.4.1 and applicable outputs provided by As-Offered Scheduling. The LMPs and related shadow prices will also be used in the Constrained Area Conditions Test and, if necessary, the Price Impact Test. Unless the Price Impact Test is performed and is failed, the LMPs calculated for *energy*-limited resources in As-Offered Pricing will be used in Pass 2. The prices produced will not be financially binding.

The following sections describe the formulation of the optimization function for As-Offered Pricing.

3.6.2.1 Inputs

All applicable inputs identified in Section 3.4.1 will be evaluated. Table 3-15 lists the outputs of As-Offered Scheduling that will also be used in As-Offered Pricing.

Table 3-15: Outputs of As-Offered Scheduling as Input to As-Offered Pricing

Input	Description
$SDG_{h,b,k}^{AOS}$	The amount of dispatchable generation scheduled at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}^{E}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled.
$ODG_{h,b}^{AOS}$	Designates whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
$S10SDG_{h,b,k}^{AOS}$	The amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}^{10S}$
$S10NDG_{h,b,k}^{AOS}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}^{10N}$.
$S30RDG_{h,b,k}^{AOS}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K_{h,b}^{30R}$.
$OHO_{h,b}^{AOS}$	Designates whether the hydroelectric resource at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

3.6.2.2 Variables and Objective Function

The variables used are mostly the same as those used in As-Offered Scheduling. However, the variables representing unit commitment decisions and hydroelectric minimum hourly output and start decisions are not needed as these decisions are fixed. Violation variables for the linked hydroelectric resource constraints are not needed in As-Offered Pricing. This is because the schedules of linked hydroelectric resources will largely be fixed from As-Offered Scheduling. That is, the same variables will be used except:

- $IDG_{h,b}$ for bus $b \in B^{DG}$ and hour $h \in \{1,..,24\}$ will no longer appear in the formulation;
- $ODG_{h,b}$ for bus $b \in B^{DG}$ and hour $h \in \{1,..,24\}$ will be fixed to a constant value as described in Section 3.6.2.3;
- $OHO_{h,b}$ for bus $b \in B^{HE}$ and hour $h \in \{1,..,24\}$ will be fixed to a constant value as described in Section 3.6.2.3; and
- $IHE_{h,b,i}$ for bus $b \in B^{HE}$, hour $h \in \{1,..,24\}$ and start indication value $i \in \{1,..,NStartMW_b\}$ will no longer appear in the formulation because hydroelectric resources with a limited number of starts will be scheduled in respect of their eligibility to set prices as described in Section 3.6.2.3.
- $SOGenLnkViol_{h,(b_1,b_2),i}$ for $(b_1, b_2) \in LNK$ such that $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$, hour $h \in \{1,..,24\}$ and $i \in \{1,..,N_{OGenLnkViol_h}\}$ will no longer appear in the formulation.$SUGenLnkViol_{h,(b_1,b_2),i}$ for $(b_1, b_2) \in LNK$ such that $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$, hour $h \in \{1,..,24\}$ and $i \in \{1,..,N_{UGenLnkViol_h}\}$ will no longer appear in the formulation.

Similar to As-Offered Scheduling, the objective function will be to maximize the gains from trade. However, any start-up costs and costs to operate at *minimum loading point* are not evaluated since the corresponding unit commitment decisions are fixed within As-Offered Pricing. The objective function is the same as in As-Offered Scheduling except:

- the start-up and minimum generation costs are constants and thus are dropped from the objective; and
- the violation cost is calculated using the set of constraint violation penalty curves for determining *market prices*.

Thus, As-Offered Pricing will maximize the value of the following expression:

$$\sum_{h=1,..,24} \begin{pmatrix} ObjPRL_h + ObjDL_h - ObjHDR_h + ObjVB_h + ObjXL_h - ObjNDG_h \\ - ObjDG_h - ObjVO_h - ObjIG_h - TB_h - ViolCost_h \end{pmatrix}$$

where:

$$ObjPRL_h = \sum_{b \in B^{PRL}} \left(\sum_{j \in J_{h,b}^{E}} SPRL_{h,b,j} \cdot PPRL_{h,b,j} \right)$$

$$ObjDL_h = \sum_{b \in B^{DL}} \left(\begin{array}{c} \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} \cdot PDL_{h,b,j} - \sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \cdot P10SDL_{h,b,j} - \\ \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \cdot P10NDL_{h,b,j} - \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \cdot P30RDL_{h,b,j} \end{array} \right)$$

$$ObjHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J_{h,b}^{E}} SHDR_{h,b,j} \cdot PHDR_{h,b,j} \right)$$

$$ObjVB_h = \sum_{v \in VB} \left(\sum_{j \in J_{h,v}^{E}} SVB_{h,v,j} \cdot PVB_{h,v,j} \right)$$

$$ObjXL_h = \sum_{d \in DX} \left(\begin{array}{c} \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \cdot PXL_{h,d,j} - \sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \cdot P10NXL_{h,d,j} \\ - \sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \cdot P30RXL_{h,d,j} \end{array} \right)$$

$$ObjNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{h,b}^{E}} SNDG_{h,b,k} \cdot PNDG_{h,b,k} \right)$$

$$ObjDG_h = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \cdot PDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \cdot P10SDG_{h,b,k} + \\ \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \cdot P10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \cdot P30RDG_{h,b,k} \end{array} \right)$$

$$ObjVO_h = \sum_{v \in VO} \left(\sum_{k \in K_{h,v}^{E}} SVO_{h,v,k} \cdot PVO_{h,v,k} \right)$$

$$ObjIG_h = \sum_{d \in DI} \left(\begin{array}{c} \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \cdot PIG_{h,d,k} + \sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \cdot P10NIG_{h,d,k} \\ + \sum_{k \in K_{h,d}^{30R}} S30IG_{h,d,k} \cdot P30RIG_{h,d,k} \end{array} \right)$$

and

$$
\begin{aligned}
ViolCost_h \ = \ & \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \cdot PLdViolPrc_{h,i} - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} \cdot PGenViolPrc_{h,i} \\
& + \sum_{i=1..N_{10SViol_h}} S10SViol_{h,i} \cdot P10SViolPrc_{h,i} \\
& + \sum_{i=1..N_{10RViol_h}} S10RViol_{h,i} \cdot P10RViolPrc_{h,i} \\
& + \sum_{i=1..N_{30RViol_h}} S30RViol_{h,i} \cdot P30RViolPrc_{h,i} \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG10RViol_h}} SREG10RViol_{r,h,i} \cdot PREG10RViolPrc_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{REG30RViol_h}} SREG30RViol_{r,h,i} \cdot PREG30RViolPrc_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG10RViol_h}} SXREG10RViol_{r,h,i} \cdot PXREG10RViolPrc_{h,i} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{i=1..N_{XREG30RViol_h}} SXREG30RViol_{r,h,i} \cdot PXREG30RViolPrc_{h,i} \right) \\
& + \sum_{f \in F_h} \left(\sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} \cdot PPreITLViolPrc_{f,h,i} \right) \\
& + \sum_{c \in C} \sum_{f \in F_{h,c}} \left(\sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \cdot PITLViolPrc_{c,f,h,i} \right) \\
& + \sum_{z \in Z_{Sch}} \left(\sum_{i=1..N_{PreXTLViol_{z,h}}} SPreXTLViol_{z,h,i} \cdot PPreXTLViolPrc_{z,h,i} \right) \\
& + \sum_{i=1..N_{NIUViol_h}} SNIUViol_{h,i} \cdot PNIUViolPrc_{h,i} \\
& + \sum_{i=1..N_{NIDViol_h}} SNIDViol_{h,i} \cdot PNIDViolPrc_{h,i}. \\
& + \sum_{b \in B^{ELR}} \left(\sum_{i=1..N_{MaxDelViol_h}} SMaxDelViol_{h,b,i} \cdot PMaxDelViolPrc_{h,b,i} \right) \\
& + \sum_{b \in B^{HE}} \left(\sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i} \cdot PMinDelViolPrc_{h,b,i} \right)
\end{aligned}
$$

$$+\sum_{s\in \mathrm{SHE}}\left(\sum_{i=1..N_{SMaxDelViol_h}} SSMaxDelViol_{h,s,i}\cdot PSMaxDelViolPrc_{h,s,i}\right)$$

$$+\sum_{s\in \mathrm{SHE}}\left(\sum_{i=1..N_{SMinDelViol_h}} SSMinDelViol_{h,s,i}\cdot PSMinDelViolPrc_{h,s,i}\right)$$

The tie-breaking term TB_h is defined as in As-Offered Scheduling. The maximization will be subject to the constraints described in the next sections.

3.6.2.3 Constraints Overview

The prices determined by As-Offered Pricing are intended to be a reflection of the marginal value of the *dispatch* and commitment decisions made in As-Offered Scheduling. Therefore, many of the constraints enforced in As-Offered Pricing are analogous to the constraints enforced in As-Offered Scheduling. However, additional constraints are required to ensure the eligibility of an *offer* or *bid* lamination to set price is appropriately reflected. The following list describes the additional constraints required.

Commitment Status Variables

Commitment decisions are fixed to the commitment statuses of resources calculated in As-Offered Scheduling. Therefore, for all hours $h\in\{1,..,24\}$ and all buses $b\in B^{DG}$:

$$ODG_{h,b} = ODG_{h,b}^{AOS}.$$

Energy-Limited Resources

For *energy*-limited resources with a maximum daily *energy* limit that was binding in As-Offered Scheduling, the schedules calculated in As-Offered Scheduling will determine the price-setting eligibility of the resource's *energy* and *operating reserve offer* laminations. In each hour, *energy* or *operating reserve* laminations up to the total amount of *energy* and *operating reserve* scheduled in As-Offered Scheduling will be eligible to set prices.

For bus $b\in B^{ELR}$, if there exists an hour $H\in\{1,..,24\}$ such that

$$\sum_{h=1..H}\left(ODG_{h,b}^{AOS}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}^{AOS}\right)+10ORConv\left(\sum_{k\in K_{H,b}^{10S}}S10SDG_{H,b,k}^{AOS}+\sum_{k\in K_{H,b}^{10N}}S10NDG_{H,b,k}^{AOS}\right)+30ORConv\left(\sum_{k\in K_{H,b}^{30R}}S30RDG_{H,b,k}^{AOS}\right)=MaxDEL_b,$$

then the maximum daily *energy* limit constraint is considered to be binding in As-Offered Scheduling. In such circumstances, the following constraint must hold for bus $b\in B^{ELR}$ for all hours $h\in\{1,..,24\}$:

$$\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}+\sum_{k\in K_{h,b}^{10S}}S10SDG_{h,b,k}+\sum_{k\in K_{h,b}^{10N}}S10NDG_{h,b,k}+\sum_{k\in K_{h,b}^{30R}}S30RDG_{h,b,k}\leq\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}^{AOS}+\sum_{k\in K_{h,b}^{10S}}S10SDG_{h,b,k}^{AOS}+\sum_{k\in K_{h,b}^{10N}}S10NDG_{h,b,k}^{AOS}+\sum_{k\in K_{h,b}^{30R}}S30RDG_{h,b,k}^{AOS}.$$

Hydroelectric Resources

For hydroelectric resources, the following constraints will be used to reflect the eligibility of *offer* and *bid* laminations to set prices in the *energy* and *operating reserve* markets. For certain operational constraints, a resource will only be limited in its ability to set prices in the *energy* market since the resource is still eligible to be scheduled for *operating reserve* when its *energy* schedule is limited by such a constraint.

Minimum Hourly Output

When a hydroelectric resource is scheduled for *energy* at or above its minimum hourly output in As-Offered Scheduling, the hydroelectric resource will also be scheduled at or above its minimum hourly output in As-Offered Pricing. The *energy offer* laminations corresponding to the minimum hourly output amount will be ineligible to set prices. When a hydroelectric resource with a minimum hourly output amount receives a zero schedule in As-Offered Scheduling, the hydroelectric resource will also receive a zero schedule in As-Offered Pricing and will be ineligible to set prices in the *energy* market. Thus, for all hours $h\in\{1,..,24\}$ and hydroelectric buses $b\in B^{HE}$:

$$ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^{E}}SDG_{h,b,k}\geq MinHO_{h,b}\cdot OHO_{h,b}^{AOS}$$

and for all $k\in K_{b,h}^{E}$:

$$0 \leq SDG_{h,b,k} \leq OHO^{AOS}_{h,b} \cdot QDG_{h,b,k}.$$

That is, the variable $OHO_{h,b}$ used in As-offered Scheduling will be set equal to the constant $OHO^{AOS}_{h,b}$.

Limited Number of Starts

Hydroelectric resources with a limited number of starts will be scheduled so that the resource is limited to set prices within an operating range consistent with the number of starts utilized by the resource's schedule determined by As-Offered Scheduling. To achieve this, the resource's schedule will be restricted to fall between the same start indication values as it fell between in As-Offered Scheduling. Thus, for all hydroelectric buses $b \in B^{HE}$ and all hours $h \in \{1,..,24\}$:

1. If $0 \leq ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG^{AOS}_{h,b,k} < StartMW_{b,1}$, then
$$0 \leq ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq StartMW_{b,1}\text{-}0.1$$
2. If $StartMW_{b,i} \leq ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG^{AOS}_{h,b,k} < StartMW_{b,i+1}$ for $i \in \{1,..,(NStartMW_b\text{-}1)\}$, then
$$StartMW_{b,i} \leq ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \leq StartMW_{b,i+1}\text{-}0.1$$
3. If $ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG^{AOS}_{h,b,k} \geq StartMW_{b,NStartMW_b}$, then
$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} \geq StartMW_{b,NStartMW_b}$$

Minimum Daily Energy Limit

For hydroelectric resources with a minimum daily *energy* limit that was binding in As-Offered Scheduling, the *energy* schedules calculated in As-Offered Scheduling will be treated as fixed blocks and will be ineligible to set prices. Thus, for all hydroelectric buses $b \in B^{HE}$ such that $MinDEL_b > 0$ and

$$\sum_{h=1..24} \left(ODG^{AOS}_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG^{AOS}_{h,b,k} \right) \leq MinDEL_b,$$

the following constraints must hold for all hours $h \in \{1,..,24\}$ and *offer* laminations $k \in K^E_{h,b}$:

$$SDG_{h,b,k} \geq SDG^{AOS}_{h,b,k}.$$

Shared Minimum Daily Energy Limit

A similar constraint holds for all sets of hydroelectric resources with a shared minimum daily *energy* limit that was binding in As-Offered Scheduling. In each hour, the sum of *energy* schedules calculated in As-Offered Scheduling for all resources in each set will be ineligible to set prices. *Energy* schedules for individual resources in each set may be changed compared to schedules in As-Offered Scheduling, but the sum of *energy* scheduled in each set will be at least equal to the sum of *energy* scheduled in As-Offered Scheduling. Thus, for all sets $s \in SHE$ such that

$$\sum_{h=1..24}\left(\sum_{b \in B_s^{HE}}\left(ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS}\right)\right) \leq MinSDEL_s,$$

the following constraints must hold for all hours $h \in \{1,..,24\}$:

$$\sum_{b \in B_s^{HE}}\left(ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}\right) \geq \sum_{b \in B_s^{HE}}\left(ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS}\right).$$

Shared Maximum Daily Energy Limit

Hydroelectric resources with a binding maximum daily *energy* limit are constrained as per the *energy*-limited resource constraint described above. A similar constraint holds for all sets of hydroelectric resources with a shared maximum daily *energy* limit that was binding in As-Offered Scheduling. In each hour, the sum of *energy* schedules calculated in As-Offered Scheduling for all resources in each set will be eligible to set prices. *Energy* schedules for individual resources in each set may be changed compared to schedules in As-Offered Scheduling, but the sum of *energy* scheduled in each set will be less than or equal to the sum of *energy* scheduled in As-Offered Scheduling.

For set $s \in SHE$, if there exists $H \in \{1,..,24\}$ such that

$$\begin{aligned}
&\sum_{h=1..H}\left(\sum_{b \in B_s^{HE}}\left(ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS}\right)\right) \\
&\quad + \sum_{b \in B_s^{HE}}\left(10ORConv\left(\sum_{k \in K_{H,b}^{10S}} S10SDG_{H,b,k}^{AOS} + \sum_{k \in K_{H,b}^{10N}} S10NDG_{H,b,k}^{AOS}\right)\right. \\
&\quad \left. + 30ORConv\left(\sum_{k \in K_{H,b}^{30R}} S30RDG_{H,b,k}^{AOS}\right)\right) = MaxSDEL_s,
\end{aligned}$$

then the maximum daily *energy* limit constraint is considered to be binding in As-Offered Scheduling.

In such circumstances, the following constraint must hold for all hours $h \in \{1,..,24\}$:

$$\sum_{b \in B_s^{HE}} \left(\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \right)$$
$$\leq \sum_{b \in B_s^{HE}} \left(\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS} + \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k}^{AOS} + \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k}^{AOS} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k}^{AOS} \right).$$

Linked Hydroelectric Resources

Energy offer laminations for linked hydroelectric resources on a cascade river system will be eligible to set prices consistently with the schedules calculated in As-Offered Scheduling. For all linked hydroelectric resources for which a MWh ratio was respected in As-Offered Scheduling, the resource will be scheduled between its As-Offered Scheduling schedule plus or minus Δ for some small tolerance Δ. The resource schedule will continue to be limited by its *offer* quantity bounds and any applicable resource minimum or maximum constraints. For all hours $h \in \{1,..,24\}$ and hydroelectric resource buses $b \in B^{HE}$ such $b \in \{b_1, b_2\}$ where $b_1 \in B_{up}^{HE}$ and $b_2 \in B_{dn}^{HE}$ for some $(b_1, b_2) \in LNK$ with $h + Lag_{b_1,b_2} \leq 24$:

$$max\left(0\,, ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS} - \Delta\,, AdjMinDG_{h,b}\right)$$
$$\leq ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}$$
$$\leq min\left(MinQDG_b + \sum_{k \in K_{h,b}^{E}} QDG_{h,b,k}\,,\ ODG_{h,b}^{AOS} \cdot MinQDG_b + \sum_{k \in K_{h,b}^{E}} SDG_{h,b,k}^{AOS} + \Delta\,,\ AdjMaxDG_{h,b} \right).$$

3.6.2.4 Bid/Offer Constraints Applying to Single Hours

Scheduling Variable Bounds and Commitment Status Variables

No schedule can be negative, nor can any schedule exceed the quantity *offered* for the respective market (*energy* and *operating reserve*). Therefore, for all hours $h \in \{1,..,24\}$:

$0 \leq SPRL_{h,b,j} \leq QPRL_{h,b,j}$ for all $b \in B^{PRL}$, $j \in J_{h,b}^{E}$;

$0 \leq SDL_{h,b,j} \leq QDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J_{h,b}^{E}$;

$0 \leq S10SDL_{h,b,j} \leq Q10SDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J_{h,b}^{10S}$;

$0 \leq S10NDL_{h,b,j} \leq Q10NDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{10N}_{h,b}$;

$0 \leq S30RDL_{h,b,j} \leq Q30RDL_{h,b,j}$ for all $b \in B^{DL}$, $j \in J^{30R}_{h,b}$;

$0 \leq SHDR_{h,b,j} \leq QHDR_{h,b,j}$ for all $b \in B^{HDR}$, $j \in J^{E}_{h,b}$;

$0 \leq SVB_{h,v,j} \leq QVB_{h,v,j}$ for all $v \in VB$, $j \in J^{E}_{h,v}$;

$0 \leq SXL_{h,d,j} \leq QXL_{h,d,j}$ for all $d \in DX$, $j \in J^{E}_{h,d}$;

$0 \leq S10NXL_{h,d,j} \leq Q10NXL_{h,d,j}$ for all $d \in DX$, $j \in J^{10N}_{h,d}$;

$0 \leq S30RXL_{h,d,j} \leq Q30RXL_{h,d,j}$ for all $d \in DX$, $j \in J^{30R}_{h,d}$;

$0 \leq SNDG_{h,b,k} \leq QNDG_{h,b,k}$ for all $b \in B^{NDG}$, $k \in K^{E}_{h,b}$;

$0 \leq SVO_{h,v,k} \leq QVO_{h,v,k}$ for all $v \in VO$, $k \in K^{E}_{h,v}$;

$0 \leq SIG_{h,d,k} \leq QIG_{h,d,k}$ for all $d \in DI$, $k \in K^{E}_{h,d}$;

$0 \leq S10NIG_{h,d,k} \leq Q10NIG_{h,d,k}$ for all $d \in DI$, $k \in K^{10N}_{h,d}$; and

$0 \leq S30RIG_{h,d,k} \leq Q30RIG_{h,d,k}$ for all $d \in DI$, $k \in K^{30R}_{h,d}$.

The schedules for dispatchable generation resources must also be consistent with their commitment status. Dispatchable *generation* resources can be scheduled to produce *energy* and *operating reserve* only if their commitment status variable is equal to 1. Therefore, for all hours $h \in \{1,..,24\}$:

$0 \leq SDG_{h,b,k} \leq ODG_{h,b} \cdot QDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{E}_{h,b}$;

$0 \leq S10SDG_{h,b,k} \leq ODG_{h,b} \cdot Q10SDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{10S}_{h,b}$;

$0 \leq S10NDG_{h,b,k} \leq ODG_{h,b} \cdot Q10NDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{10N}_{h,b}$; and

$0 \leq S30RDG_{h,b,k} \leq ODG_{h,b} \cdot Q30RDG_{h,b,k}$ for all $b \in B^{DG}$, $k \in K^{30R}_{h,b}$.

$ODG_{h,b}$ is a fixed constant in the above constraints as per Section 3.6.2.3.

Resource Minimums and Maximums

The constraints are the same as in As-Offered Scheduling. Resource minimum and maximum constraints limit a resource's ability to set prices to within the operating region defined by such constraints.

Operating Reserve Scheduling

The constraints are the same as in As-Offered Scheduling.

PSU Resources

The constraints are the same as in As-Offered Scheduling. A PSU resource that cannot provide *ten-minute operating reserve* from its duct firing region will be eligible to set prices within an operating range consistent with the schedules calculated. If the resource is scheduled for *energy* within the duct firing region, it will eligible to set prices in the *energy* and *thirty-minute operating reserve* markets. If the resource is not scheduled for *energy* within its duct firing region, it will be eligible to set prices in the *energy* and all *operating reserve* markets.

Hydroelectric Resources

A hydroelectric resource must be scheduled for its hourly must-run amount. For all hours $h \in \{1,..,24\}$ and hydroelectric resource buses $b \in B^{HE}$:

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq MinHMR_{h,b}.$$

The *energy offer* laminations corresponding to the hourly must-run amount will be ineligible to set prices.

The minimum hourly output constraints as described in As-Offered Scheduling are not required as they are replaced by the corresponding constraints in Section 3.6.2.3.

A hydroelectric resource cannot be scheduled within its *forbidden regions*. For all hours $h \in \{1,..,24\}$, all hydroelectric resource buses $b \in B^{HE}$ and all $i \in \{1,..,NFor_b\}$:

$$OFR_{h,b,i} \in \{0,1\};$$

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \leq OFR_{h,b,i} \cdot ForL_{b,i} + (1 - OFR_{h,b,i}) \cdot \left(MinQDG_b + \sum_{k \in K_{h,b}^E} QDG_{h,b,k} \right);$$

and

$$ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K_{h,b}^E} SDG_{h,b,k} \geq (1 - OFR_{h,b,i}) \cdot ForU_{b,i}.$$

A hydroelectric resource will be scheduled in respect of its *forbidden regions*, and therefore the resource is limited to set prices within the operating range determined by the adjacent *forbidden regions* between which the resource was scheduled.

Wheeling Through Transactions

These constraints are the same as in As-Offered Scheduling.

3.6.2.5 Bid/Offer Inter-Hour/Multi-Hour Constraints

Energy Ramping

These constraints are the same as in As-Offered Scheduling.

Operating Reserve Ramping

These constraints are the same as in As-Offered Scheduling.

NQS Resources

The variables associated with commitment of NQS resources are held fixed and therefore these constraints are no longer required.

Energy-Limited Resources

These constraints are the same as in As-Offered Scheduling. Schedules of *energy*-limited resources with a maximum daily *energy* limit that was binding in As-Offered Scheduling are additionally constrained as per Section 3.6.2.3.

Hydroelectric Resources

A hydroelectric resource must be scheduled for at least its minimum daily *energy*. A violation variable is provided for this constraint to ensure that the DAM calculation engine will always find a solution. For all hydroelectric resources buses $b \in B^{HE}$:

$$\sum_{h=1..24}\left(ODG_{h,b} \cdot MinQDG_b + \sum_{k\in K_{h,b}^E} SDG_{h,b,k} + \sum_{i=1..N_{MinDelViol_h}} SMinDelViol_{h,b,i}\right) \geq MinDEL_b.$$

For hydroelectric resources with a binding minimum daily *energy* limit in As-Offered Scheduling, the constraints in Section 3.6.2.3 imply the above constraint.

The maximum number of starts constraints are no longer required as they are replaced by the corresponding constraints in Section 3.6.2.3.

The schedules for hydroelectric resources must respect shared maximum daily *energy* limits. A violation variable is provided for this constraint to ensure that the DAM calculation engine will always find a solution.

For all sets $s \in SHE$ and all hours $H \in \{1,..,24\}$:

$$\begin{aligned}
&\sum_{h=1..H}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b} \cdot MinQDG_b + \sum_{k\in K_{h,b}^E} SDG_{h,b,k}\right)\right) \\
&\quad + \sum_{b\in B_s^{HE}}\left(10ORConv\left(\sum_{k\in K_{H,b}^{10S}} S10SDG_{H,b,k} + \sum_{k\in K_{H,b}^{10N}} S10NDG_{H,b,k}\right)\right. \\
&\quad \left. + 30ORConv\left(\sum_{k\in K_{H,b}^{30R}} S30RDG_{H,b,k}\right)\right) - \sum_{i=1..N_{SMaxDelViol_H}} SSMaxDelViol_{H,s,i} \\
&\quad \leq MaxSDEL_s.
\end{aligned}$$

The factors $10ORConv$ and $30ORConv$ are applied to scheduled *ten-minute* and *thirty-minute operating reserves* for *energy*-limited resources to convert MW into MWh.

The schedules for hydroelectric resources must respect shared minimum daily *energy* limits. A violation variable is provided for this constraint to ensure that the DAM calculation engine will always find a solution. For all sets $s \in SHE$:

$$\sum_{h=1..24}\left(\sum_{b\in B_s^{HE}}\left(ODG_{h,b}\cdot MinQDG_b+\sum_{k\in K_{h,b}^E} SDG_{h,b,k}\right)+\sum_{i=1..N_{SMinDelViol_h}} SSMinDelViol_{h,s,i}\right) \geq MinSDEL_s.$$

Analogous to maximum daily *energy* limits and minimum daily *energy* limits for a single resource, additional constraints will be applied when shared daily *energy* limits are binding as described in Section 3.6.2.3.

3.6.2.6 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

Energy Balance

The constraint is the same as in As-Offered Scheduling. The marginal loss factors used in the *energy* balance constraint in As-Offered Pricing will be fixed to the marginal loss factors used in the last optimization function iteration of As-Offered Scheduling.

Operating Reserve Requirements

The constraints are the same as in As-Offered Scheduling.

IESO Internal Transmission Limits

The constraints are the same as in As-Offered Scheduling. The sensitivities and limits considered are those provided by the most recent *security* assessment function iteration.

Intertie Limits

The constraints are the same as in As-Offered Scheduling.

Penalty Price Variable Bounds

The following constraints restrict the penalty price variables to the ranges determined by the penalty price curves. For all $h \in \{1,..,24\}$:

$0 \leq SLdViol_{h,i} \leq QLdViolPrc_{h,i}$ for all $i \in \{1,..,N_{LdViol_h}\}$;

$0 \leq SGenViol_{h,i} \leq QGenViolPrc_{h,i}$ for all $i \in \{1,..,N_{GenViol_h}\}$;

$0 \leq S10SViol_{h,i} \leq Q10SViolPrc_{h,i}$ for all $i \in \{1,..,N_{10SViol_h}\}$;

$0 \leq S10RViol_{h,i} \leq Q10RViolPrc_{h,i}$ for all $i \in \{1,..,N_{10RViol_h}\}$;

$0 \leq S30RViol_{h,i} \leq Q30RViolPrc_{h,i}$ for all $i \in \{1,..,N_{30RViol_h}\}$;

$0 \leq SREG10RViol_{r,h,i} \leq QREG10RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG10RViol_h}\}$;

$0 \leq SREG30RViol_{r,h,i} \leq QREG30RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{REG30RViol_h}\}$;

$0 \leq SXREG10RViol_{r,h,i} \leq QXREG10RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG10RViol_h}\}$;

$0 \leq SXREG30RViol_{r,h,i} \leq QXREG30RViolPrc_{h,i}$ for all $r \in ORREG$, $i \in \{1,..,N_{XREG30RViol_h}\}$;

$0 \leq SPreITLViol_{f,h,i} \leq QPreITLViolPrc_{f,h,i}$ for all $f \in F_h$, $i \in \{1,..,N_{PreITLViol_{f,h}}\}$;

$0 \leq SITLViol_{c,f,h,i} \leq QITLViolPrc_{c,f,h,i}$ for all $c \in C$, $f \in F_{h,c}$, $i \in \{1,..,N_{ITLViol_{c,f,h}}\}$;

$0 \leq SPreXTLViol_{z,h,i} \leq QPreXTLViolPrc_{z,h,i}$ for all $z \in Z_{Sch}$, $i \in \{1,..,N_{PreXTLViol_{z,h}}\}$;

$0 \leq SNIUViol_{h,i} \leq QNIUViolPrc_{h,i}$ for all $i \in \{1,..,N_{NIUViol_h}\}$;

$0 \leq SNIDViol_{h,i} \leq QNIDViolPrc_{h,i}$ for all $i \in \{1,..,N_{NIDViol_h}\}$;

$0 \leq SMaxDelViol_{h,b,i} \leq QMaxDelViolPrc_{h,b,i}$ for all $b \in B^{ELR}$, $i \in \{1,..,N_{MaxDelViol_h}\}$;

$0 \leq SMinDelViol_{h,b,i} \leq QMinDelViolPrc_{h,b,i}$ for all $b \in B^{HE}$, $i \in \{1,..,N_{MinDelViol_h}\}$;

$0 \leq SSMaxDelViol_{h,s,i} \leq QSMaxDelViolPrc_{h,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMaxDelViol_h}\}$; and

$0 \leq SSMinDelViol_{h,s,i} \leq QSMinDelViolPrc_{h,s,i}$ for all $s \in SHE$, $i \in \{1,..,N_{SMinDelViol_h}\}$.

3.6.2.7 Outputs

As-Offered Pricing will produce shadow prices for all constraints contributing to locational prices. A shadow price for a constraint reflects the cost savings achieved by relaxing that constraint a small amount and measuring the marginal response. LMPs will be calculated using the pricing formulas provided in Section 3.10, which specify how constraint shadow prices, marginal loss factors and constraint sensitivities are used to determine an LMP and its components.

Table 3-16 lists the shadow prices of As-Offered Pricing constraints that will be output for each hour $h \in \{1,..,24\}$.

Table 3-16: Shadow Price Outputs of As-Offered Pricing

Output	Description
SPL_h^{AOP}	shall designate the shadow price for the *energy* balance constraint.
$SPNormT_{h,f}^{AOP}$	shall designate the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour h.

Output	Description
$SPEmT_{h,c,f}^{AOP}$	shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h.
$SPExtT_{h,z}^{AOP}$	shall designate the shadow price for the import or export limit constraint $z \in Z_{Sch}$ in hour h.
$SPNIUExtBwdT_{h}^{AOP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h\text{-}1)$ and hour h.
$SPNIDExtBwdT_{h}^{AOP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour $(h\text{-}1)$ and hour h.
$SPNIUExtFwdT_{h}^{AOP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour h and hour $(h+1)$.
$SPNIDExtFwdT_{h}^{AOP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour h and hour $(h+1)$.
$SP10S_{h}^{AOP}$	shall designate the shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in hour h.
$SP10R_{h}^{AOP}$	shall designate the shadow price for the total *ten-minute operating reserve* requirement constraint in hour h.
$SP30R_{h}^{AOP}$	shall designate the shadow price for the total *thirty-minute operating reserve* requirement constraint in hour h.
$SPREGMin10R_{h,r}^{AOP}$	shall designate the shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMin30R_{h,r}^{AOP}$	shall designate the shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax10R_{h,r}^{AOP}$	shall designate the shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax30R_{h,r}^{AOP}$	shall designate the shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

Table 3-17 lists the LMPs and components for each hour $h \in \{1,..,24\}$ calculated using the pricing formulas in Section 3.10.

Table 3-17: LMP Outputs of As-Offered Pricing

Output	Description
$PRef_{h}^{AOP}$	shall designate the hour h *energy* reference price.
$LMP_{h,b}^{AOP}$	shall designate the hour h LMP for bus $b \in B$.
$PLoss_{h,b}^{AOP}$	shall designate the hour h loss component for bus $b \in B$.
$PCong_{h,b}^{AOP}$	shall designate the hour h congestion component for bus $b \in B$.
$ExtLMP_{h,d}^{AOP}$	shall designate the hour h LMP for *intertie zone* bus $d \in D$.
$IntLMP_{h,d}^{AOP}$	shall designate the hour h *intertie* border price (IBP) for *intertie zone* bus $d \in D$.
$ICP_{h,d}^{AOP}$	shall designate the hour h *intertie* congestion price (ICP) for *intertie zone* bus $d \in D$.
$PLoss_{h,d}^{AOP}$	shall designate the hour h loss component for *intertie zone* bus $d \in D$.
$PIntCong_{h,d}^{AOP}$	shall designate the hour h internal congestion component for *intertie zone* bus $d \in D$.
$PExtCong_{h,d}^{AOP}$	shall designate the hour h *intertie* congestion component for *intertie zone* bus $d \in D$.
$PNISL_{h,d}^{AOP}$	shall designate the hour h net interchange scheduling limit congestion component for *intertie zone* bus $d \in D$.
$L30RP_{h,b}^{AOP}$	shall designate the hour h *thirty-minute operating reserve* price for bus $b \in B$.
$L10NP_{h,b}^{AOP}$	shall designate hour h non-synchronized *ten-minute operating reserve* price for bus $b \in B$.
$L10SP_{h,b}^{AOP}$	shall designate the hour h synchronized *ten-minute operating reserve* price for bus $b \in B$.
$ExtL30RP_{h,d}^{AOP}$	shall designate the hour h *thirty-minute operating reserve* price for *intertie zone* bus $d \in D$.
$ExtL10NP_{h,d}^{AOP}$	shall designate the hour h non-synchronized *ten-minute operating reserve* price for *intertie zone* bus $d \in D$.

The DAM calculation engine will record all such values for informational purposes.

3.6.3. Constrained Area Conditions Test

The *IESO* will implement a conduct and impact testing methodology that will identify exercises of market power only when competition is restricted.

The goal of the constrained area conditions test is to identify when and where competition is restricted and to determine which resources will undergo the conduct test for financial *dispatch data* parameters. The *IESO* will use a specific set of conditions to determine whether resources qualify for the conduct test. These conditions are categorized into local market power conditions and global market power conditions. If no conditions are met, then the conduct test is not applied.

The following list identifies the *IESO*-defined conditions that would meet mitigation testing for *energy* and *operating reserve*. Refer to the Market Power Mitigation detailed design document for more details. Each of these conditions will be tested for separately, as detailed below.

- Local Market Power (*Energy*), including:
  - Narrow Constrained Area (NCA)
  - Dynamic Constrained Area (DCA)
  - Broad Constrained Area (BCA)
- Global Market Power (*Energy*)
- Global Market Power (*Operating Reserve*)
- Local Market Power (*Operating Reserve*)

The outputs of the conditions test are the set of resources that will be subject to the conduct test. A different set of resources will be identified for each market power condition as the conduct test depends on the condition triggered. The resource sets identified will be denoted as follows:

- $BCond_h^{NCA}$ shall designate the resources in an NCA that must be checked for local market power for *energy* in hour $h \in \{1,..,24\}$;
- $BCond_h^{DCA}$ shall designate the resources in a DCA that must be checked for local market power for *energy* in hour $h \in \{1,..,24\}$;
- $BCond_h^{BCA}$ shall designate the resources in a BCA that must be checked for local market power for *energy* in hour $h \in \{1,..,24\}$;
- $BCond_h^{GMP}$ shall designate the resources that must be checked for global market power for *energy* in hour $h \in \{1,..,24\}$;
- $BCond_h^{10S}$ shall designate the resources that must be checked for local market power for synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$;
- $BCond_h^{10N}$ shall designate the resources that must be checked for local market power for non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$;
- $BCond_h^{30R}$ shall designate the resources that must be checked for local market power for *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$;

- $BCond_h^{GMP10S}$ shall designate the resources that must be checked for global market power for synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$;
- $BCond_h^{GMP10N}$ shall designate the resources that must be checked for global market power for non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$; and
- $BCond_h^{GMP30R}$ shall designate the resources that must be checked for global market power for *thirty minute operating reserve* in hour $h \in \{1,..,24\}$.

3.6.3.1 Inputs

The constrained area conditions test will use the applicable inputs identified in Section 3.4.2. Table 3-18 lists the As-Offered Pricing outputs that will be also be used by the constrained area conditions test.

Table 3-18: Outputs of As-Offered Pricing as Input to the Constrained Area Conditions Test

Input	Description
$LMP_{h,b}^{AOP}$	The LMP for bus $b \in B$ in hour $h \in \{1,..,24\}$.
$PCong_{h,b}^{AOP}$	The congestion component of the LMP for bus $b \in B$ in hour $h \in \{1,..,24\}$.
$ExtLMP_{h,d}^{AOP}$	The LMP for *intertie* bus $d \in D$ in hour $h \in \{1,..,24\}$.
$PExtCong_{h,d}^{AOP}$	The *intertie* congestion component of the LMP for *intertie zone* bus $d \in D$ in hour $h \in \{1,..,24\}$.
$PIntCong_{h,d}^{AOP}$	The internal congestion component of the LMP for *intertie zone* bus $d \in D$ in hour $h \in \{1,..,24\}$.
$IntLMP_{h,d}^{AOP}$	The *intertie* border price (IBP) for *intertie zone* bus $d \in D$ in hour $h \in \{1,..,24\}$.
$SPNormT_{h,f}^{AOP}$	The shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour $h \in \{1,..,24\}$.
$SPEmT_{h,c,f}^{AOP}$	shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h.
$SPNIUExtBwdT_h^{AOP}$	The shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h\text{-}1)$ and hour h.
$L30RP_{h,b}^{AOP}$	The *thirty-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,..,24\}$.

Input	Description
$L10NP^{AOP}_{h,b}$	The non-synchronized *ten-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,..,24\}$.
$L10SP^{AOP}_{h,b}$	The synchronized *ten-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,..,24\}$.

3.6.3.2 Conditions Test for Local Market Power (Energy) Constrained Areas

The following sections describe the conditions that must be met for resources located within an NCA, DCA or BCA to qualify for local market power (*energy*) mitigation testing.

NCA and DCA

If at least one transmission constraint for the NCA or DCA is binding in As-Offered Pricing, all resources identified as within that constrained area will qualify to undergo the conduct test.

NCAs or DCAs that meet this criterion will be assigned to the following subsets:

- NCA_h' shall designate the NCAs that qualify for MPM in hour $h \in \{1,..,24\}$; and
- DCA_h' shall designate the DCAs that qualify for MPM in hour $h \in \{1,..,24\}$.

The process for identifying resources in NCAs and DCAs that qualify for MPM is as follows:

For each $n \in NCA$ and hour $h \in \{1,..,24\}$:

- For each transmission *facility* that transmits flow into n, $f \in F^{NCA}_n$, check if $SPNormT^{AOP}_{h,f} \neq 0$ or $SPEmT^{AOP}_{h,c,f} \neq 0$ for the inbound flow limit. If true, place n in the set NCA_h' and assign the resources in n to the set $BCond^{NCA}_h$.

For each $d \in DCA$ and hour $h \in \{1,..,24\}$r:

- For each transmission *facility* that transmits flow into d, $f \in F^{DCA}_d$, check if $SPNormT^{AOP}_{h,f} \neq 0$ 0 or $SPEmT^{AOP}_{h,c,f} \neq 0$ for the inbound flow limit. If true, place d in the set DCA_h' and assign the resources in d to the set $BCond^{DCA}_h$.

BCA

A BCA will be identified where the congestion component of the resource's LMP is greater than $BCACondThresh$, and the resource is not part of an NCA or DCA that has a binding transmission constraint.

The process for identifying BCAs that qualify for MPM is as follows:

For each hour $h \in \{1,..,24\}$:

- For each bus $b \in B^{DG}$ such that $b \notin BCond_h^{NCA} \cup BCond_h^{DCA}$, check if $PCong_{h,b}^{AOP} > BCACondThresh$. If true, then place resource b in the set $BCond_h^{BCA}$

3.6.3.3 Conditions Test for Global Market Power (Energy) Constrained Areas

There are two conditions that must both be present to test *energy* resources for global market power. The DAM calculation engine will check for these conditions, and if met, perform the conduct test on applicable resources. Conditions and applicable resources are discussed below.

Condition 1: Unable to schedule incremental imports

This condition is indicated in hour $h \in \{1,..,24\}$ by one of the following:

- Import congestion, represented by a negative *intertie* congestion component, is present on all of the Global Market Power Reference Interties. This condition is indicated by:

  $PExtCong_{h,d}^{AOP} < 0$ for bids and offers, $d \in D^{GMPRef}$, corresponding to the reference *interties* proxy location

- Net Interchange Scheduling Limit (NISL) is binding for imports, represented by a non-zero NISL shadow price for incremental imports. This condition is indicated by:

  $SPNIUExtBwdT_h^{AOP} \neq 0$

Condition 2: Pricing

If the *intertie* border price (IBP) at the Global Market Power Reference Interties is greater than the specified threshold value, then condition 2 will be met. This condition is indicated in hour $h \in \{1,..,24\}$ by:

$IntLMP_{h,d}^{AOP} > IBPThresh$ for bids and offers, $d \in D^{GMPRef}$, corresponding to the reference *interties* proxy location.

Resources Tested

If both conditions 1 and 2 are met, the DAM calculation engine will test *market participants* with resources that can meet incremental load within Ontario for global market power. Resources with a congestion component at least $1/MWh below the internal congestion component at all of the Global Market Power Reference Interties will be exempted from testing for global market power.

The process for identifying resources that qualify for the conduct test for global market power in the *energy* market is as follows.

For each hour $h \in \{1,..,24\}$, if conditions 1 and 2 to trigger global market power for *energy* testing are met:

1. Place all $b \in B^{DG}$ in the set $BCond_h^{GMP}$.
2. Next, for each transmission *facility*, check if $SPNormT_{h,f}^{AOP} \neq 0 \; or \; SPEmT_{h,c,f}^{AOP} \neq 0$. If true, then remove all resources that have positive sensitivity factor on that transmission *facility* from the set $BCond_h^{GMP}$.
3. And, for all resources $b \in B^{DG}$ in all zones, if $PCong_{h,b}^{AOP} < PIntCong_{h,d}^{AOP}$-$\$1/MWh$ where $d \in D^{GMPRef}$ (must be true for all Global Market Power Reference Interties), then remove resource b from the set $BCond_h^{GMP}$.

3.6.3.4 Conditions Test for Local Market Power (Operating Reserve) Constrained Areas

Conditions to test for local market power in the *operating reserve market* occur when there are reserve areas with a minimum requirement greater than zero. Resources offering *operating reserve* in these areas will be subject to the conduct test unless the resource is also located in a reserve area with a binding maximum restriction constraint, in which case the resource is exempt from mitigation testing for local market power in the *operating reserve* market.

The process for identifying the resources that qualify for mitigation testing for local market power for *operating reserve* is as follows.

For each $b \in B^{DG} \cup B^{DL}$ and hour $h \in \{1,..,24\}$:

- If b is in a region with a binding area reserve maximum restriction constraint, then b is exempt from the conduct test.
- Otherwise, if b is in a region with a non-zero area reserve minimum requirement, then b is subject to the conduct test and is placed in the set $BCond_h^{10S}$, $BCond_h^{10N}$,or $BCond_h^{30R}$.

3.6.3.5 Conditions Test for Global Market Power (Operating Reserve) Constrained Areas

Conditions to test for global market power in the *operating reserve* market occur when there is an *operating reserve* LMP greater than $ORGCondThresh$. All resources offering in that class of *operating reserve* will be tested, except resources in a reserve area with a binding maximum restriction constraint.

The process for identifying the resources that qualify for mitigation testing for global market power for *operating reserve* is as follows.

For each $b \in B^{DG} \cup B^{DL}$ and hour $h \in \{1,..,24\}$:

- If b is in a region with a binding max constraint, then b is exempt from the conduct test; otherwise:

- Check if $L10SP_{h,b}^{AOP}$ >ORGCondThresh. If true, then add resource b to $BCond_h^{GMP10S}$
- Check if $L10NP_{h,b}^{AOP}$ >ORGCondThresh. If true, then add resource b to $BCond_h^{GMP10N}$
- Check if $L30RP_{h,b}^{AOP}$ >ORGCondThresh. If true, then add resource b to $BCond_h^{GMP30R}$

3.6.4. Conduct Test

All resources that meet the constrained area conditions test criteria described above will undergo a conduct test. If no such resources are identified, then the Market Power Mitigation process is complete and the conduct test will not occur.

In the conduct test, the *dispatch data* parameters submitted by *market participants* for their resources will be evaluated against reference levels. The conduct test checks whether financial *dispatch data* parameter values are within a set threshold level of the reference level. If a resource qualifies for more than one conduct test in either *energy* or *operating reserve*, the test with the most stringent threshold levels will be performed.

If all resource financial *dispatch data* parameters pass the conduct test, the Market Power Mitigation process is complete and no mitigation is required. If one or more financial *dispatch data* parameters fail the conduct test, the DAM calculation engine will perform Reference Level Scheduling, Reference Level Pricing and the Market Power Mitigation Price Impact Test.

3.6.4.1 Inputs

The conduct test will use the applicable inputs identified in Section 3.4.2.

3.6.4.2 Variables

A set of resources that failed the conduct test for at least one financial *dispatch data* parameter will be identified for each condition, where:

- BCT_h^{NCA} shall designate the resources in an NCA that failed the conduct test for at least one *dispatch data* parameter in hour $h \in \{1,..,24\}$;
- BCT_h^{DCA} shall designate the resources in a DCA that failed the conduct test for at least one *dispatch data* parameter in hour $h \in \{1,..,24\}$;
- BCT_h^{BCA} shall designate the resources in a BCA that failed the conduct test for at least one *dispatch data* parameter in hour $h \in \{1,..,24\}$;
- BCT_h^{GMP} shall designate the resources that failed the global market power (*energy*) conduct test for at least one *dispatch data* parameter in hour $h \in \{1,..,24\}$;

- BCT_h^{ORL} shall designate the resources that failed the local market power (OR) conduct test for at least one *dispatch data* parameter in hour $h \in \{1,..,24\}$; and
- BCT_h^{ORG} shall designate the resources that failed the global market power conduct test for *operating reserve* for at least one *dispatch data* parameter in hour $h \in \{1,..,24\}$

The conduct test will also identify the following sets of *dispatch data* parameters for all hours $h \in \{1,..,24\}$:

- $PARAME_{h,b}$ shall designate the set of *dispatch data* parameters that failed the *energy* conduct test for bus $b \in BCT_h^{NCA} \cup BCT_h^{DCA} \cup BCT_h^{BCA} \cup BCT_h^{GMP}$ in hour h; and
- $PARAMOR_{h,b}$ shall designate the set of *dispatch data* parameters that failed the *operating reserve* conduct test for bus $b \in BCT_h^{ORL} \cup BCT_h^{ORG}$ in hour h.

For any resource at bus $b \in B^{DG}$, the following *dispatch data* parameters may be identified in $PARAME_{h,b}$:

- $EnergyOffer_k$ indicating a non-zero quantity of the *energy offer* above MLP lamination $k \in K_{h,b}^{E}$ failed the conduct test;
- $EnergyToMLP_k$ indicating a non-zero quantity of the *energy offer* for *energy* to MLP lamination $k \in K_{h,b}^{LTMLP}$ failed the conduct test;
- $SUOffer$ indicating the start-up offer failed the conduct test; and
- $SNLOffer$ indicating the speed no-load offer failed the conduct test.

For any resource at bus $b \in B^{DG} \cup B^{DL}$, the following *dispatch data* parameters may be identified in $PARAMOR_{h,b}$.

- $OR10SOffer_k$ indicating a non-zero quantity of the 10-minute synchronized *operating reserve offer* lamination $k \in K_{h,b}^{10S}$ failed the conduct test;
- $OR10NOffer_k$ indicating a non-zero quantity of the 10-minute non-synchronized *operating reserve offer* lamination $k \in K_{h,b}^{10N}$ failed the conduct test;
- $OR30ROffer_k$ indicating a non-zero quantity of the 30-minute *operating reserve offer* lamination $k \in K_{h,b}^{30R}$ failed the conduct test;
- $SUOffer$ indicating the start-up offer failed the conduct test;
- $SNLOffer$ indicating the speed no-load offer failed the conduct test; and
- $EnergyToMLP_k$ indicating a non-zero quantity of the *energy offer* for the *energy* to MLP lamination $k \in K_{h,b}^{E}$ failed the conduct test.

Commitment cost *dispatch data* parameters will be tested for all hours prior to and including the last hour where conditions are met for both the *energy* and *operating reserve* conduct test.

3.6.4.3 Conduct Test for Energy

Resources that qualify for testing for market power mitigation in the *energy* market will have the following *dispatch data* parameters evaluated:

- *Energy offer*, including *offers* up to and above MLP (only applicable if *energy offer* is greater than $CTEnMinOffer$),
- Start-up offer, and
- Speed no-load offer.

The *IESO* will perform the conduct test for resources that were selected in the constrained area conditions test for NCAs as follows.

For each hour $h \in \{1,..,24\}$ and $b \in BCond_h^{NCA}$:

- Evaluate *energy offer* above MLP: For all $k \in K_{h,b}^{E}$, if $PDG_{h,b,k} > CTEnMinOffer$ and $PDG_{h,b,k} > min(PDGRef_{h,b,k} * (1 + CTEnThresh1^{NCA}), PDGRef_{h,b,k} + CTEnThresh2^{NCA})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{NCA} and add $EnergyOffer_k$ to $PARAME_{h,b}$.
- Evaluate *energy offer* for the range of production up to MLP: For all hours prior to and including the hour that meets the conditions test, for all $k \in K_{h,b}^{LTMLP}$, if $PLTMLP_{h,b,k} > CTEnMinOffer$ and $PLTMLP_{h,b,k} > min(PLTMLPRef_{h,b,k} * (1 + CTEnThresh1^{NCA}), PLTMLPRef_{h,b,k} + CTEnThresh2^{NCA})$ then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{NCA} and add $EnergyToMLP_k$ to $PARAME_{h,b}$.
- Evaluate start-up offer: For all hours prior to and including the hour that meets the conditions test, if $SUDG_{h,b} > SUDGRef_{h,b} * (1 + CTSUThresh^{NCA})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{NCA} and add $SUOffer$ to $PARAME_{h,b}$.
- Evaluate speed no-load offer: For all hours prior to and including the hour that meets the conditions test, if $SNL_{h,b} > SNLRef_{h,b} * (1 + CTSNLThresh^{NCA})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{NCA} and add $SNLOffer$ to $PARAME_{h,b}$.

The conduct test for DCA, BCA, and Global Market Power (*Energy*) would take the same form, while referencing resources in $BCond_h^{DCA}$, $BCond_h^{BCA}$, and $BCond_h^{GMP}$ and using the appropriate conduct test thresholds. Additionally, resources will be assigned to the subsets BCT_h^{DCA}, BCT_h^{BCA}, and BCT_h^{GMP}.

3.6.4.4 Conduct Test for Operating Reserve

Resources that qualify for *operating reserve* market power mitigation will have the following parameters evaluated:

- *Operating reserve offer* (only applicable if it is greater than $CTORMinOffer$),
- Start-up offer,
- Speed no-load offer; and
- *Energy offers* for the range of production up to MLP.

As noted above, if a resource qualifies for more than one *operating reserve* conduct test, the test with the most stringent threshold levels will be performed.

The *IESO* will perform the conduct test for resources that were selected in the Local Market Power (*Operating Reserve*) constrained area conditions test as follows.

For each hour $h \in \{1,..,24\}$ and $b \in BCond_h^{10S} \cup BCond_h^{10N} \cup BCond_h^{30R}$:

- Evaluate *operating reserve offer*:
  - For all $k \in K_{h,b}^{10S}$ if $P10SDG_{h,b,k} > CTORMinOffer$ and $P10SDG_{h,b,k} > min(P10SDGRef_{h,b,k} * (1 + CTORThresh1^{ORL}), P10SDGRef_{h,b,k} + CTORThresh2^{ORL})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{ORL} and add $OR10SOffer_k$ to $PARAMOR_{h,b}$.
  - For all $k \in K_{h,b}^{10N}$ if $P10NDG_{h,b,k} > CTORMinOffer$ and $P10NDG_{h,b,k} > min(P10NDGRef_{h,b,k} * (1 + CTORThresh1^{ORL}), P10NDGRef_{h,b,k} + CTORThresh2^{ORL})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{ORL} and add $OR10NOffer_k$ to $PARAMOR_{h,b}$.
  - For all $k \in K_{h,b}^{30R}$ if $P30RDG_{h,b,k} > CTORMinOffer$ and $P30RDG_{h,b,k} > min(P30RDGRef_{h,b,k} * (1 + CTORThresh1^{ORL}), P30RDGRef_{h,b,k} + CTORThresh2^{ORL})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{ORL} and add $OR30ROffer_k$ to $PARAMOR_{h,b}$.
- Evaluate *start-up offer*: For all hours prior to and including the hour that meets the conditions test, if $SUDG_{h,b} > SUDGRef_{h,b} * (1 + CTSUThresh^{ORL})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{ORL} and add $SUOffer$ to $PARAMOR_{h,b}$.
- Evaluate *speed no-load offer*: For all hours prior to and including the hour that meets the conditions test, if $SNL_{h,b} > SNLRef_{h,b} * (1 + CTSNLThresh^{ORL})$, then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{ORL} and add $SNLOffer$ to $PARAMOR_{h,b}$.
- Evaluate *energy offers* for the range of production up to MLP: For all hours prior to and including the hour that meets the conditions test, for all $k \in K_{h,b}^{LTMLP}$, if $PLTMLP_{h,b,k} > CTEnMinOffer$ and $PLTMLP_{h,b,k} > min(PLTMLPRef_{h,b,k} * (1 + CTEnThresh1^{ORL}), PLTMLPRef_{h,b,k} +$

$CTEnThresh2^{ORL}$) then conduct test failed for resource at bus b. Assign resource to subset BCT_h^{ORL} and add $EnergyToMLP_k$ to $PARAMOR_{h,b}$.

The conduct test for Global Market Power (*Operating Reserve*) would take the same form, while referencing resources in $BCond_h^{GMP10S}$, $BCond_h^{GMP10N}$, and $BCond_h^{GMP30R}$ and using the appropriate conduct test thresholds. Additionally, resources will be assigned to the subset BCT_h^{ORG}.

3.6.4.5 Outputs

The outputs of the conduct test will include the following for each hour $h \in \{1,..,24\}$:

1. The set of resources that failed the conduct test for at least one parameter by condition type (i.e. resources included in the sets BCT_h^{NCA}, BCT_h^{DCA}, BCT_h^{BCA}, BCT_h^{GMP}, BCT_h^{ORL}, BCT_h^{ORG}).
2. The *dispatch data* parameters that failed the conduct test for the resource at bus b (i.e. *dispatch data* parameters included in the sets $PARAME_{h,b}$ and $PARAMOR_{h,b}$), and
3. A revised set of financial *dispatch data* parameters for resources that failed a conduct test with *dispatch data* parameters that failed the conduct test replaced with reference levels. For *energy* and *operating reserve offers* with multiple laminations:
   - If one or more lamination in the *energy offer* for the range of production up to MLP fails the conduct test, the DAM calculation engine will replace all laminations in the *energy offer* for the range of production up to MLP.
   - If one or more lamination in the *energy offer* for the range of production above MLP fails the conduct test, the DAM calculation engine will replace all laminations in *energy offers* for the entire range of production (up to and above MLP).
   - If one or more lamination in the *operating reserve offer* fails the conduct test, the DAM calculation engine will replace all laminations in the *operating reserve offer*.

3.6.5. Reference Level Scheduling

Reference Level Scheduling will perform a *security*-constrained unit commitment and economic *dispatch* similar to that performed by As-Offered Scheduling. Reference Level Scheduling only differs from As-Offered Scheduling in that it will use reference level *dispatch data* for any financial *dispatch data* from *registered market participants* that failed the conduct test.

Reference Level Scheduling will determine commitment statuses and schedules. These commitments will serve as inputs into Reference Level Pricing. The schedules produced will not be financially binding.

The following sections describe the formulation of the optimization function for Reference Level Scheduling.

3.6.5.1 Inputs

All applicable inputs identified in Section 3.4.1 will be used. Reference level *dispatch data* will be used for any inputs from *registered market participants* that failed the conduct test.

3.6.5.2 Variables, Objective Function, and Constraints

The variables, objective function and set of constraints are the same as those used in As-Offered Scheduling.

3.6.5.3 Outputs

Reference Level Scheduling will produce schedules and unit commitment statuses for all resources.

For each scheduling variable SXX, SXX^{RLS} shall designate the value determined in Reference Level Scheduling. For example, $SDL_{h,b,j}^{RLS}$ shall designate the schedule computed for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\} \in \{1,..,24\}$. As another example, $OHO_{h,b}^{RLS}$ shall designate whether the hydroelectric resource at bus $b \in B^{HE}$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\} \in \{1,..,24\}$.

In particular, the unit commitment statuses and affiliated start-up decision determined in Reference Level Scheduling will be denoted as follows:

- $ODG_{h,b}^{RLS} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$; and
- $IDG_{h,b}^{RLS} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled to start (reach its *minimum loading point*) in hour $h \in \{1,..,24\}$..

The DAM calculation engine will record all such values for informational purposes.

3.6.6. Reference Level Pricing

Reference Level Pricing will perform a *security*-constrained economic *dispatch* similar to that performed by As-Offered Pricing. Reference Level Pricing differs from As-Offered Pricing in that it will use reference level *dispatch data* for any financial *dispatch data* from *registered market participants* that failed the conduct test. Reference Level Pricing also differs from As-Offered Pricing in that the principle for price-setting eligibility will be applied by taking into account the Reference Level Scheduling results.

Reference Level Pricing will determine an initial set of LMPs. The LMPs will be used in the price impact test. The prices produced will not be financially binding.

The following sections describe the formulation of the optimization function for Reference Level Pricing.

3.6.6.1 Inputs

All applicable inputs identified in Section 3.4.1 will be evaluated. Reference level *dispatch data* will be used for any inputs from *registered market participants* that failed the conduct test. Table 3-19 lists the outputs of Reference Level Scheduling that will also be used for Reference Level Pricing.

Table 3-19: Output of Reference Level Scheduling as Input to Reference Level Pricing

Input	Description
$SDG^{RLS}_{h,b,k}$	The amount of dispatchable generation scheduled at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,b}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled.
$ODG^{RLS}_{h,b}$	Designates whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
$S10SDG^{RLS}_{h,b,k}$	The amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$.
$S10NDG^{RLS}_{h,b,k}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$.
$S30RDG^{RLS}_{h,b,k}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,b}$.
$OHO^{RLS}_{h,b}$	Designates whether the hydroelectric resource at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

3.6.6.2 Variables, Objective Function, and Constraints

The variables and objective function are the same as those used in As-Offered Pricing. Many of the constraints enforced in Reference Level Pricing are the same as those enforced in As-Offered Pricing. However, the constraints used to apply the principle for price setting eligibility must be modified to take into account the Reference Level Scheduling results. That is, for the additional constraints listed in Section 3.6.2.3, the As-Offered Scheduling results are replaced by the Reference Level Scheduling results as follows:

- $SDG^{AOS}_{h,b,k}$ is replaced by $SDG^{RLS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{E}_{h,b}$;
- $ODG^{AOS}_{h,b}$ is replaced by $ODG^{RLS}_{h,b}$ for all $h \in \{1,..,24\}$, $b \in B^{DG}$;
- $S10SDG^{AOS}_{h,b,k}$ is replaced by $S10SDG^{RLS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10S}_{h,b}$;
- $S10NDG^{AOS}_{h,b,k}$ is replaced by $S10NDG^{RLS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10N}_{h,b}$;
- $S30RDG^{AOS}_{h,b,k}$ is replaced by $S30RDG^{RLS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{30R}_{h,b}$; and
- $OHO^{AOS}_{h,b}$ is replaced by $OHO^{RLS}_{h,b}$ for all $h \in \{1,..,24\}$, $b \in B^{HE}$.

Additionally, the marginal loss factors used in the *energy* balance constraint in Reference Level Pricing will be fixed to the marginal loss factors used in the last optimization function iteration of Reference Level Scheduling.

3.6.6.3 Outputs

Table 3-20 lists the shadow prices of Reference Level Pricing constraints that will be output for each hour $h \in \{1,..,24\}$.

Table 3-20: Shadow Price Outputs of Reference Level Pricing

Output	Description
SPL^{RLP}_{h}	shall designate the shadow price for the *energy* balance constraint.
$SPNormT^{RLP}_{h,f}$	shall designate the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour h.
$SPEmT^{RLP}_{h,c,f}$	shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h.
$SPExtT^{RLP}_{h,z}$	shall designate the shadow price for the import or export limit constraint $z \in Z_{Sch}$ in hour h.

Output	Description
$SPNIUExtBwdT_h^{RLP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour (h-1) and hour h.
$SPNIDExtBwdT_h^{RLP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour (h-1) and hour h.
$SPNIUExtFwdT_h^{RLP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour h and hour $(h+1)$.
$SPNIDExtFwdT_h^{RLP}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour h and hour $(h+1)$.
$SP10S_h^{RLP}$	shall designate the shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in hour h.
$SP10R_h^{RLP}$	shall designate the shadow price for the total *ten-minute operating reserve* requirement constraint in hour h.
$SP30R_h^{RLP}$	shall designate the shadow price for the total *thirty-minute operating reserve* requirement constraint in hour h.
$SPREGMin10R_{h,r}^{RLP}$	shall designate the shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMin30R_{h,r}^{RLP}$	shall designate the shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax10R_{h,r}^{RLP}$	shall designate the shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax30R_{h,r}^{RLP}$	shall designate the shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

Table 3-21 lists the LMPs and components for each hour $h \in \{1,..,24\}$ calculated using the pricing formulas in Section 3.10.

Table 3-21: LMP Outputs of Reference Level Pricing

Output	Description
$PRef_h^{RLP}$	shall designate the hour h *energy* reference price.
$LMP_{h,b}^{RLP}$	shall designate the hour h LMP for bus $b \in B$.

Output	Description
$PLoss_{h,b}^{RLP}$	shall designate the hour h loss component for bus $b \in B$.
$PCong_{h,b}^{RLP}$	shall designate the hour h congestion component for bus $b \in B$.
$ExtLMP_{h,d}^{RLP}$	shall designate the hour h LMP for *intertie zone* bus $d \in D$.
$IntLMP_{h,d}^{RLP}$	shall designate the hour h *intertie* border price (IBP) for *intertie zone* bus $d \in D$.
$ICP_{h,d}^{RLP}$	shall designate the hour h *intertie* congestion price (ICP) for *intertie zone* bus $d \in D$.
$PLoss_{h,d}^{RLP}$	shall designate the hour h loss component for *intertie zone* bus $d \in D$.
$PIntCong_{h,d}^{RLP}$	shall designate the hour h internal congestion component for *intertie zone* bus $d \in D$.
$PExtCong_{h,d}^{RLP}$	shall designate the hour h *intertie* congestion component for *intertie zone* bus $d \in D$.
$PNISL_{h,d}^{RLP}$	shall designate the hour h net interchange scheduling limit congestion component for *intertie zone* bus $d \in D$.
$L30RP_{h,b}^{RLP}$	shall designate the hour h *thirty-minute operating reserve* price for bus $b \in B$.
$L10NP_{h,b}^{RLP}$	shall designate hour h non-synchronized *ten-minute operating reserve* price for bus $b \in B$.
$L10SP_{h,b}^{RLP}$	shall designate the hour h synchronized *ten-minute operating reserve* price for bus $b \in B$.
$ExtL30RP_{h,d}^{RLP}$	shall designate the hour h *thirty-minute operating reserve* price for *intertie zone* bus $d \in D$.
$ExtL10NP_{h,d}^{RLP}$	shall designate the hour h non-synchronized *ten-minute operating reserve* price for *intertie zone* bus $d \in D$.

3.6.7. Price Impact Test

If one or more *dispatch data* parameters fail a conduct test for economic withholding, then the ex-ante price impact test will be run.

The ex-ante price impact test will compare the As-Offered Pricing LMPs for *energy* or *operating reserve* with the Reference Level Pricing LMPs for *energy* or *operating reserve*. If prices in the As-Offered Pricing results are greater than the prices from the Reference Level Pricing results by more than the relevant impact threshold, then the corresponding *offer* parameters will be considered to have failed the price impact test. In this case, the corresponding *offer* component will be replaced with its reference level in Mitigated Scheduling and Mitigated Pricing.

3.6.7.1 Inputs

The Price Impact Test will use the applicable inputs identified in Section 3.4.2.3. Table 3-22 lists the As-Offered Pricing and Reference Level Pricing outputs that will be also be used by the price impact test.

Table 3-22: Outputs of As-Offered Pricing and Reference Level Pricing as Input to the Price Impact Test

Input	Description
$LMP_{h,b}^{AOP}$	The LMP for bus $b \in B$ in hour $h \in \{1,...,24\}$ from As-Offered Pricing.
$L30RP_{h,b}^{AOP}$	The *thirty-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,...,24\}$ from As-Offered Pricing.
$L10NP_{h,b}^{AOP}$	The non-synchronized *ten-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,...,24\}$ from As-Offered Pricing.
$L10SP_{h,b}^{AOP}$	The synchronized *ten-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,...,24\}$ from As-Offered Pricing.
$LMP_{h,b}^{RLP}$	The LMP for bus $b \in B$ in hour $h \in \{1,...,24\}$ from Reference Level Pricing.
$L30RP_{h,b}^{RLP}$	The *thirty-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,...,24\}$ from Reference Level Pricing.
$L10NP_{h,b}^{RLP}$	The non-synchronized *ten-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,...,24\}$ from Reference Level Pricing.
$L10SP_{h,b}^{RLP}$	The synchronized *ten-minute operating reserve* price at bus $b \in B$ in hour $h \in \{1,...,24\}$ from Reference Level Pricing.

3.6.7.2 Variables

A set of resources that failed the price impact test will be identified for each condition for all hours $h \in \{1,...,24\}$, where:

- BIT_h^{NCA} shall designate the resources in an NCA that failed the price impact test for *energy* LMP;
- BIT_h^{DCA} shall designate the resources in a DCA that failed the price impact test for *energy* LMP;

- BIT_h^{BCA} shall designate the resources in a BCA that failed price impact test for *energy* LMP;
- BIT_h^{GMP} shall designate the resources that failed the global market power (*energy*) price impact test for *energy* LMP;
- BIT_h^{ORL} shall designate the resources that failed the local market power (OR) price impact test for at least one type of *operating reserve* LMP;
- BIT_h^{ORG} shall designate the resources that failed the global market power (OR) price impact test for at least one type of *operating reserve* LMP; and
- $LMPIT_{h,b}$ shall designate the LMP that failed the price impact test for bus $b \in BIT_h^{NCA} \cup BIT_h^{DCA} \cup BIT_h^{BCA} \cup BIT_h^{GMP} \cup BIT_h^{ORL} \cup BIT_h^{ORGMP}$ in hour h.

For any resource at bus $b \in B^{DG} \cup B^{DL}$, the following LMPs may be identified in $LMPIT_{h,b}$:

- $EnergyLMP$ indicating that the *energy* LMP failed the price impact test;
- $OR10SLMP$ indicating that the synchronized *ten-minute operating reserve* LMP failed the price impact test;
- $OR10NLMP$ indicating that the non-synchronized *ten-minute operating reserve* LMP failed the price impact test; and
- $OR30RLMP$ indicating that the *thirty-minute operating reserve* LMP failed the price impact test.

3.6.7.3 Price Impact Test for Energy

The *IESO* will perform the price impact test for resources that were selected in the corresponding conduct test for *energy* as follows.

Local Market Power (Energy)

- Check NCA: For each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{NCA}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} * (1 + ITThresh1^{NCA}), LMP_{h,b}^{RLP} + ITThresh2^{NCA})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{NCA} and add $EnergyLMP$ to $LMPIT_{h,b}$.
- Check DCA: For each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{DCA}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} * (1 + ITThresh1^{DCA}), LMP_{h,b}^{RLP} + ITThresh2^{DCA})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{DCA} and add $EnergyLMP$ to $LMPIT_{h,b}$.
- Check BCA: For each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{BCA}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} * (1 + ITThresh1^{BCA}), LMP_{h,b}^{RLP} + ITThresh2^{BCA})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{BCA} and add $EnergyLMP$ to $LMPIT_{h,b}$.

Global Market Power (Energy)

For each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{GMP}$, if $LMP_{h,b}^{AOP} > min(LMP_{h,b}^{RLP} * (1 + ITThresh1^{GMP}), LMP_{h,b}^{RLP} + ITThresh2^{GMP})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{GMP} and add $EnergyLMP$ to $LMPIT_{h,b}$.

3.6.7.4 Price Impact Test for Operating Reserve

The *IESO* will perform the price impact test for resources that were selected in the corresponding conduct test for *operating reserve* as follows.

Local Market Power (Operating Reserve)

For each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{ORL}$:

- If $L30RP_{h,b}^{AOP} > L30RP_{h,b}^{RLP}$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{ORL} and add $OR30RLMP$ to $LMPIT_{h,b}$.
- If $L10NP_{h,b}^{AOP} > L10NP_{h,b}^{RLP}$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{ORL} and add $OR10NLMP$ to $LMPIT_{h,b}$.
- If $L10SP_{h,b}^{AOP} > L10SP_{h,b}^{RLP}$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{ORL} and add $OR10SLMP$ to $LMPIT_{h,b}$..

Global Market Power (Operating Reserve)

For each hour $h \in \{1,..,24\}$ and $b \in BCT_h^{ORG}$:

- If $L30RP_{h,b}^{AOP} > min(L30RP_{h,b}^{RLP} * (1 + ITThresh1^{ORG}), L30RP_{h,b}^{RLP} + ITThresh2^{ORG})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{ORG} and add $OR30RLMP$ to $LMPIT_{h,b}$.
- If $L10NP_{h,b}^{AOP} > min(L10NP_{h,b}^{RLP} * (1 + ITThresh1^{ORG}), L10NP_{h,b}^{RLP} + ITThresh2^{ORG})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{ORG} and add $OR10NLMP$ to $LMPIT_{h,b}$.
- If $L10SP_{h,b}^{AOP} > min(L10SP_{h,b}^{RLP} * (1 + ITThresh1^{ORG}), L10SP_{h,b}^{RLP} + ITThresh2^{ORG})$, price impact test failed for resource at bus b. Assign resource to subset BIT_h^{ORG} and add $OR10SLMP$ to $LMPIT_{h,b}$.

3.6.7.5 Outputs

The outputs of the price impact test will include:

- The set of resources that failed the price impact test in each hour $h \in \{1,..,24\}$ by condition type (i.e. resources included in the sets BIT_h^{NCA}, BIT_h^{DCA}, BIT_h^{BCA}, BIT_h^{GMP}, BIT_h^{ORL} and BIT_h^{ORG});
- The LMPs (*energy* and *operating reserve*) that failed the price impact test in each hour $h \in \{1,..,24\}$ for each resource at bus b (i.e. parameters included in the set $LMPIT_{h,b}$); and

- A revised set of *offer* data for resources that failed the price impact test with *dispatch data* parameters that failed the corresponding conduct test replaced with reference levels.

More detail on the revised set of *offer* data that must be output by the price impact test is provided below:

- If a resource has failed a price impact test for *energy* and falls in one of the sets BIT_h^{NCA}, BIT_h^{DCA}, BIT_h^{BCA}, or BIT_h^{GMP}, the *dispatch data* parameters in $PARAME_{h,b}$ will be used to determine which *dispatch data* parameters should be replaced.
- If a resource has failed a price impact test for *operating reserve* and falls in one of the sets BIT_h^{ORL} or BIT_h^{ORG}, the *dispatch data* parameters in $PARAMOR_{h,b}$ will be used to determine which *dispatch data offer* parameters should be replaced.
- If an NQS resource has failed a price impact test in any hour, commitment cost parameters that failed the conduct test in that hour and any hour prior will have their values replaced with the reference level for those hours. This is expressed as:
  - For each hour $h \in \{1,..,24\}$ and all $b \in B^{NQS}$ such that $b \in BIT_h^{NCA} \cup BIT_h^{DCA} \cup BIT_h^{BCA} \cup BIT_h^{GMP}$, for hours prior to and including the hour that failed the price impact test, $H \in \{1,..,h\}$, if $b \in BCT_H^{NCA} \cup BCT_H^{DCA} \cup BCT_H^{BCA} \cup BCT_H^{GMP}$ and $PARAME_{H,b}$ contains any of the commitment cost parameters $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with reference levels.
  - The same logic is true for Local Market Power and Global Market Power in the *operating reserve* market, except $PARAMOR_{H,b}$ must be checked.
- When a resource in an NCA or a DCA fails the price impact test, all other resources in that constrained area that failed the conduct test in that hour for at least one parameter will also be subject to market power mitigation (regardless of whether or not the resource failed the price impact test). For NQS resources, commitment cost parameters that failed the conduct test in any hour prior will also have their values replaced with reference levels for those hours. This can be expressed as:
  - For each hour $h \in \{1,..,24\}$, if BIT_h^{NCA} includes one or more resource in NCA, n, all resources $b \in BCT_h^{NCA}$ for NCA, n, will have the parameters in $PARAME_{h,b}$ replaced with reference levels. Additionally, for all hours up to the hour in which a resource failed the price impact test for n, for all $b \in BCT_h^{NCA}$, if $PARAME_{h,b}$ contains any of the commitment cost parameters $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with reference levels.
  - For each hour $h \in \{1,..,24\}$, if BIT_h^{DCA} includes one or more resource in DCA, d, all resources, $b \in BCT_h^{DCA}$ for DCA, d, will have the parameters in $PARAME_{h,b}$ replaced with reference levels. Additionally, for all hours up to

the hour in which a resource failed the price impact test for d, for all $b \in BCT_h^{DCA}$, if $PARAME_{h,b}$ contains any of the commitment cost parameters $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with reference levels.

- When a resource fails the *operating reserve* local market power price impact test, all other resources in the same reserve area with a non-zero reserve minimum requirement that failed the conduct test for at least one parameter will also be subject to market power mitigation (regardless of whether or not the resource failed the price impact test). For NQS resources, commitment cost parameters that failed the conduct test in any hour prior will also have their values replaced with reference levels for those hours. This can be expressed as:
  - For each hour $h \in \{1,..,24\}$, if BIT_h^{ORL} includes one or more resources in reserve area, r, all resources, $b \in BIT_h^{ORL}$ for reserve area, r, will have the parameters in $PARAMOR_{h,b}$ replaced with reference levels. Additionally, for all hours up to the hour in which a resource failed the price impact test for r, for all $b \in BCT_h^{ORL}$, if $PARAME_{h,b}$ contains any of the commitment cost parameters $SUOffer$, $SNLOffer$, or $EnergyToMLP_k$, replace these parameters with reference levels.

3.6.8. Mitigated Scheduling

Mitigated Scheduling will perform a *security*-constrained unit commitment and economic *dispatch* similar to that performed by As-Offered Scheduling. Mitigated Scheduling only differs from As-Offered Scheduling in that it will use reference level *dispatch data* for any financial *dispatch data* from *registered market participants* identified as having failed the conduct and price impact tests.

If Mitigated Scheduling is performed it will determine commitment statuses and schedules. These will comprise the scheduling results of Pass 1. These commitments will also serve as inputs into Mitigated Pricing. The schedules produced will not be financially binding.

The following sections describe the formulation of the optimization function for Mitigated Scheduling.

3.6.8.1 Inputs

All applicable inputs identified in Section 3.4.1 will be used. However, some inputs may be replaced by reference level *dispatch data* if the price impact test failed as described above.

3.6.8.2 Variables, Objective Function, and Constraints

The variables, objective function and set of constraints are the same as those used in As-Offered Scheduling.

3.6.8.3 Outputs

Mitigated Scheduling will produce schedules and unit commitment statuses for all resources.

For each scheduling variable SXX, SXX^{MS} shall designate the value determined in Mitigated Scheduling. For example, $SDL^{MS}_{h,b,j}$ shall designate the schedule computed for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$. As another example, $OHO^{MS}_{h,b}$ shall designate whether the hydroelectric resource at bus $b \in B^{HE}$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

In particular, the unit commitment statuses and affiliated start-up decision determined in Mitigated Scheduling will be denoted as follows:

- $ODG^{MS}_{h,b} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
- $IDG^{MS}_{h,b} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled to start (reach its *minimum loading point*) in hour $h \in \{1,..,24\}$.

The DAM calculation engine will record all such values for informational purposes.

3.6.9. Mitigated Pricing

Mitigated Pricing will perform a *security*-constrained economic *dispatch* similar to that performed by As-Offered Pricing. Mitigated Pricing differs from As-Offered Pricing in that it will use reference level *dispatch data* for any financial *dispatch data* from *registered market participants* identified as having failed the conduct and price impact tests. Mitigated Pricing also differs from As-Offered Pricing in that the principle for price-setting eligibility will be applied by taking into account the Mitigated Scheduling results.

Mitigated Pricing will determine an initial set of LMPs. If Mitigated Pricing is performed, the LMPs will comprise the results of Pass 1. The prices produced will not be financially binding.

The following sections describe the formulation of the optimization function for Mitigated Pricing.

3.6.9.1 Inputs

All applicable inputs identified in Section 3.4.1 will be used. However, some inputs may be replaced by reference level *dispatch data* if the price impact test failed as described above.

Table 3-23 lists the outputs of Mitigated Scheduling that will also be used as inputs to Mitigated Pricing.

Table 3-23: Outputs of Mitigated Scheduling as Input to Mitigated Pricing

Input	Description
$SDG^{MS}_{h,b,k}$	The amount of dispatchable generation scheduled at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,b}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled.
$ODG^{MS}_{h,b}$	Designates whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
$S10SDG^{MS}_{h,b,k}$	The amount of *ten-minute* synchronized *operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$.
$S10NDG^{MS}_{h,b,k}$	The amount of *ten-minute* non-synchronized *operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$.
$S30RDG^{MS}_{h,b,k}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,b}$.
$OHO^{MS}_{h,b}$	Designates whether the hydroelectric resource at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

3.6.9.2 Variables, Objective Function, and Constraints

The variables and objective function are the same as those used in As-Offered Pricing. Many of the constraints enforced in Mitigated Pricing are the same as those enforced in As-Offered Pricing. However, the constraints used to apply the principle for price-setting eligibility must be modified to take into account the results from Mitigated Scheduling. That is, for the additional constraints listed in Section 3.6.2.3, the As-Offered Scheduling results are replaced by the Mitigated Scheduling results as follows:

- $SDG^{AOS}_{h,b,k}$ is replaced by $SDG^{MS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{E}_{h,b}$;
- $ODG^{AOS}_{h,b}$ is replaced by $ODG^{MS}_{h,b}$ for all $h \in \{1,..,24\}$, $b \in B^{DG}$;
- $S10SDG^{AOS}_{h,b,k}$ is replaced by $S10SDG^{MS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10S}_{h,b}$;

- $S10NDG^{AOS}_{h,b,k}$ is replaced by $S10NDG^{MS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10N}_{h,b}$;
- $S30RDG^{AOS}_{h,b,k}$ is replaced by $S30RDG^{MS}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{30R}_{h,b}$; and
- $OHO^{AOS}_{h,b}$ is replaced by $OHO^{MS}_{h,b}$ for all $h \in \{1,..,24\}$, $b \in B^{HE}$.

Additionally, the marginal loss factors used in the *energy* balance constraint in Mitigated Pricing will be fixed to the marginal loss factors used in the last optimization function iteration of Mitigated Scheduling.

3.6.9.3 Outputs

Table 3-24 lists the shadow prices for Mitigated Pricing constraints that will be output for each hour $h \in \{1,..,24\}$.

Table 3-24: Shadow Pricing Outputs of Mitigated Pricing

Output	Description
SPL^{MP}_{h}	shall designate the shadow price for the *energy* balance constraint.
$SPNormT^{MP}_{h,f}$	shall designate the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour h.
$SPEmT^{MP}_{h,c,f}$	shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h.
$SPExtT^{MP}_{h,z}$	shall designate the shadow price for the import or export limit constraint $z \in Z_{Sch}$ in hour h.
$SPNIUExtBwdT^{MP}_{h}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h\text{-}1)$ and hour h.
$SPNIDExtBwdT^{MP}_{h}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour $(h\text{-}1)$ and hour h.
$SPNIUExtFwdT^{MP}_{h}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour h and hour $(h+1)$.
$SPNIDExtFwdT^{MP}_{h}$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour h and hour $(h+1)$.

Output	Description
$SP10S_h^{MP}$	shall designate the shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in hour h.
$SP10R_h^{MP}$	shall designate the shadow price for the total *ten-minute operating reserve* requirement constraint in hour h.
$SP30R_h^{MP}$	shall designate the shadow price for the total *thirty-minute operating reserve* requirement constraint in hour h.
$SPREGMin10R_{h,r}^{MP}$	shall designate the shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMin30R_{h,r}^{MP}$	shall designate the shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax10R_{h,r}^{MP}$	shall designate the shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax30R_{h,r}^{MP}$	shall designate the shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

Table 3-25 lists the LMPs and components for each hour $h \in \{1,..,24\}$ calculated using the pricing formulas in Section 3.10.

Table 3-25: LMP Outputs of Mitigated Pricing

Output	Description
$PRef_h^{MP}$	shall designate the hour h *energy* reference price.
$LMP_{h,b}^{MP}$	shall designate the hour h LMP for bus $b \in B$.
$PLoss_{h,b}^{MP}$	shall designate the hour h loss component for bus $b \in B$.
$PCong_{h,b}^{MP}$	shall designate the hour h congestion component for bus $b \in B$.
$ExtLMP_{h,d}^{MP}$	shall designate the hour h LMP for *intertie zone* bus $d \in D$.
$IntLMP_{h,d}^{MP}$	shall designate the hour h *intertie* border price (IBP) for *intertie zone* bus $d \in D$.
$PLoss_{h,d}^{MP}$	shall designate the hour h loss component for *intertie zone* bus $d \in D$.
$PIntCong_{h,d}^{MP}$	shall designate the hour h internal congestion component for *intertie zone* bus $d \in D$.

Output	Description
$PExtCong_{h,d}^{MP}$	shall designate the hour h *intertie* congestion component for *intertie zone* bus $d \in D$.
$PNISL_{h,d}^{MP}$	shall designate the hour h net interchange scheduling limit congestion component for *intertie zone* bus $d \in D$.
$L30RP_{h,b}^{MP}$	shall designate the hour h *thirty-minute operating reserve* price for bus $b \in B$.
$L10NP_{h,b}^{MP}$	shall designate hour h non-synchronized *ten-minute operating reserve* price for bus $b \in B$.
$L10SP_{h,b}^{MP}$	shall designate the hour h synchronized *ten-minute operating reserve* price for bus $b \in B$.
$ExtL30RP_{h,d}^{MP}$	shall designate the hour h *thirty-minute operating reserve* price for *intertie zone* bus $d \in D$.
$ExtL10NP_{h,d}^{MP}$	shall designate the hour h non-synchronized *ten-minute operating reserve* price for *intertie zone* bus $d \in D$.

3.6.10. Summary of Pass 1

In the event that the price impact test is failed, the Mitigated Scheduling and Mitigated Pricing results will comprise the Pass 1 results. Otherwise, the As-Offered Scheduling and As-Offered Pricing results will comprise the Pass 1 results.

For each scheduling variable SXX, SXX^1 shall designate the Pass 1 scheduling results. For example, $SDL_{h,b,j}^1$ shall designate the schedule for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$. As another example, $OHO_{h,b}^1$ shall designate whether the hydroelectric resource at bus $b \in B^{HE}$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$. In particular, the unit commitment statuses and affiliated start-up decision for Pass 1 will be denoted as follows:

- $ODG_{h,b}^1 \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
- $IDG_{h,b}^1 \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled to start (reach its *minimum loading point*) in hour $h \in \{1,..,24\}$.

Shadow prices for Pass 1 constraints for each hour $h \in \{1,..,24\}$ will be denoted as follows:

- SPL_h^1 shall designate the shadow price for the *energy* balance constraint;

- $SPNormT^1_{h,f}$ shall designate the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour h;
- $SPEmT^1_{h,c,f}$ shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h;
- $SPExtT^1_{h,z}$ shall designate the shadow price for the import or export limit constraint $z \in Z_{Sch}$ in hour h;
- $SPNIUExtBwdT^1_h$ shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h\text{-}1)$ and hour h;
- $SPNIDExtBwdT^1_h$ shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour $(h\text{-}1)$ and hour h;
- $SPNIUExtFwdT^1_h$ shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour h and hour $(h+1)$;
- $SPNIDExtFwdT^1_h$ shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour h and hour $(h+1)$;
- $SP10S^1_h$ shall designate the shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in hour h;
- $SP10R^1_h$ shall designate the shadow price for the total *ten-minute operating reserve* requirement constraint in hour h;
- $SP30R^1_h$ shall designate the shadow price for the total *thirty-minute operating reserve* requirement constraint in hour h;
- $SPREGMin10R^1_{h,r}$ shall designate the shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h;
- $SPREGMin30R^1_{h,r}$ shall designate the shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h;
- $SPREGMax10R^1_{h,r}$ shall designate the shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h; and
- $SPREGMax30R^1_{h,r}$ shall designate the shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

3.7. Pass 2: Reliability Scheduling and Commitment

Pass 2 will use *market participant* and *IESO* inputs along with resource and system constraints to determine a set of resource schedules and commitments. The intent of this pass is to determine whether Pass 1 has committed sufficient resources to meet peak non-dispatchable forecast *demand* and the *IESO*-specified *operating reserve* requirements. If Pass 2 determines that there are insufficient resources available to meet that peak *demand,* it may make additional non-quick start commitments, increase import schedules and decrease export schedules. Such decisions will be carried into Pass 3.

Pass 2 will execute only a scheduling algorithm and will not calculate prices.

3.7.1. Reliability Scheduling

Reliability Scheduling will perform a *security*-constrained unit commitment and economic *dispatch* similar to that performed by As-Offered Scheduling. However, Reliability Scheduling differs from As-Offered Scheduling in that its intent is to assess the supply available to meet peak non-dispatchable *demand* in each hour. To achieve this intent, Reliability Scheduling will assess certain inputs differently from As-Offered Scheduling.

Peak non-dispatchable *demand* forecasts will be used in place of average non-dispatchable *demand* forecasts. Schedules for price responsive loads and for no *bid dispatchable loads* are not calculated by the optimization function. Instead, the optimization function accounts for expected consumption of price responsive loads and for no *bid dispatchable loads* through the *demand* forecast. Virtual *bids* and *offers* will be excluded from evaluation. The *IESO's* centralized *variable generation* forecast for *variable generation* resources will be used.

Reliability Scheduling also differs from As-Offered Scheduling in its objective. Reliability Scheduling's objective is to minimize the cost of additional commitments rather than maximize the gains from trade. Reliability Scheduling will consider as-offered prices for the start-up and minimum generation costs of NQS resources not already committed in Pass 1 and will consider as-offered prices for imports, exports and *hourly demand response* resources. Reliability Scheduling will evaluate all other internal incrementally dispatchable *energy* at some small nominal value. This evaluation technique of internal dispatchable generation is necessary to minimize the cost of additional commitments and net imports to meet peak *demand*.

Dispatchable generation resources whose commitment status is "committed" in a given hour in Pass 1 are taken as committed for that hour in Reliability Scheduling. These resources will be scheduled to no less than their *minimum loading point*. Reliability Scheduling can also commit additional dispatchable generation resources by re-evaluating the commitment statuses of resources in hours they were not committed in Pass 1. Except for components of wheeling through transactions, import schedules may not decrease and export schedules may not increase from their Pass 1 values. For *energy*-limited resources, Reliability Scheduling will evaluate moving their Pass 1 schedules against the cost of replacing *energy* in that hour as measured by the applicable Pass 1 LMPs.

Reliability Scheduling will determine commitment statuses and resource schedules. The schedules produced will not be financially binding. The commitment statuses will be used to derive operational commitments.

The following sections describe the formulation of the optimization function for Reliability Scheduling.

3.7.1.1 Inputs

All applicable inputs identified in Section 3.4.1 will be used. However, some inputs may be replaced by reference level *dispatch data* if the ex-ante Market Power Mitigation process had been performed and the price impact test was failed in Pass 1.

Table 3-26 lists the outputs of Pass 1 that will also be used as inputs to Reliability Scheduling.

Table 3-26: Outputs of Pass 1 as Input to Reliability Scheduling

Input	Description
$SXL^1_{h,d,j}$	The amount of exports scheduled to *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,d}$.
$SDG^1_{h,b,k}$	The amount of dispatchable generation scheduled at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,b}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled.
$ODG^1_{h,b}$	Designates whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
$S10SDG^1_{h,b,k}$	The amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$
$S10NDG^1_{h,b,k}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$.

Input	Description
$S30RDG^{1}_{h,b,k}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{30R}_{h,b}$.
$SIG^{1}_{h,d,k}$	The amount of imports from *intertie zone* source bus $d \in DI$ scheduled in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{E}_{h,d}$.
$LMP^{1}_{h,b}$	The locational marginal price in hour $h \in \{1,..,24\}$ at bus $b \in B^{ELR} \cup B^{HE}$.

Evaluation of Internal Incrementally Dispatchable Energy

Internal incrementally dispatchable supply and load resources will be evaluated in Reliability Scheduling so that the price of incremental *energy* from these resources does not materially contribute to the objective function to meet Reliability Scheduling's objective of only evaluating additional commitment costs. Let n be some small nominal value representing a price for which scheduling a quantity from a resource has no material impact on the objective function. A value of $0.10/MWh will be used. *Dispatchable loads*, non-dispatchable generation resources, and the *energy offered* above MLP for dispatchable generation resources will be evaluated in Reliability Scheduling as follows:

- $PRucDL_{h,b,j}$ shall designate the *energy* price for incremental *energy* consumption in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *bid* lamination $j \in J^{E}_{h,b}$. It is defined by
$$PRucDL_{h,b,j} = min(n, PDL_{h,b,j}).$$
- $PRuc10SDL_{h,b,j}$ shall designate the price of being scheduled to provide synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *offer* lamination $j \in J^{10S}_{h,b}$. It is defined by
$$PRuc10SDL_{h,b,j} = min(n, P10SDL_{h,b,j}).$$
- $PRuc10NDL_{h,b,j}$ shall designate the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *offer* lamination $j \in J^{10N}_{h,b}$. It is defined by
$$PRuc10NDL_{h,b,j} = min(n, P10NDL_{h,b,j}).$$
- $PRuc30RDL_{h,b,j}$ shall designate the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ at *dispatchable load* bus $b \in B^{DL}$ in association with *offer* lamination $j \in J^{30R}_{h,b}$. It is defined by
$$PRuc30RDL_{h,b,j} = min(n, P30RDL_{h,b,j}).$$

- $PRucNDG_{h,b,k}$ shall designate the *energy* price for incremental generation in hour $h \in \{1,..,24\}$ at non-dispatchable generation bus $b \in B^{NDG}$ in association with *offer* lamination $k \in K^{E}_{h,b}$. It is defined by
$$PRucNDG_{h,b,k} = min(n, PNDG_{h,b,k}).$$
- $PRucDG_{h,b,k}$ shall designate the *energy* price for incremental generation in hour $h \in \{1,..,24\}$ at dispatchable generation bus $b \in B^{DG}$ in association with *offer* lamination $k \in K^{E}_{h,b}$. It is defined by
$$PRucDG_{h,b,k} = min(n, PDG_{h,b,k}).$$
- $PRuc10SDG_{h,b,k}$ shall designate the price of being scheduled to provide synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at dispatchable generation bus $b \in B^{DG}$ in association with *offer* lamination $k \in K^{10S}_{h,b}$. It is defined by
$$PRuc10SDG_{h,b,k} = min(n, P10SDG_{h,b,k}).$$
- $PRuc10NDG_{h,b,k}$ shall designate the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour $h \in \{1,..,24\}$ at dispatchable generation bus $b \in B^{DG}$ in association with *offer* lamination $k \in K^{10N}_{h,b}$. It is defined by
$$PRuc10NDG_{h,b,k} = min(n, P10NDG_{h,b,k}).$$
- $PRuc30RDG_{h,b,k}$ shall designate the price of being scheduled to provide *thirty-minute operating reserve* in hour $h \in \{1,..,24\}$ at dispatchable generation bus $b \in B^{DG}$ in association with *offer* lamination $k \in K^{30R}_{h,b}$. It is defined by
$$PRuc30RDG_{h,b,k} = min(n, P30RDG_{h,b,k})$$

Evaluation of Energy-Limited Resources

Energy-limited resources (ELRs) will be evaluated with the intention of maintaining the optimal usage of ELRs from Pass 1 while allowing for ELRs to contribute to the minimization of additional commitment costs. The price evaluated for *energy* and *operating reserve* from *energy*-limited resources will depend on whether the associated quantity was scheduled or unscheduled in Pass 1. For scheduled Pass 1 *energy*, the price evaluated is intended to maintain the Pass 1 schedule for the ELR, unless there is a benefit to changing the schedule and moving the *energy* to another hour. For *energy* that was not scheduled in a given hour in Pass 1, the price evaluated reflects the difference between the *offered* price of the unscheduled *energy* and the price at the resource's location as determined from Pass 1. This approximates the value of scheduling additional *energy* in that hour and is used as a measure against the cost of committing additional resources. This method for unscheduled *energy* in a given hour will only be applied when the resource's maximum daily *energy* limit constraint is binding in Pass 1. If this constraint is not binding, unscheduled *energy* will be treated in the same way as other internal incrementally dispatchable *energy*.

The treatments described above will also apply to hydroelectric resources with a shared maximum daily *energy* limit; such resources are limited in the amount of *energy* they may provide within a *dispatch day*.

The set of all resources to which the treatment for scheduled Pass 1 *energy* applies will be denoted as follows:

- $B^{LIM} = B^{ELR} \cup \{B_s^{HE}\ for\ all\ s \in SHE\}$ shall designate the set of buses identifying either *energy*-limited resources or hydroelectric resources sharing a maximum daily *energy* limit.

The set of all resources to which the treatment for unscheduled Pass 1 *energy* applies will be denoted as follows:

- $B^{BND} \subseteq B^{LIM}$ shall designate the subset of buses identifying either *energy*-limited resources or hydroelectric resources sharing a maximum daily *energy* limit with a binding maximum daily *energy* limit constraint from Pass 1.

To identify if a maximum daily *energy* limit is binding, the criteria for this condition defined in Section 3.6.2.3 for *energy*-limited resources and hydroelectric resources sharing a maximum daily *energy* limit will be assessed against the values of $ODG_{h,b}^{1}$, $SDG_{h,b,k}^{1}$, $S10SDG_{h,b,k}^{1}$, $S10NDG_{h,b,k}^{1}$ and $S30RDG_{h,b,k}^{1}$.

Each *offer* lamination from such a resource will be broken into two parts because Pass 1 may partially schedule an *offer* lamination (i.e. $0 < SDG_{h,b,k}^{1} < QDG_{h,b,k}$ for some $b \in B^{LIM}$, hour $h \in \{1,..,24\}$ and lamination $k \in K_{h,b}^{E}$). For each bus $b \in B^{LIM}$:

- $Q1DG_{h,b,k}$ shall designate an incremental quantity of *energy* generation (above and beyond the *minimum loading point*) that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 scheduled portion of the lamination. It is defined by
$$Q1DG_{h,b,k} = SDG_{h,b,k}^{1}.$$
- $P1DG_{h,b,k}$ shall designate the *energy* price for incremental generation in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 scheduled portion of the lamination. It is defined by
$$P1DG_{h,b,k} = \min\left(PDG_{h,b,k}\,, -LMP_{h,b}^{1}\right).$$
- $Q2DG_{h,b,k}$ shall designate an incremental quantity of *energy* generation (above and beyond the *minimum loading point*) that may be scheduled in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 unscheduled portion of the lamination. It is defined by
$$Q2DG_{h,b,k} = QDG_{h,b,k} - SDG_{h,b,k}^{1}.$$
- $P2DG_{h,b,k}$ shall designate the *energy* price for incremental generation in hour $h \in \{1,..,24\}$ in association with *offer* lamination $k \in K_{h,b}^{E}$ and corresponding to the Pass 1 unscheduled portion of the lamination. It is defined by

$$P2DG_{h,b,k} = \begin{cases} max(n, PDG_{h,b,k} - LMP^1_{h,b}) & if\ b \in B^{BND} \\ min(n, PDG_{h,b,k}) & otherwise \end{cases}.$$

3.7.1.2 Variables and Objective Function

The evaluation of *offers* in Reliability Scheduling is intended to minimize the cost of additional commitments and net imports to meet peak *demand*.

The variables used are mostly the same as those used in As-Offered Scheduling. However, the variables for price responsive load, virtual transaction *bids*, and virtual transaction *offers* are removed. Additionally, the following variables are added to capture the breaking of *energy*-limited resource laminations according to their Pass 1 scheduled and unscheduled quantities:

- $S1DG_{h,b,k}$ shall designate the amount of dispatchable generation scheduled at bus $b \in B^{LIM}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,b}$ corresponding to the Pass 1 scheduled portion of the lamination; and
- $S2DG_{h,b,k}$ shall designate the amount of dispatchable generation scheduled at bus $b \in B^{LIM}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,b}$ corresponding to the Pass 1 unscheduled portion of the lamination.

The objective function is the same as in As-Offered Scheduling except appropriate terms and coefficients are modified to achieve the objective of minimizing the incremental commitment costs associated with meeting the forecast peak *demand* for all hours of the next day:

- The objective function coefficients for *dispatchable load*, non-dispatchable generation resources and dispatchable generation resources are modified as described above;
- The objective functions coefficients for *energy*-limited resources are modified to reflect the pricing of the Pass 1 scheduled and unscheduled portions described above;
- The terms corresponding to virtual transaction *bids* and *offers* are removed; and
- The terms corresponding to price responsive load are removed.

Thus, Reliability Scheduling will maximize the value of the following expression:

$$\sum_{h=1,..,24} \begin{pmatrix} ObjDL_h - O1bjHDR_h + ObjXL_h - ObjNDG_h \\ - ObjDG_h - ObjIG_h - TB_h - ViolCost_h \end{pmatrix}$$

where:

$$ObjDL_h = \sum_{b \in B^{DL}} \left(\begin{array}{c} \sum_{j \in J_{h,b}^{E}} SDL_{h,b,j} \cdot PRucDL_{h,b,j} - \sum_{j \in J_{h,b}^{10S}} S10SDL_{h,b,j} \cdot PRuc10SDL_{h,b,j} - \\ \sum_{j \in J_{h,b}^{10N}} S10NDL_{h,b,j} \cdot PRuc10NDL_{h,b,j} - \sum_{j \in J_{h,b}^{30R}} S30RDL_{h,b,j} \cdot PRuc30RDL_{h,b,j} \end{array} \right)$$

$$ObjHDR_h = \sum_{b \in B^{HDR}} \left(\sum_{j \in J_{h,b}^{E}} SHDR_{h,b,j} \cdot PHDR_{h,b,j} \right)$$

$$ObjXL_h = \sum_{d \in DX} \left(\begin{array}{c} \sum_{j \in J_{h,d}^{E}} SXL_{h,d,j} \cdot PXL_{h,d,j} - \sum_{j \in J_{h,d}^{10N}} S10NXL_{h,d,j} \cdot P10NXL_{h,d,j} \\ - \sum_{j \in J_{h,d}^{30R}} S30RXL_{h,d,j} \cdot P30RXL_{h,d,j} \end{array} \right)$$

$$ObjNDG_h = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{h,b}^{E}} SNDG_{h,b,k} \cdot PRucNDG_{h,b,k} \right)$$

$$\begin{aligned} ObjDG_h &= \sum_{b \in B^{DG},\ b \notin B^{LIM}} \left(\sum_{k \in K_{h,b}^{E}} SDG_{h,b,k} \cdot PRucDG_{h,b,k} \right) \\ &+ \sum_{b \in B^{LIM}} \left(\sum_{k \in K_{h,b}^{E}} \left(S1DG_{h,b,k} \cdot P1DG_{h,b,k} + S2DG_{h,b,k} \cdot P2DG_{h,b,k} \right) \right) \\ &+ \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{h,b}^{10S}} S10SDG_{h,b,k} \cdot PRuc10SDG_{h,b,k} + \\ \sum_{k \in K_{h,b}^{10N}} S10NDG_{h,b,k} \cdot PRuc10NDG_{h,b,k} + \sum_{k \in K_{h,b}^{30R}} S30RDG_{h,b,k} \cdot PRuc30RDG_{h,b,k} \end{array} \right) \\ &+ \sum_{b \in B^{NQS}} \left(ODG_{h,b} \cdot MGODG_{h,b} + IDG_{h,b} \cdot SUDG_{h,b} \right) \end{aligned}$$

$$ObjIG_h = \sum_{d \in DI} \left(\begin{array}{c} \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k} \cdot PIG_{h,d,k} + \sum_{k \in K_{h,d}^{10N}} S10NIG_{h,d,k} \cdot P10NIG_{h,d,k} \\ + \sum_{k \in K_{h,d}^{30R}} S30RIG_{h,d,k} \cdot P30RIG_{h,d,k} \end{array} \right)$$

and $ViolCost_h$ and TB_h are computed as in As-Offered Scheduling.

3.7.1.3 Constraints Overview

Many of the constraints enforced in Reliability Scheduling are the same as those enforced in As-Offered Scheduling. However, the constraints are modified to:

- Use the peak non-dispatchable *demand* forecast;

- Remove price responsive load *bids*;
- Use the *IESO* centralized *variable generation* forecast; and
- Remove virtual transaction *bids* and *offers*.

Additional constraints are required to respect Pass 1 decisions. The following sections describe the additional constraints Reliability Scheduling requires.

Constraints Enforcing Scheduling and Commitment Decisions from Pass 1

Import schedules may not decrease from Pass 1 values. Additional imports of *energy* may be scheduled. Therefore, for all hours $h \in \{1,..,24\}$ and *intertie zone* source buses $d \in DI$ that are not part of a wheeling through transaction:

$$\sum_{k \in K^E_{h,d}} SIG_{h,d,k} \geq \sum_{k \in K^E_{h,d}} SIG^1_{h,d,k}.$$

Export schedules may not increase from Pass 1 values. Therefore, for all hours $h \in \{1,..,24\}$ and *intertie zone* sink buses $d \in DX$ that are not part of a wheeling through transaction:

$$\sum_{j \in J^E_{h,d}} SXL_{h,d,j} \leq \sum_{j \in J^E_{h,d}} SXL^1_{h,d,j}.$$

Dispatchable generation resources committed in Pass 1 may not be de-committed. Therefore for all hours $h \in \{1,..,24\}$ and buses $b \in B^{DG}$:

$$ODG_{h,b} \geq ODG^1_{h,b}.$$

Constraints Relating New Energy-Limited Resource Scheduling Variables

For *energy*-limited resources or hydroelectric resources with a shared maximum daily *energy* limit, the schedule for each *offer* lamination must be equal to the schedules corresponding to the Pass 1 scheduled and unscheduled portions. For all buses $b \in B^{LIM}$, hours $h \in \{1,..,24\}$ and *offer* laminations $k \in K^E_{h,b}$:

$$SDG_{h,b,k} = S1DG_{h,b,k} + S2DG_{h,b,k.}$$

The schedules for the Pass 1 scheduled and unscheduled portions of the lamination must respect the affiliated quantities. For all buses $b \in B^{LIM}$, hours $h \in \{1,..,24\}$ and *offer* laminations $k \in K^E_{h,b}$:

$$0 \leq S1DG_{h,b,k} \leq Q1DG_{h,b,k}$$

and

$$0 \leq S2DG_{h,b,k} \leq Q2DG_{h,b,k}..$$

3.7.1.4 Bid/Offer Constraints Applying to Single Hours

Scheduling Variable Bounds and Commitment Status Variables

These constraints are the same as in As-Offered Scheduling with the following exceptions:

- Constraints pertaining to price responsive loads will be removed; and
- Constraints pertaining to virtual transaction *bids* and *offers* will be removed.

Resource Minimums and Maximums

For *dispatchable loads* or non-dispatchable generation resources, these constraints are the same as in As-Offered Scheduling. For inadvertent payback transactions, these constraints are the same as in As-Offered Scheduling.

However, the constraints for dispatchable generation resources must be modified to reflect the *IESO* centralized *variable generation* forecast for *variable generation* resources. Therefore, the dispatchable generation resource constraints in As-Offered Scheduling are replaced with the following constraints.

Dispatchable Generation Resources

A constraint is required to limit dispatchable generation resources within their minimum and maximum output for an hour. The maximum output of a dispatchable *variable generation* resource will additionally be limited by its *IESO* forecast. For all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$, let

$$AdjMaxDG_{h,b} = \begin{cases} min(MaxDG_{h,b}, FG_{h,b}) & if\ b \in B^{VG} \\ MaxDG_{h,b} & otherwise \end{cases}$$

and

$$AdjMinDG_{h,b} = min(MinDG_{h,b}, AdjMaxDG_{h,b}).$$

Then, for all hours $h \in \{1,..,24\}$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{h,b} \leq MinQDG_b \cdot ODG_{h,b} + \sum_{k \in K_{b,h}^E} SDG_{k,h,b} \leq AdjMaxDG_{h,b}.$$

If the commitment status of the resource is fixed to 1 (i.e. $ODG_{h,b} = 1$) and if this is inconsistent with the adjusted minimum and maximum constraints (i.e. $MinQDG_b > AdjMaxDG_{h,b}$), then the commitment status will be relaxed. If the total *offered* quantity does not exceed the minimum ($MinQDG_b + \sum_{k \in K_{b,h}^E} QDG_{k,h,b} < AdjMinDG_{h,b}$), then the resource will receive a schedule of zero..

Operating Reserve Scheduling

These constraints are the same as in As-Offered Scheduling.

PSU Resources

These constraints are the same as in As-Offered Scheduling.

Hydroelectric Resources

These constraints are the same as in As-Offered Scheduling.

Wheeling Through Transactions

These constraints are the same as in As-Offered Scheduling.

3.7.1.5 Bid/Offer Inter-Hour/Multi-Hour Constraints

Energy Ramping

These constraints are the same as in As-Offered Scheduling.

Operating Reserve Ramping

These constraints are the same as in As-Offered Scheduling.

NQS Resources

These constraints are the same as in As-Offered Scheduling.

Energy-Limited Resources

These constraints are the same as in As-Offered Scheduling.

Hydroelectric Resources

These constraints are the same as in As-Offered Scheduling.

3.7.1.6 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

Energy Balance

The *energy* balance equation must be modified from As-Offered Scheduling to:

- Remove variables for virtual transaction *bids* and *offers*;
- Remove variables for price responsive load; and
- Use peak non-dispatchable *demand* forecasts, which is inclusive of price responsive load and no *bid dispatchable load*.

This modifies the constituent parts of the *energy* balance equation as described below.

Define the total amount of withdrawals scheduled at load bus $b \in B$ in hour $h \in \{1,..,24\}$, $With_{h,b}$, as either:

- all *dispatchable load* scheduled at bus b if $b \in B^{DL}$; or
- the *hourly demand response* quantity *bid* at bus b, net the amount of reduction scheduled if $b \in B^{HDR}$;

so that

$$With_{h,b} = \begin{cases} \sum_{j \in J^E_{h,b}} SDL_{h,b,j} & if\ b \in B^{DL} \\ \sum_{j \in J^E_{h,b}} (QHDR_{h,b,j} - SHDR_{h,b,j}) & if\ b \in B^{HDR} \end{cases}.$$

Define the total amount of withdrawals scheduled at *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$, $With_{h,d}$, as the exports from Ontario to that *intertie zone* sink bus. Thus,

$$With_{h,d} = \sum_{j \in J^E_{h,d}} SXL_{h,d,j}.$$

Define the total amount of injections scheduled at internal generation resource bus $b \in B$ in hour $h \in \{1,..,24\}$, $Inj_{h,b}$, as the sum of:

- either
  - o non-dispatchable generation scheduled at that bus if $b \in B^{NDG}$; or
  - o dispatchable generation scheduled at that bus if $b \in B^{DG}$; and
- ramp up energy to minimum loading point if $\mathrm{b} \in \mathrm{B}^{\mathrm{NQS}}$.

Let

$$OfferInj_{h,b} = \begin{cases} \sum_{k \in K^E_{h,b}} SNDG_{h,b,k} & if\ b \in B^{NDG} \\ ODG_{h,b} \cdot MinQDG_b + \sum_{k \in K^E_{h,b}} SDG_{h,b,k} & if\ b \in B^{DG} \end{cases}$$

and

$$RampInj_{h,b} = \begin{cases} \sum_{w=1..min(RampHrs_b, 24-h)} RampE_{b,w} \cdot IDG_{h+w,b} & if\ b \in B^{NQS} \\ 0 & otherwise \end{cases}$$

so that

$$Inj_{h,b} = OfferInj_{h,b} + RampInj_{h,b}.$$

Define the total amount of injections scheduled at *intertie zone* source bus $d \in DI$ in hour $h \in \{1,..,24\}$, $Inj_{h,d}$, as the imports into Ontario from that *intertie zone* source bus. Thus,

$$Inj_{h,d} = \sum_{k \in K_{h,d}^{E}} SIG_{h,d,k}.$$

The resulting *energy* balance constraint for hour $h \in \{1,..,24\}$ is:

$$\begin{aligned} PFL_h + \sum_{b \in B^{DL} \cup B^{HDR}} (1 + MglLoss_{h,b}) \cdot With_{h,b} + \sum_{d \in DX} (1 + MglLoss_{h,d}) \cdot With_{h,d} \\ - \sum_{i=1..N_{LdViol_h}} SLdViol_{h,i} \\ = \sum_{b \in B^{NDG} \cup B^{DG}} (1 + MglLoss_{h,b}) \cdot Inj_{h,b} + \sum_{d \in DI} (1 + MglLoss_{h,d}) \cdot Inj_{h,d} \\ - \sum_{i=1..N_{GenViol_h}} SGenViol_{h,i} + LossAdj_h. \end{aligned}$$

Operating Reserve Requirements

These constraints are the same as in As-Offered Scheduling.

IESO Internal Transmission Limits

These constraints are analogous to those in As-Offered Scheduling with terms for price responsive loads and virtual transaction *bids* and *offers* removed.

For all hours $h \in \{1,..,24\}$ and *facilities* $f \in F_h$, the linearized constraints will take the following form:

$$\begin{aligned} \sum_{b \in B^{NDG} \cup B^{DG}} PreConSF_{h,f,b} \cdot Inj_{h,b} - \sum_{b \in B^{DL} \cup B^{HDR}} PreConSF_{h,f,b} \cdot With_{h,b} \\ + \sum_{d \in DI} PreConSF_{h,f,d} \cdot Inj_{h,d} - \sum_{d \in DX} PreConSF_{h,f,d} \cdot With_{h,d} \\ - \sum_{i=1..N_{PreITLViol_{f,h}}} SPreITLViol_{f,h,i} \leq AdjNormMaxFlow_{h,f}. \end{aligned}$$

Similarly, for all hours $h \in \{1,..,24\}$, contingencies $c \in C$ and *facilities* $f \in F_{h,c}$ the linearized constraints will take the following form:

$$\begin{aligned} \sum_{b \in B^{NDG} \cup B^{DG}} SF_{h,c,f,b} \cdot Inj_{h,b} - \sum_{b \in B^{DL} \cup B^{HDR}} SF_{h,c,f,b} \cdot With_{h,b} + \sum_{d \in DI} SF_{h,c,f,d} \cdot Inj_{h,d} \\ - \sum_{d \in DX} SF_{h,c,f,d} \cdot With_{h,d} - \sum_{i=1..N_{ITLViol_{c,f,h}}} SITLViol_{c,f,h,i} \leq AdjEmMaxFlow_{h,c,f}. \end{aligned}$$

Intertie Limits

These constraints are the same as in As-Offered Scheduling.

Penalty Price Variable Bounds

These constraints are the same as in As-Offered Scheduling.

3.7.1.7 Outputs

Reliability Scheduling will produce schedules and unit commitment statuses for all resources. The results of Reliability Scheduling will comprise the Pass 2 results.

For each scheduling variable SXX, SXX^2 shall designate the value determined in Reliability Scheduling. For example, $SDL^2_{h,b,j}$ shall designate the schedule computed for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$. As another example, $OHO^2_{h,b}$ shall designate whether the hydroelectric resource at bus $b \in B^{HE}$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$.

In particular, the unit commitment statuses and affiliated start-up decision determined in Reliability Scheduling will be denoted as follows:

- $ODG^2_{h,b} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$; and
- $IDG^2_{h,b} \in \{0,1\}$ shall designate whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled to start (reach its *minimum loading point*) in hour $h \in \{1,..,24\}$.

The DAM calculation engine will record all such values for informational purposes.

3.8. Pass 3: DAM Scheduling and Pricing

Pass 3 will use *market participant* and *IESO* inputs along with resource and system constraints to determine a set of resource schedules and commitments. These schedules and commitments are calculated to meet the *IESO's* average non-dispatchable forecast *demand* and the *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports. Pass 3 will use the same set of *market participant* and *IESO* inputs used in Pass 1. Additionally, it will use the NQS commitment decisions and import and export schedules determined in Pass 1 and Pass 2 to produce a set of financially binding schedules and *settlement*-ready LMPs.

3.8.1. DAM Scheduling

DAM Scheduling will perform a *security*-constrained economic *dispatch* to meet the *IESO*'s average non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. DAM Scheduling will also evaluate *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and *bids* to export *energy*.

DAM Scheduling will use *bids* and *offers* submitted by *market participants* to maximize the gains from trade. The optimization is subject to the resource constraints accompanying those *bids* and *offers*, and system constraints imposed by the *IESO* to maintain *reliability*. If the ex-ante Market Power Mitigation process had been performed in Pass 1 and the price impact test had failed, then reference level *dispatch data* will be used for any *dispatch data* parameters identified by the mitigation process in Pass 1. These mitigated *offers* and *bids* will be transferred as inputs to Pass 3.

DAM Scheduling will produce the schedules that are used in the calculation of financially binding DAM *settlements* and of DAM make-whole payments.

The following sections describe the formulation of the optimization function for DAM Scheduling.

3.8.1.1 Inputs

All applicable inputs identified in Section 3.4.1 will be used. However, some inputs may have been replaced by reference level *dispatch data* if the ex-ante Market Power Mitigation process had been performed and the price impact test failed. Table 3-27 lists the outputs of Pass 2 that will also be used in DAM Scheduling.

Table 3-27: Outputs of Pass 2 as Input to DAM Scheduling

Input	Description
$SXL^2_{h,d,j}$	The amount of exports scheduled to *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,d}$.
$ODG^2_{h,b}$	Designates whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading point* in hour $h \in \{1,..,24\}$.
$SIG^2_{h,d,k}$	The amount of imports from *intertie zone* source bus $d \in DI$ scheduled in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,d}$.

3.8.1.2 Variables and Objective Function

The variables and objective function are the same as those used in As-Offered Scheduling. However, the variables for unit commitment decisions are fixed within the optimization. Accordingly, the start-up costs and costs to operate at *minimum loading point* are not evaluated and so the corresponding terms are dropped from the objective function.

3.8.1.3 Constraints Overview

Many of the constraints enforced in DAM Scheduling are the same as those enforced in As-Offered Scheduling. Additional constraints are required to respect Pass 2 decisions.

Import schedules may not decrease from Pass 2 values. Additional imports of *energy* may be scheduled. Therefore, for all hours $h \in \{1,..,24\}$ and *intertie zone* source buses $d \in DI$ that are not part of a wheeling through transaction:

$$\sum_{k \in K^E_{h,d}} SIG_{h,d,k} \geq \sum_{k \in K^E_{h,d}} SIG^2_{h,d,k}.$$

Export schedules may not increase from their Pass 2 values. Therefore, for all hours $h \in \{1,..,24\}$ and *intertie zone* sink buses $d \in DX$ that are not part of a wheeling through transaction:

$$\sum_{j \in J^E_{h,d}} SXL_{h,d,j} \leq \sum_{j \in J^E_{h,d}} SXL^2_{h,d,j}.$$

The commitment statuses of resources may not change from those determined in Pass 2. Therefore for all hours $h \in \{1,..,24\}$ and buses $b \in B^{DG}$:

$$ODG_{h,b} = ODG^2_{h,b}.$$

3.8.1.4 Bid/Offer Constraints Applying to Single Hours

These constraints are the same as in As-Offered Scheduling.

3.8.1.5 Bid/Offer Inter-Hour/Multi-Hour Constraints

These constraints are the same as in As-Offered Scheduling. The variables associated with commitment of NQS resources are held fixed and therefore these constraints are no longer required.

3.8.1.6 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

These constraints are the same as in As-Offered Scheduling.

3.8.1.7 Outputs

DAM Scheduling will produce constrained schedules for all resources. For each scheduling variable SXX, SXX^3 shall designate the value determined by the DAM calculation engine in Pass 3. For example, $SDL^3_{h,b,j}$ shall designate the schedule computed for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$. As another example, $OHO^3_{h,b}$ shall designate whether the hydroelectric resource at bus $b \in B^{HE}$ was scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,..,24\}$. The DAM calculation engine will record all such values for informational purposes.

Schedules will be produced for virtual *hourly demand response* resources, physical *non-dispatchable load hourly demand response* resources and physical price responsive load *hourly demand response* resources. These schedules will form the basis for standby notices in the day-ahead when required. DAM schedules produced for *dispatchable loads* providing *demand* response will not be used for the purpose of standby notices because such resources are obligated to respond to real-time *dispatch instructions*.

For information on the financially binding schedules produced by the DAM Scheduling, see Section 3.8.3 Table 3-31

3.8.2. DAM Pricing

DAM Pricing will perform a *security*-constrained economic *dispatch* to meet the *IESO*'s average non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. DAM Pricing will also evaluate *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports.

DAM Pricing will use *bids* and *offers* submitted by *market participants* to maximize the gains from trade. Like DAM Scheduling, the optimization is subject to the resource constraints accompanying those *bids* and *offers*, and system constraints imposed by the *IESO* to maintain *reliability*. However, the objective function and constraints will reflect the set of constraint violation penalty curves for market pricing. Like DAM Scheduling, if the ex-ante Market Power Mitigation process was performed in Pass 1 and the price impact test failed, then reference levels will be evaluated for any *dispatch data* parameters identified by the mitigation process.

DAM Pricing will use both the commitment statuses determined at the end of Pass 2 and the resource schedules determined in DAM Scheduling to calculate prices. The LMPs determined by DAM Pricing are intended to be a reflection of the schedules derived by DAM Scheduling in the same manner in which the As-Offered Pricing LMPs are reflective of the As-Offered Pricing schedules. Thus, an *offer* or *bid* lamination will be allowed to set prices in accordance with the principle for price-setting eligibility, which are applied after taking the DAM Scheduling results into account.

The LMPs produced by DAM Pricing will comprise the *settlement*-ready LMPs that are used in the calculation of financially binding DAM *settlements* and DAM make-whole payments. The *settlement*-ready LMPs will also be used in the determination of prices for the Ontario zone (for *settlement* of *non-dispatchable loads*) and virtual transaction zonal trading entities.

Refer to the Publishing and Reporting detailed design document for descriptions on pricing outputs from the DAM calculation engine that will be published to *market participants*.

The following sections describe the formulation of the optimization function for DAM Pricing.

3.8.2.1 Inputs

All applicable inputs identified in Section 3.4.1 will be evaluated. However, some inputs may be replaced by reference level *dispatch data* if the ex-ante Market Power Mitigation process was performed and the price impact test failed. Table 3-28 lists the outputs of DAM Scheduling that will also be used as input to DAM Pricing.

Table 3-28: Outputs of DAM Scheduling as Input to DAM Pricing

Input	Description
$SDG^3_{h,b,k}$	The amount of dispatchable generation scheduled at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^E_{h,b}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled.
$ODG^3_{h,b}$	Designates whether the dispatchable generation resource at bus $b \in B^{DG}$ was scheduled at or above its *minimum loading*

Input	Description
	point in hour $h \in \{1,...,24\}$. Note that $ODG^3_{h,b} = ODG^2_{h,b}$ for all hours $h \in \{1,...,24\}$ and buses $b \in B^{DG}$.
$S10SDG^3_{h,b,k}$	The amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^{10S}_{h,b}$.
$S10NDG^3_{h,b,k}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^{10N}_{h,b}$.
$S30RDG^3_{h,b,k}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{ELR} \cup B^{HE}$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^{30R}_{h,b}$.
$OHO^3_{h,b}$	Designates whether the hydroelectric resource at bus $b \in B^{HE}$ has been scheduled at or above $MinHO_{h,b}$ in hour $h \in \{1,...,24\}$.

Table 3-29 lists the outputs of Pass 2 that will also be used in DAM Pricing.

Table 3-29: Outputs of Pass 2 as Input to DAM Pricing

Input	Description
$SXL^2_{h,d,j}$	The amount of exports scheduled to *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,...,24\}$ in association with lamination $j \in J^E_{h,d}$.
$SIG^2_{h,d,k}$	The amount of imports from *intertie zone* source bus $d \in DI$ scheduled in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^E_{h,d}$.

3.8.2.2 Variables and Objective Function

The variables and objective function used are the same as those used in As-Offered Pricing.

3.8.2.3 Constraints Overview

Many of the constraints enforced in DAM Pricing are the same as those enforced in As-Offered Pricing. However, the constraints used in As-Offered Pricing to apply the principle for price-setting eligibility are modified to take into account the DAM

Scheduling results. That is, for the additional constraints listed in Section 3.6.2.3, the As-Offered Scheduling results are replaced by the DAM Scheduling results as follows:

- $SDG^{AOS}_{h,b,k}$ is replaced by $SDG^{3}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{E}_{h,b}$;
- $ODG^{AOS}_{h,b}$ is replaced by $ODG^{3}_{h,b}$ for all $h \in \{1,..,24\}$, $b \in B^{DG}$;
- $S10SDG^{AOS}_{h,b,k}$ is replaced by $S10SDG^{3}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10S}_{h,b}$;
- $S10NDG^{AOS}_{h,b,k}$ is replaced by $S10NDG^{3}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{10N}_{h,b}$;
- $S30RDG^{AOS}_{h,b,k}$ is replaced by $S30RDG^{3}_{h,b,k}$ for all $h \in \{1,..,24\}$, $b \in B^{ELR} \cup B^{HE}$, $k \in K^{30R}_{h,b}$; and
- $OHO^{AOS}_{h,b}$ is replaced by $OHO^{3}_{h,b}$ for all $h \in \{1,..,24\}$, $b \in B^{HE}$.

Additionally, the constraints imposed on import and export schedules based on the Pass 2 results will apply to import and export schedules in DAM Pricing. A small tolerance Δ will be used to relax the constraint to allow marginal *intertie* transactions to set prices. Therefore, for all hours $h \in \{1,..,24\}$ and *intertie zone* source buses $d \in DI$ that are not part of a wheeling through transaction:

$$\sum_{k \in K^{E}_{h,d}} SIG_{h,d,k} \geq \sum_{k \in K^{E}_{h,d}} SIG^{2}_{h,d,k} - \Delta.$$

For all hours $h \in \{1,..,24\}$ and *intertie zone* sink buses $d \in DX$ that are not part of a wheeling through transaction:

$$\sum_{j \in J^{E}_{h,d}} SXL_{h,d,j} \leq \sum_{j \in J^{E}_{h,d}} SXL^{2}_{h,d,j} + \Delta.$$

3.8.2.4 Bid/Offer Constraints Applying to Single Hours

These constraints are the same as in As-Offered Pricing.

3.8.2.5 Bid/Offer Inter-Hour/Multi-Hour Constraints

These constraints are the same as in As-Offered Pricing.

3.8.2.6 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

These constraints are the same as in As-Offered Pricing. The marginal loss factors used in the *energy* balance constraint in DAM Pricing will be fixed to the marginal loss factors used in the last optimization function iteration of DAM Scheduling.

3.8.2.7 Outputs

Table 3-30 lists the shadow prices of DAM Pricing constraints that will be output for each hour $h \in \{1,..,24\}$.

Table 3-30: Shadow Price Outputs of Day-Ahead Market Pricing

Output	Description
SPL_h^3	shall designate the shadow price for the *energy* balance constraint.
$SPNormT_{h,f}^3$	shall designate the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in hour h.
$SPEmT_{h,c,f}^3$	shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in hour h.
$SPExtT_{h,z}^3$.	shall designate the shadow price for the import or export limit constraint $z \in Z_{Sch}$ in hour h
$SPNIUExtBwdT_h^3$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour $(h\text{-}1)$ and hour h.
$SPNIDExtBwdT_h^3$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour $(h\text{-}1)$ and hour h.
$SPNIUExtFwdT_h^3$	shall designate the shadow price for the net interchange scheduling limit constraint limiting increases in net imports between hour h and hour $(h+1)$.
$SPNIDExtFwdT_h^3$	shall designate the shadow price for the net interchange scheduling limit constraint limiting decreases in net imports between hour h and hour $(h+1)$.
$SP10S_h^3$	shall designate the shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in hour h.
$SP10R_h^3$	shall designate the shadow price for the total *ten-minute operating reserve* requirement constraint in hour h.
$SP30R_h^3$	shall designate the shadow price for the total *thirty-minute operating reserve* requirement constraint in hour h.
$SPREGMin10R_{h,r}^3$	shall designate the shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

Output	Description
$SPREGMin30R^3_{h,r}$	shall designate the shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax10R^3_{h,r}$	shall designate the shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in hour h.
$SPREGMax30R^3_{h,r}$	shall designate the shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in hour h.

DAM Pricing will produce prices for all internal and external pricing nodes using the logic described in Section 3.10. The set of *settlement*-ready LMPs produced is provided in Section 3.8.3.

3.8.3. Outputs for Energy and OR Settlement

The set of buses identifying *hourly demand response* resources will be partitioned as follows:

- $B^{HDR\_PRL} \subseteq B^{HDR}$ shall designate the set of buses identifying physical *hourly demand response* resources for price responsive loads; and
- $B^{HDR\_NOT\_PRL} \subseteq B^{HDR}$ shall designate the set of buses identifying all other *hourly demand response* resources.

Table 3-31 lists the constrained schedules calculated by the optimization function that will be used to calculate the financially binding DAM schedules for price-responsive loads, *dispatchable loads*, dispatchable and non-dispatchable generation resources, imports and exports.

Table 3-31: DAM Scheduling Output used to Produce Financially Binding Schedules

Output	Description
$SPRL^3_{h,b,j}$	The amount of price responsive load scheduled at bus $b \in B^{PRL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,b}$.
$SDL^3_{h,b,j}$	The amount of *dispatchable load* scheduled at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,b}$.
$S10SDL^3_{h,b,j}$	The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10S}_{h,b}$.
$S10NDL^3_{h,b,j}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at

Output	Description
	bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10N}_{h,b}$.
$S30RDL^3_{h,b,j}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{30R}_{h,b}$.
$QHDR_{h,b,j}$-$SHDR^3_{h,b,j}$	The amount of consumption scheduled at bus $b \in B^{HDR\_PRL}$ (identifying a physical *hourly demand response* resource for a price responsive load) in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,b}$.
$SVB^3_{h,v,j}$	The amount of virtual *bid* $v \in VB$ scheduled in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,v}$.
$SXL^3_{h,d,j}$	The amount of exports scheduled to *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^E_{h,d}$.
$S10NXL^3_{h,d,j}$	The amount of non-synchronized *ten-minute operating reserve* scheduled from *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{10N}_{h,d}$.
$S30RXL^3_{h,d,j}$	The amount of *thirty-minute operating reserve* scheduled from *intertie zone* sink bus $d \in DX$ in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{30R}_{h,d}$.
$SNDG^3_{h,b,k}$	The amount of non-dispatchable generation scheduled at bus $b \in B^{NDG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,b}$.
$SDG^3_{h,b,k}$	The amount of dispatchable generation scheduled at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^E_{h,b}$. This is in addition to any $MinQDG_b$, the *minimum loading point*, which must be committed before any such generation is scheduled.
$S10SDG^3_{h,b,k}$	The amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10S}_{h,b}$.
$S10NDG^3_{h,b,k}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,..,24\}$ in association with lamination $k \in K^{10N}_{h,b}$.

Output	Description
$S30RDG^3_{h,b,k}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^{30R}_{h,b}$.
$SVO^3_{h,v,k}$	The amount of virtual *offer* $v \in VO$ scheduled in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^E_{h,v}$.
$SIG^3_{h,d,k}$	The amount of imports from *intertie zone* source bus $d \in DI$ scheduled in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^E_{h,d}$.
$S10NIG^3_{h,d,k}$	The amount of non-synchronized *ten-minute operating reserve* scheduled from *intertie zone* source bus $d \in DI$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^{10N}_{h,d}$.
$S30RIG^3_{h,d,k}$	The amount of *thirty-minute operating reserve* scheduled from *intertie zone* source bus $d \in DI$ in hour $h \in \{1,...,24\}$ in association with lamination $k \in K^{30R}_{h,d}$.

Schedules for every *delivery point* for a *non-dispatchable load* will be calculated by distributing the *demand* forecast using load distribution factors as described in Section 3.9.1. Schedules for *hourly demand response* resources that do not correspond to physical price responsive loads will be calculated by the optimization function in DAM Scheduling. Together, these two sets of schedules will be provided to the *settlement process* for the purpose of calculating the Load Forecast Deviation Charge (LFDC). For more information on this *settlement* charge, refer to Section 3.6.3 of the Market Settlement detailed design document.

Table 3-32 lists the constrained schedules produce by the optimization function for these purposes.

Table 3-32: DAM Scheduling Output used to Calculate the Load Forecast Deviation Charge (LFDC)

Output	Description
$QHDR_{h,b,j}\text{-}SHDR^{3}_{h,b,j}$	The amount of consumption scheduled at bus $b \in B^{HDR\_NOT\_PRL}$ (identifying an *hourly demand response* resource that does not correspond to a price responsive load) in hour $h \in \{1,..,24\}$ in association with lamination $j \in J^{E}_{h,b}$.

The set of internal pricing nodes will be designated by L and will include:

- Resources scheduled by the DAM calculation engine optimization function (designated B as per Section 3.4.1.1); and
- *Non-dispatchable load* locations and other internal locations without an active *bid* or *offer*.

The set of external pricing nodes will be designated by D as in Section 3.4.1.1.

Table 3-33 lists the *settlement*-ready prices that will be established for each hour $h \in \{1,..,24\}$ using the logic described in Section 3.10.

Table 3-33: Settlement-Ready LMP Outputs of the DAM Scheduling and Pricing Pass

Output	Description
$LMP^{3}_{h,b}$	The hour h LMP for node $b \in L$.
$ExtLMP^{3}_{h,d}$	The hour h LMP for *intertie zone* bus $d \in D$.
$ICP^{3}_{h,d}$	The hour h *intertie* congestion price for *intertie zone* bus $d \in D$.
$VZonalP^{3}_{h,m}$	The hour h *energy* price for virtual transaction zonal trading entity $m \in M$.
$ZonalP^{3}_{h,Ontario}$	The hour h Ontario zonal price.
$L30RP^{3}_{h,b}$	The hour h *thirty-minute operating reserve* price for bus $b \in B$.
$L10NP^{3}_{h,b}$	The hour h non-synchronized *ten-minute operating reserve* price for bus $b \in B$.
$L10SP^{3}_{h,b}$	The hour h synchronized *ten-minute operating reserve* price for bus $b \in B$.

Output	Description
$ExtL30RP^3_{h,d}$	The hour h *thirty-minute operating reserve* price for *intertie zone* bus $d \in D$.
$ExtL10NP^3_{h,d}$	The hour h non-synchronized *ten-minute operating reserve* price for *intertie zone* bus $d \in D$.

For each NQS resource bus $b \in B^{NQS}$, the hourly commitment status values ($ODG^3_{h,b}$ for $h \in \{1,..,24\}$) carried over from Reliability Scheduling will be used to derive operational commitments using the logic described in the Grid and Market Operations Integration detailed design document.

3.9. Security Assessment Function

The *security* assessment function assesses power system *security* using the schedules produced by the optimization function. As indicated in Section 3.3, the scheduling and pricing algorithms of the DAM calculation engine will include multiple iterations between the optimization function and the *security* assessment function described here. Information about the *IESO-controlled grid* such as operating *security limits*, thermal ratings, the network model, loop flow and the status of power system equipment will be used by the *security* assessment function to evaluate the *security* of the schedules provided by the optimization function against the expected *transmission system* capability. As part of its evaluation, the *security* assessment function will create the following information to provide to the next optimization function iteration:

- A *security* constraint set corresponding to violated thermal and/or operating *security limits*;
- Marginal loss factors; and
- A loss adjustment.

For each identified *security* constraint, the *security* assessment function will provide the coefficients and limits of a linear constraint in the optimization function variables to be enforced by the optimization function.

The following sections describe the inputs, the process and the outputs of the *security* assessment function.

3.9.1. Inputs

3.9.1.1 Inputs Provided by the Optimization Function

The optimization function will continue to provide the *security* assessment function with schedules for load and supply resources. With the exception of PSU resources, such schedules will be represented at their corresponding electrical buses in the network model. Similar to the DACE and as described in Section 3.12, the *security* assessment function will use the physical unit representation of combined cycle *facilities* that have elected to be represented as a PSU.

In Pass 1 and Pass 3, the following outputs of the optimization function are used by the *security* assessment function:

- The schedules for *dispatchable loads*, *hourly demand response* resources, and price responsive loads;
- The schedules for non-dispatchable and dispatchable generation;
- The schedules for *boundary entity* resource sources and sinks at each *intertie zone*; and

- The net schedules for virtual transactions for each virtual transaction trading zone.

The *security* assessment function will distribute the net schedules for virtual transactions in each trading zone to *non-dispatchable loads*, *dispatchable loads*, *hourly demand response* resources, and price responsive loads using the weighting factors for virtual transactions described in Section 3.9.1.3.

The total MW quantity allocated to a *dispatchable load*, *hourly demand response* resource or a price responsive load will be equal to the schedule determined by the optimization function plus the amount allocated in the distribution of net virtual transactions. The total MW quantity allocated to a *non-dispatchable load* will be the equal to the amount allocated in the distribution of the *IESO demand* forecast plus the amount allocated in the distribution of net virtual transactions.

In Pass 2, the following outputs of the optimization function are used by the *security* assessment function:

- The schedules for *dispatchable loads*;
- The schedules for *hourly demand response* resources;
- The schedules for non-dispatchable and dispatchable generation; and
- The schedules for *boundary entity* resource sources and sinks at each *intertie zone*.

As described in Section 3.13, the expected consumption for *non-dispatchable* loads, price responsive loads, and for no *bid dispatchable loads,* will be accounted for in Pass 2 through the *IESO* peak *demand* forecast and load distribution factors. For more information about load distribution see the details in Section 3.9.1.3.

3.9.1.2 Security Limits

Security limits are operating *security limits* (OSLs) and thermal limits. OSLs are associated with transient stability limits, voltage stability limits, dynamic stability limits and voltage decline limits. They also include limits based on equipment ratings such as thermal ratings and short-circuit capabilities. The DAM calculation engine will use OSLs and thermal limits to perform a *security* analysis of the *IESO-controlled grid*.

The *IESO* defines OSLs as a set of equations along with their activation plans. Each OSL equation is applicable for a specific area of the *IESO-controlled grid* under all elements in-service and/or specific outage conditions. An activation plan specifies which OSLs are applicable for a time period.

The *security* assessment function of the DAM calculation engine will create a linearized constraint when it determines that an OSL is violated. The linearized constraints are passed to the optimization function and are included as new constraints in the next iteration of optimization function.

An OSL equation will continue to be a function of any of the following network variables:

- Any transformer, line, branch group, or phase shifter MW flow;
- Any generation resource MW outputs;
- Any load MW; and
- The primary *demand*.

The DAM calculation engine will account for the impact of physical generation and load as well as virtual transactions in the OSL equations without the need for the *IESO* to revise the existing OSL equations or create new OSL equations.

The line, transformer, branch group and phase shifter MW flows in the OSL equations will be replaced with the sum of the pre-contingency sensitivity factors multiplied by scheduling variables.

The DAM calculation engine will consider MWs from physical generation and load as well as virtual transactions when determining whether the OSL constraints are violated. If it is determined that an OSL is violated, the linearized constraint passed to the optimization function will include the schedules of load and generation resources and virtual transactions as scheduling variables with their corresponding sensitivity factors.

The DAM calculation engine will use pre-contingency and post-contingency thermal ratings so that DAM schedules result in transmission flows that respect the thermal limits. The ratings used by the DAM calculation engine will be based on lookup table limits provided by *transmitters* and forecasted weather data. The *security* assessment function will create a linearized constraint when it determines that a thermal limit is violated. Analogous to the handling for OSLs, virtual transactions will also be considered in thermal limit constraints.

3.9.1.3 Network Model

The *security* assessment function will use the following data from the network model:

- Power system model data;
- Load distribution factors;
- A list of contingencies; and
- A list of monitored elements.

Power System Model Data

The power system model is a topology representation of the *IESO-controlled grid* and a simplified representation of power systems in neighbouring jurisdictions. The power system model data will continue to include attributes and parameters for the following power system equipment and their controls:

- Buses, breakers, switches, mid-span openers and line jumpers;
- High-voltage AC and DC transmission lines;
- Switchable and fixed shunt devices including:
- Capacitors;
  - Reactors;
  - SVCs; and
  - STATCOMs
- Series capacitors and reactors;
- Transformers, including:
  - Two-winding, three-windings and autotransformers;
  - Voltage and VAr regulators and phase shifters with impedance correction tables as a function of angle or voltage tap positions; and
  - Tap changers: Fixed, manual, automatic, off-load and on-load
- Synchronous condensers, generation resources, and load resources;
- Regulation modes, VAr capability curves, target voltages, target MWs/percentages, voltage/MW ranges, tap ratio ranges, and angle ranges as applicable to controlling devices;
- Attributes such as voltage levels and assignment to zones and areas;
- Branch groups and the power system equipment that make up each branch group; and
- Boundary Entity Resources (BERs) (i.e. sources/sinks) used for interchange scheduling purposes.

The normal tap positions for angle and voltage taps, the regulation modes of voltage taps, reactors, capacitors, phase shifters and the desired low limit/high limit voltages at buses, and normal breaker and disconnect switch statuses will continue be obtained from the power system model data.

For each hour, based on outage information, breaker and switch statuses will be modified (from normal status) to reflect power system equipment outage conditions.

Loop flows resulting from the *dispatch* within other *control areas* or transactions between other *control areas* that are not recorded as imports or exports within

Ontario (or both) will affect the loading on transmission within Ontario. The *IESO* will continue to model loop flows into or out of Ontario at various *intertie zones* as though they were generation or load that exist at given buses or combinations of buses in the *control areas* containing those *intertie zones*.

Load Distribution Factors

Load distribution factors define the load pattern that will be used to distribute the *IESO demand* forecast for each *demand* forecast area. The DAM calculation engine will use load distribution factors that are based on load patterns from the same day in previous weeks. In Pass 1 and Pass 3, the *security* assessment function will use load distribution factors to determine MW quantities at *non-dispatchable loads* based on the *IESO* average *demand* forecast. In Pass 2, the *security* assessment function will use load distribution factors to determine MW quantities at *non-dispatchable loads*, price responsive loads, and no *bid dispatchable loads* based on the *IESO* peak *demand* forecast.

Load distribution factors will also be used to determine a set of weighting factors to distribute the net virtual transactions scheduled at each virtual transaction trading zone. The DAM calculation engine will renormalize load distribution factors as per the *load facilities* mapped to each virtual transaction trading zone to determine the weighting factor for each trading zone. The sum of the weighting factors for a given virtual transaction trading zone must be equal to one.

In Pass 1 and Pass 3, the *security* assessment function will use weighting factors to distribute the net virtual transactions scheduled at each virtual transaction trading zone to *dispatchable loads*, price responsive loads, *non-dispatchable loads* and *hourly demand response* resources within the zone. To determine the total MW quantity allocated to a resource in the power system model, the quantity of virtual transactions distributed to the resource will be summed with the resource’s scheduled quantity.

In Pass 2, the weighting factors are not used since virtual transactions are not considered.

List of Contingencies

The list of contingencies will continue to include contingency name, description of contingencies and configuration settings/flags such as priority setting and flags to indicate whether 115 kV equipment should be monitored when a contingency is simulated.

List of Monitored Equipment

The list of monitored equipment indicates the equipment to be monitored for violation of thermal limits and/or voltage limits. It will continue to include the following information:

- The power system equipment name;
- The equipment type; and
- The monitoring type, i.e. thermal, voltage or no monitoring.

3.9.2. Security Assessment Function Processing

The *security* assessment function will perform the following calculations and analysis:

- Prepare a base case power flow solution for each of the 24 hours of the next *dispatch day*;
- Perform a pre-contingency *security* assessment on the base case power flow solution using pre-contingency thermal limits and operating *security limits;*
- Prepare linearized constraints using sensitivity factors for any violated pre-contingency thermal limits and operating *security limits*;
- Calculate total losses, marginal loss factors, and the loss adjustment. The loss adjustment is required to account for the difference between the total losses and the linearized losses calculated using the marginal loss factors;
- Simulate the specified contingencies to perform a post-contingency *security* assessment on the post-contingency state of the base case power flow solution using post-contingency thermal limits; and
- Prepare linearized constraints using sensitivity factors for any violated post-contingency thermal limits.

3.9.2.1 Base Case Power Flow

An AC power flow solution will continue to be prepared for each hour. If the AC power flow solution fails to converge for any hour, a non-linear DC power flow will continue to be used for that hour. If the non-linear DC power flow solution fails to converge for any hour, a linear DC power flow will be used for that hour.

The power flow solution will have features to model adjustments of phase shifters, voltage regulating transformers, reactors and capacitors, and MVAr output of generating units and synchronous condensers. In case of a network split, only the island with the largest number of *IESO-controlled grid* buses will continue to be considered.

3.9.2.2 Pre-contingency Security Assessment

When the AC or non-linear DC power flow solution is used, the pre-contingency *security* assessment will continue to check all monitored equipment for violation of their pre-contingency thermal limits. It will also check for violation of any applicable OSL equations. For every violated limit, a linearized constraint will be generated.

When the linear DC power flow solution is used, the pre-contingency *security* assessment may develop linear constraints to help the AC or non-linear DC power flow solution converge in the subsequent iterations.

These linearized constraints will be expressed in terms of scheduling variables and sensitivity factors so they can be provided to the optimization function to be used in the next optimization function iteration.

The sensitivity factors will continue to be derived based on the power flow Jacobian matrix. The sensitivity factor for a resource with respect to a line flow for example, indicates the fraction of *energy* injected at the resource bus which flows on the line.

The pre-contingency *security* assessment will continue to use the following inputs:

- OSL equations;
- Pre-contingency thermal limits;
- List of monitored equipment; and
- Base case power flow solution which also includes calculated MW flows on lines, transformers, phase shifters, and branch groups.

The line, transformer, branch group and phase shifter MW flows in the OSL equations will continue to be replaced with the sum of the pre-contingency sensitivity factors multiplied by scheduling variables. The minimum and maximum limits of OSL equations will be adjusted to reflect the difference between the calculated MW flows and the linearized MW flows using the sensitivity factors.

The pre-contingency sensitivity factor for a virtual transaction trading zone will be the weighted average of pre-contingency sensitivity factors of the *dispatchable loads*, *non-dispatchable loads*, price responsive loads, and *hourly demand response* resources within the zone. The weighting factors are based on the renormalized load distribution factors used to distribute net virtual transactions to *load facilities* as described in Load Distribution Factors within Section 3.9.1.3.

For an *intertie zone* connected to Ontario through regulating phase shifters that receive shares of the *intertie* schedule, the effective sensitivity factor of *boundary entities* in the *intertie zone* will continue to be calculated using the Jacobian matrix, shares of phase shifters in the *intertie* schedule and phase shifter sensitivities.

3.9.2.3 Loss Calculation

The *security* assessment function will calculate total losses, marginal loss factors and a loss adjustment for each hour using the base case power flow solution. All of these loss related quantities can continue to vary from hour to hour.

In the future, the static marginal loss factors used today will no longer be used. In the scheduling algorithm, the *security* assessment function will pass the marginal loss factors it calculates for each hour to the optimization function. In the pricing algorithm, the optimization function will use the marginal loss factors used in the last optimization function iteration of the corresponding scheduling algorithm.

Total losses will exclude losses in Ontario's neighboring jurisdictions. When determining marginal loss factors, the impact of losses on local branches (e.g. load step-down transformers) between the resource bus and the resource *connection point* to the *IESO-controlled grid* and losses on branches in Ontario's neighboring jurisdictions will be excluded.

The marginal loss factor for each virtual transaction trading zone will be calculated as the weighted average of marginal loss factors of the *dispatchable loads*, *non-dispatchable loads*, price responsive loads, and *hourly demand response* resources within the zone. The weighting factors will be based on the renormalized load distribution factors used to distribute net virtual transactions to load resources as described in Load Distribution Factors within Section 3.9.1.3.

3.9.2.4 Contingency Analysis

The contingency analysis function will continue to use a linear power flow analysis and consists of the following sub-functions:

- Post-contingency connectivity analysis;
- Post-contingency MW flow calculation; and
- Checking of post-contingency thermal limit violations and building of linearized constraints for violated limits.

The contingency analysis will continue to use a linear power flow analysis based on the base case power flow solution, the list of contingencies to be simulated, the list of monitored equipment and the post-contingency thermal limits. The contingencies will continue to be defined as an *outage* to branch (lines, transformers and phase shifters), injections and/or withdrawals.

The contingency analysis function will be able to model post-contingency control actions such as automatic angle tap adjustments.

The calculated post-contingency MW flows will continue to be compared to the post-contingency branch thermal limits for all the monitored equipment. For each monitored equipment, up to a pre-defined configurable number of the most severe violations will be linearized and passed to the optimization function as a linear constraint.

The calculation of the post-contingency sensitivity factors will be similar to that of the pre-contingency sensitivity factors. The updated power flow Jacobian matrix and post-contingency system states will continue to be used in the calculation of the sensitivity factors.

The post-contingency sensitivity factor for a virtual transaction zonal trading entity will be the weighted average of the post-contingency sensitivity factors for the *dispatchable loads*, *non-dispatchable loads*, price responsive loads, and *hourly demand response* resources within the zone. The weighting factors are based on the renormalized load distribution factors used to distribute net virtual transactions to load resources as described in Load Distribution Factors within Section 3.9.1.3.

3.9.3. Outputs

The following outputs of the *security* assessment function will be provided to the optimization function:

- Marginal loss factors of resources, which represent the marginal impact on *IESO-controlled grid* losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at a resource in a specific hour. When determining marginal loss factors, the impact of local branches (e.g. load step-down transformers) between the resource bus and the resource *connection point* to the *IESO-controlled grid* and losses on branches in Ontario's neighboring jurisdictions will be excluded.
- Loss adjustment quantity for each hour which is needed to correct for any discrepancy between total losses in the *IESO-controlled grid* obtained from the base case power flow and the linearized losses calculated using the marginal loss factors. Total losses will exclude losses in Ontario's neighboring jurisdictions.
- The linearized constraints for all violated pre-contingency limits for each hour.
- The linearized constraints for all violated post-contingency thermal limits for each hour.

The following outputs of the *security* assessment function are required to calculate prices for all dispatchable and non-dispatchable load and generation resources, *hourly demand response* resources, *boundary entities*, and virtual transaction zonal trading entities:

- Marginal loss factors;
- Pre-contingency sensitivity factors; and
- Post-contingency sensitivity factors.

3.10. Pricing Formulas

The DAM calculation engine will calculate LMPs for all pricing nodes using shadow prices, constraint sensitivities and marginal loss factors.

LMPs for *energy* will be calculated for the following pricing nodes:

- Dispatchable and non-dispatchable generation resource buses;
- *Dispatchable load*, price responsive load, and *hourly demand response* resource buses;
- *Non-dispatchable load* buses; and
- *Intertie zone* source and sink buses.

LMPs for *operating reserve* will be calculated for the following pricing nodes:

- Dispatchable generation resource buses;
- *Dispatchable load* buses; and
- *Intertie zone* source and sink buses.

The set of internal pricing nodes will be designated by L and will include:

- Resources scheduled by the DAM calculation engine optimization function (designated B as per Section 3.4.1.1); and
- *Non-dispatchable load* locations and other internal locations without an active *bid* or *offer*.

The set of external pricing nodes will be designated by D as in Section 3.4.1.1.

Prices will be calculated using the shadow prices determined by the pricing algorithm. If a price is not within the *maximum market clearing price* and the *settlement* floor price (the *settlement* bounds), the price and its components will be modified. The following parameters will be used when performing price modification:

- $EngyPrcCeil$ shall designate the maximum *energy* price and be set equal to the *maximum market clearing price* of $2,000/MWh;
- $EngyPrcFlr$ shall designate the *settlement* floor price and be set equal to -$100/MWh;
- $ORPrcCeil$ shall designate the maximum *operating reserve* price for any class of *operating reserve* and be set equal to the maximum market clearing price of $2,000/MW; and
- $ORPrcFlr$ shall designate the minimum *operating reserve price* for any class of *operating reserve* and be set equal to $0/MW.
- $NISLPen$ shall designate the net interchange scheduling limit constraint violation penalty price for market pricing.

A weighted average of the above *settlement*-ready prices will be used to provide zonal prices for the following pricing locations:

- Virtual transaction zonal trading entities; and
- *Non-dispatchable load zones*, including the Ontario Zone. The DAM Ontario Zonal Price will be used for *settlement* of *non-dispatchable loads.* Other *non-dispatchable load* zones are sub-zones of the Ontario Zone. The prices for these zones will be determined for informational purposes.

Non-dispatchable load zones will only contain *non-dispatchable load* buses, whereas virtual transaction zonal trading entities will be assigned buses for all load types. As a result, there may be different zonal *energy* prices for *non-dispatchable load* zones and virtual transactions zonal trading entities corresponding to the same electrical regions. The DAM calculation engine will receive virtual transaction zonal trading entity and *non-dispatchable load* zone definitions specifying the buses whose LMPs will contribute to the zonal prices. The load distribution pattern as provided to the *security* assessment function will be used to determine the weight assigned to each bus in contributing to the zonal price, where:

- $L_m^{VIRT} \subseteq L$ shall designate the buses contributing to the virtual transaction zonal trading entity price for virtual transaction zonal trading entity $m \in M$;
- $WF_{h,m,b}^{VIRT}$ shall designate the weighting factor for bus $b \in L_m^{VIRT}$ used to calculate the price for virtual transaction zonal trading entity $m \in M$ for hour $h \in \{1,..,24\}$;
- Y shall designate the *non-dispatchable load* zones in Ontario;
- $L_y^{NDL} \subseteq L$ shall designate the buses contributing to the zonal price for *non-dispatchable load* zone $y \in Y$; and
- $WF_{h,y,b}^{NDL}$ shall designate the weighting factor for bus $b \in L_y^{NDL}$ used to calculate the price for *non-dispatchable load* zone $y \in Y$ for hour $h \in \{1,..,24\}$.

The weighting factors will be obtained by renormalizing the load distribution factors so that the sum of weighting factors for an individual zone is one.

If there is insufficient information to calculate an accurate price, or if the process fails to produce a *settlement*-ready price for any other reason, this will be flagged for further review by the *IESO*.

3.10.1. Locational Marginal Prices for Energy

The LMP at a bus in an hour measures the *offered* cost of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of generation at that bus in that hour.

3.10.1.1 Energy LMPs for Internal Pricing Nodes

For each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$, *energy* LMPs and components will be calculated for every node $b \in L$ where a non-dispatchable or dispatchable generation resource, a *dispatchable load*, a price responsive load, an *hourly demand response* resource, or a *non-dispatchable load* is sited, where:

- $LMP^p_{h,b}$ shall designate the Pass p hour h LMP;
- $PRef^p_h$ shall designate the Pass p hour h *energy* reference price;
- $PLoss^p_{h,b}$ shall designate the Pass p hour h loss component; and
- $PCong^p_{h,b}$ shall designate the Pass p hour h congestion component.

The Pass p LMP at bus $b \in L$ in hour $h \in \{1,..,24\}$ will be initially calculated as follows:

$$InitLMP^p_{h,b} = InitPRef^p_h + InitPLoss^p_{h,b} + InitPCong^p_{h,b}$$

where

$$InitPRef^p_h = SPL^p_h\,;$$

$$InitPLoss^p_{h,b} = MglLoss^p_{h,b} \cdot SPL^p_h\,;$$

and

$$InitPCong^p_{h,b} = \sum_{f \in F_h} PreConSF_{h,f,b} \cdot SPNormT^p_{h,f} + \sum_{c \in C} \sum_{f \in F_{h,c}} SF_{h,c,f,b} \cdot SPEmT^p_{h,c,f}\,.$$

The reference price and loss component together reflect the cost of meeting load at bus b, incorporating the effect of marginal losses and reflect the quantity of *energy* that must be injected at the reference bus to meet additional load at bus b. The congestion component reflects the cost of transmission congestion between the reference bus and bus b and is calculated by adding the individual incremental congestion costs for the binding transmission constraints on the path between the reference bus and bus b. Each congestion cost is obtained by multiplying the shadow price for the binding transmission constraint by the corresponding sensitivity factor for bus b.

An *energy* LMP can fall outside the *settlement* bounds provided by $EngyPrcFlr$ and $EngyPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the LMP and its components (reference, loss and congestion) will be modified so that the LMP is within the *settlement* bounds.

The reference price will be modified if it is not within the *settlement* bounds. For hour $h \in \{1,..,24\}$:

a. If $InitPRef^p_h > EngyPrcCeil$, set $PRef^p_h = EngyPrcCeil$.
b. If $InitPRef^p_h < EngyPrcFlr$, set $PRef^p_h = EngyPrcFlr$.
c. Otherwise, set $PRef^p_h = InitPRef^p_h$.

The LMP and components at internal bus $b \in L$ in hour $h \in \{1,..,24\}$ will be modified as follows:

1. Modify the LMP to be within *settlement* bounds.
   a. If $InitLMP^{p}_{h,b} > EngyPrcCeil$, set $LMP^{p}_{h,b} = EngyPrcCeil$.
   b. If $InitLMP^{p}_{h,b} < EngyPrcFlr$, set $LMP^{p}_{h,b} = EngyPrcFlr$.
   c. Otherwise, set $LMP^{p}_{h,b} = InitLMP^{p}_{h,b}$.
2. If the reference price has been modified (i.e. $PRef^{p}_{h} \neq InitPRef^{p}_{h}$), recalculate the loss component.
   a. If $PRef^{p}_{h} \neq InitPRef^{p}_{h}$, set $PLoss^{p}_{h,b} = MglLoss^{p}_{h,b} \cdot PRef^{p}_{h}$.
   b. Otherwise, set $PLoss^{p}_{h,b} = InitPLoss^{p}_{h,b}$.
3. Modify the congestion component so the relationship between LMP, reference price, loss component and congestion component holds, provided the congestion component does not change mathematical signs as a result. If the congestion component changes its mathematical sign, set it to 0 and modify the loss component to maintain the relationship.
   a. If $LMP^{p}_{h,b} - PRef^{p}_{h} - PLoss^{p}_{h,b}$ and $InitPCong^{p}_{h,b}$ have the same mathematical sign, then set $PCong^{p}_{h,b} = LMP^{p}_{h,b} - PRef^{p}_{h} - PLoss^{p}_{h,b}$.
   b. Otherwise, set $PCong^{p}_{h,b} = 0$ and set $PLoss^{p}_{h,b} = LMP^{p}_{h,b} - PRef^{p}_{h}$.

If $PRef^{p}_{h} = InitPRef^{p}_{h}$, then the LMP and components for nodes with prices within the *settlement* bounds will not be modified. If $PRef^{p}_{h} \neq InitPRef^{p}_{h}$, then the LMP for nodes with prices within the *settlement* bounds will not be modified, but the components will be.

3.10.1.2 Energy LMPs for Intertie Zone Source and Sink Buses

For each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$, *energy* LMPs and components will be calculated for *intertie zone* bus $d \in D$, where:

- $ExtLMP^{p}_{h,d}$ shall designate the Pass p hour h LMP;
- $IntLMP^{p}_{h,d}$ shall designate the Pass p hour h *intertie* border price (IBP);
- $ICP^{p}_{h,d}$ shall designate the Pass p hour h *intertie* congestion price (ICP);
- $PRef^{p}_{h}$ shall designate the Pass p hour h *energy* reference price;
- $PLoss^{p}_{h,d}$ shall designate the Pass p hour h loss component;
- $PIntCong^{p}_{h,d}$ shall designate the Pass p hour h internal congestion component;
- $PExtCong^{p}_{h,d}$ shall designate the Pass p hour h *intertie* congestion component; and
- $PNISL^{p}_{h,d}$ shall designate the Pass p hour h net interchange scheduling limit congestion component.

The LMP will be the same for all buses at the same proxy location and *intertie zone*. *Intertie* transactions associated with the same proxy location, but specified as occurring at different *intertie zones*, subject to phase shifter operation, will be modelled as flowing across independent paths. Pricing of these transactions will utilize shadow prices associated with the internal transmission constraints, interchange scheduling limits and transmission losses applicable to the path associated to the relevant *intertie zone*. The Pass p LMP at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in hour $h \in \{1,..,24\}$ will be initially calculated as follows:

$$InitExtLMP_{h,d}^{p} = InitIntLMP_{h,d}^{p} + InitICP_{h,d}^{p}$$

where

$$InitPRef_{h}^{p} = SPL_{h}^{p}\,;$$

$$InitPLoss_{h,d}^{p} = MglLoss_{h,d}^{p} \cdot SPL_{h}^{p}\,;$$

$$InitPIntCong_{h,d}^{p} = \sum_{f \in F_h} PreConSF_{h,f,d} \cdot SPNormT_{h,f}^{p} + \sum_{c \in C} \sum_{f \in F_{h,c}} SF_{h,c,f,d} \cdot SPEmT_{h,c,f}^{p}\,;$$

$$InitIntLMP_{h,d}^{p} = InitPRef_{h}^{p} + InitPLoss_{h,d}^{p} + InitPIntCong_{h,d}^{p};$$

$$InitICP_{h,d}^{p} = InitPExtCong_{h,d}^{p} + InitPNISL_{h,d}^{p};$$

$$InitPExtCong_{h,d}^{p} = \sum_{z \in Z_{sch}} EnCoeff_{a,z} \cdot SPExtT_{h,z}^{p}\,;$$

and

$$\begin{aligned} InitPNISL_{h,d}^{p} = {} & SPNIUExtBwdT_{h}^{p} - SPNIUExtFwdT_{h}^{p} - SPNIDExtBwdT_{h}^{p} \\ & + SPNIDExtFwdT_{h}^{p}. \end{aligned}$$

The components comprising the *intertie* border price for a proxy location in an *intertie zone* are analogous to the components of the *energy* LMP for an internal pricing node. The marginal loss factor used to calculate the loss component will not account for losses in Ontario's neighbouring jurisdictions. The *intertie* congestion component reflects the cost of congestion at the *intertie* and is calculated by adding the individual congestion costs for the binding import and export transmission limits that affect transactions scheduled at the *intertie zone*. The NISL congestion component reflects the cost of congestion due to hour-to-hour limitations on changes in net flows over all *interties*.

To model an *intertie* as out-of-service, the *intertie* transmission limits will be set to zero and all import *offers* and export *bids* will receive a zero schedule. In this case, the LMP will be set to the *intertie* border price.

An *energy* LMP can fall outside the *settlement* bounds provided by $EngyPrcFlr$ and $EngyPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the LMP at the *intertie zone* bus and its components (reference loss, internal congestion, *intertie* congestion, and NISL congestion) will be modified so that the LMP to within the *settlement* bounds.

The modification of the IBP, reference price, loss component and internal congestion component to obtain $IntLMP^p_{h,d}$, $PRef^p_h$, $PLoss^p_{h,d}$ and $PIntCong^p_{h,d}$ will follow the procedure for price modification for internal nodes as specified in Section 3.10.1.1 The LMP, ICP, external congestion component and NISL congestion component at *intertie zone* bus $d \in D$ in hour $h \in \{1,..,24\}$ will then be modified as follows:

1. Revise the LMP to within *settlement* bounds.
   a. If $InitExtLMP^p_{h,d} > EngyPrcCeil$, set $ExtLMP^p_{h,d} = EngyPrcCeil$.
   b. If $InitExtLMP^p_{h,d} < EngyPrcFlr$, set $ExtLMP^p_{h,d} = EngyPrcFlr$.
   c. Otherwise, set $ExtLMP^p_{h,d} = InitExtLMP^p_{h,d}$.
2. If the modified LMP and IBP coincide, set the external and NISL congestion components to zero.
   a. If $ExtLMP^p_{h,d} = IntLMP^p_{h,d}$, set $PExtCong^p_{h,d} = 0$ and $PNISL^p_{h,d} = 0$.
3. Otherwise, modify the *intertie* congestion and NISL congestion components pro-rata to maintain the relationship between LMP and price components, capping the NISL congestion component at the NISL penalty price.
   a. If $ExtLMP^p_{h,d} \neq IntLMP^p_{h,d}$, set

   $$PNISL^p_{h,d} = (ExtLMP^p_{h,d}\text{-}IntLMP^p_{h,d}) \cdot \left(\frac{InitPNISL^p_{h,d}}{InitPNISL^p_{h,d} + InitPExtCong^p_{h,d}}\right).$$

      i. If $PNISL^p_{h,d} > NISLPen$, set $PNISL^p_{h,d} = NISLPen$.
      ii. If $PNISL^p_{h,d} < (-1) \cdot NISLPen$, set $PNISL^p_{h,d} = (-1) \cdot NISLPen$.

   b. Then set $PExtCong^p_{h,d} = ExtLMP^p_{h,d} - IntLMP^p_{h,d} - PNISL^p_{h,d}$.
4. Calculate the ICP as the sum of the modified *intertie* congestion and NISL congestion components.

$$ICP^p_{h,d} = PExtCong^p_{h,d} + PNISL^p_{h,d}$$

3.10.1.3 Zonal Energy Prices

For each pricing zone (including zones for *non-dispatchable load* and virtual transactions), the affiliated zonal *energy* price for an hour will be calculated as the sum of the hourly reference price, the load distribution-weighted loss component within the zone, and the load distribution-weighted congestion component within the zone. In particular, the DAM Ontario Zonal Price will be calculated in this way.

For each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$, the Pass p *energy* price for virtual transaction zonal trading entity $m \in M$ will be calculated as follows:

$$VZonalP^p_{h,m} = PRef^p_h + VZonalPLoss^p_{h,m} + VZonalPCong^p_{h,m}$$

where

$$VZonalPLoss^p_{h,m} = \sum_{b \in L^{VIRT}_m} WF^{VIRT}_{h,m,b} \cdot PLoss^p_{h,b}$$

and

$$VZonalPCong_{h,m}^{p} = \sum_{b \in L_m^{VIRT}} WF_{h,m,b}^{VIRT} \cdot PCong_{h,b}^{p}.$$

For each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$, the Pass p *energy* price for *non-dispatchable load* zone $y \in Y$ is calculated as follows:

$$ZonalP_{h,y}^{p} = PRef_h^p + ZonalPLoss_{h,y}^{p} + ZonalPCong_{h,y}^{p}$$

where

$$ZonalPLoss_{h,y}^{p} = \sum_{b \in L_y^{NDL}} WF_{h,y,b}^{NDL} \cdot PLoss_{h,b}^{p}$$

and

$$ZonalPCong_{h,y}^{p} = \sum_{b \in L_y^{NDL}} WF_{h,y,b}^{NDL} \cdot PCong_{h,b}^{p}.$$

3.10.2. Locational Marginal Prices for Operating Reserve

The LMP for a category of *operating reserve* at a bus in an hour measures the *offered* cost of meeting an infinitesimal change in the reserve requirement for that category of *operating reserve* in that hour. This is determined while also accounting for binding constraints associated with the reserve areas to which the bus belongs. *Operating reserve* prices will continue to be calculated by co-optimizing *energy* and the three categories as *operating reserve*, as implied by the formulation of the optimization function.

3.10.2.1 Operating Reserve LMPs for Internal Pricing Nodes

For each Pass $p \in \{1,3\}$ and hour $h \in \{1,..,24\}$, *operating reserve* LMPs and components will be calculated for every bus $b \in B$ where a dispatchable generation resource or *dispatchable load* is sited, where:

- $L30RP_{h,b}^{p}$ shall designate the Pass p hour h *thirty-minute operating reserve* price;
- $P30RRef_h^p$ shall designate the Pass p hour h *thirty-minute operating reserve* reference price;
- $P30RCong_{h,b}^{p}$ shall designate the Pass p hour h *thirty-minute operating reserve* congestion component;
- $L10NP_{h,b}^{p}$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve* price;
- $P10NRef_h^p$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve* reference price;

- $P10NCong^p_{h,b}$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve* congestion component;
- $L10SP^p_{h,b}$ shall designate the Pass p hour h synchronized *ten-minute operating reserve* price;
- $P10SRef^p_h$ shall designate the Pass p hour h synchronized *ten-minute operating reserve* reference price; and
- $P10SCong^p_{h,b}$ shall designate the Pass p hour h synchronized *ten-minute operating reserve* congestion component.

For each bus $b \in B$, define $ORREG_b \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus b.

The Pass p *thirty-minute operating reserve* LMP at bus $b \in B$ in hour $h \in \{1,..,24\}$ will be initially calculated as follows:

$$InitL30RP^p_{h,b} = InitP30RRef^p_h + InitP30RCong^p_{h,b}$$

where

$$InitP30RRef^p_h = SP30R^p_h$$

and

$$InitP30RCong^p_{h,b} = \sum_{r \in ORREG_b} SPREGMin30R^p_{h,r} - \sum_{r \in ORREG_b} SPREGMax30R^p_{h,r}.$$

The reference price reflects the cost of meeting an infinitesimal change in the *thirty-minute operating reserve* requirement. The congestion component reflects the cost of binding constraints associated with *reserve* areas to which the bus belongs. Such constraints in turn reflect transmission limits that prevent the delivery of activated *operating reserve* into or out of a reserve area.

The Pass p non-synchronized *ten-minute operating reserve* LMP at bus $b \in B$ in hour $h \in \{1,..,24\}$ will be initially calculated as follows:

$$InitL10\mathrm{NP}^p_{h,b} = InitP10NRef^p_h + InitP10NCong^p_{h,b}$$

where

$$InitP10NRef^p_h = SP10R^p_h + SP30R^p_h$$

and

$$\begin{aligned} InitP10NCong^p_{h,b} &= \sum_{r \in ORREG_b} \left(SPREGMin10R^p_{h,r} + SPREGMin30R^p_{h,r}\right) \\ &- \sum_{r \in ORREG_b} \left(SPREGMax10R^p_{h,r} + SPREGMax30R^p_{h,r}\right). \end{aligned}$$

The reference price reflects the cost of meeting an infinitesimal change in the non-synchronized *ten-minute operating reserve* requirement. The congestion component reflects the cost of binding constraints associated with reserve areas to which the bus belongs. Such constraints in turn reflect transmission limits that prevent the delivery of activated *operating reserve* into or out of a reserve area.

The Pass p synchronized *ten-minute operating reserve* LMP at bus $b \in B$ in hour $h \in \{1,..,24\}$ will be initially calculated as follows:

$$InitL10SP_{h,b}^{p} = InitP10SRef_{h}^{p} + InitP10SCong_{h,b}^{p}$$

where

$$InitP10SRef_{h}^{p} = SP10S_{h}^{p} + SP10R_{h}^{p} + SP30R_{h}^{p}$$

and

$$\begin{aligned} InitP10SCong_{h,b}^{p} \\ = \sum_{r \in ORREG_b} \left(SPREGMin10R_{h,r}^{p} + SPREGMin30R_{h,r}^{p}\right) \\ - \sum_{r \in ORREG_b} \left(SPREGMax10R_{h,r}^{p} + SPREGMax30R_{h,r}^{p}\right). \end{aligned}$$

The reference price reflects the cost of meeting an infinitesimal change in the synchronized *ten-minute operating reserve* requirement. The congestion component reflects the cost of binding constraints associated with reserve areas to which the bus belongs. Such constraints in turn reflect transmission limits that prevent the delivery of activated *operating* reserve into or out of a reserve area.

An *operating reserve* LMP can fall outside the *settlement* bounds of $ORPrcFlr$ and $ORPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the *operating reserve* LMP and its components (reference and congestion) will be modified so that the LMP is within the *settlement* bounds.

For each class of *operating* reserve, the reference price will be modified when it does not fall within the *settlement* bounds. For hour $h \in \{1,..,24\}$:

1. Set $P30RRef_{h}^{p} = min(max(InitP30RRef_{h}^{p}, ORPrcFlr), ORPrcCeil)$.
2. Set $P10NRef_{h}^{p} = min(max(InitP10NRef_{h}^{p}, ORPrcFlr), ORPrcCeil)$.
3. Set $P10SRef_{h}^{p} = min(max(InitP10SRef_{h}^{p}, ORPrcFlr), ORPrcCeil)$.

For each class of *operating reserve*, the LMP and components at internal bus $b \in B$ in hour $h \in \{1,..,24\}$ will be modified as follows:

1. Set $L30RP_{h,b}^{p} = min(max(InitL30RP_{h,b}^{p}, ORPrcFlr), ORPrcCeil)$ and set $P30RCong_{h,b}^{p} = L30RP_{h,b}^{p} - P30RRef_{h}^{p}$.
2. Set $L10NP_{h,b}^{p} = min(max(InitL10NP_{h,b}^{p}, ORPrcFlr), ORPrcCeil)$ and set $P10NCong_{h,b}^{p} = L10NP_{h,b}^{p} - P10NRef_{h}^{p}$.

3. Set $L10SP^{p}_{h,b} = min(max(InitL10SP^{p}_{h,b}, ORPrcFlr), ORPrcCeil)$ and set $P10SCong^{p}_{h,b} = L10SP^{p}_{h,b} - P10SRef^{p}_{h}$.

3.10.2.2 Operating Reserve LMPs for Intertie Zone Source and Sink Buses

The calculation of *operating reserve* LMPs for *intertie zone* buses is similar to internal buses except for additionally accounting for binding net import constraints. Such constraints can limit the amount of *operating reserve* that can be imported into Ontario.

For each Pass $p \in \{1,3\}$ and hour $h \in \{1,...,24\}$, the following *operating reserve* LMPs and components are calculated for *intertie zone* bus $d \in D$, where:

- $ExtL30RP^{p}_{h,d}$ shall designate the Pass p hour h *thirty-minute operating reserve* price;
- $P30RRef^{p}_{h}$ shall designate the Pass p hour h *thirty-minute operating reserve* reference price;
- $P30RIntCong^{p}_{h,d}$ shall designate the Pass p hour h *thirty-minute operating reserve* internal congestion component;
- $P30RExtCong^{p}_{h,d}$ shall designate the Pass p hour h *thirty-minute operating reserve intertie* congestion component;
- $ExtL10NP^{p}_{h,d}$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve* price;
- $P10NRef^{p}_{h}$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve* reference price;
- $P10NIntCong^{p}_{h,d}$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve* internal congestion component; and
- $P10NExtCong^{p}_{h,d}$ shall designate the Pass p hour h non-synchronized *ten-minute operating reserve intertie* congestion component.

The LMP will be the same for all buses at the same proxy location and *intertie zone*. Reserve imports associated with the same proxy location, but specified as occurring at a different *intertie zone*, subject to phase shifter operation, will be modelled as flowing across independent paths. Pricing of these reserve imports will utilize shadow prices associated with interchange scheduling limits and regional minimum and maximum *operating reserve* requirements applicable to the path associated to the relevant *intertie zone*.

For each *intertie zone* bus $d \in D$, define $ORREG_d \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus d.

The Pass p *thirty-minute operating reserve* LMP at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in hour $h \in \{1,...,24\}$ will be initially calculated as follows:

$$InitExtL30RP_{h,d}^{p} = InitP30RRef_{h}^{p} + InitP30RIntCong_{h,d}^{p} + InitP30RExtCong_{h,d}^{p}$$

where

$$InitP30RRef_{h}^{p} = SP30R_{h}^{p};$$

$$InitP30RIntCong_{h,d}^{p} = \sum_{r \in ORREG_d} SPREGMin30R_{h,r}^{p} - \sum_{r \in ORREG_d} SPREGMax30R_{h,r}^{p};$$

and

$$InitP30RExtCong_{h,d}^{p} = -\sum_{z \in Z_{Sch}} 0.5 \cdot (EnCoeff_{a,z} + 1) \cdot SPExtT_{h,z}^{p}.$$

The reference and internal congestion components are analogous to the components of the *thirty-minute operative reserve* LMP for an internal pricing node. The *intertie* congestion component reflects the cost of congestion at the *intertie* and is calculated by adding the individual congestion costs for the binding import limits that affect *operating reserve* transactions scheduled at the *intertie zone*.

The Pass p *ten-minute operating reserve* LMP at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in hour $h \in \{1,..,24\}$ will be initially calculated as follows:

$$InitExtL10NP_{h,d}^{p} = InitP10NRef_{h}^{p} + InitP10NIntCong_{h,d}^{p} + InitP10NExtCong_{h,d}^{p}$$

where

$$InitP10NRef_{h}^{p} = SP10R_{h}^{p} + SP30R_{h}^{p};$$

$$\begin{aligned} InitP10NIntCong_{h,d}^{p} &= \sum_{r \in ORREG_d} \left(SPREGMin10R_{h,r}^{p} + SPREGMin30R_{h,r}^{p}\right) \\ &\quad - \sum_{r \in ORREG_d} \left(SPREGMax10R_{h,r}^{p} + SPREGMax30R_{h,r}^{p}\right); \end{aligned}$$

and

$$InitP10NExtCong_{h,d}^{p} = -\sum_{z \in Z_{Sch}} 0.5 \cdot (EnCoeff_{a,z} + 1) \cdot SPExtT_{h,z}^{p}.$$

The reference and internal congestion components are analogous to the components of the *ten-minute operative reserve* LMP for an internal pricing node. The *intertie* congestion component reflects the cost of congestion at the *intertie* and is calculated by adding the individual congestion costs for the binding import limits that affect *operating reserve* transactions scheduled at the *intertie zone*.

There is no need to calculate a price for synchronized *ten-minute operating reserve* at *intertie zone* buses because synchronized *ten-minute operating reserve* cannot be imported.

To model an *intertie* as out-of-service, the *intertie* transmission limits will be set to zero and all *operating reserve offers* will receive a zero schedule. In this case, the *intertie operating reserve* prices will be set to be equal to the reference price for that class of *operating reserve* plus the applicable internal congestion component as described above.

An *operating reserve* LMP can fall outside the *settlement* bounds of $ORPrcFlr$ and $ORPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the *operating reserve* LMP at an *intertie zone* bus and its components (reference, internal congestion and *intertie* congestion) will be modified so that the LMP is within the *settlement* bounds.

For *thirty-minute operating reserve*, the LMP and components at *intertie zone* bus $d \in D$ in hour $h \in \{1,..,24\}$ will be modified as follows:

1. Calculate $IntL30R = InitP30RRef_h^p + InitP30RIntCong_{h,d}^p$ and modify its components using the procedure for price modification for internal nodes as specified in Section 3.10.2.1 to obtain $P30RRef_h^p$ and $P30RIntCong_{h,d}^p$.
2. Set $ExtL30RP_{h,b}^p = min(max(InitExtL30RP_{h,b}^p, ORPrcFlr), ORPrcCeil)$.
3. Set $P30RExtCong_{h,d}^p = ExtL30RP_{h,b}^p - P30RRef_h^p - P30RIntCong_{h,d}^p$.

For *ten-minute operating reserve*, the LMP and components at *intertie zone* bus $d \in D$ in hour $h \in \{1,..,24\}$ will be modified as follows:

1. Calculate $IntL10N = InitP10NRef_h^p + InitP10NIntCong_{h,d}^p$ and modify its components using the procedure for price modification for internal nodes as specified in Section 3.10.2.1 to obtain $P10NRef_h^p$ and $P10NIntCong_{h,d}^p$.
2. Set $ExtL10NP_{h,b}^p = min(max(InitExtL10NP_{h,b}^p, ORPrcFlr), ORPrcCeil)$.
3. Set $P10NExtCong_{h,d}^p = ExtL10NP_{h,b}^p - P10NRef_h^p - P10NIntCong_{h,d}^p$

3.10.3. Pricing for Islanded Nodes

The DAM calculation engine will calculate hourly LMPs for islanded nodes as follows.

NQS resources that are not connected to the main island of the system will be reconnected as inactive units (zero MW and zero MVAr) within the *security* assessment function so as to produce a price within the DAM calculation engine passes. Steps one to three of the pricing for islanded nodes logic will be used to produce a price for NQS resources:

1. Find connection paths over open switches that connect the NQS resource to the main island.
2. Determine the priority rating for each connection path identified based on a weighted sum of the base voltage over all open switches used by the reconnection path and the MW ratings of the newly connected branches.

3. Select the reconnection path with the highest priority rating, breaking ties arbitrarily.

The Substitution rules outlined in steps four to eight will be used to produce a price for all other pricing nodes that are not connected to the main island of the system due to a transmission outage, disconnection, a resource being out of service or a resource operating in *segregated mode of operation*. These substitutions rules will also apply to NQS resources for which steps one to three was unable to determine a price. The DAM calculation engine will be provided a node-level and *facility*-level substitution list for each pricing node to be used in applying the substitution rules. Steps four to eight of the pricing for islanded nodes logic will be as follows:

1. Use the LMP at a node in the node-level substitution list, provided such node is connected to the main island.
2. If no such nodes are identified, use the average LMP of all nodes at the same voltage level within the same *facility* that are connected to the main island.
3. If no such nodes are identified, use the average LMP of all nodes within the same *facility* that are connected to the main island.
4. If no such nodes are identified, use the average LMP of all nodes from another *facility* that is connected to the main island, as determined by the *facility*-level substitution list.
5. If a price is yet to be determined, use the LMP for the *reference bus*.

3.11. Data Generation for Settlement Mitigation

The DAM calculation engine will perform conduct and impact tests to determine if conditions for exercising market power exist. Mitigation in Pass 1 of the DAM calculation engine is limited to assessing impact to prices. The mitigation of make-whole payments, if necessary, will occur in the *settlement process*. Any resource that meets the conditions for the testing of make-whole payments will be subject to the make-whole payment impact test as described in the Market Settlement detailed design document.

To execute the make-whole payment impact test, the *settlement process* will require additional *dispatch data* from the DAM calculation engine as described in this section. This data will be generated after the DAM calculation engine completes Pass 3.

3.11.1. Calculation Engine Inputs Provided to the Pre-Settlement Mitigation Process

The following information from the DAM calculation engine run will be required to generate data for the make-whole payment impact test:

- A list of NQS resources that have been manually committed for *reliability* by the *IESO*, which were entered as input to Pass 1. These will be identified as NQS resources with a minimum generation constraint greater than zero in As-Offered Scheduling;
- The set of resources subject to the conduct test by the constrained area condition type (i.e. resources included in the sets BCT_h^{NCA}, BCT_h^{DCA}, BCT_h^{BCA}, BCT_h^{GMP}, BCT_h^{ORL}, BCT_h^{ORG}), which is the output from Pass 1; and
- Financially binding schedules and operational commitments by resource by hour, which is an output from Pass 3.

Outputs of the Pre-Settlement Mitigation Process The output from this process will be the enhanced mitigated for conduct *dispatch data* set, which includes the additional data that is necessary for the make whole payment impact testing. It applies to all NQS resources with financially binding schedules, using the most restrictive constrained area condition over the *settlement* period. It also includes additional *dispatch data* for dual-fuel resources, both NQS and quick-start, that have constrained schedules at the end of Pass 3.

For NQS resources with financially binding schedules, the enhanced mitigated for conduct *dispatch data* set includes for each commitment period:

- The set of hours in the commitment period;
- The most restrictive constrained area condition met in the commitment period, and

- A revised set of *dispatch data* for resources subject to conduct test, using the most restrictive constrained area conditions over the commitment period. In this data set:
    - o the *dispatch data* parameter values that fail the conduct test are replaced with their reference levels.
    - o the *dispatch data* parameter values that pass the conduct test are kept as as-offered values.

For dual-fuel resources with financially binding schedules, the calculation engine must provide:

- A revised set of *offer* data, using the fuel type not tested in Pass 1, with *dispatch data* parameters that failed the conduct test replaced with reference levels;
- For both fuel-types, a revised set of *dispatch data* for resources subject to conduct test, using the most restrictive constrained area conditions over the *settlement* period. In this data set:
    - o the *dispatch data* parameter values that fail the conduct test are replaced with their reference levels.
    - o the *dispatch data* parameter values that pass the conduct test are kept as as-offered values.

Table 3-34 lists the conduct test thresholds that must be used to perform the conduct test depending on when the resource was committed.

Table 3-34: Resources for which an Enhanced Mitigated for Conduct Dispatch Data Set Must Be Provided

Resource	Conduct Threshold Used
All *energy* resources that qualified for ex-ante mitigation testing. This includes resources identified for NCA, DCA, BCA, and global market power (*energy*) mitigation testing.	The most stringent market power mitigation thresholds for which the resource qualifies.
All NQS resources that were committed and scheduled for *energy*, did not qualify for ex-ante mitigation testing and: • had a positive congestion component greater than $0/MWh on any binding constraint, or • had a sensitivity factor greater than 0.02 on a non-binding constraint. Plus, this constraint would have been binding or would have been violated but for the commitment of the resource.	Threshold which corresponds with non-binding constraint that would have been binding or violated without the commitment (NCA, DCA, or BCA)

Resource	Conduct Threshold Used
All NQS resources that were committed and scheduled in Reliability Scheduling and Commitment	Global market power (*energy*)
All resources that were scheduled for *reliability* (i.e., minimum constraint applied).	*Reliability* constraints thresholds
All resources supplying *operating reserve* that qualified for ex-ante market power mitigation testing both for Local Market Power (*operating reserve*) and Global Market Power (*operating reserve*), and are scheduled to provide *operating reserve.*	The most stringent market power mitigation thresholds for which the resource qualifies.
All NQS resources that were committed and scheduled for *operating reserve* (that did not qualify for ex-ante mitigation testing)	Global market power (*operating reserve*) thresholds

3.12. The Pseudo-Unit Model

Combined cycle *facilities* with one or more combustion turbine (CT) units and one steam turbine (ST) unit can be *offered* into the current DACP as one or more *pseudo-units* (PSUs) comprised of a single CT together with its share of the ST capacity. The CTs and ST are referred to as the physical units (PUs). The PSU model defines the boundaries for PSU schedules and the proportional relationship between the CT and ST.

The DAM calculation engine optimization function will evaluate a combined cycle *facility* electing PSU modeling as a set of PSU resources that capture the joint economics of operating the CT and the affiliated portion of the ST together. Each PSU resource is scheduled independently, with each PSU modeling a CT and portion of the ST. Each PSU resource is scheduled proportionally according to a fixed ratio of *energy* output between the CT and ST within specific operating regions.

The DAM calculation engine *security* assessment function will continue to model the physical power system and therefore must model the combined cycle *facilities* electing PSU modeling as PUs. Injections into the power system must be simulated at their physical buses. Therefore, PU sensitivity factors will be provided in the transmission limits passed from the *security* assessment function to the optimization function.

Although the optimization function will evaluate resource economics on a PSU basis, it must handle operational information that is provided on a PU basis, either within the optimization or via pre-processing. The following operational information is provided on a PU basis:

- Both transmission constraint sensitivity factors and marginal loss factors for the CT and ST will be provided to the optimization function and translated within the optimization using the PSU model; and
- Any minimum or maximum generation constraint applied to a CT or ST will be pre-processed before the execution of the DAM calculation engine pass to provide limits on the affiliated PSU resources for the optimization function to enforce. *Outages* and de-rates will also be pre-processed before the execution of the DAM calculation engine pass.

Because the optimization function will calculate resource schedules on a PSU basis, post-processing logic will be used to allocate PSU schedules to the corresponding PUs.

3.12.1. Model Parameters

- $CMCR_k$ indicating the registered maximum continuous rating of CT $k \in \{1,..,K\}$ in MW;
- $CMLP_k$ indicating the *minimum loading point* of CT $k \in \{1,..,K\}$ in MW;

- $SMCR$ indicating the registered maximum continuous rating of the ST in MW;
- $SMLP$ indicating the *minimum loading point* of the ST in MW for a 1x1 configuration;
- SDF indicating the amount of duct firing capacity available on the ST in MW;
- $STPortion_k$ indicating the percentage of the ST capacity attributed to PSU $k \in \{1,..,K\}$; and
- $CSCM_k \in \{0,1\}$ indicating whether PSU $k \in \{1,..,K\}$ is flagged to operate in single-cycle mode for the day.

From this data, the following model parameters can be calculated for each PSU $k \in \{1,..K\}$:

- $MMCR_k$ designates the maximum continuous rating of PSU k and is given by
$$CMCR_k + SMCR \cdot STPortion_k \cdot (1 - CSCM_k)$$
- $MMLP_k$ designates the *minimum loading point* of PSU k and is given by
$$CMLP_k + SMLP \cdot (1 - CSCM_k)$$
- MDF_k designates the duct firing capacity of PSU k and is given by
$$SDF \cdot STPortion_k \cdot (1 - CSCM_k)$$
- MDR_k designates the dispatchable capacity of PSU k and is given by
$$MMCR_k - MMLP_k - MDF_k$$

The PSU model has three distinct operating regions: MLP, dispatchable and duct firing. The model parameters above determine the three operating regions of PSU $k \in \{1,..K\}$, each with an affiliated ST and CT share.

The MLP region refers to capacity between 0 and $MMLP_k$:

- The ST share in this region is
$$STShareMLP_k = \frac{SMLP \cdot (1 - CSCM_k)}{MMLP_k}.$$
- The CT share in this region is
$$CTShareMLP_k = \frac{CMLP_k}{MMLP_k}.$$

The dispatchable region refers to capacity between $MMLP_k$ and $MMLP_k + MDR_k$:

- o The ST share in this region is
$$STShareDR_k = \frac{(1 - CSCM_k)(SMCR \cdot STPortion_k - SMLP - SDF_k \cdot STPortion_k)}{MDR_k}.$$
- o The CT share in this region is
$$CTShareDR_k = \frac{CMCR_k - CMLP_k}{MDR_k}.$$

The duct firing region refers to capacity between $MMLP_k + MDR_k$ and $MMCR_k$:

- The ST share in this region is 1.
- The CT share in this region is 0.

3.12.2. Application of PU De-rates to the PSU Model

Market participants will continue to be able to submit de-rates on the CTs and ST corresponding to a combined cycle *facility* that has elected PSU modelling. When a de-rate is submitted on a physical unit, the PSU model parameters defining the dispatchable capacity and duct firing capacity will be updated in the DAM calculation engine to respect the de-rate.

To enable the DAM calculation engine to respect these PU de-rates, the *energy offers* submitted on a PSU basis will be scheduled based on the following logic:

1. A pre-processing step will determine the available parts of the operating regions above based on the CT and ST sharing relationships and the application of the PU de-rates.
2. If part of an operating region is determined to be unavailable, the corresponding *offer* laminations will not be scheduled for *energy* and *operating reserve*.

De-rates will be applied respecting the proportional relationship defined by the PSU model. The pre-processing step will not impact the CT and ST shares within the modelled operating regions and will ensure that both *energy* and *operating reserve* schedules respect the proportional relationship between the CT and the ST.

3.12.2.1 Pre-processing of De-rates

In the pre-processing step, the following operating region parameters for hour $h \in [1,..,24\}$ will be calculated for each PSU $k \in \{1,..,K\}$:

- $MLP_{h,k}$ indicating the *minimum loading point* of PSU k in hour h;
- $DR_{h,k}$ indicating the dispatchable capacity of PSU k in hour h; and
- $DF_{h,k}$ indicating the duct firing capacity of PSU k in hour h.

For each time-step $h \in \{1,..,24\}$, the following data is required for the pre-processing step:

- $CTCap_{h,k}$ indicating the capacity of CT $k \in \{1,..,K\}$ in hour h as determined by submitted de-rates;
- $STCap_h$ indicating the capacity of the ST in hour h as determined by submitted de-rates; and
- $TotalQ_{h,k}$ indicating the total quantity of *energy offered* for PSU $k \in \{1,..,K\}$ in hour h.

The first step is to calculate the amount of *energy offered* attributed to each CT ($CTAmt_{h,k}$) and ST portion ($STAmt_{h,k}$). To do so, the *energy offered* on a PSU is divided between the CT and ST according to the share percentages.

For PSU $k \in \{1,..,K\}$ and the hour $h \in \{1,..,24\}$:

1. If $TotalQ_{h,k} < MMLP_k$ then:
   a. Calculate $CTAmt_{h,k} = 0$.
   b. Calculate $STAmt_{h,k} = 0$.
2. Otherwise:
   a. Calculate $CTAmtMLP = MMLP_k \cdot CTShareMLP_k$.
   b. Calculate $STAmtMLP = MMLP_k \cdot STShareMLP_k$.
   c. If $TotalQ_{h,k} > MMLP_k + MDR_k$, then:
      i. Calculate $CTAmtDR = MDR_k \cdot CTShareDR_k$.
      ii. Calculate $STAmtDR = MDR_k \cdot STShareDR_k$.
      iii. Calculate $STAmtDF = (1 - CSCM_k) \cdot (TotalQ_{h,k} - MMLP_k - MDR_k)$.
   d. Otherwise:
      i. Calculate $CTAmtDR = (TotalQ_{h,k} - MMLP_k) \cdot CTShareDR_k$.
      ii. Calculate $STAmtDR = (TotalQ_{h,k} - MMLP_k) \cdot STShareDR_k$.
      iii. Calculate $STAmtDF = 0$.
   e. Calculate $CTAmt_{h,k} = CTAmtMLP + CTAmtDR$.
   f. Calculate $STAmt_{h,k} = STAmtMLP + STAmtDR + STAmtDF$.

The next step is to allocate the ST capacity to each PSU pro-rata according to the amount of *energy offered* attributed to each ST portion. For PSU $k \in \{1,..,K\}$ and hour $h \in \{1,..,24\}$:

3. Calculate $PRSTCap_{h,k} = \left(\frac{STAmt_{h,k}}{\sum_{w \in \{1,..,K\}} STAmt_{h,w}}\right) \cdot STCap_h$.

The last step is to recalculate the operating regions based on the application of the PU de-rates and the available parts of the CT and ST. For PSU $k \in \{1,..,K\}$ and hour $h \in \{1,..,24\}$:

4. Determine if the PSU is unavailable.
   a. If $CTAmt_{h.k} < CMLP_k$, then the PSU is unavailable.
   b. If $STAmt_{h,k} < SMLP \cdot (1 - CSCM_k)$, then the PSU is unavailable.
   c. If $CTCap_{h,k} < CMLP_k$, then the PSU is unavailable.
   d. If $PRSTCap_{h,k} < SMLP \cdot (1 - CSCM_k)$, then the PSU is unavailable.
5. Initialize the operating region parameters for hour $h \in \{1,..,24\}$ to the model parameter values.
   a. Set $MLP_{h,k} = MMLP_k$.
   b. Set $DR_{h,k} = MDR_k$.

c. Set $DF_{h,k} = MDF_k$.

6. Apply the de-rate on the CT to the dispatchable region.

a. Calculate P so that $CMLP_k + P \cdot CTShareDR_k \cdot MDR_k = CTCap_{h,k}$.

b. Update $DR_{h,k} = min(DR_{h,k}, P{\cdot}MDR_k)$.

7. If the PSU is not operating in single-cycle mode, then incrementally restrict the capacity by considering the de-rate of the ST, applying the limit first to the duct firing region and then to the dispatchable region. If the PSU is operating in single-cycle mode, then the de-rate of the ST does not apply. If $CSCM_k = 0$:

a. Calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTCap_{h,k}$.

b. If $R \leq 1$, update $DF_{h,k} = 0$, and $DR_{h,k} = min(DR_{h,k}, R \cdot MDR_k)$.

c. If $R > 1$, update $DF_{h,k} = min(DF_{h,k}, PRSTCap_{h,k} - SMLP - STShareDR_k \cdot MDR_k)$.

3.12.2.2 Identifying Available Energy Laminations

Once the de-rated operating regions have been established, scheduling limitations will be applied so that the corresponding unavailable *offer* laminations will not be scheduled for *energy* and *operating reserve*.

The *offer* quantity laminations that may be scheduled for *energy* and *operating reserve* in each operating region for hour $h \in \{1,..,24\}$ will be calculated for each PSU $k \in \{1,..,K\}$, where:

- $QMLP_{h,k}$ indicates the total quantity that may be scheduled in the MLP region;
- $QDR_{h,k}$ indicates the total quantity that may be scheduled in the dispatchable region; and
- $QDF_{h,k}$ indicates the total quantity that may be scheduled in the duct firing region.

The available *offered* quantity laminations will be determined as follows:

- The first *offered* quantity laminations up to $MLP_{h,k}$ will comprise the MLP region *offer* laminations. The available laminations will have an offered quantity less than $QMLP_{h,k}$;
- The *offered* quantity laminations between $MLP_{h,k}$ and $MDR_{h,k}$ will comprise the dispatchable region *offer* laminations. The available laminations will have an offered quantity between $MLP_{h,k}$ and $QDR_{h,k}$; and
- The *offered* quantity laminations between $MDR_{h,k}$ and $DF_{h,k}$ will comprise the duct firing region *offer* laminations. The available laminations will have an offered quantity between $MDR_{h,k}$ and $QDF_{h,k}$.

Necessarily, the following conditions will hold:

- $0 \leq QMLP_{h,k} \leq MLP_{h,k}$;
- $0 \leq QDR_{h,k} \leq DR_{h,k}$;
- $0 \leq QDF_{h,k} \leq DF_{h,k}$;
- if $QMLP_{h,k} < MLP_{h,k}$, then the PSU is unavailable and $QDR_{h,k} = QDF_{h,k} = 0$; and
- if $QDR_{h,k} < DR_{t,k}$, then $QDF_{h,k} = 0$.

3.12.3. Applying Minimum and Maximum Constraints to PSUs

As described earlier, *market participant* and *IESO* inputs into the DAM calculation engine may limit the minimum or maximum output of a resource. The minimum and maximum constraints pertaining to a combined cycle *facility* electing PSU modelling may be provided to the DAM calculation engine as either a constraint on a given CT or ST or a constraint on a given PSU resource, where:

- Commitment constraints will be provided on a physical unit basis, simultaneously identifying the physical unit as “committed” and indicating the corresponding minimum output of the unit;
- *Outages* and/or de-rates will be provided on a physical unit basis;
- *Reliability* constraints and manual constraints will typically be provided on a physical unit basis; and
- For all constraints provided on a physical unit basis, the constraints will be translated to a PSU constraint before the execution of the DAM calculation engine pass. Only the most limiting PSU constraints will be enforced within the optimization function.

For a combined cycle *facility* with K CTs and one ST, the following data will be required to translate PSU and PU constraints to the limits enforced by the DAM calculation engine optimization function:

- The model parameters $MMLP_k$, MDR_k, MDF_k, $STShareMLP_k$, $CTShareMLP_k$, $STShareDR_k$ and $CTShareDR_k$ for PSU $k \in \{1,..,K\}$;
- The effective operation regions $MLP_{h,k}$, $DR_{h,k}$ and $DF_{h,k}$ for hour $h \in \{1,..,24\}$ and PSU $k \in \{1,..,K\}$;
- The *offer* quantities $QMLP_{h,k}$, $QDR_{h,k}$ and $QDF_{h,k}$ that may be scheduled for *energy* and *operating reserve* in each operating region for hour $h \in \{1,..,24\}$ and PSU $k \in \{1,..,K\}$;
- The amount of *energy offered* attributed to the ST portion, $STAmt_{h,k}$ for hour $h \in \{1,..,24\}$ and PSU $k \in \{1,..,K\}$;
- The single-cycle flag $CSCM_k \in \{0,1\}$ indicating whether PSU $k \in \{1,..,K\}$ is flagged to operate in single-cycle mode; and
- $CTCmtd_{h,k} \in \{0,1\}$ indicating whether CT $k \in \{1,..K\}$ is considered committed in hour $h \in \{1,..,24\}$.

The subsequent sub-sections describe how each category of constraint can be translated into either:

- PSU maximum limitations, denoted $PSUMax_{h,k}$ for PSU $k \in \{1,..,K\}$ and hour $h \in \{1,..,24\}$; or
- PSU minimum limitations, denoted $PSUMin_{h,k}$ for PSU $k \in \{1,..,K\}$ and hour $h \in \{1,..,24\}$.

Suppose Q constraints impacting the combined cycle *facility* have been provided to the DAM calculation engine. For time-step $h \in \{1,..,24\}$ and for constraint $q \in \{1,..,Q\}$, the following limitations will be calculated:

- $PSUMin_{h,k}^{q}$ indicating the minimum limitation on PSU k determined by translating constraint q. When constraint q does not provide a minimum limitation on PSU k, then $PSUMin_{h,k}^{q}$ shall be set equal to 0; and
- $PSUMax_{h,k}^{q}$ indicating the maximum limitation on PSU k determined by translating constraint q. When constraint q does not provide a maximum limitation on PSU k, then $PSUMax_{h,k}^{q}$ shall be set equal to $MLP_{h,k} + DR_{h,k} + DF_{h,k}$.

The minimum and maximum limitations applied within the optimization function will be calculated as follows:

$$MinDG_{h,k} = max_{q \in \{1,..Q\}} PSUMin_{h,k}^{q}$$

and

$$MaxDG_{h,k} = min_{q \in \{1,..Q\}} PSUMax_{h,k}^{q}$$

where the necessary mapping from PSU $k \in \{1,..,K\}$ to bus $b \in B^{PSU}$ identifying a PSU resource applies.

3.12.3.1 PSU Minimum Constraints

PSU minimum constraints can modify the minimum operating limit for a given PSU resource to maintain output at or above a specific value. Unlike other PSU constraints that are provided on the physical CT or ST, PSU minimum constraints do not require any pre-processing translations and can be applied directly to the PSU resource. The minimum constraint will revise the resource's lower operating limit so that the apportioned PU schedules produced by the DAM calculation engine will collectively respect the minimum constraint value.

Suppose a minimum constraint of $PMin$ is provided on PSU $k \in \{1,..,K\}$ for hour $h \in \{1,..,24\}$. The PSU constraint is mapped directly to a PSU minimum constraint for the same amount, and so

$$PSUMin_{h,k} = PMin.$$

3.12.3.2 PSU Maximum Constraints

PSU maximum constraints can modify the high operating limit for a given PSU resource to maintain output at or below a specific value. Like PSU minimum constraints, PSU maximum constraints will also be applied directly to the PSU resource without additional pre-processing. These maximum constraints will be respected so that the collective apportioned PU schedules produced by the DAM calculation engine do not exceed the maximum constraint value.

Suppose a maximum constraint of $PMax$ is provided on PSU $k \in \{1,..,K\}$ for hour $h \in \{1,..,24\}$. The PSU constraint is mapped directly to a PSU maximum constraint for the same amount, and so

$$PSUMax_{h,k} = PMax.$$

3.12.3.3 CT Minimum Constraints

At times, it may be necessary to apply minimum physical unit constraints directly to the CT of an associated PSU resource to maintain an output at or above a specified value. The minimum constraint on the physical unit will be translated to an equivalent minimum constraint on the PSU. For a PSU resource in combined cycle mode, the CT minimum constraint will place an implied minimum restriction on the associated ST due to the PSU model relationship. The DAM calculation engine will schedule the PSU resource to respect the PSU equivalent constraint, resulting in apportioned PU schedules that respect the CT minimum limitation and implied ST limitation.

Suppose a minimum constraint of $CTMin$ is provided on CT $k \in \{1,..,K\}$ for hour $h \in \{1,..,24\}$. The constraint will be translated to PSU k as follows:

1. If the PSU is not flagged to operate in single-cycle mode (i.e. if $CSCM_k = 0$), then map the CT constraint directly to a PSU constraint using the PSU model. A restriction on the ST will be implicitly applied according to the sharing percentages.
    a. First calculate the effect of the constraint on the ST within the MLP and dispatchable regions.
        i. If $CTMin < MLP_{h,k} \cdot CTShareMLP_k$, then set
        $$STMinMLP = CTMin \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right),$$
        $$STMinDR = 0.$$
        ii. Otherwise, if $CTMin \geq MLP_{h,k} \cdot CTShareMLP_k$, then set
        $$STMinMLP = MLP_{h,k} \cdot STShareMLP_k,$$
        $$STMinDR = \left(CTMin - MLP_{h,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$
    b. Calculate $PSUMin_{h,k} = CTMin + STMinMLP + STMinDR$.
2. Otherwise, if the PSU is flagged to operate in single-cycle mode (i.e. if $CSCM_k = 1$), then map the CT constraint directly to the PSU. A restriction on the ST will not be implicitly applied according to the PSU model, and so
$$PSUMin_{h,k} = CTMin.$$

3.12.3.4 CT Maximum Constraints

It may also be necessary to apply maximum physical unit limitations on the CT of an associated PSU resource to limit the CT's maximum output at or below a specific value. The maximum constraint on the physical unit will be translated to an equivalent maximum constraint on the PSU. For a PSU resource in combined cycle mode, the CT maximum constraint will place an implied maximum restriction on the associated ST due to the PSU model relationship. The DAM calculation engine will schedule the PSU resource to respect the PSU equivalent constraint, resulting in apportioned PU schedules that respect the CT maximum output and implied ST limitation.

Suppose a maximum constraint of $CTMax$ is provided on CT $k \in \{1,..,K\}$ for hour $h \in \{1,..,24\}$. The constraint will be translated to PSU k as follows:

1. If the PSU is not flagged to operate in single-cycle mode (i.e. if $CSCM_k = 0$), then map the CT constraint directly to a PSU constraint using the PSU model. A restriction on the ST will be implicitly applied according to the sharing percentages. A CT maximum constraint will always prevent the PSU from being scheduled in its duct firing region.
    a. If $CTMax < MLP_{h,k} \cdot CTShareMLP_k$, then the PSU is unavailable (i.e. $PSUMax_{h,k} = 0$).
    b. Otherwise, calculate the effect of the constraint on the ST within the MLP and dispatchable regions.
        i. Set
        $STMaxMLP = MLP_{h,k} \cdot STShareMLP_k$,
        $STMaxDR = \left(CTMax - MLP_{h,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right)$.
        ii. Calculate $PSUMax_{h,k} = CTMax + STMaxMLP + STMaxDR$.
2. Otherwise, if the PSU is flagged to operate in single-cycle mode (i.e. if $CSCM_k = 1$), then map the CT constraint directly to the PSU. A restriction on the ST will not be implicitly applied according to the PSU model, and so
$$PSUMax_{h,k} = CTMax.$$

3.12.3.5 ST Minimum Constraints

ST minimum constraints are required to limit the minimum output of a physical ST unit such that the output of the ST is maintained at or above a specific value. An ST minimum constraint can be mapped to one or more PSU resources. It will be assigned equally to committed PSUs and translated to one or more equivalent PSU minimum constraints. The ST minimum constraint will place an implied minimum constraint on associated CT resources due to the PSU model relationship. The DAM calculation engine will schedule impacted PSU resources to respect the PSU equivalent constraint(s), resulting in apportioned PU schedules that respect the ST minimum output and the associated CT implied limitations.

Suppose a minimum constraint of $STMin$ is provided on the ST for hour $h \in \{1,..,24\}$. The constraint will be translated to PSUs that are committed and not operating in single-cycle mode as follows:

1. Identify $A \subseteq \{1,..,K\}$ indicating the set of PSUs to which the constraint may be allocated. PSU $k \in \{1,..,K\}$ is placed in set A if and only if $CSCM_k = 0$ and $CTCmtd_{h,k} = 1$. If the set A is empty (i.e. there are no PSUs on which to allocate the constraint), then no further steps are required and the ST minimum constraint will not be translated to any PSU constraints.

2. Determine the ST portion of the capacity of PSU $k \in A$. $STCap_k$ designates this portion and is given by
$$STCap_k = QMLP_{h,k} \cdot STShareMLP_k + QDR_{h,k} \cdot STShareDR_k + QDF_{h,k}.$$
3. Allocate the $STMin$ constraint equally to each PSU $k \in A$. $STPMin_k$ designates the amount allocated to the ST portion of PSU $k \in A$ and is determined by allocating $STMin$ equally to each PSU $k \in A$, while limiting the amount allocated to the ST portion of PSU k by $STCap_k$.
4. Map the ST portion minimum constraint to a PSU constraint using the PSU model. A restriction on the CT will be implicitly applied according to the sharing percentages. For each PSU $k \in A$:
    a. First calculate the effect of the constraint on the CT within the MLP and dispatchable regions.
        i. If $STPMin_k < MLP_{h,k} \cdot STShareMLP_k$, then set
        $$CTMinMLP_k = STPMin_k \cdot \left(\frac{CTShareMLP_k}{STShareMLP_k}\right),$$
        $$CTMinDR_k = 0.$$
        ii. Otherwise, if $STPMin_k \geq MLP_{h,k} \cdot STShareMLP_k$, then set
        $$CTMinMLP_k = MLP_{h,k} \cdot CTShareMLP_k,$$
        $$CTMinDR_k = \left(STPMin_k - MLP_{h,k} \cdot STShareMLP_k\right) \cdot \left(\frac{CTShareDR_k}{STShareDR_k}\right).$$
    b. Calculate $PSUMin_{h,k} = STPMin_k + CTMinMLP_k + CTMinDR_k$.

If enough PSUs with sufficient ST capacity are not committed to allocate the constraint amount fully, this process may not translate the entire quantity of the ST minimum constraint to PSU constraints.

3.12.3.6 ST Maximum Constraints

ST maximum constraints are required to limit the output of a physical ST at or below a specific value. An ST maximum constraint will be prorated across the available capacity of associated in service PSU resources and translated to one or more equivalent PSU maximum constraints. The ST maximum constraint may place an implied maximum constraint on associated CT resources due to the PSU model relationship. The DAM calculation engine will schedule impacted PSU resources to respect the PSU equivalent constraint(s), resulting in apportioned PU dispatches that respect the ST maximum output and any associated CT implied limitations.

Suppose a maximum constraint of $STMax$ is provided on the ST for hour $h \in \{1,..,24\}$. The constraint will be translated to all PSUs in the same way in which a ST de-rate is translated to all PSUs as follows:

1. Allocate the ST maximum constraint to each PSU pro-rata according to the amount of *energy offered* attributed to each ST portion. For PSU $k \in \{1,..,K\}$ and hour $h \in \{1,..,24\}$, calculate:
$$PRSTMax_{h,k} = \left(\frac{STAmt_{h,k}}{\sum_{w \in \{1,..,K\}} STAmt_{h,w}}\right) \cdot STMax.$$

2. Map the ST portion maximum constraint to a PSU constraint using the PSU model. A restriction on the CT will be implicitly applied according to the sharing percentages. For each PSU $k \in \{1,..,K\}$ such that $CSCM_k = 0$:

   a. If the prorated ST maximum constraint limits the ST portion to below its MLP (i.e. $PRSTMax_{h,k} < SMLP \cdot (1 - CSCM_k)$, then the PSU is unavailable (i.e. $PSUMax_{h,k} = 0$).

b. Otherwise, calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTMax_{h,k}$.

   i. If $R \leq 1$, set

$$PSUMax_{h,k} = MLP_{h,k} + min(DR_{h,k}, R \cdot MDR_k).$$

   ii. If $R > 1$, set

$$PSUMax_{h,k} = MLP_{h,k} + DR_{h,k} + PRSTMax_{h,k} - SMLP - STShareDR_k \cdot MDR_k.$$

3.12.3.7 Equal ST Minimum and Maximum Constraints

ST minimum constraints and maximum constraints of equal amounts may not result in PSU resource minimum and maximum constraints of equal amounts. This may occur because ST minimum constraints are only allocated to committed PSUs and are allocated equally to committed PSUs as opposed to pro-rated across available capacity. Equal minimum and maximum ST constraints may be applied to fix the steam turbine to a given output for safety, equipment or *reliability* reasons. In these circumstances, the ST minimum constraint allocation logic will be used to determine equal minimum and maximum constraints to be applied to the PSUs because the constraint represents an operational concern and is best allocated to committed PSUs.

3.12.4. Translation of PSU Schedules to PU Schedules

The PSU model determines the logic for translating *energy* and *operating reserve* schedules for the PSUs representing a combined cycle *facility* to *energy* and *operating reserve* schedules for the corresponding physical units.

For a combined cycle *facility* with K combustion turbines and one steam turbine, the following *energy* and *operating reserve* schedules for the physical units will be computed from the PSU schedules for hours $h \in \{1,..,24\}$:

- $CTE_{h,k}$ indicating the *energy* schedule for CT $k \in \{1,..,K\}$;
- $STPE_{h,k}$ indicating the *energy* schedule for the ST portion of PSU $k \in \{1,..,K\}$;
- STE_h indicating the *energy* schedule for the ST;
- $CT10S_{h,k}$ indicating the synchronized *ten-minute operating reserve* schedule for CT $k \in \{1,..,K\}$;

- $STP10S_{h,k}$ indicating the synchronized *ten-minute operating reserve* schedule for the ST portion of PSU $k \in \{1,..,K\}$;
- $ST10S_h$ indicating the synchronized *ten-minute operating reserve* schedule for the ST;
- $CT10N_{h,k}$ indicating the non-synchronized *ten-minute operating reserve* schedule for CT $k \in \{1,..,K\}$;
- $STP10N_{h,k}$ indicating the non-synchronized *ten-minute operating reserve* schedule for the ST portion of PSU $k \in \{1,..,K\}$;
- $ST10N_h$ indicating the non-synchronized *ten-minute operating reserve* schedule for the ST;
- $CT30R_{h,k}$ indicating the *thirty-minute operating reserve* schedule for CT $k \in \{1,..,K\}$;
- $STP30R_{h,k}$ indicating the *thirty-minute operating reserve* schedule for the ST portion of PSU $k \in \{1,..,K\}$; and
- $ST30R_h$ indicating the *thirty-minute operating reserve* schedule for the ST.

Suppose the DAM calculation engine has determined the following *energy* and *operating reserve* schedules for PSU $k \in \{1,..,K\}$ in hour $h \in \{1,..,24\}$:

- $SE_{h,k}$ indicating the total amount of *energy* scheduled. This schedule can be broken into three components so that $SE_{h,k} = SEMLP_{h,k} + SEDR_{h,k} + SEDF_{h,k}$ where:
  - o $SEMLP_{h,k}$ indicates the portion of the schedule corresponding to the MLP region. Necessarily $0 \leq SEMLP_{h,k} \leq QMLP_{h,k}$;
  - o $SEDR_{h,k}$ indicates the portion of the schedule corresponding to the dispatchable region. Necessarily $0 \leq SEDR_{h,k} \leq QDR_{h,k}$ and $SEDR_{h,k} > 0$ only if $SEMLP_{h,k} = QMLP_{h,k}$;
  - o $SEDF_{h,k}$ indicates the portion of the schedule corresponding to the duct firing region. Necessarily $0 \leq SEDF_{h,k} \leq QDF_{h,k}$ and $SEDF_{h,k} > 0$ only if $SEDR_{h,k} = QDR_{h,k}$;
- $S10S_{h,k}$ indicating the total amount of synchronized *ten-minute operating reserve* scheduled;
- $S10N_{h,k}$ indicating the total amount of non-synchronized *ten-minute operating reserve* scheduled. If the PSU cannot provide *operating reserve* from its duct firing region then necessarily $0 \leq SE_{h,k} + S10S_{h,k} + S10N_{h,k} \leq QMLP_{h,k} + QDR_{h,k}$; and
- $S30R_{h,k}$ indicating the total amount of *thirty-minute operating reserve* scheduled. Necessarily $0 \leq SE_{h,k} + S10S_{h,k} + S10N_{h,k} + S30R_{h,k} \leq QMLP_{h,k} + QDR_{h,k} + QDF_{h,k}$.

The following additional data is required to translate these PSU schedules to PU schedules:

- The *offer* quantities $QMLP_{h,k}, QDR_{h,k}$ and $QDF_{h,k}$ that may be scheduled for *energy* and *operating reserve* in each operating region for hour $h \in \{1,..,24\}$ and PSU $k \in \{1,..K\}$; and
- The ST and CT shares of the MLP and dispatchable regions for PSU $k \in K$ given by $STShareMLP_k$, $CTShareMLP_k$, $STShareDR_k$, and $CTShareDR_k$.

The logic to calculate the *energy* and *operating reserve* schedules for the CT and ST portion for PSU $k \in \{1,..,K\}$ in hour $h \in \{1,..,24\}$ depends on whether the PSU is scheduled at or above its *minimum loading point*. The procedure is as follows:

1. If $SE_{h,k} \geq MLP_{h,k}$, then the PSU model applies and the following logic used:
   a. The *energy* schedules from the MLP, dispatchable and duct firing regions are assigned to the CT and ST according to the sharing percentages as follows:

$$CTE_{h,k} = SEMLP_{h,k} \cdot CTShareMLP_k + SEDR_{h,k} \cdot CTShareDR_k,$$
$$STPE_{h,k} = SEMLP_{h,k} \cdot STShareMLP_k + SEDR_{h,k} \cdot STShareDR_k + SEDF_{h,k}.$$

   b. The *operating reserve* schedules are then assigned to the dispatchable and duct firing regions based on remaining capacity, assigning the spinning reserve first and then non-spinning as follows:

$$RoomDR_{h,k} = QDR_{h,k} - SEDR_{h,k},$$
$$10SDR_{h,k} = min(RoomDR_{h,k}, S10S_{h,k}),$$
$$10NDR_{h,k} = min(RoomDR_{h,k} - 10SDR_{h,k}, S10N_{h,k}),$$
$$30RDR_{h,k} = min(RoomDR_{h,k} - 10SDR_{h,k} - 10NDR_{h,k}, S30R_{h,k}),$$
$$CT10S_{h,k} = 10SDR_{h,k} \cdot CTShareDR_k,$$
$$STP10S_{h,k} = 10SDR_{h,k} \cdot STShareDR_k + (S10S_{h,k} - 10SDR_{h,k}),$$
$$CT10N_{h,k} = 10NDR_{h,k} \cdot CTShareDR_k,$$
$$STP10N_{h,k} = 10NDR_{h,k} \cdot STShareDR_k + (S10N_{h,k} - 10NDR_{h,k}),$$
$$CT30R_{h,k} = 30RDR_{h,k} \cdot CTShareDR_k,$$
$$STP30R_{h,k} = 30RDR_{h,k} \cdot STShareDR_k + (S30R_{h,k} - 30RDR_{h,k}).$$

2. If $SE_{h,k} < MLP_{h,k}$ and is ramping to MLP, the translation will be determined by the ramp up *energy* to MLP profile.

After the PSU schedules are allocated to the CT and ST portion, the ST portion schedules are summed to obtain the ST schedule as follows:

$$STE_h = \sum_{k=1,..,K} STPE_{h,k},$$
$$ST10S_h = \sum_{k=1,..,K} STP10S_{h,k},$$

$$ST10N_h = \sum_{k=1,..,K} STP10N_{h,k},$$

and

$$ST30R_h = \sum_{k=1,..,K} STP30R_{h,k}.$$

3.12.5. Pricing for PSUs

The DAM calculation engine will produce prices for PSUs by calculating weighted average marginal loss factors and weighted average sensitivities based on the PSU model parameters and scheduling results.

3.13. Determination of the Non-Dispatchable Demand Forecast

The non-dispatchable *demand* forecast used by the DAM calculation engine will be obtained from the *IESO's* hourly *demand* forecasts by identifying the portion of the forecast attributed to loads that are considered non-dispatchable and losses.

In Pass 1 and Pass 3, the hourly average *demand* forecasts for all *demand* forecast areas will be used to arrive at the hourly average non-dispatchable *demand* forecast as follows:

1. The *IESO* average *demand* forecast for each *demand* forecast area minus the total of the *bid* quantities submitted for virtual *hourly demand response* resources will be distributed to all *load facilities* in the area using the load distribution factors described in Section 3.9.1.3. The distributed forecast MW quantities will then be adjusted to account for the *bid* quantities for physical *hourly demand response* resources by subtracting the *bid* quantities for physical *hourly demand response* resources from their respective associated non-dispatchable or price responsive load facilities.

2. The average non-dispatchable *demand* forecast quantity for hour h, AFL_h, will be obtained by adding:
   - The forecast MW quantities reflecting losses; and
   - The forecast MW quantities distributed to *delivery points* for *non-dispatchable load*.

In Pass 2, the hourly peak *demand* forecasts for all *demand* forecast areas will be adjusted to arrive at the hourly peak NDL *demand* forecast as follows:

1. The *IESO* peak *demand* forecast for each *demand* forecast area minus the total of the *bid* quantities submitted for virtual *hourly demand response* resources will be distributed to all *load facilities* with *delivery points* in the area using the load distribution factors described in Section 3.9.1.3. The distributed forecast MW quantities will be adjusted to account for *bid* quantities for physical *hourly demand response* resources by subtracting the *bid* quantities for physical *hourly demand response* resources from their respective associated non-dispatchable or price responsive load facility.

2. The peak non-dispatchable *demand* forecast quantity for hour h, PFL_h , will be obtained by adding:
   - the forecast MW quantities reflecting losses;
   - the forecast MW quantities distributed to *delivery points* for *non-dispatchable loads;*
   - the forecast MW quantities distributed to *delivery points* for price responsive loads; and

- o the forecast MW quantities distributed to *delivery points* for *dispatchable loads* when no *bid* is submitted for a *dispatchable load.*

– End of Section –

4. Market Rule Requirements

The *market rules* govern the *IESO-controlled grid* and establish and govern the *IESO-administered markets*. The *market rules* codify obligations, rights and authorities for both the *IESO* and *market participants*, and the conditions under which those rights and authorities may be exercised and those obligations met.

This section is intended to provide an inventory of the changes to *market rule* provisions required to support the Day-Ahead Market (DAM) Calculation Engine detailed design, and is intended to guide the development of *market rule* amendments.

This inventory is not meant to be an exhaustive list of required rule changes, but is a “snapshot” in time based on the current state of design development of this specific design document. Resulting *market rule amendments* will incorporate the integration of the individual design documents.

New and amended Chapter 11 defined terms: These terms will be consolidated in a single document at a later time as part of the *market rule amendment* process, and will support multiple design documents.

The inventory is developed in the following tables, which describe the impacts to Appendix 7.5A (The DACP Calculation Engine Process) and Appendix 7.1A (The DAM Calculation Engine) of the *market rules* and classifies them into the following three types:

- Existing – no change: Identifies those provisions of the existing *market rules* that are not impacted by the design requirements.
- Existing – requires amendment: Identifies those provisions of the existing *market rules* that will need to be amended to support the design requirements.
- New: Identifies new *market rules* that will likely need to be added to support the design requirements.

Table 4-1: Market Rule Appendix 7.5A Impacts

Market Rule Section	Type	Topic	Requirement
All Sections	Existing - requires amendment	All Topics	• This Appendix describes the DACP calculation engine process used to determine commitments, constrained schedules, and shadow prices. • This section will be retired and replaced with a new appendix to describe the DAM calculation engine processes.

Table 4-2: Market Rule Appendix 7.1A Impacts

Market Rule Section	Type	Topic	Requirement
Section 1	New	Interpretation	• This new section includes a description of the appendix and what information will be included in the appendix. • Section 1.1 will specify the purpose of the Appendix. The Appendix describes the DAM calculation engine processes used to determine commitments, schedules, and prices. The appendix will detail the following: o The inputs to the DAM calculation engine; o The outputs from the DAM calculation engine; o The mathematical description of the algorithms and tests for each of the three passes in the DAM calculation engine; and o Similar to the existing Appendix 7.5A – The DACP Calculation Engine Process, the *market rules* will state that the DAM calculation engine output data described in Appendix 7.1A will not require the *IESO* to *publish* the output data except where expressly required by the *market rules*.

Market Rule Section	Type	Topic	Requirement
Section 2	New	The DAM Calculation Engine - Overview	• This new section provides an overview of the DAM Calculation Engine. • Section 2.1 will set out the purpose of the DAM Calculation Engine and will describe each of the three passes. o Pass 1, the Market Commitment and Market Power Mitigation Pass, determines a set of resource schedules and commitments to meet the *IESO's* average hourly forecast *demand* as well as *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response resources* and exports. Pass 1 also determines hourly locational marginal prices consistent with the scheduling and commitment decisions made in the pass. o Pass 2, the Reliability and Commitment Scheduling Pass, ensures that if the resources committed by Pass 1 are insufficient to meet peak forecast *demand* and the *IESO*-specified *operating reserve* requirements, additional resources are committed and scheduled. o Pass 3, the DAM Scheduling Pass, uses commitments determined in Pass 1 and Pass 2 to produce a set of commitments, financially binding schedules and *settlement*-ready locational marginal prices.
Section 3	New	Inputs into the DAM Calculation Engine	• This new section sets out the *market rules* around the inputs into the DAM calculation engine. • Section 3.1 – Overview: The inputs will be categorized by the DAM Calculation Engine's three functions: o Optimization function; o Ex-ante market power mitigation process; and

Market Rule Section	Type	Topic	Requirement
			o *Security* assessment function. • Section 3.2 – Inputs into the Optimization Function o Section 3.2.1 – Demand Forecasts: The section will include details of the hourly average *demand* forecast and the hourly average peak *demand* forecast prepared by the *IESO*. The *demand* forecasts will be modified to reflect the hourly (average and peak) non-dispatchable *demand* forecasts. The hourly average non-dispatchable *demand* forecast will be used in Pass 1 and Pass 3. The hourly peak non-dispatchable *demand* forecast will be used in Pass 2. o Section 3.2.2 – Forecasts from Non-Dispatchable Generation Facilities: The section will include details on the forecast output from *self-scheduling generation facilities, transitional scheduling generators* and *intermittent generators* submitted by *registered market participants* in accordance with Chapter 7. o Section 3.2.3 – Forecasts from Variable Generation Facilities: The section will include details on the forecast for *variable generation* supplied by *registered facilities* provided by (1) a *forecasting entity* and (2) the *market participant*. If the *market participant* submits a forecast for the hour, then the DAM calculation uses that value, otherwise the DAM calculation engine utilizes the *IESO's* centralized *variable generation* forecast. The forecast provided by the *market participant* will be utilized in Passes 1 and 3, and the *IESO's* centralized forecast will be used in Pass 2 (and in Pass 1 and Pass 3 where there is no forecast provided by the *market participant*).

Market Rule Section	Type	Topic	Requirement
			o Section 3.2.4 – Energy Bids and Offers: The section will include *energy offers* and *energy bids* and associated *dispatch data* submitted by *registered market participants* submitted in accordance with Chapter 7. o Section 3.2.5 – Operating Reserve Offers: The section will include *operating reserve offers* and associated *dispatch data* submitted in accordance with Chapter 7. o Section 3.2.6 – Energy Limited Resources: This section will include details on *energy* limited resources and the daily limit on the amount of *energy* that they can generate over the course of the day. o Section 3.2.7 – Non-Quick Start Generation Facilities: The section will list the inputs for non-quick start *generation facilities* including the minimum generation cost calculated from the *speed-no-load offer* and *energy* laminations up to the resource's *minimum loading point*. Additional inputs include *minimum generation block run time*, *minimum generation block down time*, *maximum number of starts per day*, ramp up *energy* to *minimum loading point* profile. o Section 3.2.8 – Pseudo-Units: The section will list the inputs for *pseudo-units* including the maximum constraints applied to a corresponding physical unit, steam turbine share of *minimum loading point* region, steam turbine share of dispatchable region, ramp up energy to *minimum loading point* profile for the combustion turbine and steam turbine, indication of whether the *pseudo-unit* can provide *ten-minute operating reserve* while scheduled in its duct firing region.

Market Rule Section	Type	Topic	Requirement
			o Section 3.2.9 – Hydroelectric Generation Facilities: The section will list the inputs for hydroelectric *generation facilities* including *forbidden regions*, minimum daily *energy* limit, minimum hourly output, hourly must run, *maximum number of starts per day*, linked resources, time lag and MWh ratio. o Section 3.2.10 – Inputs Provided by the Security Assessment Function: The section will include details on the inputs provided by the Security Assessment Function, which include: ▪ Marginal loss factors of resources; ▪ Loss adjustment quantity; ▪ Constraints for violated OSLs and pre-contingency thermal limits; and ▪ Constraints for violated post-contingency thermal limits. o Section 3.2.11 – Other Inputs: The *IESO* shall also provide other inputs into the DAM calculation engine for the optimization function. These include: ▪ *Operating reserve* requirements; ▪ *Reliability* constraints: The *IESO* will identify resources that must operate for *reliability* purposes. The *IESO* may place minimum or maximum constraints to these resources to support *reliability must-run contracts*, *reactive support service* contracts, or other *reliability* needs; and ▪ Regulation (AGC). • Section 3.3 – Inputs into the Ex-Ante Market Power Mitigation o Section 3.3.1 – Condition Testing Inputs

Market Rule Section	Type	Topic	Requirement
			▪ Section 3.3.1.2 – Constrained Area Designations: The designation of constrained areas is based on frequency and duration of congestion in the area, and whether the constraints result in supply resources being *dispatched* up, in accordance with Appendix 7.8 – Market Power Mitigation. o Section 3.3.2 – Conduct Test Inputs ▪ Section 3.3.2.1 – Reference Levels: Reference levels approximate a resource's short-run marginal costs and are used in the market power mitigation framework to determine competitive *offers* for a resource in accordance with Appendix 7.8 – Market Power Mitigation. ▪ Section 3.3.2.2 – Conduct Thresholds: Conduct thresholds will be used with reference levels to determine whether the *dispatch data* values *offered* by a resource deviate significantly from what the values would have been in a competitive market in accordance with new Appendix 7.8 – Market Power Mitigation. ▪ Section 3.3.2.3 – Other Inputs: ▪ Minimum Energy Offer: The minimum *energy offer* value for the *offer* lamination to be included in the Conduct Test. *Energy offer* laminations below this value are excluded from the Conduct Test. ▪ Minimum Operating Reserve Offer: the minimum *operating reserve offer* value for the *offer* lamination to be included

Market Rule Section	Type	Topic	Requirement
			in the Conduct Test. *Operating reserve offer* laminations below this value are excluded from the Conduct Test. o Section 3.3.3 – Price Impact Test Inputs ▪ Section 3.3.3.1 – Price Impact Thresholds: Price impact thresholds will be used to test for economic withholding in accordance with new Appendix 7.8 – Market Power Mitigation. • Section 3.4 – Inputs into the Security Assessment Function o Section 3.4.1 – Inputs Provided by the Optimization Function: The Optimization Function will provide schedules for load and supply resources (withdrawals and injections). o Section 3.4.2 – Other inputs: ▪ Security limits; ▪ Power system model data; ▪ List of contingencies to be simulated; ▪ List of monitored equipment; and Equipment thermal limits. ▪ Overlap: Offers, Bids and Data Input Chapter and Market Power Mitigation Chapter

Market Rule Section	Type	Topic	Requirement
Section 4	New	Initialization	• This new section sets out the *market rules* around the initialization processes. • Section 4.1 – Overview: The section will include an overview of the initialization processes. Prior to the execution of the three passes, the DAM calculation engine will perform the initialization processes, which include: o Selecting a *reference bus*; o Determining islanding conditions; o Applying the *variable generator* tie-breaking logic; and o Pre-processing maximum generation constraints that apply to *pseudo-units*. o Section 4.1.1 – References Buses: The section will include details on the selection of a *reference bus*. o Section 4.1.2 – Islanding: The section will include details determining islanding conditions. o Section 4.1.3 - Variable Generation Resource Tie-Breaking: The section will include details on the application of the *variable generator* tie-breaking logic. o Section 4.1.4 - Pseudo-Unit Maximum Constraints: The section will include details on the pre-processing of maximum generation constraints that apply to *pseudo-units*.
Section 5	New	Security Assessment	• This new section will set out the *market rules* around the *security* assessment function. • Section 5.1 – Overview: The section will provide an overview of the *security* assessment function. The *security* assessment function assesses power system *security* using the schedules produced by the optimization function. For hourly commitment statuses and resource schedules, the DAM

<table>
<tr><th>Market Rule Section</th><th>Type</th><th>Topic</th><th>Requirement</th></tr>
<tr><td></td><td></td><td></td><td>calculation engine iterates between an optimization function and a security assessment function.
• Section 5.2 – Inputs: The section will include the inputs into the security assessment function by referencing the inputs identified in Section 3.
• Section 5.3 – Security Assessment Function Processing: The security assessment function performs the following calculations and analyses (the details for these will be included in the market rules):
  o Base case power flow;
  o Pre-contingency security assessment;
  o Loss calculation; and
  o Contingency analysis.
• Section 5.4 – Outputs: The section will list the outputs from the Security Assessment function. The outputs include, but are not limited to:
  o Security constraint set corresponding to violated pre-contingency limits and violated post-contingency thermal limits;
  o Marginal loss factors; and
  o Loss adjustment.
    ▪ Note: In the first iteration, an initial default set of incremental loss factors and loss adjustments is used in the objective function. In subsequent iterations, the outputs from the security assessment function are used.</td></tr>
<tr><td>Section 6</td><td>New</td><td>Pass 1: Market Commitment and Market Power Mitigation Pass</td><td>• This new section sets out the market rules around the Pass 1 of the DAM Calculation Engine, including the inputs, mathematical formulations, and outputs.
• Section 6.1 – Overview: The section will contain an overview of Pass 1. Pass 1 will determine a set</td></tr>
</table>

Market Rule Section	**Type**	**Topic**	**Requirement**
			of resource schedules and commitments to meet the *IESO's* average hourly forecast *demand* as well as *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports. • Section 6.2 – Inputs: The section will include the inputs into Pass 1 by referencing the inputs identified in Section 3. • Sections 6.3 through 6.11, will detail the algorithms and tests within Pass 1. For the purposes of this inventory, these sections are broken out by algorithm or test as follows: o As-Offered Scheduling o As-Offered Pricing o Constrained Areas Conditions Test o Conduct Test o Reference Level Scheduling o Reference Level Pricing o Price Impact Test o Mitigated Scheduling o Mitigated Pricing • Section 6.12 – Locational Marginal Prices: The section will outline the locational marginal prices for Pass 1. • Section 6.13 – Outputs: The section will list the outputs from Pass 1 to be used in Pass 2. The outputs of Pass 1 include, but are not limited to: o Schedules; o Unit commitment decisions; o Operational decisions for hydroelectric *generation facilities* and for *pseudo-units*; o Shadow prices; and o Locational marginal prices.

Market Rule Section	Type	Topic	Requirement
			• Section 6.14 – Glossary of Sets, Indices, Variables and Parameters for Pass 1: The section will list the sets, indices, variables and parameters for Pass 1.
Section 6.3	New	As-Offered Scheduling	• This new section sets out the *market rules* around the As-Offered Scheduling algorithm. • Section 6.3.1 – Overview: The section includes an overview of the As-Offered Scheduling algorithm. The As-Offered Scheduling will perform a *security*-constrained unit commitment and economic *dispatch* to meet the *IESO's* average *demand* forecast of *non-dispatchable load* and *IESO*-specified *operating reserve* requirements. • Section 6.3.2 – Inputs: The section lists the inputs to the As-Offered Scheduling algorithm by referencing the inputs identified in Section 3. • Section 6.3.3 – Optimization Function for As-Offered Scheduling: The section includes details on the optimization function including: o Optimization Objective: The section will include the objective (to maximize the gains from trade). o Variables – The section will list the variables for which the DAM calculation engine will solve. o Objective Function: The section will include the optimization of the objective function in As-Offered Scheduling, which is to maximize the expression (Note: the expression will be included in the *market rules*). • Section 6.3.4 – Optimization Constraints: The section outlines the three constraint categories that apply to the schedules determined in the optimization: o Single hour constraints that ensure no violation of parameters specified in the

Market Rule Section	Type	Topic	Requirement
			dispatch data submitted by *registered market participants*; o Inter-hour and multi-hour constraints that ensure no violation of parameters specified in the *dispatch data* submitted by *registered market participants*; and o Constraints that ensure no violations of *IESO* established *reliability* inputs. • Section 6.3.5 – Bid/Offer Constraints Applying to Single Hours: The section will include details on the single hour constraints including: o Status variables and variable bounds; o Resource minimum and maximums; o *Operating reserve* scheduling; o *Pseudo-units*; o Hydroelectric *generation facilities*; and o Imports/exports (linked wheel transactions). • Section 6.3.6 – Bid/Offer Inter-Hour/Multi-Hour Constraints: The section will include details on the intra-hour/multi hour constraints including: o *Energy* ramping; o *Operating reserve* ramping; o Non-quick start *generation facilities*; o *Energy*-limited resources; and o Hydroelectric *generation facilities*. • Section 6.3.7 – Constraints to Ensure Schedules Do Not Violate Reliability Requirements: The section will include details on the constraints that ensure no *IESO* established *reliability* criteria are violated including: o *Energy* balance; o *Operating reserve* requirements;

Market Rule Section	Type	Topic	Requirement
			o *IESO* internal transmission limits; o *Intertie* limits; and o Penalty price variable bounds. • Section 6.3.8 – Outputs: The section will list the outputs from the As-Offered Scheduling algorithm. As-Offered Scheduling will produce schedules and unit commitments, as well as operational decisions for hydroelectric *generation facilities* and *pseudo-units*, from the As-Offered Scheduling algorithm.
Section 6.4	New	As-Offered Pricing	• This new section sets out the *market rules* around the As-Offered Pricing algorithm. • Section 6.4.1 – Overview: The section includes an overview of the As-Offered Pricing algorithm. The As-Offered Pricing will perform a *security*-constrained unit commitment and economic *dispatch* to meet the *IESO's* average *demand* forecast of *non-dispatchable load* and *IESO*-specified *operating reserve* requirements. • Section 6.4.2 – Inputs: The section includes the inputs to the As-Offered Pricing algorithm by referencing the inputs identified in Section 3. The section will also include a list of outputs from As-Offered Scheduling that are used as inputs to the As-Offered Pricing algorithm. • Section 6.4.3 – Optimization Function for As-Offered Pricing: The section includes details on the optimization function including: o Optimization Objective: The section will include the objective (to maximize the gains from trade). o Variables – The section will list the variables for which the DAM calculation engine will solve. o Objective Function: The optimization of the objective function in As-Offered Pricing is to maximize the expression (the expression will

Market Rule Section	Type	Topic	Requirement
			be included in the *market rules*). The objective function for the As-Offered Pricing differs from As-Offered Scheduling as follows: o the start-up and minimum generation costs are constants and thus are dropped from the objective; and o the violation cost is calculated using the set of constraint violation penalty curves for determining *market prices*. • Section 6.4.4 – Optimization Constraints: The section outlines the four constraint categories that apply to the schedules and prices determined in the optimization: o Single hour constraints that ensure no violation of parameters specified in the *dispatch data* submitted by *registered market participants*; o Inter-hour and multi-hour constraints that ensure no violation of parameters specified in the *dispatch data* submitted by *registered market participants*; o Constraints that ensure no violations of *IESO* established *reliability* inputs; and o Constraints that ensure the eligibility of an *offer* or *bid* lamination to set price is appropriately reflected. • Section 6.4.5 – Bid/Offer Constraints Applying to Single Hours: The section will include details on the single hour constraints including: o Status variables and variable bounds; o Resource minimum and maximums; o *Operating reserve* scheduling; o *Pseudo-units*;

Market Rule Section	Type	Topic	Requirement
			o Hydroelectric *generation facilities*; and o Imports/exports (linked wheel transactions) (Note: This constraint is not required in As-Offered Pricing as the import and export components of linked wheel transactions received equal schedules in As-Offered Scheduling and import and exports are not rescheduled [Section 6.4.8]). • Section 6.4.6 – Bid/Offer Inter-Hour/Multi-Hour Constraints: The section will include details on the intra-hour/multi hour constraints including: o *Energy* ramping; o *Operating reserve* ramping; o Non-quick start *generation facilities* (Note: This constraint is not required in As-Offered Pricing as the variables associated with commitments of non-quick start *generation facilities* are held fixed.); o *Energy*-limited resources; and o Hydroelectric *generation facilities*. • Section 6.4.7 – Constraints to Ensure Schedules Do Not Violate Reliability Requirements: The section will include details on the constraints that ensure no *IESO* established *reliability* criteria is violated including: o *Energy* balance; o *Operating reserve* requirements; o *IESO* internal transmission limits; o *Intertie* limits; and o Penalty price variable bounds. Note: The marginal loss factors used in the *energy* balance constraint in As-Offered Pricing will be set to the marginal loss factors used in the last

Market Rule Section	Type	Topic	Requirement
			optimization function iteration of As-Offered Scheduling. • Section 6.4.8 - Constraints to Ensure the Price Setting Eligibility Reflect Offer/Bid Laminations. The section will include details on the constraints that ensure the eligibility of an *offer* or *bid* lamination to set price is appropriately reflected including: o Commitment status variable; o Import/Export schedules; o *Pseudo-units*; o *Energy*-limited resources; and o Hydro-electric resources: ▪ Minimum hourly output; ▪ Limited number of starts; ▪ *Forbidden regions*; ▪ Minimum daily *energy* limit; ▪ Shared minimum daily *energy* limit; ▪ Shared maximum daily *energy* limit; and ▪ Linked hydroelectric *generation facilities*. • Section 6.4.9 – Outputs: The section will list the outputs from the As-Offered Pricing algorithm. As-Offered Pricing will produce shadow prices for all constraints contributing to locational marginal prices. As-Offered Pricing also produces locational marginal prices and their components.
Section 6.5	New	Constrained Areas Conditions Test	• This new section sets out the *market rules* around the Constrained Areas Conditions Test. • Section 6.5.1 – Overview: The section includes an overview of the Constrained Areas Conditions Test. The purpose of the test is to:

Market Rule Section	Type	Topic	Requirement
			o Identify when and where competition is restricted; and o Determine which resources will undergo the Conduct Test, Section 6.6, for at least one *dispatch data* parameter. • Section 6.5.2 – Conditions Test Categories: The section outlines the four test categories that identify the *IESO*-defined conditions that would meet mitigation testing for *energy* and *operating reserve*: o Local market power (*energy*), including: ▪ Narrow constrained area (NCA); ▪ Dynamic constrained area (DCA); and ▪ Broad constrained area (BCA); o Local market power (o*perating reserve*); o Global market power (*energy*); and o Global market power (*operating reserve*). • Section 6.5.3 – Inputs: The section includes the inputs to the Constrained Areas Conditions Test by referencing the inputs identified in Section 3.3. The section will also include a list of outputs from As-Offered Pricing that are used as inputs to Constrained Areas Conditions Test. • Section 6.5.4 – Local Market Power (*Energy*) Constrained Areas Conditions Test: The section will include details on the conditions that must be met to qualify for local market power (*energy*) mitigation testing for resources located within the following areas: o NCA and DCA; or o BCA. • Section 6.5.5 – Local Market Power (Operating Reserve) Constrained Areas Condition Test: The section will include details on identifying

Market Rule Section	Type	Topic	Requirement
			resources offering *operating reserve* for reserve areas with a minimum requirement greater than zero. If the resource is located in a reserve area with a binding maximum restriction constraint, then the resource will be exempted from the Conduct Test. • Section 6.5.6 – Global Market Power (Energy) Constrained Areas Conditions Test: The section will include details on the two conditions, that must be both met, to identify resources for the test. The two conditions include: o Condition 1: Unable to schedule incremental imports in the hour; and o Condition 2: The *intertie* border price at the reference *interties* is greater than the specified threshold value. o Exemptions: Resources that meet both conditions will be excluded if they fall under the condition below: • If resources in any zone have congestion components at least $1/MWh below the internal congestion component at all of the Global Market Power Reference Interties, they will not be tested for global market power. • Section 6.5.7 – Global Market Power (Operating Reserve) Constrained Areas Conditions Test: The section will include details on identifying resources in the class of *operating reserve* where the locational marginal prices is greater than the threshold for a resource's *operating reserve* locational marginal price. • Section 6.5.8 – Outputs: The section will list the outputs from the Constrained Areas Conditions Test. The output of the Constrained Areas Condition Test is a set of resources that will be subject to the Conduct Test, Section 6.6. Overlap: Market Power Mitigation Chapter

Market Rule Section	Type	Topic	Requirement
Section 6.6	New	Conduct Test	• This new section sets out the *market rules* around the Conduct Test. • Section 6.6.1 – Overview: The section includes an overview of the Constrained Areas Conditions Test. The resources that were identified in the Constrained Areas Conditions Test, Section 6.5, will be required to undergo the Conduct Test. If no resources were identified, the Conduct Test will not be required. Separate Conduct Test will be performed for resources in the *energy* market and the *operating reserve* markets. • Section 6.6.2 – Inputs: The section includes the inputs to the Conduct Test by referencing the inputs identified in Section 3.3. The inputs will also include the resources identified in Section 6.5 – Constrained Areas Conditions Test. • Section 6.6.3 – Conduct Test for Energy: The section will include details on the evaluation of the following *dispatch data* parameters: o *Energy offer*, including *offers* up to and above *minimum loading point* (only applicable if *energy offer* is greater than the minimum *energy offer* value for the *offer* lamination to be included in the Conduct Test); o Start-up offer; and o Speed-no-load offer. • Section 6.6.4 – Conduct Test for Operating Reserve: The section will include details on the evaluation of the following *dispatch data* parameters: o Operating *reserve offer* (only applicable if *operating reserve offer* is greater than the minimum *operating reserve offer* value for the *offer* lamination to be included in the Conduct Test); o Start-up offer;

Market Rule Section	Type	Topic	Requirement
			o Speed-no-load offer; and o *Energy offers* for the range of production up to *minimum loading point*. • Section 6.6.5 – Outputs: The section will list the outputs from the Conduct Test. The outputs from the Conduct Test include: o The set of resources that failed the Conduct Test; o The *dispatch data* parameters that failed the Conduct Test; and o A revised set of *offer* data for resources that failed a Conduct Test with *dispatch data* parameters that failed the Conduct Test replaced with reference levels. Overlap: Market Power Mitigation Chapter
Section 6.7	New	Reference Level Scheduling	• This new section sets out the *market rules* around the Reference Level Scheduling algorithm. • Section 6.7.1 – Overview: The section includes an overview of the Reference Level Scheduling algorithm. Reference Level Scheduling will perform a *security*-constrained unit commitment and economic *dispatch*, similar to As-Offered Scheduling with the following exception: o Reference Level Scheduling uses reference level *dispatch data* for any inputs from *registered market participants* that failed the Conduct Test. • Section 6.7.2 – Inputs: The section lists the inputs to the Reference Level Scheduling algorithm by referencing the inputs identified in Section 3. The inputs will also include the outputs from the Conduct Test, Section 6.6.5. • Section 6.7.3 – Optimization Function for Reference Level Scheduling: The optimization function for Reference Level Scheduling is the same as the optimization function for As-Offered

Market Rule Section	Type	Topic	Requirement
			Scheduling. The section will include a reference to the As-Offered Scheduling optimization function, Section 6.3.3. • Section 6.7.4 – Optimization Constraints: The optimization constraints for Reference Level Scheduling are the same as the optimization constraints for As-Offered Scheduling. The section will include a reference to the As-Offered Scheduling optimization constraints, Sections 6.3.4 through 6.3.7. • Section 6.7.5 – Outputs: The section will list the outputs from the Reference Level Scheduling algorithm. Reference Level Scheduling will produce constrained schedules and unit commitments, as well as operational decisions for hydroelectric *generation facilities* and *pseudo-units*, from the Reference Level Scheduling algorithm.
Section 6.8	New	Reference Level Pricing	• This new section sets out the *market rules* around the Reference Level Pricing algorithm. • Section 6.8.1 – Overview: The section includes an overview of the Reference Level Pricing algorithm. Reference Level Pricing will perform a *security*-constrained economic *dispatch* similar to that performed by As-Offered Pricing with the following exception: o Reference Level Pricing uses reference level *dispatch data* for any inputs from *registered market participants* that failed the Conduct Test. • Section 6.8.2 – Inputs: The section lists the inputs to the Reference Level Pricing algorithm by referencing the inputs identified in Section 3. The inputs will also include the outputs from the Conduct Test, Section 6.6.5. • Section 6.8.3 – Optimization Function: The optimization function for Reference Level Pricing is the same as the optimization function for As-Offered Pricing. The section will include a

Market Rule Section	Type	Topic	Requirement
			reference to the As-Offered Pricing optimization function, Section 6.4.3. • Section 6.8.4 – Optimization Constraints: The optimization constraints for Reference Level Pricing are the same as the optimization constraints for As-Offered Pricing with the following exception: o The constraints used to apply the principle for price-setting eligibility must be modified to take into account the Reference Level Scheduling results. • The section will include a reference to the As-Offered Pricing optimization constraints, Sections 6.4.4 through 6.4.8. • Section 6.8.5 – Outputs: The section will list the outputs from the Reference Level Pricing algorithm. Reference Level Pricing will produce shadow prices for Reference Level Pricing constraints. Reference Level Pricing will also produce locational marginal prices (and their components) for the Price Impact Test.
Section 6.9	New	Price Impact Test	• This new section sets out the *market rules* around the Price Impact Test. • Section 6.9.1 – Overview: The section includes an overview of the Price Impact Test. The Price Impact Test is required when one or more *dispatch data* parameters fails the Conduct Test. The Price Impact Test compares the As-Offered Pricing for *energy* (or *operating reserve*) prices with the Reference Level Pricing *energy* (or *operating reserve*) prices. • Section 6.9.2 – Inputs: The section includes the inputs to the Price Impact Test by referencing the inputs identified in Section 3.3. The resources that failed the Conduct Test, the outputs identified in Section 6.6.5, will be listed in the inputs section. The inputs will also include the *energy* and *operating reserve* prices identified in

Market Rule Section	Type	Topic	Requirement
			Section 6.4 – As-Offered Pricing and Section 6.8 – Reference Level Pricing. • Section 6.9.3 – Price Impact Test for Energy: The section will include details on the evaluation for the following two condition categories: o Local market power (*energy*); and o Global market power (*energy*). • Section 6.9.4 – Price Impact Test for Operating Reserve: The section will include details on the evaluation for the following two condition categories: o Local market power (*operating reserve*); and o Global market power (*operating reserve*). • Section 6.9.5 – Outputs: The section will list the outputs from the Price Impact Test. The outputs from the Price Impact Test include: o The set of resources that failed the Price Impact Test in each hour by condition type; o The locational marginal prices (*energy* and *operating reserve*) that failed the Price Impact Test in each hour; and o A revised set of *offer* data for resources that failed the Price Impact Test with *dispatch data* parameters that failed the corresponding Conduct Test replaced with reference levels. Overlap: Market Power Mitigation Chapter
Section 6.10	New	Mitigated Scheduling	• This new section sets out the *market rules* around the Mitigated Scheduling algorithm. • Section 6.10.1 – Overview: The section includes an overview of the Mitigated Scheduling algorithm. Mitigated Scheduling will perform a *security*-constrained unit commitment and economic *dispatch*, similar to As-Offered Scheduling, with the following exception:

Market Rule Section	Type	Topic	Requirement
			o Mitigated Scheduling uses reference level *dispatch data* for any inputs from *registered market participants* that failed the Conduct Test and the Price Impact Test. • Section 6.10.2 – Inputs: The section lists the inputs to the Reference Level Scheduling algorithm by referencing the inputs identified in Section 3. The inputs will also include the outputs from the Price Impact Test, Section 6.9.5. • Section 6.10.3 – Optimization Function: The optimization function for Mitigated Scheduling is the same as the optimization function for As-Offered Scheduling. The section will include a reference to the As-Offered Scheduling optimization function, Section 6.3.3. • Section 6.10.4 – Optimization Constraints: The optimization constraints for Mitigated Scheduling are the same as the optimization constraints for As-Offered Scheduling. The section will include a reference to the As-Offered Scheduling optimization constraints, Section 6.3.4 through 6.3.7. • Section 6.10.5 – Outputs: The section will list the outputs from the Mitigated Scheduling algorithm. Mitigated Scheduling produces constrained schedules and unit commitments, as well as operational decisions for hydroelectric *generation facilities* and *pseudo-units*, from the Mitigated Scheduling algorithm.
Section 6.11	New	Mitigated Pricing	• This new section sets out the *market rules* around the Mitigated Pricing algorithm. • Section 6.11.1 – Overview: The section includes an overview of the Mitigated Pricing algorithm. Mitigated Pricing will perform a *security*-constrained economic *dispatch*, similar to As-Offered Pricing, with the following exception: o Mitigated Pricing uses reference level *dispatch data* for any inputs from *registered*

Market Rule Section	Type	Topic	Requirement
			market participants that failed the Conduct Test and the Price Impact Test. • Section 6.11.2 – Inputs: The section lists the inputs to the Reference Level Pricing algorithm by referencing the inputs identified in Section 3. The inputs will also include the outputs from the Price Impact Test, Section 6.9.5. • Section 6.11.3 – Optimization Function: The optimization function for Mitigated Pricing is the same as the optimization function for As-Offered Pricing. The section will include a reference to the As-Offered Pricing optimization function, Section 6.4.3. • Section 6.11.4 – Optimization Constraints: The optimization constraints for Mitigated Pricing are the same as the optimization constraints for As-Offered Pricing, with the following exception: o The constraints used to apply the principle for price-setting eligibility will be replaced with the results from Mitigated Scheduling. • The section will include a reference to the As-Offered Pricing optimization constraints, Sections 6.4.4 through 6.4.8. Note: The marginal loss factors used in the *energy* balance constraint in Mitigated Pricing will be set to the marginal loss factors used in the last optimization function iteration of Mitigated Scheduling. • Section 6.11.5 – Outputs: The section will list the outputs from the Mitigated Pricing algorithm. Mitigated Pricing produces shadow prices for mitigated constraints for each hour. Mitigated Pricing also produces locational marginal prices and their components.
Section 7	New	Pass 2: Reliability Scheduling and	• This new section sets out the *market rules* around Pass 2 of the DAM Calculation Engine, including the inputs, mathematical formulations, and outputs.

Market Rule Section	Type	Topic	Requirement
		Commitment Pass	• Section 7.1 – Overview: The section will contain an overview of Pass 2. Pass 2 performs a least cost, *security* constrained unit commitment and economic *dispatch* to meet the forecast peak *demand* and *IESO*-specified *operating reserve* requirements. • Section 7.2 – Inputs: The section will include the inputs into Pass 2 by referencing the inputs identified in Section 3. The inputs will also include outputs from Pass 1. • Section 7.3 - Optimization Function for Pass 2: The section includes details on the optimization objective including: o Optimization Objective: The section will include the objective (to minimize the cost of additional commitments). o Variables – The section will list the variables for which the DAM calculation engine will solve. o Objective Function: The section will include the optimization of the objective function in Reliability Scheduling, which is to maximize the expression (the expression will be included in the *market rules*). • Section 7.4 – Optimization Constraints: The optimization constraints for Pass 2 are the same as the optimization constraints for Pass 1, As-Offered Scheduling, with exceptions. The constraints must be modified to: o Use the non-dispatchable peak *demand* forecast; o Remove price responsive load *bids*; o Use the *IESO* centralized *variable generation* forecast; and o Remove virtual transaction *bids* and *offers*.

Market Rule Section	Type	Topic	Requirement
			o The section will include details on the additional constraints required for Pass 2: ▪ Constraints enforcing scheduling and commitment decisions from Pass 1; and ▪ Constraints for new *energy*-limited resource scheduling variables. • The section will include a reference to the As-Offered Scheduling optimization constraints, Sections 6.3.4. through 6.3.7. • Section 7.6 – Outputs: The section will list the outputs from Pass 2, to be used in Pass 3, including but not limited to: o Schedules; o Unit commitments; and o Operational decisions for hydroelectric *generation facilities* and *pseudo-units*. • Section 7.7 – Glossary of Sets, Indices, Variables and Parameters for Pass 2: The section will list the sets, indices, variables and parameters for Pass 2.
Section 8	New	Pass 3: DAM Scheduling and Pricing Pass	• This new section sets out the *market rules* around Pass 3 of the DAM Calculation Engine, including the inputs, mathematical formulations, and outputs. • Section 8.1 – Overview: The section will contain an overview of Pass 3. Pass 3 determines a set of resource schedules and commitments to meet the *IESO*'s average hourly forecast *demand* as well as *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports. • Sections 8.2 and 8.3 will detail the algorithms within Pass 3. For the purposes of this inventory, these sections are broken out by algorithm as follows:

Market Rule Section	Type	Topic	Requirement
			o Day-Ahead Market (DAM) Scheduling o Day-Ahead Market (DAM) Pricing • Section 8.4 – Locational Marginal Prices: The section will outline the locational marginal prices for Pass3. Pass 3 will also produce locational marginal prices that may be used for *settlement* in accordance with Section 10. • Section 8.5 – Outputs: The section will list the outputs from Pass 2, which including but not limited to: o Schedules; o Unit commitments; o Operational decisions for hydroelectric *generation facilities* and *pseudo-units*; o Shadow prices; and o Locational marginal prices. • Section 8.6 – Glossary of Sets, Indices, Variables and Parameters for Pass 3: The section will list the sets, indices, variables and parameters for Pass 3.
Section 8.2	New	DAM Scheduling	• This new section sets out the *market rules* around the DAM Scheduling algorithm. • Section 8.2.1 – Overview: The section will contain an overview of the DAM Scheduling algorithm. DAM Scheduling performs a *security*-constrained economic *dispatch* to meet the *IESO*'s average *demand* forecast for *non-dispatchable load* and *IESO*-specified *operating reserve* requirements. • Section 8.2.2 – Inputs: The section will include the inputs into DAM Scheduling by referencing the inputs identified in Section 3, with the following exception: o Where *market participant* submitted *dispatch data* fails the Price Impact Test,

Market Rule Section	Type	Topic	Requirement
			the inputs will be replaced by the reference level *dispatch data*. • The inputs will also include outputs from Pass 2. • Section 8.2.3 – Optimization Function: The optimization objective for DAM Scheduling is the same as the optimization function for Pass 1, As-Offered Scheduling. The section will include a reference to the As-Offered Scheduling optimization function, Section 6.3.3, with the following exception: o The variables for unit commitment decisions are considered within the optimization. • Section 8.2.4 – Optimization Constraints: The optimization constraints for Mitigated Scheduling are the same as the optimization constraints for As-Offered Scheduling with the following exceptions: o The constraints for non-quick-start *generation facilities* are not required. This is so because the variables associated with non-quick-start *generation facilities* are held fixed; and o Additional constraints to respect Pass 2 decisions: ▪ Import schedules may not decrease from Pass 2 values; ▪ Export schedules may not increase from their Pass 2 values; and ▪ The commitment statuses of resources may not change from those determined in Pass 2. • The section will include a reference to the As-Offered Scheduling optimization constraints, Sections 6.3.4 through 6.3.7. • Section 8.2.5 – Outputs: The section will list the outputs from the DAM Scheduling algorithm. DAM

Market Rule Section	Type	Topic	Requirement
			Scheduling produces constrained schedules for all resources, as well as operational decisions for hydroelectric *generation facilities*.
Section 8.3	New	DAM Pricing	• This new section sets out the *market rules* around the DAM Pricing algorithm. • Section 8.3.1 – Overview: The section will contain an overview of the DAM Pricing algorithm. DAM Pricing performs a *security*-constrained economic *dispatch* to meet the *IESO*'s average *demand* forecast of *non-dispatchable loads* and *IESO*-specified *operating reserve* requirements. • Section 8.3.2 – Inputs: The section will include the inputs into DAM Pricing by referencing the inputs identified in Section 3, with the following exception: o Where a *market participant* fails the Price Impact Test, the inputs may be replaced by the reference level *dispatch data*. • The inputs will also include outputs from Pass 2 (commitment statuses), as well as outputs from DAM Scheduling, including: o Schedules; and o Operational decisions for hydroelectric *generation facilities*. • Section 8.3.3 – Optimization Function: The optimization function for DAM Pricing is the same as the optimization function for Pass 1, As-Offered Pricing. The section will include a reference to the As-Offered Pricing optimization function, Section 6.4.3. • Section 8.3.4 – Optimization Constraints: The optimization constraints for DAM Pricing are the same as the optimization constraints for As-Offered Pricing with the following exception: o The constraints used to apply the principle for price-setting eligibility must be modified with the DAM Scheduling results.

Market Rule Section	Type	Topic	Requirement
			• The section will include a reference to the As-Offered Scheduling optimization constraints, Sections 6.4.4 through 6.4.8. Note: The marginal loss factors used in the *energy* balance constraint in DAM Pricing will be set to the marginal loss factors used in the last optimization function iteration of DAM Scheduling. • Section 8.3.5 – Outputs: The section will list the outputs from the DAM Pricing algorithm. DAM Pricing produces shadow prices for DAM Pricing constraints. DAM Pricing also produces *settlement-ready* locational marginal prices and zonal prices (including the hourly DAM Ontario Zonal Price).
Section 9	New	Combined Cycle Modelling	• This new section sets out the *market rules* around combined cycle modelling. • Section 9.1 – Overview: The section will provide an overview of combined cycle modelling. *Registered market participants* with combined cycle plants of one or more combustion turbines and one steam turbine may choose to have the associated *generation facilities* modeled as one or more *pseudo-units*. • Section 9.2 – Modeling by the DAM Calculation Engine: The section will include details on the modeling of *pseudo-units* in the DAM calculation engine. o Section 9.2.1 – The section will include details on the modelling of *pseudo-units* in the optimization function and in the *security* assessment function. ▪ Section 9.2.1.1 - Model Parameters: The section will include the parameters used for modeling, including registration and daily *dispatch data*. ▪ Section 9.2.1.2 – Application of Physical Unit De-rates to the Pseudo-

Market Rule Section	**Type**	**Topic**	**Requirement**
			Unit Model: The section will include details on changes to the *pseudo-unit* model parameters defining the dispatchable capacity and duct firing capacity due to physical unit de-rates. ▪ Section 9.2.1.3 – Applying Minimum and Maximum Constraints to Pseudo-Units. The section will include details on the minimum and maximum constraints provided to the DAM calculation engine as constraints on combustion turbines/steams turbines, or constraints on given *pseudo-unit* resources. ▪ Section 9.2.1.4 - Translation of Pseudo-Unit Schedules to Physical Unit Schedules: The section will include details on the translation of *pseudo-unit* schedules to physical unit schedules. o Section 9.2.2 – The section will include details on the prices for *pseudo-units* produced by the DAM calculation engine.
Section 10	New	Pricing Formulation	• This new section sets out the *market rules* around the calculation of locational marginal prices. The calculation of these prices are utilized by Pass 1 and Pass 3. • Section 10.1 – Overview: The section will provide an overview of the pricing formulation for calculating locational marginal prices including: o Locational marginal prices for *energy*; o Locational marginal prices for *operating reserve*; and o Prices for islanded nodes. • The prices will be determined as follows:

Market Rule Section	Type	Topic	Requirement
			o Initial prices will be calculated using the shadow prices determined by the pricing algorithms; and o A weighted average of the above locational marginal prices will be used to provide zonal prices. Note: If locational marginal prices are unable to be produced due to insufficient information, or if the process fails, it will be flagged for further review by the *IESO*. • Section 10.2 – Locational Marginal Prices for Energy: The section will include details on the price formulation for *energy* locational marginal prices for: o Internal pricing nodes; o *Intertie zone* source and sink buses; and o Zones. • Section 10.3 – Locational Marginal Prices for Operating Reserve: The section will include details on the price formulation for *operating reserve* locational marginal prices for: o Internal pricing nodes; and o *Intertie zone* source and sink buses. • Section 10.4 – Prices for Islanded Nodes: The section will include details for: o The reconnection methodology for non-quick- start *generation facilities* that are not connected to the main island of the system; and o The substitution methodology used to produce a price for all other pricing nodes that are not connected to the main island of the system.

– End of Section –

5. Procedural Requirements

5.1. Market-Facing Procedural Impacts

Existing *market manuals* and training materials related to the DAM Calculation Engine processes will be retained to the extent possible. The majority of changes result from the replacement of the DACE with the DAM calculation engine. More specifically, instead of static marginal loss factors currently used in DACE, the *security* assessment function will calculate dynamic marginal loss factors that will be used in the optimization function and LMPs for *energy*. Updates will be made to all applicable *market manuals* that reflect changes to the day-ahead calculation engine processes.

The documents most directly related to the DAM Calculation Engine detailed design are the following:

Market Manuals:

- Market Manual 1: Connecting to Ontario's Power System, Part 1.5 - Market Registration Procedures;
- Market Manual 4: Market Operations, Part 4.2 - Submission of Dispatch Data in the RT Energy and Operating Reserve Markets;
- Market Manual 4: Market Operations, Part 4.3 - Real Time Scheduling of the Physical Markets;
- Market Manual 4: Market Operations, Part 4.4 - Transmission Rights Auction;
- Market Manual 4: Market Operations, Part 4.5 - Market Suspension and Resumption;
- Market Manual 7: System Operations, Part 7.1 - IESO-Controlled Grid Operating Procedures;
- Market Manual 7: System Operations, Part 7.2 - Near-Term Assessments and Reports;
- Market Manual 7: System Operations, Part 7.3 - Outage Management;
- Market Manual 9: Day-Ahead Commitment, Part 9.0 - DACP Overview;
- Market Manual 9: Day-Ahead Commitment, Part 9.2 - Submitting Operational and Market Data for the DACP;
- Market Manual 9: Day-Ahead Commitment, Part 9.3 - Operation of the DACP;
- Market Manual 9: Day-Ahead Commitment, Part 9.4 - Real-Time Integration of the DACP; and

- Market Manual 9: Day-Ahead Commitment, Part 9.5 - Settlement for the DACP.

Training Material:

- Guide to the Day-Ahead Commitment Process.

The following tables identify sections within market manuals and training materials that will not require changes, will require modification and new sections that will need to be added to support the DAM Calculation Engine processes in the future market.

Table 5-1: Impacts to Market Manual 1: Connecting to Ontario's Power System

Procedure	Type of change (no change, modification, new)	Section	Description
Part 1.5 – Market Registration Procedures	Modification	3 Register Equipment	There are no impacts to these sections.

Table 5-2: Impacts to Market Manual 4: Market Operations

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating reserve markets	No change	1.0 Roles and Responsibilities 2.1 and 2.2 of Real-Time Energy and Operating Reserve Markets	There are no impacts to these sections.
	Modification	2.3 Timing of the Real-Time Energy and Operating Reserve Markets	Timelines for *dispatch data* submission on the *pre-dispatch day* to be modified to reflect the fact that the day-ahead market will operate in Eastern Prevailing Time (EPT) and to update the modified DAM execution timelines.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating reserve markets	No change	2.3.1 Generation Units with Start-Up Delays 2.3.2 Replacement Energy Offers Program	There are no impacts to these sections.
	Modification	2.3.3 Procedural Steps for Submitting Dispatch Data and Revisions Until Two Hours Prior to the Dispatch Hour	Modifications required to procedural steps in order to distinguish between hourly *dispatch data* and daily *dispatch data*. Timing updates required to reflect use of EPT timeframe for DAM.
	Modification	2.4 The Structure of Dispatch Data: 2.4.1 Energy Offers and Bids 2.4.2 OR Offers 2.4.3 Energy Schedules and Forecasts	Refer to the Offers, Bids and Data Inputs detailed design document for the list of modifications required to this *market manual* section.
	Modification	2.4.4. Standing Dispatch Data	Timelines for the processing of standing *dispatch data* to be modified to reflect the DAM EPT timeframe.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating reserve markets	Modification	2.5 Dispatch Data for Importing and Exporting Energy and Importing Operating Reserve 2.5.1 Boundary Entity Resources 2.5.2 Ramp Rates 2.5.4 Wheeling Through Interchange Schedules	Refer to the Offers, Bids and Data Inputs detailed design document for a list of modifications to this *market manual* section. Section 2.5.4 Wheeling Through Interchange Schedules to be updated to reflect how these *intertie* transactions are evaluated.
	No change	2.5.3 e-Tagging 2.5.5 Validation	There are no impacts to this section.
	Modification	2.6 Capacity Exports	• This section will be updated to reflect that submitted e-Tags will no longer be required to contain "ICAP". Instead, the capacity transaction *dispatch data* parameter will be submitted as *dispatch data* for each hour that an export *bid* is submitted for a *called capacity export*. • Changes to this section are described in the Grid and Market Operations Integration detailed design document.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating reserve markets	Modification	2.7 Requests for Segregated Mode of Operation	• This section will be updated to reflect the EPT timeframe for the *pre-dispatch day*. • Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	Appendix A: Content of Dispatch Data	Refer to the Offers, Bids and Data Inputs detailed design document for a list of modifications to this *market manual* section.
	No change	Appendix D: Pre-dispatch Schedule Production and Publication Appendix E: Boundary Entity Resources Appendix F: Ontario Specific E-Tag Requirements	There are no impacts to these sections.
Part 4.3 - Real Time Scheduling of the Physical Markets	No change	1.3 Roles and Responsibilities	There are no impacts to this *market manual*.
	No change	2.0 Participant Workstation and Dispatch Workstation	There are no impacts to this *market manual*.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.3 - Real Time Scheduling of the Physical Markets	Modification	3.0 Determining Real-Time Schedules	• In addition to changes identified in the Grid and Market Operations Integration detailed design document, the list of information used to determine *real-time schedules* will be updated to reflect DAM commitments. • Refer to the RTM Calculation Engine detailed design document for the list of modifications to this market manual section.
	Modification	4.0 Determining Market Information	• Refer to the Grid and Market Operations Integration detailed design document for the updates required to this section.
	Modification	5.0 Releasing Real-Time and Market Information	• Refer to the Grid and Market Operations Integration detailed design document for the updates required to this section. • Refer to the Publishing and Reporting Market Information detailed design document for updates required to this section pertaining to public and confidential reports are described in.
	Modification	6.0 Determining Dispatch Instructions	• There are no impacts to this section. • Refer to section the Grid and Market Operations Integration detailed design document for details of the updates required to this section.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.3 - Real Time Scheduling of the Physical Markets	Modification	7.0 Issuing Dispatch Instructions	• There are no impacts to this section. • Refer to the Grid and Market Operations Integration detailed design document for details of the updates required to this section.
	No Change	8.0 Issuing Dispatch Advisories	There is no change to existing operating procedures.
	Modification	9.0 – Administrative Pricing	Updates to this section are described in Grid and Market Operations Integration detailed design document and include the following: • The *IESO* will not retroactively correct DAM prices and schedules as correcting the DAM prices after the operating day does not necessarily result in a more optimal outcome due to the implications on the *real time market*. • Public communication will advise that DAM financially binding schedules or prices will not be created or posted due to a DAM failure
	Modification	10.0 Compliance Aggregation	Refer to the Grid and Market Operations Integration detailed design document for details of the updates required to this section.
Part 4.4 - Transmission Rights Auction	No change	All Sections	This design does not impact this *market manual*.

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 4.5 - Market Suspension and Resumption	No Change	All Sections other than Section 2, 3 and Appendix A	No changes required to sections other than Section 2: Market Suspension and Section 3: Market Resumption.
	Modification	Section 2 – Market Suspension Section 3 – Market Resumption	This section will need to be updated to include the DAM scheduling process, which will need to stop while the *real-time market* is suspended and until it resumes.

Table 5-3: Impacts to Market-Manual 7: System Operations

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 7.1 - IESO-Controlled Grid Operating Procedures	Modification	7.3 Unit Readiness Program	• This section needs to be updated to indicate that the constraint will be applied after the completion of the DAM. All references to DACP will be replaced by DAM. • All instances of DA-PCG will be replaced with DA-MWP.
	No change	All other sections	This design does not impact these sections.
Part 7.2: Near-Term Assessments and Reports	Removed	5.0 Control Action Operating Reserve	This section will be discarded. Control action *operating reserve* will not be implemented in the new market.

Procedure	Type of change (no change, modification, new)	Section	Description
	Modification	Appendix B: Method to Prepare Ontario Demand Forecast	• This design does not impact this section. • Refer to the Publishing and Reporting Market Information detailed design document and Offers, Bids and Data Inputs detailed design document for details on changes to these sections.
	No change	All sections other than 5.0 and Appendix B	This design does not impact these sections. Refer to the Publishing and Reporting Market Information detailed design document and Offers, Bids and Data Inputs detailed design document for details on changes to these sections.
Part 7.3: Outage Management	Modification	General	This section requires minor changes throughout to reflect the EPT timeframe for *outage* submission deadlines when an *outage* is required as input into the DAM scheduling process. For more information on these changes, refer to the Grid and Market Operations Integration detail design document.
	Modification	4.1.4 Segregated Mode of Operation	This section requires updates to reflect new timelines for SMO submission, which will depend on whether the request for *segregated mode of operation* requires an outage to a critical transmission *facility*. For more information on these changes, refer to the Grid and Market Operations Integration detail design document.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 7.3: Outage Management	No change	All other sections	This design does not impact other sections of this market manual.

Table 5-4: Impacts to Market-Manual 9: Day-Ahead Commitment Process

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.0: DACP Overview	Modification	All Sections	Market Manual 9 will be replaced. DACP will be replaced with a financially-binding DAM.
	Modification	Section 2 About this Manual	• All sections will be replaced to reflect financially binding DAM. • Section 2.3 needs to be modified to reflect new types of participants in DAM such as price responsive loads and virtual traders. • All references to daily generator data will be replaced with daily *dispatch data.*

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 9.0: DACP Overview	Modification	Section 3.2 Optimization Process overview	• This section's content will be replaced with content that describes the new DAM passes, DAM timeline changes to 06:00 to 10:00 Eastern Prevailing Time (EPT) and inclusion of new participants such as price responsive loads and virtual transactions. • The ELR revision window content will be removed. • The section will be modified to indicate that Schedule of Record will be eliminated in the new market. • DAM results timing will be updated. • Reliability guarantees will be updated.
	Modification	Section 3.3 DACP Timeline	This section needs to be replaced with DAM timelines and diagram.
	Modification	Section 4.0 Procedures Summary	Figure 4-1 will to be updated to show the interrelationships of the future day-ahead *market manuals* and other *market manuals*.

Procedure	Type of change (no change, modification, new)	Section	Description
	Modification	Section 5 Applicability of Procedures	Table 5-1 will be updated to reflect mappings between future day-ahead market events and the applicable day-ahead market procedures.
	Modification	Appendix 6 DACP Background	This appendix may be deleted or updated to provide background for the day-ahead market.
Part 9.2 - Submitting Operational and Market Data for the DACP	Modification	All Sections	Refer to the Offers, Bids and Data Inputs detailed design document for more information on the changes required to this section.
	Modification	5.3 Request for Segregated Mode of Operation	This section will require updates for SMO submission and cancellation timelines as described in the Grid and Market Operations Integration detailed design document.
	Modification	5.4 Submit Regulation Offers	This section will require updates to reflect DAM submission timelines as described in the Grid and Market Operations Integration detailed design document.

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
	Modification	5.5 Procedure for Submitting *Dispatch Data* during Contingencies	Refer to the Grid and Market Operations Integration detailed design document for more information on the changes required to this section.
	Modification	Appendix A: Reason Codes and Valid Reasons for Change	• Refer to the Grid and Market Operations Integration detailed design document for the details of required updates to this section. • Updates required include changes to reflect the new day-ahead market and updates to market-facing tools.
Part 9.3: Operation of the DACP	Modification	All sections	• All instances of DACP will need to be changed to DAM. • In addition to the changes related to the DAM calculation engine content, other required changes to this *market manual* are described in the Grid and Market Operations Integration detailed design document.
	Modification	New	As described in the Grid and Market Operations Integration detailed design document, the ability to schedule flex OR will be incorporated into the day-ahead market. A new section detailing this and enabling the *IESO* to determine if flex OR is required will be included.
	Modification	New	As described in the Grid and Market Operations Integration detailed design document, new sections will need to be created to speak to DAM failures and DAM delays,

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.3: Operation of the DACP	Modification	4 Overview of the Operation of the DACP	Any mention of multiple DACE runs will need to be updated to a single DAM calculation engine run.
	Modification	4.1 Initial scheduling assumptions	This section will be replaced with DAM Initializing Assumptions.
	Modification	4.3 Optimization Process Overview	• This section will be updated with details of the three passes as they will be performed in the future day-ahead market, which includes figure 4-3. • New subsections will be added for each pass for a total of three subsections. • The three subsections for the current three passes will be removed.
	Modification	4.4 Scheduling the DACE Runs	This section will need to be updated to reflect the fact that there will be one DAM calculation engine run. All current subsections for this section will need to be removed as they speak to additional DACE runs.
	Modification	4.5 Completion of DACP and the DACP Schedule of Record	• Any mention of a DACE run after the 10:00 (EPT) submission window deadline will be removed • Any mention of *schedule of record* needs to be removed and replaced with similar private reports containing their financially binding schedules and commitments • Any mention of EELR optimization run will be removed

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.3: Operation of the DACP	Modification	4.6 IESO Reliability Commitment Actions 4.7 Principles for Applying DACP Commitment Actions	These sections will be removed.
	Modification	4.8.3 DACP Report Descriptions 4.9 DACP Failure Reports 4.10 DACP Schedule of Record	• The DACP *schedule of record* will cease to exist and will be replaced with other private reports. • Any mention of multiple DACE runs, or DACE runs after 10:00 (EPT) will be removed in addition to any mention of shadow prices. • Refer to the Publishing and Reporting Market Information detailed design document for additional information on the changes required to this section.
Part 9.4: RT Integration of the DACP	Modification	All sections	• All instances of DACP will need to be changed to DAM. • In addition to the changes related to the DAM calculation engine content, changes to this *market manual* are also described in the Grid and Market Operations Integration detailed design document.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.4: RT Integration of the DACP	Modification	4.1 Observing Day-Ahead Commitments in Real Time 4.1.2 Passing DACP Commitments to Real Time 4.4.2 Minimum Loading Point Price Cap	As described in the Grid and Market Operations Integration detailed design document, changes to this section will include: • Elimination of term "PCG-Eligible". • Any mention of DA-PCG and *schedule of record* will need to be updated with DAM-MWP and similar private reports replacing *schedule of record.* • Updates required to reflect that o NQS resources will be scheduled and dispatched no lower than their MLP for the duration of their MGBRT in PD through minimum constraints. o MLP and MGBRT will be submitted as daily *dispatch data*. o The initial PD calculation engine run will now be at 20:00EST.

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 9.4: RT Integration of the DACP	Modification	4.2.1 Withdraw Dispatch Data	This section will be updated to reflect the: • Elimination of content related to the Day-Ahead Generator Withdrawal charge. • Elimination of the DA-PCG impact as it specifically discusses day-ahead production cost guarantee. • The fact that the *IESO* will now consider *speed no-load costs* for the de-commitment of NQS *generation facilities* in the *pre-dispatch scheduling* process. Additionally, the *pre-dispatch scheduling* process will now automatically notify *market participants* of any de-commitment.
	Modification	4.3 - Day-Ahead Intertie Transactions	As described in the Grid and Market Operations Integration detailed design document, changes will include: • Modification to reflect that only *intertie* transactions scheduled in the DAM will be evaluated in the PD look-ahead period in hours T +2 and beyond.
	Modification	4.4.1 Pseudo Unit Offer Submission - Real Time	• Any mention of the DAM submission windows needs to be in EPT. • Any mention of *dispatch data* submitted after the 10:00 EPT submission window closes will need to be removed. • Updates also required to reflect that PSU *offer* submissions will now be evaluated on the *dispatch day* and in the *dispatch hour*.

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
	Modification	4.4.2 IESO De-commitment of Dispatchable Generation Facilities	Any mention of CMSC needs to be removed.
	Modification	4.5 Submit Dispatch Data	This section will require updates to reflect the following: • Notification of ADE expansion submission will be made through the MP-GUI instead of phone. • *Registered market participants* that operate a dispatchable *facility* will have the ability to submit an ADE expansion request when revising *dispatch data* for one or more *dispatch hours* through the MP-GUI.
Part 9.4: RT Integration of the DACP	No change	4.5.6 Submit Outage Requests	This design does not impact this section of the market manual.
	Modification	4.6 Synchronize Units Committed in the Day-Ahead	Updates will be required to reflect that constraints to MLP will be applied for hours to satisfy the *Minimum generation block run-time* of a resource that was committed in DAM.
	Modification	5.1 Withdraw Offers for a Committed Resource	• This section will need to be revised to reflect that PCG's and the Schedule of Record are being eliminated. The Schedule of Record will be replaced by the DAM schedule. • The procedural steps will need to be revised to reflect the updated tool names.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.4: RT Integration of the DACP	Modification	5.2 Respond to IESO request for decommitment	• This section will need to be revised to eliminate the term PCG and PCG-eligible. • The procedural steps will need to be revised to reflect the updated tool names.
Part 9.5: - Settlement for the Day-Ahead Commitment Process	Modification	All sections	• As described in the Market Settlement detailed design document, this manual will be replaced with a new manual to take into account the changes related to the day-ahead market. • References to Real-Time Intertie Offer Guarantee and Real-Time Intertie Failure Charge will need to be included in Market Manual 5.5.
	Modification / New	All sections	This manual will be replaced with a new manual to take into account the changes related to the day-ahead market. Refer to the Market Settlement detailed design document for additional details related to these changes.

5.2. Internal Procedural Impacts

Some of the internal procedures are related to other *IESO* processes that interact with the DAM Calculation Engine processes. Changes to the DAM Calculation Engine processes under the market renewal program will have an impact on other internal *manuals* related to the day-ahead scheduling process. However, in some areas this may be contingent upon the tools impact of the day-ahead market.

In addition, some areas of the current procedures heavily reference relevant *market rules* and supporting tools, most of which will be undergoing changes as a result of the new day-ahead market implementation and other solution enhancements. The existing procedures will be updated to account for the corresponding changes in the *market rules* and tools.

Changes or additions to internal *IESO* procedures are for internal *IESO* use as documented in Appendix B and are not included in the public version of this document. Appendix B details the impacts to internal procedures in terms of existing procedures that support the new market requirements, existing procedures that need to be updated, and new internal procedures that need to be created to support the future *real-time market* and day-ahead market.

– End of Section –

6. Business Process and Information Flow Overview

6.1. Market Facing Process Impacts

This section provides an overview to the arrangement of processes required in order to support the overall Day-Ahead Market Calculation Engine processes and the critical information flows between them.

The context diagrams presented in Section 2 of this document are considered as level 0 data flow diagrams and represent the major flows of information into and out of the Day-Ahead Market Calculation Engine. This section now presents the Day-Ahead Market Calculation Engine processes at the next level of detail (Level 1). A further break-down of the processes presented in this section (i.e. levels 2,3,4…) falls into the realm of systems design and is beyond the scope of this document.

The data flow diagram does not illustrate:

- flow of time or sequence of events (as might be illustrated in a timeline diagram);
- decision rules (as might be illustrated in Flowchart); and
- logical architecture and systems architecture (as might be illustrated in a Logical Application and Data Architecture, and/or Physical Application and Data Architecture).

What it does illustrate however, is a logical breakdown of the sub-processes that constitute a large and complex system such as the Day-Ahead Market Calculation Engines processes. Specifically, the data flow diagram presented below illustrates:

- the Day-Ahead Market Calculation Engine processes as a grouping of several major and tightly coupled sub-processes;
- the key information flows between each of the processes;
- external sources of key information required by the Day-Ahead Market Calculation Engines processes;
- external destinations of key information from the Day-Ahead Market Calculation Engines processes; and
- the same logical boundary of the Day-Ahead Market Calculation Engines processes as illustrated in the Level 0 context diagram presented in Section 0 of this document.

This section is not meant to impart information systems or technology architecture, but rather to capture the entire Day-Ahead Market Calculation Engines process as a series of interrelated sub-processes.

The functional design outlined in Section 3 of this document maps to the business process overview presented in this section. In any areas where there are inconsistencies between this section and the description of the business process provided in Section 3, the business process described in Section 3 will take precedence.

The data flow diagram illustrated in Figure 6-1 presents the Day-Ahead Market Calculation Engines processes. The following sections of this document will provide an overview to each of the main sub-processes of the Day-Ahead Market Calculation Engines process.

6.1.1. Day-Ahead Market Calculation Engines Process Map

The process map illustrated in Figure 6-1 and Figure 6-2 presents the context and components of the Day-Ahead Market Calculation Engines processes.

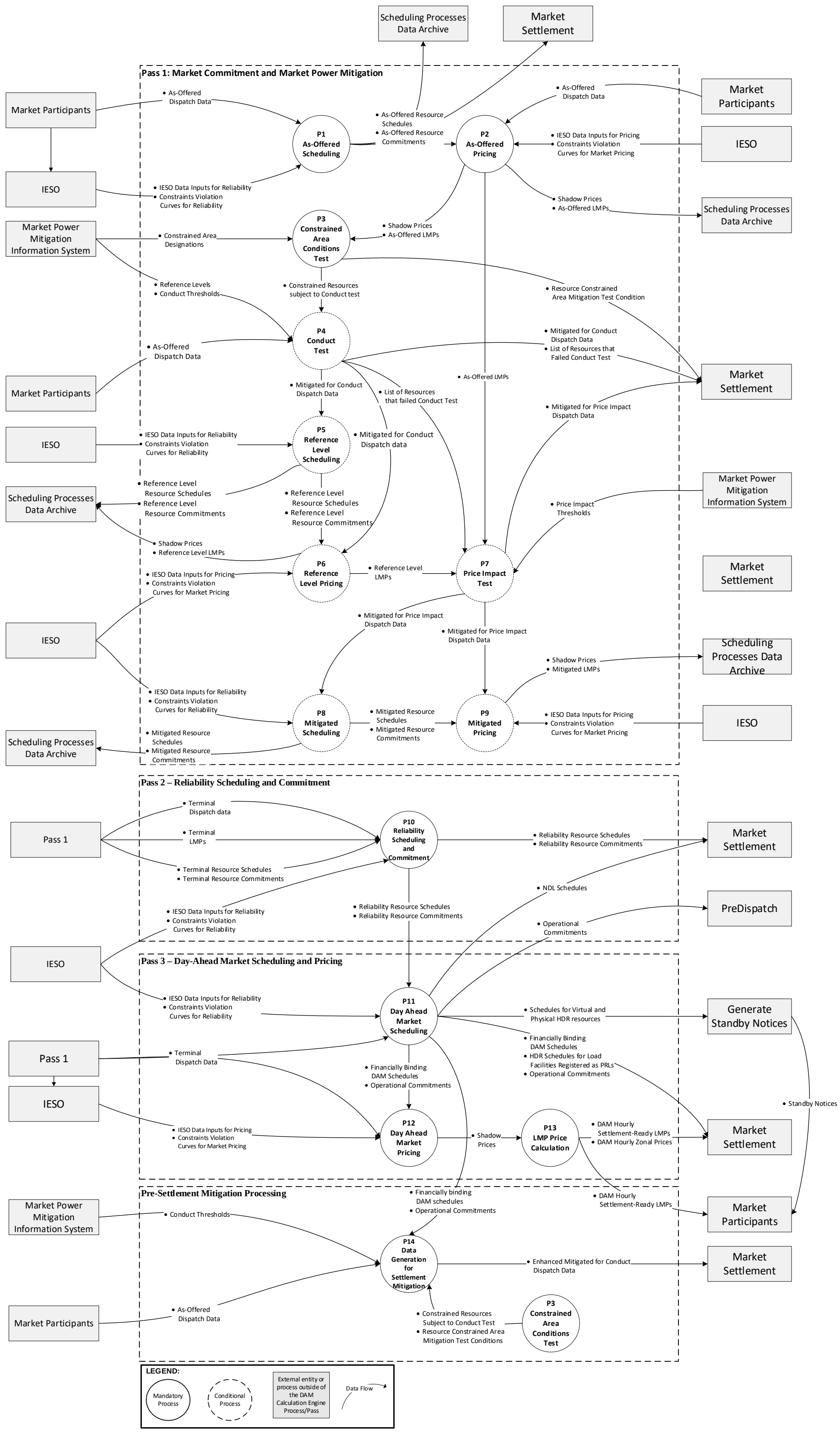

Figure 6-1: Day Ahead Market Calculation Engine Market Facing Process

6.1.2. Detailed Description of Processes and Data Flows

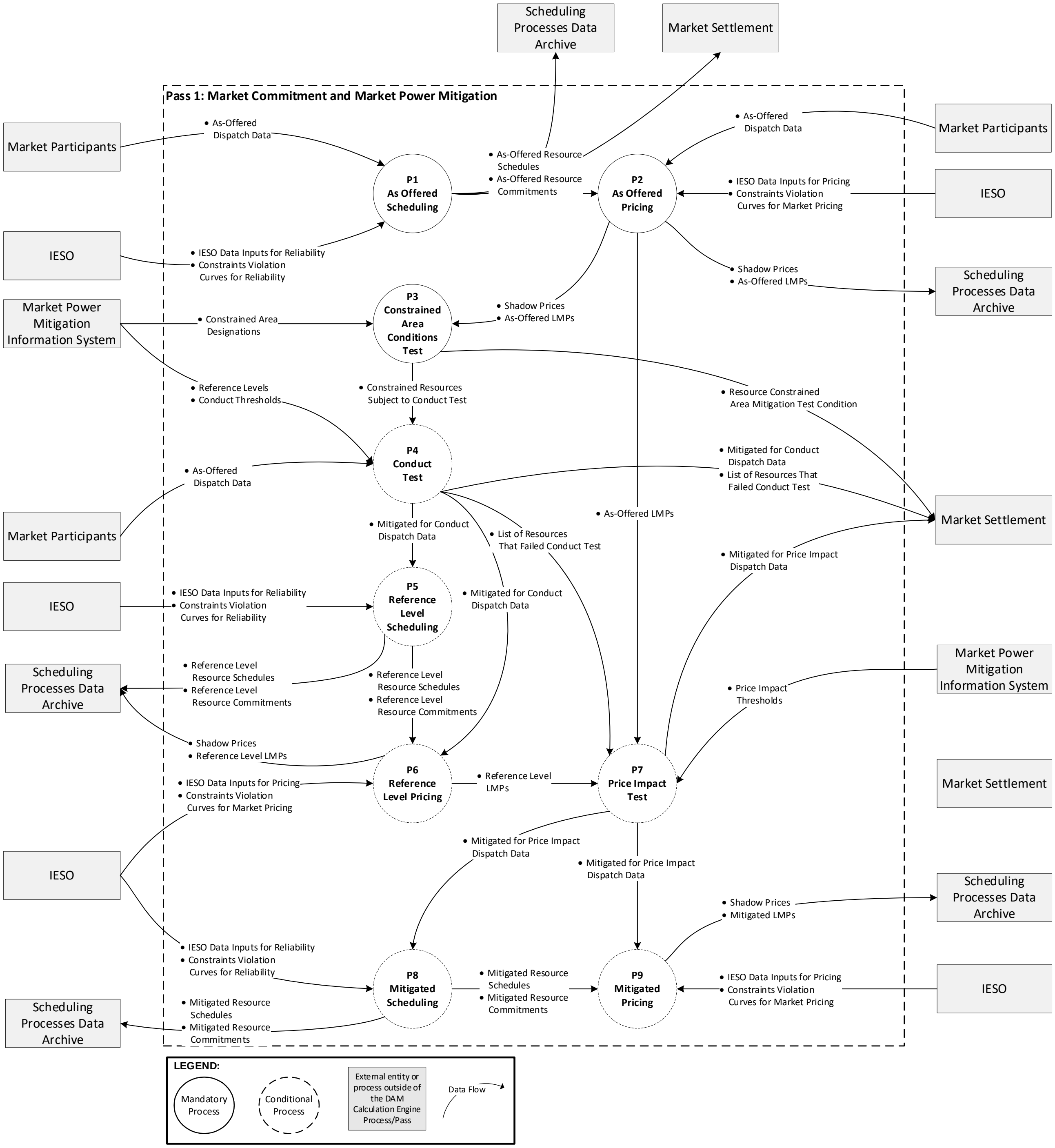

Figure 6-2: Day Ahead Market Calculation Engine Pass 1 Market Facing Process

6.1.3. Process P1 – As-Offered Scheduling

Description

This process determines an initial set of resource schedules for all *market participants* and resource commitments for eligible NQS resources*.* It maximizes the gains from trade using as-offered *dispatch data* from *market participants* and *IESO* data inputs, including the constraint violation penalty curves for meeting the *IESO's reliability* requirements.

Input and Output Data Flows

Table 6-1: Process P1 Input and Output Data Flows

Flow	Source	Target	Frequency
As-Offered Dispatch Data	Market Participants	Process P1	Daily

Description:

- The as-offered *dispatch data* refers to the set of *dispatch data* that *market participants* submit into the day-ahead market, which includes both hourly and daily *dispatch data* for *energy* and *operating reserve*.
- As-offered *dispatch data* must have successfully passed the validation of non-financial *dispatch data* and financial *dispatch data* upon submission.
- *Market participants* will submit *dispatch data, ancillary service information* and *outage* information in order to participate in the day-ahead market*.*

The *dispatch data* parameters listed below are submitted by the specified *market participants* for DAM.

- Hourly *energy bids* for:
  - Exports;
  - Virtual *demand* transactions;
  - Price responsive loads;
  - *Dispatchable loads*; and
  - *Hourly demand response* (HDR) resources

Financial *dispatch data* parameters which include;

- Hourly *energy offers* for:
  - Imports;
  - Virtual supply transactions;
  - Dispatchable *generation facilities* including *variable generation*; and

- Non-dispatchable *generation facilities*

* Hourly start-up *offers* for:
  - NQS *generation facilities*
* Hourly speed no-load *offers* for:
  - NQS *generation facilities*
* Hourly offers for *operating reserve* for:
  - Imports
  - Exports
  - Dispatchable generation resources*;* and
  - *Dispatchable loads*.

The non-financial *dispatch data* parameters listed below can be submitted by *market participants* for each resource type:

* For all dispatchable *generation facilities*:
  - *Energy* ramp rate;
  - Maximum daily *energy* limit.
* For dispatchable hydroelectric *generation facilities*:
  - Hourly must run;
  - Minimum hourly output;
  - Minimum daily *energy* limit;
  - Maximum daily *energy* limit;
  - *Maximum number of starts per day*;
  - *Forbidden regions*; and
  - Linked resources, time lag and MWh ratio.
* For NQS *generation* resources*:*
  - *Minimum loading point* (MLP);
  - *Minimum generation block run-time*;
  - *Minimum generation block down-time*;
  - *Maximum number of starts per day*;
  - Maximum daily *energy* limit
  - Ramp up *energy* to MLP (ramp hours to MLP; and *energy* per ramp hour)

- Single cycle mode (submitted by *market participants* and used to build the PSU model as described in Section 3.12)
- Lead time

- For dispatchable *variable generation facilities*:
  - *Variable generation* forecast quantity

For detailed descriptions, attributes and usage of the above *dispatch data* parameters, refer to Section 3.4.1 from Table 3-1 to Table 3-14

Flow	Source	Target	Frequency
IESO Data Inputs for Reliability	IESO	Process P1	Daily

Description:

The following *IESO* inputs will be used by Process P1 for the future day-ahead market:

- *Reliability* requirements: *Reliability* requirements are operational inputs produced by the *IESO* to satisfy grid *reliability* and *security* standards as per NERC, NPCC and *IESO market rules*. *Reliability* requirements encompass a number of inputs from the *IESO* such as *operating reserve* requirements, *security limits* and *ancillary services* to name a few.
- *Demand* forecasts: The *demand* forecast produced by the *IESO* will continue to be used as an input for the expected load in the DAM calculation engine. The *IESO* will continue to produce a *demand* forecast at the province-wide level but as the sum of four separate area *demand* forecasts.
  - The type of *demand* forecasts that will be used in Process P1: As-Offered Scheduling is the average non-dispatchable *demand* forecast described in Section 3.13.
- Network model: The network model contains a detailed topology representation of the *IESO-controlled grid* and a simplified representation of power systems in neighbouring jurisdictions.

Flow	Source	Target	Frequency
Constraint Violation Curves for Reliability	IESO	Process P1	Daily

Description:

- Constraint violation penalty curves will continue to be defined as the penalty functions for the violation of constraints in the *dispatch algorithm*. They establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints.
- The constraint violation penalty curves for *reliability* will be used by the scheduling algorithm to produce constrained schedules.

Flow	Source	Target	Frequency
As-Offered Resource Schedules	Process P1	Process P2 Scheduling Processes Data Archive Market Settlement	Daily

Description:

- The as-offered resource schedules for *energy* and *operating reserve* are the set of schedules produced by the As-Offered Scheduling Process P1 for all *market participants.* These are generated based on as-offered *dispatch data* and *IESO* input data
- *Energy* schedules are produced for:
  - Dispatchable *generation* resources*;*
  - *Variable generation;*
  - Non-dispatchable *generation* resources*;*
  - *Dispatchable loads;*
  - *Non-dispatchable loads*;
  - Price responsive loads;
  - *Hourly demand response* resources;
  - Virtual supply and *demand* transactions; and
  - Imports and exports.
- *Operating reserve* schedules are produced for:
  - Dispatchable *generation facilities*;
  - *Dispatchable loads*; and
- Imports and exports.
- Refer to Section 3.6.1.7(outputs) for details of these schedules

Flow	Source	Target	Frequency
As-Offered Resource Commitments	Process P1	Process P2 Scheduling Processes Data Archive Market Settlement	Daily

Description:
• The as-offered resource commitments are the set of commitments produced by Process P1 for eligible NQS *generation facilities* that are generated based on as-offered *dispatch data*. • Refer to Section 3.6.1.7(outputs) for details of these schedules

6.1.4. Process P2 – As-Offered Pricing

Description

This process determines a set of shadow prices and locational marginal prices (LMPs) that account for all resource and system constraints. It uses the same as-offered *dispatch data* from *market participants* and the set of *IESO* inputs from the As-Offered Scheduling Process P1 with one exception. Instead of the constraint violation penalty curves for *reliability*, As-Offered Pricing uses the constraint violation penalty curves that are relevant for pricing.

Input and Output Data Flows

Table 6-2: Process P2 Input and Output Data Flows

Flow	Source	Target	Frequency
As-Offered Resource Schedules	Process P1	Process P2	Daily
Description: • See description in Process P1 above.			
Flow	**Source**	**Target**	**Frequency**
As-Offered Resource Commitments	Process P1	Process P2	Daily
Description: • See description in Process P1 above. • These are only used by *settlement* if mitigated commitments are not produced			
Flow	**Source**	**Target**	**Frequency**
As-Offered Dispatch Data	Market Participant	Process P2	Daily
Description: • See description in Process P1 above.			

Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Pricing	IESO	Process P2	Daily

Description:

The following *IESO* inputs will be used by Process P2 for the future day-ahead market:

- *Reliability* requirements - *Reliability* requirements are operational inputs produced by the *IESO* to satisfy grid *reliability* and *security* standards as per NERC, NPCC and *IESO market rules*. *Reliability* requirements encompass a number of inputs from the *IESO* such as *operating reserve* requirements, *security limits* and *ancillary services* to name a few.
- *Demand* forecasts - The *demand* forecast produced by the *IESO* will continue to be used as an input for the expected load in the DAM calculation engine. The *IESO* will continue to produce a *demand* forecast at the province-wide level but as the sum of four separate area *demand* forecasts.
    - The type of *demand* forecasts that will be used in the As-Offered Pricing Process P2 is the average non-dispatchable *demand* forecast described in Section 3.13.
- Network model – The network model contains a detailed topology representation of the *IESO-controlled grid* and a simplified representation of power systems in neighbouring jurisdictions.
- For the calculation of prices within the DAM Calculation engine, additional pricing inputs will be required. They include the following:
    - MMCP - The *maximum market clearing price* (*MMCP*) will continue to define the maximum allowable price for *energy*, and the negative of which will continue to be the minimum allowable price for *energy* (negative *MMCP*);
    - MORP - The *maximum operating reserve price* (*MORP*) will continue to define the maximum allowable price for any class of *operating reserve;*

Flow	**Source**	**Target**	**Frequency**
Constraint Violation Curves for Market Pricing	IESO	Process P2	Daily

Description:

- Constraint violation penalty curves will continue to be defined as the penalty functions for the violation of constraints in the *dispatch algorithm*. They establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints.
- The constraint violation penalty curves for pricing will be used by the pricing algorithm to produce LMPs.

Flow	Source	Target	Frequency
Shadow Prices	Process P2	Process P3 Scheduling Processes Data Archive	Daily
Description: • A shadow price reflects the cost savings achieved by relaxing a constraint by a small amount and measuring the marginal response on the objective function. • Shadow Prices will be used to calculate the As-offered Locational Marginal Prices. • Refer to Section 3 Detailed Functional Design, Table 3-16 for details of shadow prices.			

Flow	Source	Target	Frequency
As-Offered LMPs	Process P2	Process P3 Process P7 Scheduling Processes Data Archive	Daily
Description: • LMPs represents the cost to supply an incremental load (for *energy*) or reserve requirement (for *operating reserve*) at a specific location on the transmission grid. • As-offered LMPs will be calculated using the pricing formulas provided in Section 3.10, which specify how constraint shadow prices marginal loss factors and constraint sensitivities are used to determine an LMP and its components. • The as-offered LMPs for *energy* and *operating reserve* are used as inputs into the Process P3: Constraint Area Conditions Test and Process P7: Price Impact Test. • Refer to Section 3, Table 3-17 for details of LMPs.			

6.1.5. Process P3 – Constrained Area Conditions Test

Description

When an area is constrained from being supplied by additional resources, competition is reduced and this creates the potential for the exercise of market power. The constrained area conditions test will check if resources meet the predefined conditions for a constrained area and use the results of the As-Offered Pricing Process P2 to determine if Process P4: Conduct Test needs to be initiated.

Each of the following conditions will be tested for separately:

- Local Market Power (*Energy*), including:
  - Narrow Constrained Area (NCA)

  - o Dynamic Constrained Area (DCA)
  - o Broad Constrained Area (BCA)
- Global Market Power (*Energy*)
- Global Market Power (*Operating Reserve*)
- Local Market Power (*Operating Reserve*)

Refer to the Market Power Mitigation detailed design document for more information on NCAs, DCAs and BCAs.

Input and Output Data Flows

Table 6-3: Process P3 Input and Output Data Flows

Flow	Source	Target	Frequency
Shadow Prices	Process P2	Process P3	Daily
Description: • See description in Process P2			
Flow	**Source**	**Target**	**Frequency**
As-Offered LMPs	Process P2	Process P3	Daily
Description: • See description in Process P2.			
Flow	**Source**	**Target**	**Frequency**
Constrained Area Designations	MPM Information System	Process P3	Daily
Description: • Depending on how frequently the transmission constraints bind in an area, that area will be classified as either NCA, DCA or BCA. o NCAs are areas where congestion is expected to be relatively frequent over a long duration. The *IESO* will assess NCA designations on an annual basis. o DCAs will be designated when congestion is expected to be relatively frequent but not for a long enough duration to warrant the designation of an NCA. An example of such a condition might be a transmission *outage* that results in, or is expected to result in, increased congestion leading into a load pocket for a period of days. In such cases, these load pockets will be designated as a DCA for the duration of these conditions.			

- o BCA are areas where transmission constraints that are not NCA or DCA constraints, result in supply resources being dispatched up. Transmission constraints that create load pockets that bind relatively infrequently make up the BCA.

- A list of OSLs within a load pocket designated as NCAs and DCAs, along with the associated resources will be used for the Constrained Area Condition Test Process P3.

Flow	Source	Target	Frequency
Constrained Resources Subject to Conduct test	Process P3	Process P4 Process P14	Daily

Description:

- This is a list of all resources that met the criteria for each constrained area conditions test. A different set of resources will be identified for each market power condition. This list of resources will be required as inputs to the market power mitigation conduct test (Process P3), generate data for pre-*settlement* enhancement of mitigated *dispatch data* (Process P14), and Resource Constrained Area Mitigation Test Conditions required for Settlement Mitigation of make-whole payments

Flow	Source	Target	Frequency
Resource Constrained Area Mitigation Test Conditions	Process P3	Market Settlements Process P14	Daily

Description:

- Constrained area mitigation condition for each resource at delivery point 'm' prevailing during each *settlement hour* 'h' of the next *dispatch day*.
- The relevant impact threshold used in make-whole payment impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the conduct test.
- See Table 3 3: Mitigation Conditions for Make-Whole Payment Impact Testing from the Market Power Mitigation detailed design document.

6.1.6. Process P4 – Conduct Test

Description

This is a conditional test that will take place only if certain conditions related to the restriction of competition are met. The conduct test will determine if financial *dispatch data* parameter values for a resource differ from the *IESO*-determined registered reference levels by more than the relevant conduct threshold. If one or more financial *dispatch data* parameter values for any resource fails the conduct test, then Process P5: Reference Level Scheduling and Process P6: Reference Level Pricing will occur to facilitate the Process P7: Price Impact Test. If no financial *dispatch data* parameter values fail the conduct test, then no further steps in the ex-ante Market Power Mitigation process are necessary.

Input and Output Data Flows

Table 6-4: Process P4 Input and Output Data Flows

<table>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Constrained Resources Subject to Conduct test</td><td>Process P3</td><td>Process P4</td><td>Event-based</td></tr>
<tr><td colspan="4">Description:
• See description in Process P3.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Reference Levels</td><td>Market Power Mitigation Information System</td><td>Process P4</td><td>Event-based</td></tr>
<tr><td colspan="4">Description:
• Reference levels are IESO-determined estimates of the offer parameters that a resource would have submitted if it were operating under competitive conditions. Market participants will be able to view their applicable reference levels on a confidential basis.
• The IESO will determine reference levels for financial dispatch data parameters that describe characteristics expressed in monetary terms. The financial dispatch data parameters are energy offers, operating reserve offers, speed-no-load offers and start-up offers. Reference levels for financial dispatch data parameters will be established in consultation with market participants using a cost-based methodology;</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Conduct Thresholds</td><td>Market Power Mitigation Information System</td><td>Process P4</td><td>Event-based</td></tr>
</table>

Description:

- Conduct thresholds are allowable tolerances above the established reference levels.
- The conduct threshold determines how much a *dispatch data* parameter can deviate from its reference level without failing the conduct test.
- A set of conduct thresholds will be determined for each constrained area designation and used as input for the conduct test.

Flow	Source	Target	Frequency
As-Offered Dispatch Data	Market Participant	Process P4	Daily

Description:

- The same as-offered *dispatch data* used by Process P1 is used by this process. See description in Process P1 for more information.

Flow	Source	Target	Frequency
Mitigated for Conduct Dispatch Data	Process P4	Process P5 Process P6 Market Settlement	Event-based

Description:

- Mitigated for conduct *dispatch data* is the *dispatch data* for *energy* and *operating reserve* produced when any *dispatch data* value that failed the conduct test is replaced by the reference level value for that *dispatch data* parameter. Mitigated for conduct *dispatch data* will include:
    - Financial *dispatch data* parameters for resources that failed the conduct test and were mitigated to their reference level values. See the list of financial *dispatch data* parameters within the Market Participant Data Input in Process P1;
    - Financial *dispatch data* parameters for resources that passed the conduct test and were not mitigated; and
    - Non-financial *dispatch data.* See the list of non-financial *dispatch data* parameters within the Market Participant Data Input in Process P1
- This data will be used in calculating the Reference Level schedules, commitments and LMPs through Process P5 and Process P6.
- This data will also be passed to *settlement* to be used when there is no failure of the price impact test to support make-whole payment impact testing in the Settlement Mitigation of Make-Whole Payments process performed as part of the Market Settlement process.

Flow	Source	Target	Frequency
Resources that Failed Conduct Test	Process P4	Process P7 Market Settlement	Event-based
Description: • This is a set of resources that failed the conduct test for at least one parameter by condition type. This list of resources will be required as inputs to perform Process P7: Price Impact Test. • This list of resources associated with mitigated for conduct *dispatch data* will also be passed to *settlement* to be used make-whole payment impact testing in the Settlement Mitigation of Make-Whole Payments process performed as part of the Market Settlement process.			

6.1.7. Process P5 – Reference Level Scheduling

Description

This process is identical to the Process P1: As-Offered Scheduling except that it will use mitigated financial *dispatch data* for resources that failed the conduct test.

The commitments will serve as inputs into Reference Level Pricing. The schedules produced will not be financially binding.

Input and Output Data Flows

Table 6-5: Process P5 Input and Output Data Flows

Flow	Source	Target	Frequency
Mitigated for Conduct Dispatch Data	Process P4	Process P5	Event-based
Description: • See description in Process P4.			
Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Reliability	IESO	Process P5	Daily
Description: • See description in Process P1.			

Flow	Source	Target	Frequency
Constraint Violation Curves for Reliability	IESO	Process P5	Daily

Description:

- See description in Process P1

Flow	Source	Target	Frequency
Reference Level Resource Schedules	Process P5	Process P6 Scheduling Processes Data Archive	Daily

Description:

- The reference level resource schedules for *energy* and *operating reserve* are the set of resource schedules generated during Process P5: Reference Level Scheduling. To produce the reference level resource schedules, any as-offered financial *dispatch data* value that failed the conduct test will be replaced by the reference level value for that financial *dispatch data* parameter. See the list of financial *dispatch data* parameters within the Market Participant Data Input in Process P1.
- These schedules will include the import and export schedules, which are the scheduled transactions between the *IESO-controlled grid* (ICG) and each *intertie* zone.

Flow	Source	Target	Frequency
Reference Level Resource Commitments	Process P5	Process P6 Scheduling Processes Data Archive	Daily

Description:

- The reference level resource commitments are the set of commitments for eligible NQS resources generated from P5.

6.1.8. Process P6 – Reference Level Pricing

Description

This process will produce LMPs similar to As-Offered Pricing. Reference Level Pricing differs from As-Offered Pricing in that it will use reference level *dispatch data* for any inputs from *registered market participants* that failed the conduct test. Reference Level Pricing also differs from As-Offered Pricing in that the principle for price-setting eligibility will be applied by taking into account the Reference Level Scheduling results.

Reference Level Pricing will determine a set of LMPs, which will be used in the Process P7: Price Impact Test. The prices produced will not be financially binding.

Input and Output Data Flows

Table 6-6: Process P6 Input and Output Data Flows

Flow	Source	Target	Frequency
Reference Level Resource Schedules	Process P5	Process P6	Daily
Description: • See description in Process P5 above.			
Flow	**Source**	**Target**	**Frequency**
Reference Level Resource Commitments	Process P5	Process P6	Daily
Description: • See description in Process P5 above.			
Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Pricing	IESO	Process P6	Daily
Description: • See description in Process P2 above.			
Flow	**Source**	**Target**	**Frequency**
Constraint Violation Curves for Market Pricing	IESO	Process P6	Daily

Description:			
• See description in Process P2			
Flow	**Source**	**Target**	**Frequency**
Mitigated for Conduct Dispatch Data	Process P4	Process P6	Event-based
Description: • See description in Process P4 above			
Flow	**Source**	**Target**	**Frequency**
Shadow Prices	Process P6	Scheduling Processes Data Archive	Daily
Description: • See description in Process P2 • Shadow prices will be used to calculate the Reference Level LMPs and they will not be used as a direct input into the Price Impact Test.			
Flow	**Source**	**Target**	**Frequency**
Reference Level LMPs	Process P6	Process P7 Scheduling Processes Data Archive	Daily
Description: • See the definition of LMPs in Process P2. • Reference Level LMPs will be calculated using the results of Process P6 and the pricing formulas provided in Section 3.10, which specify how constraint shadow prices are used to determine an LMP and its components. • The Reference Level LMPs for *energy* and *operating reserve* are used as inputs into the Price Impact Test.			

6.1.9. Process P7 – Price Impact Test

Description

The Price Impact Test compares the LMPs from As-Offered Pricing to the LMPs from Reference Level Pricing for each resource that failed the Conduct Test. The Price Impact Test is failed if one or more LMPs in As-Offered Pricing is greater than the corresponding LMP from Reference Level Pricing by a specified impact threshold. If the impact test is failed, then Mitigated Scheduling and Mitigated Pricing will occur.

If the Price Impact Test does not fail, then no further steps in the Market Power Mitigation process are necessary and the commitments and prices produced by As-Offered Scheduling and As-Offered Pricing are used as the inputs to Process P10: Reliability Scheduling and Commitment.

Input and Output Data Flows

Table 6-7: Process P7 Input and Output Data Flows

<table>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>As-Offered LMPs</td><td>Process P2</td><td>Process P7</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See description in Process P2 above.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Resources that Failed Conduct Test</td><td>Process P4</td><td>Process P7</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See description in Process P4 above.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Reference Level LMPs</td><td>Process P6</td><td>Process P7</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See the definition of LMPs in Process P2.
• Reference Level LMPs will be calculated using the mitigated for conduct dispatch data and the pricing formulas provided in Section 3.10, which specify how constraint shadow prices are used to determine an LMP and its components.
• The Reference Level LMPs for energy and operating reserve are used as inputs into the Price Impact Test.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Price Impact Thresholds</td><td>Market Power Mitigation Information System</td><td>Process P7</td><td>Daily</td></tr>
</table>

Description:

- The price impact threshold is the allowance that is used to determine whether prices in the as-offered results are significantly higher than prices in the reference level results.
- A set of price impact thresholds for each constrained area designation will be used as input for the Price Impact Test.

Flow	Source	Target	Frequency
Mitigated for Price Impact Dispatch Data	Process P7	Process P8 Process P9 Market Settlement	Daily

Description:

- Mitigated for price impact *dispatch data* is the *energy* and *operating reserve dispatch data* produced when the Price Impact Test fails and each *dispatch data* parameter value that also failed the Conduct Test is substituted with the applicable reference level value for that *dispatch data* parameter.
- Mitigated for price impact *dispatch data* will include;
    - o Financial *dispatch data* values that failed the Price Impact Test and the Conduct Test and were mitigated to their reference levels. See the list of financial *dispatch data* parameters within the Market Participant Data Input in Process P1;
    - o Financial *dispatch data* values that passed the price impact test and were not altered (i.e., as-submitted); and
    - o Non-financial *dispatch data*. See the list of non-financial *dispatch data* parameters within the Market Participant Data Input in Process P1.
- This data will also be used in the *settlement* process for the calculation of *energy*, *operating reserve*, make-whole payments, and other guarantee payment *settlement* amounts.
- Note that the mitigated for price impact *dispatch data* is the same as the Reference Level *dispatch data*.

6.1.10. Process P8 – Mitigated Scheduling

Description

This process will produce *security*-constrained resource schedules similar to As-Offered Scheduling. Mitigated Scheduling only differs from As-Offered Scheduling in that it will use reference level *dispatch data* for any inputs from *registered market participants* identified as having failed the Conduct test and the Price Impact Test.

If Mitigated Scheduling is performed, it will determine commitment statuses and schedules. These will comprise the scheduling and commitment results of Pass 1.

These commitments will also serve as inputs into Mitigated Pricing. The schedules produced will not be financially binding.

Input and Output Data Flows

Table 6-8: Process P8 Input and Output Data Flows

Flow	Source	Target	Frequency
Mitigated for Price Impact Dispatch Data	Process P7	Process P8	Daily
Description: • See description in Process P7 above,			
Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Reliability	IESO	Process P8	Daily
Description: • See description in Process P1 above,			
Flow	**Source**	**Target**	**Frequency**
Constraint Violation Curves for Reliability	IESO	Process P8	Daily
Description: • See description in Process P1			
Flow	**Source**	**Target**	**Frequency**
Mitigated Resource Schedules	Process P8	Process P9 Scheduling Processes Data Archive	Daily
Description: • The mitigated resource schedules for *energy* and *operating reserve* are the set of schedules for all *market participants* generated using the mitigated for price impact *dispatch data*. These are the outputs of Mitigated Scheduling in Pass 1 of the DAM calculation engine. • These schedules will include the import and export schedules which are the scheduled transactions between the *IESO-controlled grid* (ICG) and each *intertie zone*.			

Flow	Source	Target	Frequency
Mitigated Resource Commitments	Process P8	Process P9 Scheduling Processes Data Archive	Daily
Description: • The mitigated resource commitments are the set of commitments for eligible NQS resources generated based on mitigated for price impact *dispatch data*. These are outputs of Reference Level Scheduling in Pass 1 of the DAM calculation engine. • These will only be used by the *settlement* process if the commitments produced during Mitigated Scheduling are the terminal commitments.			

6.1.11. Process P9 – Mitigated Pricing

Description

This process will produce a set of shadow prices and LMPs similar to As-Offered Pricing. Mitigated Pricing differs from As-Offered Pricing in that it will use reference level *dispatch data* for any inputs from *registered market participants* identified by the Market Power Mitigation process to have failed the Conduct test and the Price Impact Test. Mitigated Pricing also differs from As-Offered Pricing in that the principle for price-setting eligibility will be applied by taking into account the Mitigated Scheduling results.

Mitigated Pricing will determine a set of LMPs. If Mitigated Pricing is performed, the LMPs will comprise the results of Pass 1. The prices produced will not be financially binding.

Input and Output Data Flows

Table 6-9: Process P9 Input and Output Data Flows

Flow	Source	Target	Frequency
Mitigated Resource Schedules	Process P8	Process P9	Daily
Description: • See description in Process P8 above.			
Flow	**Source**	**Target**	**Frequency**
Mitigated Resource Commitments	Process P8	Process P9	Daily

<table>
<tr><td colspan="4">Description:
• See description in Process P8 above.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Mitigated for Price Impact Dispatch Data</td><td>Process P7</td><td>Process P9</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See description in Process P7 above.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>IESO Data Inputs for Pricing</td><td>IESO</td><td>Process P10</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See description in Process P2 above.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Constraint Violation Curves for Market Pricing</td><td>Market Participant</td><td>Process P10</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See description in Process P2.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Shadow Prices</td><td>Process P9</td><td>Market Settlement
Scheduling Processes Data Archive</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
• See description in Process P2 above.
• Shadow prices will be used to calculate the mitigated LMPs.</td></tr>
</table>

Flow	Source	Target	Frequency
Mitigated LMPs	Process P9	Scheduling Processes Data Archive	Daily

Description:

- See the definition of LMPs in Process P2.
- Mitigated LMPs will be calculated using the results of Process P9 and the pricing formulas provided in Section 3.10, which specify how constraint shadow prices are used to determine an LMP and its components.

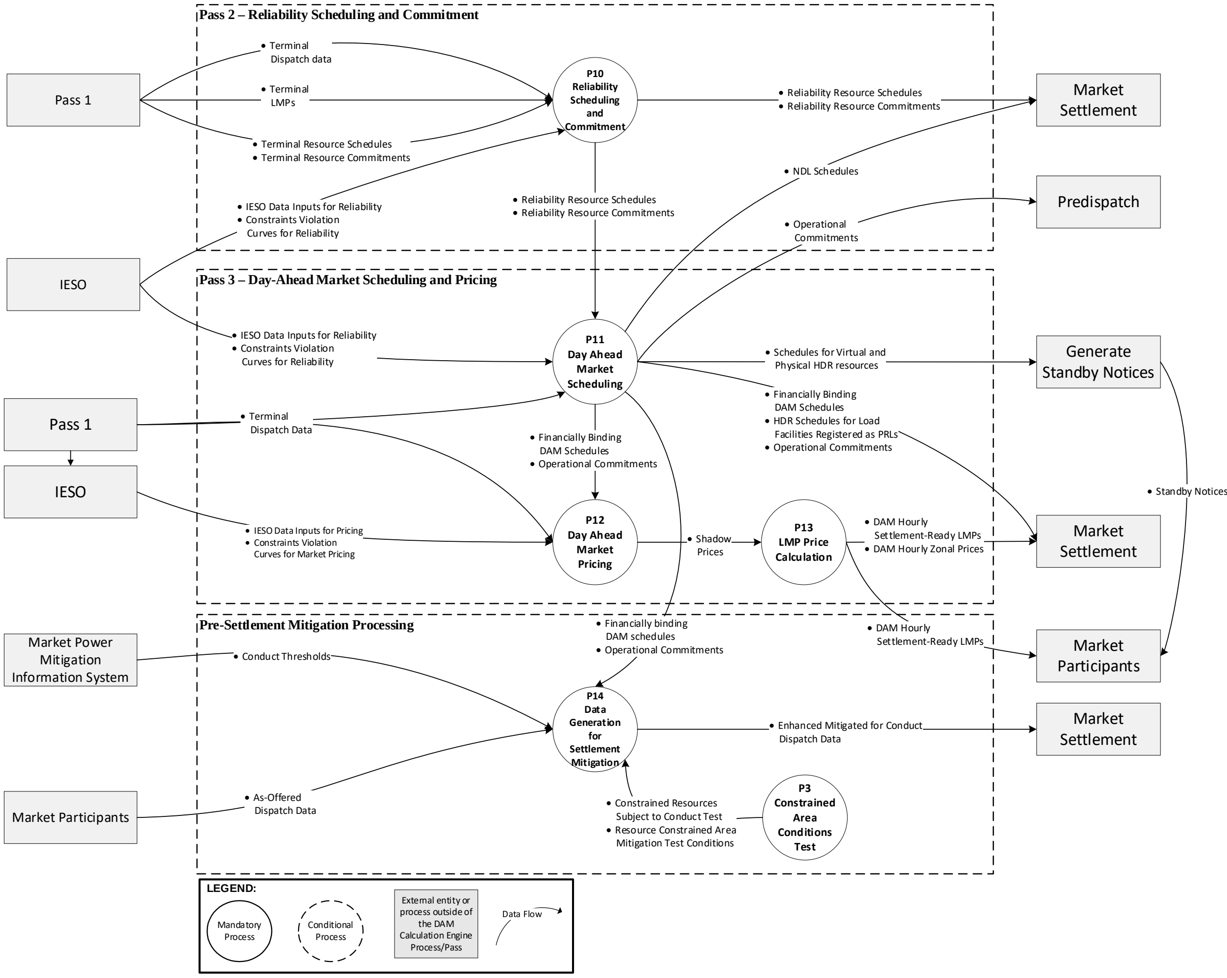

Figure 6-3: Day Ahead Market Calculation Engine Pass 2 and Pass 3 Market Facing Process

6.1.12. Process P10 – Reliability Scheduling and Commitment

Description

This process will produce *security*-constrained resource schedules similar to As-Offered Scheduling. However, Reliability Scheduling differs from As-Offered Scheduling in that its intent is to assess the available supply. To achieve this intent, Pass 2 will assess and consider certain supply and *demand* inputs differently from Pass 1.

Peak *demand* forecasts will be used in place of average *demand* forecasts in this process.

Input and Output Data Flows

Table 6-10: Process P10 Input and Output Data Flows

Flow	Source	Target	Frequency
Terminal Dispatch Data	Pass 1	Process P10	Daily

Description:

- These are the prevailing DAM *dispatch data* used at the termination of Pass 1:
  - If systems conditions are such that the conditions for the potential exercise of market power do not exist, the as-offered *dispatch data* are the terminal *dispatch data* of Pass 1 and these will be used as inputs to Pass 2.
  - Similarly, if Process P4: Conduct Test for exercise of market power fails and Process P7: Price Impact Test for exercise of market power passes, then As-Offered Scheduling and As-Offered Pricing will still remain as the terminal processes for Pass 1 and the as-offered *dispatch data* will be the terminal *dispatch data* of Pass 1, which will be used as inputs to Pass 2.
  - If the P4: Conduct Test for exercise of market power fails and P7: Price Impact Test for exercise of market power fails, then Mitigated Scheduling and Mitigated Pricing will be the terminal processes for Pass 1, and the mitigated for price impact *dispatch data* will be used as inputs to Pass 2.
- One important difference between the *dispatch data* used in Pass 1 and those used in this process is that PRL *bids*, virtual *bids* and virtual *offers* and *variable generation* forecast quantity are excluded from the *dispatch data* used in this process.

Flow	Source	Target	Frequency
Terminal LMPs	Pass 1	Process P10	Daily

Description:

- These are the prevailing LMPs produced at the termination of Pass 1:
  - If system conditions are such that the conditions for the potential exercise of market power do not exist, the as-offered LMPs are the terminal LMPs of Pass 1 and these will be used as inputs to Pass 2.
  - Similarly, if Process P4: Conduct Test for the exercise of market power fails and Process P7: Price Impact Test for the exercise of market power passes, then As-Offered Scheduling and As-Offered Pricing will still remain the terminal processes for Pass 1 and the as-offered LMPs will be the terminal LMPs of Pass 1, which will be used as inputs to Pass 2.

- o If the Process P4: Conduct Test fails and Process P7: Price Impact Test fails, then Mitigated Scheduling and Mitigated Pricing will be the terminal processes for Pass 1, and the mitigated LMPs will be used as inputs to Pass 2.

Flow	Source	Target	Frequency
Terminal Resource Schedules	Pass 1	Process P10	Daily

Description:

- These are the prevailing resource schedules (including the import and export schedules) produced at the termination of Pass 1:
  - o If system conditions are such that the conditions for the potential exercise of market power do not exist, the as-offered resource schedules are the terminal resource schedules of Pass 1 and these will be used as inputs to Pass 2.
  - o Similarly, if Process P4: Conduct Test for the exercise of market power fails and Process P7: Price Impact Test for the exercise of market power passes, then the As-offered Scheduling and Pricing processes will still remain the terminal processes for Pass 1 and the as-offered resource schedules will be the terminal resource schedules of Pass 1, which will be used as inputs to Pass 2
  - o If Process P4: Conduct Test fails and Process P7: Price Impact Test fails, then Mitigated Scheduling and Mitigated Pricing will be the terminal processes for Pass 1, and the mitigated resource schedules will be used as inputs to Pass 2.

Flow	Source	Target	Frequency
Terminal Resource Commitments	Pass 1	Process P10	Daily

Description:

- These are the prevailing resource commitments produced at the termination of Pass 1:
  - o If system conditions are such that the conditions for the potential exercise of market power do not exist, the as-offered resource commitments will be the terminal resource commitments of Pass 1 and these will be used as inputs to Pass 2.
  - o Similarly, if Process P4: Conduct Test for the exercise of market power fails and Process P7: Price Impact Test for the exercise of market power passes, then As-Offered Scheduling and As-Offered Pricing will still remain the terminal processes for Pass 1 and the as-offered resource commitments will be the terminal resource commitments of Pass 1, which will be used as inputs to Pass 2

- If Process P4: Conduct Test fails and Process P7: Price Impact Test fails, then the Mitigated Scheduling and Mitigated Pricing are the terminal processes for Pass 1, and the mitigated resource commitments will be used as inputs to Pass 2.

Flow	Source	Target	Frequency
IESO Data Inputs	IESO	Process P10	Daily

Description:

- The *IESO* data inputs used here are the same as the ones used in Process P1 above with two exceptions:
  - The four area *demand* forecasts used in this process are peak non-dispatchable *demand* forecasts including the *demand* for:
    - all *non-dispatchable loads*;
    - all price-responsive loads; and
    - all *dispatchable loads* for which no *bid* was submitted.
  - The *IESO's* centralized *variable generation* forecast for *variable generation* resources are used

Flow	Source	Target	Frequency
Constraint Violation Curves for Reliability	IESO	Process P10	Daily

Description:

- See description in Process P1.

Flow	Source	Target	Frequency
Reliability Resource Schedules	Process P10	Process P11 Market Settlements	Daily

Description:

- The *reliability* resource schedules for *energy* and *operating reserve* are the set of schedules for all *market participant* resources (excluding PRLs and virtual *energy* traders) generated using the terminal *dispatch data* and the peak area *demand* forecasts.

Flow	Source	Target	Frequency
Reliability Resource Commitments	Process P10	Process P11 Market Settlements	Daily

Description: • The *reliability* resource commitments for *energy* and *operating reserve* are the set of commitments for eligible NQS resources generated based on the terminal *dispatch data* and the peak *demand* forecast. These are outputs from the Reliability Scheduling and Commitment Pass 2 of the DAM calculation engine.

6.1.13. Process P11 – Day Ahead Market Scheduling

Description

This process will determine the financially binding DAM *energy* and *operating reserve* schedules for all supply and load resources. These schedules will include the commitments for NQS *generation facilities* determined in Pass 1 and Pass 2. DAM scheduling will also evaluate the *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports.

The schedules produced by DAM scheduling will comprise the constrained schedules that are used in the calculation of financially binding DAM *settlements* and of DAM make-whole payments.

DAM Scheduling will also produce *energy* schedules for all *delivery points* for *non-dispatchable loads*.

Input and Output Data Flows

Table 6-11: Process P11 Input and Output Data Flows

Flow	Source	Target	Frequency
IESO Data Inputs for Reliability	IESO	Process P11	Daily
Description: • See description in Process P1 above.			
Flow	**Source**	**Target**	**Frequency**
Constraint Violation Curves for Reliability	IESO	Process P11	Daily
Description: • See description in Process P1			

Flow	Source	Target	Frequency
Terminal Dispatch data	Pass 1	Process P11	Daily

Description:

- These are the prevailing DAM *dispatch data* used at the termination of Pass 1:
    - If system conditions are such that the conditions for the potential exercise of market power do not exist, the as-offered *dispatch data* are the terminal *dispatch data* of Pass 1 and these will be used as inputs to Pass 2.
    - Similarly, if Process P4: Conduct Test fails for the exercise of market power and Process P7: Price Impact Test passes for the exercise of market power, then As-Offered Scheduling and As-Offered Pricing will still remain the terminal processes for Pass 1 and the as-offered *dispatch data* will be the terminal *dispatch data* of Pass 1, which will be used as inputs to Pass 2.
    - If the Process P4: Conduct Test fails and Process P7: Price Impact Test fails, then Mitigated Scheduling and Mitigated Pricing are the terminal processes for Pass 1, and the mitigated for price impact *dispatch data* will be used as inputs to Pass 2.

Flow	Source	Target	Frequency
Reliability Resource Schedules	Process P10	Process P11	Daily

Description:

- See description in Process P10 above.

Flow	Source	Target	Frequency
Reliability Resource Commitments	Process P10	Process P11	Daily

Description:

- See description in Process P10 above.

Flow	Source	Target	Frequency
Financially binding DAM schedules	Process P11	Process P12 Process P14 Market Settlement Market Participants	Daily

Description:

- These are a set of financially binding schedules for *energy* and *operating reserve* required to meet the *IESO's* average hourly forecast *demand* as well as *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports.
- These schedules will be calculated using the same set of *market participant* and *IESO* inputs used in Pass 1. Additionally, it will use the NQS commitment decisions and import and export schedules determined in Pass 1 and Pass 2 to produce a set of financially binding schedules.
- These schedules will include the import and export schedules that are the scheduled transactions between the *IESO-controlled grid* (*ICG*) and each *intertie zone*.
- These financially binding schedules will be made available to dispatchable generation resources, non-dispatchable generation resources, *dispatchable loads*, price responsive loads, imports, exports and virtual *energy* traders.
- These schedules are used by pre-dispatch, market *settlement* and *market participants.*
- Refer to Section 3, Table 3-31 for details of the financially binding DAM schedules

Flow	Source	Target	Frequency
Operational Commitments	Process P11	Process P12 Process P14 Pre-Dispatch Market Settlement Market Participants	Daily

Description:

- The operational commitments are the set of commitments for eligible NQS resources generated based on the results of Process P11.

Flow	Source	Target	Frequency
NDL Schedules	Process P11	Market Settlement	Daily

Description:

- These are DAM schedules for withdrawal of *energy* at the *delivery points* for all *non-dispatchable loads*. These schedules will be provided to the *settlement process* for the purpose of calculating the Load Forecast Deviation Charge (LFDC)of the hourly DAM Ontario Zonal Price used for the *settlement* of the adjusted quantity of *energy* withdrawn (AQEW) by *non-dispatchable* loads in real-time.
- Refer to Section 3.8.3 for details of the NDL schedules.

Flow	Source	Target	Frequency
Schedules for Virtual and Physical HDR Resources	Process P11	Generate Standby Notices	Daily

Description:

- *Hourly demand response* (HDR) schedules represents the quantity of MWs scheduled for:
  - virtual *hourly demand response* resources aggregated within various zones in the *distribution system* and
  - physical *hourly demand response* (HDR) resources for which a *registered wholesale meter* and *delivery point* has been defined. These will include:
    - physical *non-dispatchable load* HDR resources; and
    - physical price responsive load HDR resources.
- These *hourly demand response* (HDR) resource schedules will be used to generate Standby Notices in the day-ahead when required.

Flow	Source	Target	Frequency
HDR Schedules for Load Facilities Registered as PRLs	Process P11	Market Settlements	Daily

Description:

- HDR resource schedules for *load facilities* registered as price responsive loads will be used for the *settlement* of *energy.*

Flow	Source	Target	Frequency
Standby Notices	Generate Standby Notices	Market Participants	Daily

Description:

- All physical and virtual *hourly demand response* (HDR) resources receive a Standby Report that may include a standby notice for one or more hours of the availability window on the *dispatch day*.
- Standby notices for physical and virtual HDR resources are based on their respective HDR schedules produced by the P11 process.
- An HDR resource receiving a Standby Report that includes a standby notice is required to be available to reduce its *energy* withdrawal during the *dispatch day* availability window.

6.1.14. Process P12 – Day Ahead Market Pricing

Description

The DAM Pricing will calculate shadow prices for all constraints contributing to locational prices. These shadow prices will be used in calculating the *settlement*-ready LMPs that account for all resource and system constraints.

DAM Pricing uses the same set of *market participant* and *IESO* inputs used in As-Offered Pricing, or, if applicable the reference level *dispatch data* used in Mitigated Pricing. This includes using the constraint violation penalty curves that are relevant for pricing. DAM pricing will also evaluate *demand* from virtual *bids*, *dispatchable loads*, price responsive loads, *hourly demand response* resources and exports.

Input and Output Data Flows

Table 6-12: Process P12 Input and Output Data Flows

Flow	Source	Target	Frequency
Terminal Dispatch Data	Pass 1	Process P11	Daily
Description: • See description in Process P11 above.			
Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Pricing	IESO	Process P11	Daily
Description: • See description in Process P2 above.			
Flow	**Source**	**Target**	**Frequency**
Constraint Violation Curves for Market Pricing	IESO	Process P11	Daily
Description: • See description in Process P2			
Flow	**Source**	**Target**	**Frequency**
Financially Binding DAM Schedules	Process P11	Process P12	Daily

Description: • See description in Process P11 above.			
Flow	**Source**	**Target**	**Frequency**
Operational Commitments	Process P11	Process P12	Daily
Description: • See description in Process P11 above.			
Flow	**Source**	**Target**	**Frequency**
Shadow Prices	Process P12	Process P13	Daily
Description: • See description in Process P2 above. • Shadow prices will be used to calculate the DAM hourly *settlement*-ready LMPs and DAM hourly zonal prices. • Refer to Section 3.8.2.7, Table 3-30 for details of shadow prices			

6.1.15. Process P13 – LMP Price Calculation

Description

This process will calculate *settlement*-ready prices for all pricing nodes using shadow prices and marginal loss factors produced by the Day-Ahead Market Pricing algorithm.

Input and Output Data Flows

Table 6-13: Process P13 Input and Output Data Flows

Flow	**Source**	**Target**	**Frequency**
Shadow Prices	Process P12	Process P13	Daily
Description: • See description in Process P2. • Shadow prices will be used to calculate the DAM hourly *settlement*-ready LMPs and DAM hourly zonal prices. • Refer to Section 3.8.2.7, Table 3-30 for details of shadow prices.			
Flow	**Source**	**Target**	**Frequency**

DAM Hourly Settlement-Ready LMPs	Process P13	Market Participants Market Settlement	Daily
Description: • See the definition of LMPs in Process P2. • DAM *settlement*-ready LMPs will be calculated using the pricing formulas provided in Section 3.10, which specify how constraint shadow prices are used to determine an LMP and its components. • The DAM *settlement*-ready LMPs will be calculated using the terminal *dispatch data*. • Refer to Section 3.8.3, Table 3-33 for details of DAM Hourly Settlement-ready LMPs**.**			
Flow	**Source**	**Target**	**Frequency**
DAM Hourly Zonal Prices	Process P13	Market Settlement	Daily
Description: • Pass 3 of the Day-Ahead Market calculation engine will also produce several *settlement*-ready zonal prices that are aggregated based on the weighted average of *settlement*-ready LMPs at multiple load locations within the province. The following zonal prices will be produced and used for *settlement*: o The hourly DAM Ontario Zonal Price is a single province wide price used to settle *non-dispatchable* loads; and o Nine virtual trading zone prices used to settle virtual transactions. • Refer to Section 3.8.3, Table 3-33 for details of DAM hourly zonal prices.			

6.1.16. Process P14 – Data Generation for Settlement Mitigation

Description

This process will test the relevant resources for make-whole payment impact. If conditions are met for more than one constrained area for the same resource in the same interval, hour or commitment period, then the mitigation of make-whole payments will be tested using the most restrictive set of conduct thresholds.

Input and Output Data Flows

Table 6-14: Process P14 Input and Output Data Flows

Flow	Source	Target	Frequency

Conduct Thresholds	Market Power Mitigation Information System	Process P14	Daily
Description: • See description in Process P4.			
Flow	**Source**	**Target**	**Frequency**
As-Offered Dispatch Data	Market Participants	Process P14	Daily
Description: • See description in Process P1. • This data will be used for resources that were not mitigated in Pass 1 of the DAM calculation engine but are required for make-whole payment mitigation.			
Flow	**Source**	**Target**	**Frequency**
Financially Binding DAM Schedules	Process P11	Process P14	Daily
Description: • See description in Process P11.			
Flow	**Source**	**Target**	**Frequency**
Operational Commitments	Process P11	Process P14	Daily
Description: • See description in Process P11.			
Flow	**Source**	**Target**	**Frequency**
Constrained Resources Subject to Conduct test	Process P3	Process P14	Daily
Description: • This is a list of all resources that met the Constrained Area Conditions Test criteria. A different set of resources will be identified for each market power condition as the Conduct Test depends on the condition triggered.			

Flow	**Source**	**Target**	**Frequency**
Resource Constrained Area Mitigation Test Conditions	Process P3	Market Settlements Process P14	Daily

Description:

- This is the constrained area mitigation condition for each resource at *delivery point* 'm' prevailing during each *settlement hour* 'h' of the next *dispatch day*.
- The relevant impact threshold used in make-whole payment impact testing for *market participant* 'k' will be applied depending on the constrained area condition under which the resource failed the Conduct Test.
- See Table 3-3: Mitigation Conditions for Make-Whole Payment Impact Testing from the Market Power Mitigation detailed design document.

Flow	**Source**	**Target**	**Frequency**
Enhanced Mitigated for Conduct Dispatch Data	Process P14	Market Settlement	Daily

Description:

- The enhanced mitigated for conduct *dispatch data* is the additional *dispatch data* set that must be generated for use in the *settlement* mitigation of make-whole payments process.
- This data set is produced for NQS and dual-fuel resources with financially binding schedules using the most restrictive constraint conditions over the *settlement* period.

6.2. Internal Process Impacts

The internal processes currently used for the Day-Ahead Market calculation engine processes will continue to have relevance in the future day-ahead market and *real-time market*.

Internal *IESO* processes related to the Day-Ahead Market calculation engine processes include:

- Commit Resources

The above internal processes interact with various *IESO* processes as illustrated in Section 6.1. Some changes to the DAM calculation engine processes under the market renewal program will impact other internal *IESO* processes. This impact will be contingent upon the tools of the future day-ahead market and *real-time market* which will be developed during the next phases of the project.

Changes or additions to internal *IESO* processes are for internal *IESO* use as documented in Appendix C, and are not included in the public version of this document. Appendix C details the impacts to internal processes in terms of existing processes that support the new market requirements, existing activities that need to be updated, and process and information models that may need to be updated to support the future market.

– End of Section –

Appendix A: Market Participant Interfaces

There are no interfaces between *market participants* and the DAM calculation engine. However, *market participant* interfaces with *IESO* DAM processes are covered in the Offers, Bids and Data Inputs as well as the Grid and Market Operations Integration detailed design documents.

– End of Appendix–

Appendix B: Internal-Facing Procedural Requirements *[Internal only]*

This section is confidential to the *IESO*.

– End of Appendix–

Appendix C: Business Process and Information Requirements *[Internal only]*

This section is confidential to the *IESO*.

– End of Appendix–

Appendix D: Mathematical Notation and Conventions

Let A and B be sets. Let n be a positive integer. The following mathematical notation will be adopted.

Table D-1: Mathematical Notation and Conventions

Notation	Description	Sample Usage
$a \in A$	Denotes that item a is an element of set A.	If B is the set of all buses, then "$b \in B$" denotes that b identifies a specific bus.
$\{1,..,n\}$	Denotes the set of all positive integers between 1 and n, inclusive.	"For hour $h \in \{1,..,24\}$" denotes that h identifies one of the hours 1, 2, .., 24 of the day.
$A \subseteq B$	Denotes that set A is a subset of set B. That is, if $a \in A$, then $a \in B$.	If B is the set of all buses and B^{DL} is the set of *dispatchable load* buses, then "$B^{DL} \subseteq B$" indicates that all *dispatchable load* buses are also elements of the set of buses.
$A \cap B$	Denotes the intersection of sets A and B. That is, if $c \in A$ and $c \in B$, then $c \in A \cap B$.	If B_r^{REG} is the set of buses in *operating reserve* region r and B^{DG} is the set of dispatchable generation buses, then "$B_r^{REG} \cap B^{DG}$" denotes the set of buses in *operating reserve* region r that are also dispatchable generation buses.
$A \cup B$	Denotes the union of sets A and B. That is, if $c \in A$ or $c \in B$, then $c \in A \cup B$.	If B^{DL} is the set of *dispatchable load* buses and B^{HDR} is the set of *hourly demand response* resource buses, then "$B^{DL} \cup B^{HDR}$" denotes the set containing all *dispatchable load* buses and all *hourly demand response* resource buses.
$A \times B$	Denotes the cross product of sets A and B. That is, $A \times B$ is the set of all pairs of elements (a, b) such that $a \in A$ and $b \in B$.	If DX is the set of sink buses and DI is the set of source buses, then $DX \times DI$ is the set of all possible pairs of source and sink buses.

Notation	Description	Sample Usage
$\wp(A)$	Denotes the power set of set A. That is the set of all subsets.	If B^{HE} is the set $\{ x, y, z \}$ that represents the set of buses with hydroelectric resources, then the power set of B^{HE} are $\wp(B^{HE}) = \{\{\}, \{x\}, \{y\}, \{z\}, \{x, y\}, \{x, z\}, \{y, z\}, \{x, y, z\}\}$

Let n be a positive integer. Let a_1, a_2, …, a_n be numbers. Then, standard notation for summation, minimum and maximum will be adopted as follows:

- $\sum_{i=1..n} a_i$ denotes $a_1 + a_2 + \cdots + a_n$;
- $min(a_1, .., a_n)$ denotes the minimum (i.e. the smallest) of the values a_1, a_2, …, a_n; and
- $max(a_1, .., a_n)$ denotes the maximum (i.e. the largest) of the values a_1, a_2, …, a_n.

As far as feasible, the following conventions have been adopted for the purposes of naming parameters, variables and outputs:

- Parameters denoting price quantity pairs will begin with the letters “P” and “Q” respectively while the remainder of the parameter name is identical;
- Variable names used within the optimization function will begin with the letter “O” or the letter “I” when such variables must be assigned integer values and will begin with the letter “S” otherwise;
- Variable and parameters pertaining to a particular resource or transaction type will contain an indication in the name. For example, many parameters and variables for dispatchable generation resources will contain “DG” in the name and many parameters for exports will contain “XL” in the name;
- Subsets of a given set will either be denoted by the same name with a superscript or be prefixed with that name; and
- Outputs from the scheduling or pricing algorithm for a specific process will be denoted by the corresponding variable with a superscript abbreviating the process name.

– End of Appendix–

Appendix E: Conduct and Impact Thresholds and Parameters

E.1. Market Power Mitigation Conduct Thresholds and Corresponding Parameters

Table E-1: Conduct Thresholds and Corresponding Parameters

Parameters	Description	Threshold	Reference to MPM Tables
$BCACondThresh$	Designates the threshold for the congestion component of a resource's LMP, above which the resource will meet the BCA condition.	\$25/MWh	Section 3.6.1.2
$IBPThresh$	Designates the *intertie* border price (IBP) threshold.	\$100/MWh	Section 3.6.1.3
$ORGCondThresh$	Designates the threshold for a resource's *operating reserve* LMP, above which the resource will meet the Global Market Power (*Operating reserve*) condition.	\$15/MW	Section 3.6.2.2
$CTEnThresh1^{NCA}$	Designates the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the NCA conduct test	50%.	Table 3-5
$CTEnThresh2^{NCA}$	Designates the *energy offer* conduct threshold, pertaining to allowable \$/MWh increase above the reference level, to be used for resources that are subject to the NCA conduct test.	\$25/MWh	Table 3-5
$CTSUThresh^{NCA}$	Designates the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the NCA conduct test.	25%	Table 3-5
$CTSNLThresh^{NCA}$	Designates the speed no-load offer conduct threshold, pertaining to allowable percent	25%	Table 3-5

Parameters	Description	Threshold	Reference to MPM Tables
	increase above the reference level, to be used for resources that are subject to the NCA conduct test.		
$CTEnThresh1^{DCA}$	Designates the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the DCA conduct test.	50%	Table 3-5
$CTEnThresh2^{DCA}$	Designates the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the DCA conduct test.	$25/MWh	Table 3-5
$CTSUThresh^{DCA}$	Designates the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the DCA conduct test.	25%	Table 3-5
$CTSNLThresh^{DCA}$	Designates the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the DCA conduct test.	25%	Table 3-5
$CTEnThresh1^{BCA}$	Designates the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the BCA conduct test.	200%	Table 3-7
$CTEnThresh2^{BCA}$	Designates the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the BCA conduct test.	$100/MWh .	Table 3-7

Parameters	Description	Threshold	Reference to MPM Tables
$CTSUThresh^{BCA}$	Designates the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the BCA conduct test.	100%	Table 3-7
$CTSNLThresh^{BCA}$	Designates the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the BCA conduct test.	100%	Table 3-7
$CTEnThresh1^{GMP}$	Designates the *energy offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test.	200%	Table 3-9
$CTEnThresh2^{GMP}$	Designates the *energy offer* conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test.	$100/MWh.	Table 3-9
$CTSUThresh^{GMP}$	Designates the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test.	100%	Table 3-9
$CTSNLThresh^{GMP}$	Designates the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (*Energy*) conduct test.	100%	Table 3-9
$CTORThresh1^{ORL}$	Designates the *operating reserve offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test.	10% .	Table 3-11

Parameters	Description	Threshold	Reference to MPM Tables
$CTORThresh2^{ORL}$	Designates the *operating reserve offer* conduct threshold, pertaining to allowable $/MW increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test.	$25/MW	Table 3-11
$CTEnThresh1^{ORL}$	Designates the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test.	10%	Table 3-11
$CTEnThresh2^{ORL}$	Designates the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable $/MWh increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test.	$25/MWh	Table 3-11
$CTSUThresh^{ORL}$	Designates the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test.	10%	Table 3-11
$CTSNLThresh^{ORL}$	Designates the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Local Market Power (OR) conduct test.	10%	Table 3-11
$CTORThresh1^{ORG}$	Designates the *operating reserve offer* conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test.	50%	Table 3-13
$CTORThresh2^{ORG}$	Designates the *operating reserve offer* conduct threshold, pertaining to allowable $/MW increase above the reference level, to	$25/MW	Table 3-13

Parameters	Description	Threshold	Reference to MPM Tables
	be used for resources that are subject to the Global Market Power (OR) conduct test.		
$CTEnThresh1^{ORG}$	Designates the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test.	50%	Table 3-13
$CTEnThresh2^{ORG}$	Designates the *energy offer* for *energy* to MLP conduct threshold, pertaining to allowable \$/MWh increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test.	\$25/MWh	Table 3-13
$CTSUThresh^{ORG}$	Designates the start-up offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test.	25%	Table 3-13
$CTSNLThresh^{ORG}$	Designates the speed no-load offer conduct threshold, pertaining to allowable percent increase above the reference level, to be used for resources that are subject to the Global Market Power (OR) conduct test.	25%	Table 3-13
$CTEnMinOffer$	Designates the minimum *energy offer* value for the *offer* lamination to be included in the conduct test. *Energy offer* laminations below this value are excluded from the conduct test.	\$25/MWh	Table 3-5, Table 3-7, Table 3-9
$CTORMinOffer$	Designates the minimum *operating reserve offer* value for the *offer* lamination to be included in the conduct test. *Operating reserve offer* laminations below this value are excluded from the conduct test.	\$5/MW	Table 3-11, Table 3-13

E.2. Market Power Mitigation Price Impact Thresholds and Corresponding Parameters

Table E-2: Price Impact Thresholds and Corresponding Parameters

Parameter	Description	Threshold	Reference to MPM Tables
$ITThresh1^{NCA}$	Designates the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the NCA price impact test.	50%	Table 3-6
$ITThresh2^{NCA}$	Designates the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the NCA price impact test.	$25/MWh	Table 3-6
$ITThresh1^{DCA}$	Designates the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the DCA price impact test.	50%	Table 3-6
$ITThresh2^{DCA}$	Designates the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the DCA price impact test.	$25/MWh	Table 3-6
$ITThresh1^{BCA}$	Designates the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the BCA price impact test.	100%	Table 3-8
$ITThresh2^{BCA}$	Designates the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing	$50/MWh	Table 3-8

Parameter	Description	Threshold	Reference to MPM Tables
	above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the BCA price impact test.		
$ITThresh1^{GMP}$	Designates the price impact threshold, pertaining to allowable percent increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (*Energy*) price impact test.	100%	Table 3-10
$ITThresh2^{GMP}$	Designates the price impact threshold, pertaining to allowable $/MWh increase in the *energy* LMP from As-Offered Pricing above the *energy* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (*Energy*) price impact test.	$50/MWh	Table 3-10
$ITThresh1^{ORG}$	Designates the price impact threshold, pertaining to allowable percent increase in the *operating reserve* LMP from As-Offered Pricing above the *operating reserve* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (OR) price impact test.	50%	Table 3-14
$ITThresh2^{ORG}$	Designates the price impact threshold, pertaining to allowable $/MW increase in the *operating reserve* LMP from As-Offered Pricing above the *operating reserve* LMP from Reference Level Pricing, to be used for resources that are subject to the Global Market Power (OR) price impact test.	$25/MW	Table 3-14

References

Document Name	Document ID
MRP Detailed Design: Overview	DES-16
MRP Detailed Design: Facility Registration	DES-19
MRP Detailed Design: Offers, Bids and Data Inputs	DES-21
MRP Detailed Design: Grid and Market Operations Integration	DES-22
MRP Detailed Design: Market Power Mitigation	DES-26
MRP Detailed Design: Publishing and Reporting Market Information	DES-27
MRP Detailed Design: Market Settlement	DES-28
Market Manual 1: Connecting to Ontario's Power System, Part 1.5 – Market Registration Procedures	PRO-408
Market Manual 4 Market Operations, Part 4.2 - Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets	MDP_PRO_0027
Market Manual 4 Market Operations Part 4.3 - Real Time Scheduling of the Physical Markets	MDP_PRO_0034
Market Manual 4 Market Operations, Part 4.5 - Market Suspension and Resumption	MDP_PRO_0030
Market Manual 4: Market Operations, Part 4.6 - RT Generation Cost Guarantee Program	PRO_324
Market Manual 7: System Operations, Part 7.1 - IESO-Controlled Grid Operating Procedures	MDP_PRO_0040
Market Manual 7: System Operations, Part 7.2 - Near-Term Assessments and Reports	IMP_PRO_0033
Market Manual 7 System Operations, Part 7.3 - Outage Management	IMP_PRO_0035

Document Name	Document ID
Guide to the Day-Ahead Commitment Process	N/A
Market Manual 9: Day-Ahead Commitment, Part 9.0 - DACP Overview	IESO_MAN_0041
Market Manual 9 Day-Ahead Commitment, Part 9.2 - Submitting Operational and Market Data for the DACP	IESO_MAN_0077
Market Manual 9 Day-Ahead Commitment, Part 9.3 - Operation of the DACP	IESO_MAN_0078
Market Manual 9 Day-Ahead Commitment, Part 9.4 - Real-Time Integration of the DACP	IESO_MAN_0079
Market Manual 9 Day-Ahead Commitment, Part 9.5 - Settlement for the DACP	IESO_MAN_0080
Market Rules for the Ontario Electricity Market (Market Rules)	MDP_RUL_0002

– End of Document –