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Pre-implementation Review of the Real-Time Dispatch Algorithm

Prepared for Independent Electricity System Operator

November 15 2017

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Dear Ms. Ionescu:

Subject: Independent Review of the Real-Time Algorithm used in the Ontario Electricity Market

The Independent Electricity System Operator ("IESO") oversees the safe, sustainable and reliable operation of Ontario's power system. This includes the responsibility for managing Ontario's wholesale electricity market, through which the supply and demand for electricity are kept in balance and the Hourly Ontario Energy Price is set.

The IESO asked PricewaterhouseCoopers LLP ("PwC") to conduct an independent review of the Dispatch Scheduling and Optimization algorithm and related systems prior to the implementation of these new systems in production.

The testing performed by PwC was based on section 4 of Chapter 7 and Appendix 7.5 of the IESO Market Rules. This report communicates the results of the review performed by PwC.

Yours truly,

Brian Poth
Power & Utilities Leader

Contents

A. Introduction

Background and objective of the pre-implementation review

The Independent Electricity System Operator (IESO) is responsible for operating Ontario's power system and electricity market to ensure an adequate, reliable and secure supply of energy for the province in the short and long term.

A key part of IESO's role is to administer the operation of the wholesale electricity market to ensure that the dispatch of least cost generation and load facilities for energy and reserve and to maintain the power flows on transmission facilities within security and operational limits. The wholesale electricity market operates operates in pre-dispatch (i.e., hourly) and real-time (i.e. every 5 minutes) to set the market clearing price (MCP) and to dispatch instructions specificying the required amount of energy to be injected (by sellers) or withdrawn (by buyers) based on their accepted offers and bids.

Efficient operation of the electricity market requires that the demand of the system be met with the lowest price generation and operating reserve dispatch as possible, given the bids and offers submitted and applicable constraints on the use of the IESO controlled grid. The dual goals of market efficiency and system security require the solution of a constrained optimization problem: minimizing the cost of generation and reserves, subject to meeting required demand and security constraints.

The IESO has modeled the pre-dispatch and real-time dispatch algorithm into the Dispatch and Scheduling Optimization (DSO), to determine the most efficient dispatch of resources subject to the constraints for secure operation of the grid.

The IESO initiated a project in 2017 to upgrade the Market Information System (MIS) which contains the tools and processes required to optimize the dispatch of Ontario's electricity system. This includes both the Dispatch Scheduling and Optimization (DSO) and the Day-Ahead Calculation Engine (DACE) tools. The MIS upgrade aims to bring the DSO software in line with DACE in terms of user interfaces and the underlying algorithm. An overview of the DSO is shown in Appendix A to this report.

The IESO engaged PwC to conduct a pre-implementation review of the DSO and DACE tools within the upgraded MIS test environment, using test data, to determine that the outputs of the upgraded systems are aligned with the market rules. This pre-implementation review was conducted between August and October 2017.

This report provides the following with respect to DSO:

- An overview of the dispatch algorithm;
- The specific scope of our pre-implementation review and our review approach;
- Our formal report setting out the results of our pre-implementation review;
- IESO management interpretations applicable to our pre-implementation review; and
- Appendices containing the relevant Market Rules that were reviewed.

A separate report provides the results of the pre-implementation review for DACE.

B. Overview of DSO

The DSO is a dedicated software program that runs the dispatch algorithm to determine the most efficienct dispatch of resources subject to constraints for secure operation of the grid. The inputs, proceses and outputs of the DSO are described below. Further details on the inputs and outputs of the DSO can be found in Appendix A.

Inputs to the DSO

Inputs to the DSO consist of generator offers, import offers, dispatchable load bids, export bids, technical data, outage information and forecasts from non-dispatchable resources.

Data sources include the Market Operations System (MOS), Energy Management System (EMS), Outage Scheduler (OS), Demand Forecast System (DFS), Resource Dispatch (RD), Dispatch Data Management System (DDMS), Centralized Forecasting System Database (CFSDB) and Tie-Breaking Modifier Database (TBMD). The mathematical formulation for the dispatch algorithm is described in section 4 of Chapter 7 and specified in Appendix 7.5 of the market rules.

Operation of the DSO

The DSO produces dispatch schedules and settlement prices to determine the most efficient dispatch of resources subject to the constraints for secure operation of the grid by applying an optimization program. The optimization program considers many factors from market participants such as bids and offers of energy and operating reserve, and those provided by the IESO such as the model of the transmission system. Figure 1 provides a simple overview of the overall process.

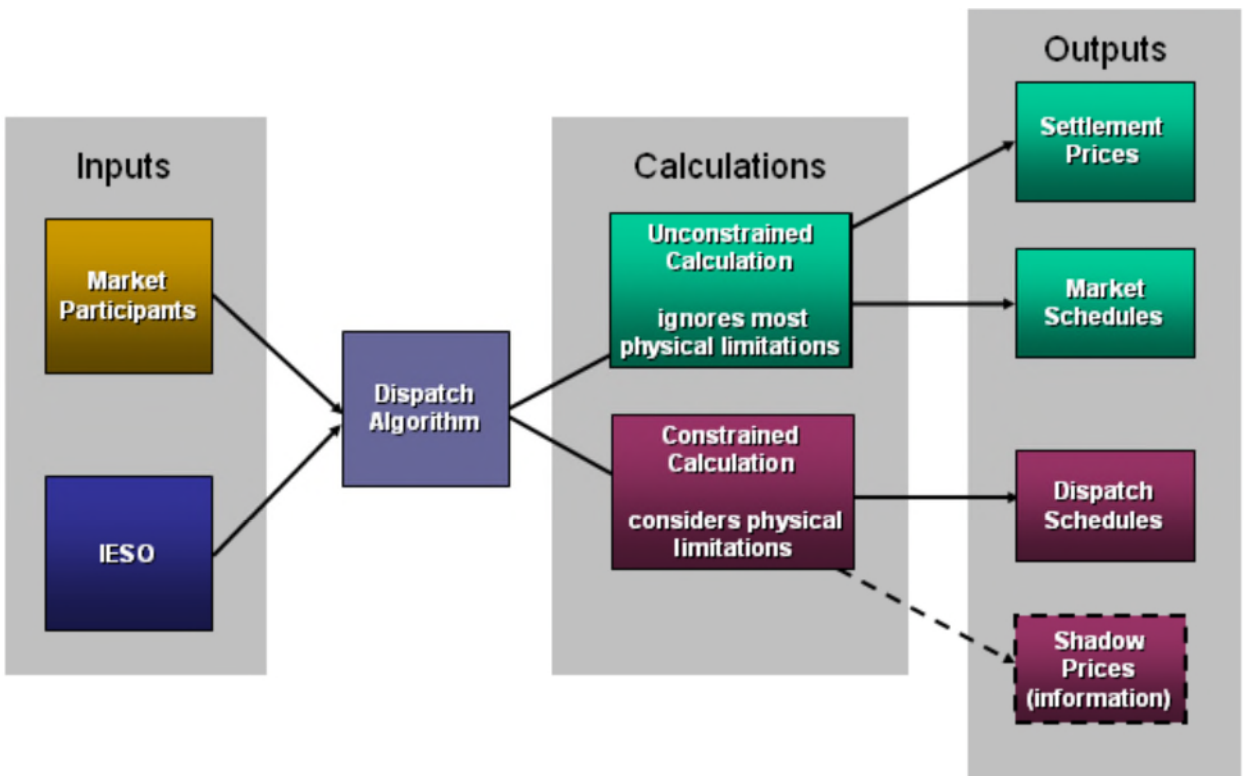


Figure 1: Overview of the DSO[1]

[1] Source: Introduction to Ontario's Physical Markets, IESO

The IESO uses the DSO to solve the constrained optimization problem by running the DSO in two different timeframes as follows:

Pre-Dispatch

The IESO uses the DSO to produce pre-dispatch constrained schedules and projected market prices which in turn facilitates the efficient and reliable operation of the market by allowing participants to anticipate conditions for the coming hours and next day.

The DSO is run hourly in 'pre-dispatch' in both the constrained and unconstrained modes. Pre-dispatch determines projected prices and schedules over a number of future hours. It also determines schedules for imports and exports for the next hour. With the exception of inter-tie prices, the pre-dispatch market prices are not financially binding.

Real-Time

The IESO also uses the DSO to produce real-time constrained schedules and real-time market schedules and prices. The real-time schedules reflect the actual generation, reserve allocation and dispatchable load levels that achieve secure operation at a minimum cost, subject to the system operator's review of the reliability of the network. The IESO issues dispatch instructions according to the real-time schedules. The real-time market prices are used, unless administered prices are necessary, to settle the market.

Further, the DSO is run in two different modes:

Constrained Mode	Unconstrained Mode
Looks forward to determine what resources need to be dispatched to meet the demand for the next interval.	Looks backwards to the interval that just ended in order to determine the price and market schedules for that interval.
Considers all physical limitations of the system: considers the detailed generation and transmission circuit relationships, losses associated with moving electricity through the system and security constraints.	Ignores most physical limitations of the system inside Ontario.
Produces dispatch instructions that are dispatched to resources and informational shadow prices.	Produces settlement prices (Market Clearing Price) and informational market schedules.

The Unconstrained mode allows the DSO to determine market economics by developing a market clearing price that is the same for all load and generation throughout the province (i.e., whereby losses or other restrictions that can cause prices to differ from location to location on the grid are ignored).

The Constrained mode allows the DSO to determine how to dispatch facilities by considering both economics along with the actual physical characteristics of the grid in order to respect system limitations.

Deviations to DSO Output

There are certain circumstances where the actual dispatch instructions are different from the outputs of the DSO runs. Market Rules 4.2.2 and 7.2.1 permit the IESO to intervene with the outcome of the dispatch algorithm and modify or override the dispatch instructions produced by the DSO for reasons related to system reliability (i.e. security and adequacy). Market Rule 4.2.3 requires the IESO to report significant differences between these manual interventions and the results of the dispatch algorithm on a monthly basis and to provide reasons for all interventions.

A “Dispatch Deviation” is defined as a dispatch instruction that differs from the resource’s real-time schedule as determined by the DSO. Dispatch Deviations can occur as a result of automated filtering or manually through verbal instruction of resources or by manual overrides (i.e., overrides to the DSO output) by Control Room operators.

The pre-implementation review was conducted using test data. As a result, there was no resource dispatch from the test system and hence no opportunity to review dispatch deviations.

C. Scope of the pre-implementation review

Scope of pre-implementation review

The scope of this review included automated and scenario testing that addresses Chapter 7.4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules.

Scope inclusions

The pre-implementation review was performed to assess the operation of the DSO to produce real-time schedules, both in the Constrained and Unconstrained mode for the sample test day provided by the IESO.

For both of these modes in real-time, our pre-implementation review considered the outputs of the DSO including determination of real-time resource limits (i.e., ramp rate limits, maximum generation capacity), the economic optimality of DSO-produced schedules (generator equilibrium pricing, dispatchable loads equilibrium pricing), the co-optimization of energy and operating reserve and the determination of the Market Clearing Price.

We also reviewed pre-dispatch schedules produced to forecast energy and determine imports/exports for the next hour.

Scope exclusions

The completeness and accuracy of the inputs to the DSO was outside of the scope of this pre-implementation review. For clarity, this also excludes manual adjustments of the inputs to the DSO.

Further, the internal processes of the DSO including the estimation of Non-Dispatchable Load (NDL) and system losses (dynamic) were outside the scope of our pre-implementation review as they are dependent on the network design model that represent the IESO grid.

Manual and automated overrides to the DSO output did not occur, since no RD schedule was generated from the test system.

The following outputs of the DSO were also out of scope:

- Obligation indicator Index
- Flow-limited transmission circuits

Limitations of pre-implementation review

We performed our pre-implementation review using automated and scenario testing of data provided by the IESO from the upgraded systems with the purpose of identifying any unintended impact to functionality as a result of the system upgrade. In the case of the DSO review, our test scenarios were based on section 4 of Chapter 7 and Appendix 7.5 of the IESO Market Rules. Any exceptions identfied as part of testing were reviewed with IESO. Test data was provided by IESO and not modifed by PwC. PwC's pre-implementation review is not intended to replace technical or user testing that the IT system vendor or IESO shall conduct.

Our Services were performed and this Report was developed in accordance with Schedule A of the contract dated 27 June 2017 and are subject to the terms and conditions included therein.

Our work was limited to the specific procedures and analysis described herein and was based only on the information made available through July 2017. Accordingly, changes in circumstances after this date could affect the findings outlined in this Report.

We are providing no opinion, attestation or other form of assurance with respect to our work and we did not verify or audit any information provided to us. The procedures conducted do not constitute an examination or a review in accordance with generally accepted auditing standards or attestation standards.

This information has been prepared solely for the use and benefit of, and pursuant to a client relationship exclusively with, IESO. PwC disclaims any contractual or other responsibility to others based on its use and, accordingly, this information may not be relied upon by anyone other IESO.

D. Pre-implementation review approach

Our approach to the DSO pre-implementation review was to assess the DSO output schedules for energy and operating reserve from both the Constrained and the Unconstrained, and both the Pre-Dispatch and Real Time sequences, for violations of the in-scope market rules. It was determined through discussion with the IESO that testing the algorithms based on a specific day of activity would constitue an effective testing methodology. As such, our testing approach utilises the test systems inputs and resulting base dispatch for the given day.

For DSO, this approach allowed us to review all resources in the IESO controlled grid for all 288 intervals of our test day. For Pre-Dispatch, we selected a specific delivery hour and evaluated the resulting 24 hours for our test day. In both cases the screening was done all resources within the IESO-controlled grid (~300) scheduled.

Specifically, our review of the Dispatch Algorithm included the following activities:

Market rule changes and MIS changes

We gained an understanding of the applicable Market Rules and related processes and procedures by:

- Reviewing the DSO procedural documentation including IESO Market Rules, Market Manuals
- Reviewing Vendor Change Requests

Automated testing

We developed and executed Automated Screening Tests to assess the DSO generated schedules' compliance with market rules related to operations limits as well as assess the overall DSO computed schedules' economic feasibility. The key activities included:

- Developing and executing automated tests to assess compliance of DSO output with the mathematical limits and representations in Appendix 7.5 of the Market Rules as well as IESO's interpretation of the market rules, documented in Appendix D.
- Screening the DSO schedules for the test day to identify individual dispatches that were sub-optimal or in violation of the unit's limits or the security constraints. Screening of schedules was done for each of the 288 scheduled intervals of the test day and all resources within the IESO-controlled grid (~300) scheduled.
- Reviewing previous management interpretations and/or archived historical outputs of the DSO for conditions in direct violation of limits defined in the Market Rules. For instance, Market Rule 6.5 of Appendix 7.5 describes the up and down ramp limits that are applied and which may be in conflict with available operating limits of a resource.
- Developing screens that tested other implications of the Market Rules.

Scenario testing

For Market Rules that were not triggered on the test day or were not covered by automated testing, we developed and performed "scenario tests" using base case and save case data as follows:

- Tests were performed in IESO testing environment by manipulating inputs and observing whether the outputs produced by the DSO are as expected.

- Performed Base Case/Save Case tests in the testing environment with IESO personnel executing the tests and PwC observing the effects of modifying inputs on the resulting DSO solution.

E. Results of the pre-implementation review

As described in the previous section of this report, this pre-implementation review was performed using automated and scenario testing of data provided by the IESO from the upgraded MIS QA environment. Tests were executed on data provided by IESO for July 20, 2017. The following summarises the results of this testing.

Any potential exceptions which would indicate a limit violation or sub-optimal dispatch identified through the above noted tests were reviewed with the IESO. We worked with the IESO to identify the root cause of these issues and obtained detailed explanations to determine the materiality of confirmed exceptions, as well as any need for further action on the part of management.

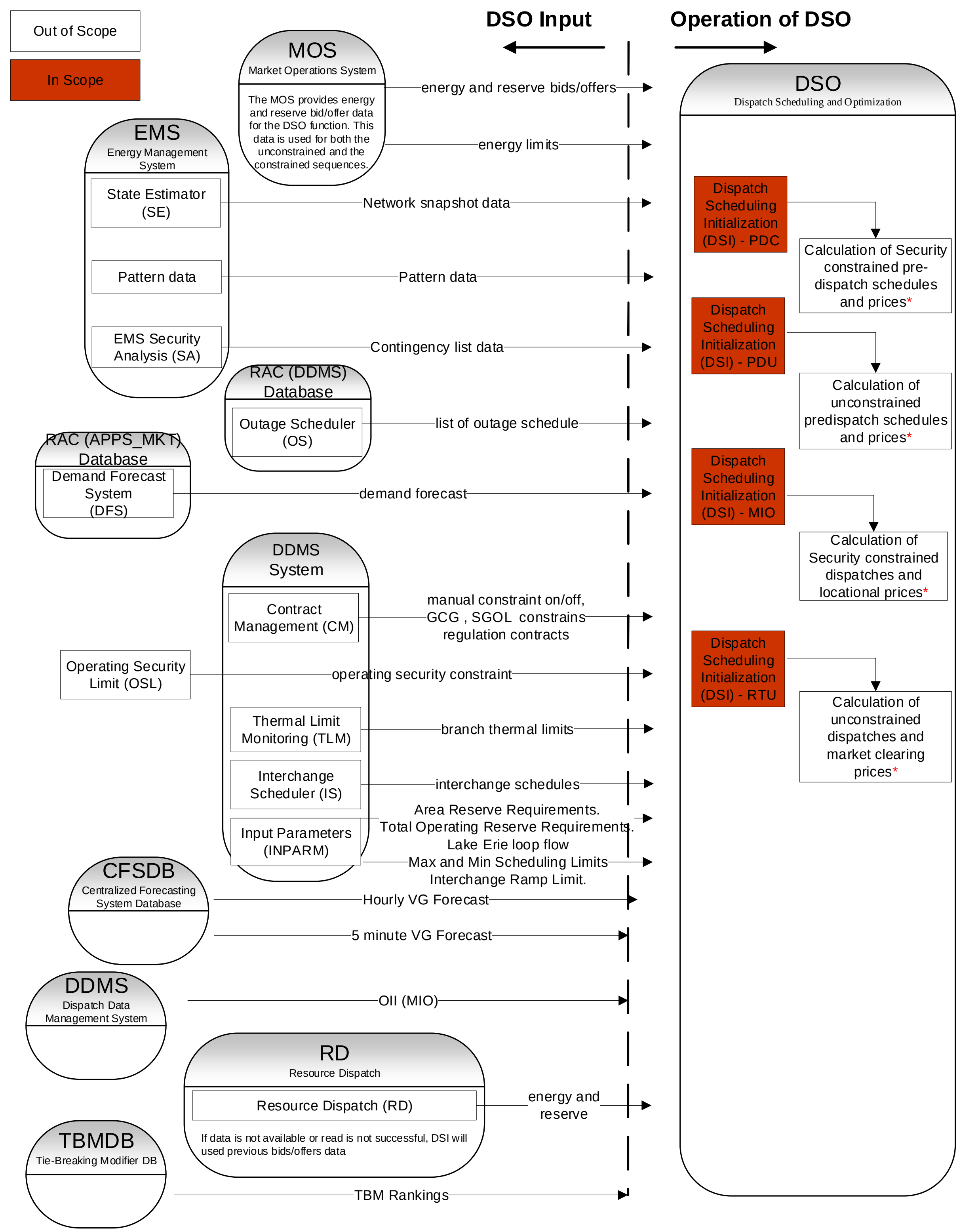
Summary of results

Based on the tests we ran as described in our approach, we have no reportable findings that may impact IESO's ability to comply with market rule obligations, or may result in the objective of the DSO optimization and related processes not being obtained.

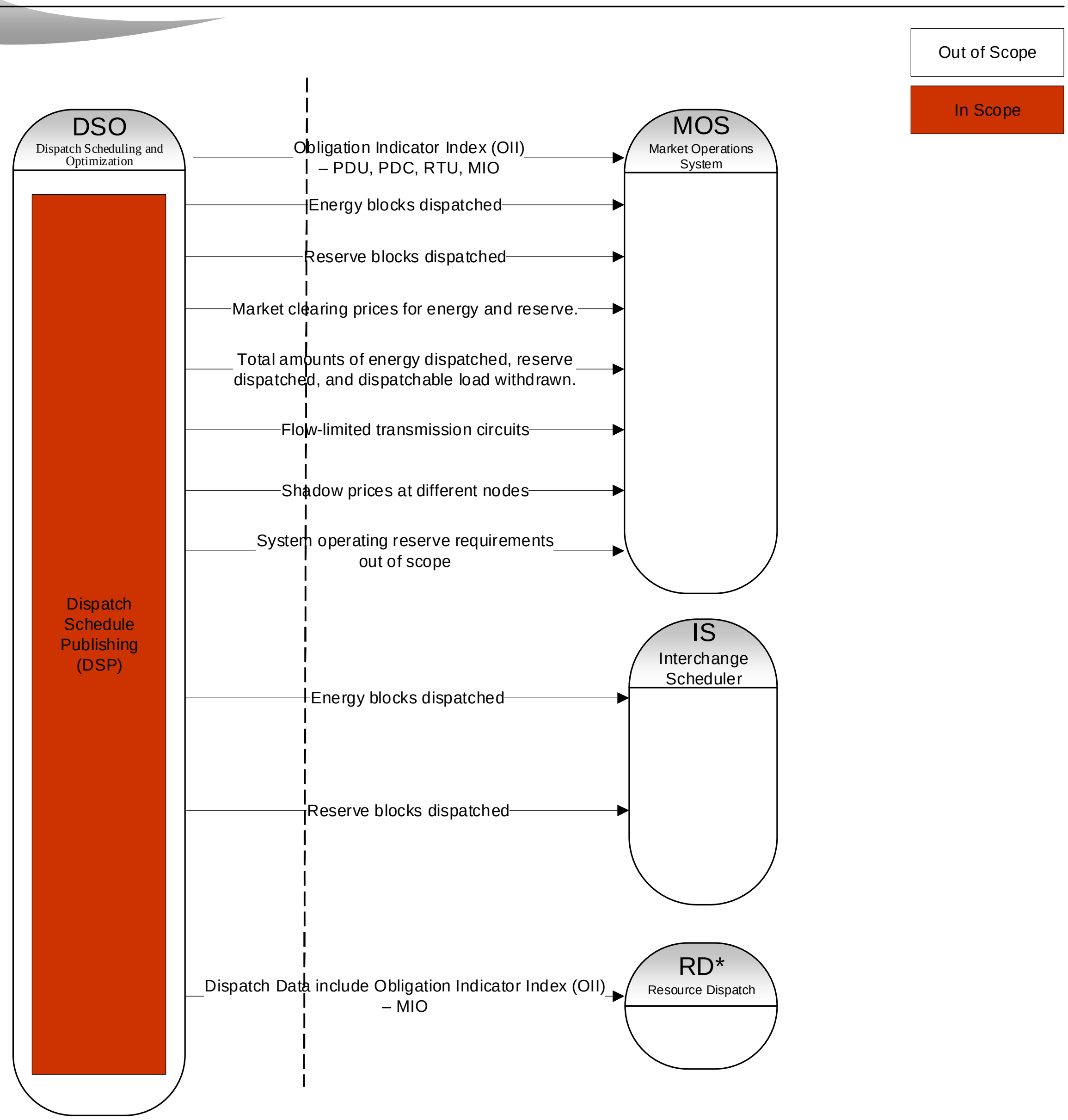
Appendices

Appendix A – Dispatch Scheduling and Optimization (DSO) Inputs and Outputs

Dispatch Scheduling and Optimization (DSO) - Inputs System Interface



Dispatch Scheduling and Optimization (DSO) - Outputs System Interface



Appendix B – Chapter 7.4 – The Dispatch Algorithm

4.1 Purpose of the Dispatch Algorithm

4.1.1 The *IESO* shall determine the various schedules and prices required by this Chapter to be developed by it using a *dispatch algorithm* based on the mathematical techniques of constrained optimisation. The form and use of this *dispatch algorithm* are summarised in this section 4 and detailed in Appendix 7.5.

4.2 Uses of the Dispatch Algorithm

4.2.1 The *IESO* may use different numerical values in, or different computerised versions of, the *dispatch algorithm* for each of the several purposes described in this Chapter, but shall keep the objective, mathematical formulation and solution procedures the same, except as specifically noted.

4.2.2 The *IESO* shall, as far as practical, use the outputs of the *dispatch algorithm* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because any *dispatch algorithm* is only an approximation of a complex physical reality and may sometimes malfunction, the *IESO* may modify or override the results of the *dispatch algorithm* when issuing *dispatch instructions* pursuant to section 7.

4.2.3 The *IESO* shall no less than once in each calendar month, *publish* a report listing and giving reasons for all significant differences between *dispatch instructions* issued and the results of the *dispatch algorithm*.

4.2.4 Unless otherwise directed by the *IESO Board*, the *IESO* shall no less than once every two calendar years, commission and *publish* the results of an independent review of the operation and application of the *dispatch algorithm* and the related *dispatch* processes and procedures. The *IESO* shall use the results of such review to determine the need or otherwise for improvements in the related *dispatch* processes and procedures in meeting the objectives of the *market rules* and/or the mathematical representation of the *electricity system* or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than May 1, 2004.

4.3 The Optimisation Objective

4.3.1 The *dispatch algorithm* shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as defined in section 4.3.2.

4.3.2 The economic gain from trade shall be defined as the difference between the value of the electricity produced (as indicated by the *energy demand* from *non-dispatchable loads* and the *energy bids* from *dispatchable loads*) and the cost of producing that electricity (as indicated by the *offers* to supply the *energy* and *operating reserves* necessary to *reliably* deliver that electricity to loads).

4.3.3 Maximising the economic gain from trade will determine quantities and prices that "clear the market," in the sense that, given the market-clearing prices and the *dispatch data*, no *market* *participant* would be economically better off (in terms of the *dispatch data* it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any *physical service*.

4.4 Inputs to the Dispatch Algorithm

4.4.1 The *IESO* shall use as inputs to the *dispatch algorithm* the data and information outlined in section 4.4 and described in more detail in Appendix 7.5.

4.4.1A [Intentionally left blank]

4.4.2 The cost to suppliers of *energy* and *operating reserves* and the value to *dispatchable loads* of delivered electricity shall be based on the most recent valid *offers* and *bids* (including standing *dispatch data*) submitted by *registered market participants* with respect to *dispatchable generation facilities* and *dispatchable load facilities*.

4.4.3 Subject to section 4.4.3A, the price-insensitive load to be met shall be the sum of:

4.4.3.1 the net energy injections (injections minus withdrawals) by all *non-dispatchable load facilities*, *self-scheduling generation facilities* and *intermittent generators* and *transitional scheduling generators*; and

4.4.3.2 any net amount by which the actual net injections (injections minus withdrawals) by all *dispatchable generation facilities* and *dispatchable load facilities* is less than the net amount implied by the *IESO's dispatch instructions* to such *facilities*.

4.4.3A Until such time that locational pricing is implemented in the *IESO-administered markets*, the price-insensitive load to be met shall be determined solely on the basis of the net *energy* injections referred to in section 4.4.3.1.

4.4.4 Limits on *intertie* flows between the *integrated power system* and neighbouring *transmission systems* shall be based on:

4.4.4.1 a simple model that assumes that each *intertie meter* is *connected* to an isolated *intertie zone* by a single transmission line;

4.4.4.2 the *IESO's* best estimate of the maximum flow on the single transmission line to each *intertie zone*, given the status of the neighbouring *transmission systems* and expected or actual unscheduled flows (including as unscheduled flows any flows planned by the *IESO* to balance interchange accounts with other *control area operators*); and

4.4.4.3 a net *interchange schedule* limit to represent the *integrated power system's* ability to respond to hourly *interchange schedule* deviations and maintain the *reliability* of the *IESO-controlled grid*.

4.4.5 Constraints on the use of the *IESO-controlled grid* shall be determined on the basis of such system *security* requirements as the *IESO* may determine necessary to maintain *reliable* system operations, which requirements shall include, at a minimum, the following:

4.4.5.1 the largest applicable *contingency events* and any increments above these required to satisfy applicable *reliability standards*;

4.4.5.2 *security* constraints on identified *facilities*;

4.4.5.3 minimum requirements for each class of *operating reserve*;

4.4.5.4 the *IESO's* commitments to neighbouring *transmission systems* for *operating reserves* and *regulation*;

4.4.5.5 the availability and need for contracted *ancillary services* and *reliability must-run resources*; and

4.4.5.6 *reliability* constraints associated with *interchange schedules* as referred to in section 4.4.4.3.

4.4.6 The following basic parameters of the *dispatch algorithm* shall be as specified from time to time by the *IESO Board:*

4.4.6.1 the *maximum market clearing price* or *MMCP* that defines the maximum allowable price for *energy*, and the negative of which defines the minimum allowable price for *energy;*

4.4.6.1A the *maximum operating reserve price* or *MORP* that defines the maximum allowable price for any class of *operating reserve*; and

4.4.6.2 the penalty functions for the violation of *dispatch algorithm* constraints.

If the output of the *dispatch algorithm* fails to satisfy *non-dispatchable demand* or the *operating reserve requirements* for any class of *operating reserve* then, subject to section 8.2.2, the penalty functions referred to in section 4.4.6.2 may influence the calculation of *market prices* for *energy* and *operating reserve* in a similar fashion to *offers* and *bids*.

4.4.7 *Interchange schedule data* shall be input as a constant value for the given *dispatch hour* unless otherwise specified by the *IESO* and shall be derived in accordance with the outputs of the *dispatch algorithm* for each *dispatch hour* as determined under section 4.6.

4.5 The Constrained and Unconstrained IESO-Controlled Grids

4.5.1 The *dispatch algorithm* shall be used to determine both operating schedules that reflect the realities of the *integrated power system* and uniform prices within the *IESO control area* that ignore *transmission system* constraints. Thus, the *dispatch algorithm* shall be capable of using the following two different models for the *integrated power system:*

4.5.1.1 an *unconstrained IESO-controlled grid model*, which ignores transmission and other *security* constraints on the *IESO-controlled grid* and assumes, in effect, that all *physical services* are provided and consumed at a single, undesignated location *connected* to several isolated *intertie zones* by single transmission lines; and

4.5.1.2 a *constrained IESO-controlled grid model*, which includes a full (but necessarily approximate) mathematical representation of the *integrated power system*, with *interconnections* modelled as single transmission lines to isolated *intertie zones* or as proportionately allocated to *intertie zones*.

4.6 Outputs of the Dispatch Algorithm

4.6.1 The *IESO* shall use the *dispatch algorithm* to determine the quantities and prices summarised in this section 4.6 and detailed in Appendix 7.5.

4.6.2 The *dispatch algorithm* shall be used with the *constrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and to each *dispatch interval*, operating schedules and their associated costs and shadow prices. The principal outputs, for each *dispatch hour* or *dispatch interval,* as the case may be, shall be the following:

4.6.2.1 the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) scheduled to be provided to the *integrated power system* by each *registered facility*;

4.6.2.2 the amounts of *energy* (in MW or MWh/hour) scheduled to be withdrawn from the *integrated power system* by each *registered facility*;

4.6.2.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* scheduled to be provided by *registered facilities*;

4.6.2.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads* and any constraint violations;

4.6.2.5 power flows and *energy* losses on transmission lines; and

4.6.2.6 the prices of providing *energy* at each set of transmission nodes identified by the *IESO* for this purpose and, subject to section 4.6.2B, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose.

4.6.2A [Intentionally left blank]

4.6.2B Until the date that is the first day of the fourth calendar month following the *market commencement date,* calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the prices of each class of *operating reserve* in each reserve area referred to in section 4.6.2.6 shall not be included as a principal output of the *dispatch algorithm*.

4.6.3 The *dispatch algorithm* shall be used with the *unconstrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and at several times after each *dispatch interval*, *market schedules* and the corresponding uniform prices within the *IESO control area*. The principal outputs of this process are the following:

4.6.3.1 the *market schedule* indicating the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) that would be provided to the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid*;

4.6.3.2 the amounts of *energy* (in MW or MWh/hour) that would be withdrawn from the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid;*

4.6.3.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* in the *market schedule*;

4.6.3.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads*, and any constraint violations that would occur if transmission were totally unconstrained on the *IESO-controlled grid*; and

4.6.3.5 the prices of providing *energy* and each class of *operating reserve* at any point within the *IESO control area* if transmission were totally unconstrained on the *IESO-controlled grid*. As provided in Chapter 9, the unconstrained prices for each *dispatch interval* shall be used for *settlement* purposes, except for *non-dispatchable loads*, who shall pay a uniform *hourly Ontario energy price* (HOEP) determined as described in section 8.3.1.

4.6.4 The *dispatch algorithm* shall be used with the constrained *IESO-controlled grid model* to determine, prior to each *dispatch hour*, *interchange schedules* and their associated costs. The *interchange schedule* for each *dispatch hour* shall be constant for the *dispatch hour* and used as inputs into the *dispatch algorithm* in accordance with section 4.4.

Appendix C – Appendix 7.5 – The Market Clearing and Pricing Process

1.1 Process Overview and Interpretation

1.1.1 This Appendix sets forth a description of the process to be used to determine *pre-dispatch schedules*, *real-time schedules*, *market schedules* and *market prices*. A detailed mathematical description is also provided in the sections that follow.

1.1.2 [Intentionally left blank]

1.1.3 References to "outputs" in this Appendix refer to data produced by software and the *IESO* shall not be required to *publish* such data except where expressly required by these *market rules*.

2. The Dispatch Scheduling and Pricing Process

2.1 Modes of Operation

2.1.1 The *dispatch* scheduling and pricing software may be operated to determine either a *pre-dispatch schedule* or a *real-time schedule* and any associated prices as required by these *market rules*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

2.1.1.1 The *pre-dispatch schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The *pre-dispatch schedule* so produced represents the *energy* forecast to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant* in each *dispatch hour*, and each class of *operating reserve* to be maintained by each *market participant* in each *dispatch hour*;

2.1.1.2 The *real-time schedule* shall represent individual *dispatch intervals*. The *real-time schedule* so produced represents the *energy* to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant*, and the *operating reserve* to be maintained by each *market participant*, in each *dispatch interval*; and

2.1.1.3 Only the *pre-dispatch schedule* shall include daily *energy* limits specified pursuant to section 3.5.7 of this Chapter.

2.1.1.4 The schedules corresponding to *offers* and *bids* located in *intertie zones* adjoining the *IESO control area* shall be fixed for all *dispatch intervals* within a *dispatch hour* in the *real-time schedule* to equal the *interchange schedules* determined for that same *dispatch hour* based on the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*.

2.2 Inputs

2.2.1 The required inputs to the *dispatch* scheduling and pricing process are:

2.2.1.1 *offers* for *energy* submitted by *generators*;

2.2.1.2 *offers* for each class of *operating reserve* submitted by *generators*;

2.2.1.3 self-schedules submitted by self-scheduling generation facilities for energy and the energy price below which each self-scheduling generation facility reasonably expects to reduce the energy output of such self-scheduling generation facility to zero determined in accordance with section 3.4.4A of this Chapter;

2.2.1.4 forecasts of *energy* submitted by *transitional scheduling generators* and intermittent *generators*;

2.2.1.5 *bids* for *energy* submitted by *dispatchable loads*;

2.2.1.6 *offers* for each class of *operating reserve* submitted by *dispatchable loads*;

2.2.1.7 forecasts of *energy* expected to be withdrawn by *non-dispatchable loads*;

2.2.1.8 coefficients of the penalty functions associated with violation of system constraints (generation, *operating reserves* and transmission) that allow relaxation of these constraints in a specified hierarchical order when the solution to the scheduling problem is otherwise infeasible;

2.2.1.9 *generation facility output* and *dispatchable load* levels prevailing at the start of the *dispatch period* calculation;

2.2.1.10 in respect of the *pre-dispatch schedule* only, daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter;

2.2.1.10A in respect of the *real time* constrained *dispatch schedule* only, the start-up and shut-down times for each *generation facility*;

2.2.1.11 the operating characteristics of all *generation facilities* and *dispatchable loads* including, but not limited to ramp-rate limits and *operating reserve* response parameters and for the *real time* constrained *dispatch schedule* only, the *minimum loading point, forbidden regions* and *period of steady operation*;

2.2.1.12 the operating characteristics of the *IESO-controlled grid* including, but not limited to, the physical flow and loss characteristics and flow limits of *transmission facilities*;

2.2.1.13 the requirements for each of *ten-minute operating reserve* that is synchronized to the *IESO-controlled grid*, *ten-minute operating reserve* that is non-synchronized to the *IESO-controlled grid* and *thirty-minute operating reserve*, and the area requirements for *ten-minute operating reserve*;

2.2.1.14 security constraints determined by the *IESO* to be applicable;

2.2.1.14A the outage schedules for transmission facilities;

2.2.1.15 the limits to be applied, where applicable, on *energy bids*, *energy offers, offers* for *operating reserve*, and *dispatch data* as the case may be, to reflect:

a. transmission loading relief constraints;

b. *generation facility outages*;

c. applicable *contracted ancillary services* arranged for use outside of the market clearing mechanism; and for the *real time* constrained *dispatch schedule* only;

d. start-up and shut-down times;

e. *minimum loading point*;

f. *forbidden regions*;

g. *period of steady operation*; and

h. forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*.

2.2.1.16 imports or exports between the *IESO-control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* including but not limited to inadvertent *intertie* flows and simultaneous activation of reserve. These shall be represented as an increase or decrease in *non-dispatchable load*.

2.3 Optimisation Objective

2.3.1 The *dispatch* scheduling and pricing process shall be a mathematical optimisation algorithm that will determine optimal schedules for each time period referred to in section 2.1.1, given the *bids* and *offers* submitted and applicable constraints on the use of the *IESO-controlled grid*. Marginal cost-based prices shall also be produced and, for such purpose, *offer* prices shall be assumed to represent the actual costs of suppliers and *bid* prices shall be assumed to represent the actual benefits of consumption by *dispatchable load facilities*.

2.3.2 The *dispatch* scheduling and pricing process shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as described in sections 4.3.2 and 4.3.3 of Chapter 7.

2.3.3 In respect of the *real time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall have as its objective function maximizing the weighted sum of the economic gain from trade among *market participants*, as described in section 4.3.2 and 4.3.3 of Chapter 7, for the *dispatch interval* and for advisory intervals within the study period. Critical intervals are those selected from the study period to be used as input to the objective function. The first critical interval is always the *dispatch interval*. The remaining critical intervals are advisory intervals.

2.4 The IESO-Controlled Grid

2.4.1 The *dispatch* scheduling and pricing process shall represent power flow relationships between locations on the *IESO-controlled grid* and between the *IESO control area* and adjoining *control areas*.

2.4.2 The *dispatch* scheduling and pricing process shall utilise a security-constrained optimal power flow with explicit representation of electrical flows on each transmission element.

2.4.3 Limits on transmission flows in either direction of flow shall be explicitly represented.

2.4.4 Security constraints may limit *generation facility* output and *dispatchable load* or any other variable so as to represent the *security limits* applicable to the *IESO-controlled grid*.

2.4.5 Subject to section 2.4.6, the *IESO* shall estimate static transmission losses and model transmission losses using penalty factors. The *IESO* shall adjust *bid* and *offer* prices using the applicable penalty factor. The *IESO* shall notify *market participants* in a timely manner of any changes to the applicable penalty factors.

2.4.6 The *IESO* shall apply a uniform penalty factor to *variable generators* that are *registered market participants*.

2.5 Operating Reserve

2.5.1 The *dispatch* scheduling and pricing process shall simultaneously optimise *energy* and *operating reserve* schedules, respecting the trade-off functions for *energy* and *operating reserve* of each *registered facility*.

2.5.2 *Operating reserve* shall be scheduled to meet all applicable *reliability standards*.

2.5.3 For the real-time *dispatch* schedule and immediately following a *contingency event*, the *operating reserve* requirements shall be reduced while *operating reserves* are restored in accordance with all applicable *reliability standards*.

2.5.4 The *dispatch* scheduling and pricing process shall respect the trade-off function between *energy* and each class of *operating reserve* separately.

2.5.5 The *operating reserve* scheduled for a *generation facility* shall reflect the ability of that *generation facility* to provide *operating reserve* over the *dispatch interval* given its ramping capability.

2.5.6 *Offers* for each class of *operating reserve* in an area shall be used to meet the requirements for that class of *operating reserve* in that area.

2.5.6A *Offers* for *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid* that are not scheduled to meet that proportion of *ten-minute operating reserve* which is required to be synchronized with the *IESO-controlled grid* may be scheduled to satisfy the remaining portion of *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*.

2.5.7 Offers for *ten-minute operating reserve* – that is synchronized with the *IESO-controlled grid* or for *ten-minute operating reserve* – that is not synchronized with the *IESO-controlled grid* and that are not scheduled to meet the *ten-minute operating reserve* requirement may be scheduled to satisfy the requirements for a *thirty-minute operating reserve*.

2.5.8 The penalty function applicable as the result of a deficiency in any class of *operating reserve* shall be allowed to have an impact on the *energy* and *operating reserve* prices in the same *dispatch period*.

2.6 Contracted Ancillary Service

2.6.1 The *dispatch* scheduling and pricing process shall include constraints specified by the *IESO* to ensure the adequate provision of *contracted ancillary services*.

2.6.2 The *IESO* may apply constraints to the scheduling of *offers* submitted by *generators* and *bids* submitted by *dispatchable loads* which have contracted to provide *contracted ancillary services* so as to ensure that they are scheduled in a manner to meet their obligations under their respective contracted *ancillary service contracts*.

2.7 Constraint Penalty Functions and Violation Variables

2.7.1 The *dispatch* scheduling and pricing process shall include penalty functions and violation variables which will allow it to automatically violate transmission constraints and operational constraints imposed by the *IESO* (but not *bids* or *offers* or the physical limits of the *facilities* of *market participants*) in situations where no solution would otherwise exist.

2.7.2 Penalty functions for the violation of constraints shall be as specified from time to time by the *IESO Board* in accordance with section 4.4.6.2 of Chapter 7.

2.7.3 Different penalty functions may apply for each of the various *transmission* and operating constraints, reflecting the relative flexibility of *transmission* and operating limits.

2.7.4 The use of violation variables shall indicate that a feasible schedule is possible as long as some constraints are relaxed. If relaxation of such constraints is acceptable for purposes of real-time operations, such feasible schedule shall be accepted. If relaxation of such constraints is not acceptable for purposes of real-time operations, the *dispatch instructions* issued may differ so that an acceptable schedule can be determined.

2.7.5 The penalty functions used by the *IESO* in an acceptable schedule determined under section 2.7.4 shall be allowed to influence *energy* and *operating reserve* prices.

2.8 Tie-Breaking

2.8.1 Except as otherwise noted in section 2.8.5, if two or more *energy offers* have the same *offer* price and interactions with the *operating reserve market* do not create differences in the cost to the market of utilising each *offer*, the schedules from these *offers* shall be prorated based on an adjusted amount of *energy offered* at that *offer price*. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.2 If two or more *energy bids* have the same *bid* price and interactions with the *operating reserve market* do not create differences in the cost to the market as a whole of utilising each *bid*, the schedules from these *bids* shall be prorated based on an adjusted amount of *energy bid* at that *bid* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.3 If two or more *offers* for a given class of *operating reserve* have the same *offer* price and provided that interactions with the *energy* market and markets for other classes of *operating reserve* do not create differences in the cost to the market as a whole of utilising each *offer*, then the schedules from these *offers* shall be prorated based on an adjusted amount of *operating reserve offered* at that *offer* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.4 The *IESO* shall randomly determine a daily *dispatch* order for *variable generators* that are *registered market participants*, and shall regularly update and publish such daily *dispatch* order in accordance with the applicable *market manual*.

2.8.5 For *variable generators* that are *registered market participants*, if two or more *energy offers* have the same *offer* price resulting in no differences in the cost to the *IESO-administered market* of utilising any of the *offers,* the schedules for these *offers* shall be determined utilising the daily dispatch order determined in accordance with section 2.8.4.

2.9 Load Curtailment

2.9.1 If *non-dispatchable load* cannot be satisfied, the *dispatch* scheduling and pricing process shall violate the power balance for the system as a whole, with *energy* prices being calculated in accordance with section 4.4.6 of this Chapter.

2.10 Self-Scheduling Generation

2.10.1 A *self-scheduling generation facility* shall be treated as a resource that will be scheduled when *energy* prices exceed the greater of negative *MMCP* and the price, if any, specified by that *self-scheduling generation facility* in its *dispatch data* pursuant to section 3.4.4A of Chapter 7. Within the software that implements the formulation described in this Appendix, each *self-schedule* shall be represented in the form of an *energy offer* each with a single *price-quantity* pair.

2.11 Inter-temporal Linkages

2.11.1 Except for the *real-time* constrained *dispatch schedule*, the *dispatch* scheduling and pricing process shall solve one *dispatch* period at a time, but shall respect the ramp rate limits applicable to *generation facilities* and *dispatchable load facilities* between *dispatch* periods.

2.11.2 In respect of a *real-time market* scheduling process, the *operating reserve* ramp rates submitted by *market participants* may be increased to levels determined by the *IESO*.

2.11.3 The *real-time* constrained *dispatch schedule* utilizes a two step optimization technique to maximize the weighted sum of the economic gain from trade among *market participants* for a number of critical intervals over a forward looking study period. For each *real time* constrained *dispatch schedule* critical intervals are selected by the *IESO* from the study period based on defined selection criteria. The first critical interval is always the *dispatch interval*, and the remaining critical intervals are advisory intervals. Both the length of the study period and the number of advisory intervals are configurable and may be changed by the *IESO* in the event of significant improvement or degradation of either computer software and hardware performance, the accuracy of the predicted *demand* values or malfunction of the algorithm. Changing the number of critical intervals will affect the number of intervals provided to *market participants* on the *dispatch* advisory reports. The number of critical intervals and the length of the study period will be documented in the applicable *market manuals*.

2.11.4 The *IESO* may switch to a single interval optimization in the event of a malfunction of the multi-interval optimization algorithm.

2.11.5 In respect of the *real-time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall consist of two steps. The first step considers all of the selected critical intervals together to provide an optimal solution. This uses linearized resource characteristics. The second step solves a set of single interval *dispatch* problems to respect the non-linearities that reflect physical characteristics of resources in accordance with section 6.5.

2.12 Outputs

2.12.1 The *dispatch* scheduling and pricing process shall produce the following outputs:

2.12.1.1 the cost to the marketplace as a whole of the solution;

2.12.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;

2.12.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;

2.12.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;

2.12.1.5 the energy output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;

2.12.1.6 the level and location of all load curtailment;

2.12.1.7 flows along all transmission lines;

2.12.1.8 losses on the *IESO-controlled grid*, in the aggregate and by transmission line;

2.12.1.9 the locational *energy* prices at each set of nodes identified by the *IESO* for this purpose for each *dispatch* period;

2.12.1.10 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*;

2.12.1.10 A the area price of *ten-minute operating reserve*; and

2.12.1.11 penalty function values that are greater than zero.

3. The Market Scheduling and Pricing Process

3.1 Modes of Operation

3.1.1 The market scheduling and pricing software may be operated to determine either a projected *market schedule* or a *market schedule*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

3.1.1.1 the projected *market schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The projected *market schedule* so produced represents the state of the *IESO-controlled grid* at the end of the *dispatch hour*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *pre-dispatch schedule* for the corresponding *dispatch hour*;

3.1.1.2 the *market schedules* shall represent individual *dispatch intervals*. Each schedule so produced represents the state of the *IESO-controlled grid* at the end of a *dispatch interval*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *real-time schedule* for the corresponding *dispatch interval*;

3.1.1.3 the projected *market schedule* shall include daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter; and

3.1.1.4 subject to section 3.1.2, the *market schedule* process shall take, as inputs, the output levels of *generation facilities* and *dispatchable load facilities* from the preceding period of the corresponding *market schedule* and pricing solution.

3.1.2 Section 3.1.1.4 shall not apply if market operations have been suspended or *administrative prices* have been applied pursuant to section 8.4A.2.2 of this Chapter. In such cases, the *generation facility* and *dispatchable load facility* initial condition inputs used to calculate the first *market schedule* determined from the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2 or from the *dispatch interval* referred to in section 8.4A.17.2 of this Chapter 7, as the case may be, shall be the output levels of *generation facilities* and *dispatchable load facilities* from the last *dispatch interval* of the last corresponding *market schedule* and pricing solution solved, with corresponding modifications to the initial ramp rates to reflect the maximum amount of ramping possible during the *dispatch intervals* for which no *market schedules* were produced.

3.2 Inputs to and Form of the Market Scheduling and Pricing Process

3.2.1 The form of and inputs to the market scheduling and pricing process shall differ from the *dispatch* scheduling and pricing process described in section 2 only as follows:

3.2.1.1 all constraints that limit the ability of *energy* to flow from one node to another node within the *IESO control area* shall be removed. The market scheduling and pricing process shall assume that all *physical services* are provided and consumed in the *IESO control area* at a single, undesignated location connected to each *intertie zone* only by a single notional *intertie*. Any link between *intertie zones* that lie outside the *IESO control area* shall be removed;

3.2.1.1A all area constraints on *ten-minute operating reserve* shall be removed;

3.2.1.1B the market model shall produce a uniform price for *energy* and for each class of *operating reserve* in the *IESO control area*. The projected *market schedule* shall also produce prices for *energy* and for each class of *operating reserve* in each of the *intertie zones* adjoining the *IESO control area*. No *intertie zone* prices are required to be produced by the *market schedule* as these values are subsequently derived from the uniform Ontario prices produced by the *market schedule* and the projected *market schedule intertie congestion prices*;

3.2.1.2 *security* constraints shall be ignored except for those that impact on *intertie* flows;

3.2.1.2A constraints imposed on *offers* and *bids* that relate to transmission loading relief shall be ignored. Constraints relating to *generation facility outage* schedules and *contracted ancillary services* shall remain;

3.2.1.3 except for flows across *interties*, transmission losses shall not be associated with transmission line flows. Transmission losses other than in respect of flows across *interties* shall be represented as an increase in *non-dispatchable load*;

3.2.1.3A subject to section 3.2.1.3B, the flow across each *intertie* for all *dispatch intervals* within a *dispatch hour* in the *market schedule* shall be equal to the flow on that *intertie* determined for that same *dispatch hour* in the *market schedule* corresponding to the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*;

3.2.1.3B where the limits on flows between *control areas* change in real-time as a result of an unplanned *intertie outage*, it shall be possible to reduce those limits in the *market schedule*;

3.2.1.4 with the exception of *emergency energy* purchases, any imports or exports between the *IESO control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* shall not be represented directly but shall be represented as an increase or a decrease in *non-dispatchable load*. *Emergency energy* purchases shall not be represented as a decrease in *non-dispatchable load* in the *market schedule*;

3.2.1.5 [Intentionally left blank]

3.2.1.6 [Intentionally left blank]

3.2.1.7 [Intentionally left blank]

3.2.1.8 [Intentionally left blank]

3.2.1.9 [Intentionally left blank]

3.2.1.10 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*;

3.2.1.11 in accordance with section 2.11.2 of Appendix 7.5, the *market schedule* may use a different ramp rate for *operating reserve* to that of the *real-time schedule*; and

3.2.1.12 during any period when the *IESO* undertakes an *emergency* control action as described in the applicable *market manual* that affects market *demand*, the *IESO* shall, as software capabilities permit, adjust market *demand* in the *market* *schedule* to offset the impact of the *emergency* control action on the market *demand* where such impact can be determined with reasonable certainty.

3.3 Outputs

3.3.1 The market scheduling and pricing process shall produce the following outputs:

3.3.1.1 the cost to the marketplace as a whole of the solution;

3.3.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;

3.3.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;

3.3.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;

3.3.1.5 the output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;

3.3.1.6 the uniform Ontario *energy* price. The projected *market schedule* shall also produce *energy* prices for each intertie zone;

3.3.1.7 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*; and

3.3.1.8 [Intentionally left blank]

3.3.1.9 penalty function values that are greater than zero.

3.3.2 As described in section 8.2.2 of this Chapter, the prices produced as part of the output of the market scheduling and pricing process shall not necessarily be the prices that are used for *settlement* purposes.

4. Glossary of Sets, Indices, Variables, and Parameters

4.1 Interpretation

4.1.1 Unless otherwise noted, all variables and parameters shall be non-negative.

4.1.2 [Intentionally left blank]

4.2 Time

4.2.1 Except where explicitly stated otherwise in Appendix 7.5 or elsewhere, the formulation presented in this Appendix represents a single *dispatch period*.

4.3 Fundamental Sets and Indices

4.3.1 Areas and Nodes

4.3.1.1 An area, interpreted in accordance with section 1.2.3 of this Chapter, is represented by an element of the set AREAS and is indexed by a.

4.3.1.2 [Intentionally left blank]

4.3.1.3 [Intentionally left blank]

4.3.1.4 Any *energy offer*, *energy bid* or *offer* for *operating reserve* can be associated with a node belonging to the set NODES. NODES has a subset INTERNALACNODES to represent those nodes in the *IESO control area* and a subset EXTERNALACNODES to represent those nodes in the *intertie zones* adjoining the *IESO control area*. NODES also has subsets INTERTIEZONE, indexed by z, describing all of those nodes within *intertie zone* z.

4.3.2 *Offers*

4.3.2.1 An *offer* is represented by an element of the set OFFERS and is indexed by g.

4.3.2.2 An *offer* has associated with it an area and a node.

4.3.2.3 [Intentionally left blank]

4.3.2.4 [Intentionally left blank]

4.3.2.5 A subset of OFFERS called $\text{OFFERS}_{\text{ENERGYLIMITED}}$ represents the *offers* which have a daily *energy* limit in force in accordance with section 3.5.7 of this Chapter.

4.3.2.6 Each element of g of OFFERS has a set of offer blocks, $\text{GENERATIONOFFERBLOCKS}_{g}$.

4.3.2.7 $\text{SECURITYGENERATIONGROUP}_{v}$ is the group of *offers* constrained with security constraint v.

4.3.2.8 Each *energy offer* has associated with it a set of $\text{GENERATIONRAMPUPBLOCKS}_{g}$ and a set of $\text{GENERATIONRAMPDOWNBLOCKS}_{g}$. Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy offer*.

4.3.2.9 The set ENERGYOFFERBOUNDS, which is indexed by g, describes the set of *energy offers* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits, *generation facility outages* as well as limits imposed by *contracted ancillary services* contracts, and forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*. These limits restrict both the *energy* and *operating reserve* output of a *generation facility*.

4.3.3 *Bids*

4.3.3.1 A *bid* is represented by an element of the set BIDS and is indexed by p

4.3.3.2 A *bid* has associated with it an area and a node.

4.3.3.3 [Intentionally left blank]

4.3.3.4 Each element of p of BIDS has a set of load blocks, $\text{PURCHASEBIDBLOCKS}_{p}$.

4.3.3.5 $\text{SECURITYPURCHASEGROUP}_{v}$ is the group of *bids* constrained with security constraint v.

4.3.3.6 Each *energy bid* p has associated with it a set of $\text{PURCHASERAMPUPBLOCKS}_{p}$ and a set of $\text{PURCHASERAMPDOWNBLOCKS}_{p}$. Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy bid*.

4.3.3.7 The set PURCHASEBOUNDS, which is indexed by p, describes the set of *energy bids* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.

4.3.4 Operating Reserve Offers

4.3.4.1 An *offer* to provide *operating reserve* by either a *generator* or a *dispatchable load* is represented by an element of the set RESERVEOFFERS and is indexed by r. The index elements r(g) and r(p) mean the value of r denoting the *operating reserve offer* associated with *generator* g and *dispatchable load* p, respectively.

4.3.4.2 An *offer* to provide *operating reserve* has associated with it an area and a node.

4.3.4.3 Each element r of RESERVEOFFERS and c of RESERVECLASSES has a set of offer blocks, $\text{RESERVEOFFERBLOCKS}_{r,c,j}$ where j is the index for the blocks.

4.3.4.4 The set RESERVEBOUNDS_{c}, which is indexed by r, describes the set of *operating reserve offers*, for each *operating reserve* class c, to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.

4.3.5 [Intentionally left blank]

4.3.5.1 [Intentionally left blank]

4.3.5.2 [Intentionally left blank]

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

4.3.6 Classes of *Operating Reserve*

4.3.6.1 A class of *operating reserve* is represented by an element of the set RESERVECLASSES and is indexed by c.

4.3.6.2 RESERVECLASSES = {RS10,RNS10,R30} where:

a. RS10 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

b. RNS10 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

c. R30 denotes *thirty-minute operating reserve*.

4.3.7 Security Measures

4.3.7.1 A security measure is represented by an element of the set SECURITY and is indexed by v.

4.3.7.2 The *IESO* may establish parameters for these security measures so as to maintain the security and adequacy of the electricity system.

4.3.7.3 [Intentionally left blank]

4.3.7.4 [Intentionally left blank]

4.3.8 Security Classes

4.3.8.1 Security classes represent the different types of security constraints that may be imposed by the *IESO* and are represented by SECURITYCLASSES.

4.3.8.2 SECURITYCLASSES ={GenericMaximum, GenericMinimum}where GenericMaximum and GenericMinimum are generic constraints that can place limits on combinations of *generation facilities* that are *dispatched* by the *IESO*, *dispatchable load* and AC branch flow simultaneously.

4.3.9 Penalty Functions

4.3.9.1 The formulation contains a number of penalty functions that allow certain constraints to be violated to some extent, with a high penalty cost.

4.3.9.2 Penalty functions have five blocks, indexed by j, so that the per unit penalty can be increased for larger violations. The blocks used are:

a. DEFICITGENERATIONBLOCKS;

b. SURPLUSGENERATIONBLOCKS;

c. [Intentionally left blank]

a. (i) [Intentionally left blank]
b. (ii) [Intentionally left blank]
c. (iii) [Intentionally left blank]

c1. DEFICIT10MINRESERVEBLOCKS;

c2. DEFICITSYNCH10MINRESERVEBLOCKS;

c3. DEFICITTOTALRESERVEBLOCKS;

c4. DEFICITAREARESERVEBLOCKS;

c5. SURPLUSAREARESERVEBLOCKS;

c6. DEFICITINTERTIEBLOCKS;

c7. SURPLUSINTERTIEBLOCKS;

c8. DEFICITEXPORT^{MMCP}BLOCKS;

d. For each v in DEFICITSECURITYBLOCKS$_{v;}$ and

e. For each v in SURPLUSSECURITYBLOCKS$_{v.}$

4.4 Derived Sets

4.4.1 There are numerous subsets that can be derived from the fundamental sets described above. A subscripted fundamental set represents all elements of the fundamental set having the attribute represented by the subscript where the subscript is either the unique index identifier or a set of specified elements of another fundamental set.

4.4.2 Examples of derived sets are:

4.4.2.1 RESERVEOFFERS$_{a,}$ which is the set of all *offers* for *operating reserve* located within *operating reserve* area a; and

4.4.2.2 [Intentionally left blank]

4.4.2.3 OFFERS$_{INTERNALACNODES,}$ which is the set of all *energy offers* at nodes in the set INTERNALACNODES (*energy offers* made from within the *IESO control area*).

4.4.2.4 [Intentionally left blank]

4.4.2.5 [Intentionally left blank]

4.5 Functions Defined on Sets

4.5.1 For ease of description, the following functions are defined that operate on elements of sets and return either another set or a single element:

4.5.1.1 *g*(.), where the argument could be an *operating reserve offer* r , or a security measure v, gives the *offer* associated with the argument.

4.5.1.2 *p*(.), where the argument could be an *operating reserve offer* r or security measure v, gives the *bid* associated with the argument.

4.5.1.3 [Intentionally left blank]

4.6 Offers and Bids

4.6.1 Parameters

$\text{GenerationBlockMax}_{g,j}$	The MW element of the jth block of the *offer*.
$\text{GenerationOfferPrice}_{g,j}$	The price element of the jth block of the *offer*. The parameter is unbounded.
$\text{PurchaseBlockMax}_{p,j}$	The MW element of the jth block of the *bid*.
$\text{PurchaseBidPrice}_{p,j}$	The price element of the jth block of the *bid*. The parameter is unbounded.

$EnergyOfferMax_g$	The maximum MW level for *energy* and *operating reserve* associated with *energy offer* g$\in$ **ENERGYOFFERBOUNDS**
$EnergyOfferMin_g$	The minimum MW *energy* level associated with *energy* offer g$\in$ **ENERGYOFFERBOUNDS**
$EnergyBidMax_p$	The maximum MW *energy* level associated with *energy bid* p $\in$ **PURCHASEBOUND**
$EnergyBidMin_p$	The minimum MW *energy* level associated with *energy bid* p $\in$ **PURCHASEBOUND**

4.6.2 Derived Parameters

$GenerationMaximum_g$	The maximum MW *energy* level associated with *energy offer* g$\in$ **OFFERS**.
$PurchaseMaximum_p$	The maximum MW *energy* level associated with *energy bid* p$\in$ **BIDS**.
$FixedPurchases$	A representation of the net amount of non-price responsive withdrawal to be supplied from *energy offers* and *energy bids*.
$GenPF_g$	The loss penalty factor for *energy offer* g$\in$ **OFFERS**.
$PurPF_p$	The loss penalty factor for *energy bid* p$\in$ **BIDS**.

4.6.3 Variables

$Generation_g$	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy offer* g$\in$ **OFFERS**.
$GenerationBlock_{gj}$	The MW *energy* scheduled from the j[th] block of *energy offer* g$\in$ **OFFERS**.
$Purchase_p$	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy bid* p$\in$ **BIDS**.
$PurchaseBlock_{pj}$	The MW *energy* scheduled from the j[th] block of *energy bid* p$\in$ **BIDS**.

4.7 Power Balance

4.7.1 Parameters [Intentionally left blank]

4.7.2 Derived Parameters [Intentionally left blank]

4.7.3 Variables

$LOSS$	The MW losses for the entire *IESO-controlled grid*.

4.8 Operating Reserve

4.8.1 [Intentionally left blank]

4.8.2 Parameters

$ReserveOfferPrice_{r,c,j}$	The price element of block j of *operating reserve* of class c associated with *operating reserve offer* r. The parameter is unbounded.
$ReserveBlockMaximum_{r,c,j}$	The maximum MW *operating reserve* of class c available from block j of *operating reserve offer* r.
$ReserveLoadingPoint10_{r}$	The *operating reserve* loading point for *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid* associated with *operating reserve offer* r. This defines the minimum *energy* value required for a generator to reach its maximum *ten-minute operating reserve offer*.
$ReserveLoadingPoint30_{r}$	The *operating reserve* loading point for *thirty-minute operating reserve* associated with *operating reserve offer* r. This defines the minimum *energy* value required for a generator to reach its maximum *thirty-minute operating reserve offer*.
$ReserveRequirement10$	The amount of *operating reserve* required to meet the *ten-minute operating reserve* requirement of the *IESO control area*.
$ReserveRequirement30$	The amount of *operating reserve* required to meet the *thirty-minute operating reserve* requirement of the *IESO control area*.
$SynchReserveProportion$	The fraction of *ten-minute operating reserve* that must be supplied by *operating reserve* that is synchronized to the *IESO-controlled*

	grid.
$ReserveOfferMax_r$	The maximum MW level associated with *operating reserve offer* r∈**RESERVEBOUNDS**.
$ReserveOfferMin_r$	The minimum MW level associated with *operating reserve offers* r∈**RESERVEBOUNDS**.

4.8.3 Derived Parameters

$ReserveMaximum10_r$	The maximum total *ten-minute operating reserve* from *operating reserve offer* r that can be delivered within ten minutes given the ramping rate for *operating reserve.*
$ReserveMaximum30_r$	The maximum total *operating reserve* from *operating reserve offer* r that can be delivered within thirty minutes given the ramping rate for *operating reserve.*

4.8.4 Variables

$Reserve_{r,c}$	The scheduled *operating reserve* of class c corresponding to *operating reserve offer r.*
$ReserveBlock_{r,c,j}$	The scheduled *operating reserve* of class c corresponding to block j of *operating reserve offer* r.

4.9 Security

4.9.1 Limits may be imposed on the output of *generation facilities*, *dispatchable load facilities* and flow on transmission equipment for *security* reasons.

4.9.2 Parameters

$GenericSecurityMinLimit_v$	The lower limit imposed on the combination of *energy offers* and *energy bids* in security constraint *v*∈**SECURITY.** The parameter is unbounded.
$GenericSecurityMaxLimit_v$	The upper limit imposed on the combination of *energy offers* and *energy bids* in security constraint v∈**SECURITY**. The parameter is unbounded.
$SecurityGroupGenerationWeight_{v,g}$	The weight associated with *energy offer* g∈**SECURITYGENERATIONGROUP**$_v$ in security constraint v. The parameter is unbounded.

$SecurityGroupPurchaseWeight_{v,p}$	The weight associated with *energy bid* p∈**SECURITYPURCHASEGROUP**$_v$ in security constraint v. The parameter is unbounded.
$MaxIntertieZoneFlow_z$	The upper limit imposed on the combination of *energy* and *operating reserve* by constraint z∈ **INTERTIEZONES**. The parameter is unbounded.
$MinIntertieZoneFlow_z$	The lower limit imposed on the combination of *energy* and *operating reserve* by constraint z∈ **INTERTIEZONES**. The parameter is unbounded.

4.10 Ramping

4.10.1 *Dispatchable load facilities* and *dispatchable generation facilities* have limits on their ability to move from one level of consumption or production to another. Ramping constraints are enforced by constraining the level of consumption or production to be between an upper and a lower limit. These limits are pre-determined, based on starting load and generation levels and *bid* and *offer* ramp rates. These limits are applicable to all *pre-dispatch schedules*, *market schedule* intervals, and to the first *dispatch interval* of each *real-time* constrained *dispatch*.

4.10.1A In the first step, of the *real time* constrained *dispatch schedule,* as described in section 2.11.5, the ramp limits are linearized and respected in the optimization.

4.10.1B In the second step, the ramp limits are determined by pre-processing based on *dispatch* load and generation in the critical intervals that precede and follow the interval under consideration. The solution is bounded by:

a) the prior critical interval solution as calculated by the second step and applicable non-linearized ramp rates; and

b) back calculating from the following critical interval solution as calculated from the first step using the applicable non-linearized ramp rates.

In the event that these two sets of bounds do not intersect then a) governs.

4.10.2 Parameters for the optimisation determined by pre-processing

$GenerationEndMax_g$	The maximum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.
$GenerationEndMin_g$	The minimum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.

PurchaseEndMax_p	The maximum load level associated with *energy bid* p∈ **BIDS**, given the corresponding starting load level.
PurchaseEndMin_p	The minimum load level associated with *energy bid* p∈ **BIDS**, given the corresponding starting load level.

4.10.3 Parameters for Pre-processing

$\text{RampRate}_{g,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j^{th} block of $\text{GENERATIONRAMPUPBLOCK}_g$ for g∈**OFFERS.**
$\text{RampRate}_{g,j}^{Down}$	The *energy* ramping down rate in MW per minute associated with the j^{th} block of $\text{GENERATIONRAMPDOWNBLOCK}_g$ for g∈**OFFERS**.
$\text{Generation}_g^{Start}$	The MW *energy* level associated with the *energy offer* at the start of a *dispatch period*. This will be the corresponding *Generation*$_g$ variable from the previous *dispatch period* for the *market schedule* and the constrained *pre-dispatch schedule*, but will be based on operational *metering data* and/or the schedule from the previous *dispatch period* for the *real-time schedule*. If the schedule from the previous *dispatch period* is not available (non-critical intervals in *the real time* constrained *dispatch schedule*) it will be produced by interpolating the *dispatches* from the critical intervals before and after it.
$\text{OperatingReserveRampRate}_g$	The single *operating reserve* ramp rate in MW per minute associated with g∈**OFFERS**.
$\text{RampRate}_{p,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j^{th} block of $\text{PURCHASERAMPUPBLOCK}_p$ p∈**BIDS**
$\text{RampRate}_{p,j}^{Down}$	The *energy* ramping down rate in MW per minute associated with the j^{th} block of $\text{PURCHASERAMPDOWNBLOCK}_p$ for p∈**BIDS**
$\text{Purchase}_p^{Start}$	The MW *energy* level associated with the *energy bid* at the start of a *dispatch period*. This will be the corresponding *Purchase*$_p$ variable from the previous *dispatch period* for the *market schedule* and the constrained *pre-dispatch schedule*, but will be based on operational *metering data* and/or the schedule from the previous *dispatch period* for the *real-time schedule*.

$OperatingReserveRampRate_p$	The single *operating reserve* ramp rate in MW per minute associated with p∈**BIDS**.
$GenerationRampBlockMax_{g,j}$	The MW component of the jth block of the generator ramp up/down block minus the MW component of the (j-1)th block of the generator ramp up/down block.
$PurchaseRampBlockMax_{p,j}$	The MW component of the jth block of the *dispatchable load* ramp up/down block minus the MW component of the (j-1)th block of the *dispatchable load* ramp up/down block.

4.10.4 Variables Used in Pre-processing

$TimeTrajStart_g^{Up}$	The time, on the ramp up trajectory for the *energy offer*, associated with the $Generation_g$ variable from the previous *dispatch period*.
$RampTraj_g^{Up}$	The ramp up trajectory for the *energy offer*.
$TimeTrajStart_g^{Down}$	The time, on the ramp down trajectory for the *energy offer*, associated with the $Generation_g$ variable from the previous *dispatch period*.
$RampTraj_g^{Down}$	The ramp down trajectory for the *energy offer*.
$TimeTrajStart_p^{Up}$	The time, on the ramp up trajectory for the *energy bid*, associated with the $Purchase_p$ variable from the previous *dispatch period*.
$RampTraj_p^{Up}$	The ramp up trajectory for the *energy bid*.
$TimeTrajStart_p^{Down}$	The time, on the ramp down trajectory for the *energy bid*, associated with the $Purchase_p$ variable from the previous *dispatch period*.
$RampTraj_p^{Down}$	The ramp down trajectory for the *energy bid*.

4.10.5 Parameters Determined by Pre-processing and Multi-Interval Optimization

$GenerationRampBlock_{g,j}$	The MW *dispatched* from the jth block of the *generation facility* ramp up/down block.
$PurchaseRampBlock_{p,j}$	The MW *dispatched* from the jth block of the *dispatchable load* ramp up/down block.

4.11 Energy Constrained Generation Units

4.11.1 Parameters for the Optimisation Determined by Pre-processing

$EnergyRemaining_g$	The amount of *energy* remaining at the beginning of the current *dispatch period* for *energy* constrained *generation facility*, as described in sections 6.6 and 8.3, associated with *energy offer* g.
$Generation_g^{Previous}$	The amount of *energy* scheduled from *energy offer* g in the preceding dispatch period.

4.11.2 Parameters for Pre-processing

$EnergyOffered_g$	The total *energy* limit for the *trading day* associated with *energy offer* g∈**OFFERS**.

4.12 Violation Variables

4.12.1 Violation variables have been added to all constraints which might potentially be violated. Most will have a very high cost indicating that the problem has no solution, but some may have lower costs indicating that the constraint can be relaxed to some degree.

4.12.1.1 Parameters

$DeficitGenerationPenalty_j$	The penalty per unit of the *DeficitGenerationBlock*$_j$ variable.
$SurplusGenerationPenalty_j$	The penalty per unit of the *SurplusGenerationBlock*$_j$ variable.
$Deficit10MinReservePenalty_j$	The penalty per unit of the *Deficit10MinReserveBlock*$_j$ variable.
$DeficitSynch10MinReservePenalty_j$	The penalty per unit of the *DeficitSynch10MinReserveBlock*$_j$ variable.
$DeficitTotalReservePenalty_j$	The penalty per unit of the *DeficitTotalReserveBlock*$_j$ variable.
$DeficitSecurityPenalty_{j,v}$	The penalty per unit of the *DeficitSecurityBlock*$_{j,v}$ variable.
$SurplusSecurityPenalty_{v,j}$	The penalty per unit of the *SurplusSecurityBlock*$_{v,j}$ variable.
$SurplusIntertiePenalty_{z,j}$	The penalty per unit of the *SurplusIntertieBlock*$_{z,j}$ variable.
$DeficitIntertiePenalty_{z,j}$	The penalty per unit of the *DeficitIntertieBlock*$_{z,j}$ variable.

$\text{Deficit Export}^{MMCP}\text{Penalty}_{z,j}$	The penalty per unit of the *Deficit Export^{MMCP} Block$_{zj}$* variable.

These penalties, which are set by the *IESO Board* as specified in section 4.4.6 of this Chapter, equal a fixed number multiplied by a quadratic function equal to constant1(x^2) + constant2(x) + constant3. The three constants are user-defined for each penalty function while x equals the sum of total fixed demand and transmission losses divided by the total capacity represented by the *energy offers*.

4.12.1.2 Variables

$DeficitGenerationBlock_j$	The amount by which the aggregate of load plus losses exceeds the *energy* generated. The blocks are cleared in order of increasing cost, so the further the power balance equation is violated, the more extreme the penalty per unit.
$SurplusGenerationBlock_j$	The amount by which *energy* generated exceeds the aggregate of load plus losses.
$Deficit10MinReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement exceeds the *ten-minute operating reserve* scheduled.
$Deficit\ Export^{MMCP}\ Block_j$	The amount contributed by block j in accounting for the amount by which the exports (bid at MMCP) have been unsatisfied.
$DeficitSynch10MinReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement that is synchronized to the *IESO-controlled grid* exceeds the *ten-minute operating reserve* scheduled.
$DeficitTotalReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the total *operating reserve* requirement exceeds the total *operating reserve* scheduled.
$DeficitSecurityBlock_{v,j}$	The amount of deficit in meeting security constraint v, in violation block j.
$SurplusSecurityBlock_{v,j}$	The amount of surplus in security constraint v, in violation block j.
$SurplusIntertieBlock_{z,j}$	The amount of surplus in *intertie zone* constraint z, in violation block j.
$DeficitIntertieBlock_{z,j}$	The amount of deficit in *intertie zone* constraint z, in violation block j.

$DeficitAreaReserveBlock_{a,j}$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a exceeds the *ten-minute operating reserve* scheduled in area a.
$SurplusAreaReserveBlock_{a,j}$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a is less than the *ten-minute operating reserve* scheduled in area a.

4.13 General Parameters

4.13.1 Parameters

$\mathrm{TradingPeriodLength}$	Being either 60 minutes, in respect of a *pre-dispatch schedule*, or 5 minutes, in respect of a constrained *real-time schedule*, or 15 minutes in respect of a *market schedule,* as the case may be.

5. Objective Function

5.1.1 As well as the market terms that are used in the objective function, violation variables associated with the various constraints also appear in the objective function.

5.1.1.1 The NetBenefit is maximised, where:

$$\begin{aligned} NetBenefit = & \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times PurPF_p \times PurchaseBlock_{p,j} \\ & - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times GenerationBlock_{g,j} \\ & - \sum_{\{j,r,c \mid j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times ReserveBlock_{r,c,j} \\ & - ViolationVariables - TieBreaking \end{aligned}$$

In respect of the *real time* constrained *dispatch schedule* only, the first step of the optimization process will maximize the weighted sum of the net benefits from trades in the *dispatch interval* and the advisory intervals. The *IESO* will set the weights for the intervals in the *real time* constrained *dispatch* study period to account for reduced accuracy of inputs for future intervals. The *IESO* shall establish the process by which weights assigned to non-critical intervals are allocated to the critical intervals.

$$NetBenefit = \sum_{\{c \in allcritical\,intervals\}} W_c \begin{bmatrix} \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times PurPF_p \times PurchaseBlock_{p,j} \\ - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times GenerationBlock_{g,j} \\ - \sum_{\{j,r,c \mid j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times ReserveBlock_{r,c,j} \\ - ViolationVariables - TieBreaking \end{bmatrix}$$

Where W_c is the weight assigned to the critical interval c.

5.1.1.2 Wherever the following notation is found:

$$\{\text{j}, x \mid \text{j} \in \textbf{XBLOCKS}_{\mathbf{x}}, \text{where } x \in \textbf{GROUP}\}$$

it shall be interpreted as, for each x in the set **GROUP**, take each of the corresponding blocks from **XBLOCKS**.

5.1.1.3 Violation Variable Terms

$$
\begin{aligned}
&\mathit{ViolationVariables} = \\
&\sum_{\{j|j\in \text{DEFICITGENERATIONBLOCKS}\}} \text{DeficitGenerationPenalty}_j \times \mathit{DeficitGenerationBlock}_j \\
&+ \sum_{\{j|j\in \text{SURPLUSGENERATIONBLOCKS}\}} \text{SurplusGenerationPenalty}_j \times \mathit{SurplusGenerationBlock}_j \\
&+ \sum_{\{j|j\in \text{DEFICIT10MINRESERVEBLOCKS}\}} \text{Deficit 10 MinReservePenalty}_j \times \mathit{Deficit10MinReserveBlock}_j \\
&+ \sum_{\{j|j\in \text{DEFICITSYNCH10MINRESERVEBLOCKS}\}} \text{Deficit 10 Min Synch ReservePenalty}_j \times \mathit{DeficitSynch10MinReserveBlock}_j \\
&+ \sum_{\{j|j\in \text{DEFICITTOTALRESERVEBLOCKS}\}} \text{DeficitTotalReservePenalty}_j \times \mathit{DeficitTotalReserveBlock}_j \\
&+ \sum_{\{j,a|j\in \text{DEFICITAREARESERVEBLOCKS}_A\text{, where } a\in \mathit{AREAS}\}} \text{Deficit10MinReservePenalty}_j \times \mathit{DeficitAreaReserveBlock}_{a,j} \\
&+ \sum_{\{j,a|j\in \text{SURPLUSAREARESERVEBLOCKS}_A\text{, where } a\in \mathit{AREAS}\}} \text{Surplus10MinReservePenalty}_j \times \mathit{SurplusAreaReserveBlock}_{a,j} \\
&+ \sum_{\{j,v|j\in \text{DEFICITSECURITYBLOCKS}_v\text{, where } v\in \text{SECURITYMIN}\}} \text{DeficitSecurityPenalty}_{v,j} \times \mathit{DeficitSecurityBlock}_{v,j} \\
&+ \sum_{\{j,v|j\in \text{SURPLUSSECURITYBLOCKS}_v\text{, where } v\in \text{SECURITYMAX}\}} \text{SurplusSecurityPenalty}_{v,j} \times \mathit{SurplusSecurityBlock}_{v,j} \\
&+ \sum_{\{j,z|j\in \text{SURPLUSINTERTIEBLOCKS}_z\text{, where } z\in \text{INTERTIEZONES}\}} \text{SurplusIntertiePenalty}_{z,j} \times \mathit{SurplusIntertieBlock}_{z,j} \\
&+ \sum_{\{j,z|j\in \text{DEFICITINTERTIEBLOCKS}_z\text{, where } z\in \text{INTERTIEZONES}\}} \text{DeficitIntertiePenalty}_{z,j} \times \mathit{DeficitIntertieBlock}_{z,j} \\
&+ \sum_{\{j,z|j\in \text{DEFICITEXPORT}^{\text{MMCP}}\text{BLOCKS}_z\text{, where } z\in \text{INTERTIEZONES}\}} \text{DeficitExport}^{\text{MMCP}}\text{Penalty}_{z,j} \times \mathit{DeficitExport}^{\mathit{MMCP}}\mathit{Block}_{z,j}
\end{aligned}
$$

5.1.1.4 The Tie Breaking Term

$$
\begin{aligned}
\mathit{TieBreaking} = &\sum_{\{j,p|j\in \text{PURCHASEBIDBLOCKS}_p\text{, where } p\in \text{BIDS}\}} \left\{ \frac{0.0005 \times \left(\mathit{PurchaseBlock}_{p,j}\right)^2}{\text{PurchaseBlockMax}_{p,j}} \right\} \\
&+ \sum_{\{j,g|j\in \text{GENERATIONOFFERBLOCKS}_g\text{, where } g\in \text{OFFERS}\}} \left\{ \frac{0.0005 \times \left(\mathit{GenerationBlock}_{g,j}\right)^2}{\text{GenerationBlockMax}_{g,j}} \right\} \\
&+ \sum_{\substack{\{j,r,c|j\in \text{RESERVEOFFERBLOCKS}_{r,c},\\ \text{where } r\in \text{RESERVEOFFERS and } c\in \text{RESERVECLASSES}\}}} \left\{ \frac{0.0005 \times \left(\mathit{ReserveBlock}_{r,c,j}\right)^2}{\text{ReserveBlockMax}_{r,c,j}} \right\}
\end{aligned}
$$

The tie breaking term involves a penalty cost of 0.0005 prorated by the amount scheduled over the maximum amount that could be scheduled from each block. When this cost is multiplied by the amount scheduled from that block, we get a quadratic function that increases as the amount scheduled increases. The penalty cost adders effectively increases the *bid* or *offer* price by zero if nothing is scheduled from the block but by 0.0005 if the entire amount represented by the *bid* or *offer* block is scheduled. This slight price gradient, which is smaller than the minimum step size of *bid* or *offer* prices, will ensure that, for example, two otherwise tied *energy offer* blocks will be scheduled to the point where their modified costs are identical, effectively achieving a prorated result.

6. Dispatch Constraints

6.1 Offers and Bids

6.1.1

$$GenerationBlock_{g,j} \leq \mathrm{GenerationBlockMax}_{g,j}$$

$$\{j, g \mid j \in \mathbf{GENERATIONOFFERBLOCKS_g}, \text{where } g \in \mathbf{OFFERS}\}$$

6.1.2

$$Generation_{\mathbf{g}} = \sum_{j \in \mathbf{GENERATIONOFFERBLOCKS_g}} GenerationBlock_{g,j}$$

$$\{g \in \mathbf{OFFERS}\}$$

6.1.3

$$Generation_{g} \geq \mathrm{EnergyOfferMin}_{g}$$

$$\{g \in \mathbf{ENERGYOFFERBOUNDS}\}$$

6.1.4

$$Generation_{g} + \sum_{c \in \mathrm{RESERVECLASSES}} Reserve_{r(g),c} \leq \mathrm{EnergyOfferMax}_{g}$$

$$\{g \in \mathbf{ENERGYOFFERBOUNDS}\}$$

6.1.5

$$PurchaseBlock_{p,j} \leq \mathrm{PurchaseBlockMax}_{p,j}$$

$$\{j, p \mid j \in \mathbf{PURCHASEBIDBLOCKS_p}, \text{where } p \in \mathbf{PURCHASES}\}$$

6.1.6

$$Purchase_{p} = \sum_{j \in \mathbf{PURCHASEBIDBLOCKS_p}} PurchaseBlock_{p,j}$$

$\{ p \in \mathbf{PURCHASES} \}$

6.1.7

$$Purchase_{p} \geq \text{EnergyBidMin}_{p}$$

$\{p \in \textbf{PURCHASEBOUNDS}\}$

6.1.8

$$Purchase_{p} \leq \text{EnergyBidMax}_{p}$$

$\{p \in \textbf{PURCHASEBOUNDS}\}$

All *energy offers* are entered as *offers* to supply a block of *energy* at a minimum price. Similarly, *energy bids* for *dispatchable load* are entered as *bids* to buy a block of *energy* at a maximum price. *Energy offers* must have the price increasing with increasing quantity while *energy bids* must have the price decreasing with increasing quantity.

6.2 Power Balance

6.2.1 The power balance equation states that the total generation must equal the sum of scheduled *energy bids* , withdrawals by *non-dispatchable load* and losses. The sum of withdrawals by *non-dispatchable load* and associated losses are input based on forecasted demand.

6.2.1.1

$$\sum_{g \in \text{OFFERS}} Generation_{g} = \sum_{p \in \text{BIDS}} Purchase_{p} + \text{FixedPurchases} + LOSS$$

$$- \sum_{j \in \text{DEFICITGENERATIONBLOCKS}} DeficitGenerationBlock_{j}$$

$$+ \sum_{j \in \text{SURPLUSGENERATIONBLOCKS}} SurplusGenerationBlock_{j}$$

6.2.1.2 [Intentionally left blank]

6.2.1.3 [Intentionally left blank]

6.3 Operating Reserve

6.3.1 [Intentionally left blank]

6.3.2 Operating reserve requirements for the IESO control area are specified for each of ten-minute operating reserve and thirty-minute operating reserve. The ten-minute operating reserve that is required to be synchronized with the IESO-controlled grid is given as a fraction of the ten-minute operating reserve requirement. Since ten-minute operating reserve that is not required for purposes of the ten-minute operating reserve requirement can be used to satisfy the thirty-minute operating reserve requirement, a total operating reserve requirement is defined and is the sum of the ten-minute operating reserve requirement and the thirty-minute operating reserve requirement.

6.3.2A Following a *contingency event*, and subject to section 4.5.10 and 4.5.21 of Chapter 5, the *IESO* shall, over one or more *dispatch intervals*, restore at a constant rate the *operating reserve* requirements to be input into the *dispatch algorithm*. To the extent practicable, the *IESO* shall restore *operating reserve* requirements so as to avoid exceeding the ability to meet those requirements through the *IESO-administered markets*.

6.3.2B *Operating reserve* requirements for areas within the *IESO control area* are specified as lower and upper limits on the amount of *ten-minute operating reserve* to be scheduled in each such area.

6.3.3 [Intentionally left blank]

6.3.3.1

$$ReserveBlock_{r,c,j} \leq \text{ReserveBlockMax}_{r,c,j}$$

$$\{ j, r, c \mid j \in \mathbf{RESERVEOFFERBLOCKS}_r, \text{ where } r \in \mathbf{RESERVEOFFERS} \text{ and } c \in \mathbf{RESERVECLASSES} \}$$

6.3.3.2

$$Reserve_{r,c} = \sum_{j \in RESERVEOFFERBLOCKS_{r,c}} ReserveBlock_{r,c,j}$$

$$\{ r \in \mathbf{RESERVEOFFERS},\ c \in \mathbf{RESERVECLASSES} \}$$

6.3.3.3 [Intentionally left blank]

6.3.3A

$$Reserve_{\mathrm{r,c}} \geq \text{ReserveOfferMin}_{r,c}$$

$$\{ r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES} \}$$

6.3.3B

$$Reserve_{\mathrm{r,c}} \leq \text{ReserveOfferMax}_{r,c}$$

$$\{ r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES} \}$$

6.3.3C The *operating reserve* scheduled from *dispatchable loads* cannot exceed the amount of *dispatchable load* scheduled.

$$\sum_{c \in RESERVECLASSES} Reserve_{r(p),c} \leq Purchase_p$$

$$\{p \in \mathbf{BIDS}\}$$

6.3.4 The *energy* and *operating reserves* scheduled from a *generation facility* must be within the capacity of the *generation facility*.

6.3.4.1

$$Generation_g + \sum_{c \in \mathrm{RESERVECLASSES}} Reserve_{r(g),c} \leq \mathrm{GenerationMaximum}_g$$

$$\{g \in \mathbf{OFFERS}\}$$

6.3.5 If a *generation facility* is operating at a low level of output, then the amount of *operating reserve* it is capable of providing may be restricted. The Reserve Loading Point corresponds to the minimum level of output at which generators can supply the maximum *operating reserve* within the time required. This maximum *operating reserve* quantity declines to zero as output reduces to zero. The maximum *operating reserve* that can be provided differs for *ten-minute operating reserve* and *thirty-minute operating reserve*, and reflects the differing amount of time available for the *generation facility* to increase its output if the *operating reserve* is activated.

6.3.5.1

$$Reserve_{r(g),RS10} \le Generation_g \times \frac{\text{ReserveMaximum10}_g}{\text{ReserveLoadingPoint10}_{r(g)}}$$

$$\{g \in \textbf{OFFERS}\}$$

$$Reserve_{r(g),R30} \le Generation_g \times \frac{\text{ReserveMaximum30}_g}{\text{ReserveLoadingPoint30}_{r(g)}}$$

$$\{g \in \textbf{OFFERS}\}$$

Where:

ReserveMaximum10$_g$ = OperatingReserveRampRate$_{r(g)}$×10

ReserveMaximum30$_g$ = OperatingReserveRampRate$_{r(g)}$×30

If either one of ReserveLoadingPoint10$_{r(g)}$ or ReserveLoadingPoint30$_{r(g)}$ equals zero then the corresponding equation shall not be included in formulation.

6.3.5.2 [Intentionally left blank]

6.3.5.3 [Intentionally left blank]

6.3.5A The amount of *ten-minute operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within ten minutes. The total *operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within thirty minutes.

6.3.5A.1

$$\sum_{c \in \{\text{RS10, RNS10}\}} Reserve_{r(g),c} \le \text{Reserve Maximum 10}_g$$

$$\{g \in \textbf{OFFERS}\}$$

6.3.5A.2

$$\sum_{c \in \text{RESERVECLASSES}} Reserve_{r(g),c} \leq \text{ReserveMaximum30}_g$$

$$\{g \in \textbf{OFFERS}\}$$

6.3.5B Constraints are imposed in *real-time dispatch* scheduling to recognize that the amount by which a *generation facility's energy* output is scheduled to change during a *dispatch interval* modifies the amount of *operating reserve* that the *generation facility* can reliably provide. For instance, if the *generation facility* ramps up during the *dispatch interval*, then the amount of *ten-minute operating reserve* it can provide within ten minutes of the start of the *dispatch interval* will be reduced.

6.3.5B.1

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS},\\ c \in \{RS10, RNS10\}}} Reserve_{r(g),c} \leq \text{Generation}_g^{start} + \text{ReserveMaximum10}_\text{g}$$

$$\{\text{g} \in \textbf{OFFERS}\}$$

6.3.5B.2

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS},\\ c \in \text{RESERVECLASSES}}} Reserve_{r(g),c} \leq \text{Generation}_g^{start} + \text{ReserveMaximum30}_\text{g}$$

$$\{\text{g} \in \textbf{OFFERS}\}$$

6.3.5C The constraints of 6.3.5B are imposed in *real-time market* scheduling and consistent with the TradingPeriodLength determined by the *IESO* in accordance with section 4.13.1 of Appendix 7.5.

6.3.6 *Operating reserve* is scheduled to meet the *operating reserve* requirements of the *IESO control area*.

6.3.6.1 Ten-minute operating reserve

$$\text{ReserveRequirement10} \leq \sum_{\substack{r \in \text{RESERVEOFFERS},\\ c \in \{RS10, RNS10\}}} Reserve_{r,c}$$

$$+ \sum_{j \in \text{DEFICT10MINRESERVEBLOCKS}} Deficit10MinReserveBlock_j$$

6.3.6.2 Ten-minute operating reserve synchronized with the IESO-controlled grid

$$\text{SynchReserveProportion} \times \text{ReserveRequirement10} \le \sum_{r \in \text{RESERVEOFFERS},\, c \in \{\text{RS10}\}} Reserve_{r,c} + \sum_{j \in \text{DEFICITSYNCH10MINRESERVEBLOCKS}} DeficitSynch10MinReserveBlock_j$$

6.3.6.3 Total operating reserve

$$\text{ReserveRequirement10} + \text{ReserveRequirement30} \le \sum_{r \in \text{RESERVEOFFERS}, c \in \text{RESERVECLASSES}} Reserve_{r,c} + \sum_{j \in DEFICITTOTALRESERVEBLOCKS} DeficitTotalReserveBlock_j$$

6.3.6.3A Area *operating reserve* requirements

$$\text{MinimumAreaOperatingReserve}_a \le \sum_{r \in RESERVEOFFERS_a, c \in \{RS10, RNS10\}} Reserve_{r,c} + \sum_{j \in DEFICITAREARESERVEBLOCKS} DeficitAreaReserve_{j,a}$$

$$\text{MaximumAreaOperating Reserve}_a \ge \sum_{r \in RESERVEOFFERS_a, c \in \{RS10, RNS10\}} Reserve_{r,c} - \sum_{j \in SURPLUSAREARESERVEBLOCKS} SurplusAreaReserve_{j,a}$$

$$\{a \in \textbf{AREAS}\}$$

6.3.6.4 The SynchReserveProportion shall be set in accordance with requirements established by *NERC*.

6.4 Security Constraints

6.4.1 In order to enable the *IESO* to direct the operations of the *IESO-controlled grid* so as to fulfil its obligations under Chapter 5, the *IESO* must define network security constraints. These network security constraints are specified in the form of maximum and minimum constraints on linear combinations of line flows, *energy offers*, and *energy bids*. During the process of solving for schedules and prices, these network security constraints, as well as other transmission constraints represented automatically within the tools, are reduced to generic *security* constraints which impose limits on the weighted sum of the $Generation_g$ and $Purchase_p$ variables, with flows being converted to constants.

6.4.2 [Intentionally left blank]

6.4.3 Generic *security* constraints only appear in the *dispatch* scheduling and pricing process and are expressed as:

6.4.3.1

$$\sum_{n \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times \textit{Purchase}_p$$
$$+ \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times \textit{Generation}_g$$
$$- \sum_{j \in \text{SURPLUSSECURITYBLOCKS}_v} \textit{SurplusSecurityBlock}_{j,v} \leq \text{GenericMaxSecurityLimit}_v$$

$$\{v \in \mathbf{SECURITY}_{GenericMaximum}\}$$

6.4.3.2

$$\sum_{p \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times \textit{Purchase}_p$$
$$+ \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times \textit{Generation}_g$$
$$+ \sum_{j \in \text{DEFICITSECURITYBLOCKS}_v} \textit{DeficitSecurityBlock}_{v,j} \geq \text{GenericMinSecurityLimit}_v$$

$$\{v \in \mathbf{SECURITY}_{GenericMinimum}\}$$

6.4.4 Constraints separate from the generic security constraints impose limits on the total *energy* flows and *operating reserve* scheduled from *intertie zones* outside the *IESO control area*. These constraints apply to both the *pre-dispatch schedule* and the *market schedule*.

$$\sum_{g \in \text{OFFERS}_z} \textit{Generation}_g - \sum_{p \in \text{BIDS}_z} \textit{Purchase}_p + \sum_{r \in \text{RESERVEOFFERS}_z, c \in \text{RESERVECLASSES}} \textit{Reserve}_{r,c}$$
$$- \sum_{j \in \text{SURPLUSINTERTIEBLOCKS}_z,} \textit{SurplusInterieBlock}_{z,j} \leq \text{MaxIntertieZoneFlow}_z$$

$$\sum_{g \in \text{OFFERS}_z} \textit{Generation}_g - \sum_{p \in \text{BIDS}_z} \textit{Purchase}_p +$$
$$+ \sum_{j \in \text{DEFICITINTERTIEBLOCKS}_z,} \textit{DeficitInterieBlock}_{z,j} \geq \text{MinIntertieZoneFlow}_z$$

$$\{z \in \mathbf{INTERTIEZONES}\}$$

6.5 Ramping

6.5.1 Any change in the output of a *generation facility* or the consumption by a *dispatchable load facility* is subject to up and down ramp rate limits. These constrain the schedule for these *facilities* at the end of the *dispatch period* to be within a band which is set by pre-processing based on knowledge of the schedule at the start of the *dispatch period* and the ramp rates.

6.5.2 Except for the advisory intervals in the *real time* constrained *dispatch*, ramping constraints are expressed as:

6.5.2.1

$$Generation_g \leq \text{GenerationEndMax}_g \qquad \{g \in \textbf{OFFERS}\}$$

6.5.2.2

$$Generation_g \geq \text{GenerationEndMin}_g \qquad \{g \in \textbf{OFFERS}\}$$

6.5.2.3

$$Purchase_p \leq \text{PurchaseEndMax}_p \qquad \{p \in \textbf{BIDS}\}$$

6.5.2.4

$$Purchase_p \geq \text{PurchaseEndMin}_p \qquad \{p \in \textbf{BIDS}\}$$

6.5.3 For purposes of sections 6.5.2.1 to 6.5.2.4, $\text{GenerationEndMax}_g$, $\text{GenerationEndMin}_g$, PurchaseEndMax_p and PurchaseEndMin_p are determined by pre-processing as described in section 8.2.

6.5.4 The ramping constraints for the advisory intervals in the first step of the multi-interval optimization of the *real time* constrained *dispatch* are linearized and included in the optimization as follows:

6.5.4.1

$$Generation_g = \sum GenerationRampBlock_{g,j} \qquad \{g \in \textbf{OFFERS}\}$$

6.5.4.2

$$Purchase_p = \sum PurchaseRampBlock_{p,j} \qquad \{p \in BIDS\}$$

6.5.4.3

$$0 \leq GenerationRampBlock_{g,j} \leq GenerationRampBlockMax_{g,j} \qquad \{g \in OFFERS\}$$

6.5.4.4

$$0 \leq PurchaseRampBlock_{p,j} \leq PurchaseRampBlockMax_{p,j} \qquad \{p \in BIDS\}$$

6.5.4.5

$$-RampRate_{g,j}^{Down} \times T_{g,j} \leq GeneratorRampBlock(i+1th\,\mathrm{int}\,erval)$$

$$-GeneratorRampBlock_{g,\,j}(ith\,\mathrm{int}\,erval) \leq RampRate_{g,j}^{Up} \times T_{g,j}$$

Where $T_{g,j} \geq 0$ and $\sum T_{g,j} \leq$ Time Interval; and

$T_{g,j}$ is the time that the generator ramps in the *GeneratorRampBlock*$_{g,j}$; where Time Interval is equal to the length of the *dispatch interval*.

6.5.4.6

$$RampRate_{p,j}^{Down} \times T_{p,j} \leq PurchaseRampBlock(i+1th\, interval) - PurchaseRampBlock_{p,j}(ith\, interval) \leq RampRate_{p,j}^{Up} \times T_{p,j}$$

Where $T_{p,j} \geq 0$ and $\sum T_{p,j} \leq$ Time Interval; and

$T_{p,j}$ is the time that the purchase ramps in the *PurchaseRampBlock*$_{p,j}$*;* where Time Interval is equal to the length of the *dispatch interval*.

6.6 Energy Constrained Generation Units

6.6.1 Some *generation units*, referred to as "*energy* constrained *generation units*", have a defined amount of *energy* which they are able to generate within the course of a *trading day*. Each *energy* constrained *generation unit* may specify an *energy* limit which will apply over the *trading day*. Where an *energy* limit is specified pursuant to section 3.5.7 of this Chapter, starting with this value a running total, EnergyRemaining, is kept by subtracting the *energy* scheduled in each *dispatch hour* from the quantity of *energy* available at the start of the *dispatch hour*.

6.6.2 Because the model is not inter-temporal, it will not use *energy* at the times at which it is of most value. Instead, it will use *energy* over the first opportunities in which it is economical to do so. Thus, it may use all of the *energy* during the low load early morning period, leaving none left during the higher price periods. It is left to the *generator* to submit *energy offers* for a *generation unit* at appropriate times to maximise the value of the *energy* available.

6.6.3 The following constraint is included only in the *pre-dispatch schedules:*

$$\text{TradingPeriodLength} \times Generation_g \leq \text{EnergyRemaining}_g$$

$$\{g \in \mathbf{OFFERS}_{ENERGYLIMITED}\}$$

6.7 Nodal Price Calculation

6.7.1 $$\lambda_n = \lambda_s + (DF_n - 1) * \lambda_s + \sum_k DF_n * a_{nk} * \mu_k$$

where:

λ_n	nodal price at an injection or withdrawal node *n* (i.e., a node connected to a *generation facility* or *load facility*)
λ_s	system marginal cost
DF_n	delivery factor for node *n* (reciprocal of penalty factor)
a_{nk}	sensitivity factor for injection at node *n* on *transmission* line *k*
μ_k	shadow price for *transmission* line *k* constraint

6.7.2 Nodal prices may be decomposed into an *energy* component, a loss component, and a component for all other *transmission* and system constraints (the three terms on the right hand side, respectively.)

7. Market Constraints

7.1 Introduction

7.1.1 The market model removes all of the AC *transmission* lines inside the *IESO control area*, and consolidates the nodes into a single representative node, the ONTARIONODE. The losses associated with the *transmission* lines in the *IESO control area* are consolidated to this node.

7.1.2 The only AC *transmission* lines in the market model are the *interties* with neighbouring *control areas*. Although these *interties* have flow variables in the market model, under current procedures each interface will have its flows constrained to the scheduled quantities for the relevant *dispatch period*, using *security* constraints.

7.2 Offers and Bids

7.2.1 The market constraints for *energy offers* and *energy bids* are identical to the *dispatch* constraints described in section 6.1 with the exception that constraints associated with the sets ENERGYOFFERBOUNDS and PURCHASEBOUNDS shall not be present if those constraints pertain to transmission loading relief.

7.3 Power Balance

7.3.1 The market power balance equations are identical to the *dispatch* power balance equations described in section 6.2, with the following exceptions:

7.3.1.1 subject to section 7.3.2, losses within the *IESO control area* will be added to FixedPurchases;

7.3.1.2 all loss sensitivity parameters (and corresponding penalty functions) for *generators* and *loads* within each *control area* outside the *IESO control grid* will be identical and will reflect the losses on the external area and the relevant *intertie;* and

7.3.1.3 subject to section 7.3.2, the following adjustments, as further defined in section 8.4, shall be made in the *real-time schedule* to reflect deviations between scheduled and actual MW output and load:

ActualPurchaseAdjustment – ActualGenerationAdjustment

7.3.2 Until such time that locational pricing is implemented in the *IESO-administered markets*:

7.3.2.1 the losses referred to in section 7.3.1.1 shall be incorporated in FixedPurchases in the manner described in section 8.4.3 ; and

7.3.2.2 no adjustments shall be made pursuant to section 7.3.1.3.

7.4 Operating Reserve

7.4.1 The market treatment of risk and *operating reserve* is identical to the *dispatch* treatment of these elements as described in section 6.3, with the exception that:

7.4.1.1 constraints on *offers* for *operating reserve* associated with the set $RESERVEBOUNDS_c$ for *operating reserve* class c shall not be present if those constraints pertain to transmission loading relief; and

7.4.1.2 the area *operating reserve* requirements are ignored.

7.5 Security Constraints

7.5.1 The only security constraints to be represented are the limits imposed on the flows of *energy* and on *operating reserve* scheduled from *intertie zones* outside the *IESO control area* as described in section 6.4.4.

7.6 Ramping

7.6.1 The mathematical description of the market constraints for ramping is identical to the mathematical description of the ramping *dispatch* constraints used in the *pre-dispatch* and the *dispatch interval* of the *real time* multi-interval *dispatch*, as described in section 6.5, except for the information and data differences specified in section 6.4 of Chapter 7.

7.7 Energy Constrained Generation Units

7.7.1 This constraint is only included in the *pre-dispatch schedules*. The market *energy* constraints are identical to the *dispatch energy* constraints as described in section 6.6.

8. Parameters and Pre-processing

8.1 Introduction

8.1.1 This section 8 contains calculations that take place before the optimization algorithm. The purpose of these calculations is to convert raw input data into the specific inputs required by the optimisation algorithm.

8.2 Ramping

8.2.1 The pre-processing calculations described in sections 8.2.2 and 8.2.3 are performed for all *energy offers*{g∈**OFFERS**}. The pre-processing calculations described in sections 7.2.4 and 7.2.5 are performed for all *bids* by *dispatchable loads* {*p*∈**BIDS**}.

8.2.2 The *energy offer* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\mathrm{GenerationEndMax}_g = RampTraj_g^{Up}(TimeTrajStart_g^{Up} + \mathrm{TradingPeriodlength})$$

where

$$Generation_g^{Start} = RampTraj_g^{Up}(TimeTrajStart_p^{Up})$$

8.2.3 The *energy offer* ramp down model is defined by the set of ramp down rates and ramp down blocks. Combined these rates and blocks define the ramp trajectory which gives the maximum decrease of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\mathrm{GenerationEndMin}_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down} + \mathrm{TradingPeriodlength}).$$

where

$$Generation_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down})$$

8.2.4 The *energy bid* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$\mathrm{PurchaseEndMax}_p = RampTraj_p^{Up}(TimeTrajStart_p^{Up} + \mathrm{TradingPeriodlength})$$

where

$$Purchase_p^{Start} = RampTraj_p^{Up}(TimeTrajStart_p^{Up})$$

8.2.5 The *energy bid* ramp down model is defined by the set of ramp down rates and ramp down blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum decrease of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$\mathrm{PurchaseEndMin}_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down} + \mathrm{TradingPeriodlength})$$

where

$$Purchase_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down})$$

8.3 Energy Constrained Generation Units

8.3.1

$$\mathrm{EnergyRemaining}_g = \mathrm{EnergyRemaining}_g^{Previous} - \mathrm{Generation}_g^{Previous} \times \mathrm{SchedPeriod}$$

where SchedPeriod is the scheduling period measured in hours, currently 1 hour. If $\mathrm{EnergyRemaining}_g$ ever takes a value of less than zero then it shall be set to zero. If $\mathrm{EnergyRemaining}_g$ is ever lower than a lower bound constraint imposed on *energy offer* g, then as part of the pre-processing process the relevant lower bounds will be reduced accordingly.

8.3.2

$\mathrm{EnergyRemaining}_g = \mathrm{EnergyOffered}_g$ in the first *dispatch period.*

8.4 Actual Dispatch Adjustment

8.4.1 Subject to section 8.4.3, Actual Generation Adjustment shall be:

8.4.1.1 for the ONTARIONODE:

$$\mathrm{ActualGenerationAdjustment}_{\mathbf{ONTARIONODE}} = \sum_{n \in \mathbf{INTERNALNODES}} \sum_{g \in \mathbf{OFFERS}_n} (Generation_g^{Actual} - Generation_g^{Scheduled})$$

where $\mathrm{Generation}_g^{\mathrm{Actual}}$ is the actual generation for generator g, and $\mathrm{Generation}_g^{\mathrm{Scheduled}}$ is the *dispatch instruction* issued for generator g; and

8.4.1.2 for $n \in$ EXTERNALACNODES:

$$\mathrm{ActualGenerationAdjustment}_n = \sum_{g \in \mathbf{OFFERS}_n} (Generation_g^{Actual} - Generation_g^{Scheduled})$$

where $\text{Generation}_g^{\text{Actual}}$ is the actual generation for generator g, and $\text{Generation}_g^{\text{Scheduled}}$ is the *dispatch instruction* issued for generator g.

8.4.2 Subject to section 8.4.3, Actual Purchase Adjustment shall be:

8.4.2.1 for the ONTARIONODE:

$$\text{ActualPurchaseAdjustment}_{\textbf{ONTARIONODE}} = \sum_{n \in \textbf{INTERNALNODES}} \sum_{p \in \textbf{BIDS}_n} (Purchase_p^{Actual} - Purchase_p^{Scheduled})$$

where $\text{Purchase}_p^{\text{Actual}}$ is the actual load for *dispatchable load* p, and $\text{Purchase}_p^{\text{Scheduled}}$ is the *dispatch instruction* issued for *dispatchable load* p; and

8.4.2.2 for $n \in$ EXTERNALACNODES:

$$\text{ActualPurchaseAdjustment}_n = \sum_{p \in \textbf{BIDS}_n} (Purchase_p^{Actual} - Purchase_p^{Scheduled})$$

where $\text{Purchase}_p^{\text{Actual}}$ is the actual load for *dispatchable load* p, and $\text{Purchase}_p^{\text{Scheduled}}$ is the *dispatch instruction* issued for *dispatchable load* p.

8.4.3 Until such time that locational pricing is implemented in the *IESO-administered markets*, there shall be no actual dispatch adjustment effected pursuant to section 8.4.1 or 8.4.2 and rather than adding the losses within the *IESO control area* to FixedPurchases, FixedPurchases shall be defined to include losses and shall be:

8.4.3.1 the sum of:

a. actual metered generation within the *IESO control area;* and
b. net scheduled flows over all *interties,*

minus

8.4.3.2 the amount of scheduled *dispatchable load* within the *IESO control area*.

Appendix D – IESO Interpretations of Chapter 7.4 and Appendix 7.5 of the Market Rules

Unit Constraints

Appendix Chapter 7.5 Section 6.1.3 states that: $\text{Generationg} \geq \text{EnergyOfferMing}$. This inequality requires that the scheduled energy not be less than the low operating limit associated with this energy offer.

Appendix Chapter 7.5 Section 6.1.4 states that: $\text{Generationg} + \Sigma\text{Reserve r(g),c} \leq \text{EnergyOfferMaxg}$. This inequality requires that the total amount of scheduled energy and operating reserve not exceed the high operating limit associated with this energy offer.

High and low operating limits are determined based on a combination of parameters, which include: offered energy capacity, outages, derates, operational constraints, wind/solar forecasts and minimum loading points.

Appendix Chapter 7.5 Section 6.5.2 states that: $\text{Generationg} < \text{GenerationEndMaxg}$ and $\text{Generationg} > \text{GenerationEndMing}$ requiring that the total amount of energy scheduled be within the maximum ramping up and ramping down capacity of the unit.

These inequalities do not have a violation variable associated with them and therefore, cannot be relaxed when in conflict with another inequality. As such, while the Market Rules referenced above specify the DSO will respect offered operating limits and ramp rates, there is a superseding merit order of constraints as operating limits and then ramp rates.