Market Rules

Chapter 7 System Operations and Physical Markets - Appendices

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Distribution List

Name	**Organization**

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Appendix 7.1 – Energy Offer, Schedule or Forecast Information

1.1 Within the IESO Control Area

1.1.1 Unique plant identifier (by *generation unit* or *generation units* that have been aggregated with the approval of the *IESO*).

1.1.2 Contact information.

1.1.3 Hour(s) for which *offer*, schedule or forecast applies.

1.1.4 [Intentionally left blank – section deleted]

1.1.5 For a *dispatchable generation facility*, two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*. If the *generator* has specified *forbidden regions*, the submitted *offer price-quantity pairs* must include a quantity equal to each of the lower and upper limits of each *forbidden region*.

1.1.6 For a *dispatchable generation facility*, one to five sets of ramp quantity and ramp up/ramp down values for each *dispatch hour* applicable to the entire range of generator output contained in the *offer*.

1.1.7 Daily *energy* limit (if applicable).

1.1.8 [Intentionally left blank – section deleted]

1.1.9 [Intentionally left blank – section deleted]

1.1.10 Is this a standing *offer*, schedule or forecast? Yes/No. If Yes, Date To: ________
For which day(s) of the week? ____________________

1.2 Offers Outside the IESO Control Area

1.2.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.2.2 Contact information.

1.2.3 Hour(s) for which *offer* applies.

1.2.4 [Intentionally left blank]

1.2.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*.

1.2.6 Daily *energy* limit (if applicable).

1.2.7 [Intentionally left blank]

1.2.8 Is this a standing *offer*? – Yes/No. If Yes, Date To: _____ For which day(s) of the week? __________

1.2.9 Source *control area* (determined by selecting appropriate *boundary entity* resource).

1.2.10 [Intentionally left blank]

1.2.10A *NERC* transaction tag identification.

1.2.11 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.11.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates;

1.2.11.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*; and

1.2.11.3 interchange scheduling defaults specified by the relevant *standards authority* shall be used unless otherwise approved by the *IESO*. Transactions shall be one hour in duration, in accordance with agreements between *control areas* along the path. Transactions shall ramp in/out over the hour and shall respect a ten-minute ramp period.

1.3 [Intentionally left blank – section deleted]

1.3.1 [Intentionally left blank – section deleted]

1.3.2 [Intentionally left blank – section deleted]

1.3.3 [Intentionally left blank – section deleted]

1.3.4 [Intentionally left blank – section deleted]

Appendix 7.2 – Energy Bid Information

1.1 Within the IESO Control Area

1.1.1 Unique load identifier.

1.1.2 Contact information.

1.1.3 Hours for which *bid* applies.

1.1.4 [Intentionally left blank]

1.1.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

1.1.6 One to five ramp sets of ramp quantity and ramp up/ramp down values for each *dispatch hour* applicable to the entire range of load contained in the *bid*.

1.1.7 [Intentionally left blank]

1.1.8 [Intentionally left blank]

1.1.9 Is this a standing *bid*? Yes/No. If Yes, Date To:_________ For which day(s) of the week? __________________

1.2 Bids Outside the IESO Control Area

1.2.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.2.2 Contact information.

1.2.3 Hour(s) for which *bid* applies.

1.2.4 [Intentionally left blank]

1.2.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

1.2.6 [Intentionally left blank]

1.2.7 [Intentionally left blank]

1.2.8 Is this a standing *bid*? – Yes/No. If Yes, Date To: ________ For which day(s) of the week? ______

1.2.9 Sink *control area* (determined by selecting appropriate *boundary entity* resource).

1.2.10 [Intentionally left blank]

1.2.10A *NERC* transaction tag identification.

1.2.11 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.11.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates;

1.2.11.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*; and

1.2.11.3 interchange scheduling defaults specified by the relevant *standards authority* shall be used unless otherwise approved by the *IESO*. Transactions shall be one hour in duration, in accordance with agreements between *control areas* along the path. Transactions shall ramp in/out over the hour and shall respect a ten-minute ramp period.

Appendix 7.3 – Operating Reserve Offer Information

1.1 Generators Within the IESO Control Area

1.1.1 Unique plant identifier (by *generation unit* or *IESO*-approved aggregated *generation units*).

1.1.2 Contact information.

1.1.3 Hour(s) for which *offer* applies.

1.1.4 Minimum MW level of *generator* output at which the *generation unit* can offer its maximum level of *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*.

1.1.5 Minimum MW level of generator output at which the *generation unit* can offer its maximum level of *thirty-minute operating reserve*.

1.1.6 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.1.7 One ramping rate applicable for all categories of *operating reserve* being offered.

1.1.8 [Intentionally left blank]

1.1.9 [Intentionally left blank]

1.1.10 [Intentionally left blank]

1.1.11 Is this a standing *offer*? Yes/No. If Yes, Date To: _________ For which day(s) of the week? _________

1.2 Offers Outside the IESO Control Area

1.2.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.2.2 Contact information.

1.2.3 Hour(s) for which *offer* applies.

1.2.4 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.2.5 [Intentionally left blank]

1.2.6 Is this a standing *offer*? – Yes/No. If Yes, Date To: _____ For which day(s) of the week?______

1.2.7 Source *control area* (determined by selecting appropriate *boundary entity* resource).

1.2.7A *NERC* transaction tag identification.

1.2.8 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.8.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates; and

1.2.8.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*.

1.3 Load Within the IESO Control Area

1.3.1 Unique load identifier.

1.3.2 Contact information.

1.3.3 Hour(s) for which *offer* applies.

1.3.4 [Intentionally left blank]

1.3.5 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.3.6 One ramping rate applicable for all categories of *operating reserve* being offered.

1.3.7 [Intentionally left blank]

1.3.8 [Intentionally left blank]

1.3.9 Is this a standing *offer*? Yes/No. If Yes, Date To: _______ For which day(s) of the week? __________

1.4 Loads Outside the IESO Control Area

1.4.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.4.2 Contact information.

1.4.3 Hour(s) for which *offer* applies.

1.4.4 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.4.5 [Intentionally left blank]

1.4.6 Is this a standing *offer* – Yes/No. If Yes, Date To: _________ For which day(s) of the week? _____

1.4.7 Sink *control area* (determined by selecting appropriate *boundary entity* resource).

1.4.7A *NERC* transaction tag identification.

1.4.8 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.4.8.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates; and

1.4.8.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*.

Appendix 7.4 – Transmission Information Required for Scheduling and Dispatching

1.1 Transmission Information Required for Scheduling and Dispatching

1.1.1 Full *connection-related reliability information* and transmission system data is required to be provided and updated to the *IESO* in accordance with Section 2.2.5 of Chapter 7 and Appendix 4.16 of Chapter 4.

1.1.2 Advance outage information is required to be provided to the *IESO* in terms of Chapter 5.

1.1.3 The following information is required to be advised to the *IESO* for scheduling and *dispatch* purposes:

1.1.3.1 any change to the maximum thermal rating of any transmission branch as advised by the *IESO* to be included in the scheduling *dispatch* and pricing algorithm; and

1.1.3.2 any change to the proposed *outage* plan as advised to and approved by the *IESO*.

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*;

2.12.1.10A 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, $RESERVEOFFERBLOCKS_{r,c,j}$ 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]

(i) [Intentionally left blank]

(ii) [Intentionally left blank]

(iii) [Intentionally left blank]

c1. DEFICIT10MINRESERVEBLOCKS;

c2. DEFICITSYNCH10MINRESERVEBLOCKS;

c3. DEFICITTOTALRESERVEBLOCKS;

c4. DEFICITAREARESERVEBLOCKS;

c5. SURPLUSAREARESERVEBLOCKS;

c6. DEFICITINTERTIEBLOCKS;

c7. SURPLUSINTERTIEBLOCKS;

c8. $\text{DEFICITEXPORT}^{\text{MMCP}}\text{BLOCKS}$;

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

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

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 $\text{RESERVEOFFERS}_{a,}$ 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 $\text{OFFERS}_{\text{INTERNALACNODES},}$ 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

$GenerationBlockMax_{g,j}$	The MW element of the j[th] block of the *offer*.
$GenerationOfferPrice_{g,j}$	The price element of the j[th] block of the *offer*. The parameter is unbounded.
$PurchaseBlockMax_{p,j}$	The MW element of the j[th] block of the *bid*.
$PurchaseBidPrice_{p,j}$	The price element of the j[th] block of the *bid*. The parameter is unbounded.
$EnergyOfferMax_{g}$	The maximum MW level for *energy* and *operating reserve* associated with *energy offer* g∈ **ENERGYOFFERBOUNDS**
$EnergyOfferMin_{g}$	The minimum MW *energy* level associated with *energy* offer g∈ **ENERGYOFFERBOUNDS**
$EnergyBidMax_{p}$	The maximum MW *energy* level associated with *energy bid* p ∈ **PURCHASEBOUND**
$EnergyBidMin_{p}$	The minimum MW *energy* level associated with *energy bid* p ∈ **PURCHASEBOUND**

4.6.2 Derived Parameters

$GenerationMaximum_{g}$	The maximum MW *energy* level associated with *energy offer* g∈ **OFFERS**.
$PurchaseMaximum_{p}$	The maximum MW *energy* level associated with *energy bid* p∈ **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∈ **OFFERS**.
$PurPF_{p}$	The loss penalty factor for *energy bid* p∈ **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∈ **OFFERS**.
$GenerationBlock_{gj}$	The MW *energy* scheduled from the j^{th} block of *energy offer* g∈ **OFFERS**.
$Purchase_p$	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy bid* p∈ **BIDS**.
$PurchaseBlock_{pj}$	The MW *energy* scheduled from the j^{th} block of *energy bid* p∈ **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

$\text{ReserveOfferPrice}_{r,c,j}$	The price element of block j of *operating reserve* of class c associated with *operating reserve offer* r. The parameter is unbounded.
$\text{ReserveBlockMaximum}_{r,c,j}$	The maximum MW *operating reserve* of class c available from block j of *operating reserve offer* r.
$\text{ReserveLoadingPoint10}_{r}$	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*.
$\text{ReserveLoadingPoint30}_{r}$	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*.
$\text{ReserveOfferMax}_{r}$	The maximum MW level associated with *operating reserve offer* $r \in$ **RESERVEBOUNDS**.
$\text{ReserveOfferMin}_{r}$	The minimum MW level associated with *operating reserve offers* $r \in$ **RESERVEBOUNDS**.

4.8.3 Derived Parameters

$\text{ReserveMaximum10}_r$	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*.
$\text{ReserveMaximum30}_r$	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

$\text{Reserve}_{r,c}$	The scheduled *operating reserve* of class c corresponding to *operating reserve offer r*.
$\text{ReserveBlock}_{r,c,j}$	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

$\text{GenericSecurityMinLimit}_v$	The lower limit imposed on the combination of *energy offers* and *energy bids* in security constraint $v \in$ **SECURITY.** The parameter is unbounded.
$\text{GenericSecurityMaxLimit}_v$	The upper limit imposed on the combination of *energy offers* and *energy bids* in security constraint $v \in$ **SECURITY**. The parameter is unbounded.
$\text{SecurityGroupGenerationWeight}_{v,g}$	The weight associated with *energy offer* $g \in \mathbf{SECURITYGENERATIONGROUP}_v$ in security constraint v. The parameter is unbounded.

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

$\text{GenerationEndMax}_g$	The maximum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.
$\text{GenerationEndMin}_g$	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 $g \in$ **OFFERS**.
$\text{RampRate}_{p,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j^{th} block of $\text{PURCHASERAMPUPBLOCK}_p$ $p \in$ **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 $p \in$ **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.*
$\text{OperatingReserveRampRate}_p$	The single *operating reserve* ramp rate in MW per minute associated with $p \in$ **BIDS**.
$\text{GenerationRampBlockMax}_{g,j}$	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.
$\text{PurchaseRampBlockMax}_{p,j}$	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.
$\text{Generation}_g^{Previous}$	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.
$Deficit\ Export^{MMCP}Penalty_{z,j}$	The penalty per unit of the $Deficit\ Export^{MMCP}\ Block_{z,j}$ 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

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:

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

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.

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

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

5.1.1.2 Wherever the following notation is found:

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

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

$$
\begin{aligned}
ViolationVariables = & \sum_{\{j \mid j \in \text{DEFICITGENERATIONBLOCKS}\}} \text{DeficitGenerationPenalty}_j \times DeficitGenerationBlock_j \\
+ & \sum_{\{j \mid j \in \text{SURPLUSGENERATIONBLOCKS}\}} \text{SurplusGenerationPenalty}_j \times SurplusGenerationBlock_j \\
+ & \sum_{\{j \mid j \in \text{DEFICIT10MINRESERVEBLOCKS}\}} \text{Deficit10MinReservePenalty}_j \times Deficit10MinReserveBlock_j \\
+ & \sum_{\{j \mid j \in \text{DEFICITSYNCH10MINRESERVEBLOCKS}\}} \text{Deficit10MinSynchReservePenalty}_j \times DeficitSynch10MinReserveBlock_j \\
+ & \sum_{\{j \mid j \in \text{DEFICITTOTALRESERVEBLOCKS}\}} \text{DeficitTotalReservePenalty}_j \times DeficitTotalReserveBlock_j \\
+ & \sum_{\{j,a \mid j \in \text{DEFICITAREARESERVEBLOCKS}_A\text{, where } a \in AREAS\}} \text{Deficit10MinReservePenalty}_j \times DeficitAreaReserveBlock_{a,j} \\
+ & \sum_{\{j,a \mid j \in \text{SURPLUSAREARESERVEBLOCKS}_A\text{, where } a \in AREAS\}} \text{Surplus10MinReservePenalty}_j \times SurplusAreaReserveBlock_{a,j} \\
+ & \sum_{\{j,v \mid j \in \text{DEFICITSECURITYBLOCKS}_v\text{, where } v \in \text{SECURITYMIN}\}} \text{DeficitSecurityPenalty}_{v,j} \times DeficitSecurityBlock_{v,j} \\
+ & \sum_{\{j,v \mid j \in \text{SURPLUSSECURITYBLOCKS}_v\text{, where } v \in \text{SECURITYMAX}\}} \text{SurplusSecurityPenalty}_{v,j} \times SurplusSecurityBlock_{v,j} \\
+ & \sum_{\{j,z \mid j \in \text{SURPLUSINTERTIEBLOCKS}_z\text{, where } z \in \text{INTERTIEZONES}\}} \text{SurplusIntertiePenalty}_{z,j} \times SurplusIntertieBlock_{z,j} \\
+ & \sum_{\{j,z \mid j \in \text{DEFICITINTERTIEBLOCKS}_z\text{, where } z \in \text{INTERTIEZONES}\}} \text{DeficitIntertiePenalty}_{z,j} \times DeficitIntertieBlock_{z,j} \\
+ & \sum_{\{j,z \mid j \in \text{DEFICITEXPORT}^{\text{MMCP}}\text{BLOCKS}_z\text{, where } z \in \text{INTERTIEZONES}\}} \text{DeficitExport}^{\text{MMCP}}\text{Penalty}_{z,j} \times DeficitExport^{MMCP}Block_{z,j}
\end{aligned}
$$

5.1.1.4 The Tie Breaking Term

$$TieBreaking = \sum_{\{j,p \mid j \in \mathbf{PURCHASEBIDBLOCKS}_p, \text{where } p \in \mathbf{BIDS}\}} \left\{ \frac{0.0005 \times \left(PurchaseBlock_{p,j}\right)^2}{\text{PurchaseBlockMax}_{p,j}} \right\}$$
$$+ \sum_{\{j,g \mid j \in \mathbf{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \mathbf{OFFERS}\}} \left\{ \frac{0.0005 \times \left(GenerationBlock_{g,j}\right)^2}{\text{GenerationBlockMax}_{g,j}} \right\}$$
$$+ \sum_{\substack{\{j,r,c \mid j \in \mathbf{RESERVEOFFERBLOCKS}_{r,c}, \\ \text{where } r \in \mathbf{RESERVEOFFERS} \text{ and } c \in \mathbf{RESERVECLASSES}\}}} \left\{ \frac{0.0005 \times \left(ReserveBlock_{r,c,j}\right)^2}{\text{ReserveBlockMax}_{r,c,j}} \right\}$$

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

$$GenerationBlock_{g,j} \le \text{GenerationBlockMax}_{g,j}$$

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

6.1.2

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

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

6.1.3

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

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

6.1.4

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

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

6.1.5

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

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

6.1.6

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

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

6.1.7

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

$$\{p \in \mathbf{PURCHASEBOUNDS}\}$$

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

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

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

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

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

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

6.3.3B

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

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

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

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

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

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$_{\mathrm{r(g)}}$ or ReserveLoadingPoint30$_{\mathrm{r(g)}}$ 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

$$\sum_{c \in \{\text{RS10, RNS10}\}} Reserve_{r(g),c} \le \text{Reserve Maximum10}_g$$

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

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

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

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

6.3.5B.2

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

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

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

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

6.3.6.3 Total operating reserve

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

6.3.6.3A Area *operating reserve* requirements

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

$$\text{MaximumAreaOperatingReserve}_a \geq \sum_{r \in RESERVEOFFERS_a, c \in \{RS10, RNS10\}} Reserve_{r,c} - \sum_{j \in SURPLUSAREARESERVEBLOCKS} SurplusAreaReserve_{j,a} \quad \{a \in \mathbf{AREAS}\}$$

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

$$\sum_{p \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times Purchase_p$$
$$+ \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times Generation_g$$
$$- \sum_{j \in \text{SURPLUSSECURITYBLOCKS}_v} SurplusSecurityBlock_{j,v} \leq \text{GenericMaxSecurityLimit}_v$$
$$\{v \in \mathbf{SECURITY}_{GenericMaximum}\}$$

6.4.3.2

$$\sum_{p \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times Purchase_p$$
$$+ \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times Generation_g$$
$$+ \sum_{j \in \text{DEFICITSECURITYBLOCKS}_v} DeficitSecurityBlock_{v,j} \geq \text{GenericMinSecurityLimit}_v$$
$$\{v \in \textbf{SECURITY}_{GenericMinimum}\}$$

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*.

$$\sum_{g \in \text{OFFERS}_z} Generation_g - \sum_{p \in \text{BIDS}_z} Purchase_p + \sum_{r \in \text{RESERVEOFFERS}_z, c \in \text{RESERVECLASSES}} Reserve_{r,c}$$
$$- \sum_{j \in \text{SURPLUSINTERTIEBLOCKS}_z,} SurplusInterieBlock_{z,j} \leq \text{MaxIntertieZoneFlow}_z$$

$$\sum_{g \in \text{OFFERS}_z} Generation_g - \sum_{p \in \text{BIDS}_z} Purchase_p +$$
$$+ \sum_{j \in \text{DEFICITINTERTIEBLOCKS}_z,} DeficitInterieBlock_{z,j} \geq \text{MinIntertieZoneFlow}_z$$

$$\{z \in \textbf{INTERTIEZONES}\}$$

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

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

6.5.4.4

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

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 to or 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* $\{g \in \mathbf{OFFERS}\}$. The pre-processing calculations described in sections 7.2.4 and 7.2.5 are performed for all *bids* by *dispatchable loads* $\{p \in \mathbf{BIDS}\}$.

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:

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

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:

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

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:

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

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:

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

where

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

8.3 Energy Constrained Generation Units

8.3.1 $$\text{EnergyRemaining}_g = \text{EnergyRemaining}_g^{Previous} - \text{Generation}_g^{Previous} \times \text{SchedPeriod}$$

where SchedPeriod is the scheduling period measured in hours, currently 1 hour. If EnergyRemaining_g ever takes a value of less than zero then it shall be set to zero. If 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 $\text{EnergyRemaining}_g = \text{EnergyOffered}_g$ 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:

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

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; and

8.4.1.2 for $n \in$ EXTERNALACNODES:

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

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:

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

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:

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

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 7.5A – The DACP Calculation Engine Process

1.1 Interpretation

1.1.1 This appendix describes the DACP calculation engine process used to determine commitments, constrained schedules, and shadow prices.

1.1.1.1 Commitment refers to the availability of *generation facilities* and imports to provide *energy* and/or *operating reserve* and *dispatchable loads* and exports to provide *operating reserve*.

1.1.1.2 The constrained schedules of the *schedule of record* are assessed in the calculation of production cost guarantees.

1.1.1.3 The shadow price of a location indicates the price of meeting an infinitesmal amount of change in load at that location.

1.1.2 The mathematical description of the optimization algorithm of the DACP calculation engine process is also described in this appendix.

1.1.3 The DACP calculation engine "outputs" described in this appendix refer to data produced by DACP calculation engine and the *IESO* shall not be required to *publish* such data except where expressly required by these *market rules*.

2. DACP Calculation Engine

2.1 Overview

2.1.1 The DACP calculation engine is a core component of the DACP process that performs the functions of commitment and constrained scheduling over a 24-hour period for *energy* and *operating reserves,* and the calculation of shadow prices. The DACP calculation engine executes three passes to produce the final *schedule of record*.

2.1.1.1 Pass 1, the Commitment Pass determines the initial set of commitments and constrained schedules required to satisfy the average forecast *demand* of the next day. Details of Pass 1 are described in section 4.

2.1.1.2 Pass 2, the Reliability Pass ensures that if the resources committed by Pass 1 are insufficient to satisfy peak forecast *demand*, additional resources are committed and scheduled. Details of Pass 2 are described in section 5.

2.1.1.3 Pass 3, the Scheduling Pass uses the commitments made in Passes 1 and 2 to determine the *schedule of record* and the associated constrained schedules to meet average forecast *demand*. Details of Pass 3 are described in section 6.

2.1.2 Since each pass provides constrained schedules, the DACP calculation engine will iterate the calculations for constrained schedules with *security* assessments until there are no *security* violations. The *security* assessment functionality is described in section 4.4.

3. Inputs into the DACP Calculation Engine

3.1 Demand Forecast

3.1.1 The *IESO* shall prepare forecasts of the total *demand* in Ontario for each hour of the next day. This hourly forecast will be modified by the DACP calculation engine so that the expected consumption associated with *dispatchable loads* will be removed. Average hourly *demand* forecasts will be used as inputs to Passes 1 and 3. Peak hourly *demand* forecasts will be used as inputs to Pass 2.

3.2 Energy Offers and Bids

3.2.1 A registered market participant may submit an energy offer or energy bid and associated dispatch data with respect to a given registered facility for each dispatch hour of the next day for DACP. Energy offers, bids and dispatch data shall be submitted in accordance to Chapter 7 and may be limited in accordance with section 2.2.1.15 of Appendix 7.5.

3.3 Operating Reserve Offers

3.3.1 A *registered market participant* may submit an *offer* and associated *dispatch data* to provide each class of *operating reserve* for each *dispatch hour* of the next day for DACP. *Operating reserve offers* and *dispatch data* shall be submitted in accordance to Chapter 7.

3.4 Forecasts from Self-Scheduling Generation Facilities, Transitional Scheduling Generators and Intermittent Generators

3.4.1 The DACP calculation engine will take into account the expected output of *self-scheduling generation facilities, transitional scheduling generators and intermittent generators* when committing resources to meet forecast *demand* for the next day. The *registered market participant* representing such generation at each location will inform the *IESO* of the amount of *energy* it expects to produce in each hour of the next day as a function of price in accordance to Chapter 7.

3.5 Ramp up to Minimum Loading Point

3.5.1 In order for the DACP calculation engine to determine constrained schedules in Pass 3 that account for the *energy* produced by *generation facilities* during ramping to their *minimum loading points*, an approximate value of this *energy* will be used. This *energy* will be represented by a fraction of the unit's *minimum loading point* in the hour prior to the first hour it is scheduled.

3.6 Energy Limited Resources

3.6.1 *Energy* limited resources constitute a subset of *generation facilities* that at times can be limited in the amount of *energy* they can provide during each day.

3.6.2 An *energy* limited resource shall designate the daily limit on the amount of *energy* it could be scheduled to generate over the course of the day.

3.7 Transmission Inputs

3.7.1. Transmission inputs are based on information prepared by the *IESO* for the *security* assessment function of the DACP calculation engine described in section 4.4. These inputs include:

3.7.1.1 Internal transmission constraints;

3.7.1.2 Limits on imports and exports;

3.7.1.3 Loop flows; and

3.7.1.4 Transmission losses.

3.8 Other Inputs

3.8.1 The *IESO* shall also provide other inputs into the DACP calculation engine that are necessary in order to ensure a solution that is consistent with system *reliability*. These include:

3.8.1.1 Distribution of internal *demand*;

3.8.1.2 Distribution of imports, exports and loop flows;

3.8.1.3 *Operating reserve* requirements;

3.8.1.4 Must-run resources for other reliability purposes;

3.8.1.5 Regulation *(AGC);*

3.8.1.6 Voltage constraints;

3.8.1.7 Initializing assumptions regarding resources in operation; and

3.8.1.8 Costs of violations.

4. Pass 1: Constrained Commitment to Meet Average Demand

4.1 Overview

4.1.1 Pass 1 performs a least cost, *security* constrained, unit commitment and constrained scheduling to meet the forecast average *demand* and *IESO*-specified *operating reserve* requirements for each hour of the next day.

4.1.2 This pass will use *bids* and *offers* and associated *dispatch data* submitted by *registered market participants* to maximize the gains from trade (i.e., the difference between the total price of *bids* submitted by *market participants* whose *bids* were scheduled, and the total price of *offers* submitted by *market participants* whose *offers* were scheduled). The optimization is subject to the constraints accompanying those *bids* and *offers*, and constraints imposed by the *IESO* to ensure reliable service.

4.2 Inputs for Pass 1

4.2.1 Inputs for Pass 1 include those described in section 3.

4.3 Optimization Objective for Pass 1

4.3.1 The objective function of Pass 1 is to maximize the gains from trade. This is accomplished by maximizing the sum of the following quantities for each hour of the trade day:

The value of:

- Scheduled exports;

Less the *offered* costs of:

- Scheduled *operating reserve* from exports;
- The foregone opportunity due to scheduled load reductions;
- Scheduled operating reserve from dispatchable load;
- Scheduled hourly imports;
- Scheduled *operating reserve* from imports;
- Scheduled operating reserve from generation facilities;
- Scheduled generation;
- Hourly costs for speed no-load for committed *generation facilities*; and
- Startup cost for committed generation facilities;

Less the cost of:

- Scheduled violation variables.

4.3.2 The cost for each violation variable for each hour is the hourly magnitude of the violation variable multiplied by the price (in $ per MW per hour) for relaxing the particular constraint. The hourly cost associated with all violation variables is the sum of the individual hourly costs for:

- Projected load curtailment due to a supply deficit;

- Scheduling additional load to offset surplus must-run *generation facility* requirements (the minus sign is required since the violation price is negative);
    - *Operating reserve* requirement deficits;
    - All reserve area minimum *operating reserve* requirement deficits;
    - All reserve area *operating reserve* excesses above maximum requirements;
    - Pre-contingency and post-contingency limit violations for internal transmission facilities;
    - Pre-contingency limit violations for import or export *interties*; and
    - Exceeding the up or down ramp limits for the total net schedule change for imports and exports.

4.4 Security Assessment

4.4.1 For constrained scheduling, the DACP calculation engine iterates a *security* assessment function with the scheduling function. The scheduling function produces schedules which are passed to the *security* assessment function. The *security* assessment function determines losses and additional constraints which feed back to the subsequent iteration of the scheduling function.

4.4.2 The *security* assessment function used by Pass 1 is common to all passes of the DACP calculation engine process.

4.4.3 The *security* assessment function performs the following calculations and analyses:

4.4.3.1 Base case solution: A base case solution function prepares a power flow solution for each hour. This function automatically selects the power system model state (i.e., breaker/switch status, tap positions, desired voltages, etc) applicable to the forecast of conditions for the hour and input schedules. An AC load flow program is used; however, a DC load flow may be used should the AC load flow fail to converge.

4.4.3.2 Loss calculation: The solved power flow is used to calculate Ontario *transmission system* losses, incremental loss factors and loss adjustments to be used in the power balance constraint of the scheduling function.

4.4.3.3 Pre-contingency *security* assessment: Continuous thermal limits for all monitored equipment and operating *security limits* are monitored to check for pre-contingency limit violations. Violated limits are linearized and incorporated as constraints for use by the scheduling function.

4.4.3.4 Linear contingency analysis: A variation of the DC load flow is used to simulate all valid contingencies, calculate post contingency flows and check for limited time (i.e. emergency) thermal limit violations. Violated limits are linearized and incorporated as constraints for use by the scheduling function.

4.4.4 In the first iteration, before any processing by the *security* assessment functions, an initial default set of incremental loss factors and loss adjustments is used in the scheduling function. In this iteration, there are no transmission constraints from the *security* assessment. In subsequent iterations, the outputs from the *security* assessment function are used.

4.4.5 The *IESO* maintains sets of data as outlined in Appendix 7.5, section 2.4 for use in the *security* assessment processes for the *real-time market* and operation. The *security* assessment function will use this same set of data to obtain:

4.4.5.1 the power system model;

4.4.5.2 status of power system equipment;

4.4.5.3 list of contingencies to be simulated;

4.4.5.4 list of monitored equipment;

4.4.5.5 equipment thermal limits; and

4.4.5.6 operating *security limits* (angular stability, voltage stability and voltage decline).

4.4.6 Constraint violation variables, when violated indicate the type of problem that is not allowing the optimization of the objective function to have a solution. The equivalent constraint violation variables and their values as used in the *real-time market* and described Appendix 7.5, section 4.12 are utilized by the DACP calculation engine. Further details of these inputs for the DACP calculation engine are described in section 4.6.2.4.

4.5 Outputs from Pass 1

4.5.1 The primary outputs of Pass 1 which are used in Pass 2 and other DACP processes include the following:

4.5.1.1 Commitments;

4.5.1.2 Constrained schedules for *energy*; and

4.5.1.3 Shadow prices for *energy*.

4.6 Glossary of Sets, Indices, Variables and Parameters for Pass 1

4.6.1 Fundamental Sets and Indices

A	The set of all *intertie zones* a.
B	The set of buses b within Ontario, corresponding to *bids* and offers at locations on the *IESO-controlled grid.*
C	The set of contingencies conditions c to be considered in the *security* assessment.
D	The set of buses d outside Ontario, corresponding to *bids* and offers at *intertie zones*.
F	The set of transmission *facilities* (or groups of transmission *facilities*) f in Ontario for which constraints have been identified.
J	The set of all *bids* j. Each *price-quantity pair* of a *bid* submitted by a *market participant* would be represented by a unique element j in the set.
J_b	The subset of those *bids* j consisting of *bids* for a *dispatchable load* resource at a bus b.
J_d	The subset of those *bids* j consisting of *bids* for an export to *intertie zone* sink bus d.
K	The set of all *offers*. Each *price-quantity pair* of an *offer* submitted by a *market participant* would be represented by a unique element k in the set.
K_b	The subset of those *offers* consisting of *offers* for a *generation facility* at a bus b.
K_d	The subset of those *offers* consisting of *offers* for an import to *intertie zone* source bus d.
$ORREG$	The set of reserve areas, or regions, for which minimum and maximum *operating reserve* requirements have been defined. Each region r of the set $ORREG$ consists of a set of buses at which *operating reserve* satisfying the minimum and maximum *operating reserve* requirement for that region may be located.
Z_{sch}	The set of all *interties* (or groups of *interties)* z for which constraints have been identified.

a	An *intertie zone*.
b	A bus corresponding to *bids* and *offers*. A single *facility* for which multiple *energy bids* are allowed may be represented as multiple buses, corresponding to the individual *bids*.
c	A contingency condition considered in the *security* assessment.
d	A bus outside Ontario corresponding to *bids* and *offers* in *intertie zones*.
f	A transmission *facility* for which a constraint has been identified. This includes groups of transmission *facilities*.
h	One of the day-ahead hours, from 1 to 24.
j	A *bid* or portion of a *bid* representing a single *price-quantity pair*.
k	An *offer* or portion of an *offer* representing a single *price-quantity pair*.
r	An *operating reserve* region within Ontario.
z	An *intertie* for which a constraint has been identified. This includes groups of *interties*.

4.6.2 Variables and Parameters

4.6.2.1 Bid and Offer Inputs

Dispatchable Loads:

$QPRL_{j,h,b}$	An incremental quantity of reduction in *energy* consumption that may be scheduled for a *dispatchable load* in hour h at bus b in association with *bid* j.
$PPRL_{j,h,b}$	The lowest *energy* price at which the incremental quantity of reduction in *energy* consumption specified in *bid* j should be scheduled in hour h at bus b.

$10SQPRL_{j,h,b}$	The synchronized *ten-minute operating reserve* quantity associated with *bid j* in hour *h* at bus *b* for *dispatchable loads* qualified to do so.
$10SPPRL_{j,h,b}$	The price of being scheduled to provide synchronized *ten-minute operating reserve* associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$10NQPRL_{j,h,b}$	The non-synchronized *ten-minute operating reserve* quantity associated with *bid j* in hour *h* at bus *b* for *dispatchable loads* qualified to do so.
$10NPPRL_{j,h,b}$	The price of being scheduled to provide non-synchronized *ten-minute operating reserve* associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$30RQPRL_{j,h,b}$	The *thirty-minute operating reserve* quantity associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$30RPPRL_{j,h,b}$	The price of being scheduled to provide *thirty-minute operating reserve* associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$ORRPRL_b$	The *operating reserve* ramp rate per minute for reductions in load consumption at bus *b*.
$URRPRL_b$	The maximum rate per minute at which a *dispatchable load* that wishes to consume *energy* at bus *b* can decrease its amount of energy consumption.
$DRRPRL_b$	The maximum rate per minute at which a *dispatchable load* that wishes to consume *energy* at bus *b* can increase its amount of load consumption.

Exports:

$QHXL_{j,h,d}$	The maximum quantity of *energy* for which an export to *intertie zone* sink bus *d* in hour *h* may be scheduled in association with *bid j*.

$PHXL_{j,h,d}$	The highest price at which *energy* should be scheduled for an export to *intertie zone* sink bus *d* in hour *h* in association with *bid j*.
$QX10N_{j,h,d}$	The non-synchronized *ten-minute operating reserve* quantity associated with *bid j* in hour *h* at *intertie zone* sink bus *d* for an export qualified to do so.
$PX10N_{j,h,d}$	The price of being scheduled to provide non-synchronized *ten-minute operating reserve* associated with *bid j* in hour *h* at *intertie zone* sink bus *d*, for an export qualified to do so.
$QX30R_{j,h,d}$	The *thirty-minute operating reserve* quantity associated with *bid j* in hour *h* at *intertie zone* sink bus *d*, for an export qualified to do so.
$PX30R_{j,h,d}$	The price of being scheduled to provide *thirty-minute operating reserve* associated with *bid j* in hour *h* at *intertie zone* sink bus *d*, for an export qualified to do so.
$ORRHXL_d$	The *operating reserve* ramp rate per minute for exports at *intertie zone* sink bus *d*, as specified by the *IESO*.

Dispatchable Generators:

$MinQPRG_{h,b}$	The *minimum loading point* which is the minimum amount of *energy* that a *generation facility* at bus *b* is willing to produce in hour *h*, if scheduled to operate.
$SUPRG_{h,b}$	The *offered start-up cost* that a *generation facility* at bus *b* incurs in order to start and synchronize in hour *h*.
$SNL_{h,b}$	The *offered speed no-load cost* to maintain a *generation facility* synchronized with zero net *energy* injected into the system in hour *h*.
$MGOPRG_{h,b}$	The *offered* minimum generation cost for a *generation facility* at bus *b* in order to operate at its *minimum loading point* in hour *h.* This is calculated as the sum of $SNL_{h,b}$ and the incremental price, $PPRG_{k,h,b}$ for *energy* up to the *minimum loading point*, $MinQPRG_{h,b}$.

$QPRG_{k,h,b}$	An incremental quantity of *energy* generation (above and beyond the *minimum loading point*) that may be scheduled at bus *b* in hour *h* in association with *offer k.*
$PPRG_{k,h,b}$	The lowest *energy* price at which incremental generation should be scheduled at bus *b* in hour *h* in association with *offer k*.
$10SPPRG_{k,h,b}$	The *offered* price of being scheduled to provide synchronized *ten-minute operating reserve* in hour *h* at bus *b* in association with *offer k.*
$10SQPRG_{k,h,b}$	The *offered* quantity of synchronized *ten-minute operating reserve* in hour *h* at bus *b* in association with *offer k*.
$10NPPRG_{k,h,b}$	The *offered* price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour *h* at bus *b* in association with *offer k*.
$10NQPRG_{k,h,b}$	The *offered* quantity of non-synchronized *ten-minute operating reserve* in association with *offer k*.
$30RPPRG_{k,h,b}$	The *offered* price of being scheduled to provide *thirty-minute operating reserve* in association with *offer k*.
$30RQPRG_{k,h,b}$	The *offered* quantity of *thirty-minute operating reserve* in hour *h* at bus *b* in association with *offer k*.
$ORRPRG_{b}$	The maximum *operating reserve* ramp rate per minute at bus *b*.
$MRTPRG_{b}$	The *minimum generation block run time* period for which a *generation facility* at bus *b* must be scheduled to operate if its *offer* to generate is accepted.
$MDTPRG_{b}$	The *minimum generation block down time* period between the end of one period when a *generation facility* at bus *b* is scheduled to operate and the beginning of the next period when it is scheduled to operate.

$MaxStartsPRG_b$	The maximum number of times per day a *generation facility* at bus *b* can be scheduled tostart.
$URRPRG_b$	The maximum rate per minute at which a *generation facility offering* to produce at bus *b* can increase the amount of *energy* it supplies.
$DRRPRG_b$	The maximum rate per minute at which a *generation facility offering* to produce at bus *b* can decrease the amount of *energy* it supplies.
EL_b	The daily limit on the amount of *energy* that an *energy* limited resource at bus *b* may be scheduled to generate over the course of the day (*maximum daily energy limit*).

Imports:

$QHIG_{k,h,d}$	The maximum quantity of *energy* for which an import from *intertie zone* source bus *d* in hour *h* may be scheduled in association with *offer k*.
$PHIG_{k,h,d}$	The lowest price at which an import from *intertie zone* source bus *d* in hour *h* in association with *offer k* should be scheduled.
$QI10N_{k,h,d}$	The non-synchronized *ten-minute operating reserve* quantity associated with *offer k* in hour *h* at *intertie zone* source bus *d*.
$PI10N_{k,h,d}$	The price of being scheduled to provide non-synchronized *ten-minute operating reserve* associated with *offer k* in hour *h* at *intertie zone* source bus *d*.
$QI30R_{k,h,d}$	The non-synchronized *thirty-minute operating reserve* quantity associated with *offer k* in hour *h* at *intertie zone* source bus *d*.
$PI30R_{k,h,d}$	The price of being scheduled to provide non-synchronized *thirty-minute operating reserve* associated with *offer k* in hour *h* at *intertie zone* source bus *d*.

$ORRHIG_d$	The *operating reserve* ramp rate per minute for imports at *intertie zone* source bus *d*, as specified by the *IESO*.

4.6.2.2 Transmission and Security Inputs and Intermediate Variables

$EnCoeff_{a,z}$	The coefficient for calculating the contribution of scheduled *energy* flows (and *operating reserve*, in the case of inflows) over *intertie zone a* which is part of the *intertie* group *z*. $EnCoeff_{a,z}$ takes the value +1 to account for limits on scheduled flows into Ontario and the value -1 to account for limits on scheduled flows out of Ontario.
$MaxExtSch_{z,h}$	The maximum flow limit over an *intertie z* in hour *h*.
$ExtDSC_h$	The maximum decrease in total net flows over all *interties* from hour to hour, which limits the hour-to-hour decreases in net imports (calculated as imports less exports) from all the *intertie zones*.
$ExtUSC_h$	The maximum increase in total net flows over all *interties* from hour to hour, which limits the hour-to-hour increases in net imports (calculated as imports less exports) from all the *intertie zones*.
$PF_{h,a}$	The anticipated inflow into Ontario from *intertie zone a* in hour *h* that result from loop flows.
$MglLoss_{h,b}$	The marginal impact on transmission losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at the bus *b* in hour *h*.
$LossAdj_h$	The adjustment needed for hour *h* to correct for any discrepancy between actual Ontario total system losses using a base case power flow from the *security* assessment function and system losses that would be calculated using the marginal transmission loss factors.
$With^1_{h,b}$	The total amount of withdrawals scheduled in Pass 1 at each bus *b* in each hour *h*, for scheduled *dispatchable loads*.

$With^{1}_{h,d}$	The total amount of withdrawals scheduled in Pass 1 at each bus *d* in each hour *h*, for exports and outflows associated with loop flows for buses in *intertie zones*.
$Inj^{1}_{h,b}$	The total amount of injections scheduled in Pass 1 at each bus *b* in each hour *h*, for scheduled generation.
$Inj^{1}_{h,d}$	The total amount of injections scheduled in Pass 1 at each bus *d* in each hour *h*, for imports and inflows associated with loop flows for buses in *intertie zones*.
$PreConSF_{b,f,h}$	The fraction of *energy* injected at bus *b* which flows on transmission *facility f* during hour *h* under pre-contingency conditions.
$AdjNormMaxFlow_{f,h}$	The maximum flow allowed on transmission *facility f* in hour *h* as determined by the *security* assessment for pre-contingency conditions.
$SF_{b,f,c,h}$	The fraction of *energy* injected at bus *b* which flows on a transmission *facility f* during hour *h* under post-contingency conditions.
$AdjEmMaxFlow_{f,c,h}$	The maximum flow allowed on transmission *facility f* in hour *h* as determined by the *security* assessment for post-contingency condition *c*.

4.6.2.3 Other Inputs

Distribution of Load, Imports and Exports and Loop Flows

$LDF_{h,b}$	Load distribution factors, for loads which are distributed across Ontario, representing the proportion of the load at bus *b* in hour *h*. This is based on historical telemetry data.
AFL_{h}	Average Ontario *demand* forecast in hour *h* with the expected consumption associated with *dispatchable loads* removed.
PFL_{h}	Peak Ontario *demand* forecast in hour *h* with the expected consumption associated with *dispatchable loads* removed.

$ProxyUPIWt_{d,a}$	The proportion of inflows associated with loop flows from *intertie zone a* that shall be assigned to each bus *d* in the *control area* in which that *intertie zone* is located.
$ProxyUPOWt_{d,a}$	The proportion of outflows associated with loop flows from *intertie zone a* that shall be assigned to each bus *d* in the *control area* in which that *intertie zone* is located.
10ORConv	The factor applied to scheduled *ten-minute operating reserve* for *energy* limited resources to convert MW into MWh. This factor shall be 1.0.
30ORConv	The factor applied to scheduled *thirty-minute operating reserve* for *energy* limited resources to convert MW into MWh. This factor shall be 1.0.

Operating Reserve Requirements:

$TOT10R_h$	Minimum requirement for the total amount of *ten-minute operating reserve*.
$TOT10S_h$	The total amount of synchronized *ten-minute operating reserve* required in hour *h,* which is a percentage of the total *ten-minute operating reserve* requirement.
$TOT30R_h$	Minimum requirement for the total amount of *thirty-minute operating reserve*.
$REGMin10R_{r,h}$	The minimum requirement for *ten-minute operating reserve* in region *r* in hour *h*.
$REGMax10R_{r,h}$	The maximum amount of *ten-minute operating reserve* that may be provided in region *r* in hour *h.*
$REGMin30R_{r,h}$	The minimum requirement for *thirty-minute operating reserve* in region *r* in hour *h*.
$REGMax30R_{r,h}$	The maximum amount of *thirty-minute operating reserve* that may be provided in region *r* in hour *h.*

Other Ancillary Service and Resource Initializing Assumptions:

$MaxPRL_{h,b}$	The maximum amount of load reduction that a *dispatchable load* can achieve at bus *b* in hour *h*.

$MinPRG_{h,b}$	The minimum output for a *generation facility* at bus *b* in hour *h,* that is the most restrictive of the limits for *regulation* or voltage support, providing *AGC* or due to outages.
$MaxPRG_{h,b}$	The maximum output for a *generation facility* at bus *b* in hour *h,* that is the most restrictive of the limits for *regulation* or voltage support, providing *AGC* or due to outages.
$InitOperHrs_b$	The number of consecutive hours at the end of the previous day for which the *generation facility* or load at bus *b* was scheduled to operate.

4.6.2.4 Constraint Violation Price Inputs

PLdViol	The value that the DACP calculation engine will assign to scheduling the forecast load. As measured by the effect on the value of the objective function, if the cost of serving that load (in dollars per MWh) exceeds *PLdViol*, then that load would not be scheduled. This is not applicable to Pass 1 since *PLdViol* will exceed maximum *bid* price allowed and no *bid* load could be scheduled at this price. This equals the shortage cost for *energy* applied in the *real-time market*.
PGenViol	The price at which additional load will be included above the scheduled amount when the amount of *energy generation facilities* produce at their *minimum loading points* exceeds the amount of load scheduled on the system. This equals the negative of the shortage cost for *energy* applied in the *real-time market*.
P10SViol	The price at which the overall minimum synchronized *ten-minute operating reserve* requirement may be violated. This equals the shortage cost for synchronized *ten-minute operating reserve* applied in the *real-time market*.

P10RViol	The price at which the overall minimum *ten-minute operating reserve* requirement may be violated. This equals the shortage cost for total *ten-minute operating reserve* applied in the *real-time market*.
P30RViol	The price at which the overall minimum *thirty-minute operating reserve* requirement may be violated. This equals the shortage cost for total *thirty-minute operating reserve* applied in the *real-time market*.
PREG10RViol	The price at which the regional minimum *ten-minute operating reserve* requirements may be violated. This equals the shortage cost for the corresponding value applied in the *real-time market*.
PXREG10RViol	The price at which the regional maximum *ten-minute operating reserve* requirements may be violated. This equals the shortage cost for the corresponding value applied in the *real-time market*.
PREG30RViol	The price at which the regional minimum *thirty-minute operating reserve* requirements may be violated This equals the shortage cost for the corresponding value applied in the *real-time market*.
PXREG30RViol	The price at which the regional maximum *thirty-minute operating reserve* requirements may be violated. This equals the shortage cost for the corresponding value applied in the *real-time market*.
PPreConITLViol	The price at which pre-contingency flows over internal transmission may exceed that *facility*'s limit. This equals the shortage cost for base case *security limits* applied in the *real-time market*.
PITLViol	The price at which flows over an internal transmission *facility* following a contingency may exceed that *facility*'s limit. This equals the shortage cost for contingency constrained *security limits* applied in the *real-time market*.

PPreConXTLViol	The price at which the pre-contingency import and export *intertie* limits may be violated. This equals the shortage cost for inter *control area* scheduling limits applied in the *real-time market*.
PRmpXTLViol	The price at which the limit for hour to hour changes (up and down) of total net scheduled imports from *intertie zones* may be violated. This equals the shortage cost for inter *control area* scheduling limits applied in the *real-time market*.

4.6.2.5 Output Schedule and Commitment Variables

$SHXL^{1}_{j,h,d}$	The amount of exports scheduled in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SX10N^{1}_{j,h,d}$	The amount of non-synchronized *ten-minute operating reserve* scheduled from the export in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SX30R^{1}_{j,h,d}$	The amount of *thirty-minute operating reserve* scheduled from the export in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SPRL^{1}_{j,h,b}$	The amount of *dispatchable load* reduction scheduled at bus *b* in hour *h* in Pass 1 in association with *bid j*.
$10SSPRL^{1}_{j,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 1 in association with *bid j*.
$10NSPRL^{1}_{j,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 1 in association with *bid j*.
$30RSPRL^{1}_{j,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 1 in association with *bid j*.

$SHIG^{1}_{k,h,d}$	The amount of hourly imports scheduled in hour *h* from *intertie zone* source bus *d* in Pass 1 in association with *offer k*.
$SI10N^{1}_{k,h,d}$	The amount of imported *ten-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 1 in association with *offer k*.
$SI30R^{1}_{k,h,d}$	The amount of imported *thirty-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 1 in association with *offer k*.
$SPRG^{1}_{k,h,b}$	The amount of *energy* scheduled for the *generation facility* at bus *b* in hour *h* in Pass 1 in association with *offer k*. This is in addition to any $MinQPRG_{h,b}$, the *minimum loading point*, which must also be committed.
$OPRG^{1}_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled in hour *h* in Pass 1.
$IPRG^{1}_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled to start in hour *h* in Pass 1.
$10SSPRG^{1}_{k,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 1 in association with *offer k*.
$10NSPRG^{1}_{k,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 1 in association with *offer k*.
$30RSPRG^{1}_{k,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 1 in association with *offer k*.

4.6.2.6 Output Violation Variables

$ViolCost^{1}_{h}$	The cost incurred in order to avoid having the Pass 1 schedules for hour *h* violate specified constraints.
$SLdViol^{1}_{h}$	Projected load curtailment, that is, the amount of load that cannot be met using *offers* scheduled or committed in hour *h* in Pass 1.

$SGenViol^{1}_{h}$	The amount of additional load that must be scheduled in hour *h* in Pass 1 to ensure that there is enough load on the system to offset the must-run requirements of *generation facilities*.
$S10SViol^{1}_{h}$	The amount by which the overall synchronized *ten-minute operating reserve* requirement is not met in hour *h* of Pass 1 because the cost of meeting that portion of the requirement was greater than or equal to *P10SViol.*
$S10RViol^{1}_{h}$	The amount by which the overall *ten-minute operating reserve* requirement is not met in hour *h* of Pass 1 (above and beyond any failure to meet the synchronized *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P10RViol.*
$S30RViol^{1}_{h}$	The amount by which the overall *thirty-minute operating reserve* requirement is not met in hour *h* of Pass 1 (above and beyond any failure to meet the *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P30RViol.*
$SREG10RViol^{1}_{r,h}$	The amount by which the minimum *ten-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 1 because the cost of meeting that portion of the requirement was greater than or equal to *PREG10RViol.*
$SREG30RViol^{1}_{r,h}$	The amount by which the minimum *thirty-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 1 because the cost of meeting that portion of the requirement was greater than or equal to *PREG30RViol.*
$SXREG10RViol^{1}_{r,h}$	The amount by which the *ten-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 1 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG10RViol.*

$SXREG30RViol^{1}_{r,h}$	The amount by which the *thirty-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 1 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG30RViol.*
$SPreConITLViol^{1}_{f,h}$	The amount by which pre-contingency flows over *facility f* in hour *h* of Pass 1 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConITLViol.*
$SITLViol^{1}_{f,c,h}$	The amount by which flows over *facility f* that would follow the occurrence of contingency *c* in hour *h* of Pass 1 exceed the emergency limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PITLViol.*
$SPreConXTLViol^{1}_{z,h}$	The amount by which *intertie* flows over *facility z* in hour *h* of Pass 1 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConXTLViol.*
$SURmpXTLViol^{1}_{h}$	The amount by which the total net scheduled import increase for hour *h* in Pass 1 exceeds the up ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*
$SDRmpXTLViol^{1}_{h}$	The amount by which the total net scheduled import decrease in hour *h* of Pass 1 exceed the down ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

4.6.2.7 Output Shadow Prices

Shadow Prices of Constraints:

SPL^{1}_{h} The Pass 1 shadow price measuring the rate of change of the objective function for a change in load at the *reference bus* in hour *h*.

$SPNormT^1_{f,h}$ The Pass 1 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjNormMaxFlow_{f,h}$, on flows over transmission *facilities* in normal conditions for *facility f* in hour *h*.

$SPEmT^1_{f,c,h}$ The Pass 1 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjEmMaxFlow_{f,c,h}$, on flows over transmission *facilities* in emergency conditions for *facility f* in monitored contingency *c* in hour *h*.

Shadow Price for Energy:

$LMP^1_{h,b}$ The Pass 1 locational marginal price for *energy* at each bus *b* in each hour *h*. It measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of supply at that bus in that hour in Pass 1.

4.6.2.8 Energy Ramp Rates

$RmpRngMaxPRL_{j,b}$ The maximum load reduction to which the ramp rates $URRPRL_{j,b}$ and $DRRPRL_{j,b}$ apply for a *dispatchable load* at bus *b*. The largest $RmpRngMaxPRL_{j,b}$ must be greater than or equal to maximum load reduction bid.

$URRPRL_{j,b}$ The maximum rate per minute at which a *dispatchable load* at bus *b* can decrease its consumption of energy while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b}$.

$DRRPRL_{j,b}$ The maximum rate per minute at which a *dispatchable load* at bus *b* can increase its consumption of energy while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b}$.

$RmpRngMaxPRG_{k,b}$ The maximum output level to which the ramp rates $URRPRG_{k,b}$ and $DRRPRG_{k,b}$ apply for a *generation facility* at bus *b*. The largest $RmpRngMaxPRG_{k,h,b}$ must be greater than or equal to maximum *energy offered*.

$URRPRG_{k,b}$ The maximum rate per minute at which a *generation facility* at bus *b* can increase its output while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$.

$DRRPRG_{k,b}$ The maximum rate per minute at which a *generation facility* at bus b can decrease its output in hour h while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$.

4.7 Objective Function

4.7.1 The optimization of the objective function in Pass 1 is to maximize the expression:

$$\sum_{h=1,\ldots,24}\left\{\begin{array}{l}\sum_{d\in DX, j\in J_d}\left(SHXL^1_{j,h,d}\cdot PHXL_{j,h,d}-SX10N^1_{j,h,d}\cdot PX10N_{j,h,d}-SX30R^1_{j,h,d}\cdot PX30R_{j,h,d}\right)\\ -\sum_{b\in B}\left[\begin{array}{l}\sum_{j\in J_b}SPRL^1_{j,h,b}\cdot PPRL_{j,h,b}\\ +\sum_{j\in J_b}\begin{array}{l}10SSPRL^1_{j,h,b}\cdot 10SPPRL_{j,h,b}+10NSPRL^1_{j,h,b}\cdot 10NPPRL_{j,h,b}+\\ 30RSPRL^1_{j,h,b}\cdot 30RPPRL_{j,h,b}\end{array}\end{array}\right]\\ -\sum_{d\in DI, k\in K_d}\left(SHIG^1_{k,h,d}\cdot PHIG_{k,h,d}+SI10N^1_{k,h,d}\cdot PI10N_{k,h,d}+SI30R^1_{k,h,d}\cdot PI30R_{k,h,d}\right)\\ -\sum_{b\in B}\left[\begin{array}{l}\sum_{k\in K_b}\left(SPRG^1_{k,h,b}\cdot PPRG_{k,h,b}\right)\\ +OPRG^1_{h,b}\cdot MGOPRG_{h,b}+IPRG^1_{h,b}\cdot SUPRG_{h,b}\\ +\sum_{k\in K_b}\begin{array}{l}10SSPRG^1_{k,h,b}\cdot 10SPPRG_{k,h,b}+10NSPRG^1_{k,h,b}\cdot 10NPPRG_{k,h,b}\\ +30RSPRG^1_{k,h,b}\cdot 30RPPRG_{k,h,b}\end{array}\end{array}\right]\\ -ViolCost^1_h\end{array}\right\};$$

where $ViolCost^1_h$ is calculated as follows:

$$
\begin{aligned}
ViolCost_h^1 &= SLdViol_h^1 \cdot PLdViol - SGenViol_h^1 \cdot PGenViol \\
&+ S10SViol_h^1 \cdot P10SViol + S10RViol_h^1 \cdot P10RViol \\
&+ S30RViol_h^1 \cdot P30RViol \\
&+ \sum_{r \in ORREG} \begin{pmatrix} SREG10RViol_{r,h}^1 \cdot PREG10RViol \\ + SREG30RViol_{r,h}^1 \cdot PREG30RViol \\ + SXREG10RViol_{r,h}^1 \cdot PXREG10RViol \\ + SXREG30RViol_{r,h}^1 \cdot PXREG30RViol \end{pmatrix} \\
&+ \sum_{f \in F} SPreConITLViol_{f,h,}^1 \cdot PPreConITLViol \\
&+ \sum_{f \in F, c \in C} SITLViol_{f,c,h}^1 \cdot PITLViol \\
&+ \sum_{z \in Z} SPreConXTLViol_{z,h}^1 \cdot PPreConXTLViol \\
&+ SURmpXTLViol_h^1 \cdot PRmpXTLViol \\
&+ SDRmpXTLViol_h^1 \cdot PRmpXTLViol.
\end{aligned}
$$

4.7.2 The Pass 1 maximization is subject to the constraints described in the next section.

4.8 Constraints Overview

4.8.1 The constraints that apply to the optimization above can be broken into the categories:

a) Single hour constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *bids* and *offers* submitted by *registered market participants*;

b) Inter-hour and multi-hour constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *bids* and *offers* submitted by *registered market participants*; and

c) Constraints to ensure that those schedules do not violate *reliability* criteria established by the *IESO*.

4.9 Bid/Offer Constraints Applying to Single Hours

4.9.1 Status Variables and Capacity Constraints

4.9.1.1 A Boolean variable, $OPRG^{1}_{h,b}$ indicates whether a *dispatchable generation facility* at bus b is committed in hour h. A value of zero indicates that a resource is not committed, while a value of one indicates that it is committed. Therefore:

$$OPRG^{1}_{h,b} = 0 \text{ or } 1,$$

for all hours h and buses b.

4.9.1.2 Must-run resources will be considered committed for all must-run hours. Regulating units will be considered committed for all the hours that they are regulating. *Generation facilities* with zero commitment cost (i.e., their *minimum loading point*s, *start-up costs minimum generation block run-times* and *minimum generation block down times* are zero) and hourly loads, imports and exports will be considered committed for all the hours.

4.9.1.3 No schedule can be negative, nor can any schedule exceed the amount of capacity *offered* for that service (*energy* and *operating reserve*). Therefore:

$$0 \le SPRL^1_{j,h,b} \le QPRL_{j,h,b};$$

$$0 \le 10SSPRL^1_{j,h,b} \le 10SQPRL_{j,h,b};$$

$$0 \le 10NSPRL^1_{j,h,b} \le 10NQPRL_{j,h,b};$$

$$0 \le 30RSPRL^1_{j,h,b} \le 30RQPRL_{j,h,b};$$

$$0 \le SHXL^1_{j,h,d} \le QHXL_{j,h,d};$$

$$0 \le SX10N^1_{j,h,d} \le QX10N_{j,h,d};$$

$$0 \le SX30R^1_{j,h,d} \le QX30R_{j,h,d};$$

$$0 \le SHIG^1_{k,h,d} \le QHIG_{k,h,d};$$

$$0 \le SI10N^1_{k,h,d} \le QI10N_{k,h,d}; \text{ and}$$

$$0 \le SI30R^1_{k,h,d} \le QI30R_{k,h,d}$$

for all *bids* j, *offers* k, hours h, buses b and *intertie zones* sink/source bus d.

4.9.1.4 In the case of *generation facilities*, in addition to restrictions on their schedules similar to those above, their schedules must be consistent with their operating status as described above. *Generation facilities* can be scheduled to produce *energy* and/or *operating reserve* only if they are committed. Therefore:

$$0 \le SPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot QPRG_{k,h,b};$$

$$0 \le 10SSPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot 10SQPRG_{k,h,b};$$

$$0 \le 10NSPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot 10NQPRG_{k,h,b}; \text{ and}$$

$$0 \le 30RSPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot 30RQPRG_{k,h,b}$$

for all *offers* k, hours h, and buses b.

4.9.1.5 In the case of linked wheeling transactions (the export *bid* and the import *offer* have the same *NERC* tag identifier), the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore:

$$\sum_{j \in J_d} SHXL^1_{j,h,dx} = \sum_{k \in k_d} SHIG^1_{k,h,di}$$

where dx and di are the respective buses of the export and import schedules associated with the wheeling transactions.

4.9.1.6 The minimum and/or maximum output of internal resources may be limited because of *outages* and/or de-ratings or in order for the units to provide *regulation* or voltage support. These constraints will take the form:

$$MinPRG_{h,b} \le MinQPRG_{h,b} \cdot OPRG^1_{h,b} + \sum_{k \in K_b} SPRG^1_{k,h,b} \le MaxPRG_{h,b}.$$

4.9.1.7 Similarly, the maximum level of load reduction is the mechanism by which a *dispatchable load* indicates any de-rating to its registered maximum load reduction level due to mechanical or operational adjustments to their equipment. The constraint will take the form:

$$\sum_{j \in J_b} SPRL^1_{j,h,b} \le MaxPRL_{h,b}.$$

4.9.2 Operating Reserve Constraints

4.9.2.1 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load (maximum load *bid* minus the load reductions). These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq 30 \cdot ORRPRL_b\text{; and}$$

$$\sum_{j \in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq \sum_{j \in J_b}(QPRL_{j,h,b} - SPRL^1_{j,h,b}).$$

4.9.2.2 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to increase load reduction (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8):

$$\sum_{j \in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq -\sum_{j \in J_b}\left[\left(QPRL_{j,h-1,b} - SPRL^1_{j,h-1,b}\right) - \left(QPRL_{j,h,b} - SPRL^1_{j,h,b}\right)\right]$$
$$+ 60 \cdot URRPRL_b.$$

4.9.2.3 Finally, the total 10-minute synchronized, 10-minute non-synchronized and 30-minute *operating reserve* from committed *dispatchable load* cannot exceed the *dispatchable load's* Pass 1 scheduled consumption:

$$\sum_{j \in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq MaxPRL_{h,b} - \sum_{j \in J_b} SPRL^1_{j,h,b}.$$

4.9.2.4 The amount of 10-minute synchronized reserve plus the 10-minute non-synchronized reserve that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_b} 10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} \leq 10 \cdot ORRPRL_b.$$

4.9.2.5 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *generation facility* cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) \leq 30 \cdot ORRPRG_b \text{; and}$$

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) \leq \sum_{k \in K_b} (QPRG_{k,h,b} - SPRG^1_{k,h,b}).$$

4.9.2.6 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable generation facility* cannot exceed the *generation facility's* ramp capability (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8). Ramping considerations from start ups or shut downs are not carried forward from one day to the next:

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) \le \sum_{k \in K_b} (SPRG^1_{k,h-1,b} - SPRG^1_{k,h,b}) + 60 \times URRPRG_b$$

and

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) + \sum_{k \in K_b} (SPRG^1_{kh,b}) \le [(h-n) * 60 + 30] \times URRPRG_b \times OPRG^1_{h,b}$$

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

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) + \sum_{k \in K_b} (SPRG^1_{k,h,b}) \le [(m-h) * 60 + 30] \times DRRPRG_b \times OPRG^1_{h,b}$$

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

4.9.2.7 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *generation facility* cannot exceed its Pass 1 unscheduled capacity:

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) \leq MaxPRG_{h,b} - \sum_{k \in K_b} SPRG^1_{k,h,b} - MinQPRG_{h,b}.$$

4.9.2.8 The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *generation facility* is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b}) \leq 10 \cdot ORRPRG_b.$$

4.9.2.9 The total reserve (10-minute non-synchronized and 30-minute) from hourly exports cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled export. These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_d} (SX10N^1_{j,h,d} + SX30R^1_{j,h,d}) \leq 30 \cdot ORRHXL_d; \text{ and}$$

$$\sum_{j \in J_d} (SX10N^1_{j,h,d} + SX30R^1_{j,h,d}) \leq \sum_{j \in J_d} SHXL^1_{j,h,d}.$$

4.9.2.10 The amount of 10-minute non-synchronized reserve that hourly export is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_d} (SX10N^1_{j,h,d}) \leq 10 \cdot ORRHXL_d.$$

4.9.2.11 The total reserve (10-minute non-synchronized and 30-minute) from hourly imports cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_d}(SI10N^1_{k,h,d} + SI30R^1_{k,h,d}) \leq 30 \cdot ORRHIG_d \text{; and}$$

$$\sum_{k \in K_d}(SI10N^1_{k,h,d} + SI30R^1_{k,h,d}) \leq \sum_{k \in K_d}(QHIG_{k,h,d} - SHIG^1_{k,h,d}).$$

4.9.2.12 The amount of 10-minute non-synchronized reserve that hourly import is scheduled to provide cannot exceed the amount by which it can increase the output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_d} SI10N^1_{k,h,d} \leq 10 \cdot ORRHIG_d.$$

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

4.10.1 Status Variables

4.10.1.1 A Boolean variable, $IPRG^1_{h,b}$, indicates that a *generation facility* at bus *b* is scheduled to start up on hour *h*. A value of zero indicates that a resource is not scheduled to start up, while a value of one indicates that it is scheduled to start up. Therefore, for $h > 1$:

$$IPRG^1_{h,b} = \begin{cases} 1, & \text{if } OPRG^1_{h-1,b} = 0 \text{ and } OPRG^1_{h,b} = 1 \\ 0, & \text{otherwise.} \end{cases}$$

4.10.1.2 For $h = 1$, the determination of whether a resource was previously operating must make reference to the initial conditions:

$$IPRG_{h,b}^{1} = \begin{cases} 1, & \text{if } InitOperHrs_b = 0 \text{ and } OPRG_{h,b}^{1} = 1 \\ 0, & \text{otherwise.} \end{cases}$$

4.10.2 Ramping

4.10.2.1 *Energy* schedules for each resource cannot vary by more than an hour's ramping capacity for that resource. The *energy* schedule change in the hour in which the unit is scheduled to start or shut down depends on the unit ramp rate below its *minimum loading point*. Almost all non-quick start units will need one or more hours to reach their *minimum loading point* and to go down from *minimum loading point* to zero. Since non-committed units must be assigned zero output and committed units must operate at or above their *minimum loading point*, it is assumed that these units will be at their *minimum loading point* at the beginning of the first commitment hour and at the end of the hour before shut down.

4.10.2.2 The following three part constraint ensures that *energy* schedules do not exceed the *generation facility's* ramp capability in the hours where the *generation facility* starts, stays on and shuts down.

Start Up Scenario ($OPRG^1_{h,b} = 1$, and $OPRG^1_{h-1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^1_{k,h,b} \leq \sum_{k \in K_b} 30 \times URRPRG_b$$

Continued On Scenario ($OPRG^1_{h-1,b} = OPRG^1_{h,b} = 1$)

$$\sum_{k \in K_b} (SPRG^1_{k,h-1,b}) - 60 \times DRRPRG_b \leq \sum_{k \in K_b} SPRG^1_{k,h,b}$$

$$\leq \sum_{k \in K_b} (SPRG^1_{k,h-1,b}) + 60 \times URRPRG_b$$

Shut Down Scenario ($OPRG^1_{h,b} = 1$, and $OPRG^1_{h+1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^1_{k,h,b} \leq \sum_{k \in K_b} 30 \times DRRPRG_b$$

4.10.2.3 It should be noted that this ramp up/down is in addition to the *minimum loading point*. The unit commitment process handles the *minimum loading point* change. This ramp only affects the incremental change above the *minimum loading point*.

4.10.2.4 The *dispatchable loads* are considered committed in all hours. Similar logic is applied to *dispatchable loads* to arrive at the following constraint:

$$\sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^1_{j,h-1,b}\right) - 60 \cdot URRPRL_{h,b}$$

$$\leq \sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^1_{j,h,b}\right)$$

$$\leq \sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^1_{j,h-1,b}\right) + 60 \cdot DRRPRL_{h,b}.$$

4.10.2.5 The above two constraints apply for all hours from 1 to 24. In the above two constraints the variables related to hour zero belong to the last hour of the previous day and are obtained from the initializing assumptions.

4.10.2.6 The ramping rates in the ramping constraints must be adjusted to allow the resource to:

a) Ramp down from its lower limit in hour (*h-1*) to its upper limit in hour *h*.

b) Ramp up from its upper limit in hour (*h-1*) to its lower limit in hour *h*.

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

4.10.2.8 In the above ramping constraints, a single ramp up and a single ramp down, $URRPRG_b$ and $DRRPRG_b$ for *generation facilities* and $URRPRL_b$ and $DRRPRL_b$ for *dispatchable loads* are used. The ramp rate is assumed constant over the full operating range of the *dispatchable load* and *generation facility*. However, this is not the case. *Dispatchable load bids* and *generator offers* will include multi-*energy* ramp rates.

4.10.2.9 In the *dispatchable load bids*, multi-*energy* ramp rates would be specified as:

a) $RmpRngMaxPRL_{j,\ b}$ shall designate the level of maximum load reduction to which the ramp rates $URRPRL_{j,b}$ and $DRRPRL_{j,b}$ shall apply. $RmpRngMaxPRL_{5,b}$ must be greater than or equal to maximum load reduction *bid*.

b) $URRPRL_{j,b}$ shall designate the maximum rate per minute at which a *dispatchable load* at bus *b* can increase load reduction while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b.}$ $RmpRngMaxPRL_{0,b}$ is equal to the minimum load reduction.

c) $DRRPRL_{j,b}$ shall designate the maximum rate per minute at which a *dispatchable load* at bus *b* can decrease load reduction while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b.}$ $RmpRngMaxPRL_{0,b}$ is equal to the minimum load reduction.

4.10.2.10 The multi-*energy* ramp rates would be specified for *generation facilities* as:

a) $RmpRngMaxPRG_{k,b}$ shall designate the maximum generation output level to which the ramp rates $URRPRG_{k,b}$ and $DRRPRG_{k,b}$ shall apply. $RmpRngMaxPRG_{5,b}$ must be greater than or equal to maximum generation output *offered*.

b) $URRPRG_{k,b}$ shall designate the maximum rate per minute at which a *generation facility* at bus *b* can increase its output while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$. $RmpRngMaxPRG_{0,b}$ is equal to its *minimum loading point*.

c) $DRRPRG_{k,b}$ shall designate the maximum rate per minute at which a *generation facility* at bus *b* can decrease its output while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$. $RmpRngMaxPRG_{0,b}$ is equal to its *minimum loading point*.

4.10.3 Minimum Generation Block Run Time and Minimum Generation Block Down Time

4.10.3.1 Schedules for *generators* must observe *minimum generation block run times* and *minimum generation block down times*. At the beginning of the day, a *generation facility*'s previous day schedule is considered,

if $0 < InitOperHrs_b < MRTPRG_b$, then that *generation facility* has yet to complete its *minimum generation block run time*, and:

$$OPRG^1_{1,b}, OPRG^1_{2,b}, \ldots, OPRG^1_{\min(24, MRTPRG_b - InitOperHrs_b), b} = 1.$$

4.10.3.2 During the day,

if $OPRG^1_{h,b} = 1$, $OPRG^1_{h+1,b} = 0$, and $MDTPRG_b > 1$, then the *generation facility* at bus *b* has been scheduled to shut down during hour $h + 1$. It must be scheduled to remain off until it has completed its *minimum generation block down time* or we reach the end of the day. Therefore:

$$OPRG^1_{h+2,b}, OPRG^1_{h+3,b}, \ldots, OPRG^1_{\min(24, h+MDTPRG_b), b} = 0.$$

And if $OPRG^1_{h,b} = 0$, $OPRG^1_{h+1,b} = 1$, and $MRTPRG_b > 1$, then the *generation facility* at bus b has been scheduled to start up during hour $h + 1$. It must be scheduled to remain in operation until it has completed its *minimum generation block run time* or we reach the end of the day, so:

$$OPRG^1_{h+2,b}, OPRG^1_{h+3,b}, \ldots, OPRG^1_{\min(24, h+MRTPRG_b), b} = 1, \text{and}$$

$$OPRG^1_{0,b} = \begin{cases} 0, \text{ if } InitOperHrs_b = 0 \\ 1, \text{ otherwise.} \end{cases}$$

4.10.4 Energy Limited Resources

4.10.4.1 A constraint must be added in order to ensure that *energy* limited units are not scheduled to provide more *energy* than they have indicated they are capable of providing. In addition to limiting *energy* schedules over the course of the day to the *energy* limit specified for a unit, this constraint must also ensure that units are not scheduled to provide *energy* in amounts that would preclude them from providing reserve when activated. Given these factors, therefore:

$$\sum_{h=1}^{1}\left(OPRG^{1}_{h,b} \cdot MinQPRG_{h,b} + \sum_{k\in K_b} SPRG^{1}_{k,h,b}\right)$$
$$+ 10ORConv\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,1,b} + \sum_{k\in K_b} 10NSPRG^{1}_{k,1,b}\right)$$
$$+ 30ORConv \sum_{k\in K_b} 30RSPRG^{1}_{k,1,b} \le EL_b;$$

$$\sum_{h=1}^{2}\left(OPRG^{1}_{h,b} \cdot MinQPRG_{h,b} + \sum_{k\in K_b} SPRG^{1}_{k,h,b}\right)$$
$$+ 10ORConv\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,2,b} + \sum_{k\in K_b} 10NSPRG^{1}_{k,2,b}\right)$$
$$+ 30ORConv \sum_{k\in K_b} 30RSPRG^{1}_{k,2,b} \le EL_b;$$

M

$$\sum_{h=1}^{24}\left(OPRG^{1}_{h,b} \cdot MinQPRG_{h,b} + \sum_{k\in K_b} SPRG^{1}_{k,h,b}\right)$$
$$+ 10ORConv\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,24,b} + \sum_{k\in K_b} 10NSPRG^{1}_{k,24,b}\right)$$
$$+ 30ORConv \sum_{k\in K_b} 30RSPRG^{1}_{k,24,b} \le EL_b$$

for all buses b at which *energy*-limited resources are located. The factors *10ORConv* and *30ORConv* are applied to scheduled *ten-minute* and *thirty-minute operating reserves* for *energy*-limited resources to convert MW into MWh. This factor is initially set to unity.

4.10.5 Maximum Number of Starts

4.10.5.1 To ensure that *generation facilities* are not scheduled to be cycled on and off more than their specified maximum number in a day, the following constraint is defined:

$$\sum_{h=1}^{24} IPRG^{1}_{h,b} \le MaxStartsPRG_b.$$

4.11 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

4.11.1 Load

4.11.1.1 For each hour of the DACP, the total amount of *energy* generated in the DACP schedule, plus scheduled imports must be sufficient to meet forecast *demand*, scheduled exports, and transmission losses consistent with these schedules. It will be easiest to break the derivation of the constraint that will ensure this occurs into several steps.

4.11.1.2 The total amount of withdrawals scheduled in Pass 1 at each bus *b* in each hour *h*, $With^1_{h,b}$, is the sum of:

- the portion of the load forecast for that hour that has been allocated to that bus; and
- all *dispatchable load bid*, net of the amount of load reduction scheduled (since the *dispatchable load* is excluded from the *demand* forecast by the DACP calculation engine), yielding:

$$With^1_{h,b} = LDF_{h,b} \cdot AFL_h + \left[\sum_{j \in J_h} \left(QPRL_{j,h,b} - SPRL^1_{j,h,b} \right) \right]; \text{ and}$$

the total amount of withdrawals scheduled in Pass 1 at each *intertie zone* sink bus *d* in each hour *h*, $With^1_{h,d}$, is the sum of:

- exports from Ontario to each *intertie zone* sink bus; and
- outflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$With^1_{h,d} = \sum_{j \in J_d} (SHXL^1_{j,h,d}) - \sum_{a \in A} ProxyUPOWt_{d,a} \cdot \min(0, PF_{h,a}).$$

4.11.1.3 The total amount of injections scheduled in Pass 1 at each bus *b* in each hour *h*, $Inj^1_{h,b}$, is the sum of

- *generation facilities* scheduled at that bus, yielding:

$$Inj^{1}_{h,b} = OPRG^{1}_{h,b} \cdot MinQPRG_{h,b} + \sum_{k \in K_b} SPRG^{1}_{k,h,b}; \text{ and}$$

the total amount of injections scheduled in Pass 1 at each *intertie zone* source bus d in each hour h, $Inj^{1}_{h,b}$, is the sum of:

- imports into Ontario from each *intertie zone* source bus; and
- inflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose:

$$Inj^{1}_{h,d} = \sum_{k \in K_d} SHIG^{1}_{k,h,d} + \sum_{a \in A} ProxyUPIWt_{d,a} \cdot \max(0, PF_{h,a}).$$

4.11.1.4 Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses (or reduction in losses) that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between actual and marginal losses. Load reduction associated with the *demand* constraint violation will be subtracted from the total load and generation reduction will be subtracted from total generation associated with the *demand* constraint violation to ensure that the DACP calculation engine will always produce a solution. These violation variables are assigned a very high cost to limit their use to infeasible cases.

$$\begin{aligned} &\sum_{b \in B} (1 + MglLoss_{h,b}) With^{1}_{h,b} + \sum_{d \in D} (1 + MglLoss_{h,d}) With^{1}_{h,d} - SLdViol^{1}_{h} \\ &\quad = \sum_{b \in B} (1 + MglLoss_{h,b}) Inj^{1}_{h,b} \\ &\quad\quad + \sum_{d \in D} (1 + MglLoss_{h,d}) Inj^{1}_{h,d} - SGenViol^{1}_{h} + LossAdj_{h}. \end{aligned}$$

4.11.2 Operating Reserve

4.11.2.1 Sufficient *operating reserve* must be provided on the system to meet system wide requirements for 10-minute synchronized reserve, *ten-minute operating reserve* and *thirty-minute operating reserve*, as well as all applicable regional minimum and maximum requirements for *operating reserve*.

4.11.2.2 Therefore, taking into consideration the potential not to meet these minimum and maximum requirements if the cost of meeting those requirements becomes too high:

$$\sum_{b \in B}\left(\sum_{k \in K_b} 10SSPRG^1_{k,h,b}\right) + \sum_{b \in B}\left(\sum_{j \in J_b} 10SSPRL^1_{j,h,b}\right) + S10SViol^1_h \geq TOT10S_h;$$

$$\begin{aligned}&\sum_{b \in B}\left(\sum_{j \in J_b} 10SSPRL^1_{j,h,b}\right) + \sum_{b \in B}\left(\sum_{k \in K_b} 10SSPRG^1_{k,h,b}\right) + S10RViol^1_h \\ &+ \sum_{b \in B}\left(\sum_{k \in K_b} 10NSPRG^1_{k,h,b}\right) + \sum_{b \in B}\left(\sum_{j \in J_b} 10NSPRL^1_{j,h,b}\right) \\ &+ \sum_{d \in D}\left(\sum_{k \in K_d} SI10N^1_{k,h,d}\right) + \sum_{d \in D}\left(\sum_{j \in J_d} SX10N^1_{j,h,d}\right) \geq TOT10R_h; \text{ and}\end{aligned}$$

$$\begin{aligned}&\sum_{b \in B}\left(\sum_{j \in J_b} 10SSPRL^1_{j,h,b}\right) + \sum_{b \in B}\left(\sum_{k \in K_b} 10SSPRG^1_{k,h,b}\right) + S30RViol^1_h \\ &+ \sum_{b \in B}\left(\sum_{k \in K_b} (10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b})\right) \\ &+ \sum_{b \in B}\left(\sum_{j \in J_b} (10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})\right) \\ &+ \sum_{d \in D}\left(\sum_{k \in K_d} (SI10N^1_{k,h,d} + SI30R^1_{k,h,d})\right) \\ &+ \sum_{d \in D}\left(\sum_{j \in J_d} (SX10N^1_{j,h,d} + SX30R^1_{j,h,d})\right) \geq TOT30R_h\end{aligned}$$

for all hours h, and

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^{1}_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,h,b}\right)+SREG10RViol^{1}_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^{1}_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^{1}_{j,h,b}\right)$$
$$\geq REGMin10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^{1}_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,h,b}\right)-SXREG10RViol^{1}_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^{1}_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^{1}_{j,h,b}\right)$$
$$\leq REGMax10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^{1}_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,h,b}\right)+SREG30RViol^{1}_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^{1}_{k,h,b}+30RSPRG^{1}_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^{1}_{j,h,b}+30RSPRL^{1}_{j,h,b})\right)$$
$$\geq REGMin30R_{r,h}; \text{ and}$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^{1}_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^{1}_{k,h,b}\right)-SXREG30RViol^{1}_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^{1}_{k,h,b}+30RSPRG^{1}_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^{1}_{j,h,b}+30RSPRL^{1}_{j,h,b})\right)$$
$$\leq REGMax30R_{r,h}$$

for all hours h, and for all regions r in the set *ORREG*.

4.11.3 Internal Transmission Limits

4.11.3.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 1 of the DACP calculation engine would not violate any *security limits* in either the pre-contingency state or after any contingency.

4.11.3.2 To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus will be used.

4.11.3.3 The *security* assessment function of the DACP calculation engine will linearize binding (violated) pre-contingency limits on transmission *facilities* within Ontario. The linearized constraints will take the form:

$$\sum_{b \in B} PreConSF_{b,f,h}(Inj^1_{h,b} - With^1_{h,b}) + \sum_{d \in D} PreConSF_{d,f,h}(Inj^1_{h,d} - With^1_{h,d}) - SPreConITL\ Viol^1_{f,h} \leq AdjNormMax\ Flow_{f,h}$$

where B is the set of buses within Ontario and D is the set of sink and source buses outside Ontario, for all *facilities* f and hours h.

4.11.3.4 Similarly, the linearized binding post-contingency limits will take the form:

$$\sum_{b \in B} SF_{b,f,c,h}(Inj^1_{h,b} - With^1_{h,b}) + \sum_{d \in D} SF_{d,f,c,h}(Inj^1_{h,d} - With^1_{h,d}) - SITLViol^1_{f,c,h} \leq AdjEmMaxFl\ ow_{f,c,h}$$

for all *facilities* f, hours h, and monitored contingencies c.

4.11.4 Intertie Limits and Constraints on Net Imports

4.11.4.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 1 of the DACP calculation engine would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. To ensure this, we must calculate the net amount of *energy* scheduled to flow over each *intertie* in each hour and the amount of *operating reserve* scheduled to be provided by resources in that *control area*. This will be summed over all affected *interties*. The result will be compared to the limit associated with that constraint. Consequently:

$$\sum_{a\in A}\left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d\in DI_a,k\in K_d}(SHIG^1_{k,h,d})+PF_{h,a}-\sum_{d\in DX_a,j\in J_d}(SHXL^1_{j,h,d})\right)+ \\ 0.5(EnCoeff_{a,z}+1)\left[\begin{array}{l}\sum_{d\in DI_a,k\in K_d}\left(SI10N^1_{k,h,d}+SI30R^1_{k,h,d}\right) \\ +\sum_{d\in DX_a,j\in J_d}\left(SX10N^1_{j,h,d}+SX30R^1_{j,h,d}\right)\end{array}\right]\end{array}\right]$$
$$\leq MaxExtSch_{z,h}$$

for all hours h, for all *intertie zones* a relevant to the constraint z

$(EnCoeff_{a,z}\neq 0)$,

and for all constraints z in the set Z_{sch}.

4.11.4.2 In addition, changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour. It cannot exceed the sum of net import schedule for all *interties* for the previous hour plus the maximum permitted hourly increase. It cannot be less than the sum of the net import schedule for all *interties* for the previous hour minus the maximum permitted hourly decrease. Violation variables are provided for both the up and down ramp limits to ensure that the DACP calculation engine will always find a solution. Therefore:

$$\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^1_{k,h-1,d})-\sum_{j\in J_d}(SHXL^1_{j,h-1,d})\right)-ExtDSC_h-SDRmpXTLViol^1_h$$
$$\leq\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^1_{k,h,a})-\sum_{j\in J_d}(SHXL^1_{j,h,d})\right)$$
$$\leq\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^1_{k,h-1,d})-\sum_{j\in J_d}(SHXL^1_{j,h-1,d})\right)+ExtUSC_h+SURmpXTLViol^1_h$$

for all hours h (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8).

4.12 Shadow Prices for Energy

4.12.1 The Pass 1 shadow price at each bus *b* in each hour *h* measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of generation at that bus in that hour in Pass 1. The Pass 1 shadow price at each bus *b* in each hour *h,* given the inputs and constraints into Pass 1, shall be calculated at internal locations as:

$$LMP^{1}_{h,b} = \left(1 + MglLoss_{h,b}\right) \cdot SPL^{1}_{h} + \sum_{f} \begin{pmatrix} PreConSF_{b,f,h} \cdot SPNormT^{1}_{f,h} \\ + \sum_{c} SF_{b,f,c,h} \cdot SPEmT^{1}_{f,c,h} \end{pmatrix}$$

4.12.2 The first portion of the right-hand side of this equation measures the cost of meeting load at bus *b*, incorporating the effect of marginal losses. It reflects the quantity of *energy* that must be injected at the *reference bus* to meet additional load at each bus *b*. The term in the summation reflects the cost of transmission congestion resulting from an infinitesimal increase in withdrawals at each bus *b* on each pre- and post-contingency internal transmission constraint. It is calculated as the product of each:

a) Shadow price, which measures the impact on the cost on that constraint if there were a one-to-one correspondence between increases in load and flows on the constraint (i.e., if each MW of increased load caused an increase in 1 MW inflows over the constraint); and

b) The shift factor for that bus and that constraint, which measures the actual impact of additional withdrawals at each bus on flows over that constraint.

4.12.3 [Intentionally left blank – section deleted]

5. Pass 2: Constrained Commitment to

Meet Peak Demand

5.1 Overview

5.1.1 Pass 2 performs a least cost, *security* constrained unit commitment and constrained scheduling to meet the forecast peak *demand* and *IESO*-specified *operating reserve* requirements.

5.1.2 In each hour, peak *demand* occurs for a fraction of that hour. If additional commitment of *generation facilitie*s above those made in Pass 1 are required to meet peak *demand*, these *generation facilities* would only need to be operating for a fraction of the hour. Therefore, in Pass 2, the DACP calculation engine performs least cost optimization with respect to minimizing commitment costs to satisfy peak *demand*.

5.1.3 Imports and exports can only be scheduled on an hourly basis and *generation facilities* and *dispatchable load*s can follow 5-minute dispatches to meet peak *demand*. To account for this difference in scheduling, the incremental prices of *generator offer*s and *dispatchable load bids* will be evaluated on this basis against import *offer*s and export *bids*. This evaluation of *generator offer*s and *dispatchable load bids* is explained in detail in section 5.7.

5.1.4 *Generation facilities* already committed in Pass 1 is taken as committed in Pass 2. These resources will be scheduled to no less than their *minimum loading points*. Additional commitments of *offers* from *generators* are allowed.

5.1.5 Imports scheduled in Pass 1 must be scheduled to at least that value in Pass 2. Additional hourly imports may be scheduled. Hourly exports may be scheduled to a lower but not higher value than that determined in Pass 1. The import and export components of linked wheel transactions can be scheduled higher or lower than the schedules produced in Pass 1. The commitments and schedules calculated in Pass 2 will be used in Pass 3.

5.2 Inputs into Pass 2

5.2.1 All inputs identified in section 3 will be used in Pass 2. In addition, Pass 1 *generation facility* commitments, import schedules, exports schedules and shadow prices will also be used as input into Pass 2.

5.3 Optimization Objective for Pass 2

5.3.1 As for Pass 1, the gains from trade shall be maximized for Pass 2. This is accomplished by maximizing the same objective function described in section 4.3 used for Pass 1.

5.4 Security Assessment

5.4.1 The same *security* assessment is performed as described in section 4.4.

5.5 Outputs from Pass 2

5.5.1 The primary outputs of Pass 2 which are used in Pass 3 and other DACP processes include the following:

5.5.1.1 Commitments; and

5.5.1.2 Constrained schedules for *energy*.

5.6 Glossary of Sets, Indices, Variables and Parameters for Pass 2

5.6.1 Fundamental Sets and Indices

5.6.1.1 Same as those described in section 4.6.1.

5.6.2 Variables and Parameters

5.6.2.1 Bid and Offer Inputs

Same as those described in 4.6.2.1. In addition, the variables below are used to account for the fact that *generation facilities* and *dispatchable loads* are able to follow 5-minute dispatches to meet peak *demand* but imports and exports are only scheduled on an hourly basis:

$PmtPRG_{k,h,b}$ The lowest incremental *energy price* at which an incremental amount of *energy* should be scheduled at bus b in hour h in association with offer k to meet peak *demand*.

$PmtPRL_{j,h,b}$ The lowest incremental *energy price* at which an incremental quantity of reduction in *energy* consumption should be scheduled at bus b in hour h in association with bid j to meet peak *demand*.

PriceMultiplier A *bid* and *offer* adjustment factor to account for the value of energy from *dispatchable loads* and *generation facilities* dispatched on a 5-minute basis to meet peak *demand* of any hour. This factor shall be 12.

5.6.2.2 Transmission and Security Inputs and Intermediate Variables

Same as those described in 4.6.2.2.

5.6.2.3 Other Inputs

Same as those described in 4.6.2.3.

5.6.2.4 Constraint Violation Price Inputs

Same as those described in 4.6.2.4.

5.6.2.5 Variables determined in Pass 1 and Used in Pass 2

$SHXL^1_{j,h,d}$ The amount of exports scheduled in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.

$SHIG^1_{k,h,d}$ The amount of imports scheduled in hour *h* in Pass 1 from *intertie zone* source bus *d* in associate with *offer k*.

$OPRG^1_{h,b}$ Indication of whether a *generation facility* at bus *b* was scheduled to operate in hour *h* in Pass 1.

$LMP^1_{h,b}$ The Pass 1 locational marginal price for *energy* at each bus *b* in each hour *h*.

5.6.2.6 Output Schedule and Commitment Variables

$SHXL^2_{j,h,d}$ The amount of exports scheduled in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j*.

$SX10N^2_{j,h,d}$ The amount of non-synchronized *ten-minute operating reserve* scheduled from the export in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j*.

$SX30R^2_{j,h,d}$ The amount of *thirty-minute operating reserve* scheduled from the export in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j*.

$SPRL^2_{j,h,b}$	The amount of *dispatchable load* reduction scheduled at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$10SSPRL^2_{j,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$10NSPRL^2_{j,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$30RSPRL^2_{j,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$SHIG^2_{k,h,d}$	The amount of hourly imports scheduled in hour *h* from *intertie zone* source bus *d* in Pass 2 in association with *offer k.*
$SI10N^2_{k,h,d}$	The amount of imported *ten-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 2 in association with *offer k.*
$SI30R^2_{k,h,d}$	The amount of imported *thirty-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 2 in association with *offer k.*
$SPRG^2_{k,h,b}$	The amount of *energy* scheduled for the *generation facility* at bus *b* in hour *h* in Pass 2 in association with *offer k*. This is in addition to any $MinQPRG_{h,b}$, the *minimum loading point*, which must also be committed.
$OPRG^2_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled in hour *h* in Pass 2.
$IPRG^2_{h,b}$	Represents whether *generation facility* at bus *b* has been scheduled to start in hour *h* in Pass 2.
$10SSPRG^2_{k,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 2 in association with *offer k*.
$10NSPRG^2_{k,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 2 in association with *offer k*.

$30RSPRG^2_{k,h,b}$ The amount of *thirty-minute operating reserve* that a qualified *generation facility* at bus b is scheduled to provide in hour h in Pass 2 in association with *offer* k.

5.6.2.7 Output Violation Variables

$ViolCost^2_h$ The cost incurred in order to avoid having the Pass 2 schedules for hour h violate specified constraints.

$SLdViol^2_h$ Projected load curtailment, that is, the amount of load that cannot be met using *offers* scheduled or committed in hour h in Pass 2.

$SGenViol^2_h$ The amount of additional load that must be scheduled in hour h in Pass 2 to ensure that there is enough load on the system to offset the must-run requirements of *generation facilities*.

$S10SViol^2_h$ The amount by which the overall synchronized *ten-minute operating reserve* requirement is not met in hour h of Pass 2 because the cost of meeting that portion of the requirement was greater than or equal to *P10SViol.*

$S10RViol^2_h$ The amount by which the overall *ten-minute operating reserve* requirement is not met in hour h of Pass 2 (above and beyond any failure to meet the synchronized *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P10RViol.*

$S30RViol^2_h$ The amount by which the overall *thirty-minute operating reserve* requirement is not met in hour h of Pass 2 (above and beyond any failure to meet the *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P30RViol.*

$SREG10RViol^2_{r,h}$ The amount by which the minimum *ten-minute operating reserve* requirement for region r is not met in hour h of Pass 2 because the cost of meeting that portion of the requirement was greater than or equal to *PREG10RViol.*

$SREG30RViol^2_{r,h}$ The amount by which the minimum *thirty-minute operating reserve* requirement for region r is not met in hour h of Pass 2 because the cost of meeting that portion of the requirement was greater than or equal to *PREG30RViol.*

$SXREG10RViol^2_{r,h}$	The amount by which the *ten-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 2 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG10RViol.*
$SXREG30RViol^2_{r,h}$	The amount by which the *thirty-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 2 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG30RViol.*
$SPreConITLViol^2_{f,h}$	The amount by which pre-contingency flows over *facility f* in hour *h* of Pass 2 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConITLViol.*
$SITLViol^2_{f,c,h}$	The amount by which flows over *facility f* that would follow the occurrence of contingency *c* in hour *h* of Pass 2 exceed the emergency limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PITLViol.*
$SPreConXTLViol^2_{z,h}$	The amount by which *intertie* flows over *facility z* in hour *h* of Pass 2 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConXTLViol.*
$SURmpXTLViol^2_h$	The amount by which the total net scheduled import increase for hour *h* in Pass 2 exceeds the up ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*
$SDRmpXTLViol^2_h$	The amount by which the total net scheduled import decrease in hour *h* of Pass 2 exceed the down ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

5.6.2.8 Energy Ramp Rates

Same as those in section 4.6.2.8.

5.7 Evaluation of Generator Offers and Dispatchable Load Bids

5.7.1 All *offer*s for *generation facilities* that were committed in Pass 1 will be evaluated in Pass 2 as such:

5.7.1.1 $PmtPRG_{k,h,b}$, designates the lowest incremental *energy* price at which an incremental amount of *energy* should be scheduled at bus *b* in hour *h* in association with *offer k.* It shall be set to:

$$PmtPRG_{k,h,b} = LMP^1_{h,b} + \frac{PPRG_{k,h,b} - LMP^1_{h,b}}{PriceMultiplier}$$

for $PPRG_{k,h,b} > LMP^1_{h,b}$ and

$$PmtPRG_{k,h,b} = PPRG_{h,b}$$

for $PPRG_{k,h,b} \le LMP^1_{h,b}$.

5.7.1.2 All other elements of the *offer*s will be used in Pass 2 as submitted.

5.7.2 All *dispatchable load bids* will be evaluated in Pass 2 as such:

5.7.2.1 $PmtPRL_{j,h,b}$, designates the lowest incremental *energy price* at which an incremental quantity of reduction in *energy* consumption specified in *bid j* should be scheduled in hour *h* at bus *b.* It shall be set to:

$$PmtPRL_{j,h,b} = LMP^1_{h,b} + \frac{PPRL_{j,h,b} - LMP^1_{h,b}}{PriceMultiplier}$$

for $PPRL_{j,h,b} > LMP^1_{h,b}$ and

$$PmtPRL_{j,h,b} = PPRL_{h,b}$$

for $PPRL_{j,h,b} \le LMP^1_{h,b}$.

5.7.2.2 Other elements of the *dispatchable load bids* will be used in Pass 2 as submitted.

5.8 Objective Function

5.8.1 The optimization of the objective function in Pass 2 is to maximize the expression:

$$\sum_{h=1,\ldots,24}\left\{\begin{array}{l}
\sum_{d\in DX,j\in J_d}\left(SHXL^2_{j,h,d}\cdot PHXL_{j,h,d}-SX10N^2_{j,h,d}\cdot PX10N_{j,h,d}-SX30R^2_{j,h,d}\cdot PX30R_{j,h,d}\right)\\
-\sum_{b\in B}\left[\begin{array}{l}\sum_{j\in J_b}SPRL^2_{j,h,b}\cdot PmtPRL_{j,h,b}\\
+\sum_{j\in J_b}\begin{array}{l}10SSPRL^2_{j,h,b}\cdot 10SPPRL_{j,h,b}+10NSPRL^2_{j,h,b}\cdot 10NPPRL_{j,h,b}+\\ 30RSPRL^2_{j,h,b}\cdot 30RPPRL_{j,h,b}\end{array}\end{array}\right]\\
-\sum_{d\in DI,k\in K_d}\left(SHIG^2_{k,h,d}\cdot PHIG_{k,h,d}+SI10N^2_{k,h,d}\cdot PI10N_{k,h,d}+SI30R^2_{k,h,d}\cdot PI30R_{k,h,d}\right)\\
-\sum_{b\in B}\left[\begin{array}{l}\sum_{k\in K_b}\left(SPRG^2_{k,h,b}\cdot PmtPRG_{k,h,b}\right)\\
+OPRG^2_{h,b}\cdot MGOPRG_{h,b}+IPRG^2_{h,b}\cdot SUPRG_{h,b}\\
+\sum_{k\in K_b}\begin{array}{l}10SSPRG^2_{k,h,b}\cdot 10SPPRG_{k,h,b}+10NSPRG^2_{k,h,b}\cdot 10NPPRG_{k,h,b}\\ +30RSPRG^2_{k,h,b}\cdot 30RPPRG_{k,h,b}\end{array}\end{array}\right]\\
-ViolCost^2_h
\end{array}\right\};$$

where $ViolCost^2{}_h$ is calculated as follows:

$$
\begin{aligned}
ViolCost_h^2 = {} & SLdViol_h^2 \cdot PLdViol - SGenViol_h^2 \cdot PGenViol \\
& + S10SViol_h^2 \cdot P10SViol + S10RViol_h^2 \cdot P10RViol \\
& + S30RViol_h^2 \cdot P30RViol \\
& + \sum_{r \in ORREG} \begin{pmatrix} SREG10RViol_{r,h}^2 \cdot PREG10RViol \\ + SREG30RViol_{r,h}^2 \cdot PREG30RViol \\ + SXREG10RViol_{r,h}^2 \cdot PXREG10RViol \\ + SXREG30RViol_{r,h}^2 \cdot PXREG30RViol \end{pmatrix} \\
& + \sum_{z \in Z} \left(SPreConXTLViol_{z,h}^2 \cdot PPreConXTLViol \right) \\
& + SURmpXTLViol^2 \cdot PRmpXTLViol + SDRmpXTLViol^2 \cdot PRmpXTLViol \\
& + \sum_{f \in F} SPreConITLViol_{f,h}^2 \cdot PPreConITLViol \\
& + \sum_{f \in F, c \in C} SITLViol_{f,c,h}^2 \cdot PITLViol.
\end{aligned}
$$

5.8.2 The Pass 2 maximization is subject to the constraints described in the next section.

5.9 Constraints Overview

5.9.1 The constraints applied to the Pass 2 optimization mirror those used in Pass 1 and described in sections 4.8 through 4.11. They must be modified to:

a) Apply to schedules determined in Pass 2;

b) Reflect peak *demand* forecast compared to average *demand* forecast used in Pass 1; and

c) Reflect additional constraints limiting changes in internal resource (*generation facilities* and *dispatchable loads*) commitments, import and export schedules determined in Pass 1.

5.10 Bid/Offer Constraints Applying to Single Hours

5.10.1 Status Variables and Capacity Constraints

5.10.1.1 For the same reasons as discussed in section 4.9 for Pass 1:

$OPRG^2_{h,b} = 0$ or 1, for all hours h and buses b;

$$0 \le SPRL^2_{j,h,b} \le QPRL_{j,h,b};$$

$$0 \le 10SSPRL^2_{j,h,b} \le 10SQPRL_{j,h,b};$$

$$0 \le 10NSPRL^2_{j,h,b} \le 10NQPRL_{j,h,b};$$

$$0 \le 30RSPRL^2_{j,h,b} \le 30RQPRL_{j,h,b};$$

$$0 \le SI10N^2_{k,h,d} \le QI10N_{k,h,d};$$

$$0 \le SI30R^2_{k,h,d} \le QI30R_{k,h,d};$$

$$0 \le SHIG^2_{k,h,d} \le QHIG_{k,h,d};$$

$$0 \le SHXL^2_{j,h,d} \le QHXL_{j,h,d};$$

$$0 \le SX10N^2_{j,h,d} \le QX10N_{j,h,d};$$

$$0 \le SX30R^2_{j,h,d} \le QX30R_{j,h,d};$$

$$0 \le SPRG^2_{k,h,b} \le OPRG^2_{h,b} \cdot QPRG_{k,h,b};$$

$$0 \le 10SSPRG^2_{k,h,b} \le OPRG^2_{h,b} \cdot 10SQPRG_{k,h,b};$$

$$0 \le 10NSPRG^2_{k,h,b} \le OPRG^2_{h,b} \cdot 10NQPRG_{k,h,b}; \text{ and}$$

$$0 \le 30RSPRG^2_{k,h,b} \le OPRG^2_{h,b} \cdot 30RQPRG_{k,h,b}$$

for all modified *bids* j, modified *offers* k, hours h, and buses b, and *intertie zones* source/sink bus d.

5.10.1.2 In the case of linked wheeling transactions (the export *bid* and the import *offer* have the same *NERC* tag identifier), the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore:

$$\sum_{j \in J_d} SHXL^2_{j,h,dx} = \sum_{k \in k_d} SHIG^2_{k,h,di}$$

where *dx* and *di* are the respective buses of the export and import schedules associated with the wheeling transactions.

5.10.1.3 The minimum and/or maximum output of the *generation facilities* may be limited because of *outages* and/or de-ratings or in order for the units to provide *regulation* or voltage support. These constraints will take the form:

$$MinPRG_{h,b} \leq MinQPRG_{h,b} \cdot OPRG^2_{h,b} + \sum_{k \in K_b} (SPRG^2_{k,h,b}) \leq MaxPRG_{h,b}.$$

5.10.1.4 Similarly, the maximum level of load reduction is the mechanism by which a *dispatchable load* indicates any de-rating to its registered maximum load reduction level due to mechanical or operational adjustments to their *facility*. The constraint will take the form:

$$\sum_{j \in J_b} SPRL^2_{j,h,b} \leq MaxPRL_{h,b}.$$

5.10.2 Operating Reserve Constraints

5.10.2.1 The total reserve (10-minute synchronized and non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load (maximum load *bid* minus the load reductions). These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_b} (10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\leq 30 \cdot ORRPRL_b; \text{ and}$$

$$\sum_{j \in J_b} (10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\leq \sum_{j \in J_b} (QPRL_{j,h,b} - SPRL^2_{j,h,b}).$$

5.10.2.2 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to increase load reduction (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8):

$$\sum_{j \in J_b} (10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\leq -\sum_{j \in J_b} \left[\left(QPRL_{j,h-1,b} - SPRL^2_{j,h-1,b} \right) - \left(QPRL_{j,h,b} - SPRL^2_{j,h,b} \right) \right]$$
$$+ 60 \cdot URRPRL_b .$$

5.10.2.3 Finally, the total (10-minute synchronized, 10-minute non synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* Pass 2 scheduled consumption:

$$\sum_{j \in J_b} (10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\leq MaxPRL_{h,b} - \sum_{j \in J_b} SPRL^2_{j,h,b} .$$

5.10.2.4 The amount of 10-minute synchronized and non-synchronized reserve that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_b} 10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} \leq 10 \cdot ORRPRL_b .$$

5.10.2.5 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *generation facility* cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\leq 30 \cdot ORRPRG_b \text{; and}$$

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\leq \sum_{k \in K_b} (QPRG_{k,h,b} - SPRG^2_{k,h,b}).$$

5.10.2.6 In addition, this next constraint ensures that the total(10-minute synchronized, 10-minute non-synchronized and 30-minute) from the committed *generation facility* cannot exceed its ramp capability (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8). Ramping considerations from start ups or shut downs are not carried forward from one day to the next:

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\leq \sum_{k \in K_b} \left(SPRG^2_{k,h-1,b} - SPRG^2_{k,h,b}\right) + 60 \times URRPRG_b$$

and

$$\sum_{k \in K_b} \left(10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b}\right) + \sum_{k \in K_b} \left(SPRG^2_{k,h,b}\right)$$
$$\leq [(h - n) * 60 + 30] \times URRPRG_b \times OPRG^2_{h,b}$$

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

and

$$\sum_{k \in K_b} \left(10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b}\right) + \sum_{k \in K_b} \left(SPRG^2_{k,h,b}\right)$$
$$\leq [(m - h) * 60 + 30] \times DRRPRG_b \times OPRG^2_{h,b}$$

5.10.2.7 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from the committed *generation facility* cannot exceed its Pass 2 unscheduled capacity:

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b}) \leq MaxPRG_{h,b} - \sum_{k \in K_b} SPRG^2_{k,h,b} - MinQPRG_{h,b}.$$

5.10.2.8 The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *generation facility* is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b}) \leq 10 \cdot ORRPRG_b.$$

5.10.2.9 The total reserve (10-minute non-synchronized and 30-minute) from hourly exports cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled export. These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_d} (SX10N^2_{j,h,d} + SX30R^2_{j,h,d}) \leq 30 \cdot ORRHXL_d; \text{ and}$$

$$\sum_{j \in J_d} (SX10N^2_{j,h,d} + SX30R^2_{j,h,d}) \leq \sum_{j \in J_d} SHXL^2_{j,h,d}.$$

5.10.2.10 The amount of 10-minute non-synchronized reserve that an hourly export is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_d} SX10N^2_{j,h,d} \leq 10 \cdot ORRHXL_d.$$

5.10.2.11 The total reserve (10-minute non-synchronized and 30-minute) from hourly imports cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_d} (SI10N^2_{k,h,d} + SI30R^2_{k,h,d}) \leq 30 \cdot ORRHIG_d \text{; and}$$

$$\sum_{k \in K_d} (SI10N^2_{k,h,d} + SI30R^2_{k,h,d}) \leq \sum_{k \in K_d} (QHIG_{k,h,d} - SHIG^2_{k,h,d}).$$

5.10.2.12 The amount of 10-minute non-synchronized reserve that hourly import is scheduled to provide cannot exceed the amount by which it can increase the output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_d} SI10N^2_{k,h,d} \leq 10 \cdot ORRHIG_d.$$

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

5.11.1 Status Variables

5.11.1.1 For the same reasons as discussed for Pass 1, for *generation facilities* that are scheduled to start up, and for hour, $h > 1$:

$$IPRG^2_{h,b} = \begin{cases} 1, \text{ if } OPRG^2_{h-1,b} = 0 \text{ and } OPRG^2_{h,b} = 1 \\ 0, \text{ otherwise.} \end{cases}$$

For $h = 1$:

$$IPRG^2_{h,b} = \begin{cases} 1, \text{ if } InitOperHrs_b = 0 \text{ and } OPRG^2_{h,b} = 1 \\ 0, \text{ otherwise.} \end{cases}$$

5.11.2 Ramping

5.11.2.1 Constraints limiting hour-to-hour changes in *energy* schedules are congruous to those used in Pass 1.

Start Up Scenario ($OPRG^2_{h,b} = 1$, and $OPRG^2_{h-1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^2_{k,h,b} \leq \sum_{k \in K_b} 30 \times URRPRG_b$$

Continued On Scenario ($OPRG^2_{h-1,b} = OPRG^2_{h,b} = 1$)

$$\sum_{k \in K_b} \left(SPRG^2_{k,h-1,b}\right) - 60 \times DRRPRG_b \leq \sum_{k \in K_b} SPRG^2_{k,h,b}$$

$$\leq \sum_{k \in K_b} \left(SPRG^2_{k,h-1,b}\right) + 60 \times URRPRG_b$$

Shut Down Scenario ($OPRG^2_{h,b} = 1$, and $OPRG^2_{h+1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^2_{k,h,b} \leq \sum_{k \in K_b} 30 \times DRRPRG_b$$

5.11.2.2 Similarly, the ramping constraint for the *dispatchable load* will be as follows:

$$\sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^2_{j,h-1,b}\right) - 60 \cdot URRPRL_b$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^2_{j,h,b}\right)$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^2_{j,h-1,b}\right) + 60 \cdot DRRPRL_b.$$

5.11.2.3 The above two constraints apply for all hours from 1 to 24. In the above two constraints the variables related to hour zero belong to the last hour of the previous day and are obtained from the initializing assumptions.

5.11.2.4 The ramping rates in the ramping constraints must be adjusted to allow the resource to:

a) Ramp down from its lower limit in hour (*h-1*) to its upper limit in hour *h*.

b) Ramp up from its upper limit in hour (*h-1*) to its lower limit in hour *h*.

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

5.11.2.6 In the above ramping constraints, a single ramp up and a single ramp down, $URRPRG_b$ and $DRRPRG_b$ for *generation facilities* and $URRPRL_b$ and $DRRPRL_b$ for *dispatchable loads* are used. The ramp rate is assumed constant over the full operating range of the *dispatchable load* and *generation facility*. However, this is not the case. *Dispatchable load bids and generator offers* will include multi-*energy* ramp rates. The multiple ramp rates are described in sections 4.10.2.8 and 4.10.2.9.

5.11.3 Minimum Generation Block Run-Time and Minimum Generation Block Down Time

5.11.3.1 Constraints pertaining to *minimum generation block run-times* and *minimum generation block down times* precisely mirror those used in Pass 1. Therefore,

if $0 < InitOperHrs_b < MRTPRG_b$, then

$$OPRG^2_{1,b}, OPRG^2_{2,b}, \ldots, OPRG^2_{\min(24, MRTPRG_b - InitOperHrs_b), b} = 1;$$

if $OPRG^2{}_{h,b} = 1$, $OPRG^2{}_{h+1,b} = 0$, and $MDTPRG_b > 1$, then

$$OPRG^2_{h+2,b}, OPRG^2_{h+3,b}, \ldots, OPRG^2_{\min(24, h+MDTPRG_b), b} = 0; \text{ and}$$

and if $OPRG^2{}_{h,b} = 0$, $OPRG^2{}_{h+1,b} = 1$, and $MRTPRG_b > 1$, then

$$OPRG^2_{h+2,b}, OPRG^2_{h+3,b}, \ldots, OPRG^2_{\min(24, h+MRTPRG_b), b} = 1$$

for all hours h and buses b and

$$OPRG^2_{0,b} = \begin{cases} 0, \text{ if } InitOperHrs_b = 0 \\ 1, \text{ otherwise.} \end{cases}$$

5.11.4 Energy Limited Resources

5.11.4.1 A constraint must be added in order to ensure that *energy* limited units are not scheduled to provide more *energy* than they have indicated they are capable of providing. In addition to limiting *energy* schedules over the course of the day to the *energy* limit specified for a unit, this constraint must also ensure that units are not scheduled to provide *energy* in amounts that would preclude them from providing reserve when activated. Given those factors:

Therefore:

$$\begin{aligned}
&\sum_{h=1}^{1}\left(OPRG_{h,b}^{2}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}(SPRG_{k,h,b}^{2})\right)\\
&\quad+10ORConv\left(\sum_{k\in K_b}10SSPRG_{k,1,b}^{2}+\sum_{k\in K_b}10NSPRG_{k,1,b}^{2}\right)\\
&\quad+30ORConv\sum_{k\in K_b}30RSPRG_{k,1,b}^{2}\le EL_b;\\
&\sum_{h=1}^{2}\left(OPRG_{h,b}^{2}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}(SPRG_{k,h,b}^{2})\right)\\
&\quad+10ORConv\left(\sum_{k\in K_b}10SSPRG_{k,2,b}^{2}+\sum_{k\in K_b}10NSPRG_{k,2,b}^{2}\right)\\
&\quad+30ORConv\sum_{k\in K_b}30RSPRG_{k,2,b}^{2}\le EL_b;\\
&\qquad\qquad\qquad\mathrm{M}\\
&\sum_{h=1}^{24}\left(OPRG_{h,b}^{2}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}(SPRG_{k,h,b}^{2})\right)\\
&\quad+10ORConv\left(\sum_{k\in K_b}10SSPRG_{k,24,b}^{2}+\sum_{k\in K_b}10NSPRG_{k,24,b}^{2}\right)\\
&\quad+30ORConv\sum_{k\in K_b}30RSPRG_{k,24,b}^{2}\le EL_b
\end{aligned}$$

for all buses *b* at which *energy* limited resources are located. The factors *10ORConv* and *30ORConv* are applied to scheduled *ten-minute* and *thirty-minute operating reserves* for *energy* limited resources to convert MW into MWh. This factor is set to unity.

5.11.5 Maximum Number of Starts

5.11.5.1 To ensure that *generation facilities* are not scheduled to cycle on and off more than their specified maximum number in a day, the following constraints are defined:

$$\sum_{h=1}^{24} IPRG^2_{h,b} \leq MaxStartsPRG_b.$$

5.12 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

5.12.1 Load

5.12.1.1 Load constraints are structured in the same manner as described in section 4.11.1 for Pass 1.

5.12.1.2 The total amount of withdrawals scheduled in Pass 2 at each bus *b* in each hour *h*, $With^2_{h,b}$, is the sum of:

- the portion of the load forecast for that hour that has been allocated to that bus; and
- all *dispatchable load bid*, net of the amount of load reduction scheduled (since the *dispatchable load* is excluded from the *demand* forecast by the DACP calculation engine), yielding:

$$With^2_{h,b} = LDF_{h,b} \cdot PFL_h + \left[\sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^2_{j,h,b} \right) \right]; \text{ and}$$

the total amount of withdrawals scheduled in Pass 2 at each *intertie zone* sink bus *d* in each hour *h*, $With^2_{h,d}$, is the sum of:

- exports from Ontario to each *intertie zone* sink bus; and
- outflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$With^2_{h,d} = \sum_{j \in J_d}(SHXL^2_{j,h,d}) - \sum_{a \in A} ProxyUPOWt_{d,a} \cdot \min(0, PF_{h,a}).$$

5.12.1.3 The total amount of injections scheduled in Pass 2 at each bus b in each hour h, $Inj^2_{h,b}$, is the sum of:

- *generation facilities* scheduled at that bus, yielding:

$$Inj^2_{h,b} = OPRG^2_{h,b} \cdot MinQPRG_{h,b} + \sum_{k \in K_b}\left(SPRG^2_{k,h,b}\right); \text{ and}$$

the total amount of injections scheduled in Pass 2 at each *intertie zone* source bus d in each hour h, $Inj^2_{h,d}$, is the sum of:

- imports into Ontario from each *intertie zone* source bus; and
- inflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$Inj^2_{h,d} = \sum_{k \in K_d}(SHIG^2_{k,h,d}) + \sum_{a \in A} ProxyUPIWt_{d,a} \cdot \max(0, PF_{h,a}).$$

5.12.1.4 Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses (or reduction in losses) that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between actual and marginal losses. Load reduction associated with the *demand* constraint violation will be subtracted from the total load and generation reduction associated with the *demand* constraint violation will be subtracted from total generation to ensure that the calculation engine will always produce a solution. These violation variables are assigned a very high cost to limit their use to infeasible cases.

$$\sum_{b \in B}(1+MglLoss_{h,b})With_{h,b}^2 + \sum_{d \in D}(1+MglLoss_{h,b})With_{h,d}^2 - SLdViol_h^2$$
$$= \sum_{b \in B}(1+MglLoss_{h,b})Inj_{h,b}^2$$
$$+ \sum_{d \in D}(1+MglLoss_{h,d})Inj_{h,d}^2 - SGenViol_h^2 + LossAdj_h.$$

5.12.2 Operating Reserve

5.12.2.1 Sufficient *operating reserve* must be provided on the system to meet system wide requirements for 10-minute synchronized reserve, *ten-minute operating reserve* and *thirty-minute operating reserve*, as well as all applicable regional minimum and maximum requirements for *operating reserve*.

5.12.2.2 Therefore, taking into consideration the potential not to meet these minimum and maximum requirements if the cost of meeting those requirements becomes too high:

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+S10SViol^2_h$$
$$\geq TOT10S_h;$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+S10RViol^2_h$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b} 10NSPRG^2_{k,h,b}\right)+\sum_{b\in B}\left(\sum_{j\in J_b} 10NSPRL^2_{j,h,b}\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d} SI10N^2_{k,h,d}\right)+\sum_{d\in D}\left(\sum_{j\in J_d} SX10N^2_{j,h,d}\right)\geq TOT10R_h; \text{ and}$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+S30RViol^2_h$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b}(10NSPRG^2_{k,h,b}+30RSPRG^2_{k,h,b})\right)$$
$$+\sum_{b\in B}\left(\sum_{j\in J_b}(10NSPRL^2_{j,h,b}+30RSPRL^2_{j,h,b})\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d}(SI10N^2_{k,h,d}+SI30R^2_{k,h,d})\right)$$
$$+\sum_{d\in D}\left(\sum_{j\in J_d}(SX10N^2_{j,h,d}+SX30R^2_{j,h,d})\right)\geq TOT30R_h$$

for all hours h, and

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+SREG10RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^2_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^2_{j,h,b}\right)$$
$$\geq REGMin10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)-SXREG10RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^2_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^2_{j,h,b}\right)$$
$$\le REGMax10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+SREG30RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^2_{k,h,b}+30RSPRG^2_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^2_{j,h,b}+30RSPRL^2_{j,h,b})\right)$$
$$\ge REGMin30_{r,h};\text{ and}$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)-SXREG30RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^2_{k,h,b}+30RSPRG^2_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^2_{j,h,b}+30RSPRL^2_{j,h,b})\right)$$
$$\le REGMax30R_{r,h}$$

for all hours h, and for all regions r in the set *ORREG*.

5.12.3 Internal Transmission Limits

5.12.3.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 2 of the calculation engine would not violate any *security limits* in either the pre-contingency state or in any contingency. To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus will be used.

5.12.3.2 Then the pre-contingency limits on transmission within Ontario will not be violated if:

$$\sum_{b \in B} PreConSF_{b,f,h}(Inj^2_{h,b} - With^2_{h,b}) + \sum_{d \in D} PreConSF_{d,f,h}(Inj^2_{h,d} - With^2_{h,d}) - SPreConITLViol^2_{f,h} \le AdjNormMaxFlow_{f,h}$$

for all *facilities* f and hours h.

5.12.3.3 Post-contingency limits on transmission *facilities* within Ontario will not be violated if:

$$\sum_{b \in B} SF_{b,f,c,h}(Inj^2_{h,b} - With^2_{h,b}) + \sum_{d \in D} SF_{d,f,c,h}(Inj^2_{h,d} - With^2_{h,d}) - SITLViol^2_{f,c,h} \le AdjEmMaxFlow_{f,c,h}$$

for all *facilities* f, hours h, and monitored contingencies c.

5.12.4 Intertie Limits and Constraints on Net Imports

5.12.4.1 The calculation engine would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. To ensure this, we must calculate the net amount of *energy* scheduled to flow over each *intertie* in each hour and the amount of *operating reserve* scheduled to be provided by resources in that *control area*. This will be summed over all affected *interties*. The result will be compared to the limit associated with that constraint. Consequently:

$$\sum_{a \in A} \left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d \in DI_a, k \in K_d} (SHIG^2_{k,h,d}) + PF_{h,a} - \sum_{d \in DX_a, j \in J_d} \left(SHXL^2_{j,h,d} \right) \right) + \\ 0.5(EnCoeff_{a,z} + 1) \left[\begin{array}{l} \sum_{d \in DI_a, k \in K_d} \left(SI10N^2_{k,h,d} + SI30R^2_{k,h,d} \right) \\ + \sum_{d \in DX_a, j \in J_d} \left(SX10N^2_{j,h,d} + SX30R^2_{j,h,d} \right) \end{array} \right] \end{array} \right] \le MaxExtSch_{z,h}$$

for all hours h, for all *intertie zones* a relevant to the constraint z

$(EnCoeff_{a,z} \neq 0)$, and for all constraints z in the set Z_{sch}.

5.12.4.2 In addition, changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour. It cannot exceed the sum of net import schedule for all *interties* for the previous hour plus the maximum permitted hourly increase. It cannot be less than the sum of the net import schedule for all *interties* for the previous hour minus the maximum permitted hourly decrease. Violation variables are provided for both the up and down ramp limits to ensure that the calculation engine will always find a solution.

Therefore:

$$\sum_{d \in D}\left(\sum_{k \in K_d}(SHIG^2_{k,h-1,d}) - \sum_{j \in J_d}(SHXL^2_{j,h-1,d})\right) - ExtDSC_h - SDRmpXTLViol^2_h$$
$$\leq \sum_{d \in D}\left(\sum_{k \in K_d}(SHIG^2_{k,h,d}) - \sum_{j \in J_d}(SHXL^2_{j,h,d})\right)$$
$$\leq \sum_{d \in D}\left(\sum_{k \in K_d}(SHIG^2_{k,h-1,d}) - \sum_{j \in J_d}(SHXL^2_{j,h-1,d})\right) + ExtUSC_h + SURmpXTLViol^2_h$$

for all hours h (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8).

5.12.5 Intertie Schedule Limits Based on Pass 1 Output

5.12.5.1 Pass 2 will not reduce the amount of imported *energy* scheduled from each *intertie zone* in any hour. Additional imports of *energy* may be scheduled in Pass 2. Therefore, for imports that are not part of a linked wheeling transaction:

$$SHIG^2_{k,h,d} \geq SHIG^1_{k,h,d}$$

for all *offers* k, hours h and *intertie zones* source bus d.

5.12.5.2 Pass 2 will not increase the amount of exported *energy* scheduled from each *intertie zone* sink bus in any hour over the amount scheduled in Pass 1.

5.12.5.3 Therefore, for exports that are not part of a linked wheeling transaction:

$$SHXL^{2}_{j,h,d} \leq SHXL^{1}_{j,h,d}$$

for all *bids* *j*, hours *h* and *intertie zones* sink bus *d*.

5.12.5.4 Finally, the purpose of Pass 2 is to determine whether additional *generation facilities* need to be committed to ensure that the *IESO* can meet peak forecast load, given the resources committed in Pass 1 (and if so, which resources are committed). Consequently, it will be necessary to ensure that resources committed in Pass 1 are not de-committed in this pass. Therefore:

$$OPRG^{2}_{h,b} \geq OPRG^{1}_{h,b}$$

for all hours *h* and buses.

6. Pass 3: Constrained Scheduling to Meet Average Demand

6.1 Overview

6.1.1 Pass 3 performs a least cost, *security* constrained scheduling to meet the forecast average *demand* and *IESO*-specified *operating reserve* requirements.

6.1.2 The *commitment* for generation and schedules for imports *and* exports, resulting from Pass 2 are used to schedule the least cost set of resources (*dispatchable loads, generation facilities,* imports and exports) to meet average forecast *demand* and *IESO*-specified *operating reserve* requirements, taking account of all transmission limitations including *intertie* transfer limits.

6.1.3 *Generation facilities* committed in Passes 1 and 2 will be scheduled. There will be no additional exports scheduled beyond what was scheduled in Pass 2. Imports will not be scheduled below what was scheduled in Pass 2. The import and export components of linked wheel transactions are allowed to go higher or lower than schedules produced in Pass 2.

6.2 Inputs into Pass 3

6.2.1 Inputs for Pass 3 include those described in section 3.

6.2.2 In addition, commitments from Passes 1 and 2 and schedules from Pass 2 are used as inputs.

6.3 Optimization Objective for Pass 3

6.3.1 As for Passes 1 and 2, the gains from trade shall be maximized for Pass 3. This is accomplished by maximizing an objective function similar to that described in 4.3. The Pass 3 objective function is different in that it does not include the variables for commitment. This is so because no more commitment is required for Pass 3.

6.4 Security Assessment

6.4.1 The same *security* assessment is performed as described in section 4.4.

6.5 Outputs from Pass 3

6.5.1 The primary outputs of Pass 3 include the following:

4.5.1.1 Constrained schedules for *energy* for the *schedule of record*; and

4.5.1.2 Shadow prices.

6.6 Glossary of Sets, Indices, Variables and Parameters for Pass 3

6.6.1 Fundamental Sets and Indices

6.6.1.1 Same as those described in section 4.6.1.

6.6.2 Variables and Parameters

6.6.2.1 Bid and Offer Inputs

Same as those described in 4.6.2.1.

6.6.2.2 Transmission and Security Inputs and Intermediate Variables

Same as those described in 4.6.2.2.

6.6.2.3 Other Inputs

Same as those described in 4.6.2.3.

6.6.2.4 Constraint Violation Price Inputs

Same as those described in 4.6.2.4.

6.6.2.5 Variables determined in Pass 2 and Used in Pass 3

$SHXL^{2}_{j,h,d}$ The amount of exports scheduled in hour h in Pass 2 from *intertie zone* sink bus d in association with *bid* j.

$SHIG^{2}_{k,h,d}$ The amount of imports scheduled in hour h in Pass 2 from *intertie zone* source bus d in association with *offer* k.

$OPRG^{2}_{h,b}$ Indication of whether a *generation facility* at bus b was scheduled to operate in hour h in Pass 2.

$IPRG^{2}_{h,b}$ Indication of whether a *generation facility* at bus b was scheduled to start in hour h in Pass 2.

6.6.2.6 Output Schedule and Commitment Variables

$SHXL^{3}_{j,h,d}$ The amount of exports scheduled in hour h in Pass 3 from *intertie zone* sink bus d in association with *bid* j.

$SX10N^{3}_{j,h,d}$ The amount of non-synchronized *ten-minute operating reserve* scheduled from the export in hour h in Pass 3 from *intertie zone* sink bus d in association with *bid* j.

$SX30R^{3}_{j,h,d}$ The amount of *thirty-minute operating reserve* scheduled from the export in hour h in Pass 3 from *intertie zone* sink bus d in association with *bid* j.

$SPRL^{3}_{j,h,b}$ The amount of *dispatchable load* reduction scheduled at bus b in hour h in Pass 3 in association with *bid* j.

$10SSPRL^{3}_{j,h,b}$ The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus b in hour h in Pass 3 in association with *bid* j.

$10NSPRL^3_{j,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 3 in association with *bid j*.
$30RSPRL^3_{j,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 3 in association with *bid j*.
$SHIG^3_{k,h,d}$	The amount of hourly imports scheduled in hour *h* from *intertie zone* source bus *d* in Pass 3 in association with *offer k.*
$SI10N^3_{k,h,d}$	The amount of imported *ten-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 3 in association with *offer k.*
$SI30R^3_{k,h,d}$	The amount of imported *thirty-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 3 in association with *offer k.*
$SPRG^3_{k,h,b}$	The amount of *energy* scheduled for the *generation facility* at bus *b* in hour *h* in Pass 3 in association with *offer k*. This is in addition to any $MinQPRG_{h,b}$, the *minimum loading point*, which must also be committed.
$OPRG^3_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled in hour *h* in Pass 3.
$IPRG^3_{h,b}$	Represents whether *generation facility* at bus *b* has been scheduled to start in hour *h* in Pass 3.
RAMPUP_ENRG	The coefficient used to calculate the estimated fraction of a *generation facility*'s *minimum loading point* in the hour prior to the first hour it is scheduled. This value is used by the DACP calculation engine to determine constrained schedules in Pass 3 so that the *energy* produced by the *generation facility* during ramping to their *minimum loading point* is accounted for.
$10SSPRG^3_{k,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 3 in association with *offer k*.
$10NSPRG^3_{k,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 3 in association with *offer k.*

$30RSPRG^3_{k,h,b}$ The amount of *thirty-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 3 in association with *offer k*.

6.6.2.7 Output Violation Variables

$ViolCost^3_h$ The cost incurred in order to avoid having the Pass 3 schedules for hour *h* violate specified constraints.

$SLdViol^3_h$ Projected load curtailment, that is, the amount of load that cannot be met using *offers* scheduled or committed in hour *h* in Pass 3.

$SGenViol^3_h$ The amount of additional load that must be scheduled in hour *h* in Pass 3 to ensure that there is enough load on the system to offset the must-run requirements of *generation facilities*.

$S10SViol^3_h$ The amount by which the overall synchronized *ten-minute operating reserve* requirement is not met in hour *h* of Pass 3 because the cost of meeting that portion of the requirement was greater than or equal to *P10SViol.*

$S10RViol^3_h$ The amount by which the overall *ten-minute operating reserve* requirement is not met in hour *h* of Pass 3 (above and beyond any failure to meet the synchronized *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P10RViol.*

$S30RViol^3_h$ The amount by which the overall *thirty-minute operating reserve* requirement is not met in hour *h* of Pass 3 (above and beyond any failure to meet the *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P30RViol.*

$SREG10RViol^3_{r,h}$ The amount by which the minimum *ten-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 3 because the cost of meeting that portion of the requirement was greater than or equal to *PREG10RViol.*

$SREG30RViol^3_{r,h}$ The amount by which the minimum *thirty-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 3 because the cost of meeting that portion of the requirement was greater than or equal to *PREG30RViol.*

$SXREG10RViol^3_{r,h}$ The amount by which the *ten-minute operating reserve* scheduled for region r exceeds the maximum required in hour h of Pass 3 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG10RViol.*

$SXREG30RViol^3_{r,h}$ The amount by which the *thirty-minute operating reserve* scheduled for region r exceeds the maximum required in hour h of Pass 3 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG30RViol.*

$SPreConITLViol^3_{f,h}$ The amount by which pre-contingency flows over *facility f* in hour h of Pass 3 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConITLViol.*

$SITLViol^3_{f,c,h}$ The amount by which flows over *facility f* that would follow the occurrence of contingency c in hour h of Pass 3 exceed the emergency limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PITLViol.*

$SPreConXTLViol^3_{z,h}$ The amount by which *intertie* flows over *facility z* in hour h of Pass 3 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConXTLViol.*

$SURmpXTLViol^3_h$ The amount by which the total net scheduled import increase for hour h in Pass 3 exceeds the up ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

$SDRmpXTLViol^3_h$ The amount by which the total net scheduled import decrease in hour h of Pass 2 exceed the down ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

6.6.2.8 Output Shadow Prices

Shadow Prices of Constraints:

SPL^3_h	The Pass 3 shadow price measuring the rate of change of the objective function for a change in load at the *reference bus* in hour *h*.
$SPNormT^3_{f,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjNormMaxFlow_{f,h}$, on flows over transmission *facilities* in normal conditions for *facility f* in hour *h*.
$SPEmT^3_{f,c,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjEmMaxFlow_{f,c,h}$, on flows over transmission *facilities* in emergency conditions for *facility f* in monitored contingency *c* in hour *h*.
$SPExtT^3_{z,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $MaxExtSch_{z,h}$, on flows over transmission *facilities* on the boundary between Ontario and other *control areas* for each constraint z in hour *h*.
$SPRUExtT^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $ExtUSC_h$, on the upward change of the sum of net imports over all *interties* from the previous hour to hour *h*.
$SPRDExtT^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $ExtDSC_h$, on the downward change of the sum of net imports over all *interties* from the previous hour to hour *h*.
$SP10S^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the total synchronized *ten-minute operating reserve* requirement, $TOT10S_h$, in hour *h*.
$SP10R^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the total *ten-minute operating reserve* requirement, $TOT10R_h$, in hour *h*.
$SP30R^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the total *thirty-minute operating reserve* requirement, $TOT30R_h$, in hour *h*.
$SPREGMin10R^3_{r,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the minimum *ten-minute*

operating reserve requirement, $REGMin10R_{r,h}$, for region r in hour h.

$SPREGMin30R^3_{r,h}$ The Pass 3 shadow price measuring the rate of change of the objective function for a change in the minimum *thirty-minute operating reserve* requirement, $REGMin30R_{r,h}$, for region r in hour h.

$SPREGMax10R^3_{r,h}$ The Pass 3 shadow price measuring the rate of change of the objective function for a change in the maximum *ten-minute operating reserve* limit, $REGMax10R_{r,h}$, for region r in hour h.

$SPREGMax30R^3_{r,h}$ The Pass 3 shadow price measuring the rate of change of the objective function for a change in the maximum *thirty-minute operating reserve* limit, $REGMax30R_{r,h}$, for region r in hour h.

Shadow Price for Energy:

$\mathrm{LMP}^3_{\mathrm{h,b}}$ The Pass 3 locational marginal price for *energy* at each bus b in each hour h. It measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of supply at that bus in that hour in Pass 3.

$ExtLMP^3_{h,d}$ The Pass 3 locational marginal price for *energy* at each *intertie zone* sink and source bus d in each hour h. It measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of supply at that bus in that hour in Pass 3.

6.6.2.9 Energy Ramp Rates

Same as those in section 4.6.2.8.

6.7 Objective Function

6.7.1 The optimization of the objective function in Pass 3 is to maximize the expression:

$$\sum_{h=1,\ldots,24}\left\{\begin{array}{l}\sum_{d\in DX,j\in J_d}\left(SHXL^3_{j,h,d}\cdot PHXL_{j,h,d}-SX10N^3_{j,h,d}\cdot PX10N_{j,h,d}-SX30R^3_{j,h,d}\cdot PX30R_{j,h,d}\right)\\ -\sum_{b\in B}\left[\begin{array}{l}\sum_{j\in J_b}SPRL^3_{j,h,b}\cdot PPRL_{j,h,b}\\ +\sum_{j\in J_b}\begin{array}{l}10NSPRL^3_{j,h,b}\cdot 10NPPRL_{j,h,b}+10SSPRL^3_{j,h,b}\cdot 10SPPRL_{j,h,b}+\\ 30RSPRL^3_{j,h,b}\cdot 30RPPRL_{j,h,b}\end{array}\end{array}\right]\\ -\sum_{d\in DI,k\in K_d}\left(SHIG^3_{k,h,d}\cdot PHIG_{k,h,d}+SI10N^3_{k,h,d}\cdot PI10N_{k,h,d}+SI30R^3_{k,h,d}\cdot PI30R_{k,h,d}\right)\\ -\sum_{b\in B}\left[\begin{array}{l}\sum_{k\in K_b}\left(SPRG^3_{k,h,b}\cdot PPRG_{k,h,b}\right)\\ +\sum_{k\in K_b}\begin{array}{l}10SSPRG^3_{k,h,b}\cdot 10SPPRG_{k,h,b}+10NSPRG^3_{k,h,b}\cdot 10NPPRG_{k,h,b}\\ +30RSPRG^3_{k,h,b}\cdot 30RPPRG_{k,h,b}\end{array}\end{array}\right]\\ -ViolCost^3_h\end{array}\right\};$$

where $ViolCost^3{}_h$ is calculated as follows:

$$\begin{aligned}ViolCost^3_h &= SLdViol^3_h\cdot PLdViol - SGenViol^3_h\cdot PGenViol\\ &+S10SViol^3_h\cdot P10SViol + S10RViol^3_h\cdot P10RViol\\ &+S30RViol^3_h\cdot P30RViol\\ &+\sum_{r\in ORREG}\left(\begin{array}{l}SREG10RViol^3_{r,h}\cdot PREG10RViol\\ +SREG30RViol^3_{r,h}\cdot PREG30RViol\\ +SXREG10RViol^3_{r,h}\cdot PXREG10RViol\\ +SXREG30RViol^3_{r,h}\cdot PXREG30RViol\end{array}\right)\\ &+\sum_{z\in Z}\left(SPreConXTLViol^3_{z,h}\cdot PPreConXTLViol\right)\\ &+SURmpXTLViol^3\cdot PRmpXTLViol + SDRmpXTLViol^3\cdot PRmpXTLViol\\ &+\sum_{f\in F}SPreConITLViol^3_{f,h}\cdot PPreConITLViol\\ &+\sum_{f\in F,c\in C}SITLViol^3_{f,c,h}\cdot PITLViol.\end{aligned}$$

6.8 Constraints Overview

6.8.1 Resources not already committed in Pass 2 will not be scheduled and the constraints that require their inputs will be eliminated.

6.9 Bid/Offer Constraints Applying to Single Hours

6.9.1 Status Variables and Capacity Constraints

6.9.1.1 No schedule can be negative, nor can any schedule exceed the amount of capacity *offered* for that service. Therefore:

$$0 \le SPRL^3_{j,h,b} \le QPRL_{j,h,b};$$

$$0 \le 10SSPRL^3_{j,h,b} \le 10SQPRL_{j,h,b};$$

$$0 \le 10NSPRL^3_{j,h,b} \le 10NQPRL_{j,h,b};$$

$$0 \le 30RSPRL^3_{j,h,b} \le 30RQPRL_{j,h,b};$$

$$0 \le SHXL^3_{j,h,d} \le QHXL_{j,h,d};$$

$$0 \le SX10N^3_{j,h,d} \le QX10N_{j,h,d};$$

$$0 \le SX30R^3_{j,h,d} \le QX30R_{j,h,d};$$

$$0 \le SHIG^3_{k,h,d} \le QHIG_{k,h,d};$$

$$0 \le SI10N^3_{k,h,d} \le QI10N_{k,h,d}; \text{ and}$$

$$0 \le SI30R^3_{k,h,d} \le QI30R_{k,h,d};$$

for all *bids* j, *offers* k, hours h, buses b and *intertie zones* source/sink buses d.

6.9.1.2 In the case of *generation facilities*, in addition to restrictions on their schedules similar to those above, their schedules must be consistent with their operating status determined at the conclusion of Pass 2. To simplify the writing of subsequent constraints, we will define the following variable for buses where *generation facilities* are located:

$$OPRG^3_{h,b} = OPRG^2_{h,b}; \text{ and}$$

$$IPRG^3_{h,b} = IPRG^2_{h,b}$$

which will indicate whether a resource at bus b may be scheduled to operate or start in Pass 3 in hour h. Then:

$$0 \le SPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot QPRG_{k,h,b};$$

$$0 \le 10SSPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot 10SQPRG_{k,h,b};$$

$$0 \le 10NSPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot 10NQPRG_{k,h,b}; \text{ and}$$

$$0 \le 30RSPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot 30RQPRG_{k,h,b}$$

for all *offers* k, hours h, and buses b.

6.9.1.3 In the case of linked wheeling transactions (the export *bid* and the import *offer* have the same *NERC* tag identifier), the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore:

$$\sum_{j \in J_d} SHXL^3_{j,h,dx} = \sum_{k \in k_d} SHIG^3_{k,h,di}$$

where dx and di are the respective buses of the export and import schedules associated with the wheeling transactions.

6.9.1.4 The minimum and/or maximum output of the *generation facilities* may be limited because of *outages* and/or de-ratings or in order for the units to provide *regulation* or voltage support. These constraints will take the form:

$$MinPRG_{h,b} \le MinQPRG_{h,b}(OPRG^3_{h,b}) + \sum_{k \in K_b} SPRG^3_{k,h,b} \le MaxPRG_{h,b}.$$

6.9.1.5 Similarly, the maximum level of load reduction is the mechanism by which a *dispatchable load* indicates any de-rating to its registered maximum load reduction level due to mechanical or operational adjustments to their *facility*. The constraint will take the form:

$$\sum_{j \in J_b} SPRL^3_{j,h,b} \le MaxPRL_{h,b}.$$

6.9.2 Operating Reserve Constraints

6.9.2.1 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load (maximum load *bid* minus the load reductions). These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq 30 \cdot ORRPRL_b \text{; and}$$

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq \sum_{j \in J_b} (QPRL_{j,h,b} - SPRL^3_{j,h,b}).$$

6.9.2.2 In addition, this next constraint ensures that the total(10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to increase load reduction (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8):

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq -\sum_{j \in J_b} \left[\left(QPRL_{j,h-1,b} - SPRL^3_{j,h-1,b} \right) - \left(QPRL_{j,h,b} - SPRL^3_{j,h,b} \right) \right] + 60 \cdot URRPRL_b.$$

6.9.2.3 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* Pass 3 scheduled consumption:

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq MaxPRL_{h,b} - \sum_{j \in J_b} SPRL^3_{j,h,b}.$$

6.9.2.4 The amount of 10-minute synchronized and 10-minute non-synchronized reserve that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_b} 10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} \leq 10 \cdot ORRPRL_b.$$

6.9.2.5 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed *generation facility* cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b}) \leq 30 \cdot ORRPRG_b \text{; and}$$

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b}) \leq \sum_{k \in K_b} (QPRG_{k,h,b} - SPRG^3_{k,h,b}).$$

6.9.2.6 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed *generation facility* cannot exceed its ramp capability (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8). Ramping considerations from start ups or shut downs are not carried forward from one day to the next:

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 10RSPRG^3_{k,h,b}) \leq \sum_{k \in K_b} \left(SPRG^3_{k,h-1,b} - SPRG^3_{k,h,b}\right) + 60 \times URRPRG_b$$

and

$$\sum_{k \in K_b} \left(10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b}\right) + \sum_{k \in K_b} \left(SPRG^3_{k,h,b}\right) \leq [(h-n) * 60 + 30] \times URRPRG_b \times OPRG^3_{h,b}$$

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

and

$$\sum_{k \in K_b}(10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b}) + \sum_{k \in K_b}(SPRG^3_{k,h,b}) \le [(m-h)*60+30] \times DRRPRG_b \times OPRG^3_{h,b}$$

where m is the hour of the last shut down in or after hour h

6.9.2.7 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed *generation facility* cannot exceed the *it*s Pass 3 unscheduled capacity:

$$\sum_{k \in K_b}(10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b}) \le MaxPRG_{h,b} - \sum_{k \in K_b} SPRG^3_{k,h,b} - MinQPRG_{h,b}.$$

6.9.2.8 The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *generation facility* is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_b}(10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b}) \le 10 \cdot ORRPRG_b.$$

6.9.2.9 The total reserve (10-minute non-synchronized and 30-minute) from hourly exports cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled export. These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_d}(SX10N^3_{j,h,d} + SX30R^3_{j,h,d}) \le 30 \cdot ORRHXL_d;$$

and

$$\sum_{j \in J_d}(SX10N^3_{j,h,d} + SX30R^3_{j,h,d}) \le \sum_{j \in J_d} SHXL^3_{j,h,d}.$$

6.9.2.10 The amount of 10-minute non-synchronized reserve that hourly export is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_d} SX10N^3_{j,h,d} \leq 10 \cdot ORRHXL_d .$$

6.9.2.11 The total reserve (10-minute non-synchronized and 30-minute) from hourly imports cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_d} (SI10N^3_{k,h,d} + SI30R^3_{k,h,d}) \leq 30 \cdot ORRHIG_d ;$$

and

$$\sum_{k \in K_d} (SI10N^3_{k,h,d} + SI30R^3_{k,h,d}) \leq \sum_{k \in K_d} (QHIG_{k,h,d} - SHIG^3_{k,h,d}).$$

6.9.2.12 The amount of 10-minute non-synchronized reserve that hourly import is scheduled to provide cannot exceed the amount by which it can increase the output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_d} SI10N^3_{k,h,d} \leq 10 \cdot ORRHIG_d .$$

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

6.10.1 Ramping

6.10.1.1 *Energy* schedules for each resource cannot vary by more than an hour’s ramping capacity for that resource. The *energy* schedule change in the hour in which the unit is scheduled to start or shut down depends on the unit ramp rate below its *minimum loading point*. Almost all non-quick start *generation facilities* will need one or more hours to reach their *minimum loading point* and to go down from *minimum loading point* to zero. Since non-committed *generation facilities* must be assigned zero output and committed units must operate at or above their *minimum loading point*, it is assumed that these units will be at their *minimum loading point* at the beginning of the first commitment hour and at the end of the hour before shut down.

6.10.1.2 The following three part constraint ensures that the *energy* schedules do not exceed the *generation facility's* ramp capability in the hours where the unit starts, stays on and shuts down.

Start Up Scenario ($OPRG^3_{h,b} = 1$, and $OPRG^3_{h-1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^3_{k,h,b} \leq \sum_{k \in K_b} 30 \times URRPRG_b$$

Continued On Scenario ($OPRG^3_{h-1,b} = OPRG^3_{h,b} = 1$)

$$\sum_{k \in K_b} \left(SPRG^3_{k,h-1,b}\right) - 60 \times DRRPRG_b \leq \sum_{k \in K_b} SPRG^3_{k,h,b}$$

$$\leq \sum_{k \in K_b} \left(SPRG^3_{k,h-1,b}\right) + 60 \times URRPRG_b$$

Shut Down Scenario ($OPRG^3_{h,b} = 1$, and $OPRG^3_{h+1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^3_{k,h,b} \leq \sum_{k \in K_b} 30 \times DRRPRG_b$$

6.10.1.3 It should be noted that these ramp up/down rates apply to the operating range above the *minimum loading point* of the *generation facility*.

6.10.1.4 Similar logic is applied to *dispatchable loads* to arrive at the following constraint:

$$\sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^3_{j,h-1,b} \right) - 60 \cdot URRPRL_{h,b}$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^3_{j,h,b} \right)$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^3_{j,h-1,b} \right) + 60 \cdot DRRPRL_{h,b}.$$

6.10.1.5 The above two constraints apply for all hours from 1 to 24. In the above two constraints the variables related to hour zero belong to the last hour of the previous day and are obtained from the initializing assumptions.

6.10.1.6 The ramping rates in the ramping constraints must be adjusted to allow the resource to:

a) Ramp down from its lower limit in hour (*h-1*) to its upper limit in hour *h*.

b) Ramp up from its upper limit in hour (*h-1*) to its lower limit in hour *h*.

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

6.10.1.8 In the above ramping constraints, a single ramp up and a single ramp down, $URRPRG_b$ and $DRRPRG_b$ for *generation facilities* and $URRPRL_b$ and $DRRPRL_b$ for *dispatchable loads* are used. The ramp rate is assumed constant over the full operating range of the *dispatchable load and generation facility*. However, this is not the case. *Dispatchable load bids and generator offers* will include multi-*energy* ramp rates. The multiple ramp rates are described in sections 4.10.2.8 and 4.10.2.9.

6.10.2 Energy Limited Resources

6.10.2.1 Constraints applying to *energy* limited resources are very similar to the constraints used in Pass 1. Therefore:

$$\sum_{h=1}^{1}\left(OPRG_{h,b}^{3}\cdot MinQPRG_{h,b}+\sum_{k\in K_b} SPRG_{k,h,b}^{3}\right)$$
$$+10ORConv\left(\sum_{k\in K_b} 10SSPRG_{k,1,b}^{3}+\sum_{k\in K_b} 10NSPRG_{k,1,b}^{3}\right)$$
$$+30ORConv\sum_{k\in K_b} 30RSPRG_{k,1,b}^{3}\leq EL_b;$$

$$\sum_{h=1}^{2}\left(OPRG_{h,b}^{3}\cdot MinQPRG_{h,b}+\sum_{k\in K_b} SPRG_{k,h,b}^{3}\right)$$
$$+10ORConv\left(\sum_{k\in K_b} 10SSPRG_{k,2,b}^{3}+\sum_{k\in K_b} 10NSPRG_{k,2,b}^{3}\right)$$
$$+30ORConv\sum_{k\in K_b} 30RSPRG_{k,2,b}^{3}\leq EL_b;$$

M

$$\sum_{h=1}^{24}\left(OPRG_{h,b}^{3}\cdot MinQPRG_{h,b}+\sum_{k\in K_b} SPRG_{k,h,b}^{3}\right)$$
$$+10ORConv\left(\sum_{k\in K_b} 10SSPRG_{k,24,b}^{3}+\sum_{k\in K_b} 10NSPRG_{k,24,b}^{3}\right)$$
$$+30ORConv\sum_{k\in K_b} 30RSPRG_{k,24,b}^{3}\leq EL_b$$

for all hours *h* and for all buses *b* at which *energy* limited resources are located. The factors *10ORConv* and *30ORConv* are applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserves* for *energy*-limited resources to convert MW into MWh. This factor is set to unity.

6.11 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

6.11.1 Load

6.11.1.1 The total amount of withdrawals scheduled in Pass 3 at each bus *b* in each hour *h*, $With^{3}_{h,b}$, is the sum of:

- the portion of the load forecast for that hour that has been allocated to that bus; and

- all *dispatchable load bid*, net of the amount of load reduction scheduled (since the *dispatchable load* is excluded from the *demand* forecast by the DACP calculation engine), yielding:

$$With^{3}_{h,b} = LDF_{h,b} \cdot AFL_{h} + \left[\sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^{3}_{j,h,b} \right) \right]; \text{and}$$

the total amount of withdrawals scheduled in Pass 3 at each *intertie zone* sink bus d in each hour h, $With^{3}_{h,b}$, is the sum of:

- exports from Ontario to each *intertie zone* sink bus; and
- outflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$With^{3}_{h,d} = \sum_{j \in J_d} (SHXL^{3}_{j,h,d}) - \sum_{a \in A} ProxyUPOWt_{d,a} \cdot \min(0, PF_{h,a}).$$

6.11.1.2 The total amount of injections scheduled in Pass 3 at each bus b in each hour h, $Inj^{3}_{h,b}$, is the sum of:

- generation scheduled at that bus, yielding:

$$Inj^{3}_{h,b} = (OPRG^{3}_{h,b} + RAMPUP\_ENRG \cdot IPRG^{3}_{h+1,b}) MinQPRG_{h,b} + \sum_{k \in K_b} \left(SPRG^{3}_{k,h,b} \right); \text{and}$$

the total amount of injections scheduled in Pass 3 at each *intertie zone* source bus d in each hour h, $Inj^{3}_{h,d}$, is the sum of:

- imports into Ontario from each *intertie zone* source bus; and
- inflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose:

$$Inj_{h,d}^{3} = \sum_{k \in K_d} (SHIG_{k,h,d}^{3}) + \sum_{a \in A} ProxyUPIWt_{d,a} \cdot \max(0, PF_{h,a}).$$

6.11.1.3 Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses (or reduction in losses) that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between actual and marginal losses. Load reduction associated with the *demand* constraint violation will be subtracted from the total load and generation reduction associated with the *demand* constraint violation will be subtracted from total generation to ensure that the calculation engine will always produce a solution. These violation variables are assigned a very high cost to limit their use to infeasible cases.

$$\begin{aligned}&\sum_{b \in B} (1 + MglLoss_{h,b}) With_{h,b}^{3} + \sum_{d \in D} (1 + MglLoss_{h,b}) With_{h,d}^{3} - SLDViol_{h}^{3} \\ &\quad = \sum_{b \in B} (1 + MglLoss_{h,b}) Inj_{h,b}^{3} + \sum_{d \in D} (1 + MglLoss_{h,d}) Inj_{h,d}^{3} \\ &\quad - SGenViol_{h}^{3} + LossAdj_{h}.\end{aligned}$$

6.11.2 Operating Reserve

6.11.2.1 Sufficient *operating reserve* must be provided on the system to meet system wide requirements for 10-minute synchronized reserve, *ten-minute operating reserve* and *thirty-minute operating reserve*, as well as all applicable regional minimum and maximum requirements for *operating reserve*.

6.11.2.2 Therefore, taking into consideration the potential not to meet these minimum and maximum requirements if the cost of meeting those requirements becomes too high:

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+S10SViol^3_h$$
$$\geq TOT10S_h;$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+S10RViol^3_h$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b} 10NSPRG^3_{k,h,b}\right)+\sum_{b\in B}\left(\sum_{j\in J_b} 10NSPRL^3_{j,h,b}\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d} SI10N^3_{k,h,d}\right)+\sum_{d\in D}\left(\sum_{j\in J_d} SX10N^3_{j,h,d}\right)$$
$$\geq TOT10R_h; \text{ and}$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+S30RViol^3_h$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b}(10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b})\right)$$
$$+\sum_{b\in B}\left(\sum_{j\in J_b}(10NSPRL^3_{j,h,b}+30RSPRL^3_{j,h,b})\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d}(SI10N^3_{k,h,d}+SI30R^3_{k,h,d})\right)$$
$$+\sum_{d\in D}\left(\sum_{j\in J_d}(SX10N^3_{j,h,d}+SX30R^3_{j,h,d})\right)$$
$$\geq TOT30R_h$$

for all hours h; and

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+SREG10RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^3_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^3_{j,h,b}\right)$$
$$\geq REGMin10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)-SXREG10RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^3_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^3_{j,h,b}\right)$$
$$\leq REGMax10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+SREG30RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^3_{j,h,b}+30RSPRL^3_{j,h,b})\right)$$
$$\geq REGMin30R_{r,h};\text{ and}$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)-SXREG30RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^3_{j,h,b}+30RSPRL^3_{j,h,b})\right)$$
$$\leq REGMax30R_{r,h}$$

for all hours h, and for all regions r in the set *ORREG*.

6.11.3 Internal Transmission Limits

6.11.3.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 3 of the calculation engine would not violate any *security limits* in either the pre-contingency state or in any contingency. To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus will be used.

6.11.3.2 Then the pre-contingency limits on transmission within Ontario will not be violated if:

$$\sum_{b \in B} PreConSF_{b,f,h}(Inj^3_{h,b} - With^3_{h,b}) + \sum_{d \in D} PreConSF_{d,f,h}(Inj^3_{h,d} - With^3_{h,d}) \\ - SPreConITLViol^3_{f,h} \leq AdjNormMaxFlow_{f,h}$$

for all *facilities* f and hours h.

6.11.3.3 Post-contingency limits on transmission *facilities* within Ontario will not be violated if:

$$\sum_{b \in B} SF_{b,f,c,h}(Inj^3_{h,b} - With^3_{h,b}) + \sum_{d \in D} SF_{d,f,c,h}(Inj^3_{h,d} - With^3_{h,d}) \\ - SITLViol^3_{f,c,h} \leq AdjEmMaxFlow_{f,c,h}$$

for all *facilities* f, hours h, and monitored contingencies c.

6.11.4 Intertie Transmission Limits and Constraints on Net Imports

6.11.4.1 The calculation engine would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. To ensure this, we must calculate the net amount of *energy* scheduled to flow over each *intertie* in each hour and the amount of *operating reserve* scheduled to be provided by resources in that *control area*. This will be summed over all affected *interties*. The result will be compared to the limit associated with that constraint. Consequently:

$$\sum_{a\in A}\left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d\in DI_a,k\in K_d}(SHIG^3_{k,h,d})+PF_{h,a}-\sum_{d\in DX_a,j\in J_d}\left(SHXL^3_{j,h,d}\right)\right)+ \\ 0.5(EnCoeff_{a,z}+1)\left[\begin{array}{l}\sum_{d\in DI_a,k\in K_d}\left(SI10N^3_{k,h,d}+SI30R^3_{k,h,d}\right) \\ +\sum_{d\in DX_a,j\in J_d}\left(SX10N^3_{j,h,d}+SX30R^3_{j,h,d}\right)\end{array}\right]\end{array}\right]$$
$$\leq MaxExtSch_{z,h}$$

for all hours *h*, for all *intertie zones* *a* relevant to the constraint *z*

($EnCoeff_{a,z} \neq 0$), and for all constraints *z* in the set Z_{sch}.

6.11.4.2 In addition, changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour. It cannot exceed the sum of net import schedule for all *interties* for the previous hour plus the maximum permitted hourly increase. It cannot be less than the sum of the net import schedule for all *interties* for the previous hour minus the maximum permitted hourly decrease. Violation variables are provided for both the up and down ramp limits to ensure that the calculation engine will always find a solution. Therefore:

$$\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^3_{k,h-1,d})-\sum_{j\in J_d}(SHXL^3_{j,h-1,d})\right)-ExtDSC_h-SDRmpXTLViol^3_h$$
$$\leq\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^3_{k,h,d})-\sum_{j\in J_d}(SHXL^3_{j,h,d})\right)$$
$$\leq\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^3_{k,h-1,d})-\sum_{j\in J_d}(SHXL^3_{j,h-1,d})\right)+ExtUSC_h+SURmpXTLViol^3_h$$

for all hours *h* (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8).

6.11.5 Intertie Schedule Limits Based on Pass 2 Outputs

6.11.5.1 Pass 3 will not reduce the amount of imported *energy* scheduled from each *intertie zone* in any hour. Additional imports of *energy* may be scheduled in Pass 3, Therefore, for imports that are not part of a linked wheeling transaction:

$$SHIG^3_{k,h,d} \geq SHIG^2_{k,h,d}$$

for all *offers* k, hours h and *intertie zones* source bus d, and:

6.11.5.2 Pass 3 will not increase the amount of exported *energy* scheduled from each *intertie zone* in any hour to the amount scheduled in Pass 2.

6.11.5.3 Therefore, for exports that are not part of a linked wheeling transaction:

$$SHXL^3_{j,h,d} \leq SHXL^2_{j,h,d}.$$

6.12 Shadow Prices

6.12.1 The *IESO* shall also determine *energy* and *operating reserve* prices in Pass 3 that will be *published* for informational purposes.

6.12.2 Shadow Energy Prices

6.12.2.1 The Pass 3 shadow price at each bus b in each hour h shall be calculated at buses in Ontario as:

$$LMP^3_{h,b} = \left(1 + MglLoss_{h,b}\right) \cdot SPL^3_h + \sum_{f \in F} \left(\begin{array}{l} PreConSF_{b,f,h} \cdot SPNormT^3_{f,h} \\ + \sum_{c \in C} SF_{b,f,c,h} \cdot SPEmT^3_{f,c,h} \end{array} \right)$$

6.12.3 Shadow Energy Prices at *Intertie Zones*

6.12.3.1 The Pass 3 shadow price at each *intertie zone* source/sink bus d in each hour h is calculated as:

$$\begin{aligned} ExtLMP^3_{h,d} & \\ &= \left(1 + MglLoss_{h,d}\right) \cdot SPL^3_h + \sum_{f \in F} \left(\begin{array}{l} PreConSF_{d,f,h} \cdot SPNormT^3_{f,h} \\ + \sum_{c \in C} (SF_{d,f,c,h} \cdot SPEmT^3_{f,c,h}) \end{array} \right) \\ &+ \sum_{z \in Z_{sch}} (EnCoeff_{a,z} \cdot SPExtT^3_{z,h}) + SPRUExtT^3_h - SPRDExtT^3_h \end{aligned}$$

6.12.3.2 The first component of this calculation, the cost of meeting load at each *intertie zone* reflecting marginal losses incurred in transmitting *energy* from the *reference bus* to that *intertie zone*, is the same as the first component of the previous equation. The second component of this calculation determines the effect of congestion on internal transmission *facilities* on the price at each bus.

6.12.3.3 The last three components reflect the impact of limits on imports or exports, which are relevant for the calculation of prices at *intertie zones*. The first of the three components provides the effect of congestion resulting from *security limits* associated with *interties* between Ontario and *intertie zones*, for all constraints *z* in the set Z_{sch}. The last two components reflect the congestion cost resulting from the upward/downward limits of hour-to-hour net *energy* changes across all *interties*.

6.12.4 Shadow 30-Minute Reserve Prices

6.12.4.1 Shadow prices can also be calculated for each bus, reflecting the marginal contribution that each category of *operating reserve* would have if provided at that bus to increasing the value of the objective function. For each bus *b,* define $ORREG_b$ as the subset of *ORREG* consisting of regions that include bus *b.* The Pass 3 price of *thirty-minute operating reserve* at a given bus *b,* $L30RP^3_{h,b}$, is the shadow price of the total *thirty-minute operating reserve* constraint, plus the shadow prices of all of the constraints requiring a minimum amount of *thirty-minute operating reserve* to be provided by resources in regions that include that bus, minus the shadow prices of all the constraints limiting the amount of *thirty-minute operating reserve* that can be provided by resources in regions that include that bus; given these definitions:

$$L30RP^3_{h,b} = SP30R^3_h + \sum_{r \in ORREG_b} SPREGMin30R^3_{r,h} - \sum_{r \in ORREG_b} SPREGMax30R^3_{r,h}.$$

6.12.5 Shadow 10-Minute Non-synchronized Reserve Prices

6.12.5.1 The Pass 3 price of 10-minute non-synchronized reserve at a given bus *b,* $L10NP^3_{h,b}$, is the shadow price of the total *ten-* and *thirty-minute operating reserve* constraints, plus the shadow prices of all of the constraints requiring a minimum amount of *ten-* or *thirty-minute* *operating reserve* to be provided by resources in regions that include that bus, minus the shadow prices of all the constraints limiting the amount of *ten-* or *thirty-minute operating reserve* that can be provided by resources in regions that include that bus:

$$
\begin{aligned}
& L10NP_{h,b}^{3} \\
& \quad = SP10R_{h}^{3} + SP30R_{h}^{3} \\
& \qquad + \sum_{r \in ORREG_b} \left(SPREGMin10R_{r,h}^{3} + SPREGMin30R_{r,h}^{3} \right) \\
& \qquad - \sum_{r \in ORREG_b} \left(SPREGMax10R_{r,h}^{3} + SPREGMax30R_{r,h}^{3} \right).
\end{aligned}
$$

6.12.6 Shadow 10-Minute Synchronized Reserve Prices

6.12.6.1 Finally, the Pass 3 price of 10-minute synchronized reserve at a given bus *b,* $L10SP^{3}_{h,b}$, is the shadow price of the total *ten-* and *thirty-minute operating reserve* constraints and the total 10-minute synchronized reserve constraint, plus the shadow prices of all of the constraints requiring a minimum amount of *ten-* or *thirty-minute operating reserve* or 10-minute synchronized reserve to be provided by resources in regions that include that bus, minus the shadow prices of all the constraints limiting the amount of *ten-* or *thirty-minute operating reserve* or 10-minute synchronized reserve that can be provided by resources in regions that include that bus:

$$
\begin{aligned}
& L10SP_{h,b}^{3} \\
& \quad = SP10S_{h}^{3} + SP10R_{h}^{3} + SP30R_{h}^{3} \\
& \qquad + \sum_{r \in ORREG_b} \left(SPREGMin10R_{r,h}^{3} + SPREGMin30R_{r,h}^{3} \right) \\
& \qquad - \sum_{r \in ORREG_b} \left(SPREGMax10R_{r,h}^{3} + SPREGMax30R_{r,h}^{3} \right).
\end{aligned}
$$

6.12.7 Shadow Operating Reserve Prices at *Intertie Zones*

6.12.7.1 Shadow *operating reserve* prices can also be calculated for *intertie zones*. These prices need to take into account the shadow prices of constraints in the set Z_{sch}, as some of these constraints will limit the amount of *operating reserve* that can be imported into Ontario. They do not need to take into account the shadow prices of constraints associated with lower limits on the amount of *operating reserve* that must be supplied within regions of Ontario or upper limits on the amount of *operating reserve* that may be supplied within regions of Ontario, since imported *operating reserve* will not affect either of these types of constraints. Nor do they need to take into account the shadow price for the hour-to-hour change in net *energy* flow over all *interties*, as these constraints will only affect the amount of *energy* that can be scheduled to flow into or out of Ontario.

6.12.7.2 The Pass 3 price of *thirty-minute operating reserve* at a given *intertie zone a,* $Ext30RP^3_{h,a}$, is the shadow price of the total *thirty-minute operating reserve* constraint, minus the product of:

- the impact that imports of *operating reserve* from that *intertie zone* have on each constraint limiting the import of *operating reserve* from that *intertie zone*, and
- the shadow price of that constraint, summed over all constraints:

$$Ext30RP^3_{h,a} = SP30R^3_h - \sum_{z \in Z_{sch}} 0.5(ENCoeff_{a,z} + 1)SPExtT^3_{z,h}.$$

6.12.7.3 The Pass 3 price of *ten-minute operating reserve* at a given *intertie zone a,* $Ext10RP^3_{h,a}$, is the shadow price of the total *ten-* and *thirty-minute operating reserve* constraints, minus the product of:

- the impact that imports of *operating reserve* from that *intertie zone* have on each constraint limiting the import of *operating reserve* from that *intertie zone*, and
- the shadow price of that constraint, summed over all constraints:

$$Ext10RP^3_{h,a} = SP10R^3_h + SP30R^3_h - \sum_{z \in Z_{sch}} 0.5(ENCoeff_{a,z} + 1)SPExtT^3_{z,h}.$$

6.12.7.4 There is no need to calculate a price for 10-minute synchronized reserve at *intertie zones*, since 10-minute synchronized reserve cannot be imported.

7. Combined-Cycle Modeling

7.1 Overview

7.1.1 *Registered market participants* with combined-cycle plants of one or more combustion turbines and one steam turbine may choose to have the associated *generation facilities* modeled as one or more *pseudo-units*. Each *pseudo-unit* comprises of a single combustion turbine and a share of the steam turbine capacity. Inputs for *pseudo-units* used by the DACP calculation engine are described in Chapter 7, section 2.2.6G.

7.2 Modeling by DACP Calculation Engine

7.2.1 The *pseudo-units* are independently scheduled in each pass subject to the optimization objective function described in sections 4.3, 5.3 and 6.3 respectively. However, the security assessment described in section 4.4 is performed for each *generation facility* of the combined-cycle plant.

7.2.2 As the security assessment function iterates with the scheduling function of the DACP calculation engine, the output relationship of each combustion turbine and its share of output from the steam turbine is respected. This output relationship is described as follows:

7.2.2.1 For a combined-cycle plant with i combustion turbines and one steam turbine, it is represented by *i pseudo-units*.

7.2.2.2 For each *pseudo-unit i*, let $pst_{i,k}$ represent the percentage of the *pseudo-unit*'s schedule that relates to the steam turbine in association with *offer k*.

7.2.2.3 Then for each *pseudo-unit i*, the percentage of the *pseudo-unit's* schedule that relates to the combustion turbine i is (100% - $pst_{i,k}$).

7.2.2.4 For a given *pseudo-unit* schedule $SPSU_{k,h}$ for hour h and k offers its associated combustion turbine schedule is:

$$\sum_{k} SPSU_{k,h} \times (100\% - pst_{i,k}).$$

7.2.2.5 And the steam turbine schedule of the *pseudo-unit* plant for hour h is:

$$\sum_{i}\sum_{k} SPSU_{k,h} \times pst_{i,k}.$$

Appendix 7.6 – Local Market Power

1.1 Dispatch of Constrained Off Facilities and Constrained On Facilities

1.1.1 The *IESO* shall, pursuant to this Chapter 7, *dispatch* a *registered facility* as a *constrained on facility* or a *constrained off facility* when, without such action, the *reliability* of the *IESO-controlled grid* cannot be maintained due to a transmission flow constraint on the *IESO-controlled grid* or a *security limit.* The *IESO* shall *dispatch registered facilities* as *constrained on facilities* and *constrained off facilities* in such economic merit order as will enable it to meet its *reliability* obligations under these *market rules* at the lowest cost.

1.1.2 [Intentionally left blank – section deleted]

1.1.3 Subject to section 9.4.5 of Chapter 7 and sections 1.4.5.1 and 1.6.7.1, each *constrained on facility* or *constrained off facility* shall, in addition to such other *settlement* credits to which it may be entitled in accordance with Chapter 9, receive a congestion management *settlement* credit calculated in accordance with section 3.5.2 of Chapter 9.

1.2 Investigation of Local Market Power and Constrained Off Events

1.2.1 Subject to sections 1.2.1C, 1.2.2 or 1.2.6, where the *IESO* determines that a *constrained on event* or *constrained off event* may have occurred, the *IESO* shall conduct the analyses referred to in section 1.3 to establish whether local market power existed and as a preliminary step in determining whether the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3 is justified.

1.2.1A For purposes of establishing *designated constrained off watch zones* and for identifying persistent and significant *constrained off events* within *designated constrained off watch zones,* the *IESO* shall conduct the analysis set out in the applicable *market manual*.

The *market manual* shall include but not necessarily be limited to a description of:

- criteria for identifying *designated constrained off watch zones* and for revoking such designations;

- criteria for determining persistent and significant congestion management *settlement* credit payments for *constrained off events* within *designated constrained off watch zones*; and

- the manner for determining an initial estimated replacement price for the *investigated price*.

1.2.1B When developing the criteria referred to in section 1.2.1A, the *IESO* shall be guided by the following principles:

- areas within Ontario where nodal *energy* prices are materially different from the price of *energy* in either the *pre-dispatch schedule* or the *real-time schedule* are more likely to be *designated constrained off watch zones*; and

- *constrained off events* that occur more frequently over periods of time or that occur less frequently but involve larger congestion management *settlement* credit payments are more likely to be considered persistent and significant, justifying the price investigation analysis referred to in section 1.4.1.

When developing the initial estimated replacement price for the *investigated price* referred to in section 1.2.1A, the *IESO* shall be guided by the principle that the *market participant* should be financially indifferent to being constrained off relative to the profit it would have earned under the *market schedule*, with due consideration to the following:

- recent *offers* or *bids* submitted by the *market participant*;

- market prices in neighbouring jurisdictions;

- *market participant* costs as estimated through information provided by the *market participant*;

- in the case of energy limited resources, an assessment of opportunity costs; and

- any other information considered relevant by the *IESO*.

1.2.1C If after completing the analysis prescribed by section 1.2.1A, the *IESO* determines that a *market participant* received persistent and significant congestion management *settlement* credit payments for *constrained off events* in one or more *constrained off watch zones*, the *IESO* shall conduct the analysis referred to in section 1.4.1 to determine whether the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3.

1.2.1D The *IESO* shall monitor conditions on the *IESO-controlled grid* and publish any changes in the status of the *designated constrained off watch zones* before they take effect. *Market participants* may request a review of such designations, stating reasons for requesting the review, and the *IESO* shall undertake such review unless in its judgement the review is considered to be unwarranted.

1.2.2 The *IESO* shall not be required to conduct the analysis referred to in sections 1.2.1 or 1.2.1A if the *IESO* anticipates that:

1.2.2.1 the maximum adjustment to the congestion management *settlement* credit referred to in section 1.1.3 that may be effected on the basis of such analyses and of the analysis referred to in section 1.4.1 would not exceed the threshold amount *published* by the *IESO* pursuant to section 1.2.3; or

1.2.2.2 the impact of the price contained in the *energy bid* or the *energy offer* submitted by the *constrained on facility* or the *constrained off facility* is, in the *IESO's* opinion, not material.

1.2.3 The *IESO* shall determine and *publish* the threshold amount referred to in section 1.2.2.1, which shall be the minimum amount of an adjustment to a congestion management *settlement* credit referred to in section 1.1.3 that will, subject to sections 1.2.2.2 and 1.2.6, trigger an obligation on the *IESO* to conduct the analyses referred to in sections 1.2.1 or 1.2.1A.

1.2.4 [Intentionally left blank – section deleted]

1.2.5 [Intentionally left blank – section deleted]

1.2.6 Where the *IESO* cannot, for any reason, conduct the analyses referred to in section 1.3 in the manner described in that section, it may conduct such other analyses as it determines appropriate either prior to conducting the analysis described in section 1.4.1, if any, or as part of such analysis.

1.2.7 Where section 1.2.6 applies:

1.2.7.1 the *IESO* shall cease investigation of the *investigated price* where the *IESO* determines that the results of the analyses do not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3; or

1.2.7.2 the *IESO* shall conduct the analysis referred to in section 1.4.1 where the *IESO* determines that the results of the analyses referred to in section 1.2.6 reveal that the *investigated price* may justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3.

1.3 Local Market Power Screens

1.3.1 The *IESO* shall review the inputs and outputs of the *dispatch algorithm* for the *dispatch intervals* to which the *investigated price* relates, and such other information as the *IESO* determines appropriate, for the purpose of determining whether a transmission flow constraint on the *IESO-controlled grid* or a *security limit* resulted in a *constrained on event* or a *constrained off event.*

1.3.2 The *IESO* shall determine whether the *investigated price* falls within the range determined in accordance with section 1.3.8 using the *reference prices* referred to in section 1.3.3 and the factors derived from the methodology approved by the *IESO Board* pursuant to section 1.3.5.

1.3.3 For the purposes of section 1.3.2, the *reference prices* shall be:

1.3.3.1 the *historical reference price* representing *business days* between the hours of 07:00 and 23:00 EST for the *investigated facility*; or

1.3.3.1A the *historical reference price* representing all time periods other than those specified in section 1.3.3.1 for the *investigated facility*,

as the case may be depending on whether the *investigated price* was submitted for the time period indicated in section 1.3.3.1 or section 1.3.3.1A, referred to as P_h, or

1.3.3.1B where permitted by section 1.3.4, such alternative *reference price*, if any, as may be established by the *IESO Board* and published pursuant to section 1.3.4, referred to as P_a; and

1.3.3.2 the *market price* for *energy* determined for the *dispatch interval* to which the *investigated price* relates, referred to as P_m,

provided that,

1.3.3.3 if *dispatch data* that has been accepted by the *IESO*, as reflected in the *market schedules* for that *investigated facility,* is not available in respect of the *investigated facility* which is; i) a hydroelectric *generation facility* for at least ten of the thirty days; or ii) or for all other *facilities* at least fifteen of the ninety days, comprising the period over which the relevant *historical reference price* referred to in sections 1.3.3.1 and 1.3.3.1A is calculated, or

1.3.3.4 if the *investigated facility* is a *boundary entity* withdrawing *energy* from the *IESO-administered markets* at an *intertie* that has been designated by the *IESO* as an uncontested export *intertie*, being an *intertie*:

a. where at least ninety percent of the withdrawals over that *intertie* in the ninety days prior to such designation have been accounted for by one *market participant*, or

b. which is uncontested in accordance with criteria stipulated by the *IESO Board* (which criteria shall also specify the factors allowing revocation of the designation).

sections 1.3.3.1 and 1.3.3.1A shall not apply and only the *reference price* referred to in section 1.3.3.2 shall be used for the purposes of section 1.3.2.

1.3.4 The *IESO Board* may establish the alternative *reference price* referred to in section 1.3.3.1B based on an average of the price contained in all *energy offers* or *energy bids* submitted by the *registered market participant* for an *investigated facility* and accepted by the *IESO*, as reflected in the most recent *market schedules* for that *investigated facility*, during the time periods specified in section 1.3.3.1 or the time periods specified in section 1.3.3.1A as the case may be, in respect of a given increment or increments of supply or consumption. No such alternative *reference price* shall be used by the *IESO* for the purposes of section 1.3.3.1B until the manner of determination of such *reference price* and the conditions in which it may be applied have been *published* by the *IESO*.

1.3.5 The *IESO* shall publish the methodology, as determined by the *market surveillance panel* and approved by the *IESO Board*, for determining a pair of high end factors and a pair of low end factors for each type of *reference price* referred to in section 1.3.3, including the alternative *reference price* referred to in section 1.3.3.1B, if any.

1.3.5.1 [Intentionally left blank – section deleted]

1.3.5.2 [Intentionally left blank – section deleted]

1.3.6 The methodology referred to in section 1.3.5 for determining the pair of high end factors and the pair of low end factors for each type of *reference price* shall be established based on the concept that it is acceptable for the congestion management *settlement* credit referred to in section 1.1.3 to be larger as the number of consecutive or the number of cumulative hours that a *registered facility* may be *dispatched* as a *constrained on facility* or as a *constrained off facility* decrease. Accordingly:

1.3.6.1 one of each such pair of high end factors and one of each such pair of low end factors shall vary according to the number of consecutive hours that a *registered facility* was *dispatched* as a *constrained on facility* or a *constrained off facility* during the *constrained on event* or *constrained off event* being investigated; and

1.3.6.2 the other of each such pair shall vary according to the cumulative number of hours that a *registered facility* was *dispatched* as a *constrained on facility* or a *constrained off facility* in the ninety-day period preceding the *constrained on event* or *constrained off event* being investigated and during such *constrained on event* or *constrained off event*.

1.3.7 The methodology referred to in section 1.3.5 for determining the pair of high end factors and the pair of low end factors may differ for, and the resulting pairs of factors may also differ for, each of the *reference prices* referred to in section 1.3.3, including the alternative *reference price*, if any, referred to in section 1.3.3.1B. For each such *reference price*:

1.3.7.1 the high end factors shall decrease as either the number of consecutive hours or the number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively, increase, provided that neither of such factors shall be less than the value 1.0; and

1.3.7.2 the low end factors shall increase as either the number of consecutive hours or the number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively, increase, provided that such neither of such factors shall be greater than the value 1.0.

1.3.8 The *IESO* shall establish the range referred to in section 1.3.2 in respect of an *investigated price* as follows:

1.3.8.1 for the high end of the range the *IESO* shall:

a. calculate, for each applicable *reference price* referred to in section 1.3.3, high end values for each of the number of consecutive hours and the number of cumulative hours referred in sections 1.3.6.1 and 1.3.6.2, respectively, using the following equation:

reference price + absolute value (*reference price*) x (factor – 1)

where the factor used in the above equation is the high end factor determined for that type of *reference price* in accordance with sections 1.3.5 to 1.3.7 that corresponds to the appropriate number of consecutive hours or number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively;

b. select, in respect of each applicable *reference price*, the lesser of the high end values calculated pursuant to section 1.3.8.1(a); and

c. select the larger of the high end values based on P_m or P_h or, where the alternative *reference price* referred to in section 1.3.3.1B is used, based on P_m or P_a; and

1.3.8.2 for the low end of the range the *IESO* shall:

a. calculate, for each applicable *reference price* referred to in section 1.3.3, low end values for each of the number of consecutive hours and the number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively, using the following equation:

reference price + absolute value (*reference price*) x (factor – 1)

where the factor used in the above equation is the low end factor determined for that type of *reference price* in accordance with sections 1.3.5 to 1.3.7 that corresponds to the appropriate number of consecutive hours or number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively;

b. select, in respect of each applicable *reference price*, the larger of the low end values calculated pursuant to section 1.3.8.2(a); and

c. select the lesser of the low end values based on P_m or P_h or, where the alternative *reference price* referred to in section 1.3.3.1B is used, based on P_m or P_a.

1.3.9 The *IESO* shall determine whether, in the *IESO's* opinion, there existed sufficient competition for the provision of the *physical services* that the *investigated facility* was to provide in being *dispatched* as a *constrained on facility* or a *constrained off facility*. The *IESO* shall determine whether sufficient competition existed based on the number of *market participants* and the MW quantity associated with, as applicable:

1.3.9.1 *energy offers,* not included in the *market schedule*, for a *generation facility* or an import that could have been constrained on; and

1.3.9.2 *energy bids,* included in the *market schedule,* for a *dispatchable load* or an export that could have been constrained off;

or,

1.3.9.3 *energy offers,* included in *the market schedule,* for a *generation facility* or an import that could have been constrained off; and

1.3.9.4 *energy bids,* not included in the *market schedule,* for a *dispatchable load* or an export that could have been constrained on;

for those *market participants* that could have effectively responded to *dispatch instructions* comparable to those issued for the *investigated facility*.

1.3.10 Where the *IESO* determines:

1.3.10.1 pursuant to section 1.3.1, that a transmission flow constraint on the *IESO-controlled grid* or a *security limit* did not result in a constrained *on event* or a *constrained off event*;

1.3.10.2 pursuant to section 1.3.2, that the investigated price falls within the range referred to in that section; or

1.3.10.3 pursuant to section 1.3.9, that sufficient competition existed for the provision of the physical services that the *investigated facility* was dispatched as a *constrained on facility* or a *constrained off facility* to provide,

the *IESO* shall, subject to section 1.8, cease investigation of the *investigated price.*

1.3.11 [Intentionally left blank – section deleted]

1.3.11.1 [Intentionally left blank – section deleted]

1.3.11.2 [Intentionally left blank – section deleted]

1.3.12 For the purpose of Appendix 7.6, local market power is established where the *IESO* determines:

1.3.12.1 pursuant to section 1.3.1, that a transmission flow constraint on the *IESO-controlled grid* or a *security limit* resulted in *constrained on event* or a *constrained off event*;

1.3.12.2 pursuant to section 1.3.2, that the *investigated price* falls outside of the range referred to in that section; and

1.3.12.3 pursuant to section 1.3.9, that sufficient competition did not exist for the provision of the *physical services* that the *investigated facility* was *dispatched* as a *constrained on facility* or a *constrained off facility* to provide.

If the *IESO* establishes that local market power exists, the *IESO* shall conduct the analysis referred to in 1.4.1 to determine whether the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3.

1.3.12.4 [Intentionally left blank – section deleted]

1.3.12.5 [Intentionally left blank – section deleted]

1.3.13 [Intentionally left blank – section deleted]

1.3.13.1 [Intentionally left blank – section deleted]

1.3.13.2 [Intentionally left blank – section deleted]

1.3.13.3 [Intentionally left blank – section deleted]

1.3.13.4 [Intentionally left blank – section deleted]

1.4 Price Investigation

1.4.1 Subject to section 1.4.2, the *IESO* shall conduct an analysis of such factors that the *IESO* considers relevant to a determination of whether the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, which factors may include:

1.4.1.1 the price, and variations in the price, of the fuel used by the *investigated facility;*

1.4.1.2 the degree to which the prices contained in the *energy offers* or *energy bids* submitted by the *registered market* participant for the *investigated facility* and accepted by the *IESO*, as reflected in the *market schedules* for that *investigated facility*, have varied over time;

1.4.1.3 [Intentionally left blank – section deleted]

1.4.1.4 market prices and variations in market prices in neighbouring jurisdictions;

1.4.1.5 opportunity costs for *energy* limited resources; and

1.4.1.6 for investigations of *constrained off events* in *designated constrained off watch zones* prescribed in section 1.2.1A, such other considerations as set out in the applicable *market manual*.

1.4.2 The *IESO* shall not be required to conduct the analysis referred to in section 1.4.1 and shall cease investigation of the *investigated price* if, in the *IESO*'s opinion:

1.4.2.1 the *IESO* does not have sufficient reliable information upon which to base the determination referred to in section 1.4.1;

1.4.2.2 the level of effort that would be required to conduct the analysis is large relative to the materiality of the anticipated impact of the *investigated price*; or

1.4.2.3 the conduct of the analysis would constitute an inefficient utilization of the *IESO's* resources, having regard to the *IESO*'s other activities and to the desire to allocate resources to the investigation of *energy offers* and *energy bids* that are most likely to require remedial action pursuant to this Appendix.

1.4.3 Where, based on the analysis conducted in section 1.4.1 and on the criteria specified in section 1.4A, the *IESO* determines that:

1.4.3.1 the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* shall, subject to section 1.8, cease investigation of the *investigated price*; or

1.4.3.2 the *investigated price* may justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* shall provide the *registered market participant* for the *investigated facility* with a reasonable opportunity to make representations as to why the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3. As part of its representations, the *registered market participant* may request that the *IESO* apply for the purpose of replacing the *investigated price* pursuant to section 1.4.5.1:

a. alternate high end or low end values in place of those prescribed by section 1.3.8, or

b. an alternate replacement price to the initial estimated replacement price referred to in section 1.2.1A.

1.4.4 Where, following a consideration of any representations made by the *registered market participant* for the *investigated facility* pursuant to section 1.4.3.2, the *IESO* determines that the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* shall, subject to section 1.8, cease investigation of the *investigated price.*

1.4.5 Where, following a consideration of any representations made by the *registered market participant* for the *investigated facility* pursuant to section 1.4.3.2 and based on the criteria specified in section 1.4A, the *IESO* determines that the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3:

1.4.5.1 the *IESO* shall replace the *investigated price* with the following as applicable, or such other value as may be agreed to by the *IESO* and the *market participant*:

a. in the case of a *constrained on generation unit* or a *constrained off dispatchable load*, the high end of the range determined in accordance with section 1.3.8.1;

b. in the case of a *constrained off generation unit* or a *constrained on dispatchable load*, the low end of the range determined in accordance with section 1.3.8.2;

c. [Intentionally left blank – section deleted]

d. in the case of persistent and significant *constrained off events* within *designated constrained off watch zones*, the initial estimated replacement price referred to in section 1.2.1A, or

1.4.5.2 the *IESO* may commence an inquiry pursuant to section 1.6.1.

1.4.5A Where section 1.4.5.1 applies, the *IESO* shall:

1.4.5A.1 re-calculate the congestion management *settlement* credit referred to in section 1.1.3 on the basis of the price referred to in section 1.4.5.1; and

1.4.5A.2 provide notice to the *registered market participant* for the *investigated facility* specifying:

a. the grounds and associated information upon which the *IESO* is relying in support of its intention to use, for *settlement* purposes, the re-calculated congestion management *settlement* credit referred to in section 1.4.5A.1;

b. an estimate of the replacement price for the *investigated price* referred to in section 1.4.5.1; and

c. the right of the *registered market participant* to request, within five *business days* of the date of receipt of the notice, an inquiry pursuant to section 1.6.1.

1.4.6 Where, following a consideration of any representations made by the *registered market participant* for the *investigated facility* pursuant to section 1.4.3.2 and the criteria specified in section 1.4A, the *IESO* determines that the *investigated price* may justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* may commence an inquiry pursuant to section 1.6.1.

1.4.7 [Intentionally left blank – section deleted]

1.4.7.1 [Intentionally left blank – section deleted]

1.4.7.2 [Intentionally left blank – section deleted]

1.4.7.3 [Intentionally left blank – section deleted]

1.4.8 Where a *registered market participant* requests an inquiry pursuant to section 1.4.5A.2c within the time referred to in that section, the *IESO* shall not take any action pursuant to section 1.4.5.1 and shall conduct an inquiry pursuant to section 1.6.1.

1.4.9 Where a *registered market participant* does not request an inquiry pursuant to section 1.4.5A.2c within the time referred to in that section, the *IESO* shall use, for *settlement* purposes, the re-calculated congestion management *settlement* credit referred to in section 1.4.5A.1.

1.4A Criteria for Re-calculating Congestion Management Settlement Credits

1.4A.1 Having established in section 1.3 that local market power existed or that persistent and significant *constrained off events* occurred within *designated constrained off watch zones* pursuant to section 1.2.1A, the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3 shall be justified if the *IESO* establishes that the *investigated price* is not consistent with:

1.4A.1.1 the marginal costs of the *generation facility* that received the congestion management *settlement* credit;

1.4A.1.2 opportunity costs or replacement energy costs of a *generation facility*, *dispatchable load facility* or *boundary entity*; or

1.4A.1.3 value or benefits of consumption for a *dispatchable load facility or* an exporting *boundary entity,*

and such other additional values, benefits or costs as the *IESO* may determine relevant.

1.4A.2 Such values, benefits, and costs referred to in section 1.4A.1 will be based on information available to the *IESO* at the time of its decision under section 1.4, which may be:

1.4A.2.1 estimated information available to the *IESO*; or

1.4A.2.2 information provided by the *registered market participant* as part of its representations under section 1.4.3.2 or otherwise.

1.5 [Intentionally left blank – section deleted]

1.5.1 [Intentionally left blank – section deleted]

1.5.1.1 [Intentionally left blank – section deleted]

1.5.1.2 [Intentionally left blank – section deleted]

1.5.2 [Intentionally left blank – section deleted]

1.6 Inquiry

1.6.1 Where the *IESO* determines that an inquiry is required under section 1.4.5.2 or section 1.4.6 or an inquiry is requested by the *registered market participant* for the *investigated facility* under section 1.4.5A.2c, the *IESO* shall conduct an inquiry to determine whether the *investigated price* falls within the range determined in accordance with section 1.6.3 or 1.6.6, as the case may be, and shall notify the *registered market participant* for the *investigated facility* of the commencement of the inquiry. During such inquiry, the *IESO* shall provide the *registered market participant* for the *investigated facility* with a reasonable opportunity to make representations as to why the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3 including, but not limited to, representations:

1.6.1.1 as to the costs that should be considered for purposes of the determination referred to in section 1.6.3;

1.6.1.2 where section 1.6.6 applies, as to the costs or other information that should be considered for purposes of the determination referred to in that section; and

1.6.1.3 where applicable, as to the costs that should be considered for purposes of the adjustment referred to in section 1.6.4 and the revenues, operating income and forecasts or estimates referred to in section 1.6.5.

1.6.2 The *IESO* shall, for the purposes of determining the range referred to in section 1.6.1, notify the *registered market participant* for the *investigated facility* of the information required to be submitted by it for that purpose and shall use such information to the extent that the *IESO* determines that such information is complete and accurate. The *registered market participant* shall supply this information to the *IESO* by the date specified in the notification. Where the *IESO* determines that such information is incomplete or inaccurate, or where the *IESO* considers that the information received from the *registered market participant* is insufficient for the purpose of determining the range referred to in section 1.6.1, the *IESO* may refer the matter to the *dispute resolution panel* pursuant to section 2 of Chapter 3 and request, in the *notice of dispute*, that the *dispute resolution panel* complete the inquiry.

1.6.3 The *IESO* shall determine the range referred to in section 1.6.1 with respect to a *constrained on generation unit* or a *constrained off generation unit* in accordance with the following:

1.6.3.1 the low end of the range shall be the short-run marginal cost associated with that portion of the *generation unit's* output that was *dispatched* as a *constrained on generation unit* or a *constrained off generation unit* determined on the basis of:

a. fuel costs;

b. variable operating and maintenance costs;

c. opportunity costs; and

d. any other appropriate costs,

adjusted, where applicable and as the *IESO* may determine appropriate, by deducting an amount equal to the cycle costs incurred in circumstances where a *constrained off generation unit* was required to cease operation solely as a result of being *dispatched* as a *constrained off generation unit*. For the purposes of calculating the short-run marginal cost, the *IESO* may exclude any of the foregoing cost factors, or estimate any of these cost factors, in the event the *market participant* does not supply the necessary information as requested by the *IESO* pursuant to section 1.6.2; and

1.6.3.2 the high end of the range shall be 110 percent of the amount calculated in accordance with section 1.6.3.1, adjusted in accordance with one or both of the following as may be applicable and as the *IESO* may determine appropriate:

a. by adding an amount equal to the cycle costs incurred in circumstances where a *constrained on generation unit* was required to operate solely as a result of being *dispatched* as a *constrained on generation unit*; and

b. where section 1.6.4 applies, adding an amount equal to the *investigated facility's* fixed and embedded costs or such portion thereof as determined appropriate by the *IESO* in accordance with that section.

1.6.4 Where an investigated facility is a constrained on generation unit that, in the IESO's opinion based on the investigated facility's operating history:

1.6.4.1 has not recovered, during the twelve-month period prior to the *constrained on event* to which the *investigated price* relates:

a. the whole of the operating costs; and

b. such portion of the fixed and embedded costs as determined appropriate by the *IESO,*

associated with having been dispatched as a *constrained on generation unit* as a result of that *constrained on event*; or

1.6.4.2 in the case of a *generation unit*:

a. that commenced operations less than twelve months prior to the *constrained on event* in respect of which the *investigated price* was submitted; or

b. with respect to which the *constrained on event* to which the *investigated price* relates occurred less than twelve months following the *market commencement date*,

might not recover, during the twelve-month period beginning on the date of commencement of operations referred to in section 1.6.4.2(a) or the *market commencement date*, as the case may be,

the *IESO* may make the adjustment referred to in section 1.6.3.2(b) in such amount as determined appropriate by the *IESO*, based on the considerations referred to in section 1.6.5.

1.6.5 In determining whether to make the adjustment referred to in section 1.6.4 and in determining the amount of any such adjustment, the *IESO* shall:

1.6.5.1 consider the *investigated facility's* revenues and operating income associated with dispatch of the *investigated facility* prior to the *constrained on event* to which the *investigated price* relates; and

1.6.5.2 where section 1.6.4.2 applies consider:

a. the *investigated facility's* revenues and operating income associated with dispatch of the *investigated facility* prior to the *constrained on event* to which the *investigated price* relates; and

b. based on such forecasts or estimates as the *IESO* considers appropriate including, but not limited to, prorating the revenues and operating income referred to in section 1.6.5.2(a) over the period equal to the difference between (i) and (ii) referred to below in this section 1.6.5.2(b), the revenues and operating income that may be projected or estimated to be associated with *dispatch* of the *investigated facility* for a period equal to the difference between: (i) twelve months; and (ii) the period of time between the date of commencement of operations referred to in section 1.6.4.2(a) or the *market commencement date*, as the case may be, and the *constrained on event* to which the *investigated price* relates.

1.6.6 The *IESO* shall determine the range referred to in section 1.6.1 with respect to an *investigated facility* that is a *constrained on dispatchable load* or a *constrained off dispatchable load* in accordance with the following:

1.6.6.1 the low end of the range shall be 90 percent of the value or opportunity costs associated with that portion of the *facility's* consumption that was *dispatched* as a *constrained on dispatchable load* which may be determined on the basis of:

a. net profit or value associated with consumption, excluding the costs of purchasing *energy*;

b. opportunity costs, which may be the alternate cost for obtaining *energy* for consumption; and

c. any other appropriate value or benefits of consumption to the *market participant*,

adjusted, where applicable and as the *IESO* may determine appropriate, by adding an amount equal to the cycle costs incurred in circumstances where a *constrained on dispatchable load* was required to operate solely as a result of being *dispatched* as a *constrained on facility*. For the purposes of calculating the value or opportunity cost, the *IESO* may exclude any of the foregoing cost factors, or estimate any of these cost factors, in the event the *market participant* does not supply the necessary information as requested by the *IESO* pursuant to section 1.6.2.

1.6.6.2 the high end of the range shall be 110 percent of the amount calculated in accordance with section 1.6.6.1 and adjusted, as may be applicable and as the *IESO* may determine appropriate, by adding an amount equal to the cycle costs incurred in circumstances where the *facility* was *dispatched* as a *constrained off dispatchable load*.

1.6.7 Where the *investigated price* falls outside the range determined in accordance with section 1.6.3 or 1.6.6, as the case may be, the *IESO*:

1.6.7.1 shall replace the *investigated price* with a price determined in accordance with section 1.6.8 and revise, for *settlement* purposes, the congestion management *settlement* credit referred to in section 1.1.3 on the basis of such price;

1.6.7.2 [Intentionally left blank – section deleted]

1.6.7.3 shall provide the *registered market participant* for the *investigated facility* with written reasons describing the manner in which the range referred to in section 1.6.7 and the revision referred to in section 1.6.7.1 have been calculated.

1.6.8 The price at which the *IESO* shall, pursuant to section 1.6.7.1, replace the *investigated price* shall be determined as follows:

1.6.8.1 where the *investigated facility* is a *constrained on generation unit*, the amount determined pursuant to section 1.6.3.2;

1.6.8.2 where the *investigated facility* is a *constrained off generation unit*, the amount determined pursuant to section 1.6.3.1;

1.6.8.3 where the *investigated facility* is a *constrained off dispatchable load*, the amount that represents the high end of the range referred to in section 1.6.1, determined in accordance with the methodology developed pursuant to section 1.6.6; and

1.6.8.4 where the *investigated facility* is a *constrained on dispatchable load*, the amount that represents the low end of the range referred to in section 1.6.1, determined in accordance with the methodology developed pursuant to section 1.6.6.

1.6.9 [Intentionally left blank – section deleted]

1.6.10 Where the *investigated price* falls within the range calculated in accordance with section 1.6.3 or 1.6.6, as the case may be, the *IESO* shall not take the action referred to in section 1.6.7 and shall notify the *registered market participant* for the *investigated facility* accordingly.

1.7 Settlement

1.7.1 Where the *IESO* revises a *settlement credit* in accordance with section 1.4.5.1 or 1.6.7.1:

1.7.1.1 the revision shall be applied, in accordance with section 1.7.2, to the last *preliminary settlement statement* issued to:

a. the *metered market participant* for the *investigated facility* that is a *generation unit* or *dispatchable load*, or

b. the *registered market participant* for the *investigated facility* that is a *boundary entity*

for the current *billing period* for which such revised *settlement credit* is calculated; and

1.7.1.2 a consequential revision effected in accordance with section 1.7.2 shall, where applicable, be applied in accordance with section 4.8.2 of Chapter 9.

1.7.2 Where the *IESO* determines that a revision referred to in section 1.7.1.1 and a consequential revision referred to in section 1.7.1.2 are required to reflect alterations to payments due on a previous *invoice*, the *IESO* shall:

1.7.2.1 for the *market participant* for the *investigated facility* referred to in section 1.7.1.1, reflect the revision in the *market participant's* last preliminary *settlement statement* issued for the current *billing period* for which the revised *settlement* credit is calculated;

1.7.2.2 for the *market participant* for the *investigated facility* referred to in section 1.7.1.1, include in the *preliminary settlement statement* a debit adjustment reflecting *default interest* on the difference between:

a. the amount of the *settlement* credit as revised in accordance with section 1.4.5.1 or 1.6.7.1, and

b. the amount of the *settlement* credit that would otherwise have been applicable,

accrued:

c. from the *date* on which overpayment was made to the *market participant* for the *investigated facility* for the *constrained on event* or the *constrained off event* to which the *investigated price* relates,

d. to the *market participant payment date* to which the *preliminary settlement statement* relates; and

1.7.2.3 apply the amounts received pursuant to section 1.7.2.1 and 1.7.2.2 in accordance with section 4.8.2 of Chapter 9.

1.7.2.4 [Intentionally left blank]

1.7.2.5 [Intentionally left blank]

1.7.3 [Intentionally left blank]

1.7.3.1 [Intentionally left blank]

1.7.3.2 [Intentionally left blank]

1.7.4 [Intentionally left blank – section deleted]

1.8 No Prejudice to Other Investigations

1.8.1 Nothing in this Appendix shall preclude the *market assessment unit* or the *market surveillance panel* from conducting, in accordance with section 3 of Chapter 3, any monitoring or evaluation activity or analysis or any investigation with respect to or that involves an *energy bid* or an *energy offer* that has been the subject of an investigation or inquiry pursuant to this Appendix, provided that no *registered market participant* shall, as a result of such activity, analysis or investigation, be subject to the imposition of any financial sanction by the *IESO* other than the revision of a *settlement* credit effected in accordance with this Appendix.

1.9 Non-application

1.9.1 Notwithstanding any other provision of this Appendix, the *IESO* shall not commence or continue an investigation or an inquiry pursuant to this Appendix in respect of an *energy offer* or an *energy bid* submitted by a *constrained off facility* or a *constrained on facility* where it is determined that the *facility*:

1.9.1.1 is one with respect to which there exists a *reliability must-run contract* or a *contracted ancillary services* contract with the *IESO* that contains provisions fixing, by reference to a pre-determined amount or to a formula, the price at which *energy offers* or *energy bids* are to be submitted thereunder and the *investigated price* is consistent with such pre-determined amount or formula; and

1.9.1.2 was dispatched as a constrained on facility or a constrained off facility pursuant to and in accordance with such reliability must-run contract or such contracted ancillary services contract.

Appendix 7.7 – Radial Intertie Transactions

1.1 Applicable Configurations

1.1.1 A *registered facility* that is a *generation facility* that is connected electrically over a *radial intertie* to a neighbouring *control area* may only provide electricity or any *physical service* for delivery out of the *integrated power system* if it is, with the approval of the *IESO,* operating such *registered facility* in a *segregated mode of operation.*

1.2 Dispatch Data

1.2.1 A *market participant* that intends for a *registered facility* to operate in a segregated mode of operation shall maintain *dispatch data* that was submitted for that *registered facility* for each *dispatch hour* during which a *registered facility* will or is intended to operate in segregated mode of operation. The *market participant* may revise the applicable *dispatch data* in accordance with the timelines for submission of revised *dispatch data* specified in section 3.3 of Chapter 7.

1.2.2 Notwithstanding the provisions of section 3.3 of Chapter 7, if the *IESO*:

1.2.2.1 denies a Request for Segregation; or

1.2.2.2 revokes its approval to operate a *registered facility* in a *segregated mode of operation* or terminates the operation of a *registered facility* in a *segregated mode of operation* in accordance with section 1.3.6,

the *IESO* shall permit new or revised *dispatch data* to be submitted to the *IESO* in respect of the *registered facility* for the *dispatch hours* to which such denied request pertains.

1.3 Scheduling & Scheduling Approval

1.3.1 A registered *market participant* shall, within the time required by section 1.3.3, submit a *Request for Segregation* to the *IESO* for approval to operate its *registered facility* in a *segregated mode of operation* and shall submit an *outage* request, in accordance with the provisions specified in section 6.4 of Chapter 5 and the applicable *market manual*, to the *IESO* for the *registered facilities* intended to operate in a *segregated mode of operation.* The *registered market participant* shall make such a *Request for Segregation* in accordance with the applicable *market manual* and the information contained in such *Request for Segregation* shall include, but not be limited to:

1.3.1.1 the time at which operation in a *segregated mode of operation* is intended to commence;

1.3.1.2 the length of time that the applicable *registered facilities* are intended to operate in a *segregated mode of operation*; and

1.3.1.3 a list of the *registered facilities* that are intended to operate in a *segregated mode of operation*.

1.3.2 If a *registered market participant* wishes to revise the contents of a *Request for Segregation* it shall submit a new *Request for Segregation* and shall submit a new *outage* request to the *IESO* in accordance with section 1.3.1.

1.3.3 A *Request for Segregation* shall be made no earlier than 12:00 EST on the pre-dispatch day and no later than 2 hours prior to the start of the first *dispatch hour* to which such request pertains, unless otherwise agreed by the *IESO*. When the *Request for Segregation* is for the operation of a *registered facility* in a *segregated mode of operation* for more than one day the *IESO* may approve such operation for up to two *business days*.

1.3.4 Upon receipt of the *Request for Segregation* the *IESO* shall make a decision regarding a *Request for Segregation* as soon as practicable but no later than such time that allows the *transmitter*, referred to in section 1.3.5, a minimum of 90 minutes or such lesser time as agreed to by the *transmitter* to switch any applicable equipment or *facilities* required to permit implementation of the *segregated mode of operation* prior to the time set out in section 1.3.1.1, and shall notify the *registered market participant* of such decision. The *IESO*:

1.3.4.1 shall deny such *Request for Segregation* if:

a. such *Request for Segregation* pertains to a *registered facility* located in the province of Ontario and would threaten the reliability of the *IESO-controlled grid*; or

b. the *metering installation* for the *registered facility* to which such *Request for Segregation* relates does not comply with section 4.1A.1 of Chapter 6; or

c. such *Request for Segregation* pertains to a *registered facility* located outside the province of Ontario and would threaten the *security* of the *IESO-controlled grid*; and

1.3.4.2 may deny such *Request for Segregation* if the *metered market participant* for the *metering installation* for the *registered facility* to which such *Request for Segregation* relates has previously failed to comply with section 1.2.1.7 of Appendix 6.1 of Chapter 6 for a period in which such *registered facility* operated in a *segregated mode of operation.*

1.3.5 If the *IESO* approves a *Request for Segregation,* it shall direct the relevant *transmitter* to:

1.3.5.1 switch any applicable equipment or *facilities* required to permit implementation of the *segregated mode of operation* at the time referred to in section 1.3.1.1;

1.3.5.2 switch any applicable equipment or *facilities* required to cease implementation of the *segregated mode of operation* at the expiry of the time referred to in section 1.3.1.2.

1.3.6 The *IESO* may at any time revoke its approval to operate a *registered facility* in a *segregated mode of operation* or terminate the operation of a *registered facility* in a *segregated mode of operation,* as the case may be, for the reason described in section 1.3.4.1(b), where the *metered market participant* is failing to comply with section 1.2.1.7 of Appendix 6.1 of Chapter 6 in respect of the *metering installation* for such *registered facility* or where, in the *IESO's* opinion, such approval or such continued operation would threaten the *reliability* of a *local area* which forms part of the *IESO-controlled grid* or the *security* of the *integrated power system,* and shall notify the *registered market participant* accordingly. Where the *IESO* intends to revoke its approval to operate a *registered facility* in a *segregated mode of operation,* it shall revoke any direction issued pursuant to section 1.3.5. Where the *IESO* intends to terminate such operation, the *IESO* shall direct the relevant *transmitter* to switch any applicable equipment or *facilities* required to cease implementation of the *segregated mode of operation*. Where the *IESO* revokes its approval to operate a *registered facility* in a *segregated mode of* *operation* or terminates the operation of a *registered facility* in a *segregated mode of operation,* as the case may be, the *registered market participant* for that *registered facility* shall not be entitled to compensation for any costs, losses or damages from the *IESO* for such revocation or termination.

1.3.7 The *IESO* shall coordinate and confirm with the applicable *control area operator:*

1.3.7.1 the switching to be effected by the relevant *transmitter* in accordance with section 1.3.5 or 1.3.6; and

1.3.7.2 the names of the *registered facilities* that will operate in a *segregated mode of operation*.

1.3.8 The *IESO* shall not issue *dispatch instructions* to a *registered facility* in respect of any *dispatch hour* during which such *registered facility* is operating in a *segregated mode of operation*. All instructions relating to *dispatch* for the *registered facility* while operating in a *segregated mode of operation* shall be sent directly by the applicable *control area operator* to the *registered market participant*.

1.4 Settlements

1.4.1 The delivery of electricity or a *physical service* by a *registered facility* while operating in a *segregated mode of operation* shall be excluded from the *IESO's settlement process* and in no event shall the *IESO* be required to effect payment in respect of any electricity or *physical service* so delivered.

1.4.2 Notwithstanding section 1.4.1, a *registered market participant* that operates a *registered facility* in a *segregated mode of operation* shall submit such scheduling information to the *IESO* as may be necessary to enable the *IESO* to determine the amounts payable by the *registered market participant* for *export service* related to such operation.

1.4.3 Any costs incurred by a *transmitter* in complying with a direction issued pursuant to section 1.3.5 or 1.3.6 shall be borne by the *registered market participant* or the *transmitter* in the manner specified in their *connection agreement.*

1.4.4 The *registered market participant* shall be solely liable in respect of any positive or negative inadvertent accumulated while its *registered facilities* are operating in the *segregated mode of operation.*