

Market Rules

Chapter 9

Settlements and Billing

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1. Introductory Rules

1.1 Application and Purpose

1.1.1 This chapter applies to:

1.1.1.1 the *IESO*; and

1.1.1.2 market participants.

1.1.2 This chapter sets out the respective rights and obligations of the *IESO* and of *market participants* in determining, billing for and effecting payment in respect of financial obligations arising from the *IESO-administered markets*, other provisions of the *market rules*, the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, including the following:

1.1.2.1 the energy forward market;

1.1.2.2 the *energy market*;

1.1.2.3 the operating reserve market;

1.1.2.4 congestion management;

1.1.2.5 transmission rights (TRs);

1.1.2.6 the *capacity reserve market* (if activated by the *IESO*);

1.1.2.7 operating deviations;

1.1.2.8 ancillary services and reliability must-run contracts;

1.1.2.9 transmission service charges and connection charges collected by the *IESO*;

1.1.2.10 rural rate protection;

1.1.2.11 the *IESO* administration charge;

1.1.2.12 penalties and fines;

1.1.2.13 any debt retirement charge;

- 1.1.2.14 rebates and other payments arising from market power mitigation measures;
- 1.1.2.15 the day-ahead commitment process; and
- 1.1.2.16 forecasting services relating to *variable generation*.

1.2 Regulated Settlement Amounts and Related Payment Charges

- 1.2.1 Notwithstanding any other provision within the *market rules*, the *IESO* shall, with respect to determining, collecting and remitting applicable *settlement amounts*, comply with the relevant provisions of the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, and any related regulations, as amended from time to time.
 - 1.2.1.1 [Intentionally left blank – section deleted]
 - 1.2.1.2 [Intentionally left blank – section deleted]
- 1.2.2 [Intentionally left blank – section deleted]
- 1.2.3 Notwithstanding any other provision within the *market rules*, *market participants* shall remit to the *IESO* such applicable *settlement amounts* and other payments as may be required under the relevant provisions of the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and any related regulations, as amended from time to time.
 - 1.2.3.1 [Intentionally left blank – section deleted]
 - 1.2.3.2 [Intentionally left blank – section deleted]

2. Settlement Data Collection and Management

2.1 Metering and Metering Responsibilities

- 2.1.1 Subject to section 2.1.1A, every *meter* utilised for determining *settlement amounts* according to this Chapter must be a *registered wholesale meter (RWM)*.
- 2.1.1A Nothing in section 2.1.1 shall be construed as requiring the *IESO* to determine *settlement amounts* on the basis of an *RWM* in circumstances where:

- 2.1.1A.1 it is permitted to use another *meter* for this purpose pursuant to section 3.1.4A; or
 - 2.1.1A.2 in circumstances where the *IESO* has determined that determination of *settlement amounts* using a *metering installation* whose registration has expired is required for the efficient operation of the *IESO-administered markets*; or
 - 2.1.1A.3 the *IESO* is determining *settlement amounts* related to the Emergency Load Reduction Program specified in section 15 of Chapter 7 using a measurement and verification plan referred to in section 15.1.1.2 of Chapter 7; or
 - 2.1.1A.4 the *IESO* has not permitted the use of the *RWM* for determining *settlement amounts* for the reason specified section 4.2.2A of Chapter 6.
- 2.1.2 A single *metered market participant* must be designated for each *RWM* that is not an *intertie metering point*.
- 2.1.3 The same *metered market participant* must be designated for all *primary RWMs*, other than *intertie metering points*, for which any *metering data* will be allocated to any single *registered facility*.
- 2.1.4 A *metered market participant* may, with respect to each *RWM* for which it is the *metered market participant*, submit *physical allocation data* to the *IESO* in accordance with section 2.4. If any quantity determined by *metering data* is not allocated to any other *market participant* by proper application of *physical allocation data* provided to the *IESO* by the *metered market participant* for that *RWM*, such quantity shall for *settlement* purposes be allocated by the *IESO* to that *metered market participant* as set forth in section 2.4.4.
- 2.1.5 The *IESO* shall be responsible for *metering data* and its allocation with respect to all *intertie metering points*. The *IESO*, in accordance with operating agreements with other *control areas*, shall:
- 2.1.5.1 to the extent required to fulfill its obligations under this Chapter, interpret and apply the protocols governing interchanges between the *IESO-controlled grid* and other *control areas*;
 - 2.1.5.2 provide to the *settlement process* the *interchange schedule data* described in section 2.5; and
 - 2.1.5.3 determine the allocated quantities called for by section 3.1.9 based on scheduled *intertie* flows even when these differ from actual flows as determined by *metering data*.

2.1.6 Each market participant registered as the registered market participant responsible for a registered facility shall designate to the IESO a single metered market participant responsible for submitting to the IESO the physical allocation data permitted by this Chapter with respect to that registered facility.

2.1.6.1 [Intentionally left blank]

2.1.6.2 [Intentionally left blank]

2.1A Station Service

2.1A.1 The registered *market participant* for a facility consuming transmission station service or connection station service shall:

2.1A.1.1 identify to the *IESO* the fraction of the *energy* withdrawn at that *facility* supplied from the *IESO-controlled grid* which is not such *station service*; and

2.1A.1.2 ensure that the consumption of the *energy* referred to in section 2.1A.1.1 is measured by an *RWM* that complies with the requirements of Chapter 6.

2.1A.2 For *settlement* purposes, *transmission station service* shall be treated as a transmission loss.

2.1A.3 Where *connection station service* is not separately metered by an *RWM*, the *energy* consumption associated with *connection station service* shall be estimated by the *metered market participant* designated by the *registered market participant* for the relevant *connection facility* or, in the absence of such a *metered market participant*, by such *registered market participant*, in accordance with the equations and procedures described in the applicable *market manuals*, which estimate shall be stamped by a registered professional engineer and shall be subject to audit by the *IESO*.

2.1A.4 For settlement purposes, *connection station service* shall be treated as follows:

2.1A.4.1 where the *energy consumption* associated with *connection station service* is included in the *energy consumption* measured by an *RWM*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

- a. amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* in the proportions provided by the *metering service provider* for that *RWM*, and the provision of such proportions shall constitute certification by such *metering service provider* that such proportions have been agreed between the *metering service provider* and all *market participants* whose *facilities* are connected to the relevant *connection facility*; or
- b. where the *metering service provider* has not provided the proportions referred to in section 2.1A.4.1(a), to the *metered market participant* for that *RWM* in accordance with section 2.4.4; or

2.1A.4.2 where the *energy consumption* associated with *connection station service* is not included in the *energy consumption* measured by an *RWM*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

- a. amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* in the proportions provided by the *metering service provider* for each *RWM* measuring the flow of *energy* taken from the *connection facility*. The proportions provided by each *metering service provider* shall reflect agreement amongst all applicable *metering service providers* and shall only be accepted by the *IESO* if the proportions provided by all applicable *metering service providers* sum to one. The provision of such proportions shall constitute certification by each such *metering service provider* that it has reached agreement with all other applicable *metering service providers* in respect of such proportions; or
- b. where one or more of the *metering service providers* referred to in section 2.1A.4.2(a) has not provided the *IESO* with the proportions referred to in that section, amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* on the basis of the number of *load serving breakers* serving each such *market participant*.

- 2.1A.5 A *metering service provider* who provides to the *IESO* factors for apportioning *connection station service* and site specific losses pursuant to section 2.1A.4.1(a) or 2.1A.4.2(a) may, no more than once in each calendar year or more frequently if required by the registration of a new *RWM*, submit to the *IESO* revised proportions for the purposes of apportioning the *energy* referred to in section 2.1A.4. The provision of such revised proportions shall constitute certification by such *metering service provider* as to the agreement referred to in section 2.1A.4.1(a) or 2.1A.4.2(a), as the case may be.
- 2.1A.6 For greater certainty, nothing in section 2.1A.4 shall be construed as permitting the apportionment of *connection service* and site specific losses to a *market participant* in respect of a *facility* that is an *embedded load facility* or an *embedded generation facility*.
- 2.1A.6A Where the sum of *energy* associated with *connection station service* and with site specific losses is apportioned by the *IESO* pursuant to sections 2.1A.4.1(b) or 2.1A.4.2(b) by reason of the failure of all applicable *metering service providers* to reach agreement as to the proportions referred to in sections 2.1A.4.1(a) or 2.1A.4.2(a) as the case may be, any *market participant* that is the subject of such apportionment may submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall, in the *notice of dispute*:
- 2.1A.6A.1 name all other *market participants* which are the subject of the same apportionment as *respondents*; and
- 2.1A.6A.2 request that the arbitrator determine an alternative apportionment.
- 2.1A.6B Where an *arbitrator* determines an alternative apportionment pursuant to section 2.1A.6A, the *metering service provider* for each applicable *RWM* shall, within 5 *business days* of the date of the award of the *arbitrator*, file with the *IESO* proportions for apportioning the sum of *energy* associated with *connection station service* and with site specific losses that reflect such alternative apportionment.
- 2.1A.7 Subject to section 2.1A.9, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by a *generation unit* passing through the *metering installation* net of all applicable *generation station service*, the costs associated with *generation station service* shall, for *settlement* purposes, be apportioned:
- 2.1A.7.1 amongst those *generation units* consuming such *generation station service* in the proportions provided by the *metering service provider* for the relevant *metering installation*; or
- 2.1A.7.2 where the *metering service provider* has not provided the proportions referred to in section 2.1A.7.1, equally amongst all such *generation units*,

provided that, in either case such apportionment results in a totalization of the applicable *RWMs* that is identical to the totalization of the *meters* required to meet the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4.

- 2.1A.8 A *metering service provider* who provides the *IESO* with proportions pursuant to section 2.1A.7.1 may submit up to two requests in a calendar year to the *IESO* to have such proportions revised, provided that the giving of effect to such revisions shall be subject to the mutual agreement of the *metering service provider* and the *IESO*.
- 2.1A.9 If the consumption of *generation station service* results in:
- 2.1A.9.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 3.1.9, accruing at the location of a *generation unit* which is part of an eligible *generation facility* within the meaning of section 2.1A.13 in circumstances where the injection of *energy* by that *generation facility* as a whole exceeds the withdrawal of *energy* by that *generation facility* as a whole during a given *metering interval*; and
- 2.1A.9.2 such accrual of AQEW results in *hourly uplift*, non-hourly *settlement amounts*, or both, accruing at the location referred to in section 2.1A.9.1 during any *metering interval* within an *energy market billing period*,
- the *metered market participant* for that *generation facility* shall, subject to section 2.1A.10, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.1A.9.2.
- 2.1A.10 No reimbursement will be provided to a *metered market participant* pursuant to section 2.1A.9 in respect of amounts attributable to the following:
- 2.1A.10.1 transmission services charges;
- 2.1A.10.2 any applicable penalties, awards or adjustments reflected in the *invoice* issued to the *metered market participant*; or
- 2.1A.10.3 any other *settlement amounts* where such a reimbursement:
- is prohibited by *applicable law*; or
 - where the *settlement amount* is collected by the *IESO* pursuant to an obligation imposed upon it by *applicable law*, is not permitted by such *applicable law*.

- 2.1A.11 [Intentionally left blank – section deleted]
- 2.1A.12 [Intentionally left blank – section deleted]
- 2.1A.13 For the purposes of section 2.1A.9.1, a *generation facility* may be designated by the *IESO* as an eligible *generation facility* where the *generation facility*:
- 2.1A.13.1 is comprised of two or more *registered facilities*:
- a. whose *metering data* is not summed to a single value pursuant to the process described in section 2.4.3; and
 - b. that have the same *metered market participant*;
- 2.1A.13.2 is located within the *IESO control area*; and
- 2.1A.13.3 has associated with it *generation station service* that serves more than one *registered facility* included within that *generation facility*.
- 2.1A.14 The *IESO* shall recover any amount reimbursed pursuant to section 2.1A.9 as described in section 4.8.1.6.

2.2 Metering Data Recording and Collection Frequency

- 2.2.1 All *metering data* must be recorded for each *metering interval* except as otherwise provided in section 2.2.2 or elsewhere in these *market rules*.
- 2.2.2 A RWM that serves only non-dispatchable load, self-scheduled generation facilities, transitional scheduling generators or intermittent generators need not record any metering data regarding energy (in MWh) or reactive energy (in MVARh) for *metering intervals* but must record such metering data for each settlement hour. Metering data regarding demand or power (in MW) shall be recorded by such RWMs for such intervals as the *IESO* may specify in the applicable market manual.
- 2.2.3 An *intertie metering point* shall record *metering data* in a manner consistent with the applicable interchange protocol.
- 2.2.4 *Metering data* shall be collected by or delivered to the *IESO* in accordance with Appendix 9.1 or in accordance with such other schedule as the *IESO* may determine from time to time.

2.3 Collection and Validation of Metering Data

- 2.3.1 The *IESO* shall collect or receive *metering data* directly from *RWMs*, in such other manner as may be specified in Appendix 9.1 and from such other processes as may be appropriate. Such *metering data* will initially be “raw” data that have not been validated or corrected by the *VEE process*.

- 2.3.2 The raw *metering data* collected by or delivered to the *IESO* shall be subjected to the *VEE process* described in Appendix 9.1. The *VEE process* shall:
- 2.3.2.1 convert raw *metering data* into validated, corrected or estimated “*settlement ready*” *metering data* suitable for use in determining *settlement amounts*;
 - 2.3.2.2 operate according to the *settlement* schedule specified in section 6;
 - 2.3.2.3 detect errors in *metering data* resulting from improper operational conditions and/or hardware/software malfunctions, including failures of or errors in metering or communication hardware, and from *metering data* exceeding pre-defined variances or tolerances; and
 - 2.3.2.4 use operational system data, including historical generation and load patterns and data collected by or delivered to the *IESO*, as appropriate, for validating raw *metering data*, and for editing, estimating and correcting *metering data* found to be erroneous or missing.
- 2.3.2A While undergoing the *VEE process*, *metering data* from a given registered *metering installation* in respect of a given *trading day* or, where applicable, estimates thereof, shall bear appropriate flags and shall be accessible by electronic means by any person referred to in section 10.1.3 of Chapter 6 on the day following such *trading day*.
- 2.3.3 Subject to section 2.3.4, all *metering data* in respect of a given registered *metering installation* for a given *trading day* used for determining *settlement amounts* pursuant to this Chapter shall be “*settlement ready*” *metering data* that has been validated and corrected by the *VEE process*. Such “*settlement ready*” *metering data* shall be accessible by electronic means by any person referred to in section 10.1.3 of Chapter 6 no later than five *business days* following such *trading day*, providing that the applicable *metering service provider* has resolved any trouble call pertaining to such *metering data*.
- 2.3.4 *Metering data* used for determining *settlement amounts* pursuant to this Chapter shall, where applicable, be adjusted to reflect the estimation or deeming provisions set forth in sections 11.1.4.2 and 11.1.6, respectively, of Chapter 6.

2.4 Collection of Physical Allocation Data

Rule Note:

1. [Intentionally left blank]

- 2.4.1 Each *metered market participant* that is eligible to do so pursuant to section 2.4.5 may, for each *RWM* with respect to which it is the *metered market participant*, submit to the *IESO physical allocation data* for allocating *metering data* among

market participants. Such *physical allocation data* shall be submitted in the form and on the schedule described in the applicable *market manual*.

2.4.1.1 [Intentionally left blank]

2.4.1.2 [Intentionally left blank]

2.4.1.3 [Intentionally left blank]

2.4.1.4 [Intentionally left blank]

2.4.2 The *IESO* shall be entitled to and shall rely on the *physical allocation data* received from a *metered market participant* for the purpose of allocating *metering data* and associated *settlement amounts* and, notwithstanding section 13 of Chapter 1:

2.4.2.1 the *IESO* shall not be liable to any person in respect of the allocation of:

- a. any *metering data* when effected in accordance with such *physical allocation data*; or
- b. any *settlement amounts* calculated on the basis of such *physical allocation data*; and

2.4.2.2 the *metered market participant* providing the *IESO* with such *physical allocation data* shall indemnify and hold harmless the *IESO* in respect of any and all claims, losses, costs, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation by the *IESO* of *metering data* in accordance with such *physical allocation data* or from the allocation by the *IESO* of any associated *settlement amounts*,

provided that nothing in this section 2.4.2 shall be construed as affecting the liability of the *IESO* in respect of the conduct of the adjustment and summation activities referred to in section 2.4.3.

2.4.3 Prior to the application of any *physical allocation data* received from a *metered market participant*, the *metering data* from each *RWM* that is the subject of the *physical allocation data* shall be:

2.4.3.1 adjusted by the *IESO* in accordance with section 4.2.3 of Chapter 6; and

- 2.4.3.2 summed with *metering data* from all other applicable *RWMs* in accordance with the applicable totalization table comprised in the relevant *meter point* documentation submitted in respect of the *RWM* pursuant to section 1.3 of Appendix 6.5 of Chapter 6.
- 2.4.4 *Metering data* from one or more *RWMs*, adjusted and summed in accordance with section 2.4.3, shall be attributed to the *metered market participant* for the applicable *RWM* or *RWMs* unless the *metered market participant* submits to the *IESO physical allocation data* with respect to such *metering data*
- 2.4.5 A *metered market participant* for an *RWM* or *RWMs* shall not submit *physical allocation data* in respect of such *RWM* or *RWMs* unless:
- 2.4.5.1 the *metered market participant* for such *RWM* or *RWMs* is a distributor and submits physical allocation data providing for the allocation of such metering data to:
- a. another *market participant* that is a *retailer*;
 - b. another *market participant* that is a *transmitter*;
 - c. an *embedded market participant* whose *facility* is embedded within the *metered market participant's distribution system*; or
 - d. another *market participant* that is a *distributor* whose *distribution system* is neighbouring on that of the *metered market participant*, provided that the *physical allocation data* represents the flow of *energy* between such *distribution system* and the *metered market participant's distribution system*; or
- 2.4.5.2 the *RWM* or *RWMs* are associated with a registered facility other than a distribution system and the *metered market participant* for such *RWM* or *RWMs* provides physical allocation data for the allocation of such metering data to another market participant,

and, subject to section 2.4.6, the *metered market participant* submitting the *physical allocation data* demonstrates to the *IESO*, in the manner described in the applicable *market manual*, that the other *market participant* to whom such *physical allocation data* relates has consented to the attribution to it of such *metering data*.

- 2.4.6 The last paragraph of section 2.4.5 shall not come into force until the date that is the first day of the seventh calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs.

- 2.4.7 A *metered market participant* that is eligible to submit *physical allocation data* pursuant to section 2.4.5 may, with respect to each *RWM* for which it is the *metered market participant*, submit a data file containing non-negative percentage values which are:
- 2.4.7.1 individually, each less than or equal to 100%; and
 - 2.4.7.2 in the aggregate also less than or equal to 100%,
- indicating the fraction of the *metering data*, adjusted and summed in accordance with section 2.4.3, that is to be allocated to each *market participant* in each *metering interval*. Such data file must be provided to the *IESO* in advance of operation, on the schedule described in the applicable *market manual*.
- 2.4.8 If all *metering data* in respect of a given *RWM* or *RWMs*, adjusted and summed in accordance with section 2.4.3, is to be attributed to a single *market participant*, the *metered market participant* for the applicable *RWM* or *RWMs* may submit to the *IESO* a standing declaration to that effect provided that such *metered market participant* is eligible to submit *physical allocation data* in accordance with section 2.4.5.
- 2.4.9 A *metered market participant* that is eligible to submit *physical allocation data* pursuant to section 2.4.5 may, with respect to each *RWM* for which it is the *metered market participant*, submit a data file indicating the absolute amount of each physical quantity included in the *metering data*, not exceeding the quantity resulting from the application of the processes described in section 2.4.3, to be allocated to each *market participant*. Such data file shall be provided to the *IESO* in preliminary form within 2 *business days* after the *dispatch day* to which it applies, and in final form within 6 *business days* after such *dispatch day*. Where the aggregate quantity indicated in such data file is not equal to the quantity resulting from the application of the processes described in section 2.4.3, the *IESO* shall:
- 2.4.9.1 where the aggregate quantity indicated in such data file is less than the quantity resulting from the application of the processes described in section 2.4.3, attribute the difference to the *metered market participant*; or
 - 2.4.9.2 where the aggregate quantity indicated in such data file is greater than the quantity resulting from the application of the processes described in section 2.4.3, disregard the data file and allow the *metered market participant* to resubmit it such that:

- a. the resulting aggregate quantity is less than or equal to the quantity resulting from the application of the processes described in section 2.4.3; and
- b. the resubmission of the file is consistent with the form and schedule described in section 2.4.1.

2.4.10 Any *settlement amount* that is realised or avoided by a *metered market participant* solely as a result of the submission of *physical allocation data* pursuant to this section 2.4 may be considered by the *IESO* as a benefit within the meaning of section 6.6.7 of Chapter 3 for purposes of the application of section 6.6.12 of that Chapter when fixing the amount of a financial penalty imposed in respect of the *metered market participant's* failure to follow *dispatch instructions* during such time as such *physical allocation data* was in effect.

2.4.11 If the *IESO* issues a *notice of intent to suspend* or a *suspension order* to a *market participant* that has been allocated *metering data* under section 2.4.5, section 6.3.5 of Chapter 3 shall apply and the *IESO* shall notify any *market participant* who has allocated *metering data* to the *market participant* who is the subject of the *IESO's* actions.

2.4A Delivery Points

2.4A.1 The *delivery point* for a given *RWM* shall be determined by the *IESO* in accordance with:

2.4A.1.1 adjusting the *metering data* from that *RWM* in accordance with section 4.2.3 of Chapter 6; and

2.4A.1.2 summing the *metering data* from that *RWM* with *metering data* from all other applicable *RWMs* in accordance with the applicable totalization table comprised in the relevant *meter point* documentation submitted in respect of that *RWM* pursuant to section 1.3 of Appendix 6.5 of Chapter 6.

2.4A.2 For the purposes of the determination of the *settlement amounts* referred to in sections 3, 4 and 5, all references to an *RWM*, an *RWM m* or a *registered facility k/m* shall be deemed to be a reference to the *delivery point* associated with:

2.4A.2.1 the *RWM*; or

2.4A.2.2 the *RWM* or *RWMs* associated with the *registered facility*,

as the case may be.

2.5 Collection of Interchange Schedule Data

- 2.5.1 The *IESO* shall, in co-operation with other *control area operators*, *security coordinators* and *interconnected transmitters* and in accordance with applicable interchange protocols, determine the following *interchange schedule data* for each *settlement hour*:
- 2.5.1.1 the total scheduled flows of *energy*, and of any other physical quantity or *physical service* traded in the *IESO-administered markets*, across each transmission interface between the *IESO-controlled grid* and an *intertie zone*; and
 - 2.5.1.2 the allocation of each scheduled *intertie* flow among *market participants*.
- 2.5.2 The *IESO settlement process* shall use the *interchange schedule data* to determine *settlement amounts* even though the total scheduled flows on all *interties* may be either more or less than actual physical flows as measured by all *intertie metering points*. The *IESO* shall manage deviations between scheduled and actual *intertie* flows in accordance with interchange protocols with other *control areas* and the requirements of applicable *standards authorities*, with any resulting financial gains or losses ultimately accruing or charged to *market participants* through the *hourly uplift*.
- 2.5.3 The *IESO* shall *publish* the total scheduled and actual flows of *energy* between the *IESO-controlled grid* and each *intertie zone*.

2.6 Collection of Physical Bilateral Contract Data

- 2.6.1 Any selling *market participant* may, under the provisions of Chapter 8, submit to the *IESO physical bilateral contract data* that define *physical bilateral contract quantities* of *energy* that it is selling to a specified buying *market participant* in specified hours and at specified primary RWMs or *intertie metering points*.
- 2.6.2 *Physical bilateral contract quantities* shall not be included in the quantities of *energy* used to determine *settlement amounts* related to *energy*, although they may be used to determine other *settlement amounts* as provided in this Chapter.
- 2.6.3 Physical bilateral contract quantities must specify total quantities for each settlement hour, not quantities for metering intervals within a settlement hour. The *IESO* shall divide hourly physical bilateral contract quantities into equal interval quantities when necessary for determining settlement amounts as provided for in section 3.1.6.

- 2.6.4 The *IESO* shall submit directly to the *settlement process* the *physical bilateral contract quantities* submitted by each *market participant* for each *settlement hour* as provided in section 3.1.6.

2.7 Collection of Transmission Right (TR) Data

- 2.7.1 The *IESO* shall implement, in accordance with Chapter 8, *TR auctions* that will result in an allocation among *market participants of transmission rights* associated with the transactions referred to in section 4.1.1.1 of Chapter 8 and conveying rights to *settlement amounts* based on differences in *energy prices* between the specified injection *TR zone* and the specified withdrawal *TR zone* with which each *TR* is associated.
- 2.7.2 The *IESO* shall submit to the *settlement process* by the sixth *business day* after each *dispatch day* the following data related to *TRs*:
- 2.7.2.1 the quantities, in MW, of *TRs* held by each *TR holder* with respect to each applicable pair of specified injection and withdrawal *TR zones* for each *settlement hour* of such *dispatch day*; and
- 2.7.2.2 the total proceeds from the sale of *TRs* in respect of all rounds of a *TR auction* that is concluded on such *dispatch day*.

2.8 Collection of Capacity Reserve Market Data

- 2.8.1 If the *capacity reserve market* is active, the *IESO* shall operate such *capacity reserve market* to determine the *capacity reserve quantity* (in MW) provided by each *registered market participant* and the *capacity reserve price* for each hour of the applicable *obligation period*.
- 2.8.2 [Intentionally left blank]
- 2.8.3 The price and quantity data from the *capacity reserve market* with respect to each *dispatch day* shall be provided by the *IESO* directly to the *settlement process*.

2.9 Collection of Ancillary Service Data

- 2.9.1 The *IESO* shall submit to the *settlement process* the data from *contracted ancillary service contracts* and from the daily *dispatch* process necessary to determine *contracted ancillary service payments*.

2.10 Collection of Market Price and Other Settlement Data

- 2.10.1 The *IESO* shall submit to the *settlement process* all *market prices* determined by the *IESO* according to the provisions of Chapter 7, and all *metering data* and

other *operating results* available to the *IESO* as may be needed by the *settlement process* for determining *settlement amounts* pursuant to this Chapter.

2.11 Settlement Record Retention, Confidentiality, and Reliability

- 2.11.1 Subject to section 2.11.3, the *IESO* shall retain all *settlement* records for a period adequate to support the *settlement* audit referred to in section 6.17 and/or a *settlement statement re-calculation*, but in no case for less than seven years.
- 2.11.2 The *IESO* shall periodically review the period for which *settlement* records are retained and shall, if required and subject to section 2.11.3, take such steps as may be required to effect a change in such period.
- 2.11.3 The period for which *settlement* records are retained shall comply with the requirements of any regulatory authority having jurisdiction over the *IESO* or *market participants*.
- 2.11.4 *Settlement* and supporting data for each *trading day* of a *billing period* shall be made available by direct electronic means to the relevant *market participant* as soon as the data become available to the *IESO*. The data shall remain available via electronic access until the earlier of 60 days from the end of the *billing period* and the date on which invoicing and payment activities for that *billing period* have been completed.
- 2.11.5 The *IESO* shall safeguard any *settlement* information that is *confidential information* in accordance with section 5 of Chapter 3.
- 2.11.6 The *IESO* shall assure that back-up computer and communication systems are available for the *settlement process* and shall, in accordance with section 6.1, use such back-up systems in the event that equipment failure or an emergency evacuation makes the primary systems referred to in section 6.1.1 unavailable.

3. Determination of Hourly Settlement Amounts

3.1 Hourly Settlement Variables and Data

- 3.1.1 The *IESO* shall determine hourly *settlement amounts* for the *hourly markets* using the hourly price and quantity variables and data described in this section 3.1.

3.1.2 The *IESO* shall determine *energy forward market* prices and quantities as provided in Chapter 8, and shall provide the following data from the *energy forward market* directly to the *settlement process*:

FMQS_{k,h} = *energy forward market* quantity cleared (positive if *offer* and negative if *bid*), in MWh, by *market participant* 'k' in *settlement hour* 'h'

FMP_h = *energy forward market* price, in \$/MWh, in *settlement hour* 'h'

Day-Ahead Commitment Process Variables, Data and Information

3.1.2A The *IESO* shall determine the following day-ahead quantities from the *schedule of record*, and provide them directly to the *settlement process*:

DA_DQSI_{k,h}^{i,t} = *schedule of record* quantity scheduled for injection by *market participant* 'k' for an import transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

DA_DQSI_{k,h}^{m,t} = *schedule of record* quantity scheduled for injection by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'

DA_DQSW_{k,h}^{i,t} = *schedule of record* quantity scheduled for withdrawal by *market participant* 'k' for an export transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

DA_ELMP_h^{m,t} = day-ahead constrained *schedule* *intertie* price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'

DA_ILMP_h^{m,t} = day-ahead constrained *schedule* *intertie* price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

3.1.2B The *IESO* shall provide directly to the *settlement process*:

3.1.2B.1 information to identify *market participants* which are deemed to have accepted in accordance with section 5.8.4 of Chapter 7 a day-ahead production cost guarantee for their *generation facility*;

3.1.2B.2 information to identify any event in which the *IESO* de-commits a *generation facility* between the release and publication of the *schedule of record* and the end of its committed schedule *in the schedule of record* where the *market participant* has been deemed to have accepted in accordance with section 5.8.4 of Chapter 7 a day-ahead production cost guarantee for that *facility*;

- 3.1.2B.3 exemptions from the day-ahead import failure charge described in section 3.8B, for any applicable import transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B;
- 3.1.2B.4 exemptions from the day-ahead export failure charge described in section 3.8D, for any applicable export transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B;
- 3.1.2B.5 exemptions from the day-ahead linked wheel failure charge described in section 3.8E, for any applicable linked wheel transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B; and
- 3.1.2B.6 exemptions from the day-ahead *generator* withdrawal charge described in section 3.8F, for any applicable *registered facility* scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.3.
- 3.1.2B.7 the following information:

DA_BE_{k,h}^{m,t} = *energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *delivery point* ‘m’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

DA_BE_{k,h}^{i,t} = *energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

DA_BL_{k,h}^{i,t} = *energy bids* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

DA_SNLC_{k,h}^m = as-offered *speed-no-load cost* associated with *three-part offers* for a given *settlement hour* ‘h’ for *market participant* ‘k’ at

		<i>delivery point 'm'</i>
DA_SUC _{k,h} ^m	=	as-offered <i>start-up cost</i> associated with <i>three-part offers</i> for a given <i>settlement hour 'h'</i> for <i>market participant 'k'</i> at <i>delivery point 'm'</i>
MLP _{k,h} ^{m,t}	=	minimum output of <i>energy</i> the <i>market participant 'k'</i> at <i>delivery point 'm'</i> can maintain without ignition support in <i>metering interval 't'</i> of <i>settlement hour 'h'</i>
OPCAP _{k,h,m,t}	=	de-rated generation capacity submitted by <i>market participant 'k'</i> at <i>delivery point 'm'</i> in <i>metering interval 't'</i> of <i>settlement hour 'h'</i>

3.1.2C The IESO shall determine from the *pre-dispatch schedule* and the *pre-dispatch projected market schedule*, and provide directly to the *settlement process* the following *pre-dispatch prices* and quantities:

PD_DQSI _{k,h} ^{i,t}	=	<i>pre-dispatch</i> constrained quantity scheduled for injection by <i>market participant 'k'</i> at <i>intertie metering point 'i'</i> during <i>metering interval 't'</i> of <i>settlement hour 'h'</i>
PD_DQSW _{k,h} ^{i,t}	=	<i>pre-dispatch</i> constrained quantity scheduled for withdrawal by <i>market participant 'k'</i> at <i>intertie metering point 'i'</i> during <i>metering interval 't'</i> of <i>settlement hour 'h'</i>
PD_EMP _h ^{m,t}	=	<i>pre-dispatch</i> projected <i>energy market price</i> applicable to all <i>delivery points 'm'</i> in the Ontario zone in <i>metering interval 't'</i> of <i>settlement hour 'h'</i>
		In instances where this variable is provided to the <i>settlement process</i> on an hourly basis as determined in section 3.9, it shall be deemed to apply uniformly to all <i>metering intervals 't'</i> in <i>settlement hour 'h'</i>
PD_ELMP _h ^{m,t}	=	<i>pre-dispatch</i> constrained schedule <i>intertie</i> price at the <i>delivery point 'm'</i> of the sink for the export transaction during <i>metering interval 't'</i> of <i>settlement hour 'h'</i>
PD_ILMP _h ^{m,t}	=	<i>pre-dispatch</i> constrained schedule <i>intertie</i> price at the <i>delivery point 'm'</i> of the source for the import transaction during <i>metering interval 't'</i> of <i>settlement hour 'h'</i>

3.1.2D The IESO shall provide directly to the *settlement process*:

3.1.2D.1 exceptions from the real-time import failure charge set out in section 3.8C.2 for any applicable import transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in

accordance with chapter 7, section 7.5.8B;3.1.2D.2 exceptions from the real-time export failure charge set out in section 3.8C.4 for any applicable export transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2D.3 the adjustment of amounts provided for in section 6.6.10A.2 of Chapter 3;

3.1.2D.4 any applicable price bias adjustment factors, as described in section 3.8C.7, utilised in the calculation of the:

- a. real-time import failure charge; or
- b. real-time export failure charge;

that are in effect as of the *settlement hour* in which such *settlement amounts* are calculated by the *IESO*; and

3.1.2D.5 the following information:

$PD_BE_{k,h}^{i,t}$ = *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$PD_BL_{k,h}^{i,t}$ = *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

3.1.3 The *IESO* shall determine *energy market* prices and quantities as provided in Chapter 7 and shall provide the following variables and data from the *energy market*, determined in accordance with section 3.1.4A, directly to the *settlement process*:

$MQSI_{k,h}^{m,t}$	=	market quantity scheduled for injection in the <i>market schedule</i> by <i>market participant</i> ‘k’ at location m or <i>intertie metering point</i> ‘m’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’
$MQSW_{k,h}^{m,t}$	=	market quantity scheduled for withdrawal in the <i>market schedule</i> by <i>market participant</i> ‘k’ at location m or <i>intertie metering point</i> ‘m’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’
$DQSI_{k,h}^{m,t}$	=	<i>dispatch</i> quantity scheduled for injection in the <i>real-time schedule</i> by <i>market participant</i> ‘k’ at location m or <i>intertie metering point</i> ‘m’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’ determined on the basis of the <i>dispatch instructions</i> issued to <i>market participant</i> ‘k’ for that <i>metering interval</i>
$DQSW_{k,h}^{m,t}$	=	<i>dispatch</i> quantity scheduled for withdrawal in the <i>real-time schedule</i> by <i>market participant</i> ‘k’ at location m or <i>intertie metering point</i> ‘m’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’ determined on the basis of the <i>dispatch instructions</i> issued to <i>market participant</i> ‘k’ for that <i>metering interval</i>
$TMQSI_h^{m,t}$	=	total market quantity scheduled for injection in the <i>market schedule</i> by all <i>market participants</i> at location m or <i>intertie metering point</i> ‘m’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’
	=	$\sum_k MQSI_{k,h}^{m,t}$, with k = all <i>market participants</i>
$EMP_h^{m,t}$	=	<i>energy market price</i> at delivery point ‘m’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’
$ICP_h^{i,t}$	=	<i>intertie congestion price</i> for energy at <i>intertie metering point</i> ‘i’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’
		where $i \in M$ such that M is the set of all <i>delivery points</i> ‘m’ and <i>intertie metering points</i> ‘m’.
$EMP_h^{i,t}$	=	<i>energy market price</i> at <i>intertie metering point</i> ‘i’ in <i>metering interval</i> ‘t’ of <i>settlement hour</i> ‘h’
	=	$ICP_h^{i,t} + EMP_h^{m,t}$ subject to the constraints outlined in sections 8.2.2.4 and 8.2.2.5 of Chapter 7.
		where m is any <i>delivery point</i> while uniform pricing exists.
		where $i \in M$ such that M is the set of all <i>delivery points</i> ‘m’ and <i>intertie metering points</i> ‘m’.
$HOEP_h$	=	<i>hourly Ontario energy price</i> in <i>settlement hour</i> ‘h’
	=	$\sum_{m,t} EMP_h^{m,t} / 12$,
		with t = all <i>metering intervals</i> in <i>settlement hour</i> ‘h’
		m = all <i>primary RWMs</i>

3.1.4 The IESO shall determine *operating reserve market* prices and quantities in a process integrated with the *energy market*, as provided in Chapter 7. For each of the two types “r” of *class r reserves*, the IESO shall provide directly to the *settlement process* the following variables and data, determined in accordance with section 3.1.4A:

- $PROR_{r,h}^{m,t}$ = market price (in \$/MW) of class r reserve in metering interval ‘t’ of settlement hour ‘h’ at delivery point ‘m’ or *intertie metering point* ‘m’
- $PROR_{r,h}^{i,t}$ = market price (in \$/MW) of class r reserve in metering interval ‘t’ of settlement hour ‘h’ at *intertie metering point* ‘i’
 where $i \in M$ such that M is the set of all *delivery points* ‘m’ and *intertie metering points* ‘m’.
- = $ICP_{r,h}^{i,t} + PROR_{r,h}^{m,t}$ subject to the constraints outlined in sections 8.2.2.6 and 8.2.2.7 of Chapter 7.
 where m is any *delivery point* while uniform pricing exists.
- $ICP_{r,h}^{i,t}$ = *intertie congestion price* for class r reserve at *intertie metering point* ‘i’ in metering interval ‘t’ of settlement hour ‘h’
 where $i \in M$ such that M is the set of all *delivery points* ‘m’ and *intertie metering points* ‘m’.
- $SQROR_{r,k,h}^{m,t}$ = scheduled quantity (in MW) of class r reserve for market participant ‘k’ in metering interval ‘t’ of settlement hour ‘h’ at location m or *intertie metering point* ‘m’ as described in the *market schedule*
- $DQSR_{r,k,h}^{m,t}$ = *dispatch* quantity (in MW) of class r reserve for market participant ‘k’ at location m in metering interval ‘t’ or *intertie metering point* ‘m’ of settlement hour ‘h’ as determined on the basis of the *dispatch instructions* issued to market participant ‘k’ for that *metering interval*

3.1.4A For the purposes of sections 3.1.3, 3.1.4 and 3.5.2, “location m” in respect of *market participant* ‘k’ shall mean the location of:

- 3.1.4A.1 the relevant *meter* used by *market participant* ‘k’ to meet the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 in respect of *registered facility* k/m, where such requirements apply in respect of *registered facility* k/m; or
- 3.1.4A.2 the *RWM* for *registered facility* k/m, where the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 do not apply in respect of *registered facility* k/m.

3.1.5 If the daily *capacity reserve market* is active, the IESO shall determine *capacity reserve prices* and *capacity reserve quantities* in the *capacity reserve market* and shall provide the following variables and data directly to the *settlement process*:

$QCAPR_{k,h}^m$ = capacity reserve quantity (in MW) sold by market participant 'k' at RWM m for settlement hour 'h'

$PCAPR_h^m$ = capacity reserve price (in \$/MW/hr) at RWM m in settlement hour 'h'

- 3.1.6 Physical bilateral contract quantities shall be determined for each settlement hour by the IESO using physical bilateral contract data submitted by selling market participants and, where so required by the nature of the physical bilateral contract data, operating results. The IESO shall divide each hourly physical bilateral contract quantity into equal physical bilateral contract quantities if determination of settlement amounts requires quantities for each metering interval of each settlement hour. The IESO shall provide the following variables and data directly to the settlement process:

$BCQ_{s,b,h}^m$ = physical bilateral contract quantity of energy (in MWh) sold by selling market participant s to buying market participant b at primary or intertie metering point 'm' in settlement hour 'h'

$BCQ_{s,b,h}^{m,t}$ = physical bilateral contract quantity of energy (in MWh) sold by selling market participant s to buying market participant b at primary or intertie metering point 'm' for each metering interval 't' in settlement hour 'h'

=

$(1/12) \times BCQ_{s,b,h}^m$, for all 12 metering intervals 't' in settlement hour 'h'

- 3.1.7 The IESO shall offer a service whereby the selling market participant in a physical bilateral contract or the selling market participant under a financial bilateral contract may assume responsibility for components of the buying or buying market participant's settlement obligations other than those for energy.

- 3.1.8 The IESO shall provide the following TR data directly to the settlement process:

$QTR_{k,h}^{m,n}$ = quantity of TRs (in MW) assigned to market participant 'k' for transmission from primary or intertie metering point 'm' to primary or intertie metering point 'n' for settlement hour 'h'

- 3.1.9 The IESO shall determine the following allocated physical quantities for each market participant for each primary RWM and each intertie metering point using metering data, operating results, physical allocation data submitted by metered market participants and interchange schedule data. If physical quantities are provided only for each settlement hour (as they may be for interchange schedules, non-dispatchable loads, self-scheduled generation facilities, transitional scheduling generators and intermittent generators), the IESO shall, if necessary for settlement purposes, determine the interval amounts defined below by dividing the hourly amounts into twelve equal interval amounts:

- $AQEI_{k,h}^{m,t}$ = allocated quantity (in MWh) of *energy injected* by *market participant* ‘k’ at *primary or intertie metering point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’
- $AQEW_{k,h}^{m,t}$ = allocated quantity (in MWh) of *energy withdrawn* by *market participant* ‘k’ at *primary or intertie metering point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’
- $AQOR_{r,k,h}^{m,t}$ = allocated quantity (in MW) of *class r reserve* for *market participant* ‘k’ at *primary or intertie metering point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’
- $AQCR_{k,h}^{m,t}$ = allocated *capacity reserve quantity* (in MW) for *market participant* ‘k’ at *primary or intertie metering point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’

3.1.10 [Intentionally left blank – section deleted]

3.1.11 The *IESO* shall, in accordance with the applicable *market manual*, determine the required *settlement data* for *registered market participants* that submitted *dispatch data* for *facilities* operating as *pseudo-units*, using the information submitted under Chapter 7, sections 2.2.6G and 2.2.6J, and shall provide this *settlement data* directly to the *settlement process*.

3.2 Hourly Settlement Amounts in the Energy Forward Market

3.2.1 The hourly net *energy forward market settlement* credit (debit if negative) for *market participant* ‘k’ (“ $NFMSC_{k,h}$ ”) shall be determined by the following equation:

$$NFMSC_{k,h} = FMQS_{k,h} \times (FMP_h - HOEP_h)$$

3.3 Hourly Settlement Amounts in the Real-Time Energy Market

3.3.1 The hourly net *energy market settlement* credit for *market participant* ‘k’ in *settlement hour* ‘h’ (“ $NEMSC_{k,h}$ ”) shall be determined by the appropriate equations set forth in section 3.3.2 and where applicable, in accordance with section 2.1.2 of Chapter 8.

3.3.2 For *market participant* ‘k’, $NEMSC_{k,h}$ shall be the sum, over all *metering intervals* ‘t’ in *settlement hour* ‘h’ and all *RWMs* and *intertie metering points*, of the *settlement amounts* determined for each *metering interval* and *RWMs* or *intertie metering point*, as follows:

3.3.2.1 in respect of a dispatchable facility or intertie metering point:

$$\text{NEMSC}_{k,h} = \sum_{t,m} (\text{EMP}_h^{m,t} \times ((\text{AQEI}_{k,h}^{m,t} - \text{AQEW}_{k,h}^{m,t}) + \sum_{s,b} (\text{BCQ}_{s,k,h}^{m,t} - \text{BCQ}_{k,b,h}^{m,t})))$$

where:

t = all *metering intervals* in *settlement hour* ‘h’

m = all *RWMs* relating to a *dispatchable facility* and all *intertie metering points*

s = all *selling market participants*

b = all *buying market participants*

and

3.3.2.2 in respect of a non-dispatchable load facility, a self-scheduling generation facility, a transitional scheduling generator or intermittent generator.

$$\text{NEMSC}_{k,h} = \text{HOEP}_h \times \sum_{t,m} (\text{AQEI}_{k,h}^{m,t} - \text{AQEW}_{k,h}^{m,t} + \sum_s \text{BCQ}_{s,k,h}^{m,t}) - \sum_{n,b,t} (\text{EMP}_h^{n,t} \times \text{BCQ}_{k,b,h}^{n,t})$$

where:

m = all *RWMs* relating to a *non-dispatchable load facility*, a *self-scheduling generation facility*, a *transitional scheduling generator* or *intermittent generator*

n = all *RWMs* and *intertie metering points*

s = all *selling market participants*

b = all *buying market participants*

t = all *metering intervals* in *settlement hour* ‘h’

3.3.3 [Intentionally left blank]

3.4 Hourly Settlement Amounts for Operating Reserve

3.4.1 The hourly *operating reserve settlement credit* for *market participant* ‘k’ in *settlement hour* ‘h’ (“ORSC_{k,h}”) shall be determined by the following equation:

$$\text{ORSC}_{k,h} = \sum_{m,t,r} \text{PROR}_{r,h}^{m,t} \times \text{AQOR}_{r,k,h}^{m,t},$$

where:

m = all *primary RWM’s* and *intertie metering points*

t = all *metering intervals* in *settlement hour* ‘h’

r = 1 for *ten-minute reserve*,

= 2 for *thirty-minute reserve*

3.5 Hourly Settlement Amounts for Congestion Management

3.5.1 The *dispatch instructions* provided by the *IESO* to market participant ‘k’ will sometimes instruct k to deviate from its *market schedule* in ways that, based on *market participant ‘k’s offers and bids*, imply a change to *market participant ‘k’s net operating profits* relative to the operating profits implied by *market participant ‘k’s market schedule*. When this occurs and *market participant ‘k’* responds to the *IESO’s dispatch instructions*, *market participant ‘k’* shall, subject to Appendix 7.6 of Chapter 7, receive as compensation a *settlement credit* equal to the change in implied operating profits resulting from such response, calculated in accordance with section 3.5.2. If *market participant ‘k’* does not fully or accurately respond to its *dispatch instructions* from the *IESO*, the compensation paid to *market participant ‘k’* shall be altered as set forth in this section 3.5, or as otherwise specified by the *IESO*.

3.5.1A A *registered market participant* for a *registered facility* that is a *dispatchable load* is not entitled to a congestion management settlement credit determined in accordance with section 3.5.2 where that *registered facility’s DQSW* is less than the corresponding *MQSW* at that location for the same *metering interval* as the result of that *registered facility’s own equipment or operational limitations*, if:

3.5.1A.1 that *registered facility* does not fully or accurately respond to its *dispatch instructions*; or

3.5.1A.2 the ramping capability of that *registered facility*, as represented by the ramp rate set out in the *offers or bids*, is below the threshold for the *IESO* to modify *dispatch instructions* and thereby prevents changes to the *dispatch*;

and then the *IESO* may withhold or recover such congestion management settlement credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

3.5.1B A *market participant* shall not be *invoiced* congestion management settlement credits for an export transaction if that transaction attracted the congestion management settlement credits under the following conditions:

3.5.1B.1 the net *interchange schedule* limit is binding in the *market schedule* on an economic export transaction in pre-dispatch, and subsequently, in accordance with section 6.1.3 of Chapter 7, the *IESO* increases the quantity of that transaction in the *real-time schedule*; or

3.5.1B.2 the net *interchange schedule* limit is binding in the *market schedule* on an uneconomic export transaction in pre-dispatch, and subsequently, in

accordance with section 6.1.3 of Chapter 7, the *IESO* decreases the quantity of that transaction in the *real-time schedule*.

The amount of congestion management settlement credits referred to in this section is limited to the portion of the transaction that is modified by the *IESO*.

3.5.1C [Intentionally left blank – section deleted]

3.5.1D A *registered market participant* for a *registered facility* that is a *dispatchable load* shall not be entitled to a congestion management *settlement credit* determined in accordance with section 3.5.2 for *settlement hour* ‘h’ where:

3.5.1D.1 the *price-quantity pairs* contained in the *energy bid* associated with that *registered facility* for *settlement hour* ‘h’ are not identical to the *price-quantity pairs* in the *energy bid* associated with the same *registered facility* for the applicable preceding *settlement hour* or following *settlement hour*;

3.5.1D.2 the change in *energy bid* as referred to in section 3.5.1D.1 results in a change in the quantity scheduled in the *market schedule* for that *registered facility* as described in the applicable *market manual*;

3.5.1D.3 the change in *energy bid* as referred to in section 3.5.1D.1 results in the ramping of the that *registered facility* as described in the applicable *market manual*; and

3.5.1D.4 that *registered facility*’s DQSW is less than the corresponding MQSW at that location for any *metering interval* falling within *settlement hour* ‘h’.

3.5.2 Subject to sections 3.5.1A, 3.5.1D, 3.5.6, 3.5.6A, 3.5.6B, 3.5.6C, 3.5.6D and 3.5.9 and subject to Appendix 7.6 of Chapter 7, the hourly congestion *management settlement credit* for *market participant* ‘k’ for *settlement hour* ‘h’ (“CMSC_{k,h}”) shall be determined by the following equation:

Let ‘BE’ be a matrix of n *price-quantity pairs* offered by *market participant* ‘k’ to supply *energy* during *settlement hour* ‘h’

Let ‘BR_r’ be a matrix of n *price-quantity pairs* offered by *market participant* ‘k’ to supply class r *operating reserve* during *settlement hour* ‘h’

Let ‘BL’ be a matrix of n *price-quantity pairs* bid by *market participant* ‘k’ to withdraw *energy* by a *dispatchable load* during *settlement hour* ‘h’

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an n x 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P, Q, B) = P \cdot Q - \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Where:

s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

B is matrix BE, BR_r, or BL (see above)

Using the terms below, let CMSC be expressed as follows:

$$CMSC_{k,h} = OPE_{k,h} + OPR_{k,h} + OPL_{k,h}$$

Where:

$OPE_{k,h}$ represents that component of the *congestion management settlement credit* for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on *energy production* subject to section 3.5.1 and is calculated as follows:

$$OPE_{k,h} = \sum_{m,t} \left[OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \left[\text{MAX} \left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE) \right) \right] \right]$$

Where:

$$\text{MAX}[X,Y] = \text{Maximum of X or Y}$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}$ is not equal to the mathematical sign of $AQEI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}$, the component of $OPE_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

$OPR_{k,h}$ represents that component of the *congestion management settlement credit* for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the provision of *operating reserve* subject to section 3.5.1 and is calculated as follows:

$$OPR_{k,h} = \sum_{m,t,r} \left[OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r) - \left[\text{MAX} \left(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, BR_r), OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r) \right) \right] \right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSR_{r,k,h}^{m,t} - SQROR_{r,k,h}^{m,t}$ is not equal to the mathematical sign of $AQOR_{r,k,h}^{m,t} - SQROR_{r,k,h}^{m,t}$, the component of $OPR_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

$OPL_{k,h}$ represents that component of the *congestion management settlement credit* for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the withdrawal of *energy* by a *dispatchable load* subject to section 3.5.1. $OPL_{k,h}$ utilizes the negative of each output from each component Operating Profit (OP) function so as to correct for negative revenue streams (owing to withdrawals of *energy*).

$OPL_{k,h}$ is calculated as follows:

$$OPL_{k,h} = \sum_{m,t} \left[-1 \times OP(EMP_h^{m,t}, MQSW_{k,h}^{m,t}, BL) - \text{MAX}(-1 \times OP(EMP_h^{m,t}, DQSW_{k,h}^{m,t}, BL), -1 \times OP(EMP_h^{m,t}, AQEW_{k,h}^{m,t}, BL)) \right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSW_{k,h}^{m,t} - MQSW_{k,h}^{m,t}$ is not equal to the mathematical sign of $AQEW_{k,h}^{m,t} - MQSW_{k,h}^{m,t}$, the component of $OPL_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

3.5.3 [Intentionally left blank]

3.5.4 Subject to section 5.3.4 of Chapter 5, during instances where $CMSC_{k,h}$ is calculated at an *intertie metering point* at which a *market participant* is conducting an import or export transaction for a *physical service* that is subject to a *constrained off event* that is reflected in *dispatch instructions* issued by the *IESO* as a result of a request initiated by an entity other than the *IESO*, the *IESO* shall not calculate any portion of $CMSC_{k,h}$ pertaining to the affected transaction for those *metering intervals* within *settlement hour* 'h' in which such conditions exist, and for greater certainty, during any *metering interval* in which:

3.5.4.1 $MQSIk, hm, t$ is not equal to $DQSIk, hm, t$ as a result of such a constrained off event;

3.5.4.2 $MQSWk, hm, t$ is not equal to $DQSWk, hm, t$ as a result of such a constrained off event; or

3.5.4.3 SQROR_{r,k,hm,t} is not equal to DQSR_{r,k,hm,t} as a result of such a constrained off event;

and irrespective of whether or not a *constrained on event* or a *constrained off event* was affecting the transaction in any preceding *metering interval*.

3.5.5 A DQSI, DQSW or DQSR, quantity as the case may be, that departs from its corresponding *market schedule* quantity due to the circumstances described in section 3.5.4 shall be denoted as such within the supporting data provided to the affected *market participant* as part of the content of *settlement statements* described in sections 6.5.3.1 and 6.5.3.2.

3.5.6 The *IESO* shall adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *offer price* that:

3.5.6.1 is associated with a *generation facility* or is associated with an injecting *boundary entity*; and

3.5.6.2 is less than a specified lower limit where such limit is the lesser of 0.00 \$/MWh and the *energy market price* for the applicable *dispatch interval*;

to that lower limit.

3.5.6A The *IESO* may adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *bid price* that:

3.5.6A.1 is associated with a *dispatchable load facility* or is associated with a withdrawing *boundary entity*;

3.5.6A.2 is less than the prices determined by the *IESO* in accordance with the applicable *market manual*; and

3.5.6A.3 is less than the *energy market price* in the applicable Ontario or *intertie zone* for the applicable *dispatch interval*;

to the lesser of the prices determined by the *IESO* in accordance with the applicable *market manual* and the *energy market price* in the applicable Ontario or *intertie zone*.

3.5.6B A *registered market participant* for a *registered facility* that is a *dispatchable generation facility*, who:

- increases the *offer price* associated with the *generation facility minimum loading point* for its *minimum generation block run-time* so that under Chapter

7 section 5.7.1.4 the *registered market participant* for the *generation facility* is no longer eligible for the applicable guarantee; and

- has received a manual constraint from the *IESO* for the *generation facility* under Chapter 7 section 6.3A.2 or 6.3A.4;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit, determined in accordance with section 3.5.2, associated with that *offer* price increase for *settlement hour* ‘h’, where *settlement hour* ‘h’ falls within the *generation facility minimum generation block run-time*. The *IESO* may recover such congestion management *settlement* credit in accordance with section 3.5.6E.

3.5.6C A *registered market participant* for a *registered facility* that is a *dispatchable generation facility*, who, for *settlement hour* ‘h’:

- is unable to comply with a *dispatch instruction* under section 7.5.3 of Chapter 7, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; and/or
- requests that the *IESO* apply a constraint to the *dispatchable generation facility* to prevent endangering the safety of any person, equipment damage, or violation or any *applicable law*, excluding constraints applied under Chapter 7 sections 6.3A.2 or 6.3A.4;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit, determined in accordance with section 3.5.2, resulting from the above actions for *settlement hour* ‘h’. The *IESO* may recover such congestion management *settlement* credit in accordance with section 3.5.6E.

3.5.6D A *registered market participant* for a *registered facility* that is a *dispatchable generation facility* and is fuelled by a related *generation facility*, who, for *settlement hour* ‘h’:

- has received a constraint from the *IESO* for the *dispatchable generation facility* as per the applicable *market manual*; and
- submits or has submitted an *offer* price for that *dispatchable generation facility* for *settlement hour* ‘h’ greater than a specified limit defined in the applicable *market manual*;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit, determined in accordance with section 3.5.2, associated with that *offer* price for *settlement hour* ‘h’. The *IESO* may recover such congestion management *settlement* credit in accordance with section 3.5.6E.

3.5.6E The *IESO* may recover congestion management *settlement* credits in accordance with sections 3.5.6B, 3.5.6C and 3.5.6D. In this situation, the *IESO* shall:

- notify the *market participant* of its intent to recover that congestion management *settlement* credit; and
- notify the *market participant* of the time, which shall not be less than five *business days* from the date of receipt of the notice, within which the *market participant* may make written representations in response to the *IESO's* intent.

On receiving a response from the *market participant* within the specified time period, or upon expiry of the specified time period within which no response is received from the *market participant*, the *IESO* shall either:

- determine the amount of the congestion management *settlement* credit to recover and notify the *market participant* accordingly; or
- gather further information as the *IESO* determines appropriate to determine the amount of the congestion management *settlement* credit to recover and notify the *market participant* accordingly of the determination.

The *IESO* shall redistribute any payments that are recovered in accordance with section 4.8.2.

3.5.7 [Intentionally left blank – section deleted]

3.5.7A A *registered market participant* for a *constrained on generation facility* is not entitled to a congestion management *settlement* credits determined in accordance with section 3.5.2 for that *facility* up to *minimum loading point* if the congestion management *settlement* credit is earned as a result of constraints applied under Chapter 7, section 5.8.5 for hours in the day after the *dispatch day*. In this case, the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

Linked Wheeling Through Transactions Not Eligible for CMSC Payment

3.5.8 Notwithstanding any other provision in the *market rules*, a *market participant* shall not be eligible for any congestion management *settlement* credit payments for a wheeling through transaction where the *market participant* effects the transaction by linking an *energy offer* and *energy bid* under section 3.5.8.2 of Chapter 7.

3.5.9 The *IESO* may limit, withhold or recover any congestion management *settlement* credits that result from the acceptance by the *IESO* of the replacement *energy* referred to in section 3.3.4C of Chapter 7 and shall redistribute any recovered payments in accordance with section 4.8.2. Any applicable congestion management *settlement* credits for replacement *energy* accepted by the *IESO* shall be limited as set out in the applicable *market manual* to an *IESO* estimate of what would have been received by the original *facility* had it not experienced the *forced outage*.

3.6 Hourly Settlement Amounts for Transmission Rights and Charges

3.6.1 The *TR settlement credit for market participant ‘k’ in settlement hour ‘h’* (“ $TRSC_{k,h}$ ”) shall, other than where section 4.4.2.2 of Chapter 8 applies, be determined by the following equation:

$$TRSC_{k,h} = \max[0, \sum_{j,i} (1/12) \times QTR_{k,h}^{ij} \times \sum_t (EMP_h^{j,t} - EMP_h^{i,t})]$$

where:

j = all *primary RWM’s and intertie metering points*

i = all *primary RWM’s and intertie metering points*

3.6.2 The contribution to the *transmission charge reduction fund* in settlement hour ‘h’ (“ $TCRF_h$ ”) shall be the net congestion rentals collected by the *IESO* (the negative of the net *energy market settlement credit* paid to *market participants*) less the net payments from the *IESO* to *market participants* under *TRs*, or:

$$TCRF_h = \sum_{t,m} (EMP_h^{m,t} - EMP_h^{REF,t}) \times \sum_k (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - \sum_k TRSC_{k,h}$$

where:

t = all *metering intervals* in settlement hour ‘h’

m = all *primary RWMs and intertie metering points*

k = all *market participants*

$EMP_h^{REF,t}$ = *energy market price at the reference bus in metering interval ‘t’ of settlement hour ‘h’*. Until such time that locational pricing is implemented in the *IESO-administered markets*, the uniform *energy market price* is the *energy market price at the reference bus*.

3.6.3 Disbursements from the *TR clearing account* authorised by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be used by the *IESO* in accordance with section 4.7.

3.6.4 Any net revenues received from the sale of a *TR* in a *TR auction*, along with the hourly balance accrued in the *transmission charge reduction fund*, shall be credited to the *TR clearing account* and shall be used in accordance with the provisions of section 3.6.3 and of Chapter 8.

3.7 Hourly Settlement Amounts in the Capacity Reserve Market

- 3.7.1 This section 3.7 is applicable only if the *capacity reserve market* has been activated by the *IESO Board* and has not been deactivated.
- 3.7.2 The hourly *capacity reserve settlement credit to market participant* ‘k’ for providing *capacity reserve* in *settlement hour* ‘h’ is $CAPRSC_{k,h}$ defined by the following equation:

$$CAPRSC_{k,h} = \sum_m QCAPR_{k,h}^m \times PCAPR_h^m,$$

where:

m = all *primary RWM’s* and *inertie metering points*

3.8 Hourly Settlement Amounts for Operating Deviations

- 3.8.1 The *IESO* may adjust by means of a debit the *settlement statement* of any *market participant* who is compensated in the market for providing *operating reserve* from a specific *registered facility* that operates in a way that does not provide the service for which it has been paid. Such debits in any *settlement hour* may represent either the decreased value of services provided in that same *settlement hour*, or the value of *operating reserve* services deemed not to have been provided in earlier *dispatch hours* as a result of failure to perform when called in the later *dispatch hour* associated with that *settlement hour*. The hourly *settlement debits* for failure to provide *energy* from *operating reserve* and *capacity reserve* when it is called are set forth in this section 3.8.
- 3.8.2 An *operating reserve shortfall settlement debit* may be assessed on any *market participant* ‘k’ responsible for a *registered facility* at *RWM* m, which will be *registered facility* “k/m” for the purpose of this section 3.8.2 and of section 3.8.4, that is scheduled by the *IESO* to provide *class r reserve* of class 1 or 2 (i.e., *ten-minute reserve* or *thirty-minute reserve*) and then fails to provide *energy* from that class of *operating reserve* when instructed to do so by the *IESO* according to these *market rules*. The amount of *market participant* ‘k’s *operating reserve shortfall settlement debit* for *class r reserve* for *settlement hour* ‘h’ (“ORSSD_{k,r,h}”) is determined as follows:
- 3.8.2.1 the *energy shortfall fraction* for *class r reserve* for *registered facility* k/m in *metering interval* ‘t’ of *settlement hour* ‘h’ (“ORES_{k,r,h}^{m,b}”) is defined as follows:

where *operating reserve* is provided from a *generator*:

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

where *operating reserve* is provided from a *dispatchable load*:

$$\text{ORESF}_{k,r,h}^{m,t} = \text{MAX} [(AQEW_{k,h}^{m,t} - SE_{k,h}^{m,t}) / AQEW_{k,h}^{m,t}, 0]$$

in either of the above cases:

$\text{ORESF}_{k,r,h}^{m,t}$ shall be 0 if:

- a. $SE_{k,h}^{m,t}=0$;
- b. no *class r reserve* is activated for *registered facility k/m*, at *RWM m* during *metering interval 't'* of *settlement hour 'h'*; or
- c. $\text{ORESF}_{k,r,h}^{m,t}$ is less than the value established by the *IESO Board* and *published* in accordance with section 3.8.2.4.

Where:

$SE_{k,h}^{m,t}$ = total scheduled *energy*, including activated *operating reserve*, from *registered facility* k/m at *RWM* m, determined on the basis of the *dispatch instructions* for *metering interval* ‘t’ of *settlement hour* ‘h’.

3.8.2.2 define $\Sigma_{T,H} ORRSC_{k,r,H}^{m,T}$ = total *settlement credits* for *class r reserve* (including congestion management *settlement credits* related to *class r reserve*) during the lesser of:

- a. where *registered facility* k/m has not been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour*, all *metering intervals* during the current *settlement hour* and all of the *metering intervals* within the 719 *settlement hours* preceding the current *settlement hour*; or
- b. where *registered facility* k/m has been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour* all *metering intervals* between the current *metering interval*, including the current *metering interval* and the most recent *metering interval* preceding the current *metering interval*, in which the *market participant* ‘k’ received a *dispatch instruction* for the activation of *class r reserve* from *registered facility* k/m.

3.8.2.3 $ORSSD_{k,r,h}$ is defined as follows:

- a. where the most recent *dispatch instruction* issued to the *market participant* for the activation of *class r reserve* prior to the current *metering interval* was issued within the 719 *settlement hours* preceding the current *settlement hour* and resulted in $ORES_{k,r,h}^{m,t}$ that exceeded the value referred to in section 3.8.2.4, $ORSSD_{k,r,h} = \Sigma_{m,t} [ORES_{k,r,h}^{m,t} \times \Sigma_{T,H} (ORRSC_{k,r,H}^{m,T})]$; or
- b. in all other cases, $ORSSD_{k,r,h} = \Sigma_{m,t} [ORES_{k,r,h}^{m,t} \times \Sigma_{T,H} (ORRSC_{k,r,H}^{m,T})/2]$

where:

t = all *metering intervals* in *settlement hour* ‘h’ in which $ORESF_{k,r,h}^{m,t}$ exceeds the value referred to in section 3.8.2.4

T = all *metering intervals* referred to in section 3.8.2.2 (a), or 3.8.2.2 (b) as the case may be

H = all *settlement hours* referred to in section 3.8.2.2 (a), or 3.8.2.2 (b) as the case may be

m = all *RWMs* serving *market participant* ‘k’s *registered facilities*

3.8.2.4 For the purposes of section 3.8.2.1(c), the *IESO Board* shall establish, and the *IESO* shall *publish*, a value below which $ORESF_{k,r,h}^{m,t}$ shall be set at zero. Where the *IESO Board* revises such value:

- a. any such revised value shall be *published* by the *IESO*; and
- b. the revised value shall not be used for the purposes of calculating $ORESF_{k,r,h}^{m,t}$ until 31st *trading day* following the date of publication.

3.8.3 [Intentionally left blank]

3.8.4 [Intentionally left blank]

3.8.4.1 [Intentionally left blank]

3.8.4.2 [Intentionally left blank]

3.8.4.3 [Intentionally left blank]

3.8.5 [Intentionally left blank]

3.8A Hourly Settlement Amounts for Intertie Offer Guarantees

3.8A.1 The *market prices* determined by the *real-time market schedule* provided by the *IESO* used for the *settlement* of a *boundary entity* associated with an *intertie metering point* will sometimes deviate from:

- in the case of an import transaction not scheduled in the *schedule of record*, its accepted *offer prices* in the *pre-dispatch market schedule* (the “*projected market schedule*”) in ways that, based on the *real-time dispatch process*, imply a change to *market participant* ‘k’s net operating profits relative to the

operating profits implied by the *pre-dispatch market schedule* for that *boundary entity*; or

- in the case of an import transaction scheduled in the *schedule of record*, its accepted *offer* prices in the *schedule of record* in ways that, based on the *real-time dispatch process*, imply a change to *market participant 'k'*'s net operating profits relative to the operating profits implied by the *schedule of record* for that *boundary entity*.

When this occurs but subject to section 3.8A.3, *market participant 'k'* associated with that *boundary entity* for *settlement hour 'h'* shall receive as compensation:

3.8A.1.1 in the case of an import transaction not scheduled in the *schedule of record*, a *real-time intertie offer guarantee (RT_IOG_{k,h}) settlement credit* for the import of *energy* into the *IESO-administered markets* equal to the cumulative losses resulting from a negative change in implied operating profits over the course of each *settlement hour*, resulting from such *settlement*, calculated in accordance with section 3.8A.2; or

3.8A.1.2 in the case of an import transaction scheduled in the *schedule of record*, the larger of a *real-time intertie offer guarantee settlement credit (RT_IOG_{k,h})* or the *day-ahead intertie offer guarantee settlement credit (DA_IOG_{k,h})* for the import of *energy* into the *IESO-administered markets* equal to the cumulative losses resulting from a negative change in implied operating profits over the course of each *settlement hour*, resulting from such *settlement*, calculated in accordance with section 3.8A.2 or 3.8A.2B as the case may be.

Real-Time Intertie Offer Guarantee

3.8A.2 The *real-time intertie offer guarantee settlement credit* for *market participant 'k'* for *settlement hour 'h'* ("*RT_IOG_{k,h}*") shall be determined by the following equation:

Let $OP(P,Q,B)$ be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of *price-quantity pairs*:

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows :

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

‘P’ is $EMP_h^{i,t}$: the real-time 5-minute *energy market price* at the applicable *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

‘Q’ is $MQSI_{k,h}^{i,t}$: the market quantity scheduled for injection in the *market schedule* by *market participant* ‘k’ at *intertie metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ‘h’

‘B’ is matrix $BE_{k,h}^{i,t}$ of N *price-quantity pairs* offered by *market participant* ‘k’ to supply *energy* from a particular *boundary entity* associated with an *intertie metering point* ‘i’ in the *IESO-administered markets*, during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by offered price where offered prices are in column 1 and offered quantities are in column 2.

Using the terms below, let $RT_IOG_{k,h}$ be expressed as follows:

$$RT_IOG_{k,h} = EIM_{k,h}$$

Where:

$EIM_{k,h}$ represents that component of the real-time *intertie offer guarantee settlement credit* for *market participant* ‘k’ during *settlement hour* ‘h’ attributable to import of *energy* into the *IESO-administered markets* at all relevant *intertie metering points* ‘i’ in accordance with the rationale referred to in section 3.8A.1 and is calculated as follows:

$$EIM_{k,h} = \sum_I (-1) \bullet \text{MIN} \left[0, \sum_T \text{OP}(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE) \right]$$

Such that:

I is the set of all relevant *intertie metering points* ‘i’

T is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’

$EMP_h^{i,t}$ is the real-time 5-minute *energy market price* at the applicable *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

Day-Ahead Intertie Offer Guarantee

3.8A.2A The day-ahead *intertie offer* guarantee *settlement* credit for *market participant* ‘k’ for *settlement hour* ‘h’ (“DA_I OG_{k,h}”) shall be determined for import transactions that are not part of a day-ahead linked wheel.

3.8A.2B The day-ahead *intertie offer* guarantee *settlement* credit for *market participant* ‘k’ for *settlement hour* ‘h’ (“DA_I OG_{k,h}”) shall be determined by the following equation:

DA_BE_{k,h}^{i,t} is the offer matrix of N price-quantity pairs for the eligible import transaction scheduled in the *schedule of record* for *market participant* ‘k’ during *metering interval* ‘t’ for settlement hour ‘h’ at *intertie metering point* ‘i’ arranged in ascending order by offered price where offered prices are in column 1 and offered quantities are in column 2.

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of *price-quantity pairs*:

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows :

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

‘P’ is EMP_h^{i,t}: the real-time 5-minute *energy market price* at the applicable *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

‘Q’ is the minimum of:

- DA_DQSI_{k,h}^{i,t}: the *schedule of record* constrained quantity scheduled for injection by *market participant* ‘k’ for an import transaction at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’; or
- DQSI_{k,h}^{i,t}: the real-time constrained quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’;

‘B’ is matrix DA_BE_{k,h}^{i,t}: *energy offers* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-*

quantity pair where offered prices are in column 1 and offered quantities are in column 2;

such that the day-ahead *intertie offer* guarantee is formulated as follows:

The principles for the settlement of the day-ahead *intertie offer* guarantee are as follows:

1. Component 1: Any shortfall in payment on the real-time import flow of the *schedule of record* will be based upon the real-time revenue received for that amount of *energy* in comparison with the costs submitted in the importer's day-ahead *offer*;
2. Component 2: For the portion of *schedule of record* that is not implemented in the real-time *dispatch* schedule, the day-ahead *intertie offer* guarantee will guarantee the cost incurred of arranging the import (where the real-time *offer* price is less than day ahead *offer* price) or subtract any revenue gained (where the real-time *offer* price is greater than the day-ahead *offer* price)¹; and
3. Component 3: Any income from real-time congestion management settlement credit (CMSC) included in an importer's *schedule of record* delivered in real-time will be used to reduce the day-ahead *intertie offer* guarantee payment.

The Day-Ahead Intertie Offer Guarantee is calculated as follows:

$$DA_IOG_{k,h} = \text{MAX} \left[0, \sum_T (DA_IOG_COMP1_{k,h}^{i,t} + DA_IOG_COMP2_{k,h}^{i,t} - DA_IOG_COMP3_{k,h}^{i,t}) \right]$$

Where:

T = set of all *metering intervals* 't' in the set of all *settlement hour* 'h'

¹ Where the real-time *offer* is equal to the day-ahead *offer*, the cost/gain is equal to zero (0).

Component 1

Component 1 includes any shortfall in payment on the delivered real-time *dispatch* of the *schedule of record* based upon the real-time revenue received for that amount of *energy* in comparison with the costs as represented in the importer's day-ahead *offer*. Component 1 is calculated as follows:

$$DA_IOG_COMP1_{k,h}^{i,t} = \text{As-offered day-ahead costs for the minimum of the importer's } \textit{schedule of record} \text{ and the real-time constrained schedule for the interval minus all real-time revenue received over the interval for that amount of } \textit{energy}$$

$$DA_IOG_COMP1_{k,h}^{i,t} = (-1) \times OP \left(EMP_h^{i,t}, \text{MIN} \left(DA_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t} \right), DA_BE_{k,h}^{i,t} \right)$$

Component 2

If, as a result of economic selection, a portion of the *schedule of record* is not implemented in the real-time *dispatch* schedule, the day-ahead *intertie offer* guarantee:

- Guarantees the cost of arranging the delivery if the real-time *offer* is less than the day-ahead *offer*; or
- Subtracts any gain where the real-time *offer* is greater than the day-ahead *offer*.
- If there are no real-time *energy offers* submitted by the *market participant* for any portion of the day-ahead constrained schedule, the real-time *energy offers* for that portion of *energy* will be set to MMCP (*Maximum Market Clearing Price*) for the purposes of calculating Component 2.
- If the real-time *energy offers* for any portion of the day-ahead constrained schedule is below \$0.00 \$/MWh (i.e. negative), the real-time *energy offers* for that portion of *energy* will be set to \$0.00 \$/MWh for the purposes of calculating Component 2.
- Component 2 is calculated as follows:

As-offered day-ahead costs for the difference between:

$$DA_IOG_COMP2_{k,h}^{i,t} = \begin{aligned} & \bullet \text{ the minimum of the importer's } \textit{schedule of record} \\ & \text{quantity, or the real-time constrained schedule; and} \\ & \bullet \text{ the minimum of the importer's } \textit{schedule of record} \\ & \text{quantity.} \end{aligned}$$

over the interval minus all real-time *energy offers* (with a minimum limit of zero) over the interval for that amount of *energy*

$$\text{DA_IOG_COMP2}_{k,h}^{i,t} = \text{XDA_BE}_{k,h}^{i,t} - \text{MAX}(0, \text{XBE}_{k,h}^{i,t})$$

Where:

Let $\text{XBE}_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an $n \times 2$ matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times (Q_n - Q_{n-1}) \right] + (Q - Q_{s^*}) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

Let $\text{XDA_BE}_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an $n \times 2$ matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1}) \right] + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$$c^* = \begin{aligned} & \text{the highest indexed row of matrix } \text{XDA_BE}_{k,h}^{i,t} \text{ such that } Q_{c^*} \leq \\ & \min[\text{DA_DQSI}_{k,h}^{i,t}, \text{DQSI}_{k,h}^{i,t}] \leq Q_n \text{ and where } Q_{c^*-1} = \\ & \min[\text{DA_DQSI}_{k,h}^{i,t}, \text{DQSI}_{k,h}^{i,t}] \text{ and where if } Q_{c^*} < Q_{c^*-1}, \text{ let } Q_{c^*} = \\ & Q_{c^*-1} \end{aligned}$$

$$d^* = \begin{aligned} & \text{the highest indexed row of matrix } \text{XDA_BE}_{k,h}^{i,t} \text{ such that } Q_{d^*} \leq \\ & \text{DA_DQSI}_{k,h}^{i,t} \leq Q_n \end{aligned}$$

$$p^* = \begin{aligned} & \text{the highest indexed row of matrix } \text{XBE}_{k,h}^{i,t} \text{ such that } Q_{p^*} \leq \\ & \min[\text{DA_DQSI}_{k,h}^{i,t}, \text{DQSI}_{k,h}^{i,t}] \leq Q_n \text{ and where } Q_{p^*-1} = \\ & \min[\text{DA_DQSI}_{k,h}^{i,t}, \text{DQSI}_{k,h}^{i,t}] \text{ and where if } Q_{p^*} < Q_{p^*-1}, \text{ let } \\ & Q_{p^*} = Q_{p^*-1} \end{aligned}$$

s^* = the highest indexed row of matrix $XBE_{k,h}^{i,t}$ such that $Q_{s^*} \leq DA_DQSI_{k,h}^{i,t} \leq Q_n$

Component 3

- The DA-IOG payment for an import will be reduced by the income received from real time *congestion management settlement credit* (CMSC) for the importer’s *schedule of record* delivered in real-time.
- The importer’s *schedule of record* will be measured against both the real-time constrained schedule and the real-time unconstrained schedule to determine the amount of revenue from CMSC that should be included in the day-ahead *intertie offer* guarantee calculation.
- For any interval, there are six possible orderings of the amount of an importer’s capacity that may be included in the *schedule of record*, the real-time unconstrained schedule and the real-time constrained schedule. Table 0-1: Ordering of Importer’s Capacity and Day-Ahead Intertie Offer Guarantee Component 3 summarizes the six possible orderings and the inclusion of Component 3 in the day-ahead *intertie offer* guarantee calculation.
- For the purposes of determining the applicable CMSC in Component 3, the *offer price* is subject to Section 3.5.6.

Table 0-1: Ordering of Importer’s Capacity and Day-Ahead Intertie Offer Guarantee Component 3

Scenario	Ordering	Component 3 - CMSC Included?
1	DQSI >= MQSI >= DA_DQSI	N
2	MQSI >= DQSI >= DA_DQSI	N
3	DQSI > DA_DQSI > MQSI	Y (Partial CMSC)
4	MQSI > DA_DQSI > DQSI	Y (Partial CMSC)
5	DA_DQSI >= DQSI > MQSI	Y (All CMSC)
6	DA_DQSI >= MQSI > DQSI	Y (All CMSC)

Component 3 is calculated as follows :

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = \text{Income received from real time congestion management settlement credits (CMSC) for the importer's } \textit{schedule of record} \text{ delivered in real-time over the interval}$$

Component 3 is only calculated when the real-time CMSC for the same interval is a value other than zero.

Scenario 1

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = 0$$

Scenario 2

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = 0$$

Scenario 3

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = \text{OP} \left(\text{EMP}_h^{i,t}, \text{MQSI}_{k,h}^{i,t}, \text{BE}_{k,h}^{i,t} \right) - \text{OP} \left(\text{EMP}_h^{i,t}, \text{DA_DQSI}_{k,h}^{i,t}, \text{BE}_{k,h}^{i,t} \right)$$

Scenario 4

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = \text{OP} \left(\text{EMP}_h^{i,t}, \text{DA_DQSI}_{k,h}^{i,t}, \text{BE}_{k,h}^{i,t} \right) - \text{OP} \left(\text{EMP}_h^{i,t}, \text{DQSI}_{k,h}^{i,t}, \text{BE}_{k,h}^{i,t} \right)$$

Scenario 5

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = \text{Congestion management settlement credit calculated as per Section 3.5.}$$

Scenario 6

$$\text{DA_IOG_COMP3}_{k,h}^{i,t} = \text{Congestion management settlement credit calculated as per Section 3.5.}$$

Intertie Offer Guarantee Settlement

3.8A.3 The cumulative *intertie offer guarantee settlement* credits payable to a *market participant* for any and all applicable *settlement hours* in the *real-time market* for an *energy billing period* shall be adjusted by the *IESO* in accordance with section 3.8A.4 to nullify such credits where:

3.8A.3.1 that *market participant* has submitted one or more *energy offers* and one or more *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; or

3.8A.3.2 the *market assessment unit* has determined that the *market participant* has an agreement or arrangement to share the *intertie offer guarantee settlement* credit with one or more other *market participants* and they have submitted one or more *energy offers* and one or more *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; or

3.8A.3.3 the *market participant* has one or more import transactions in the *schedule of record* at an *intertie metering point* and where:

the same import transaction is subsequently scheduled in the corresponding *metering interval* of the corresponding *settlement hour* in the *real-time market*; and

the *market participant* submits one or more *schedule of record* and/or real-time *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*;

and, at least one of such *energy offers* and one of such *energy bids* is scheduled.

For certainty, any *market participant* shall have recourse to the dispute resolution provisions of section 2 of Chapter 3 if it believes that the *market assessment unit* did not have reasonable grounds for making the determination that the *market participant* had any such agreement or arrangement with another *market participant* as described in section 3.8A.3.2.

3.8A.4 The combined day-ahead and real-time *intertie offer* guarantees and *intertie offer guarantee settlement* credit offset (“IOG Offset”) process is as follows. Any adjustment made by the *IESO* under section 3.8A.3 shall be applied with respect to any export transaction in the constrained schedule for *market participant* ‘k’ in each *settlement hour* ‘h’ for which *market participant* ‘k’ is entitled to receive a real-time or day-ahead *intertie offer guarantee settlement* credit meeting the conditions set out in section 3.8A.3. The total amount offset shall be limited by the cumulative quantity of the export transactions expressed in the constrained schedule for that *settlement hour* and shall not exceed the total combined real-

time and day-ahead *intertie offer* guarantee *settlement* credits received for the *settlement hour*. Where the cumulative quantity of the export transactions expressed in the constrained schedule for the *settlement hour* is less than the cumulative quantity of imports triggering real-time and day-ahead *intertie offer* guarantee *settlement* credits for that same *settlement hour*, the real-time and day-ahead *intertie offer* guarantee *settlement* credits will be offset in ascending order from the import transaction with the smallest real-time and/or day-ahead *intertie offer* guarantee *settlement* rate to the import transaction attracting the largest real-time and/or largest day-ahead *intertie offer* guarantee *settlement* rate and only up until the point at which the total quantity of import transactions equals the total quantity of export transactions, and may be expressed as described in the general rule that follows.

The offset process described in this section shall apply to:

- real-time *intertie offer* guarantee *settlement* credits meeting the criteria of section 3.8A.3.1; or
- real-time *intertie offer* guarantee *settlement* credits or day-ahead *intertie offer* guarantee *settlement* credits meeting the criteria of section 3.8A.3.3.

For the purposes of this calculation all applicable real-time or day-ahead *intertie offer* guarantee *settlement* credits meeting the criteria described above, attributable to *market participant* ‘k’ for *settlement hour* ‘h’ shall be arranged in ascending order by rate (dollars per megawatt per transaction), and subject to the following decision rules:

- a. [Intentionally left blank – section deleted]
- b. Where a day-ahead *intertie offer* guarantee *settlement* credit is associated with the import transaction, but no real-time *intertie offer* guarantee *settlement* credit was applicable, the day-ahead *intertie offer* guarantee *settlement* credit will be included;
- c. Where a real-time *intertie offer* guarantee *settlement* credit is associated with the import transaction, but no day-ahead *intertie offer* guarantee *settlement* credit is applicable, the real-time *intertie offer* guarantee *settlement* credit will be included;

The ordering of these *settlement amounts* is described in terms of a general rule as follows:

Let $MI_{k,h}^i$ [N,13] be an N by 13 matrix of N pairs of import quantities scheduled for injection by *market participant* ‘k’ in the real-time *dispatch schedule* and/or the constrained schedule from the DACP *schedule of record* in the *settlement hour* ‘h’ (DA_DQSI_{k,h}ⁱ and/or DQSI_{k,h}ⁱ as the case may be) paired with the corresponding day-ahead *intertie offer* guarantee, the component of the real-time *intertie offer* guarantee *settlement* credit, DA-IOG rate, RT-IOG rate, DA Offset

DQSW, DA-Offset Flag, Settlement rate, (gross) IOG\$, RT Offset DQSW, IOG Offset \$, (net) IOG \$ for all *intertie metering points* ‘i’ arranged in ascending order by *settlement* rate in each row. Columns 1 through 4 are original inputs to the matrix, while columns 5 through 13 are derived.

The general rules to settle IOG are as follows:

Note: $MI_{k,h}$ [N,13] matrix has been transposed such that the columns are on the rows.

Event Type	General Rule
Matrix $MI_{k,h}$ [Row ‘n’, Column 1]	$DA_DQSI_{k,h}^i$ Associated with the settlement amount in column 3
Matrix $MI_{k,h}$ [Row ‘n’, Column 2]	$DQSI_{k,h}^i$ Associated with the settlement amount in column 3 and 4
Matrix $MI_{k,h}$ [Row ‘n’, Column 3]	$DA_IOG_{k,h}^i$
Matrix $MI_{k,h}$ [Row ‘n’, Column 4]	$RT_IOG_{k,h}^i$
Matrix $MI_{k,h}$ [Row ‘n’, Column 5]	$MI_{k,h}$ [n,5] $\{DA_IOG_RATE_{k,h}^i\} = DA_IOG_{k,h}^i / \text{MIN}(DA_DQSI_{k,h}^i, DQSI_{k,h}^i)$
Matrix $MI_{k,h}$ [Row ‘n’, Column 6]	$MI_{k,h}$ [n,6] $\{RT_IOG_RATE_{k,h}^i\} = RT_IOG_{k,h}^i / DQSI_{k,h}^i$
Matrix $MI_{k,h}$ [Row ‘n’, Column 7]	$MI_{k,h}$ [n,7] $\{DA_OFFSET_DQSW_{k,h}^i\}$
Matrix $MI_{k,h}$ [Row ‘n’, Column 8]	$MI_{k,h}$ [n,8] $\{DA_OFFSET_FLAG_{k,h}^i\} = \text{“Y” or “N”}$ Such that: $DA_OFFSET_FLAG_{k,h}^i = \text{“Y”}$ when $\{DA_OFFSET_DQSW_{k,h}^i\} > 50\%$ of $\text{MIN}\{DA_DQSI_{k,h}^i, DQSI_{k,h}^i\}$
Matrix $MI_{k,h}$ [Row ‘n’, Column 9]	$MI_{k,h}$ [n,9] $\{IOG_SETTLEMENT_RATE_{k,h}^i\} = RT_IOG_RATE_{k,h}^i$ if $DA_OFFSET_FLAG_{k,h}^i = \text{“Y”}$;

	<p>OR</p> $MI_{k,h}^i [n,9] \{IOG_SETTLEMENT_RATE_{k,h}^i\} =$ $MAX[DA_IOG_RATE_{k,h}^i, RT_IOG_RATE_{k,h}^i]$ <p>if $DA_OFFSET_FLAG_{k,h}^i = "N"$;</p> <p>Subject to:</p> $MI_{k,h} [n,9] \geq MI_{k,h} [n-1,9];$ $MI_{k,h} [1,9] = MIN[MI_{k,h} [1 \text{ to } N,9]];$ $[MI_{k,h} [1 \text{ to } N,9]] \leq 0$
Matrix $MI_{k,h}$ [Row 'n', Column 10]	$MI_{k,h}^i [n,10] \{IOG\$_{k,h}^i\} =$ <p>the $DA_IOG\\$_{k,h}^i$ or $RT_IOG\\$_{k,h}^i$ associated with the Settlement Rate k,h^i (i.e. $RT_IOG_RATE_{k,h}^i$ or $MAX(DA_IOG_RATE_{k,h}^i, RT_IOG_RATE_{k,h}^i)$)</p>
Matrix $MI_{k,h}$ [Row 'n', Column 11]	$MI_{k,h} [n,11] \{RT_OFFSET_DQSW_{k,h}^i\}$
Matrix $MI_{k,h}$ [Row 'n', Column 12]	$MI_{k,h} [n,12] \{IOG_OFFSET_{k,h}^i\}$
Matrix $MI_{k,h}$ [Row 'n', Column 13]	$MI_{k,h} [n,13] \{Net_IOG_{k,h}^i\} =$ $MI_{k,h} [n,10] \{IOG\$_{k,h}^i\} - MI_{k,h}^i [n,12]$ $\{IOG_OFFSET_{k,h}^i\}$



The outcomes from the general rules are as follows

	A	B	C	D
Event Type	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is not offset Day Ahead	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is offset Day Ahead	An import transaction scheduled only in the real-time and receiving a RT-IOG but no DA-IOG	An import transaction scheduled both in the day ahead and in the real-time receiving DA-IOG and RT-IOG.
Matrix $MI_{k,h}$ [Row 'n', Column 1]	$DA_DQSI_{k,h}^i$	$DA_DQSI_{k,h}^i$	NULL	$DA_DQSI_{k,h}^i$
Matrix $MI_{k,h}$ [Row 'n', Column 2]	$DQSI_{k,h}^i$	$DQSI_{k,h}^i$	$DQSI_{k,h}^i$	$DQSI_{k,h}^i$
Matrix $MI_{k,h}$ [Row 'n', Column 3]	$DA_IOG_{k,h}^i$	$DA_IOG_{k,h}^i$	$DA_IOG_{k,h}^i$ = NULL	$DA_IOG_{k,h}^i$
Matrix $MI_{k,h}$ [Row 'n', Column 4]	$RT_IOG_{k,h}^i$ = NULL	$RT_IOG_{k,h}^i$ = NULL	$RT_IOG_{k,h}^i$	$RT_IOG_{k,h}^i$
Matrix $MI_{k,h}$ [Row 'n', Column 5]	$\{DA_IOG_RATE_{k,h}^i\}$	$\{DA_IOG_RATE_{k,h}^i\}$	NULL	$\{DA_IOG_RATE_{k,h}^i\}$
Matrix $MI_{k,h}$ [Row 'n', Column 6]	$\{RT_IOG_RATE_{k,h}^i\}$ = NULL	$\{RT_IOG_RATE_{k,h}^i\}$ = NULL	$\{RT_IOG_RATE_{k,h}^i\}$	$\{RT_IOG_RATE_{k,h}^i\}$
Matrix $MI_{k,h}$ [Row 'n', Column 7]	$\{DA_OFFSET_DQS_{k,h}^i\} = 0$	$\{DA_OFFSET_DQ_{k,h}^i\} > 0$	NULL	$\{DA_OFFSET_DQ_{k,h}^i\} \geq 0$
Matrix $MI_{k,h}$ [Row 'n', Column 8]	$\{DA_OFFSET_FLA_{k,h}^i\} = "N"$	$\{DA_OFFSET_FLA_{k,h}^i\} = "Y"$	NULL	$\{DA_OFFSET_FLA_{k,h}^i\} = "Y"$ or "N"
Matrix $MI_{k,h}$ [Row 'n', Column 9]	$MI_{k,h} [n,9]$ $\{IOG_SETTLEMENT_RATE_{k,h}^i\} =$ $\{DA_IOG_RATE_{k,h}^i\}$	NULL	$MI_{k,h} [n,9]$ $\{IOG_SETTLEMENT_RATE_{k,h}^i\} =$ $\{RT_IOG_RATE_{k,h}^i\}$	$MI_{k,h} [n,9]$ $\{IOG_SETTLEMENT_RATE_{k,h}^i\} =$ $\{RT_IOG_RATE_{k,h}^i\}$ or $MAX(DA_IOG_RATE_{k,h}^i)$

	A	B	C	D
Event Type	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is not offset Day Ahead	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is offset Day Ahead	An import transaction scheduled only in the real-time and receiving a RT-IOG but no DA-IOG	An import transaction scheduled both in the day ahead and in the real-time receiving DA-IOG and RT-IOG.
				$RT_IOG_RATE_{k,h}^i$)
Matrix $MI_{k,h}$ [Row 'n', Column 10]	$MI_{k,h} [n,10]$ $\{IOG\$_{k,h}^i\} =$ $DA_IOG\$_{k,h}^i$	NULL	$MI_{k,h} [n,10]$ $\{IOG\$_{k,h}^i\} =$ $RT_IOG\$_{k,h}^i$	$MI_{k,h} [n,10]$ $\{IOG\$_{k,h}^i\} =$ $\{RT_IOG\$_{k,h}^i\}$ or $MAX(DA_IOG\$_{k,h}^i, RT_IOG\$_{k,h}^i)$
Matrix $MI_{k,h}$ [Row 'n', Column 11]	$MI_{k,h} [n,11]$ $\{RT_OFFSET_DQS$ $W_{k,h}^i\} \geq 0$	NULL	$MI_{k,h} [n,11]$ $\{RT_OFFSET_DQS$ $W_{k,h}^i\} \geq 0$	$MI_{k,h} [n,11]$ $\{RT_OFFSET_DQ$ $SW_{k,h}^i\} \geq 0$
Matrix $MI_{k,h}$ [Row 'n', Column 12]	$MI_{k,h} [n,12]$ $\{IOG_OFFSET_{k,h}^i\}$ ≥ 0	NULL	$MI_{k,h} [n,12]$ $\{IOG_OFFSET_{k,h}^i\}$ ≥ 0	$MI_{k,h} [n,12]$ $\{IOG_OFFSET_{k,h}^i\}$ ≥ 0
Matrix $MI_{k,h}$ [Row 'n', Column 13]	$MI_{k,h} [n,13]$ $\{Net_IOG_{k,h}^i\} =$ $MI_{k,h} [n,10]$ $\{IOG\$_{k,h}^i\} - MI_{k,h}$ $[n,12]$ $\{IOG_OFFSET_{k,h}^i\}$	NULL	$MI_{k,h} [n,13]$ $\{Net_IOG_{k,h}^i\} =$ $MI_{k,h} [n,10]$ $\{IOG\$_{k,h}^i\} - MI_{k,h}$ $[n,12]$ $\{IOG_OFFSET_{k,h}^i\}$	$MI_{k,h} [n,13]$ $\{Net_IOG_{k,h}^i\} =$ $MI_{k,h} [n,10]$ $\{IOG\$_{k,h}^i\} - MI_{k,h}$ $[n,12]$ $\{IOG_OFFSET_{k,h}^i\}$

The Day-Ahead IOG rate ($DA_IOG_RATE_{k,h}^i$) column 5, at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the day ahead constrained import schedule value in columns 1 ($DA_DQSI_{k,h}^i$) and real time import schedule value in column 2 ($DQSI_{k,h}^i$) and the $DA_IOG_{k,h}^i$ value in Column 3 of each unique row 'n' in matrix $MI_{k,h}$ as follows:

$DA_IOG_RATE_{k,h}^i$	=	$\text{IF} \left[DA_IOG_{k,h}^i \text{ is not NULL, } \frac{DA_IOG_{k,h}^i}{\text{MIN}(DA_DQSI_{k,h}^i, DQSI_{k,h}^i)}, 0 \right]$
-------------------------	---	--

The Real-Time IOG rate ($RT_IOG_RATE_{k,h}^i$) column 6 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the real-time constrained import schedule of column 2 and the $RT_IOG_{k,h}^i$ value of Column 4 of each unique row 'n' in matrix $MI_{k,h}$ as follows:

$RT_IOG_RATE_{k,h}^i$	=	$\text{IF} \left[RT_IOG_{k,h}^i \text{ is not NULL, } \frac{RT_IOG_{k,h}^i}{DQSI_{k,h}^i}, 0 \right]$
-------------------------	---	--

The matrix is arranged in ascending order on $DA_IOG_RATE_{k,h}^i$ (Column 5) from the lowest rate to the highest rate.

The day-ahead export schedule quantity offset by *market participant* 'k' at an *intertie metering point* 'i' in *settlement hour* 'h' ($DA_OFFSET_DQSW_{k,h}^i$) column 7 is calculated using the day ahead constrained import schedule value in columns 1 ($DA_DQSI_{k,h}^i$), real time import schedule value in column 2 ($DQSI_{k,h}^i$) and the day ahead constrained export schedule value for the *market participant* for an hour as follows:

$DA_DQSW_REM_{k,h}$	=	$\left[\text{MAX} \left[0, \left(\sum DA_DQSW_{k,h}^i - \sum_{i=1}^n DA_OFFSET_DQSW_{k,h}^i \right) \right] \right]$
-----------------------	---	--

$DA_OFFSET_DQSW_{k,h}^i$	=	$\text{MIN} [DA_DQSI_{k,h}^i, DQSI_{k,h}^i, DA_DQSW_REM_{k,h}]$
----------------------------	---	--



Where:

I	=	set of all <i>intertie metering points</i> 'i'
---	---	--

n	=	The number of day ahead import transactions with DA_OFFSET_DQSW at each pass.
---	---	---

The day-ahead IOG offset flag (DA_OFFSET_FLAG_{k,h}ⁱ) column 8 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the values in column 7 DA_OFFSET_DQSW_{k,h}ⁱ, columns 1 (DA_DQSI_{k,h}ⁱ) and real time import schedule value in column 2 (DQSI_{k,h}ⁱ) of each unique row 'n' in matrix MI_{k,h} as follows:

DA_OFFSET_FLAG _{k,h} ⁱ	=	IF(DA_OFFSET_DQSW _{k,h} ⁱ > [50% × MIN(DA_DQSI _{k,h} ⁱ , DQSI _{k,h} ⁱ)], Y, N)
--	---	---

The IOG offset rate (IOG_SETTLEMENT_RATE_{k,h}ⁱ) column 9 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the values in Column 5 (DA_IOG_RATE_{k,h}ⁱ) and Column 6 (RT_IOG_RATE_{k,h}ⁱ) of each unique row 'n' in matrix MI_{k,h} as follows:

IOG_SETTLEMENT_RATE _{k,h} ⁱ	=	IF[DA_OFFSET_FLAG _{k,h} ⁱ =Y, RT_IOG_RATE _{k,h} ⁱ , MAX(RT_IOG_RATE _{k,h} ⁱ , DA_IOG_RATE _{k,h} ⁱ)]
		Subject to: MI _{k,h} [n,9] >= MI _{k,h} [n-1,9]; MI _{k,h} [1,9] = MIN[MI _{k,h} [1 to N,9]]; [MI _{k,h} [1 to N,9]] <> 0

The IOG dollar amount (IOG\$_{k,h}ⁱ) column 10 at an *intertie metering point* 'i' in *settlement hour* 'h' is the IOG dollar amount associated with the rate used in Column 9 (IOG_SETTLEMENT_RATE_{k,h}ⁱ).

The matrix is arranged in ascending order of (IOG_SETTLEMENT_RATE_{k,h}ⁱ) (Column 9) from the lowest rate to the highest rate.

The real-time export schedule quantity offset by *market participant* ‘k’ at an *intertie metering point* ‘i’ in *settlement hour* ‘h’ (RT_OFFSET_DQSW_{k,h}ⁱ) column 11 is calculated using the real-time constrained import schedule values in column 2 (DQSI_{k,h}ⁱ) and the real time constrained export schedule value for the market participant for an hour as follows:

$$RT_DQSW_REM_{k,h} = \left[\text{MAX} \left[0, \left(\sum_{i=1}^I DQSW_{k,h}^i - \sum_{i=1}^n RT_OFFSET_DQSW_{k,h}^i \right) \right] \right]$$

$$RT_OFFSET_DQSW_{k,h}^i = \text{MIN} [DQSI_{k,h}^i, RT_DQSW_REM_{k,h}]$$

Where:

$$I = \text{set of all } \textit{intertie metering points} \textit{ 'i'}$$

$$n = \text{The number of real time import transactions with } RT_OFFSET_DQSW \text{ at each pass.}$$

The IOG offset *settlement amount* for *market participant* ‘k’ at an *intertie metering point* ‘i’ in *settlement hour* ‘h’ (IOG_OFFSET_{k,h}ⁱ) column 12 is calculated using column 9 (IOG_SETTLEMENT_RATE_{k,h}ⁱ) and column 11 (RT_OFFSET_DQSW_{k,h}ⁱ) as follows:

$$IOG_OFFSET_{k,h}^i = (IOG_SETTLEMENT_RATE_{k,h}^i \times RT_OFFSET_DQSW_{k,h}^i)$$

The IOG *settlement amount* for *market participant* ‘k’ at an *intertie metering point* ‘i’ in *metering settlement hour* ‘h’ (NET_IOG_{k,h}ⁱ) column 13 is calculated using column 10 (IOG\$_{k,h}ⁱ) and column 12 (IOG_OFFSET_{k,h}ⁱ) as follows:

$$NET_IOG_{k,h}^i = (IOG\$_{k,h}^i - IOG_OFFSET_{k,h}^i)$$

3.8A.5 [Intentionally left blank – section deleted]

3.8A.6 [Intentionally left blank – section deleted]

Day-Ahead Intertie Offer Guarantee Adjustments

3.8A.7 [Intentionally left blank – section deleted]

3.8A.8 [Intentionally left blank – section deleted]

3.8A.9 [Intentionally left blank – section deleted]

3.8B Day Ahead Import Failure Charge

3.8B.1 The *IESO* shall apply the day-ahead import failure charge specified in section 3.8B.2 to a *market participant* for any quantity of *energy* scheduled for injection at an *intertie metering point* scheduled in the *schedule of record* where:

3.8B.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for injection in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8B.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO*, that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B of these *market rules*; and

3.8B.1.3 the import transaction is not part of a day-ahead linked wheel.

3.8B.2 For all import transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8B.1, the day-ahead import failure charge shall be formulated as follows:

Let $OP(P,Q,B)$ be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows :

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $PD_EMP_h^{m,t}$: pre-dispatch projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

'Q' is $DA_ISD_{k,h}^{i,t}$ as defined below; and

'B' is $DA_BE_{k,h}^{i,t}$: energy offers submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-*

quantity pair where offered prices are in column 1 and offered quantities are in column 2; or

‘B’ is PD_BE_{k,h}^{i,t}: *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2.

the *offer matrix of price-quantity pairs* for the applicable import transaction that was submitted by *market participant* ‘k’ and scheduled in the *pre-dispatch of record* during *metering interval* ‘t’ for *settlement hour* ‘h’ of the *real-time trading day*

and,

Let DA_ISD_{k,h}^{i,t} be the day-ahead import scheduling deviation quantity calculated for *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ as determined by the formula:

$$\begin{aligned} \text{DA import scheduling deviation quantity (DA_ISD}_{k,h}^{i,t})} &= \text{MAX (day-ahead import transaction quantity – pre-dispatch import transaction quantity, 0)} \\ \text{DA_ISD}_{k,h}^{i,t} &= \text{MAX (DA_DQSI}_{k,h}^{i,t} - \text{PD_DQSI}_{k,h}^{i,t}, 0) \end{aligned}$$

Where:

DA_DQSI_{k,h}^{i,t} is the *schedule of record* quantity scheduled for injection by *market participant* ‘k’ for an import transaction at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’; and

PD_DQSI_{k,h}^{i,t} is the pre-dispatch quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

Let XPD_BE_{k,h}^{i,t} be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times (Q_n - Q_{n-1}) \right] + (Q - Q_{s^*}) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2



- p^* = the highest indexed row of matrix $XPD_BE_{k,h}^{i,t}$ such that $Q_{p^*} \leq PD_DQSI_{k,h}^{i,t} \leq Q_n$ and where $Q_{p^*-1} = PD_DQSI_{k,h}^{i,t}$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$
- s^* = the highest indexed row of matrix $XPD_BE_{k,h}^{i,t}$ such that $Q_{s^*} \leq DA_DQSI_{k,h}^{i,t} \leq Q_n$

Let $XDA_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an $n \times 2$ matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1}) \right] + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

- c^* = the highest indexed row of matrix $XDA_BE_{k,h}^{i,t}$ such that $Q_{c^*} \leq PD_DQSI_{k,h}^{i,t} \leq Q_n$ and where $Q_{c^*-1} = PD_DQSI_{k,h}^{i,t}$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$
- d^* = the highest indexed row of matrix $XDA_BE_{k,h}^{i,t}$ such that $Q_{d^*} \leq DA_DQSI_{k,h}^{i,t} \leq Q_n$

Such that the day-ahead import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$$\begin{aligned}
 DA_IFC_{k,h} &= \text{For all } \textit{intertie metering points} \text{ and all } \textit{metering intervals} \\
 &\text{during the } \textit{settlement hour}: \\
 &-1 \times \text{MINIMUM of:} \\
 &[\text{MAXIMUM of:} \\
 &\quad [[\text{The sum of all revenues implied by each import} \\
 &\quad \text{transaction valued at the } \textit{pre-dispatch energy market} \\
 &\quad \textit{price} \text{ in the Ontario zone for the difference in quantity}
 \end{aligned}$$

scheduled in pre-dispatch and the quantity scheduled in the *schedule of record*.

Minus:

Those costs represented through the *offers* for the import transaction scheduled in the *schedule of record*] or zero],

[MAXIMUM of:

[the pre-dispatch *offer* to increase quantity scheduled in pre-dispatch to quantity scheduled day-ahead minus the day-ahead *offer* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*]

or zero],

[day-ahead import scheduling deviation quantity times the MAXIMUM of (zero or the pre-dispatch *energy market price* in the Ontario zone)]]

DA_IFC_{k,h} =

$$\sum_{i \in T} (-1) \times \text{MIN} \left[\text{MAX} \left(0, \text{OP} \left(\text{PD_EMP}_h^{m,t}, \text{DA_DQSI}_{k,h}^{i,t}, \text{DA_BE}_{k,h}^{i,t} \right) - \text{OP} \left(\text{PD_EMP}_h^{m,t}, \text{PD_DQSI}_{k,h}^{i,t}, \text{DA_BE}_{k,h}^{i,t} \right) \right), \right. \\ \left. \text{MAX} \left(0, \text{XPD_BE}_{k,h}^{i,t} - \text{XDA_BE}_{k,h}^{i,t} \right), \left(\text{MAX} \left(0, \text{PD_EMP}_h^{m,t} \right) \times \text{DA_ISD}_{k,h}^{i,t} \right) \right]$$

Where:

DA_BE_{k,h}^{i,t} are energy offers submitted into the schedule of record, represented as an N by 2 matrix of price-quantity pairs for each market participant 'k' at intertie metering point 'i' during metering interval 't' of settlement hour 'h' arranged in ascending order by the offered price in each price-quantity pair where offered prices are in column 1 and offered quantities are in column 2;

PD_BE_{k,h}^{i,t} are energy offers submitted in pre-dispatch, represented as an N by 2 matrix of price-quantity pairs for each market participant 'k' at intertie metering point 'i' during metering interval 't' of settlement hour 'h' arranged in ascending order by the offered price in each price-quantity pair where offered prices are in column 1 and offered quantities are in column 2;

PD_EMP_h^{m,t} is the PD_EMP_h^{m,t};

'T' is the set of all metering intervals 't' in settlement hour 'h';

'I' is the set of all intertie metering points 'i'.

3.8C Real-Time Import and Real-Time Export Failure Charges

3.8C.1 The real-time import failure charge and the real-time export failure charges referred to in section 7.5.8B of Chapter 7 are *settlement amounts* that shall be determined in sections 3.8C.2 and 3.8C.3 and in sections 3.8C.4 and 3.8C.5 respectively.

Real-time Import Failure Charge

3.8C.2 The *IESO* shall assess a *market participant* with a real-time import failure charge for any quantity of *energy* scheduled for injection at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.2.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for injection in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8C.2.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO*, that the failure was due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8C.3 For all import transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.2, the real-time import failure charge shall be formulated as follows:

Let $RT_ISD_{k,h}^{i,t}$ be the real-time import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

$$\begin{aligned} \text{Real-time Import Scheduling Deviation Quantity} &= \text{MAX} (\text{pre-dispatch import transaction quantity} - \text{real-time import transaction quantity}, 0) \\ RT_ISD_{k,h}^{i,t} &= \text{MAX} (PD_DQSI_{k,h}^{i,t} - DQSI_{k,h}^{i,t}, 0) \end{aligned}$$

such that the real-time import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$$\begin{aligned} RT_IFC_{k,h} &= \text{For all } \textit{intertie metering points}: \\ &-1 \times [\text{MAXIMUM of:} \\ &\quad [[\text{The difference between: the real-time } \textit{energy} \end{aligned}$$

market price in the Ontario zone adjusted by the prevailing price bias adjustment factor for imports in effect for the *settlement hour* minus the *pre-dispatch* projected *energy market price* in the Ontario zone

times :

real-time import scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the real-time import scheduling deviation quantity times the maximum of the real-time *energy market price* in the Ontario zone or zero]

$$RT_IFC_{k,h} = \sum^{i,T} (-1) \times \text{MIN} \left[\text{MAX} \left[0, (\text{EMP}_h^{m,t} + \text{PB_IM}_h^t - \text{PD_EMP}_h^{m,t}) \times \text{RT_ISD}_{k,h}^{i,t} \right], \text{MAX} (0, \text{EMP}_h^{m,t}) \times \text{RT_ISD}_{k,h}^{i,t} \right]$$

where:

$\text{PD_EMP}_h^{m,t}$ is the pre-dispatch projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h';

$\text{EMP}_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h';

PB_IM_h^t is the price bias adjustment factor for import transactions in effect during *metering interval* 't' of *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i';

'T' is the set of all metering intervals in settlement hour 'h'.

Real-time Export Failure Charge

3.8C.4 The IESO shall assess a *market participant* with a real-time export failure charge for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.4.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for withdrawal in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8C.4.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO*, that the failure was due to bona fide and legitimate reasons described in chapter 7, section 7.5.8B.

3.8C.5 For all export transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.4, the real-time export failure charge shall be formulated as follows:

Let $RT_ESD_{k,h}^{i,t}$ be the real-time export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Export Scheduling Deviation Quantity = MAX (*pre-dispatch* export transaction quantity – real-time export transaction quantity, 0)

$RT_ESD_{k,h}^{i,t}$ = MAX (PD_DQSW $_{k,h}^{i,t}$ - DQSW $_{k,h}^{i,t}$, 0)

such that the real-time export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

RT_EFC $_{k,h}$ = For all *intertie metering points*:
 -1 x [MAXIMUM of:
 [[The difference between the *pre-dispatch* projected *energy market price* in the Ontario zone minus the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for exports in effect for the *settlement hour*]
 times :
 real-time export scheduling deviation quantity.]
 or zero,]
 subject to: a maximum value of the:
 real-time export scheduling deviation quantity times the maximum of the *pre-dispatch energy market price* in the Ontario zone or zero]

$$RT_EFC_{k,h} = \sum^{I,T} (-1) \times \text{MIN} \left[\text{MAX} \left[0, (PD_EMP_h^{m,t} - EMP_h^{m,t} - PB_EX_h^t) \times RT_ESD_{k,h}^{i,t} \right], \text{MAX} (0, PD_EMP_h^{m,t}) \times RT_ESD_{k,h}^{i,t} \right]$$

where:

$PD_EMP_h^{m,t}$ is the *pre-dispatch* projected energy market price applicable to all *delivery points* ‘m’ in the Ontario zone during *metering interval* ‘t’ of *settlement hour* ‘h’

$EMP_h^{m,t}$ is the real-time 5-minute energy market price applicable to all *delivery points* ‘m’ in the Ontario zone during *metering interval* ‘t’ of *settlement hour* ‘h’

$PB_EX_h^t$ is the price bias adjustment factor for export transactions in effect during *metering interval* ‘t’ of *settlement hour* ‘h’

‘I’ is the set of all *intertie metering points* ‘i’

‘T’ is the set of all metering intervals in settlement hour ‘h’

- 3.8C.6 Where any import transaction scheduled in the *pre-dispatch schedule of record* and subsequently scheduled at the same *intertie metering point* in the *real-time market* is subject to both the day ahead import failure charge of section 3.8B and the real-time import failure charge of section 3.8C, the *market participant* shall be assessed with the greater of these charges but not both.
- 3.8C.7 The *IESO* shall determine, in accordance with the applicable *market manual*, any applicable price bias adjustment factors to be used in the calculation of the real-time import failure charge and the real-time export failure charge. The price bias adjustment factor shall compensate for systematic differences between the pre-dispatch and real-time price.
- 3.8C.8 The *IESO* shall *publish* all applicable price bias adjustment factors in advance of the *settlement hours* to which such factors apply.
- 3.8C.9 Until the *IESO* has the software capability to include the following *settlement amounts*:
- the real-time import failure charge ($RT_IFC_{k,h}$); or
 - the real-time export failure charge ($RT_EFC_{k,h}$),
- as hourly settlement amounts on preliminary settlement statements under section 6.5.2A.1, the *IESO* may include such settlement amounts in the preliminary settlement statement issued in respect of the last trading day of a billing period. The *IESO* shall give market participants 5 days notice of when such software

capability will be put into service. This section shall then cease to have effect and shall be noted as “[Intentionally left blank – section deleted]”.

3.8D Day Ahead Export Failure Charge

3.8D.1 The *IESO* shall apply the day-ahead export failure charge specified in section 3.8D.2 to a *market participant* for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* scheduled in the *schedule of record*

where:

3.8D.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for withdrawal in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*;

3.8D.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO*, that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B; and

3.8D.1.3 the export transaction is not part of a day-ahead linked wheel.

3.8D.2 For all export transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8D.1, the day-ahead export failure charge shall be formulated as follows:

Let $OP(P, Q, B)$ be a profit function of Price (P), Quantity (Q) and an N by 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows :

$$OP(P, Q, B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s^* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

‘ P ’ is $PD_EMP_h^{m,t}$: *pre-dispatch projected energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

‘ Q ’ is $DA_ESD_{k,h}^{i,t}$ as defined below; and

‘B’ is $DA_BL_{k,h}^{i,t}$: *energy bids* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2; or

‘B’ is $PD_BL_{k,h}^{i,t}$: *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *delivery point* ‘m’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

the *offer matrix of price-quantity pairs* for the applicable export transaction that was submitted by *market participant* ‘k’ and scheduled in the *schedule of record* during *metering interval* ‘t’ for *settlement hour* ‘h’ of the *real-time trading day* and,

Let $XDA_BL_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1}) + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy bids* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

$$c^* = \begin{array}{l} \text{the highest indexed row of matrix } XDA_BL_{k,h}^{i,t} \\ \text{such that } Q_{c^*} \leq PD_DQSW_{k,h}^{i,t} \leq Q_n \text{ and where} \\ Q_{c^*-1} = PD_DQSW_{k,h}^{i,t} \text{ and where if } Q_{c^*} < Q_{c^*-1}, \\ \text{let } Q_{c^*} = Q_{c^*-1} \end{array}$$

$$d^* = \begin{array}{l} \text{the highest indexed row of matrix } XDA_BL_{k,h}^{i,t} \\ \text{such that } Q_{d^*} \leq DA_DQSW_{k,h}^{i,t} \leq Q_n \end{array}$$

Let $XPD_BL_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_i \times (Q_n - Q_{n-1}) \right] + (Q - Q_{s^*}) \times P_{s^*+1}$$



where matrix (B) *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$$p^* = \begin{array}{l} \text{the highest indexed row of matrix } XPD_BL_{k,h}^{i,t} \text{ such} \\ \text{that } Q_{p^*} \leq PD_DQSW_{k,h}^{i,t} \leq Q_n \text{ and where } Q_{p^*-1} = \\ PD_DQSW_{k,h}^{i,t} \text{ and where if } Q_{p^*} < Q_{p^*-1}, \text{ let } Q_{p^*} = \\ Q_{p^*-1} \end{array}$$

$$s^* = \begin{array}{l} \text{the highest indexed row of matrix } XPD_BL_{k,h}^{i,t} \text{ such} \\ \text{that } Q_{s^*} \leq DA_DQSW_{k,h}^{i,t} \leq Q_n \end{array}$$

Such that the day-ahead export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$$DA_EFC_{k,h} = \begin{array}{l} \text{For all } \textit{intertie metering points} \text{ and all } \textit{metering intervals} \\ \text{during the } \textit{settlement hour}: \\ -1 \times \text{MINIMUM of:} \\ [\text{MAXIMUM of:} \\ \quad [-1 \times [\text{The sum of all revenues implied by each export} \\ \text{transaction valued at the } \textit{pre-dispatch energy market} \\ \text{price in the Ontario zone for the difference in quantity} \\ \text{scheduled in pre-dispatch and the quantity scheduled in} \\ \text{the } \textit{schedule of record}. \\ \text{Minus:} \\ \text{Those costs represented through the } \textit{offers} \text{ for the} \\ \text{export transaction scheduled in the } \textit{schedule of record}] \\ \text{or zero}], \\ [\text{MAXIMUM of:} \\ \quad [\text{the day-ahead } \textit{bid} \text{ to increase quantity scheduled in} \\ \text{pre-dispatch to quantity scheduled day-ahead minus the} \\ \text{pre-dispatch } \textit{bid} \text{ to increase quantity scheduled in pre-} \\ \text{dispatch to quantity scheduled in the } \textit{schedule of} \\ \text{record}] \\ \text{or zero}] \\ \text{MAXIMUM of (zero or the day-ahead } \textit{bid} \text{ to increase quantity} \\ \text{scheduled in pre-dispatch to quantity scheduled in the } \textit{schedule} \\ \text{of record})] \end{array}$$

$$DA_EFC_{k,h} = \sum_{i,T} (-1) \times \text{MIN} \left[\text{MAX} \left(0, (-1) \times \text{OP} \left(\text{PD_EMP}_h^{m,t}, \text{DA_DQSW}_{k,h}^{i,t}, \text{DA_BL}_{k,h}^{i,t} \right) - (-1) \right. \right. \\ \left. \left. \times \text{OP} \left(\text{PD_EMP}_h^{m,t}, \text{PD_DQSW}_{k,h}^{i,t}, \text{DA_BL}_{k,h}^{i,t} \right) \right), \text{MAX} \left(0, \text{XDA_BL}_{k,h}^{i,t} - \text{XPD_BL}_{k,h}^{i,t} \right), \text{MAX} \left(0, \text{XDA_BL}_{k,h}^{i,t} \right) \right]$$

Where:

$\text{DA_BL}_{k,h}^{i,t}$ are energy bids submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered *price in each price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2;

$\text{PD_BL}_{k,h}^{i,t}$ are energy bids submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered *price in each price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2;

$\text{PD_EMP}_h^{m,t}$ is the *pre-dispatch projected energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i'.

3.8E Day Ahead Linked Wheel Failure Charge

3.8E.1 The IESO shall apply the day-ahead linked wheel failure charge specified in section 3.8E.2 to a *market participant* for any quantity of *energy* scheduled for a linked wheel at an *intertie metering point* scheduled in the *schedule of record*

where:

3.8E.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch quantity* scheduled for a linked wheel in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8E.1.2 the IESO has not determined, nor has the *market participant* demonstrated to the satisfaction of the IESO, that the failure is due to

bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8E.2 For all linked wheel transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8E.1, the day-ahead linked wheel failure charge shall be formulated as follows:

Day-ahead linked wheel scheduling deviation
(DA_LWSD_{k,h}^{i,t}) = MAX[(day-ahead import – hour-ahead pre-dispatch import), (day-ahead export – hour-ahead pre-dispatch export)]

DA_LWSD_{k,h}^{i,t} = MAX[(DA_DQSI_{k,h}^{i,t} - PD_DQSI_{k,h}^{i,t}), (DA_DQSW_{k,h}^{i,t} - PD_DQSW_{k,h}^{i,t})]

Where:

DA_DQSI_{k,h}^{i,t} is *schedule of record* quantity scheduled for injection by *market participant* ‘k’ at *delivery point* ‘m’ during *metering interval* ‘t’ of *settlement hour* ‘h’;

PD_DQSI_{k,h}^{i,t} is the *pre-dispatch* constrained quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’;

DA_DQSW_{k,h}^{i,t} is the *schedule of record* quantity scheduled for withdrawal by *market participant* ‘k’ at *delivery point* ‘m’ during *metering interval* ‘t’ of *settlement hour* ‘h’; and

PD_DQSW_{k,h}^{i,t} is the *pre-dispatch* constrained quantity scheduled for withdrawal by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

Day-ahead price spread
(DA_PS_{k,h}^{i,t}) = day-ahead constrained *intertie* price of the sink for the export transaction minus day-ahead constrained *intertie* price of the source for the import transaction

DA_PS_{k,h}^{i,t} = DA_ELMP_{k,h}^{m,t} – DA_ILMP_{k,h}^{m,t}

Where:

DA_ELMP_{k,h}^{i,t} is the day-ahead constrained *intertie* price at the *intertie metering*

point 'i' of the sink for the export transaction during metering interval 't' of settlement hour 'h'; and

DA_ILMP_h^{i,t} is the day-ahead constrained intertie price at the intertie metering point 'i' of the source for the import transaction during metering interval 't' of settlement hour 'h'

Pre-dispatch price spread
(PD_PS_{k,h}^{i,t}) = pre-dispatch constrained schedule *intertie* price of the sink for the export transaction – pre-dispatch constrained *intertie* price of the source for the import transaction

PD_PS_{k,h}^{i,t} = PD_ELMP_h^{m,t} – PD_ILMP_h^{m,t}

Where:

PD_ELMP_h^{i,t} is the pre-dispatch constrained schedule intertie price at the intertie metering point 'i' of the sink for the export transaction during metering interval 't' of settlement hour 'h'; and

PD_ILMP_h^{i,t} is the pre-dispatch constrained intertie price at the intertie metering point 'i' of the source for the import transaction during metering interval 't' of settlement hour 'h'

Such that the day-ahead linked wheel failure charge for *market participant 'k'* during *settlement hour 'h'* for all *intertie metering points 'i'* may be formulated with the above components as follows:

DA_LWFC_{k,h} = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x [The day-ahead linked wheel scheduling deviation quantity.

Multiplied by:

MAXIMUM of:

The day-ahead price spread less the pre-dispatch price spread or zero],



$$DA_LWFC_{k,h} = \sum_{i,T} (-1) \times \left[(DA_LWSD_{k,h}^{i,t}) \times \text{MAX}[0, (DA_PS_{k,h}^{i,t} - PD_PS_{k,h}^{i,t})] \right]$$

Where:

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’;

‘I’ is the set of all *intertie metering points* ‘i’.

3.8E.3 If a day-ahead linked wheel failure charge specified in section 3.8E.2 applies to a linked wheel where a real-time import failure charge specified in section 3.8C.3 and/or a real-time export failure charge specified in section 3.8C.5 applies to the same linked wheel, a charge shall apply to the *market participant* equal to the lesser of:

3.8E.3.1 the day-ahead linked wheel failure charge specified in section 3.8E.2; and

3.8E.3.2 the sum of the real-time import failure charge and the real-time export failure charge, both subject to the scheduling deviation quantity between the *schedule of record* and the *pre-dispatch schedule*, as follows:

$$RT_EFC_DALW_{k,h}^i + RT_IFC_DALW_{k,h}^i$$

Where:

RT_EFC_DALW _{k,h} ⁱ	=	real-time export failure charge for the export portion of the day-ahead linked wheel for the quantity failure from day-ahead to Pre-dispatch
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RT_EFC_DALW _{k,h} ⁱ	=	$\sum^T (-1) \times \text{MIN} \left[\text{MAX} \left[0, (PD_EMP_h^{m,t} - EMP_h^{m,t} - PB_EX_h^t) \right] \times \text{MAX} \left((DA_DQSW_{k,h}^{i,t} - PD_DQSW_{k,h}^{i,t}), 0 \right), \text{MAX}(0, PD_EMP_h^{m,t}) \right] \times \text{MAX} \left((DA_DQSW_{k,h}^{i,t} - PD_DQSW_{k,h}^{i,t}), 0 \right)$
---	---	--

RT_IFC_DALW _{k,h} ⁱ	=	real-time import failure charge for the import portion of the day-ahead linked wheel for the quantity failure from day-ahead to Pre-dispatch
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$RT_IFC_DALW_{k,h}^i$	$=$	$\sum_{t=1}^T (-1) \times \text{MIN} \left[\text{MAX} \left[0, \left(\text{EMP}_h^{m,t} + \text{PB_IM}_h^t \right. \right. \right.$ $\left. \left. - \text{PD_EMP}_h^{m,t} \right) \times \text{MAX} \left(\left(\text{DA_DQSI}_{k,h}^{i,t} - \text{PD_DQSI}_{k,h}^{i,t} \right), 0 \right) \right], \text{MAX} \left(0, \text{EMP}_h^{m,t} \right) \right.$ $\left. \times \text{MAX} \left(\left(\text{DA_DQSI}_{k,h}^{i,t} - \text{PD_DQSI}_{k,h}^{i,t} \right), 0 \right) \right]$
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3.8F Day-Ahead Generator Withdrawal Charge

3.8F.1 The IESO shall apply the day-ahead *generator* withdrawal charge specified in section 3.8F.2 to a *market participant* who was deemed to have accepted the day-ahead production cost guarantee in accordance with Section 5.8.4 of Chapter 7 for any quantity of *energy* scheduled for injection at a *metering point* scheduled in the *schedule of record* where:

3.8F.1.1 the *market participant* withdraws their commitment scheduled in the *schedule of record* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *metering point*; and,

3.8F.1.2 the IESO has not determined, nor has the *market participant* demonstrated to the satisfaction of the IESO, that the failure is to prevent endangering the safety of any person, damage to equipment, or violation of any *applicable law*.

3.8F.2 The day-ahead *generator* withdrawal charge shall be formulated as follows:

If withdrawal notification is received at or 4 hours prior to the first withdrawal hour in real time (PD – 4), then the Withdrawal Charge is calculated as follows:

$$DA_GWC_{k,start}^{event} = \text{MIN} \left(0, \sum_{i=1}^n (-1) \times \text{OP} \left(\text{MIN} \left(\text{PD_EMP}_h^{m,t}, \text{EMP}_h^{m,t} \right), \text{MLP}_{k,h}^{m,t}, \text{DA_BE}_{k,h}^{m,t} \right) \right)$$

Where:

n = the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ for the total number of hours with a *schedule of record* that are withdrawn

start event = the set of hours with a contiguous *schedule of record*

If withdrawal notification is received later than PD-4 or if the *market participant* does not notify the IESO of their intent to withdraw and does not inject for the hours committed in the *schedule of record*, then the withdrawal charge is calculated as follows:

$$DA_GWC_{k,start\ event} = \text{MIN} \left(0, \sum_{i=1}^n (-1) \times OP \left(EMP_h^{m,t}, MLP_{k,h}^{m,t}, DA_BE_{k,h}^{m,t} \right) \right)$$

Where:

n = the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ for the total number of hours with a *schedule of record* for the start event that are withdrawn

start event = the set of hours with a contiguous *schedule of record*

3.9 Hourly Uplift Settlement Amounts

3.9.1 The hourly *settlement amounts* defined by the preceding provisions of this section 3 will result in an hourly *settlement deficit* that shall be recovered from *market participants* as a whole through the *hourly uplift*. The total *hourly uplift settlement amount* for *settlement hour* ‘h’ (“HUSA_h”) shall be determined according to the following equation:

$$HUSA_h = \sum_K (NEMSC_{k,h} + ORSC_{k,h} + CAPRSC_{k,h} + CMSC_{k,h} + TRSC_{k,h} + IOG_{k,h}) + TCRF_h - \sum_K (CRSSD_{k,h} + \sum_R ORSSD_{k,r,h} + DA_IFC_{k,h} + RT_IFC_{k,h} + DA_EFC_{k,h} + RT_EFC_{k,h} + DA_LWFC_{k,h})$$

over all ‘k’ *market participants*

$NEMSC_{k,h}$ = net *energy market settlement credit* for *market participant* ‘k’ in *settlement hour* ‘h’

$ORSC_{k,h}$ = *operating reserve market settlement credit* for *market*

participant 'k' in settlement hour 'h'

$CAPRSC_{k,h}$ = *capacity reserve market settlement credit for market participant 'k' in settlement hour 'h'*

$CMSC_{k,h}$ = *congestion management settlement credit for market participant 'k' in settlement hour 'h'*

$TRSC_{k,h}$ = *transmission rights settlement credit for market participant 'k' in settlement hour 'h'*

$IOG_{k,h}$ = *intertie offer guarantee settlement credit for the market participant 'k' in settlement hour 'h'*

$DA_IFC_{k,h}$ = *day-ahead import failure charge for the market participant 'k' in settlement hour 'h'*

$RT_IFC_{k,h}$ = *real-time import failure charge for the market participant 'k' in settlement hour 'h'*

$DA_EFC_{k,h}$ = *day-ahead export failure charge for the market participant 'k' in settlement hour 'h'*

$RT_EFC_{k,h}$ = *real-time export failure charge for the market participant 'k' in settlement hour 'h'*

$DA_LWFC_{k,h}$ = *day-ahead linked wheel failure charge for the market participant 'k' in settlement hour 'h'*

$TCRF_h$ = *transmission charge reduction fund contribution in settlement hour 'h'*

$CRSSD_{k,h}$ = *capacity reserve settlement debit for operating deviations for market participant 'k' in settlement hour 'h'*

$ORSSD_{k,r,h}$ = *operating reserve settlement debit for operating deviations for class r reserve for market participant 'k' in settlement hour 'h'*

Where:

'K' is the set of all *market participants 'k'*

'R' is the set of each class r of *operating reserve*

- 3.9.2 The *IESO* shall allocate *hourly uplift* on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* within each *settlement hour* in which an *hourly uplift settlement amount* accrues.
- 3.9.3 *Hourly uplift* and non-hourly *settlement amounts* shall be disaggregated on *settlement statements* in such manner as shall be determined by the *IESO*.
- 3.9.4 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:
- the day-ahead *intertie offer guarantee settlement* ($DA_IOG_{k,h}$); or
 - the day-ahead import failure charge ($DA_IFC_{k,h}$),
- in the *hourly uplift settlement amount*, the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.1 or 4.8.2 respectively commencing with the activation of the day-ahead commitment process.
- 3.9.5 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:
- the real-time import failure charge ($RT_IFC_{k,h}$); or
 - the real-time export failure charge ($RT_EFC_{k,h}$),
- in the *hourly uplift settlement amount*, the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.2.

4. Non-hourly Settlement Amounts

4.1 Transmission Tariff Charges

- 4.1.1 The *IESO* shall collect from *transmission customers*, and distribute to *transmitters*, *transmission service charges* approved by the *OEB* in accordance with Chapter 10.

4.2 Ancillary Service Payments

- 4.2.1 The *IESO* shall have the authority to negotiate *reliability must-run contracts* with *registered market participants* or prospective *registered market participants* regarding the operation of *reliability must-run resources* in accordance with section 9 of Chapter 7. Where such *reliability must-run contracts* provide both for payments from the *energy market* and *operating reserve market* pursuant to

section 3 and additional payments for making *physical services*, other than *contracted ancillary services*, available to those markets, any such additional payments required to be made in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in \$/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

- 4.2.2 The *IESO* shall contract for *certified black start facilities* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for such *certified black start facilities* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in \$/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.
- 4.2.3 The *IESO* shall contract for *regulation* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for *regulation* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in \$/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.
- 4.2.3A [Intentionally left blank – section deleted]
- 4.2.4 The *IESO* shall contract for *reactive support service* and *voltage control service* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for such *reactive support service* and *voltage control service* in a given *energy market billing period* shall be recovered in accordance with the following:
- 4.2.4.1 *market participants* shall pay for such costs through a uniform charge, in \$/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*;
- 4.2.4.2 there shall be no power factor requirements or penalties associated with electrical power flowing out of Ontario through *intertie metering points*; and
- 4.2.4.3 there shall be no separate compensation from the *IESO* for *reactive support service* and *voltage control service* from equipment such as capacitor banks, reactor banks, and synchronous condensers owned by *transmitters*. Any compensation for providing such *ancillary services*

shall be included in the *transmission services charges* to the extent provided by the *OEB*.

4.2.5 Subject to sections 9.4.2 and 9.4.4 of Chapter 7, no compensation shall be paid for *ancillary services* provided pursuant to the *connection* requirements of Chapter 4.

4.2.6 [Intentionally left blank]

4.3 [Intentionally left blank]

4.4 Rural and Remote Settlement

4.4.1 The *IESO* shall collect and distribute payments relating to *rural and remote settlement* in accordance with directions of the *OEB* and any regulations made under the *Ontario Energy Board Act, 1998*.

4.5 IESO Administration Charge, Penalties, and Fines

4.5.1 The *IESO* shall determine a methodology for calculating and allocating an *IESO administration charge*.

4.5.2 The *IESO* shall develop and *publish* a schedule of penalties and fines and describe how these will be implemented.

4.6 Debt Retirement Charge

4.6.1 The *IESO* shall collect and remit payments relating to the *debt retirement charge* from such *market participants*, at such times and in such amounts as may be required by any regulations made pursuant to the *Electricity Act, 1998*.

4.7 TR Clearing Account Disbursements

4.7.1 Disbursements from the *TR clearing account* ordered by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be distributed to each *market participant ‘k’* as a non-hourly *settlement amount* according to its allocated quantity of *energy* withdrawn at all *RWMs* and *intertie metering points* during the *energy market billing period* immediately preceding the current *energy market billing period* in the manner described in section 4.7.2.

4.7.2 The portion of any disbursement from the *TR clearing account* payable to *market participant ‘k’* in the current *energy market billing period* shall be calculated as follows:

$$\text{TRCAC}_k = \frac{\text{TRCAD}}{\sum_{K,H} \text{AQEW}_{k,h}} \times \sum_H \text{AQEW}_{k,h}$$

Where:

TRCAC_k = the *TR clearing account credit payable to market participant 'k' in the current energy market billing period*

TRCAD = the total dollar value of all disbursements from the *TR clearing account* authorised by the *IESO Board* in the *current energy market billing period*

M = the set of all *RWMs m* and *intertie metering points 'm'* during the *energy market billing period* immediately preceding the *current energy market billing period*

K = the set of all *market participants 'k'* during the *energy market billing period* immediately preceding the *current energy market billing period*

T = the set of all *metering intervals t* in the *energy market billing period* immediately preceding the *current energy market billing period*

H = the set of all *settlement hours 'h'* in the *energy market billing period* immediately preceding the *current energy market billing period*

4.7A [Intentionally left blank – section deleted]

4.7A.1 [Intentionally left blank – section deleted]

4.7A.1.1 [Intentionally left blank – section deleted]

4.7A.1.2 [Intentionally left blank – section deleted]

4.7A.2 [Intentionally left blank – section deleted]

4.7B Real-Time Generation Cost Guarantee Payments

4.7B.1 The *IESO* shall determine on a *per-start* basis, for each *generation facility* that has met the eligibility criteria for the real-time generation cost guarantee specified in sections 2.2, 5.7 and 6.3A of Chapter 7, the following:

- 4.7B.1.1 the sum of the following revenues earned in each *dispatch interval* during the period from synchronisation until the end of the *minimum generation block run-time* or the end of the *minimum run-time*, whichever comes first:
- a. *energy market* prices multiplied by the sum of the applicable AQEI and any applicable *physical allocation data*, for *energy* injected up to and including the *minimum loading point*; and
 - b. any congestion management *settlement* credit payments resulting from the *facility* being constrained on in order to meet its *minimum loading point*; and
- 4.7B.1.2 the applicable *combined guaranteed costs* for the specified *generation facility* for the start to which the revenues determined in accordance with 4.7B.1.1 apply. The *combined guaranteed costs* will be calculated by the *IESO* and will be the sum of the following costs:
- a. fuel costs for start up and ramp to *minimum loading point* submitted by the *market participant* as outlined in section 2.2B.1.4, and
 - b. the *offer price* associated with the real-time *dispatch* multiplied by the *energy* injected, to a maximum of the *minimum loading point*, during the period from the beginning of the *minimum generation block run-time* until the earlier of:

the end of the period representing *minimum generation block run-time*; or

the end of the period representing *minimum run-time*.

The other costs that are to be considered in addition to those specified in the definition of *combined guaranteed cost* are:

- a. incremental operating costs for start up and ramp to *minimum loading point*; and
- b. incremental maintenance costs for start up and ramp to *minimum loading point*;

where both of these additional cost components are reported to the *IESO* in the manner specified in the applicable *market manual*.

- 4.7B.2 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7B.1.1 is greater than or equal to the *combined guaranteed costs* referred to in section 4.7B.1.2, then no additional payments are made in respect of the eligible *generation facility* by the *IESO*.
- 4.7B.3 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7B.1.1 is less than the *combined guaranteed costs* referred to in section 4.7B.1.2, then the *IESO* shall calculate that difference and shall include that amount in the form of additional payments made in respect of the eligible *generation facility*.
- 4.7B.4 A *real-time* generation cost guarantee shall not be paid for a *generation unit* with respect to costs incurred or revenues accrued by that *generation unit* for which a day-ahead production cost guarantee applies under section 4.7D.

4.7C Transitional Demand Response Payments

- 4.7C.1 A *market participant* participating in the Transitional Demand Response Program shall provide *settlement* data to the *IESO* in the time and manner specified in the applicable *market manual*. The *IESO* may audit any submitted *settlement* data and supporting information.
- 4.7C.2 The *IESO* shall remit Transitional Demand Response Program payments, if any, to the applicable *market participant* in the time and manner specified in the applicable *market manual*.
- 4.7C.3 The *IESO* may recover from a *market participant* any previous Transitional Demand Response Program payment or portion thereof if the audit of the *market participant's settlement* data and supporting information indicates an overpayment was made to the *market participant*.

4.7D Day-Ahead Production Cost Guarantee Payments

- 4.7D.1 The *IESO* shall determine on a *per-start* basis, for each *generation unit* that has met the criteria set out in chapter 7, sections 5.8.4, a day-ahead production costs guarantee consisting of the following components:
- a. Component 1 is any shortfall in payment on the delivered real-time *dispatch* of the *schedule of record* and will be based upon the real-time revenue received for that amount of *energy* in comparison with the value as represented in the *generator's day-ahead offer* for incremental *energy* and *speed-no-load costs*;

- b. Component 2 is the value of arranging the delivery (where the real-time *offer* is less than the day-ahead *offer*), or any gain (where the real-time *offer* is greater than the day-ahead *offer*)² for the portion of *schedule of record* quantity that is not implemented in the real-time *dispatch* schedule;
- c. Component 3 is any income from real-time *energy* congestion management settlement credit (CMSC) included in a *generator's schedule of record* delivered in real-time and will be used to reduce the day-ahead production cost guarantee payment;
- d. Component 4 is any income from real-time *operating reserve* in a *generator's schedule of record* that was not dispatched in real-time and will be used to reduce the day-ahead production cost guarantee payment; and
- e. Component 5 is the as-offered *start-up cost* (as-offered value of bringing an off-line *generator* on-line to *minimum loading point*).

4.7D.2 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7D.1.1 is greater than or equal to the sum of the costs referred to in section 4.7D.1.2, then the IESO shall make no additional payments in respect of the eligible *generation unit*.

- a. Variant 1: If the *generation unit* is not operating from the previous *dispatch day* into the current *dispatch day*, the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 5. Variant 1 occurs when:
 - the *generation unit* is not operating at the end of the previous DACP dispatch day (Day-1 HE 24 indicates off-line status); or
 - the *generation unit* is operating at the end of the previous DACP dispatch day (Day-1, HE 24 indicates on-line status) but it is not operating into the current DACP dispatch day (Day 0, HE 1 indicates off-line status); or
 - the *generation unit* is scheduled to start later in the current DACP dispatch day.
- b. Variant 2: If the *generation unit* is operating from the previous *dispatch day* into the current *dispatch day*, to complete its *minimum generation block run-time* the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 4 but does not

² Where the real-time *offer* is equal to the day-ahead *offer*, the value/gain is equal to zero (0).

include Component 5. The day-ahead production costs guarantee calculation also includes a clawback for Component 1 and Component 3

- c. Variant 3: If a *generation unit* is operating from the previous *dispatch day* into the current *dispatch day* and has completed its *minimum generation block run-time* in the previous *dispatch day*, the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 4 but does not include Component 5. Variant 3 occurs when:
- the *generation unit* is operating from the previous DACP *dispatch day* (Day-1, HE 24 indicates on-line status) into the current DACP *dispatch day* (Day 0, HE 1 indicates on-line status) and has completed its *MGBRT* in the previous DACP *dispatch day*; or
 - the *generation unit* is operating from the previous DACP *dispatch day* (Day-1, HE 24 indicates on-line status) into the current DACP *dispatch day*, (Day 0, HE 1 indicates on-line status) and has not completed its *MGBRT* and is scheduled in the current DACP *dispatch day* for hours in excess of completing its *MGBRT* from the previous DACP *dispatch day*. Variant 3 in the current DACP *dispatch day* is only for the hours in excess of completing the *MGBRT* hours for the start from the previous DACP *dispatch day*.

4.7D.3 The IESO shall calculate the day-ahead production cost guarantee components 1 through 4 for each interval in the *schedule of record* where the *generator* is injecting into the *IESO-controlled grid*.

4.7D.4 The IESO shall calculate the day-ahead production cost guarantee components based on the type of schedule described in Section 4.7D.2.1 as follows:

Component 1 – Variants 1, 2 and 3

Component 1 includes any shortfall in payment for the minimum of the *generator's schedule of record*, real-time constrained schedule and the allocated quantity of *energy* injected based upon the real-time revenue received for that amount of *energy* in comparison with the costs as represented in the *generator's day-ahead offer*. Component 1 is calculated as follows:

PCG_COMP1_{k,h}^{m,t} = All day-ahead costs excluding as-offered *start-up costs* for the minimum of the *generator's schedule of record*, real-time constrained scheduled and the allocated quantity of *energy* injected over the interval minus all real-time revenue received over the interval for that amount of *energy*

$$PCG_COMP1_{k,h}^{m,t} = (-1) \times OP \left(EMP_h^{m,t}, \min \left(DA_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t} \right), DA_BE_{k,h}^{m,t} \right) + \frac{DA_SNLC_{k,h}^m}{12}$$

Component 1 Clawback – Variant 2

Component 1 Clawback recovers the day-ahead production cost guarantee Component 1 paid up to the *minimum loading point* for the remaining hours of *MGBRT*. Component 1 Clawback– Variant 2 is calculated as follows:

PCG_COMP1_CB_{k,h}^{m,t} = All day-ahead costs excluding as-offered *start-up costs* up to the minimum of the *generation facility's minimum loading point* and the allocated quantity of *energy* injected over the interval minus all real-time revenue received over the interval for that amount of *energy*

$$PCG_COMP1_CB_{k,h}^{m,t} = (-1) \times OP \left(EMP_h^{m,t}, \min \left(AQEI_{k,h}^{m,t}, MLP_{k,h}^{m,t} \right), DA_BE_{k,h}^{m,t} \right) + \frac{DA_SNLC_{k,h}^m}{12}$$

Component 2 – Variants 1, 2 and 3

If, as a result of economic selection, a portion of the *schedule of record* is not implemented in the real-time *dispatch* schedule, the day-ahead production cost guarantee:

- Guarantees the cost of arranging the delivery if the real-time *offer price* is less than the day-ahead *offer price*; or
- Subtracts any gain where the real-time *offer price* is greater than the day-ahead *offer price*.

In the absence of a forced de-rating or a scheduled de-rating, if there are no real-time *energy offers* for any portion of the day-ahead constrained schedule, the real-time *energy offers* for that portion of *energy* will be set to MMCP (*Maximum Market Clearing Price*) for the purposes of calculating Component 2.

If the real-time *energy offers* for any portion of the day-ahead constrained schedule is below \$0.00 \$/MWh (i.e. negative), the real-time *energy offers* for that portion of *energy* will be set to \$0.00 \$/MWh for the purposes of calculating Component 2.

Component 2 is calculated as follows:

$$\begin{aligned}
 \text{PCG_COMP2}_{k,h}^{m,t} &= \text{As-offered day-ahead costs excluding as-offered } \textit{start-up costs} \text{ for} \\
 &\quad \text{the difference between:} \\
 &\quad \bullet \text{ the minimum of the } \textit{generator's schedule of record}, \text{ the de-} \\
 &\quad \text{rated value of the } \textit{generation facility} \text{ or the maximum of the} \\
 &\quad \text{real-time constrained schedule and the allocated quantity of} \\
 &\quad \textit{energy injected}; \text{ and} \\
 &\quad \bullet \text{ the minimum of the } \textit{generator's schedule of record} \text{ and the} \\
 &\quad \text{de-rated value of the } \textit{generation facility} \\
 &\quad \text{over the interval minus all real-time } \textit{energy offers} \text{ (with a minimum} \\
 &\quad \text{limit of zero) over the interval for that amount of } \textit{energy}
 \end{aligned}$$

$$\text{PCG_COMP2}_{k,h}^{m,t} = \text{XDA_BE}_{k,h}^{m,t} - \text{MAX}(0, \text{XBE}_{k,h}^{m,t})$$

Where:

Let $\text{XBE}_{k,h}^{m,t}$ be the function which calculates the area under the curve created by an $n \times 2$ matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p}^{s^*} P_n \times (Q_n - Q_{n-1}) \right] + (Q - Q_{s^*}) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *metering point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

Let $XDA_BE_{k,h}^{m,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c}^{d^*} P_n \times (Q_n - Q_{n-1}) \right] + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *metering point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

- c^* = the highest indexed row of matrix $XDA_BE_{k,h}^{m,t}$ such that $Q_{c^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})] \leq Q_n$ and where $Q_{c^*-1} = \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})]$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$
- d^* = the highest indexed row of matrix $XDA_BE_{k,h}^{m,t}$ such that $Q_{d^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}] \leq Q_n$
- p^* = the highest indexed row of matrix $XBE_{k,h}^{m,t}$ such that $Q_{p^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})] \leq Q_n$ and where $Q_{p^*-1} = \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})]$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$

s^* = the highest indexed row of matrix $XBE_{k,h}^{m,t}$ such that $Q_{s^*} \leq \min[DA_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}] \leq Q_n$

Component 3 – Variants 1, 2 and 3

- The day-ahead production cost guarantee payment for a *generator* will be reduced by the income received from real time congestion management settlement credits (CMSC) for the *generator’s schedule of record* delivered in real-time.
- The *generator’s schedule of record* will be measured against both the real-time constrained schedule and the real-time unconstrained schedule to determine the amount of revenue from congestion management settlement credits that should be included in the day-ahead production cost guarantee calculation.
- For any interval, there are six possible orderings of the amount of a *generation facility’s* capacity that may be included in the *schedule of record*, the real-time constrained schedule and the real-time unconstrained schedule. The table below summarizes the six possible orderings and the inclusion of Component 3 in the day-ahead production cost guarantee calculation.

For the purposes of determining the applicable CMSC in Component 3, the *offer price* is subject to Section 3.5.6.

Table: Ordering of Generator’s Capacity and Day-Ahead Production Cost Guarantee Component 3

Scenario	Ordering	Component 3 - CMSC Included?
1	DQSI >= MQSI >= DA DQSI	N
2	MQSI >= DQSI >= DA DQSI	N
3	DQSI > DA DQSI > MQSI	Y (Partial CMSC)
4	MQSI > DA DQSI > DQSI	Y (Partial CMSC)
5	DA DQSI >= DQSI > MQSI	Y (All CMSC)
6	DA DQSI >= MQSI > DQSI	Y (All CMSC)

Component 3 is calculated as follows :

$PCG_COMP3_{k,h}^{m,t}$ = Income received from real time congestion management settlement credits (CMSC) for the *generator’s schedule of record* delivered in real-time over the interval

Component 3 is only calculated when:

- the real-time CMSC ($TD_{k,h,105}^{m,t}$) for the same interval is a value other than zero; and
- the mathematical sign of (DQSI-MQSI) is equal to the mathematical sign of (AQEI-MQSI).

Scenario 1

$$PCG_COMP3_{k,h}^{m,t} = 0$$

Scenario 2

$$PCG_COMP3_{k,h}^{m,t} = 0$$

Scenario 3

$$PCG_COMP3_{k,h}^{m,t} = OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}) - \text{MAX} \left(OP(EMP_h^{m,t}, DA_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}) \right)$$

Scenario 4

$$PCG_COMP3_{k,h}^{m,t} = OP(EMP_h^{m,t}, DA_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}) - \text{MAX} \left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}) \right)$$

Scenario 5

$$PCG_COMP3_{k,h}^{m,t} = \text{Congestion management settlement credit calculated as per Section 3.5.}$$

Scenario 6

$$PCG_COMP3_{k,h}^{m,t} = \text{Congestion management settlement credit calculated as per Section 3.5.}$$

Component 3 Clawback – Variant 2

- Component 3 Clawback – Variant 2 recovers the congestion management settlement credits (CMSC) paid up to the *minimum loading point* for the remaining hours of MGBRT. Component 3 Clawback – Variant 2 is calculated as follows :

Income received from real time congestion management settlement credits (CMSC) from the minimum of *generation units minimum loading point* and the allocated quantity of energy injected to the real-time unconstrained schedule over the interval

$$PCG_COMP3_CB_{k,h}^{m,t} =$$

Component 3 Clawback - Variant 2 is only calculated when:

- the *schedule of record* is not less than both the real-time constrained schedule and the real-time unconstrained schedule and the event is a constrained-on event (i.e. Scenarios 3 and 5);
- the *minimum loading point* is greater than the real-time unconstrained schedule; and
- Component 3 ($PCG_COMP3_{k,h}^{m,t}$) for the same interval is a value other than zero.

Scenario 1

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Scenario 2

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Scenario 3

In Scenario 3, the clawback ($PCG_COMP3_CB_{k,h}^{m,t}$) is only calculated when the *minimum loading point* is greater than the real-time unconstrained schedule.

$$PCG_COMP3_CB_{k,h}^{m,t} = \text{MAX} \left(\text{OP} \left(\text{EMP}_h^{m,t}, \text{MLP}_{k,h}^{m,t}, \text{BE}_{k,h}^{m,t} \right), \text{OP} \left(\text{EMP}_h^{m,t}, \text{AQEI}_{k,h}^{m,t}, \text{BE}_{k,h}^{m,t} \right) \right) - \text{OP} \left(\text{EMP}_h^{m,t}, \text{MQSI}_{k,h}^{m,t}, \text{BE}_{k,h}^{m,t} \right)$$

Scenario 4

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Scenario 5

In Scenario 5, the clawback ($PCG_COMP3_CB_{k,h}^{m,t}$) is only calculated when the *minimum loading point* is greater than the real-time unconstrained schedule.

$$PCG_COMP3_CB_{k,h}^{m,t} = \text{MAX} \left(\text{OP}(\text{EMP}_h^{m,t}, \text{MLP}_{k,h}^{m,t}, \text{BE}_{k,h}^{m,t}), \text{OP}(\text{EMP}_h^{m,t}, \text{AQEI}_{k,h}^{m,t}, \text{BE}_{k,h}^{m,t}) \right) - \text{OP}(\text{EMP}_h^{m,t}, \text{MQSI}_{k,h}^{m,t}, \text{BE}_{k,h}^{m,t})$$

Scenario 6

$$PCG_COMP3_CB_{k,h}^{m,t} = 0$$

Component 4 – Variants 1, 2 and 3

The day-ahead production cost guarantee payment for a *generator* will be reduced by the income received from real-time *operating reserve* for the *generator's schedule of record* not dispatched in real-time.

Component 4 is calculated as follows:

$$PCG_COMP4_{k,h}^{m,t} = \text{net income received from real-time } \textit{operating reserve} \text{ over the interval for the } \textit{generator's schedule of record} \text{ not dispatched in real-time}$$

$$PCG_COMP4_{k,h}^{m,t} = \text{OP}(\text{PROR}_{r1,h}^{m,t}, \text{30R_SQROR}_{r1,k,h}^{m,t}, \text{BR}_{k,h}^{m,t}) + \text{OP}(\text{PROR}_{r2,h}^{m,t}, \text{10NS_SQROR}_{r2,k,h}^{m,t}, \text{BR}_{k,h}^{m,t}) + \text{OP}(\text{PROR}_{r3,h}^{m,t}, \text{10S_SQROR}_{r3,k,h}^{m,t}, \text{BR}_{k,h}^{m,t})$$

Where:

$$r1 = 30\text{-minute } \textit{operating reserve}$$

$$r2 = 10\text{-minute non-spinning } \textit{operating reserve}$$

$$r3 = 10\text{-minute spinning } \textit{operating reserve}$$

$$30R_SQROR_{r1,k,h}^{m,t} = \text{MAX} \left[0, \text{MIN} \left(\text{DA_DQSI}_{k,h}^{m,t} - \text{MQSI}_{k,h}^{m,t}, \text{SQROR}_{r1,k,h}^{m,t} \right) \right]$$

$$10NS_SQROR_{r2,k,h}^{m,t} = \text{MAX} \left[0, \text{MIN} \left(\text{DA_DQSI}_{k,h}^{m,t} - \text{MQSI}_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t}, \text{SQROR}_{r2,k,h}^{m,t} \right) \right]$$

$$10S_SQROR_{r3,k,h}^{m,t} = \text{MAX} \left[0, \text{MIN} \left(\text{DA_DQSI}_{k,h}^{m,t} - \text{MQSI}_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t} - 10NS_SQROR_{r2,k,h}^{m,t}, \text{SQROR}_{r3,k,h}^{m,t} \right) \right]$$

$$x^* = \text{the highest indexed row of matrix } BR_{r1,k,h}^{m,t}, \text{ such that } QR_{x^*} \leq \text{max}[0, \text{min}(\text{DA_DQSI}_{k,h}^{m,t} - \text{MQSI}_{k,h}^{m,t}, \text{SQROR}_{r1,k,h}^{m,t})] \leq QR_n \text{ and where } QR_0 = 0$$

$$y^* = \text{the highest indexed row of matrix } BR_{r2,k,h}^{m,t} \text{ such that } QR_{y^*} \leq \text{max}[0, \text{min}(\text{DA_DQSI}_{k,h}^{m,t} - \text{MQSI}_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t}, \text{SQROR}_{r2,k,h}^{m,t})] \leq QR_n \text{ and where } QR_0 = 0$$

$$z^* = \text{the highest indexed row of matrix } BR_{r3,k,h}^{m,t}, \text{ such that } QR_{z^*} \leq \text{max}[0, \text{min}(\text{DA_DQSI}_{k,h}^{m,t} - \text{MQSI}_{k,h}^{m,t} - 30R_SQROR_{r1,k,h}^{m,t} - 10NS_SQROR_{r2,k,h}^{m,t}, \text{SQROR}_{r3,k,h}^{m,t})] \leq QR_n \text{ and where } QR_0 = 0$$

Component 5 – Variant 1

Component 5 is the as-offered *start-up cost* incurred to bring an off-line *generation unit* through all the unit specific start-up procedures, including synchronization and ramp up to *minimum loading point*. Component 5 is calculated as follows:

$$PCG_COMP5_{k,h}^{m,t} = \text{As-offered } \textit{start-up cost} \text{ submitted by the } \textit{market participant} \text{ for the DACP start event.}$$

The rules for calculating Component 5 are as follows:

- **Scenario 1:** If the *market participant* achieves *minimum loading point* within the first 6 intervals³ of the start of the DACP scheduled period, the full as-offered start-up cost is considered.
- **Scenario 2:** If the *generation unit* achieves *minimum loading point* between the start of the 7th interval and before the start of the 18th interval of the start of the EDAC scheduled period, the as-offered start-up cost is calculated on a fractional basis. The as-offered start-up cost is calculated based on the number of 5-minute intervals the

³ The duration of an interval is 5 minutes.

resource takes to achieve *minimum loading point* between the start of the 7th interval and before the start of the 18th interval.

- **Scenario 3:** If the *generation unit* achieves *minimum loading point* after the 17th interval of the start of the DACP scheduled period (i.e. 18th interval and onwards), the as-offered *start-up cost* is not considered.

Scenario 1

$$PCG_COMP5_{k,h}^{m,t} = DA_SUC_{k,h}^m$$

Scenario 2

$$PCG_COMP5_{k,h}^{m,t} = DA_SUC_{k,h}^m - \left(DA_SUC_{k,h}^m \times \frac{1}{DA_INT} \times SUC_INT \right)$$

Where

$$DA_INT = 12$$

$$SUC_INT = \text{number of 5-minute intervals between Interval 7 and 18 the } \textit{market participant} \text{ takes to achieve } \textit{minimum loading point}.$$

Scenario 3

$$PCG_COMP5_{k,h}^{m,t} = 0$$

Component 5 – Variants 2 and 3

Component 5 is not calculated for Variants 2 and 3.

- 4.7D.5 If for each DACP start event for each eligible *generation unit* the sum of the revenues referred to in section 4.7D.4 is greater than or equal to the sum of the costs referred to in section 4.7D.4, then the IESO shall make no additional payments in respect of the eligible *generation facility*.
- 4.7D.6 If for each DACP start event for each eligible *generation unit* the sum of the revenues referred to in section 4.7D.4 is less than the sum of the costs referred to in section 4.7D.4, then the *IESO* shall include that amount in the form of additional payments made in respect of the eligible *generation facility*.

4.7E Day-Ahead Fuel Cost Compensation Settlement Amount

4.7E.1 In the event that the *IESO*, in order to maintain reliable operation of the *IESO-controlled grid* requires a *generation facility*:

- that was included in the *schedule of record*; and
- for which the *registered market participant* for the *generation facility* is deemed to have accepted the day-ahead production cost guarantee in accordance with Section 5.8.4 of Chapter 7;

either to desynchronize from the *IESO-controlled grid* prior to the end of its commitment scheduled in the *schedule of record* or not to synchronize to the *IESO-controlled grid*, the *market participant* may, in accordance with chapter 7 section 6.3B, claim, in the manner specified in the applicable *market manual*, reimbursement of financial losses related to the procurement of fuel for operation at its commitment scheduled in the *schedule of record* and which was not ultimately utilized by that *generation facility*.

4.7E.2 Where the *IESO* determines that claims made under section 4.7E.1 are valid, such compensation claims will be applied to the *market participant's settlement statement* for the last *trading day* of each *real-time market billing period* after the determination has been made.

4.7E.3 All claims made to the *IESO* pursuant to section 4.7E.1 may be subject to audit by the *IESO* which may obligate the *market participant* to demonstrate or otherwise make a binding declaration that the financial loss being claimed was not mitigated through the actions of:

- the market participant;
- an *affiliate* or subsidiary of the *market participant*; or
- any other party that may have a commercial relationship with the *market participant* where that commercial relationship involves compensation of any kind that is directly related to the mitigation of the financial loss being claimed.

4.7E.4 The cumulative *settlement amounts* payable to *market participants* for each real-time *energy market billing period* under the provisions of section 4.7E.2 shall be recovered from *market participants* in accordance with section 4.8.1.12.

4.7F Emergency Load Reduction Program

- 4.7F.1 A *market participant* participating in the Emergency Load Reduction Program shall provide *settlement data* to the *IESO* in the time and manner specified in the applicable *market manual*. The *IESO* may audit any submitted *settlement data* and supporting information.
- 4.7F.2 The *IESO* shall remit Emergency Load Reduction Program payments, if any, to the applicable *market participant* in the time and manner specified in the applicable *market manual*.
- 4.7F.3 The *IESO* may recover from a *market participant* any previous Emergency Load Reduction Program payment or portion thereof if the audit of the *market participant's settlement data* and supporting information submitted under section 4.7F.1 indicates an overpayment was made to the *market participant*.

4.7G Forecasting for Variable Generation

- 4.7G.1 The *IESO* may contract for forecasting services relating to *variable generation*.

4.8 Additional Non-Hourly Settlement Amounts

- 4.8.1 The *IESO* shall, at the end of each *energy market billing period*, recover from *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, the following amounts:
- 4.8.1.1 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 5.3.4 of Chapter 4;
 - 4.8.1.2 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 5.3.4 of Chapter 5;
 - 4.8.1.3 any out-of-pocket expenses paid in that *energy market billing period* by the *IESO* pursuant to section 6.7.4 of Chapter 5;
 - 4.8.1.4 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 8.4A.9 of Chapter 7;
 - 4.8.1.5 any costs incurred in that *energy market billing period* by the *IESO* to acquire *emergency energy* pursuant to section 2.3.3A of Chapter 5;
 - 4.8.1.6 any reimbursement paid in that *energy market billing period* by the *IESO* pursuant to section 2.1A.12.2(a);

- 4.8.1.7 any funds borrowed by the *IESO* and any associated interest costs incurred by the *IESO* in the preceding *energy market billing period* pursuant to section 6.14.5.2;
 - 4.8.1.8 [Intentionally left blank – section deleted]
 - 4.8.1.9 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 4.7B.3;
 - 4.8.1.10 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 4.7C;
 - 4.8.1.11 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 8.2.6 of Chapter 5;
 - 4.8.1.12 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7D;
 - 4.8.1.13 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7E; and
 - 4.8.1.14 [Intentionally left blank – section deleted]
 - 4.8.1.15 any compensation for Emergency Load Reduction Program participants paid in that *energy market billing period* by the *IESO* pursuant to section 4.7F; and
 - 4.8.1.16 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7G.
- 4.8.2 The *IESO* shall, at the end of each *energy market billing period*, distribute to *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, the following amounts:
- 4.8.2.1 any compensation received by the *IESO* for the provision of *emergency energy* pursuant to section 4.4A.1 of Chapter 5;
 - 4.8.2.2 any compensation received by the *IESO* as a result of a local market power investigation as set out in sections 1.7.1 and 1.7.2 of Appendix 7.6;
 - 4.8.2.3 [Intentionally left blank – section deleted]

- 4.8.2.4 [Intentionally left blank – section deleted]
- 4.8.2.5 any payments recovered by the *IESO* in accordance with sections 3.5.1A and 3.5.6E;
- 4.8.2.6 any adjustments made by the *IESO* in accordance with section 3.5.7;
- 4.8.2.7 any adjustments to Transitional Demand Response Program payments pursuant to section 4.7C;
- 4.8.2.8 any proceeds from the day-ahead import failure charge that are not distributed as a component of *hourly uplift* under section 3.9.4;
- 4.8.2.9 any proceeds from the real-time import failure charge or the real-time export failure charge that in accordance with section 3.9.5 are not distributed as a component of *hourly uplift*;
- 4.8.2.10 any proceeds from the recovery of congestion management *settlement* credits or other *settlement amounts* in accordance with section 6.6.10A.2 of Chapter 3, excluding any payments recovered under section 4.18.1.6 of Chapter 8;
- 4.8.2.11 any recovery of day-ahead *intertie offer* guarantee payments pursuant to section 3.3A.13 of Chapter 7;
- 4.8.2.12 any adjustments to Emergency Load Reduction Program payments pursuant to section 4.7F;
- 4.8.2.13 any recovery of payments made by the *IESO* under section 3.5.9; and
- 4.8.2.14 any proceeds from the day-ahead *generator* withdrawal charge under section 3.8F.

5. Market Power Mitigation

5.1 Settlement of Market Power Mitigation Rebate

5.1.1 Any payment received by the *IESO* pursuant to the terms of any agreement:

5.1.1.1 to which the *IESO* is required by its *licence* to be a party;

5.1.1.2 which incorporates the terms of a directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the *Ontario Energy Board Act, 1998*; and

5.1.1.3 which provides for the payment to the *IESO* of a rebate of certain *settlement amounts*,

shall be distributed in accordance with the *IESO licence*, as amended from time to time.

5.1.2 [Intentionally left blank]

5.1.3 [Intentionally left blank]

5.1.4 [Intentionally left blank]

5.1.5 [Intentionally left blank]

5.1.6 [Intentionally left blank]

6. Settlement Statements

6.1 Communication of Settlement Information

6.1.1 All communications between *market participants* and the *IESO* relating to the *settlement* process shall be effected using the *electronic information system* and other such means of communication as may be specified in applicable *market manuals*.

6.1.2 If there is a failure of a communication system and it is not possible to communicate in accordance with the *electronic information system* or where applicable, the means of communication specified in the applicable *market manuals*, then the *IESO* or the *market participant*, as the case may be, shall communicate information relating to the *settlement process* by facsimile or other alternative means specified by the *IESO*.

6.2 Settlement Schedule and Payments Calendar

- 6.2.1 At least 60 days prior to the *market commencement date*, and by October 15 of each year subsequent to the *market commencement date*, the *IESO* shall *publish* a draft *IESO Settlement Schedule & Payments Calendar* or *SSPC* for the following calendar year (or, in the case of the calendar year in which the *market commencement date* occurs, for the remainder of the calendar year) showing the following dates, fixed, subject to sections 6.3.20 to 6.3.29, in accordance with the relevant provisions of this section 6:
- 6.2.1.1 the dates by which the *IESO* shall issue to each applicable *market participant*, a *preliminary settlement statement* for each *trading day* for:
- charges or payments incurred in the day-ahead *energy forward market*; and
 - charges or payments incurred in respect of all rounds of any *TR auction* that is concluded on such *trading day*;
- 6.2.1.2 the dates by which the *IESO* shall, subject to sections 6.3.20 and 6.3.21.1, issue to each applicable *market participant*, a *preliminary settlement statement* for each *trading day* for:
- charges or payments incurred in the *real-time markets*; and
 - charges or payments incurred in the *TR market* other than those referred to in section 6.2.1.1 (b);
- 6.2.1.3 the dates by which any errors or omissions in each *preliminary settlement statement* referred to in section 6.2.1.1 must be notified to the *IESO*;
- 6.2.1.4 the dates by which any errors or omissions in each *preliminary settlement statement* referred to in section 6.2.1.2 must, subject to sections 6.3.21.2 and 6.3.22.2, be notified to the *IESO*;
- 6.2.1.5 the dates by which the *IESO* shall issue to each applicable *market participant*, a *final settlement statement* for each *trading day* for:
- the day-ahead *energy forward market*; and
 - all rounds of any *TR auction* that is concluded on such *trading day*;
- 6.2.1.6 the dates by which the *IESO* shall, subject to sections 6.3.20 and 6.3.21.1, issue to each applicable *market participant*, a *final settlement statement* for each *trading day* for:

- a. the *real-time markets*; and
 - b. the *TR market* other than in respect of the element referred to in section 6.2.1.5 (b);
- 6.2.1.7 the dates by which the *IESO* shall issue to each applicable *market participant*, an *invoice* for each *billing period* of a *trading week* for:
 - a. the day-ahead *energy forward market*; and
 - b. all rounds of a *TR auction* that is concluded during such *billing period*;
- 6.2.1.8 the dates by which the *IESO* shall, subject to sections 6.3.20, 6.3.21.1, 6.3.23 and 6.3.29, issue to each applicable *market participant* an *invoice* for each *billing period* of a calendar month for:
 - a. the *real-time markets*; and
 - b. the *TR market* other than in respect of the element referred to in section 6.2.1.7 (b);
- 6.2.1.9 the dates by which *market participants* shall, subject to sections 6.3.23, 6.3.27 and 6.3.29, be required to make payments into the *IESO settlement clearing account* in *settlement* of *invoices*; and
- 6.2.1.10 the dates by which *market participants* shall, subject to sections 6.3.23, 6.3.27 and 6.3.29 receive payments from the *IESO settlement clearing account* of amounts owing to them.
- 6.2.2 The *IESO* shall make the draft *SSPC* available to *market participants*.
- 6.2.3 *Market participants* shall have two weeks from the date of *publication* referred to in section 6.2.1 to submit comments and objections regarding the draft *SSPC* to the *IESO*.
- 6.2.4 No later than 30 days prior to the *market commencement date*, and by November 15 of each year subsequent to the *market commencement date*, the *IESO* shall, after considering any comments and objections received pursuant to section 6.2.3, *publish* the final *SSPC* for the following calendar year (or, in the case of the calendar year in which the *market commencement date* occurs, for the remainder of the calendar year).
- 6.2.5 The final *SSPC* shall, subject to sections 6.2.6, 6.3.20 to 6.3.29, be binding on the *IESO* and on *market participants*.
- 6.2.6 For the period that section 6.3.10A is in effect, the *IESO* shall *publish* a revised *SSPC* to reflect the dates by which *market participants* must notify the *IESO* of any errors or omissions in each of the *preliminary settlement statements* referred

to in section 6.2.1.2. The revised *SSPC* shall be binding on the *IESO* and *market participants*.

6.3 Settlement Cycles

Energy Forward Market and TR auctions

- 6.3.1 The *preliminary settlement statement* for each *trading day* in the day-ahead *energy forward market* and for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued 2 *business days* after the *trading day*.
- 6.3.2 After the *preliminary settlement statement* referred to in section 6.3.1 is issued, each *market participant* shall have 2 *business days* in which to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.6.
- 6.3.3 The *final settlement statement* for each *trading day* in the day-ahead *energy forward market* and for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued 6 *business days* after the *trading day*. The *final settlement statement* shall, subject to section 6.10.1, constitute the basis for invoicing and billing in respect of that *trading day*.
- 6.3.4 The *IESO* shall issue one invoice to each *market participant*, covering all *trading days* within a *billing period*, on the same *business day* it issues the *final settlement statement* for the last *trading day* of that *billing period*.
- 6.3.5 The *market participant payment date* for each day-ahead *energy forward market billing period* and for all rounds of any *TR auction* that is concluded during such *billing period* shall occur on the second *business day* after the *invoice* is issued.
- 6.3.6 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.12 so as to ensure that the *market participant's* payments for day-ahead *energy forward market* transactions and in respect of all rounds of any *TR auction* that is concluded in each day-ahead *energy forward market billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.
- 6.3.7 The *IESO payment date* for each day-ahead *energy forward market billing period* and for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* after the corresponding *market participant payment date*.
- 6.3.8 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.12 so as to ensure that the sums owing to each *market participant* for day-ahead *energy forward market* transactions and in respect of all rounds of any *TR auction* that is concluded in each day-ahead *energy forward*

market billing period reach each *market participant's settlement account* no later than the *close of banking business* (of the bank at which the *market participant's settlement account* is held) on the *IESO payment date*.

Real-Time Markets

- 6.3.9 Subject to sections 6.3.20 and 6.3.21.1, the *preliminary settlement statement* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.1 shall be issued ten *business days* after the *trading day*. The *preliminary settlement statement* shall, subject to section 6.3.23, constitute the basis for initial invoicing and billing.
- 6.3.10 After the *preliminary settlement statement* referred to in section 6.3.9 is issued, each *market participant* shall, subject to sections 6.3.10A, 6.3.18.1, 6.3.21.2 and 6.3.22.2, have four *business days* to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.6.
- 6.3.10A Each *market participant* shall have five *business days* to notify the *IESO* of errors or omissions in the *preliminary settlement statements* issued for each of the *trading days* of the first two *billing periods* following the first use of the day-ahead commitment process referred to in section 1.7.3 of chapter 7.
- 6.3.11 Subject to sections 6.3.18.2, 6.3.20 and 6.3.21.1, the *final settlement statement* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.3 shall be issued ten *business days* after the issuance of the *preliminary settlement statement* for that *trading day* and shall, in the case of the *real-time markets*, reflect the outcome of the validation procedure undertaken in accordance with section 6.6.
- 6.3.12 The *final settlement statement* shall, subject to sections 6.3.23 and 6.10.1, be the basis for final invoicing and billing.
- 6.3.13 The *IESO* shall, subject to section 6.3.23 and 6.3.29, issue one *invoice* to each *market participant*, covering all *trading days* within a *billing period* on the same day it issues the *preliminary settlement statement* for the last *trading day* of that *billing period*.
- 6.3.14 The *market participant* payment date for each *real-time market billing period* and for each *TR market billing period* shall, subject to section 6.3.23, 6.3.27 and 6.3.29, be the second *business day* following the issuance of the *invoice*.
- 6.3.15 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.12 so as to ensure that the *market participant's* payments for each *real-time market billing period* and for each *TR market billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

- 6.3.16 The *IESO* payment date for each *real-time market billing period* and for each *TR market billing period* shall, subject to sections 6.3.23, 6.3.27 and 6.3.29, be the second *business day* after the *market participant payment date*.
- 6.3.17 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.12 so as to ensure that the sums owing to each *market participant, forecasting entity*, and to each *transmitter* for each *real-time market billing period* and for each *TR market billing period* reach the *market participant's settlement account* or the *transmitter's transmission services settlement account*, as the case may be, no later than the *close of banking business* (of the bank at which the *market participant's settlement account* or the *transmitter's transmission services settlement account* is held) on the *IESO payment date*.
- 6.3.18 Until such time as this section 6.3.18 ceases to have effect in accordance with section 6.3.19:
- 6.3.18.1 each *market participant* shall have five *business days* in which to notify the *IESO* of errors or omissions in a *preliminary settlement statement* in lieu of the period referred to in section 6.3.10; and
- 6.3.18.2 *final settlement statements* for each *trading day* shall be issued twelve *business days* after the issuance of the *preliminary settlement statement* for that *trading day* in lieu of the period referred to in section 6.3.11.
- 6.3.19 Section 6.3.18 shall cease to have effect:
- 6.3.19.1 where the *market commencement date* occurs between January 1 and June 30, on January 1 of the calendar year immediately following the calendar year in which the *market commencement date* occurs; or
- 6.3.19.2 where the *market commencement date* occurs between July 1 and December 31, on July 1 of the calendar year immediately following the calendar year in which the *market commencement date* occurs.
- 6.3.20 The *IESO* may delay the issuance of *preliminary settlement statements* for a *trading day* to a date later than that provided for in section 6.3.9 where, in the *IESO's* opinion significant inaccuracies exist in the *preliminary settlement statements* such as to justify such delay.
- 6.3.21 Where the *IESO* delays the issuance of *preliminary settlement statements* for a *trading day* pursuant to section 6.3.20:
- 6.3.21.1 the issuance of *preliminary settlement statements* for any immediately succeeding *trading days* that would otherwise be required pursuant to section 6.3.9 to be issued prior to the date referred to in section

- 6.3.22.1 shall be delayed to that date or to such later date or dates as may be determined and *published* by the *IESO* having regard to the number of such *trading days*; and
- 6.3.21.2 the date by which *market participants* must notify the *IESO* of errors or omissions in any *preliminary settlement statements* for each of the *trading days* referred to in section 6.3.21.1 shall be delayed:
- a. while section 6.3.18.1 is in effect, to the date that is five *business days* from the date on which the corresponding *preliminary settlement statements* were issued in accordance with section 6.3.21.1; or
 - b. when section 6.3.18.1 ceases to have effect, to the date that is four *business days* from the date on which the corresponding *preliminary settlement statements* were issued in accordance with section 6.3.21.1.
- 6.3.22 Where the *IESO* delays the issuance of *preliminary settlement statements* for a *trading day* pursuant to section 6.3.20, the *IESO* shall *publish* notice of such delay, which notice shall indicate:
- 6.3.22.1 the date on which such *preliminary settlement statements* shall be issued in lieu of the date referred to in section 6.3.9;
- 6.3.22.2 the date by which *market participants* must notify the *IESO* of errors or omissions in such *preliminary settlement statements*, determined in accordance with section 6.3.10 or 6.3.18.1, as the case may be;
- 6.3.22.3 the date by which the *final settlement statements* for such *trading day* shall be issued in lieu of the date referred to in section 6.3.11 or 6.3.18.2, as the case may be; and
- 6.3.22.4 whether the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.23.
- 6.3.23 Where the *IESO* determines that it will be unable to issue *invoices* calculated in accordance with section 6.10.1 in respect of a given *energy market billing period* on or within 1 *business day* of the applicable date specified in the *SSPC* by reason of the delay in issuance of *preliminary settlement statements* referred to in section 6.3.20 or 6.3.21 or for any other reason, the *IESO* shall, within two *business days* of the applicable date specified in the *SSPC*, issue to each *market participant* an estimated *invoice* for such *energy market billing period* in a net amount determined in accordance with section 6.3.25.

- 6.3.24 Where the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.23 or to delay the issuance of *invoices* pursuant to section 6.3.29, the *IESO* shall:
- 6.3.24.1 issue:
- a. *invoices* calculated in accordance with section 6.10.1 in respect of a given *energy market billing period* within 1 *business day* of the applicable date specified in the *SSPC*; or
 - b. estimated *invoices* within 2 *business days* of the applicable date specified in the *SSPC*,
- as the case may be; and
- 6.3.24.2 *publish* a notice indicating whether the *IESO* intends, in accordance with section 6.3.27, to delay each of the *market participant payment date* and the *IESO payment date* associated with such *invoices* or estimated *invoices*.
- 6.3.25 The amount of an estimated *invoice* issued to a *market participant* pursuant to section 6.3.23 shall, subject to section 6.3.26, be equal to the aggregate of:
- 6.3.25.1 the net total for that *market participant* for all *trading days* that occurred during the *energy market billing period* prior to the date on which the issuance of *preliminary settlement statements* commenced to be delayed pursuant to section 6.3.20 or 6.3.21.1, as the case may be; and
- 6.3.25.2 for each *trading day* in the *energy market billing period* that occurred subsequent to the date referred to in section 6.3.25.1, the net total for that *market participant* as set forth in the *final settlement statements* issued to that *market participant* in the preceding *energy market billing period*, commencing with the *final settlement statement* issued for the last *trading day* of such preceding *energy market billing period* and using a number of *final settlement statements* equal to the number of *trading days* in the current *energy market billing period* occurring subsequent to the date referred to in section 6.3.25.1.
- 6.3.26 Where the data required to determine the amount of an estimated *invoice* in accordance with section 6.3.25 is not readily available at the relevant time, the *IESO* shall issue to each applicable *market participant* an estimated *invoice* in an amount equal to:
- 6.3.26.1 the net amount of the *invoice* issued to the *market participant* for the preceding *energy market billing period*; or

- 6.3.26.2 zero, if no *invoice* was issued to the *market participant* for the preceding *energy market billing period*.
- 6.3.27 Where the *IESO* issues estimated *invoices* pursuant to section 6.3.24 or delays the issuance of *invoices* pursuant to section 6.3.29 in respect of a given *energy market billing period*, the *IESO* may, where the delay resulting in the need to issue an estimated *invoice* or to delay the issuance of the *invoices* has or is likely to have an adverse effect on the operation of the *IESO settlement clearing account*, delay each of the *market participant payment date* and the *IESO payment date* associated with such estimated *invoice* or delayed *invoice* by one *business day* relative to the periods referred to in section 6.3.14, or 6.3.16 respectively.
- 6.3.28 Where the *IESO* issues to a *market participant* an estimated *invoice* in respect of a given *energy market billing period* pursuant to section 6.3.23, the *IESO* shall adjust the *invoice* issued to the *market participant* for the next *energy market billing period* to reflect any net difference between the amount of the estimated *invoice* and the amount that would have been set forth on the *market participant's invoice* had the *invoice* been calculated in accordance with section 6.10.1 rather than estimated in accordance with section 6.3.23.
- 6.3.29 Where the *IESO* determines that:
- 6.3.29.1 it will be unable to issue *invoices* calculated in accordance with section 6.10.1 in respect of a given *energy market billing period* on the applicable date specified in the *SSPC* by reason of the delay in issuance of *preliminary settlement statements* referred to in section 6.3.20 or 6.3.21.1, or for any other reason; and
- 6.3.29.2 it is able to issue such *invoices* within 1 *business day* of the applicable date specified in the *SSPC* such that the estimated *invoice* procedure referred to in sections 6.3.23 to 6.3.28 does not apply,

the *IESO* may delay the issuance of such *invoices* for such *energy market billing period* for a period of up to 1 *business day* relative to the applicable date specified in the *SSPC*.

6.4 Settlement Statement Process

- 6.4.1 The *IESO* shall issue *settlement statements* to each *market participant* to cover each *trading day* in accordance with section 6.5 and section 6.7, and shall provide *settlement* data in accordance with section 6.5.2 and section 6.5.3.
- 6.4.2 For each *settlement statement*, the *IESO* shall calculate a net *settlement amount* for each *market participant* for the *trading day*. The net *settlement amount* shall be comprised of:

- 6.4.2.1 the aggregate of the trading amounts from each transaction in each *settlement hour* in the *trading day*; and
- 6.4.2.2 the aggregate of the amounts for the purchase or sale of *TRs* in all rounds of any *TR auction* that is concluded on the trading day, adjusted to reflect any fees payable by the *market participant* and any other adjustment amounts payable or receivable pursuant to these *market rules*.
- 6.4.3 The net *settlement* amount referred to in section 6.4.2 shall be a positive or negative dollar amount for each *market participant* and:
- 6.4.3.1 where the net *settlement* amount for a *market participant* is negative, the absolute value of the *settlement* amount shall be an amount payable by the *market participant* to the *IESO*; or
- 6.4.3.2 where the net *settlement* amount for a *market participant* is positive, the *settlement* amount shall be an amount receivable by the *market participant* from the *IESO*.
- 6.4.4 *Settlement statements* shall be considered issued to *market participants* when released in accordance with the applicable *market manuals*.
- 6.4.5 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive a *settlement statement* on the date specified for issuance of such *settlement statement* in the *SSPC* or, where applicable, on any of the dates referred to in section 6.3.21.1 and 6.3.22. Each *market participant* shall be deemed to have received a given *settlement statement* on the relevant date specified in the *SSPC* or, where applicable, on any of the dates referred to in sections 6.3.21.1 and 6.3.22, unless it notifies the *IESO* to the contrary.
- 6.4.6 In the event that a *market participant* notifies the *IESO* that it has failed to receive a *settlement statement* on the date specified for that *settlement statement* in the *SSPC* or, where applicable, on any of the dates referred to in sections 6.3.21.1 and 6.3.22, the *IESO* shall re-send the *settlement statement*, in which case the *settlement statement* shall be considered to have been received on the date the re-sent *settlement statement* is sent to the *market participant*.

6.5 Preliminary Statement Coverage

- 6.5.1 The *IESO* shall issue to each *market participant* separate preliminary *settlement statements* to cover:
- 6.5.1.1 transactions in the day-ahead *energy forward market* and all rounds of any *TR auction* that is concluded on a given *trading day*; and
 - 6.5.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.5.1.1,
- in accordance with the timelines set forth in:
- 6.5.1.3 section 6.3.1; or
 - 6.5.1.4 any of sections 6.3.9, 6.3.20 and 6.3.21.1, as may be applicable.
- 6.5.2 *Preliminary settlement statements* related to each *market participant* for the day-ahead *energy forward market* and for all rounds of any *TR auction* that is concluded on a given *trading day* shall include, in electronic format, for each *settlement hour* of the relevant *trading day* or for each such *TR auction*, as the case may be, referenced by applicable *charge type*:
- 6.5.2.1 the net quantity (in MWh) of *energy* bought or sold by the *market participant* in the *energy forward market* for that *settlement hour*;
 - 6.5.2.2 the *energy forward market price* in that *settlement hour*;
 - 6.5.2.3 the hourly Ontario *energy price* in that *settlement hour*;
 - 6.5.2.4 the payment for the *settlement hour*, either from the *market participant* to the *IESO*, or from the *IESO* to the *market participant*;
 - 6.5.2.4A all fees, charges, credits and payments applicable to the *market participant* in respect of the purchase or sale of a *TR* in all rounds of such *TR auction*;
 - 6.5.2.5 all *energy forward market fees*, charges and payments applicable to that *market participant* and the basis for deriving those fees, charges or payments; and
 - 6.5.2.6 for each type of charge listed, the total *trading day's charges* and a *billing period-to-date total*.

- 6.5.2A *Preliminary settlement statements* related to each *market participant* for the *real-time markets* and for the *TR market*, other than in respect of the element referred to in section 6.5.2, shall include the *settlement amounts*, prices and quantities described in section 6.5.3, presented as follows:
- 6.5.2A.1 for each hourly *settlement amount* referred to in section 3, by *metering interval* or *settlement hour*, as the case may be, depending upon the manner of calculation of the *settlement amount* as described in section 3;
 - 6.5.2A.2 for each non-hourly *settlement amount* referred to in section 4 or 5 that is required to be calculated over or in respect of a given *billing period*, by *billing period*, provided that such non-hourly *settlement amounts* shall be included only in the *preliminary settlement statement* issued in respect of the last *trading day* of a *billing period*; and
 - 6.5.2A.3 for each non-hourly *settlement amount*, other than those referred to in section 6.5.2A.2, by *metering interval*, *settlement hour*, or *trading day*, as the case may be, depending upon the time period over or with respect to which the relevant *settlement amount* is required to be calculated pursuant to section 4, or 5.
- 6.5.3 The *preliminary settlement statements* referred to in section 6.5.2A shall be in electronic format and shall set forth, for the *market participant* to whom the *preliminary settlement statement* is issued and referenced by applicable *charge type*:
- 6.5.3.1 the *energy* injected or withdrawn by each of that *market participant's registered facilities* as determined in each of:
 - a. the *market schedule*; and
 - b. the *real-time schedule*;
 - c. [Intentionally left blank]
 - 6.5.3.1A the allocated quantities of *energy* withdrawn or injected by each of that *market participant's registered facilities* to the extent that such quantities have not otherwise been allocated to another *market participant* through the allocation process described in section 2.4, where applicable;
 - 6.5.3.1B the allocated quantities of *energy* withdrawn or injected which have been allocated to that *market participant* through the allocation process described in section 2.4, where applicable;

- 6.5.3.2 the aggregate quantity of each class of *operating reserve* provided by each of that *market participant's registered facilities* as determined in each of:
 - a. the *market schedule*; and
 - b. the *real-time schedule*;
 - c. [Intentionally left blank]
- 6.5.3.3 the aggregate quantities or capacities, as the case may be, of each *contracted ancillary service* scheduled and provided from each of that *market participant's registered facilities*;
- 6.5.3.4 the aggregate capacity reserve quantity provided by each of that market participant's registered facilities;
- 6.5.3.5 the physical bilateral contract quantities for each market participant;
- 6.5.3.6 the availability payments to be made in each billing period under reliability must-run contracts to each of that market participant's reliability must-run resources;
- 6.5.3.7 details of performance incentive payments or penalties applicable to the *market participant*;
- 6.5.3.8 the hourly energy price applying to each of that market participant's registered facilities;
- 6.5.3.9 the applicable 5-minute price for each class of *operating reserve* for each of that *market participant's registered facilities*;
- 6.5.3.10 detailed calculations of applicable *transmission services charges*, and the *market participant's* share of these;
- 6.5.3.11 the total of each type of *contracted ancillary service* charges, and the *market participant's* share of these;
- 6.5.3.12 all *real-time market* fees, charges and payments applicable to the *market participant* and the basis for deriving those fees, charges or payments;
- 6.5.3.13 for each type of charge listed, the total *trading day's* charges and a *billing period-to-date* total; and
- 6.5.3.14 [Intentionally left blank]

- 6.5.3.15 [Intentionally left blank]
- 6.5.3.16 all *TR market* fees, charges, credits and payments applicable to the *market participant*, other than in respect of the elements referred to in section 6.5.2.5.

6.6 Validation of Preliminary Settlement Statement

- 6.6.1 Each *market participant* shall have the opportunity to review its *preliminary settlement statements*. A *market participant* may register a disagreement with the *IESO* with respect to such *preliminary settlement statements* in accordance with the timelines set forth in:
 - 6.6.1.1 section 6.3.2; and
 - 6.6.1.2 section 6.3.10, 6.3.18.1, 6.3.21.2 or 6.3.22.2, as the case may be.
- 6.6.2 Subject to sections 6.6.9 and 6.6.11, if a *market participant* disagrees with any item or calculation set forth in a *preliminary settlement statement* that it has received, or considers that there is an omission in such *preliminary settlement statement*, it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* which shall clearly state, with supporting material, the nature of the disagreement and a proposed resolution of it. Such *notice of disagreement* shall relate to only one *preliminary settlement statement* and shall include at least the following information:
 - 6.6.2.1 the date of issuance of the *preliminary settlement statement* in question;
 - 6.6.2.2 the *dispatch day* in question;
 - 6.6.2.3 the item(s) or omission(s) in question;
 - 6.6.2.4 the reasons for the disagreement;
 - 6.6.2.5 where applicable, the proposed adjustment to the data used to calculate any relevant *settlement amount* on the *preliminary settlement statement*; and
 - 6.6.2.6 where applicable, the proposed correction to any calculation of the relevant *settlement amount* on the *preliminary settlement statement*.
- 6.6.2A Where a *notice of disagreement* includes a proposed adjustment to:
 - 6.6.2A.1 physical bilateral contract data;

6.6.2A.2 physical allocation data; or

6.6.2A.3 any data of a comparable nature which may be identified by the *IESO* from time to time,

the *IESO* shall notify any other *market participant* to whom items 6.6.2A.1, 6.6.2A.2, or 6.6.2A.3 relates of such proposed adjustment prior to taking any action under section 6.6.6.

6.6.3 The *notice of disagreement* issued by the *market participant* shall be acknowledged by the *IESO* upon receipt.

6.6.4 The issuance of a *notice of disagreement* shall not remove the obligation of the *market participant* to settle any *invoice* based on the *preliminary settlement statement* in accordance with section 6.3.7 or section 6.3.14.

6.6.5 Subject to section 6.6.9 the *IESO* shall use the information provided in and with a *notice of disagreement*, and any other information available to the *IESO*, to investigate the subject-matter of the disagreement.

6.6.6 The *IESO* shall, based on its investigations, propose one of the actions described in sections 6.6.6.1 to 6.6.6.3. After informing the *market participant* of its intended actions and providing the *market participant* an opportunity to respond, the *IESO* shall do one of the following:

6.6.6.1 if the *IESO* concludes that no error has occurred in the *preliminary settlement statement*, it will so inform the *market participant* and take no further action;

6.6.6.2 if the *IESO* concurs fully with the *market participant's* proposed adjustment or correction, it shall adjust the corresponding *final settlement statement* accordingly;

6.6.6.3 if the *IESO* does not concur fully with the *market participant's* proposed adjustment or correction but does conclude that some adjustment is required, it shall so advise the *market participant* of the changes that the *IESO* proposes to make and it shall adjust the corresponding *final settlement statement* accordingly; or

6.6.6.4 if the *IESO* concludes that some adjustment may be required but requires additional time to complete its investigation, it shall so advise the *market participant* and shall, within 15 *business days* of the issuance of the corresponding *final settlement statement*, do one of the following:

- a. if the *IESO* concludes that no error has occurred in the *preliminary settlement statement*, it will so inform the *market participant* and take no further action;
- b. if the *IESO* concurs fully with the *market participant's* proposed adjustment or correction, it shall, subject to such delay as may be engendered by the application of section 6.3.20 or 6.3.21.1, adjust the next available *preliminary settlement statement* accordingly; or
- c. if the *IESO* does not concur fully with the *market participant's* proposed adjustment or correction but does conclude that some adjustment is required, it shall so advise the *market participant* of the changes that the *IESO* proposes to make and it shall, subject to such delay as may be engendered by the application of section 6.3.20 or 6.3.21.1, adjust the next available *preliminary settlement statement* accordingly.

6.6.7 If the *IESO* and the *market participant* are unable, with reasonable efforts, to resolve the disagreement before the date for issuing the corresponding *final settlement statement* or the next available *preliminary settlement statement*, as the case may be, the *IESO* shall issue the corresponding *final settlement statement* or the next available *preliminary settlement statement* without taking into account the disagreement and the disagreement may be pursued through the dispute resolution procedure described in section 6.8.2A or 6.8.2B.

6.6.8 Any changes required to be made in the final *settlement amounts* as a result of the validation process described in this section 6.6 shall, subject to section 6.16.3, be included as:

6.6.8.1 a debit or credit in the *final settlement statement*, or

6.6.8.2 if the *IESO* has already issued the *final settlement statement* prior to the determination of the required change, as:

- a. a *current period adjustment* to a subsequent *preliminary settlement statement* issued for each affected *market participant* if the total amount to be credited or debited is less than \$3,500,000; or
- b. an *adjustment period allocation* to a subsequent *preliminary settlement statement* issued for each affected *market participant* if the total amount to be debited or credited is greater than or equal to \$3,500,000. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a *market participant* who has exited the market, such amounts shall then be included as a *current period adjustment* to a subsequent *preliminary settlement statement*.

- 6.6.9 No *market participant* may submit a *notice of disagreement*, and the *IESO* shall not investigate the subject-matter of a *notice of disagreement* unless the *notice of disagreement* is submitted to the *IESO* within the time specified in:
- 6.6.9.1 section 6.3.2; or
 - 6.6.9.2 section 6.3.10 or 6.3.18.1, as the case may be.
- 6.6.10 The amount of any adjustment in respect of a *preliminary settlement statement* that has not been the subject of a *notice of disagreement* filed within the time referred to in section 6.6.9 shall be deemed not to constitute an underpayment or an overpayment by or to any *market participant*.
- 6.6.11 No *market participant* may submit a *notice of disagreement* in respect of the calculation of:
- 6.6.11.1 the 5-minute *energy market price* for any *dispatch interval* in a given *settlement hour*;
 - 6.6.11.2 the 5-minute price for any class of *operating reserve* for any *dispatch interval* in a given *settlement hour*;
 - 6.6.11.3 the *energy forward market price* for a given *settlement hour*; or
 - 6.6.11.4 the hourly Ontario energy price for a given settlement hour,
- and the *IESO* shall not investigate the subject-matter of a *notice of disagreement* to the extent that it relates to any of the elements noted in sections 6.6.11.1 to 6.6.11.4.
- 6.6.12 Nothing in section 6.6.11 shall prevent a *market participant* from submitting, or the *IESO* from investigating, a *notice of disagreement* that relates to the manner in which any of the elements noted in sections 6.6.11.1 to 6.6.11.4 have been applied for purposes of the calculation of the *market participant's net settlement amount*.

6.7 Final Settlement Statement Coverage

- 6.7.1 The *IESO* shall issue to each *market participant* separate *final settlement statements* to cover:
- 6.7.1.1 transactions in the day-ahead *energy forward market* and all rounds of any *TR auction* that is concluded on a given *trading day*; and
 - 6.7.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.7.1.1,

in accordance with the timelines set forth in:

- 6.7.1.3 section 6.3.3; and
 - 6.7.1.4 any of sections 6.3.11, 6.3.18.2, 6.3.21.1 and 6.3.22.3, as may be applicable.
- 6.7.2 The *final settlement statement* shall be in the same form as the *preliminary settlement statement* and shall include all of the information provided in the *preliminary settlement statement*, as amended following the validation procedure set forth in section 6.6 where applicable.
- 6.7.3 In accordance with the provisions of sections 6.6.6 and 6.6.8, *final settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the *final settlement statements*.
- 6.7.4 Each *market participant* that receives a *final settlement statement* is required to pay any net debit on the corresponding *market participant payment date* and shall be entitled to receive any net credit shown in the *final settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of the debit or credit.
- 6.7.5 If a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* that:
- 6.7.5.1 consists of an adjustment to the corresponding *preliminary settlement statement* made pursuant to section 6.6.6.2; and
 - 6.7.5.2 that does not reflect the agreement between the *IESO* and the *market participant* as to the adjustment,
- the *market participant* may attempt to resolve the disagreement with the *IESO*. If the *IESO* and the *market participant* are unable to resolve the disagreement, the provisions of section 6.8.2A or 6.8.2B shall apply.
- 6.7.6 If a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* that:
- 6.7.6.1 differs in amount from the same item or calculation set forth on the corresponding *preliminary settlement statement*; and
 - 6.7.6.2 is not an item or calculation identified on the *final settlement statement* as associated with an adjustment flag indicating that an adjustment has been made,

the *market participant* may attempt to resolve the disagreement with the *IESO*. If the *IESO* and the *market participant* are unable to resolve the disagreement, the provisions of section 6.8.2A or 6.8.2B shall apply.

- 6.7.7 If a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* other than one referred to in section 6.7.5 or 6.7.6, the provisions of section 6.8.9 shall apply provided that the *notice of dispute* is filed within twenty *business days* of the date of issuance of the *final settlement statement*.

6.8 Settlement Statement Recalculations

6.8.1 [Intentionally left blank]

6.8.2 [Intentionally left blank]

6.8.2A If a *market participant*, after having made reasonable efforts to resolve with the *IESO* any disagreement:

6.8.2A.1 relating to a *notice of disagreement* that complies with section 6.6.9; or

6.8.2A.2 referred to in section 6.7.5 or 6.7.6,

requires a *settlement statement re-calculation*, it shall, subject to section 6.8.8, submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall request, in the *notice of dispute*, that the *arbitrator* order that the *IESO* effect a *settlement statement re-calculation*.

6.8.2B If a *market participant*, after having made reasonable efforts to resolve with the *IESO* any disagreement referred to in section 6.8.2A does not require a *settlement statement re-calculation*, it shall, subject to section 6.8.8, submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall indicate, in the *notice of dispute*, the contested amount.

6.8.3 [Intentionally left blank]

6.8.4 If a *settlement statement re-calculation* is ordered by the *arbitrator*, the *IESO* shall arrange to have the *settlement statement re-calculation* carried out as soon as is reasonably practicable following the *arbitrator's* order, subject to the availability of data and of the *IESO's* resources.

6.8.5 If a *settlement statement re-calculation* is ordered by the *arbitrator*, the *IESO* shall:

6.8.5.1 for the *market participant* that originally filed the *notice of dispute* that resulted in the *settlement statement re-calculation*, reflect the amounts to be debited or credited in a subsequent *preliminary settlement*

statement issued for the *market participant* as soon as practicable after the *settlement statement re-calculation* has been effected. Any credit adjustment made to such *market participant*, being a refund of payments already made, shall include interest at the *default interest rate* from the date the overpayment was received to the time that the repayment is credited to the relevant *market participant settlement account*;

- 6.8.5.2 arrange to have all net adjustments for each *market participant*, and any interest on such net adjustments, placed into the *IESO adjustment account*; and
- 6.8.5.3 for any other *market participant* affected by the *settlement statement re-calculation*, reflect the amounts to be debited or credited in a subsequent *preliminary settlement statement* issued for the *market participant* by means of applying the incremental dollar amount determined in section 6.8.5.1 as:
 - a. a *current period adjustment* to all such *preliminary settlement statements* if the amount to be debited or credited to the *market participant* that originally filed the *notice of dispute* which resulted in the *settlement statement re-calculation* is less than \$3,500,000; or
 - b. an *adjustment period allocation* to all such *preliminary settlement statements* if the amount to be debited or credited to the *market participant* that originally filed the *notice of dispute* which resulted in the *settlement statement re-calculation* is greater than or equal to \$3,500,000. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a *market participant* who has exited the market, such amounts shall then be included as a *current period adjustment* to a subsequent *preliminary settlement statement*.

6.8.6 [Intentionally left blank]

6.8.6.1 [Intentionally left blank]

6.8.6.2 [Intentionally left blank]

6.8.6.3 [Intentionally left blank]

6.8.7 [Intentionally left blank]

6.8.8 No *market participant* may submit, and the *secretary* shall not accept or take any action with respect to, a *notice of dispute* if:

- 6.8.8.1 the *notice of dispute* relates to a *notice of disagreement* in respect of a disagreement other than the one to which section 6.7.5 applies and more than twenty *business days* has elapsed since the date of issuance of the *final settlement statement* referred to in section 6.6.6.3;
- 6.8.8.2 the *notice of dispute* relates to a *notice of disagreement* in respect of a disagreement to which section 6.7.5 applies and more than twenty *business days* has elapsed since the date of issuance of the *final settlement statement* referred to in that section; or
- 6.8.8.3 the *notice of dispute* relates to a disagreement to which section 6.7.6 applies and more than twenty *business days* has elapsed since the date of issuance of the *final settlement statement* referred to in that section.
- 6.8.9 If a *market participant* wishes to dispute a *final settlement statement* referred to in section 6.7.7, it shall submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall indicate, in the *notice of dispute*, the contested amount and whether a *settlement statement re-calculation* is requested.
- 6.8.10 No *market participant* may submit, and the *secretary* shall not accept or take any action with respect to, a *notice of dispute* filed pursuant to section 6.8.9 if more than twenty *business days* has elapsed since the date on which the *final settlement statement* to which the *notice of dispute* relates was issued.
- 6.8.11 [Intentionally left blank]
- 6.8.12 Sections 6.8.3 to 6.8.7 apply in respect of any *settlement statement re-calculation* requested in or ordered in response to a *notice of dispute* to which section 6.8.9 applies.

6.9 Responsibility of the IESO

- 6.9.1 In carrying out its *settlement* responsibilities, the *IESO* shall operate in a non-discriminatory manner.
- 6.9.2 The *IESO* shall not be a counter-party to any trade transacted through the *real-time markets* or the day-ahead *energy forward market*.
- 6.9.3 [Intentionally left blank]

6.10 Settlement Invoices

- 6.10.1 Unless the *IESO* has invoked the estimated *invoice* procedure pursuant to section 6.3.23, each *invoice* issued by the *IESO* to a *market participant* shall be based on any *final settlement statements* available at that time, with *preliminary settlement statements* used for the balance of the *billing period*. The *invoice* shall also include any outstanding adjustments between the *preliminary settlement statements* and the *final settlement statements* for the previous *billing period*. In each *invoice*, other than an estimated *invoice* issued pursuant to section 6.3.23:
- 6.10.1.1 each line item shall correspond to a distinct commodity or service bought or sold over the *billing period*; and
 - 6.10.1.2 the *charge type* appearing on the *invoice* shall allow *invoice* line items to be cross-referenced to the relevant *settlement statements*.
- 6.10.2 The *IESO* shall, on the days specified in the *SSPC* or, where applicable, on either of the dates referred to in section 6.3.24.1, issue an *invoice* to each *market participant* showing:
- 6.10.2.1 the dollar amounts which are to be paid by or to the *market participant*, according to *settlement statements* as specified in section 6.10.1 or as estimated pursuant to section 6.3.23;
 - 6.10.2.2 the *market participant payment date* by which such amounts (if any) are to be paid by the *market participant* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account*);
 - 6.10.2.3 the *IESO payment date* by which the *IESO* is to make payments (if any) to the *market participant* no later than the *close of banking business* (of the bank at which the *market participant settlement account* is held); and
 - 6.10.2.4 details of the *IESO settlement clearing account*, including the bank name, account number and *electronic funds transfer* instructions, to which any amounts owed by the *market participant* are to be paid in accordance with section 6.10.2.2.
- 6.10.3 *Invoices* shall be considered issued to *market participants* when released by the *IESO* in accordance with the applicable *market manuals*.
- 6.10.4 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive an *invoice* on the date specified for the issuance of such *invoice* in the *SSPC* or, where applicable, on either of the dates referred to in section 6.3.24.1.

Each *market participant* shall be deemed to have received its *invoice* on the relevant date specified in the *SSPC* or, where applicable, on either of the dates referred to in section 6.3.24.1, unless it notifies the *IESO* to the contrary.

- 6.10.5 In the event that a *market participant* notifies the *IESO* that it has failed to receive an *invoice* on the relevant date specified in the *SSPC* or, where applicable, on either of the dates referred to in section 6.3.24.1, the *IESO* shall re-send the appropriate *invoice* and the *invoice* shall be considered received on the date the re-sent *invoice* is sent to the *market participant*.

6.11 Payment of Invoices

- 6.11.1 Subject to section 6.11.2 and section 11.5 of Chapter 2, each *market participant* shall pay the full net *invoice* amount by the *market participant payment date* specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27 and 6.3.29, regardless of whether or not the *market participant* has initiated or continues to have a dispute respecting the net amount payable.
- 6.11.2 A *market participant* may pay at an earlier date than the *market participant payment date* specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29 in accordance with the following:
- 6.11.2.1 notification must be given to the *IESO* before submitting such prepayment or before converting an existing overpayment by the *market participant* into a prepayment;
 - 6.11.2.2 the prepayment notification shall specify the dollar amount prepaid;
 - 6.11.2.3 a prepayment shall be made by the *market participant* into the *IESO prepayment account* designated by the *IESO*;
 - 6.11.2.4 on any *market participant payment date*, the *IESO* may initiate the transfer of necessary funds from the *IESO's prepayment account* to the *IESO settlement clearing account* to discharge, up to the amount of the prepayment, that *market participant's* outstanding payment obligations arising in relation to that *market participant payment date*; and
 - 6.11.2.5 [Intentionally left blank]
 - 6.11.2.6 [Intentionally left blank]
 - 6.11.2.7 subject to section 5.6.3 of Chapter 2, and notwithstanding section 4.18.1.2 of Chapter 8, funds held in an *IESO prepayment account* on

behalf a *market participant* may be applied by the *IESO* to any outstanding financial obligations of that *market participant* to the *IESO* for transactions carried out in the *IESO-administered markets*.

- 6.11.3 With respect to transmission service charges, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant transmitter's transmission services settlement account sufficient funds to pay in full the transmission service charges falling due to that transmitter on any *IESO* payment date specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29.
- 6.11.4 With respect to the *IESO administration charge*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account sufficient funds to pay in full the *IESO administration charge* falling due on any *IESO payment date* specified in the *SSPC* in priority to any other payments to be made on that *IESO payment date* or on subsequent days out of the *IESO settlement clearing account*.
- 6.11.4A With respect to the smart metering charge, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account only those funds that were received in the *IESO settlement clearing account* in payment of the smart metering charge. The smart metering charge is the fee approved by the *OEB* to recover costs incurred by the *IESO* solely as a result of the *IESO* acting as the Smart Metering Entity and its responsibilities related to the smart metering initiative.
- 6.11.5 The *IESO* shall, on the *IESO payment date* specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29, determine the amounts available in the *IESO settlement clearing account* for distribution to *market participants* or the *forecasting entity*, and shall, if necessary, borrow funds in accordance with the provisions of section 6.14 if necessary to enable the *IESO settlement clearing account* to clear no later than 11:00 am on the *IESO payment date*.

6.12 Funds Transfer

- 6.12.1 All payments by *market participants* in respect of *settlement matters* shall be made to the *IESO settlement clearing account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.
- 6.12.2 All payments by the *IESO* to *market participants* in respect of *settlement matters* shall be made to each *market participant's market participant settlement account*

or to each transmitter's transmission services *settlement account* via electronic funds transfer and shall be effected by the dates and times specified in this Chapter.

- 6.12.3 In the event of failure of any *electronic funds transfer* system affecting the ability of either a *market participant* or the *IESO* to make payments, the affected party shall arrange for alternative means of payment so as to ensure that payment is effected by the dates and times specified in this Chapter.
- 6.12.4 No *market participant* shall include in any *electronic funds transfer* amounts attributable to more than one *invoice* or prepayment, unless such *electronic funds transfer* is in such form as may be specified in the applicable *market manual*.
- 6.12.5 The *IESO* shall be entitled to and shall rely on the information contained in or accompanying an *electronic funds transfer* received pursuant to section 6.12.4 for the purpose of allocating the aggregate amount of an *electronic funds transfer* referred to in that section and, notwithstanding section 13 of Chapter 1:
- 6.12.5.1 the *IESO* shall not be liable to any person in respect of the allocation of:
- a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.12.6.1; or
 - b. the amount of any associated overpayment or underpayment effected in accordance with section 6.12.6.2; and
- 6.12.5.2 the *market participant* providing the *IESO* with such information shall indemnify and hold harmless the *IESO* in respect of any claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation by the *IESO* of:
- a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.12.6.1; or
 - b. the amount of any associated overpayment or underpayment effected in accordance with section 6.12.6.2.
- 6.12.6 Where a *market participant* that initiates an *electronic funds transfer* to which section 6.12.4 applies fails to provide the information contained in or accompanying an *electronic funds transfer* referred to in section 6.12.4, the *IESO* shall allocate:
- 6.12.6.1 the aggregate amount of the *electronic funds transfer*; and
- 6.12.6.2 the entire amount of any associated overpayment or underpayment,

to that *market participant*.

6.13 Confirmation Notices

- 6.13.1 At the end of each calendar month, the *IESO* shall issue a *monthly confirmation notice* to each *market participant* which shall contain statements of the amounts received from or paid out to the *market participant* on each *market participant payment date* and *IESO payment date* in that month and any payments outstanding.

6.14 Payment Default

- 6.14.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29, the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account*.
- 6.14.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.
- 6.14.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.11.2, the provisions of section 6.3 of Chapter 3 shall apply and *default interest* shall accrue on all amounts outstanding.
- 6.14.3A If the *market participant's invoice* includes a *settlement amount* owing for the smart metering charge under section 6.11.4A and the *market participant*:
- fails to remit the full *invoice* amount due by the *market participant payment date*; and
 - does not direct the *IESO* how to apportion the payment between the smart metering charge and all other *settlement amounts* on the *invoice* prior to the *IESO payment date*,
the *IESO* shall allocate the payment made by the *market participant* first to satisfying any *settlement amounts* due under the *market rules* before being applied to the smart metering charge.
- 6.14.4 The *IESO* shall be authorised to borrow short-term funds to clear the credits in any settlement cycle only if the following conditions are met:
- 6.14.4.1 there are insufficient funds remitted into the *IESO settlement clearing account* or *TR clearing account* to pay all applicable *market creditors* due for payment from the funds in the *IESO settlement clearing account* or *TR clearing account*, and clear the *IESO settlement*

clearing account or *TR clearing account* on a given *IESO payment date*, due to:

- a. payment default by one or more *market participants* in the *day-ahead energy forward market* or the *real-time markets*; or
- b. the circumstances referred to in section 4.19.2 or 4.19.6 of Chapter 8;

6.14.4.2 [Intentionally left blank]

6.14.5 If the *IESO* borrows short-term funds pursuant to section 6.14.4, it shall recover this borrowing:

6.14.5.1 where the insufficient funds were due to a payment default referred to in section 6.14.4.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules* and as referred to in section 8.1.2.2 and then, if necessary, by imposing the *default levy* in accordance with section 8 of Chapter 2; or

6.14.5.2 where the insufficient funds were due to the circumstances referred to in section 6.14.4.1 (b), in the manner referred to in sections 4.19.3 and 4.19.5 of Chapter 8 and then, if necessary, by recovering from *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.14.6 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account*, and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participants* or to the circumstances referred to in section 6.14.4.1 (b), the *IESO* shall borrow funds in accordance with section 6.14.4 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date*.

6.14.7 If the *IESO* has exhausted credit availability contemplated by section 6.14.4, then the *IESO* shall pay *real-time market creditors* on a pro rata basis in proportion to the amounts owed to each *real-time market creditor*. Any amounts that remain owing to *real-time market creditors* shall bear interest at the *default interest rate* until paid.

6.14.8 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default*

levy, the *IESO* shall first repay all existing lines of credit and other banking facilities, including the portion of the *deferred payment plan line of credit* applicable to such *defaulting market participants*, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *real-time market creditors* owed amounts pursuant to section 6.14.7.

6.15 Payment Errors, Adjustments, and Interest

6.15.1 If a *market participant* receives an overpayment on any *IESO payment date*:

6.15.1.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* of the overpayment or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.15.1.2 if the *IESO* determines or becomes aware of the overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* of the overpayment;

6.15.1.3 the *market participant* receiving the overpayment shall, until it has refunded the overpayment to the *IESO*, be deemed to be holding the amount of such overpayment in trust for any other *market participants* that may have been underpaid in consequence of such overpayment, pro rata to the amount of the underpayment;

6.15.1.4 the *IESO* shall be entitled to treat the overpayment and any interest accruing thereon as an unpaid amount to which section 6.14 applies; and

6.15.1.5 if not repaid fully within 2 *business days* of receiving the overpayment, the unpaid amount of any overpayment shall bear interest at the *default interest rate* from the date of overpayment until the date on which repayment is credited to the *IESO's* relevant *settlement account*.

6.15.2 The *IESO* shall be responsible for identifying any *market participants* who have been underpaid as a result of an overpayment to another *market participant*.

6.15.3 The *IESO* shall pay any underpaid *market participant* for the amounts of their underpayment, including interest calculated from the date the *market participant* should have been paid, as soon as practicable following repayment by the overpaid *market participant*.

6.15.4 If a *market participant* has overpaid the *IESO* on any *market participant* payment date:

- 6.15.4.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;
 - 6.15.4.2 if the *IESO* determines or becomes aware of such overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly;
 - 6.15.4.3 the *market participant* may request that the overpaid amount be either refunded or treated as a prepayment pursuant with section 6.11.2; and
 - 6.15.4.4 any related administration and transaction costs incurred by the *IESO* in managing and resolving the over-payment shall be charged to the account of the *market participant* involved.
- 6.15.5 If the *IESO* underpays any *market participant* on any *IESO* payment date:
- 6.15.5.1 the *market participant* shall notify the *IESO* of such underpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;
 - 6.15.5.2 if the *IESO* determines or becomes aware of the underpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly; and
 - 6.15.5.3 the *IESO* shall use all reasonable endeavours to promptly correct any underpayments, including interest thereon at the *default interest rate*.
- 6.15.6 If the *IESO* is underpaid by a *market participant* on any *market participant payment date*, the provisions of section 6.14 or of section 4.20 of Chapter 8 shall apply.
- 6.15.7 If the *IESO* borrows funds in accordance with section 6.14.4 because a payment due from a *market participant* was received too late to be credited to the *IESO settlement clearing account* by close of banking business (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* when such payment was due, then such remittance when it does arrive shall be used to repay the borrowed funds. Any such late payments shall be charged the *Canadian prime interest rate* plus 2%.
- 6.15.8 If the *IESO* holds or has under its control after five *business days* from receipt in the *IESO settlement clearing account* amounts which it ought properly to have paid to *market participants*, such *market participants* shall be entitled to interest on such amounts at the *default interest rate* from the date on which the *IESO*

commenced to improperly hold or have such amounts under its control to the date on which such amounts are paid to the relevant *market participants*.

- 6.15.9 Monies in the *IESO settlement accounts* at the end of each year which have been earned from interest on funds in the *IESO settlement accounts* and which are not attributable to any incomplete *settlement process* or outstanding *settlement dispute* shall be used to off-set the *IESO administration charge* in the following year.

6.16 Settlement Financial Balance/Maximum Amount Payable by IESO

- 6.16.1 The *IESO* shall provide and operate a *settlement control process* to monitor the financial balance of the calculated charges and payments so as to ensure that, subject to section 6.16.3:
- 6.16.1.1 for *hourly market* transactions, other than transactions in the *TR market*, the sum of all payments for all *market creditors* involved in such *hourly market* transactions exactly equal the sum of all charges for *market debtors* involved in such *hourly market* transactions for each *trading day* of a *billing period*; and
 - 6.16.1.2 for all other transactions, other than transactions in the *TR market* including monthly charges, adjustment charges and payments, the sum of all payments to *market creditors* of those transactions exactly equals the sum of all charges to *market debtors* of those transactions for each *billing period*.
- 6.16.2 Subject to the provisions of section 6.14, the *IESO* shall not be liable to make payments in excess of the amount it receives for transactions in the *day-ahead energy forward market* or the *real-time markets*.
- 6.16.3 If there is an aggregate imbalance for all transactions for a given *trading day* or *billing period*, the *IESO* shall, in accordance with section 6.16.4 or by such other means as the *IESO* determines appropriate, recover that portion of the imbalance that arises by virtue of the rounding of *settlement amounts* or of an adjustment to the *settlement statement* of one *market participant* that is too small to be reflected in corresponding *settlement statement* of other *market participants* provided that:
- 6.16.3.1 the manner of calculation of that portion of the imbalance can be evidenced in a manner satisfactory for purposes of the audit referred to in section 6.17; and
 - 6.16.3.2 that portion of the imbalance has accumulated to an amount which is sufficient to permit recovery.

- 6.16.4 The *IESO* may recover the portion of an aggregate imbalance referred to in section 6.16.3 by means of an adjustment to a *settlement statement* applied:
- 6.16.4.1 to *market participants* to whom *hourly uplift* may be allocated pursuant to these *market rules*;
 - 6.16.4.2 in the same manner as *hourly uplift*; and
 - 6.16.4.3 in respect of all *settlement hours* of the last day of the *billing period* in which the portion of such aggregate imbalance is determined to arise and be recoverable pursuant to section 6.16.3.

6.17 Audit

- 6.17.1 The audit of *settlement* functions referred to in this section 6.17 shall serve to examine and evaluate compliance with management control objectives and operational effectiveness of *settlement processes* and procedures.
- 6.17.2 The audits referred to in section 6.17.3 shall be performed by an external, independent auditing firm.
- 6.17.3 Unless otherwise directed by the *IESO Board*, the *IESO* shall every two years, on the anniversary of the *market commencement date*, direct a comprehensive external audit on the *settlement processes* and procedures. The audit shall include the following tasks:
- 6.17.3.1 gauge the performance of the *settlement process* in meeting the objectives of these *market rules*;
 - 6.17.3.2 review the accuracy and timeliness of the production of *settlement statements*, including *settlement* calculations and financial allocations;
 - 6.17.3.3 review the accuracy and timeliness of the production of *invoices* and supporting market and system information;
 - 6.17.3.4 review the *reliability* and integrity of the market and system operational data used in the *settlement processes* and procedures;
 - 6.17.3.5 review the *reliability* and security of the information technology system infrastructure used to measure, validate, classify, compute and report *settlement* information;
 - 6.17.3.6 review the adequacy of *settlement processes* and procedures to safeguard *confidential information*; and



- 6.17.3.7 review the adequacy and effectiveness of risk management controls of the *settlement processes* and tools, including the effectiveness of the *disaster recovery plan*.
- 6.17.4 *Settlement statements*, financial *settlement* records and any documentation pertaining to the *IESO's settlement* activities shall, subject to sections 2.11.1 to 2.11.3, be kept in secure storage for a period of at least seven years and made available for auditing purposes.
- 6.17.5 An audit report shall be prepared by the auditors in respect of each audit conducted pursuant to this section 6.17 and shall be commissioned on the basis that the audit report must be provided to the *IESO* within one month after completion of the audit activities.
- 6.17.6 Each audit report prepared pursuant to this section 6.17 shall be made available to a *market participant* upon request, subject to such measures as may be required to be taken to safeguard any *confidential information* contained in such audit report.

6.18 Settlement Accounts

- 6.18.1 The *IESO* shall establish and maintain the *settlement accounts* described in this section 6.18 for the operation of its *settlement* and billing systems.
- 6.18.2 The *IESO* shall obtain lines of credit and other banking facilities it deems necessary for the operation of the *settlement accounts* described in this section 6.18, which lines of credit and other banking facilities shall not exceed an aggregate amount approved by the *IESO Board*.
- 6.18.3 The *IESO* may establish *settlement accounts* in addition to those referred to in this section 6.18 as may be necessary to implement the *settlement* and billing processes outlined in this Chapter. *Market participants* shall be notified 60 *business days* prior to any such additional *settlement accounts* becoming *operational*.
- 6.18.4 The *IESO* shall open and maintain the *IESO settlement clearing account* as a single bank account to and from which all *settlement* payments shall be made in accordance with the provisions of this Chapter and the details of which shall appear in the *invoices* sent by the *IESO* to *market participants* as provided in section 6.10.2.4.
- 6.18.5 [Intentionally left blank]
- 6.18.5.1 [Intentionally left blank]
- 6.18.5.2 [Intentionally left blank]
- 6.18.5.3 [Intentionally left blank]

- 6.18.6 The *IESO* shall open and maintain the *IESO adjustment account*, which *account* shall operate as follows:
- 6.18.6.1 the *IESO adjustment account* shall be a single bank account established to receive and disburse payments related to penalties, damages, fines and payment adjustments arising from resolved *settlement* disputes, and to reimburse the *IESO* for any associated costs or expenses;
 - 6.18.6.2 any amounts paid into the *IESO adjustment account* by *market participants* shall first be applied to reimburse the *IESO* in respect of any costs or expenses described in section 6.18.6.1 which it has or will incur. Any remaining amount shall be credited to the *IESO adjustment account*; and
 - 6.18.6.3 the *IESO Board* shall review, at least annually, the allocation of any credit balance of the *IESO adjustment account*, and may:
 - a. establish an amount to be retained in the *IESO adjustment account*;
 - b. direct that some or all of the credit balance be applied to special education projects or initiatives; and/or
 - c. direct that some or all of the balance be used to reduce the *IESO administration charge* in the following year.
- 6.18.7 The *IESO* shall open and maintain the *IESO prepayment account*, which *account* shall operate as follows:
- 6.18.7.1 the *IESO prepayment account* shall be a bank account established for *market participants* to deposit prepayments at an earlier date than the specified *market participant payment date*; and
 - 6.18.7.2 the arrangements for making the prepayment and transferring funds from the *IESO prepayment account* to the *IESO settlement clearing account* shall be in accordance with the provisions of section 6.11.2.
- 6.18.7A The *IESO* shall open and maintain the *TR clearing account*, which *account* shall operate in the manner described in sections 4.18 and 4.19 of Chapter 8.
- 6.18.8 Unless otherwise specified, the *IESO* shall recover all banking costs reasonably incurred in opening and operating the *IESO's settlement accounts* through the *IESO administration charge*.
- 6.18.9 The *IESO* shall maintain its *settlement accounts* at a bank or financial institution in the Province of Ontario approved by the *IESO Board*.

- 6.18.10 Each *transmitter* shall be required to open and maintain a *transmission services settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.
- 6.18.11 Each *transmitter* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *transmitter's transmission services settlement account*.
- 6.18.12 Each *market participant* shall be required to open and maintain a *market participant settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.
- 6.18.13 Each *market participant* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *market participant's market participant settlement account*.
- 6.18.14 [Intentionally left blank]
- 6.18.15 The *settlement accounts* referred to in this section 6.18 may be changed or closed as follows:
- 6.18.15.1 the *IESO* may change the bank or the details of any of its *settlement accounts*, on the condition that the bank or financial institution is reasonably acceptable to the *IESO Board* and that all *market participants* are notified by the *IESO* in writing at least 60 *business days* before the change takes effect; and
- 6.18.15.2 any *transmitter* or *market participant* may change its bank or the details of its *settlement account*, on the condition that the *IESO* is notified in writing at least 60 *business days* before the change takes effect.

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