Market Rules

Chapter 9

Settlements and Billing

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Public

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Table of Contents

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*, and *applicable law* including without limitation the Electricity Act, 1998, the Ontario Energy Board Act, 1998, and any regulations enacted thereunder including, but not limited to the following:

1.1.2.1 [Intentionally left blank – section deleted]

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 [Intentionally left blank – section deleted]

1.1.2.7 operating deviations;

1.1.2.8 *ancillary services* and *reliability must-run contracts*;

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

1.1.2.10 [Intentionally left blank – section deleted]

1.1.2.11 the *IESO* administration charge;

1.1.2.12 penalties and fines;

1.1.2.13 [Intentionally left blank – section deleted]

1.1.2.14 rebates and other payments arising from market power mitigation measures;

1.1.2.15 the day-ahead commitment process;

1.1.2.16 forecasting services relating to *variable generation*;

1.1.2.17 *capacity obligations*; and

1.1.2.18 ramp-down *settlement* amount.

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 *applicable law* including without limitation the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, and any regulations enacted thereunder, 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 *applicable law* including without limitation the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and any regulations enacted thereunder, 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;

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*;

2.1.1A.3 [Intentionally left blank – section deleted]

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;

2.1.1A.5 [Intentionally left blank – section deleted]

2.1.1A.6 the *IESO* is determining *settlement amounts* related to *capacity obligations* using measurement data submitted by *capacity market participants* with an *hourly demand response resource*.

2.1.2 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 [Intentionally left blank – section deleted]

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 [Intentionally left blank – section deleted]

2.1.6.1 [Intentionally left blank]

2.1.6.2 [Intentionally left blank]

2.1A Station Service

2.1A.1 The *market participant* responsible for registering 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 and submitted by the *market participant* responsible for registering the relevant *connection facility* in accordance with the equations and procedures described in the applicable *market manuals*, which estimate shall be stamped by a registered professional engineer and shall be subject to audit by the *IESO*.

2.1A.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*.

b. [Intentionally left blank – section deleted]

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 station service* and site specific losses to a *market participant* in respect of a *facility* that is an *embedded load facility,* an *embedded generation facility,* or an *embedded electricity storage facility.*

2.1A.6A Where the sum of *energy* associated with *connection station service* and with site specific losses is apportioned by the *IESO* pursuant to section 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, 7.3A, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4.

2.1A.7A Subject to section 2.1A.9A, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by an *electricity storage unit* passing through the *metering installation* net of all applicable *electricity storage station service*, the costs associated with *electricity storage station service* shall, for *settlement* purposes, be apportioned:

2.1A.7A.1 amongst those electricity storage units consuming such electricity storage station service in the proportions provided by the metering service provider for the relevant metering installation; or

2.1A.7A.2 where the *metering service provider* has not provided the proportions referred to in section 2.1A.7A.1, equally amongst all such *electricity storage 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, 7.3A, 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.9A If the consumption of *electricity storage station service* results in:

2.1A.9A.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 3.1.9, accruing at the location of an *electricity storage unit* which is part of an eligible *electricity storage facility* within the meaning of section 2.1A.13A in circumstances where the injection of *energy* by that *electricity storage facility* as a whole exceeds the withdrawal of *energy* by that *electricity storage facility* as a whole during a given *metering interval*; and

2.1A.9A.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 *electricity storage facility* shall, subject to section 2.1A.10, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.1A.9A.2.

2.1A.10 No reimbursement will be provided to a *metered market participant* pursuant to section 2.1A.9 or 2.1A.9A 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:

a. is prohibited by *applicable law* or the *market rules*; or

b. where the *settlement amount* is collected by the *IESO* pursuant to an obligation imposed upon it by *applicable law,* is not permitted by such *applicable law.*

2.1A.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. [Intentionally left blank – section deleted]

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.13A For the purposes of section 2.1A.9A.1, an *electricity storage facility* may be designated by the *IESO* as an eligible *electricity storage facility* where the *electricity storage facility*:

2.1A.13A.1 is comprised of two or more *registered facilities* that have the same metered market participant;

2.1A.13A.2 is located within the *IESO control area*; and

2.1A.13A.3 has associated with it *electricity storage station service* that serves more than one *registered facility* included within that *electricity storage facility*.

2.1A.14 The *IESO* shall recover any amount reimbursed pursuant to section 2.1A.9 or 2.1A.9A 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-scheduling generation facilities, self-scheduling electricity storage 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 *RWM*s, 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 and 11.1.6, respectively, of Chapter 6.

2.4 [Intentionally left blank – section deleted]

2.4.1 [Intentionally left blank – section deleted]

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 [Intentionally left blank – section deleted]

2.4.2.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]

2.4.2.2 [Intentionally left blank – section deleted]

2.4.3 [Intentionally left blank – section deleted]

2.4.3.1 [Intentionally left blank – section deleted]

2.4.3.2 [Intentionally left blank – section deleted]

2.4.4 [Intentionally left blank – section deleted]

2.4.5 [Intentionally left blank – section deleted]

2.4.5.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]
c. [Intentionally left blank – section deleted]
d. [Intentionally left blank – section deleted]

2.4.5.2 [Intentionally left blank – section deleted]

2.4.6 [Intentionally left blank – section deleted]

2.4.7 [Intentionally left blank – section deleted]

2.4.7.1 [Intentionally left blank – section deleted]

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2.4.8 [Intentionally left blank – section deleted]

2.4.9 [Intentionally left blank – section deleted]

2.4.9.1 [Intentionally left blank – section deleted]

2.4.9.2 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

2.4.10 [Intentionally left blank – section deleted]

2.4.11 [Intentionally left blank – section deleted]

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 *TR*s in respect of all rounds of a *TR auction* that is concluded on such *dispatch day*.

2.8 [Intentionally left blank – section deleted]

2.8.1 [Intentionally left blank – section deleted]

2.8.2 [Intentionally left blank – section deleted]

2.8.3 [Intentionally left blank – section deleted]

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 6.19, matters described in section 6.8.12.4, and/or a *dispute outcome*, but in no case for less than seven years.

2.11.2 The *IESO* shall periodically review the period for which *settlement* records are retained and shall, if required and subject to section 2.11.3, take such steps as may be required to effect a change in such period.

2.11.3 The period for which *settlement* records are retained shall comply with the requirements of any regulatory authority having jurisdiction over the *IESO* or *market participants*.

2.11.4 *Settlement* and supporting data for each *trading day* of a *billing period* shall be made available by direct electronic means to the relevant *market participant* as soon as 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 [Intentionally left blank – section deleted]

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 *delivery point* ‘m’

$DA\_SUC_{k,h}^{m}$ = as-offered *start-up cost* associated with *three-part offers* for a given *settlement hour* ‘h’ for *market participant* ‘k’ at *delivery point* ‘m’

$MLP_{k,h}^{m,t}$ = minimum output of *energy* the *market participant* ‘k’ at *delivery point* ‘m’ can maintain without ignition support in *metering interval* ‘t’ of *settlement hour* ‘h’

$OPCAP_{k,h}^{m,t}$ = de-rated *generation capacity* submitted by *market participant* ‘k’ at *delivery point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’

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:

$PD\_DQSI_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$PD\_DQSW_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

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

In instances where this variable is provided to the s*ettlement process* on an hourly basis as determined in section 3.9, it shall be deemed to apply uniformly to all *metering intervals* 't' in *settlement hour* 'h'

$PD\_ELMP_{h}^{m,t}$ = *pre-dispatch* constrained schedule *intertie* price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'

$PD\_ILMP_{h}^{m,t}$ = *pre-dispatch* constrained schedule *intertie* price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

3.1.2D 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 *market schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$MQSW_{k,h}^{m,t}$ = market quantity scheduled for withdrawal in the *market schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$DQSI_{k,h}^{m,t}$ = *dispatch* quantity scheduled for injection in the *real-time schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h' determined on the basis of the *dispatch instructions* issued to *market participant* 'k' for that *metering interval*

$DQSW_{k,h}^{m,t}$ = *dispatch* quantity scheduled for withdrawal in the *real-time schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h' determined on the basis of the *dispatch instructions* issued to *market participant* ‘k’ for that *metering interval*

$TMQSI_h^{m,t}$ = total market quantity scheduled for injection in the *market schedule* by all *market participant*s at location m or *intertie metering point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’

= $\sum_k MQSI_{k,h}^{m,t}$, with k = all *market participants*

$EMP_h^{m,t}$ = *energy market* price at *delivery point* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’

$ICP_h^{i,t}$ = where i $\in$ M such that M is the set of all *delivery points* ‘m’ and *intertie metering points* ‘m’

$EMP_h^{i,t}$ = *energy market price* at intertie *metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ‘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 *delivery point* while uniform pricing exists.

= where i $\in$ M such that M is the set of all *delivery points* ‘m’ and *intertie metering points* ‘m’.

$HOEP_h$ = hourly Ontario energy price in settlement hour ‘h’

= $\sum_{m,t} EMP_h^{m,t}/12$,
with t = all *metering intervals* in *settlement hour* ‘h’
m = all *primary RWM*s

$x_h^{m,t}$ = a *settlement* floor price for *energy* applicable to *intertie metering point* ‘m’ *metering interval* ‘t’ in *settlement hour* ‘h’, as set in the applicable *market manual*. The need for a *settlement* floor price other than *MMCP* shall remain in effect only until floor prices for *energy offers* from *registered market participants* that are *variable generators* or nuclear *generators* go into effect.

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 ∈ 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 ∈ 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 [Intentionally left blank – section deleted]

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* 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*, *self-scheduling electricity storage 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'

3.1.10 The *IESO* shall provide the following *capacity auction* information and provide them directly to the *settlement process*:

$CARC_k^m$ = the quantity of *energy* (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant 'k'* at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual*;

$CACP^z$ = the *capacity auction clearing price* (in \$/MW per day) for the relevant *trading day* in electrical zone 'z'.

$CACP^z_h$ = the *capacity auction clearing price* for *settlement hour* 'h' (in \$/MWh) within the *availability window* in electrical zone 'z', determined by taking the *capacity auction clearing price* for the applicable *obligation period* and electrical zone and dividing by the number of *settlement hours* within the *availability window* of the relevant *trading day* within the *obligation period.*

$CAEO^m_{h,k}$ = the quantity of *auction capacity* for *settlement hour* 'h' (in MW) made available by *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* of the *availability window* determined as the lesser of the *resource's energy offers* (in MW) submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable.

$CARC_k^m$ = the quantity (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant* 'k' at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual;*

$CBOC^{m}_{k}$ = the buy-out capacity is an amount (in MW) by which the *capacity obligation* for the *obligation period* for *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' is being reduced as per the *capacity market participant's* election pursuant to section 4.7J.3 of Chapter 9.

$CCO^{m}_{k,h}$ = the *capacity obligation* (in MW) for the *obligation period* per *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* 'h', as may be adjusted pursuant to the *market rules*.

$CICAP^{m}_{k}$ = the *cleared ICAP* (in MW) for *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, as determined in accordance with the applicable *market manual*.

$CNPF_{tm}$ = for a given *energy market billing period* 'tm', the non-performance factor as listed in Section 7.1 of Market Manual 12.

$DREBQ^{m}_{k,h}$ = the quantity (in MW) of *auction capacity* made available by an *hourly demand response resource* or *capacity dispatchable load resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' of the *availability window*, determined as the lesser of the *resource's energy bids* submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable, and where such value exceeds the $CARC_{k}^{m}$ for the *resource* in the relevant *energy market billing period*, the $DREBQ^{m}_{k,h}$ shall equal such $CARC_{k}^{m}$.

$DRSQty^{m}_{k,h}$ = the quantity of *energy* (in MW) scheduled for withdrawal in the *real-time market* by *market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' of the *availability window*, as described in all *real-time schedules* for such *settlement hour*.

$HDRBP^{m}_{k,h}$ = the price component (in $/MWh) of the *energy bid* submitted in the *real time market* for *hourly demand response resource* by *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' within the *availability window.*

$HDRDC^{m}_{k,h}$ = the delivered capacity (in MWh) by *hourly demand response resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' within the *activation window* of the applicable test activation, calculated as follows:

$$\mathrm{Min}(\mathrm{Curtailed\ MW}^{m}{}_{k,h}\,, \sum_{t=1}^{12}(\frac{\mathrm{Min}(\mathrm{TBQ}^{m}{}_{k,h}, \mathrm{CARC}_{k^{m}}, \mathrm{CCO}^{m}{}_{k,\mathrm{h}})}{12}) - DQSW^{m,t}_{k,h})$$

Where:

(a) "Curtailed $MW^{m}_{k,h}$" is the difference (in MWh) between baseline value, calculated in accordance with the applicable *market manual*, and actual consumption measurement data by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as calculated in accordance with the applicable *market manual*.

(b) "$TBQ^{m}_{k,h}$" is the offered quantity of *energy* (in MW) contained in the last lamination of the *price quantity pair* of the *energy bid* submitted in the *real time market* by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h'.

HDRTAPR = the out of market test activation rate (in $/MWh), as set out in the applicable *market manual.*

$OCMW^{i}_{k}$ = the *over committed capacity* (in MW) of a *generator-backed capacity import resource* for *capacity market participant* 'k' at *intertie metering point* 'i', as determined by the *IESO*.

RAC^{m}_{k} = the available capacity (in MW) of a *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, and is determined in accordance with the following:

(a) For *capacity dispatchable load resources* and *hourly demand response resources*:

$RAC^{m}_{k} = MIN(DREBQ^{m}_{k,h}, (1.15* CCO^{m}_{k,h}), CICAP^{m}_{k}, CARC_{k}^{m})$

Where:

(i) $CARC_k^m$ is only applicable to *virtual hourly demand response resources*

(b) For *capacity generation resources*, *system-backed capacity import resources*, *generator-backed capacity import resources* and *capacity storage resources*:

$$RAC^m_k = MIN(CAEO^m_{h,k}, (1.15^* \ CCO^m_{k,h}), CICAP^m_k)$$

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 [Intentionally left blank – section deleted]

3.2.1 [Intentionally left blank – section deleted]

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 an *intertie metering point* associated with:

- an injecting boundary entity;
- a withdrawing *boundary entity* where the associated *intertie congestion price* is less than zero; or,
- a withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7 section 3.5.8.2:

$$NEMSC_{k,h} = \Sigma_{t,m} \left(EMP_h^{m,t} \times \left((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) + \Sigma_{s,b} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t})\right)\right)$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *RWMs* relating to a *dispatchable facility* and all *intertie metering points* associated with: i) any injecting *boundary entities*; ii) any withdrawing *boundary entities* where the associated *intertie congestion price* is less than zero; and, iii) any withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7 section 3.5.8.2

s = all *selling market participants*

b= all *buying market participants*

and

3.3.2.1A in respect of an *intertie metering point* associated with a withdrawing *boundary entity* where that *intertie congestion price* is not less than zero:

$$NEMSC_{k,h} = \Sigma_{t,m} \left((MAX\ (x_h^{m,t}, EMP_h^{m,t})) \times AQEW_{k,h}^{m,t}\right)$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *intertie metering points* where the *intertie congestion price* is not less than zero

and

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

$$NEMSC_{k,h} = HOEP_h \times \Sigma_{t,m} (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \Sigma_s BCQ_{s,k,h}^{m,t}) - \Sigma_{n,b,t} (EMP_h^{n,t} \times BCQ_{k,b,h}^{n,t})$$

where:

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

n = all *RWMs* and *intertie metering point*s

s = all *selling market participant*s

b= all *buying market participants*

t = all *metering interval*s in *settlement hour* 'h'

3.3.3 [Intentionally left blank]

3.4 Hourly Settlement Amounts for Operating Reserve and Charges

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:

$$ORSC_{k,h} = \sum_{m,t,r} PROR_{r,h}^{m,t} \times AQOR_{r,k,h}^{m,t}$$

where:

m = all *primary RWMs* and *intertie metering points*

t = all *metering intervals* in *settlement hour* 'h'

r1 = 10-minute spinning *operating reserve*

r2 = 10-minute non-spinning *operating reserve;* and

r3 = 30-minute *operating reserve*.

3.4.2 The *IESO* shall apply the non-accessibility charge specified in section 7.4.2.1 of Chapter 7, and a *market participant* shall be subject to such non-accessibility charge, for every *dispatch interval* where the *market participant* is scheduled to provide *operating reserve* but was not dispatched to increase *energy generation* or reduce energy withdrawal pursuant to section 7.4.3 Chapter 7, and where the total scheduled *operating reserve* is greater than the total accessible *operating reserve* as determined by:

$$\sum_R AQOR_{rn,k,h}^{m,t} > TAOR_{k,h}^{m,t} \text{ and } \sum_R AQOR_{rn,k,h}^{m,t} > 0$$

Where:

R: is the set of all classes of *operating reserve*

For *operating reserve* provided by a *dispatchable load*:

$$\mathrm{TAOR}_{k,h}^{m,t}=\mathrm{Max}\left(0,\mathrm{AQEW}_{k,h}^{m,t}-\mathrm{MC}_{m}^{h,t}\right)$$

$MC_{m}^{h,t}$ = minimum consumption level and is equal to the quantity in the *price-quantity pair* where the *bid* price is *MMCP*

For *operating reserve* provided by a *generator* other than aggregated *facilities*:

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

$MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch* scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each *dispatch interval*

3.4.2.1 Where *operating reserve* is scheduled to be provided by aggregated *facilities,* a *market participant* shall be subject to a non-accessibility charge for every *dispatch interval* where the *market participant* is scheduled to provide *operating reserve* but was not dispatched to increase *energy generation* pursuant to section 7.4.3 of Chapter 7, and where the total scheduled *operating reserve* is greater than the total accessible *operating reserve* as determined by:

$$\sum_{R}^{M} AQOR_{rn,k,h}^{m,t} > TAOR\_CA_{k,h}^{M,t}, \text{ and } \sum_{R}^{M} AQOR_{rn,k,h}^{m,t} > 0$$

Where:

R: is the set of all classes of *operating reserve*

M: is set of all *delivery points* 'm' that are compliance aggregated

Total accessible *operating reserve* (TAOR) for aggregated *generators:*

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

$MAX\_CAP_{k,h}^{m,t}$= the maximum limit used in determining the *real-time schedule* in the *dispatch* scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each *dispatch interval*

3.4.3 Where it is determined that a non-accessibility charge is to be applied to a *market participant* pursuant to section 3.4.2, the non-accessibility charge shall be calculated for each class of *operating reserve* as follows:

For synchronized *ten-minute operating reserve*:

$$ORSCB_{r1,k,h}^{m,t}=Min\left(0,\left(TAOR_{k,h}^{m,t}\text{-}AQOR_{r1,k,h}^{m,t}\right)\times PROR_{r1,h}^{m,t}\right)$$

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

$$ORSCB_{r2,k,h}^{m,t}=Min\left(0,\left(Max\left(0,TAOR_{k,h}^{m,t}\text{-}AQOR_{r1,k,h}^{m,t}\right)\text{-}AQOR_{r2,k,h}^{m,t}\right)\times PROR_{r2,h}^{m,t}\right)$$

For *thirty-minute operating reserve*:

$$ORSCB_{r3,k,h}^{m,t}=Min\left(0,\left(Max\left(0,TAOR_{k,h}^{m,t}\text{-}AQOR_{r1,k,h}^{m,t}\text{-}AQOR_{r2,k,h}^{m,t}\right)\text{-}AQOR_{r3,k,h}^{m,t}\right)\times PROR_{r3,h}^{m,t}\right)$$

Where:

$AQOR_{rn,k,h}^{m,t}$: Allocated quantity in MW of *class r reserve* for *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h';

$PROR_{rn,h}^{m,t}$: *Market price* in $/MW of *class r reserve* in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm';

r1 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

r2 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

r3 denotes *thirty-minute operating reserve*.

3.4.3.1 Where it is determined that a non-accessibility charge is to be applied to a *market participant* pursuant to section 3.4.2.1, the amount of nonaccessible *operating reserve* shall be determined for each class of *operating reserve* as follows:

For aggregated *generators* scheduled to provide synchronized *ten-minute operating reserve*:

$$\mathrm{ORIA\_CA}^{\mathrm{M,t}}_{\mathrm{r1,k,h}} = \mathrm{Min}\left(0, \mathrm{TAOR\_CA}^{\mathrm{M,t}}_{\mathrm{k,h}} - \sum^{\mathrm{M}} \mathrm{AQOR}^{\mathrm{m,t}}_{\mathrm{r1,k,h}}\right)$$

For aggregated *generators* scheduled to provide non-synchronized *ten-minute operating reserve*:

$$ORIA\_CA^{M,t}_{r2,k,h} = Min\left(0, Max\left(0, TAOR\_CA^{M,t}_{k,h} - \sum^{M} AQOR^{m,t}_{r1,k,h}\right) - \sum^{M} AQOR^{m,t}_{r2,k,h}\right)$$

For aggregated *generators* scheduled to provide *thirty-minute operating reserve*:

$$ORIA\_CA^{M,t}_{r3,k,h} = Min\left(0, Max\left(0, TAOR\_CA^{M,t}_{k,h} - \sum^{M} AQOR^{m,t}_{r1,k,h} - \sum^{M} AQOR^{m,t}_{r2,k,h}\right) - \sum^{M} AQOR^{m,t}_{r3,k,h}\right)$$

Where:

$AQOR^{m,t}_{rn,k,h}$: Allocated quantity in MW of *class r reserve* for *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h';

r1 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

r2 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

r3 denotes *thirty-minute operating reserve*.

3.4.3.2 The non-accessibility charge calculated pursuant to section 3.4.2.1 will be divided among individual aggregate *facilities* on a pro-rated based on the percentage of total inaccessible *operating reserve* attributed to it as determined as follows:

$$\mathrm{ORCF}_{\mathrm{rn,k,h}}^{\mathrm{m,t}} = \frac{\mathrm{ORIA}_{\mathrm{rn,k,h}}^{\mathrm{m,t}}}{\sum^{\mathrm{M1}} \mathrm{ORIA}_{\mathrm{rn,k,h}}^{\mathrm{m,t}}}$$

M1: is the set of delivery point 'm' where a resource has operating reserve scheduled for OR class 'rn'.

For synchronized *ten-minute operating reserve*:

$$\mathrm{ORIA}_{\mathrm{r1,k,h}}^{\mathrm{m,t}} = \mathrm{Min}\left(0, \left(\mathrm{TAOR}_{\mathrm{k,h}}^{\mathrm{m,t}} - \mathrm{AQOR}_{\mathrm{r1,k,h}}^{\mathrm{m,t}}\right)\right)$$

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

$$\mathrm{ORIA}_{\mathrm{r2,k,h}}^{\mathrm{m,t}} = \mathrm{Min}\left(0, \left(\mathrm{Max}\left(0, \mathrm{TAOR}_{\mathrm{k,h}}^{\mathrm{m,t}} - \mathrm{AQOR}_{\mathrm{r1,k,h}}^{\mathrm{m,t}}\right) - \mathrm{AQOR}_{\mathrm{r2,k,h}}^{\mathrm{m,t}}\right)\right)$$

For *thirty-minute operating reserve*:

$$\mathrm{ORIA}_{\mathrm{r3,k,h}}^{\mathrm{m,t}} = \mathrm{Min}\left(0, \left(\mathrm{Max}\left(0, \mathrm{TAOR}_{\mathrm{k,h}}^{\mathrm{m,t}} - \mathrm{AQOR}_{\mathrm{r1,k,h}}^{\mathrm{m,t}} - \mathrm{AQOR}_{\mathrm{r2,k,h}}^{\mathrm{m,t}}\right) - \mathrm{AQOR}_{\mathrm{r3,k,h}}^{\mathrm{m,t}}\right)\right)$$

Where:

Total inaccessible *operating reserve* for *generators:*

$$\mathrm{ORIA}_{\mathrm{rn,k,h}}^{\mathrm{m,t}} = \mathrm{Min}\left(0, \mathrm{TAOR}_{\mathrm{k,h}}^{\mathrm{m,t}} - \sum_{\mathrm{R}} \mathrm{AQOR}_{\mathrm{rn,k,h}}^{\mathrm{m,t}}\right)$$

Total accessible *operating reserve* for *generators*:

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

3.4.3.3 The non-accessibility charge calculated pursuant to section 3.4.3.2 will be calculated for an individual aggregate *facility* as follows:

$$\mathrm{ORSCB}_{\mathrm{rn,k,h}}^{\mathrm{m,t}} = \mathrm{ORIA\_CA}_{\mathrm{rn,k,h}}^{\mathrm{M,t}} \times \mathrm{ORCF}_{\mathrm{rn,k,h}}^{\mathrm{m,t}} \times \mathrm{PROR}_{\mathrm{rn,h}}^{\mathrm{m,t}}$$

Where:

$PROR_{rn,h}^{m,t}$: *Market price* in $/MW of *class r reserve* in *metering interval* 't' of *settlement hour* 'h' at *RWM* 'm'.

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* or an *electricity storage facility* withdrawing *energy* 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* or an *electricity storage facility* withdrawing energy, 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 locaton for any *metering interval* falling within *settlement hour* 'h'.

3.5.1E For the purpose of calculating congestion management *settlement* credits for *variable generators* that are *registered market participants*:

3.5.1E.1 if the *registered facility* is required to follow *dispatch instructions* issued by the *IESO* for any given *dispatch intervals,* the corresponding congestion management *settlement* credits for those *dispatch intervals* shall be calculated using the *market schedule* quantity determined in accordance with section 6.4.2.9A of Chapter 7; and

3.5.1E.2 except as noted in section 3.5.1F, the *market participant* shall not be eligible for congestion management *settlement* credits in *dispatch intervals* where the *registered facility* is issued a *release notification* by the *IESO* in accordance with section 7.1, which remains in effect for any *dispatch interval*.

3.5.1F For the purpose of calculating congestion management *settlement* credits for *variable generators* that are *registered market participants,* if the *registered facility* is subject to a *release notification* for a given *dispatch interval*, and for that *dispatch interval* the *registered facility's* $MQSI_{k,h}^{m,t}$ is less than the corresponding $DQSI_{k,h}^{m,t}$ for the same *dispatch interval* as a result of the *market participant's energy offers* being partially or fully uneconomic in the unconstrained schedule relative to the constrained schedule, the congestion management *settlement* credits for that *dispatch interval* shall be calculated pursuant to section 3.5.2A using the difference between the operating profit based on the *market schedule* quantity $MQSI_{k,h}^{m,t}$ determined in accordance with section 6.4.2.9B of Chapter 7 and the operating profit calculated based on the allocated quantity of *energy* injected (AQEI) for the same *dispatch interval*.

3.5.1G A *registered market participant* for a *registered facility* that is a *dispatchable generation facility* or an *electricity storage facility* injecting *energy*, shall not be entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 for any *dispatch interval 't'* within *settlement hour* 'h' where:

3.5.1G.1 the registered facility is not a quick-start facility;

3.5.1G.2 the *IESO* has identified the *dispatch interval* as part of consecutive

ramp-down *dispatch intervals* resulting in the shutdown of the *registered facility,* including those where the *registered facility* does not fully or accurately respond to its *dispatch instructions*, in accordance with the applicable *market manual*; and

3.5.1G.3 the *registered facility's* $MQSI_{k,h}^{m,t}$ is less than the corresponding

$DQSI_{k,h}^{m,t}$ for the same *dispatch interval*.

A *registered facility* subject to the withholding or recovery of a congestion management *settlement* credit for a *dispatch interval* under this section shall receive a ramp-down *settlement* amount for the applicable *dispatch interval* in accordance with section 3.5A.

3.5.2 Subject to sections 3.5.1A, 3.5.1D, 3.5.1E, 3.5.1F, 3.5.1G, 3.5.6, 3.5.6A, 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6F, 3.5.6G, 3.5.9, 3.5.10 and 3.5.11 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* or an *electricity storage facility* 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:

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

Where:

MAX[X,Y] = 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:

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

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* or an *electricity storage facility* 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:

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

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.

3.5.2A For purposes of section 3.5.1F, for *variable generators* that are *registered market participants*, the $OPE_{k,h}$ equation in section 3.5.2 shall be calculated as follows:

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

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 $MQSI_{k,h}^{m,t}$ is not equal to $DQSI_{k,h}^{m,t}$ as a result of such a *constrained off event*;

3.5.4.2 $MQSW_{k,h}^{m,t}$ is not equal to $DQSW_{k,h}^{m,t}$ as a result of such a *constrained off event*; or

3.5.4.3 $SQROR_{r,k,h}^{m,t}$ is not equal to $DQSR_{r,k,h}^{m,t}$ 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 6.5.4.1 and 6.5.4.3.

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,* an injecting *electricity storage 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* or a withdrawing *electricity storage facility*;

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 or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, 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 or ramp-down *settlement* amount in accordance with section 3.5.6E.

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

- is unable to comply with a *dispatch instruction* under section7.5.3 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 or the dispatchable electricity storage facility that can inject* to prevent endangering the safety of any person, equipment damage, or violation of 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 or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, resulting from the above actions for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount 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 or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, associated with that *offer* price for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6E The *IESO* may recover congestion management *settlement* credits or ramp-down *settlement* amounts in accordance with sections 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6G and Section 21.5 of Chapter 7. In this situation, the *IESO* shall:

- notify the *market participant* of its intent to recover that *congestion management settlement credit* or ramp-down *settlement amount*; 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 or ramp-down *settlement* amount 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 or ramp-down *settlement* amount 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.

3.5.6F Where the *energy market price* for the applicable *dispatch interval* is less than zero, 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:

3.5.6F.1 is associated with a withdrawing *boundary entity* at an *intertie* that is not import congested; and

3.5.6F.2 is greater than the *energy market price* in the applicable *intertie zone* for the applicable *dispatch interval;*

to the prices determined by the *IESO* in accordance with the applicable *market manual*.

3.5.6G A *registered market participant* for a *registered facility* that is a *dispatchable load*, or a dispatchable *electricity storage facility* that can withdraw, 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 load facility* or the dispatchable *electricity storage facility* that can withdraw to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law;*

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.

3.5.7 [Intentionally left blank – section deleted]

3.5.7A A *registered market participant* for a *constrained on generation unit* 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.

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 or ramp-down *settlement* amounts 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 or ramp-down *settlement* amounts 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.*

3.5.10 In accordance with the applicable *market manual*, a *market participant* shall not be entitled to any congestion management *settlement* credits determined in accordance with section 3.5.2 and attributable to a *constrained off event* associated with an *energy* offer or an *energy* bid from a *boundary entity* for an injection into or withdrawal from the *IESO-controlled grid,* where the *constrained off event* appears in the *pre-dispatch schedule* identified in section 6.1.3 of Chapter 7. 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.

3.5.11 A *market participant* shall not be eligible for any congestion management *settlement* credit payments in respect of an *energy* bid from a *boundary entity* for a *called capacity export*. The *IESO* may withhold or recover any congestion management *settlement* credits paid in respect of *called capacity exports* and shall redistribute any recovered payments in accordance with section 4.8.2.

3.5A Hourly Settlement Amounts for Ramp-Down

3.5A.1 Subject to section 3.5A.2, the ramp-down *settlement* amount for any *dispatch interval* ‘t’ identified in section 3.5.1G for market *participant* ‘k’ within *settlement hour* ‘h’(“$RDSA_{k,h}$”) shall be the lesser of:

- the congestion management *settlement* credit for *dispatch interval* ‘t’ which was withheld or recovered under section 3.5.1G; and
- the ramp-down compensation (“$RDC_{k,h}^{m,t}$”) as determined by the following equation:

Let ‘BE’ be a matrix of n *price-quantity pairs* offered by *market participant* ‘k’ to supply *energy* during the *settlement hour* immediately before the hour in which ramp-down begins, adjusted by a factor as specified in the applicable *market manual*.

Let OP(P,Q,B) be a 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 BE such that $Q_{s*} \leq Q \leq Q_n$ and where, $Q_0=0$

Using the terms below, let $RDC_{k,h}^{m,t}$ be expressed as follows:

$$RDC_{k,h}m,t = MAX\left[0,\begin{bmatrix} OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \\ MAX\left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right)\end{bmatrix}\right]$$

3.5A.2 The *IESO* may recover the hourly ramp-down *settlement* amount determined in accordance with section 3.5A.1 pursuant to sections 3.5.6B, 3.5.6C, 3.5.6D and 3.5.6E, as applicable.

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:

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

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:

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

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 [Intentionally left blank – section deleted]

3.7.1 [Intentionally left blank – section deleted]

3.7.2 [Intentionally left blank – section deleted]

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* 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 1or 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' ("$ORESF_{k,r,h}^{m,t}$") is defined as follows:

where *operating reserve* is provided from a *generator,* or from an *electricity storage participant* injecting *energy* :

$$ORESF_{k,r,h}^{m,t} = MAX\,[(SE_{k,h}^{m,t} – AQEI_{k,h}^{m,t})/SE_{k,h}^{m,t}, 0]$$

where *operating reserve* is provided from a *dispatchable load* or from an *electricity storage participant* withdrawing *energy*:

$$ORESF_{k,r,h}^{m,t} = MAX\,[(AQEW_{k,h}^{m,t} – SE_{k,h}^{m,t}) / AQEW_{k,h}^{m,t}, 0]$$

in either of the above cases:

$ORESF_{k,r,h}^{m,t}$ 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. $ORESF_{k,r,h}^{m,t}$ 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 $\sum_{T,H} ORRSC_{k,r,H}^{m,T}$ = 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 $ORESF_{k,r,h}^{m,t}$ that exceeded the value referred to in section 3.8.2.4,
$ORSSD_{k,r,h} = \sum_{m,t} [ORESF_{k,r,h}^{m,t} \times \sum_{T,H} (ORRSC_{k,r,H}^{m,T})]$; or

b. in all other cases,
$$ORSSD_{k,r,h} = \sum_{m,t} [ORESF_{k,r,h}^{m,t} \times \sum_{T,H} (ORRSC_{k,r,H}^{m,T})/2]$$

where:

t = all *metering interval*s 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 $Q_{s^*} \le Q \le Q_n$ 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:

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

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’ (“$DA\_IOG_{k,h}$”) 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’ (“$DA\_IOG_{k,h}$”) 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:

$$DA\_IOG_{k,h} = MAX\left[0, \sum_{T}\left(DA\_IOG\_COMP1_{k,h}^{i,t} + DA\_IOG\_COMP2_{k,h}^{i,t} - DA\_IOG\_COMP3_{k,h}^{i,t}\right)\right]$$

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:

$DA\_IOG\_COMP1_{k,h}^{i,t}$ = As-offered day-ahead costs for the minimum of the importer's *schedule of record* and the real-time constrained schedule for the interval minus all real-time revenue received over the interval for that amount of *energy*

$$DA\_IOG\_COMP1_{k,h}^{i,t} = (-1)\times OP\left(EMP_{h}^{i,t}, MIN\left(DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}\right), DA\_BE_{k,h}^{i,t}\right)$$

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:

$DA\_IOG\_COMP2_{k,h}^{i,t}$ = As-offered day-ahead costs for the difference between:

- the minimum of the importer's *schedule of record* quantity, or the real-time constrained schedule; and
- the minimum of the importer's *schedule of record* quantity.

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

$$DA\_IOG\_COMP2_{k,h}^{i,t} = XDA\_BE_{k,h}^{i,t} - MAX\left(0, XBE_{k,h}^{i,t}\right)$$

Where:

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

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

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

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

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* = the highest indexed row of matrix $XDA\_BE_{k,h}^{i,t}$ such that $Q_{c*} \leq \min[DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t},] \leq Q_n$ and where $Q_{c*-1} = \min[DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}]$ and where if $Q_{c*} < Q_{c*-1}$, let $Q_{c*} = Q_{c*-1}$

d* = the highest indexed row of matrix XDA_BEk,hi,t such that Qd* ≤ DA_DQSIk,hi,t ≤ Qn

p* = the highest indexed row of matrix XBEk,hi,t such that Qp* ≤ min[DA_DQSIk,hi,t, DQSIk,hi,t] ≤ Qn and where Qp*-1 = min[DA_DQSIk,hi,t, DQSIk,hi,t] and where if Qp* < Qp*-1, let Qp* = Qp*-1

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 o*ffer 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 :

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = Income received from real time congestion management *settlement* credits (CMSC) for the importer's *schedule of record* 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

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = 0

Scenario 2

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = 0

Scenario 3

$$DA\_IOG\_COMP3_{k,h}^{i,t} = OP\left(EMP_{h}^{i,t}, MQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - OP\left(EMP_{h}^{i,t}, DA\_DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right)$$

Scenario 4

$$DA\_IOG\_COMP3_{k,h}^{i,t} = OP\left(EMP_{h}^{i,t}, DA\_DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - OP\left(EMP_{h}^{i,t}, DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right)$$

Scenario 5

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Scenario 6

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = 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; and

where the export transaction of such *energy bid* is settled at the *energy market* price at the *intertie metering point* and not a *settlement* floor price as set out in section 3.3.2.1A.

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 $MI_{k,h}^{t}$ [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] {$DA\_IOG\_RATE_{k,h}^{i}$}=

	$DA\_IOG_{k,h}^{i}$ / $MIN(DA\_DQSI_{k,h}^{i}, DQSI_{k,h}^{i})$
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] { $DA\_OFFSET\_FLAG_{k,h}^{i}$ } = "Y" or "N" Such that: $DA\_OFFSET\_FLAG_{k,h}^{i}$ = "Y" when {$DA\_OFFSET\_DQSW_{k,h}^{i}$}> 50% of $MIN\{DA\_DQSI_{k,h}^{i}, DQSI_{k,h}^{i}\}$
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 $DA\_OFFSET\_FLAG_{k,h}^{i}$ = "Y" ; OR $MI_{k,h}^{i}$ [n,9] {$IOG\_SETTLEMENT\_RATE_{k,h}^{i}$} = $MAX[DA\_IOG\_RATE_{k,h}^{i}, RT\_IOG\_RATE_{k,h}^{i}]$ if $DA\_OFFSET\_FLAG_{k,h}^{i}$ = "N"; 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
Matrix $MI_{k,h}$ [Row 'n', Column 10]	$MI_{k,h}^{i}$ [n,10] {$IOG\$_{k,h}^{i}$} = 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 $MAX(DA\_IOG\_RATE_{k,h}^{i}, RT\_IOG\_RATE_{k,h}^{i})$)
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]	{$DA\_OFFSET\_DQSW_{k,h}^{i}$} = 0	{$DA\_OFFSET\_DQSW_{k,h}^{i}$} > 0	NULL	{$DA\_OFFSET\_DQSW_{k,h}^{i}$} >= 0

	A	B	C	D
Matrix $MI_{k,h}$ [Row 'n', Column 8]	{DA_OFFSET_FLAG$_{k,h}^{i}$ } = "N"	{DA_OFFSET_FLAG$_{k,h}^{i}$ } = "Y"	NULL	{DA_OFFSET_FLAG$_{k,h}^{i}$ } = "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$_{k,h}^{i}$, 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_DQSW $_{k,h}^{i}$ } >= 0	NULL	$MI_{k,h}$ [n,11] {RT_OFFSET_DQSW $_{k,h}^{i}$ } >= 0	$MI_{k,h}$ [n,11] {RT_OFFSET_DQSW $_{k,h}^{i}$ } >= 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:

$DA\_IOG\ RATE_{k,h}^{i}$	=	$IF\left[DA\_IOG_{k,h}^{i} \text{ is not NULL}, \frac{DA\_IOG_{k,h}^{i}}{MIN(DA\_DQSI_{k,h}^{i}, DQSI_{k,h}^{i})}, 0\right]$

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:

$RT\_IOG\ RATE_{k,h}^{i}$	=	$IF\left[RT\_IOG_{k,h}^{i} \text{ is not NULL}, \frac{RT\_IOG_{k,h}^{i}}{DQSI_{k,h}^{i}}, 0\right]$

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:

$DA\_DQSW\_REM_{k,h}$	=	$\left[MAX\left[0, \left(\sum^{I} DA\_DQSW_{k,h}^{I} - \sum_{i=1}^{n} DA\_OFFSET\_DQSW_{k,h}^{i}\right)\right]\right]$

$DA\_OFFSET\_DQSW_{k,h}^{i}$	=	$MIN\left[DA\_DQSI_{k,h}^{i}, DQSI_{k,h}^{i}, DA\_DQSW\_REM_{k,h}\right]$

Where:

I = set of all *intertie metering points* '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:

$\text{DA\_OFFSET\_FLAG}_{k,h}^{i}$	=	$\text{IF}\left(\text{DA\_OFFSET\_DQSW}_{k,h}^{i} > [50\% \times \text{MIN}\left(\text{DA\_DQSI}_{k,h}^{i}, \text{DQSI}_{k,h}^{i}\right)], \text{Y}, \text{N}\right)$

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:

$\text{IOG\_SETTLEMENT\_RATE}_{k,h}^{i}$	=	$\text{IF}\left[\text{DA\_OFFSET\_FLAG}_{k,h}^{i}=\text{Y}, \text{RT\_IOG\_RATE}_{k,h}^{i}, \text{MAX}(\text{RT\_IOG\_RATE}_{k,h}^{i}, \text{DA\_IOG\_RATE}_{k,h}^{i})\right]$
		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:

$RT\_DQSW\_REM_{k,h}$	=	$\left[MAX\left[0,\left(\sum^{I} DQSW^{i}_{k,h} - \sum_{i=1}^{n} RT\_OFFSET\_DQSW^{i}_{k,h}\right)\right]\right]$

$RT\_OFFSET\_DQSW_{k,h}{}^{i}$	=	$MIN\left[DQSI^{i}_{k,h}, RT\_DQSW\_REM_{k,h}\right]$

Where:

I = set of all *intertie metering points* ‘i’

n = The number of day ahead import transactions with DA_OFFSET_DQSW 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:

$IOG\_OFFSET_{k,h}{}^{i}$	=	$\left(IOG\_SETTLEMENT\_RATE^{i}_{k,h} \times RT\_OFFSET\_DQSW^{i}_{k,h}\right)$

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 column10 ($IOG\$_{k,h}{}^{i}$) and column 12 ($IOG\_OFFSET_{k,h}{}^{i}$) as follows:

$NET\_IOG_{k,h}{}^{i}$	=	$\left(IOG\$^{i}_{k,h} - IOG\_OFFSET^{i}_{k,h}\right)$

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:

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

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:

DA import scheduling deviation quantity ($DA\_ISD_{k,h}^{i,t}$)	=	MAX (day-ahead import transaction quantity – pre-dispatch import transaction quantity, 0)
$DA\_ISD_{k,h}^{i,t}$	=	MAX ($DA\_DQSI_{k,h}^{i,t} – PD\_DQSI_{k,h}^{i,t}$, 0) 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 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 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:

$DA\_IFC_{k,h}$ = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x MINIMUM of:

[MAXIMUM of:

[[The sum of all revenues implied by each import transaction valued at the *pre-dispatch energy market price* in the Ontario zone for the difference in quantity 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)]]

$DA\_IFC_{k,h}$ =

$$\sum_{I,T}(-1)\times MIN\Big[MAX\Big(0,OP\big(PD\_EMP_{h}^{m,t},DA\_DQSI_{k,h}^{i,t},DA\_BE_{k,h}^{i,t}\big)-OP\big(PD\_EMP_{h}^{m,t},PD\_DQSI_{k,h}^{i,t},DA\_BE_{k,h}^{i,t}\big),$$

$$MAX\big(0,XPD\_BE_{k,h}^{i,t}-XDA\_BE_{k,h}^{i,t}\big),\big(MAX(0,PD\_EMP_{h}^{m,t})\times DA\_ISD_{k,h}^{i,t}\big)\Big]$$

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:

Real-time Import Scheduling Deviation Quantity	=	MAX (*pre-dispatch* import transaction quantity – real-time import transaction quantity, 0)
$RT\_ISD_{k,h}^{i,t}$	=	$MAX (PD\_DQSI_{k,h}^{i,t} - DQSI_{k,h}^{i,t}, 0)$

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:

$RT\_IFC_{k,h}$ = For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between: the real-time *energy 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]

$$RT\_IFC_{k,h} = \sum^{I,T} (-1) \times MIN\left[MAX\left[0, (EMP_h^{m,t} + PB\_IM_h^{t} - PD\_EMP_h^{m,t}) \times RT\_ISD_{k,h}^{i,t}\right], MAX(0, EMP_h^{m,t}) \times RT\_ISD_{k,h}^{i,t}\right]$$

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’;

$PB\_IM_h^t$ 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]

$$RT\_EFC_{k,h} = \sum^{I,T}(-1) \times MIN\left[MAX\left[0,(PD\_EMP_h^{m,t} - EMP_h^{m,t} - PB\_EX_h^{t}) \times RT\_ESD_{k,h}^{i,t}\right], MAX(0,PD\_EMP_h^{m,t}) \times RT\_ESD_{k,h}^{i,t}\right]$$

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 [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 e*ach *price quantity pair* where offered price*s 'P' are i*n 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*	=	the highest indexed row of matrix $XDA\_BL_{k,h}^{i,t}$ such that $Q_{c^*} \leq PD\_DQSW_{k,h}^{i,t} \leq Q_n$ and where $Q_{c^*-1} = PD\_DQSW_{k,h}^{i,t}$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$
d*	=	the highest indexed row of matrix $XDA\_BL_{k,h}^{i,t}$ such that $Q_{d^*} \leq DA\_DQSW_{k,h}^{i,t} \leq Q_n$

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

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:

$DA\_EFC_{k,h}$ = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x MINIMUM of:

[MAXIMUM of:

[-1 x [The sum of all revenues implied by each export transaction valued at the *pre-dispatch energy market price* in the Ontario zone for the difference in quantity scheduled in pre-dispatch and the quantity scheduled in the *schedule of record*.

Minus:

Those costs represented through the *offers* for the export transaction scheduled in the *schedule of record*]

or zero],

[MAXIMUM of:

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

or zero]

MAXIMUM of (zero or the day-ahead *bid* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*)]

$DA\_EFC_{k,h}$ =

$$\sum_{I,T}(-1) \times \text{MIN}\Big[\text{MAX}\Big(0,(-1) \times \text{OP}\big(\text{PD\_EMP}_h^{m,t}, \text{DA\_DQSW}_{k,h}^{i,t}, \text{DA\_BL}_{k,h}^{i,t}\big) - (-1) \times \text{OP}\big(\text{PD\_EMP}_h^{m,t}, \text{PD\_DQSW}_{k,h}^{i,t}, \text{DA\_BL}_{k,h}^{i,t}\big)\Big), \text{MAX}\big(0, \text{XDA\_BL}_{k,h}^{i,t} - \text{XPD\_BL}_{k,h}^{i,t}\big), \text{MAX}\big(0, \text{XDA\_BL}_{k,h}^{i,t}\big)\Big]$$

Where:

$DA\_BL_{k,h}^{i,t}$ 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 e*ach *price quantity pair* where offered prices *‘P’ are i*n column 1 and offered quantities ‘Q’ are in column 2;

$PD\_BL_{k,h}^{i,t}$ 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 e*ach *price quantity pair* where offered prices *‘P’ are i*n column 1 and offered quantities ‘Q’ are in column 2;

$PD\_EMP_h^{m,t}$ 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 schedule *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: $DA\_ELMP_{h}^{i,t}$ is the day-ahead 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 $DA\_ILMP_{h}^{i,t}$ 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],

$$DA\_LWFC_{k,h} = \sum_{I,T} (-1) \times \left[\left(DA\_LWSD_{k,h}^{i,t}\right) \times MAX\left[0, \left(DA\_PS_{k,h}^{i,t} - PD\_PS_{k,h}^{i,t}\right)\right]\right]$$

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

$RT\_EFC\_DALW_{k,h}^{i}$	=	$\sum^{T}(-1) \times MIN\left[MAX\left[0, \left(PD\_EMP_{h}^{m,t} - EMP_{h}^{m,t} - PB\_EX_{h}^{t}\right) \times MAX\left(\left(DA\_DQSW_{k,h}^{i,t} - PD\_DQSW_{k,h}^{i,t}\right), 0\right)\right], MAX\left(0, PD\_EMP_{h}^{m,t}\right) \times MAX\left(\left(DA\_DQSW_{k,h}^{i,t} - PD\_DQSW_{k,h}^{i,t}\right), 0\right)\right]$

$RT\_IFC\_DALW_{k,h}^{i}$	=	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

$RT\_IFC\_DALW_{k,h}^{i}$	=	$\sum^{T}(-1) \times MIN\left[MAX\left[0, \left(EMP_{h}^{m,t} + PB\_IM_{h}^{t} - PD\_EMP_{h}^{m,t}\right) \times MAX\left(\left(DA\_DQSI_{k,h}^{i,t} - PD\_DQSI_{k,h}^{i,t}\right), 0\right)\right], MAX\left(0, EMP_{h}^{m,t}\right) \times MAX\left(\left(DA\_DQSI_{k,h}^{i,t} - PD\_DQSI_{k,h}^{i,t}\right), 0\right)\right]$

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:

$$DA\_GWC_{k,start\ event} = MIN\left(0, \sum_{i=1}^{n} (-1) \times OP\left(MIN\left(PD\_EMP_h^{m,t}, EMP_h^{m,t}\right), MLP_{k,h}^{m,t}, DA\_BE_{k,h}^{m,t}\right)\right)$$

Where:

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

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

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:

$$HUSA_h = \sum_K \left(NEMSC_{k,h} + ORSC_{k,h} + CMSC_{k,h} + RDSA_{k,h} + TRSC_{k,h} + IOG_{k,h}\right) + TCRF_{k,h} - \sum_K \left(\sum_R ORSSD_{k,r,h} + \sum_R ORSCB_{r,k,h} + DA\_IFC_{k,h} + RT\_IFC_{k,h} + DA\_EFC_{k,h} + RT\_EFC_{k,h} + DA\_LWFC_{k,h}\right)$$

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'

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

$RDSA_{k,h}$ = ramp-down *settlement* amount 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'

$TCRF_{k,h}$ = transmission charge reduction fund contribution 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'

$ORSCB_{r,k,h}$ = *operating reserve* non-accessibility charge for *class r reserve* for *market participant* 'k' in *settlement hour* 'h'

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 services 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 [Intentionally left blank – section deleted]

4.4.1 [Intentionally left blank – section deleted]

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 [Intentionally left blank – section deleted]

4.6 [Intentionally left blank – section deleted]

4.6.1 [Intentionally left blank – section deleted]

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 among *market participants* based on the proportionate share of all *transmission service charges* paid during *energy market billing periods* immediately preceding the current *energy market billing period,* in accordance with this section 4.7.

4.7.1.1 The portion of the total disbursements from the *TR clearing* account allotted to *market participants* that have paid provincial transmission charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of energy withdrawn from the *IESO-controlled grid* at all *RWMs* excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.7.2 and 4.7.3.

4.7.1.2 The portion of the total disbursements from the *TR clearing account* allotted to *market participants* that have paid *export transmission service* charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of *energy* withdrawn from the *IESO-controlled grid* at all *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.7.2 and 4.7.3.

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:

$$TRCAC_k = \frac{TRCAD}{\sum_{K,H}^{M,T} AQEW_{k,h}^{m,t}} \times \sum_{H}^{M,T} AQEW_{k,h}^{m,t}$$

For *market participants* that have paid provincial transmission service charges in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$$TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} (AQEW_{k,h}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}^{m,t})$$

For *market participants* that have paid *export transmission service* charges in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$$TRCAC_k = TRCAD_E \times \sum_H{}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

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

$$TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAD$$

$TRCAC_k$ = 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*

$TRCAD_L$ = the portion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period* allocated to *market participants* that have paid provincial transmission service charges “C” in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

$TRCAD_E$ = the portion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the *current energy market billing period* allocated to *market participants* that have paid *export transmission service* charges “C1” in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

M = the set of all *RWMs* ‘m’ excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

I = *intertie metering points* ‘i’ during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

K = the set of all *market participants* ‘k’ during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

T = the set of all *metering intervals* ‘t’ in *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

H = the set of all *settlement hours* ‘h’ in *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

C = the set of all monthly service charge types ‘c’ as follows: 650,651,652

C1 = the set of all monthly export transmission charge types ‘c’ as follows: 653

4.7.3 Where a $TRCAC_k$ is payable to a former *market participant*, the *IESO* will endeavour to distribute the $TRCAC_k$ as specified in the applicable *market manual*. If the *IESO* cannot distribute a $TRCAC_k$ to a former *market participant* as specified in the applicable *market manual,* such amounts shall remain in the *TR clearing account* for subsequent debits in accordance with section 4.18.1 of Chapter 8.

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 2.2B, 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 synchronization 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 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*.

4.7B.1.2 the applicable *combined guaranteed costs* for the specified submission to which the revenues determined in accordance with 4.7B.1.1 apply. Subject to section 4.7B.1.3, the *combined guaranteed costs* will be calculated by the *IESO* and will be the sum of the following costs:

4.7B.1.2A the submitted eligible costs, determined in accordance with section 4.7B.5 and section 2.2B.6 of Chapter 7, as applicable; and

4.7B.1.2B 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*.

4.7B.1.2.C [Intentionally left blank – section deleted]

4.7B.1.3 the elements of the *combined guaranteed costs* in section 4.7B.1.2A shall be deemed to be zero where a *market participant* is also eligible for the start-up cost component of a day-ahead production cost guarantee attributable to the same start-up event.

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.

4.7B.4A A real-time generation cost guarantee shall not be paid where a *generation unit* has committed its *capacity* to an external *control area* and:

4.7B.4A.1 the external *control area operator* has called a *called capacity export* prior to the *generation unit* being scheduled for the real-time generation cost guarantee in accordance with section 5.7 of Chapter 7; or

4.7B.4A.2 the external *control area operator* has called a *called capacity export* after the *generation unit* has been scheduled for the real-time generation cost guarantee in accordance with section 5.7 of Chapter 7 and the *IESO* is restricting other transactions on *interconnected systems* in accordance with section 2.3 and 5.7 of Chapter 5, while maintaining the *called capacity export* transaction.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

Calculating Eligible Costs:

4.7B.5 The *IESO* shall calculate the submitted eligible costs described in section 2.2B.5 of Chapter 7, as follows and as further specified in the applicable *market manual*:

4.7B.5.1 The incremental fuel cost is equal to the fuel price multiplied by the fuel quantity where:

Fuel price =

- pre-approved price, adjusted by the applicable foreign exchange rate, if any; plus
- pre-approved services price adder; plus
- pre-approved cap and trade price adder, if applicable.

Fuel quantity =

- submitted *start volume*; plus

- submitted *start volume* multiplied by the pre-approved compressor volume adder fuel percentage, except for purposes of calculating cap and trade costs.

4.7B.5.2 The incremental operating and maintenance cost is equal to:

- electricity consumption cost, equal to the pre-approved electricity consumption price multiplied by the pre-approved electricity consumption quantity; plus
- pre-approved operating consumables cost adder; plus
- pre-approved planned maintenance cost adder, adjusted by the applicable foreign exchange rate, if any.

4.7C [Intentionally left blank – section deleted]

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

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

4.7C.3 [Intentionally left blank – section deleted]

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*

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

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 The *IESO* shall determine the type of schedule and which components described in Section 4.7D.1 are included in the day-ahead production cost guarantee, for each *generation unit,* as follows:

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 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 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*

$$PCG\_COMP1\_CB_{k,h}^{m,t} = (-1)\times OP\left(EMP_{h}^{m,t}, MIN\left(AQEI_{k,h}^{m,t}, MLP_{k,h}^{m,t}\right), DA\_BE^{m,t}\right) + \frac{DA\_SNLC_{k,h}^{m}}{12}$$

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:

$PCG\_COMP2_{k,h}^{m,t}$ = As-offered day-ahead costs excluding as-offered *start-up costs* for the difference between:

- the minimum of the *generator's schedule of record*, the de-rated value of the *generation facility* or the maximum of the real-time constrained schedule and the allocated quantity of *energy* injected; and
- the minimum of the *generator's schedule of record* and the de-rated value of the *generation facility*

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

$$PCG\_COMP2_{k,h}^{m,t} = XDA\_BE_{k,h}^{m,t} - MAX\left(0, XBE_{k,h}^{m,t}\right)$$

Where:

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

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

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 m*etering 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*:

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

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 o*ffer 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

$$PCG\_COMP3_{k,h}^{m,t} = OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) - MAX\left(OP\left(EMP_h^{m,t}, DA\_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right)$$

Scenario 4

$$PCG\_COMP3_{k,h}^{m,t} = OP\left(EMP_h^{m,t}, DA\_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) - MAX\left(OP\left(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right)$$

Scenario 5

$PCG\_COMP3_{k,h}^{m,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Scenario 6

$PCG\_COMP3_{k,h}^{m,t}$ = 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:

$PCG\_COMP3\_CB_{k,h}^{m,t}$ = 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

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.

$$PCG\_COMP3\_CB_{k,h}^{m,t} = MAX\left(OP\left(EMP_h^{m,t}, MLP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right.\right. - OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)$$

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.

$$PCG\_COMP3\_CB_{k,h}^{m,t} = MAX\left(OP\left(EMP_h^{m,t}, MLP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right) - OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)$$

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:

$PCG\_COMP4_{k,h}^{m,t}$ = net income received from real-time *operating reserve* over the interval for the *generator's schedule of record* not dispatched in real-time

$$PCG\_COMP4_{k,h}^{m,t} = OP\left(PROR_{r1,h}^{m,t}, 30R\_SQROR_{r1,k,h}^{m,t}, BR_{k,h}^{m,t}\right) + OP\left(PROR_{r2,h}^{m,t}, 10NS\_SQROR_{r2,k,h}^{m,t}, BR_{k,h}^{m,t}\right) + OP\left(PROR_{r3,h}^{m,t}, 10S\_SQROR_{r3,k,h}^{m,t}, BR_{k,h}^{m,t}\right)$$

Where:

r1 = *30-minute operating reserve*

r*2* = 10-minute non-spinning *operating reserve*

r*3* = 10-minute spinning *operating reserve*

$$30R\_SQROR_{r1,k,h}^{m,t} = MAX\left[0, MIN\left(DA\_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t}, SQROR_{r1,k,h}^{m,t}\right)\right]$$

$$10NS\_SQROR_{r2,k,h}^{m,t} = MAX\left[0, MIN\left(DA\_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t} - 30R\_SQROR_{r1,k,h}^{m,t}, SQROR_{r2,k,h}^{m,t}\right)\right]$$

$$10S\_SQROR_{r3,k,h}^{m,t} = MAX\left[0, MIN\left(DA\_DQSI_{k,h}^{m,t} - MQSI_{k,h}^{m,t} - 30R\_SQROR_{r1,k,h}^{m,t} - 10NS\_SQROR_{r2,k,h}^{m,t}, SQROR_{r3,k,h}^{m,t}\right)\right]$$

x^* = the highest indexed row of matrix $BR_{r1,k,h}^{m,t}$, such that $QR_{x^*} \leq max[0, min(DA\_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t}, SQROR_{r1,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

y^* = the highest indexed row of matrix $BR_{r2,k,h}^{m,t}$ such that $QR_{y^*} \leq max[0, min(DA\_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t} - 30R\_SQROR_{r1,k,h}^{m,t}, SQROR_{r2,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

z^* = the highest indexed row of matrix $BR_{r3,k,h}^{m,t}$, such that $QR_{z^*} \leq max[0, min(DA\_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t} - 30R\_SQROR_{r1,k,h}^{m,t} - 10NS\_SQROR_{r1,k,h}^{m,t}, SQROR_{r3,k,h}^{m,t})] \leq QR_n$ 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:

$PCG\_COMP5_{k,h}^{m,t}$ = As-offered *start-up cost* submitted by the *market participant* 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 intervals[3] 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 DACP 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 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.

[3] The duration of an interval is 5 minutes.

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 = number of 5-minute intervals between Interval 7 and 18 the *market participant* takes to achieve *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 Subject to section 4.7D.7, 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*.

4.7D.7 A *generation unit* shall not be eligible for additional payments determined in accordance with section 4.7D.6 when:

- the *generation unit's* online status in Day-1, HE24 is attributed to any *pre-dispatch schedule* other than a *schedule of record;* and
- the *generation unit* receives a Variant 3 type *schedule of record* beginning in Day0, HE1 pursuant to section 4.7D.2.c for the purpose of ramping down the *generation unit* to offline status; and
- the *generation unit* would have otherwise not been economic in HE1 of Day 0.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

4.7D.8 A day-ahead production cost guarantee shall not be paid where a *generation unit* has committed its capacity to an external *control area* and:

4.7D.8.1 the external *control area operator* has called a *called capacity export* prior to the *generation unit* being scheduled for the day-ahead production cost guarantee in accordance with section 5.8 of Chapter 7; or

4.7D.8.2 the external *control area operator* has called a *called capacity export* after the *generation unit* has been scheduled for the day-ahead production cost guarantee in accordance with section 5.8 of Chapter 7 and the *IESO* is restricting other transactions on *interconnected systems* in accordance with section 2.3 and 5.7 of Chapter 5, while maintaining the *called capacity export* transaction.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

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*:

a. that was included in the *schedule of record*; and

b. 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 de-synchronize 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:

a. the *market participant*;

b. an *affiliate* or subsidiary of the *market participant*; or

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

4.7E.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 [Intentionally left blank – section deleted]

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

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

4.7F.3 [Intentionally left blank – section deleted]

4.7G Forecasting for Variable Generation

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

4.7H [Intentionally left blank – section deleted]

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

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

4.7H.3 [Intentionally left blank – section deleted]

4.7I [Intentionally left blank – section deleted]

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

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

4.7I.3 [Intentionally left blank – section deleted]

4.7J Capacity Obligations

Capacity Obligation Availability Payments

4.7J.1 The *capacity auction* availability payment *settlement amount* for *capacity market participant* ‘k’ at *delivery point* or *intertie metering point* ‘m’ for the relevant *energy market billing period* (“$CAAP^{m}_{k}$") shall be calculated for each *energy market billing period* and disbursed to *capacity market participants* who have a *capacity obligation* during the relevant *obligation period* and which shall be calculated as follows:

$$CAAP^{m}_{k} = \Sigma^{H} CCO^{m}_{k,h} \text{ x } CACP^{z}_{h}$$

Where:

(a) ‘H’ is the set of all *settlement hours* within the *availability window* of all *business days* in the relevant *energy market billing period*.

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

Capacity Obligation Availability Charges

4.7J.2.1 The *capacity auction* availability charge *settlement amount* for *capacity market participant* ‘k’ at *delivery point* or *intertie metering point* ‘m’ for the relevant *trading day* (“$CAAC^{m}_{k}$”) shall be collected from such *capacity market participants* in accordance with the following:

4.7J.2.1A In regards to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*, the *capacity auction* availability charge *settlement amount* shall be calculated for each *trading day* for which it receives a standby notice and it fails for any *settlement hour* of the *availability window* during such *trading day* to submit a *demand response energy bid* in an amount that is greater than or equal to its *capacity obligation* in the day-ahead commitment process and maintain such *energy bid* through the *real-time energy market.* The *capacity auction* availability charge *settlement amount* is calculated as follows:

$$CAAC^{m}_{k} = \Sigma^{H} (-1) \times Max(0, CCO^{m}_{k,h} - DREBQ^{m}_{k,h}) \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*;

(b) If the *capacity market participant* did not submit a *demand response energy bid* for its *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be, for *settlement hour* 'h' in the day-ahead commitment process or failed to maintain such *energy bid* through the *real-time energy market*, $DREBQ^{m}_{k,h} = 0$;

(c) In regards to *hourly demand response resource*, if the *demand response energy bids* submitted for *settlement hour* 'h' does not form part of *energy bids* spanning at least four consecutive *settlement hours*, $DREBQ^{m}_{k,h} = 0$;

(d) If the *demand response energy bid* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *demand response energy bid* submitted in the *real-time market* for the same *settlement hour*, $DREBQ^{m}_{k,h}$ shall be equal to the lesser of the two *demand response energy bids*; and

(e) Notwithstanding any of the foregoing, $DREBQ^{m}_{k,h}$ shall not exceed the $CARC^{m}_{k}$ for the *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be.

4.7J.2.1B For a *capacity market participant* participating with a *capacity generation resource*, *system-backed capacity import resource*, *generator-backed capacity import resource*, or *capacity storage resource*, the *capacity auction* availability charge *settlement amount* shall be calculated for each *trading day* it fails for any *settlement hour* of an *availability window* during such *trading day* to submit *energy offer* in an amount that is greater than or equal to its *capacity obligation* in the day-ahead commitment process and maintain such *energy offer* in accordance with the applicable *market manual*. The *capacity* *auction* availability charge *settlement amount* is calculated as follows:

$$CAAC^{m}_{k} = \Sigma^{H} (-1) \text{ x } Max(0, CCO^{m}_{k,h} - CAEO^{m}_{h,k}) \text{ x } CACP^{z}_{h} \text{ x } CNPF_{tm}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*;

(b) If the *capacity market participant* did not submit an *energy offer* in the day-ahead commitment process or maintain such *energy offer* in accordance with the applicable *market manual* for *settlement hour* 'h', $CAEO^{m}_{h,k} = 0$;

(c) If the *energy offer* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *energy offers* submitted in *pre-dispatch* or the *real-time market* for the same *settlement hour*, the $CAEO^{m}_{h,k}$ shall be equal to the lesser of any such *energy offers*; and

(d) If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window,* the $CAEO^{m}_{h,k}$ for the remaining *settlement hours* of the *availability window* after receiving such non-zero *energy dispatch instruction* shall be equal to the *energy offer* applicable to the *settlement hour* in which they receive such non-zero *energy dispatch instruction.*

Capacity Obligation Dispatch Charges

4.7J.2.2 Subject to section 19.4.5 and 7.5.3 of Chapter 7, the *capacity auction* dispatch charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' ("$CADC^{m}_{k,h}$") shall be calculated and collected from such *capacity market participant* participating with a commercial or industrial *hourly demand response resource* for each *settlement hour* of an *availability window* in which the *hourly demand response resource* fails to comply with an activation notice, as determined in accordance with section 4.7J.2.2.1, and which shall be calculated in accordance with the following:

$CADC^{m}_{k,h} = (-1) \times DRSQty^{m}_{k,h} \times CACP^{z}_{h} \times CNPF_{tm}$

Where:

(a) ‘h’ is a *settlement hour* in which the *hourly demand response resource* failed to comply with its activation notice, as determined in accordance with the applicable *market manual*.

(b) ‘tm’ is the *energy market billing period* that corresponds to *settlement hour* ‘h’.

4.7J.2.2.1 A commercial or industrial *hourly demand response resource* is determined to have failed to comply with an activation notice if the following condition is true:

$C\&I\_HDR\_BL^{m,t}_{k,h} - HDR\_AC^{m,t}_{k,h} < 85\% \times (TBQ^{m,t}_{k,h} - DQSW_{k,h}^{m,t})$

Where:

(a) “$C\&I\_HDR\_BL^{m,t}_{k,h}$” is the amount calculated pursuant to the applicable *market manual*.

(b) “$HDR\_AC^{m,t}_{k,h}$” is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* ‘k’ at *delivery point* ‘m’ for the *hourly demand response resource* in *metering interval* ‘t’ of *settlement hour* “h”, as determined in accordance with the submitted measurement data and AQEW, as the case may be.

(c) “$TBQ^{m,t}_{k,h}$ ” has the same meaning as ascribed to the same variable within the definition of $HDRDC^{m}_{k,h}$ in section 3.1.10.

Capacity Obligation Administration Charges

4.7J.2.3 The *capacity auction* administration charge *settlement amount* for *capacity market participant* ‘k’ at *delivery point* ‘m’ in the relevant *energy market billing period* (“$CAADM^{m}_{k}$”) shall be calculated and collected from each *capacity market participant* participating with a virtual *hourly demand response resource* or a *generator-backed capacity import resource* for each *energy market billing period* in which such *capacity market participant* fails to provide timely, accurate and complete data, including measurement data to the *IESO* in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CAADM^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Charges

4.7J.2.4 The *capacity auction* capacity charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *energy market billing period* ("$CACC^{m}_{k}$") shall be calculated and collected from each *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to deliver its *cleared ICAP* within the applicable threshold, as set out in the applicable *market manual,* in response to a *capacity auction capacity test*, and which shall be calculated as follows:

$$CACC^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

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

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

Capacity Obligation Capacity Import Call Failure Charges

4.7J.2.7 Subject to section 7.5.8A of Chapter 7, the *capacity auction* capacity import failure *settlement amount* for *capacity market participant* 'k' participating with a *generator-backed capacity import resource* at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CACIF^m_k$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to satisfy its *capacity obligation* in response to a *capacity import call*, as determined in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CACIF^m_k = (-1) \times CAAP^m_k$$

Where:

(a) '$CAAP^m_k$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Deficiency Charges

4.7J.2.8 The *capacity auction* capacity deficiency *settlement amount* for *capacity market participant* 'k' at *intertie metering point* 'i' for the relevant *energy market billing period* ("$CACD^i_k$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which the *IESO* has determined that all or a portion of the *capacity market participant's capacity obligation* is *over committed capacity*, and which shall be calculated and collected for the entire *obligation period* in accordance with the following:

$$CACD^i_k = \sum^H (-1.5) \times OCMW^i_k \times CACP^z_h$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* within the relevant *energy market billing period*.

4.7J.2.8.1 If the *IESO* determines that all or a portion of the *capacity market participant's capacity obligation* is *over committed* *capacity*, the *capacity market participant's capacity obligation* shall be reduced by the amount of *over committed capacity* effective as of the first *trading day* of the subsequent *energy market billing period*. If such reduction in the *capacity market participant's capacity obligation* for such resource results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such resource is forfeited effective as of the first *trading day* of the subsequent *energy market billing period*.

Capacity Obligation In-Period Cleared UCAP Adjustment Charge

4.7J.2.9 The *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAIPA^m_k$") shall be calculated and collected from such *capacity market participant* for i) the *energy market billing period* in which the *IESO* provided notice to the *capacity market participant* that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*; ii) each prior *energy market billing period* of the relevant *obligation period* included as an adjustment to the next scheduled *recalculated settlement statement* for such *energy market billing period*; and iii) if the *capacity market participant* has filed a *notice of disagreement* in regards to the outcome of a *capacity auction capacity test,* each subsequent *energy market billing period* of the relevant *obligation period*. The *capacity obligation* in-period UCAP adjustment charge *settlement amount* is calculated as follows:

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

Where:

(a) $CAAP^m_k$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1.

(b) $CAAC^m_{k,h}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as calculated pursuant to section 4.7J.2.1.

(c) ‘H’ is the set of all *settlement hours* ‘h’ within the *availability window* of the relevant *energy market billing period.*

(d) ‘UCAP Adjustment’ is a de-rate (in %) based on the *hourly demand response resource’s* delivered performance during a *capacity auction capacity test*, as determined in accordance with the applicable *market manual*. If the *capacity market participant* has filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with section 6.8, and but for filing such *notice of disagreement* the *capacity market participant* would have forfeited any of its *capacity obligation* pursuant to section 19.4.18 of Chapter 7, then the UCAP Adjustment shall equal 100%.

Capacity Obligation Buy-Out Charges

4.7J.3 A *capacity market participant* or a *capacity auction participant* may elect to be subject to a *capacity obligation* buy-out charge *settlement amount* for all, or a portion of, their *capacity obligation* in accordance with the applicable *market manual*. Upon the *IESO’s* acceptance of a buy-out request, the *capacity market participant’s capacity obligation* shall be reduced to reflect the approved buy-out and the *IESO* shall calculate the *capacity obligation* buy-out *settlement amount* for such *capacity market participant* ‘k’ at *delivery point* or *intertie metering point* ‘m’ (“$CABOC^m_k$”) which shall be calculated as follows:

$$CABOC^m_k = 50\% \text{ x } \Sigma^H \, CBOC^m_k \text{ x } CACP^z_h \text{ x } (1 - CNPF_{tm})$$

Where:

(a) ‘H’ is the set of all *settlement hours* within the *availability window* of all *trading days* from the buy-out effective date to the end of the *commitment period*.

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

Measurement Data Audit

4.7J.4 At any time, the *IESO* may audit any submitted measurement data and supporting information and a *capacity market participant* shall provide such information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that actual measurement data and supporting information differed from the submitted measurement data and supporting information, the

IESO shall recover from or distribute to a *capacity market participant* any resulting over or under payment, as applicable.

Capacity Obligation Dispatch Test Activation and Capacity Obligation Emergency Activation Payment

4.7J.5 Subject to section 4.7J.5.3, the *IESO* shall calculate and disburse a *capacity auction dispatch test* payment *settlement amount* or *capacity auction* emergency activation payment *settlement amount* for a valid *capacity auction dispatch test* or emergency activation, respectively, of an *hourly demand response resource* to the applicable *capacity market participant*, in accordance with the following:

4.7J.5.1 in regards to *capacity auction dispatch tests*, the c*apacity auction dispatch test* payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CATAP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

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

4.7J.5.2 in regards to *emergency operating state* activation, the *capacity auction emergency operating state* activation payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CAEOP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CAEOP^{m}_{k,h} = Max(0, HDRBP^{m}_{k,h} – Max(0,HOEP_{h})) \text{ X } HDRDC^{m}_{k,h}$$

4.7J.5.3 If measurement data for any *metering interval* within a *settlement hour* was not submitted to the *IESO* in accordance with the applicable *market manual,* the *capacity market participant* shall not be eligible to receive a *capacity auction* test activation payment *settlement amount* or a *capacity auction emergency operating state* activation payment *settlement amount* for such *settlement hour*.

Capacity Obligation Availability Charges True-Up Payment

4.7J.6 The *capacity obligation* availability charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CAACT^{m}_{k}$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which (i) the *capacity market participant* was subject to an availability charge pursuant to section 4.7J.2.1 or 4.7J.2.1A; and

(ii) the *capacity market participant offered* an amount of capacity in excess of the *capacity obligation* of its *capacity auction resource* for at least one *settlement hour* within the *availability window* of the applicable *obligation period*. The *capacity auction* availability charge true-up *settlement amount* shall be calculated as follows*:*

$CAACT^{m}_{k}$ = (Min ((-1) x $\sum^{TM}$ (($\sum^{D}$ $CAAC^{m}_{k}$) + UCAP Adjustment x $CAAP^{m}_{k}$ + $CAIPA^{m}_{k}$), $\sum^{H}$ Max (0,(RAC_{k} – $CCO_{k,h}$) x $CACP_{h}$ x $CNPF_{tm}$))

Where:

(a) $CAAC^{m}_{k}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *trading day,* as calculated as the sum of the *capacity obligation* availability charge *settlement amount* of each *settlement hour* within the relevant *availability window* determined pursuant to section 4.7J.2.1;

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

(c) $CAAP^{m}_{k}$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1;

(d) $CAIPA^{m}_{k}$ is the *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.2.9*;*

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

(f) 'tm' is the *energy market billing period* associated with *settlement hour* 'h' within the relevant *obligation period;*

(g) 'TM' is the set of all *energy market billing periods* within the relevant *obligation period;* and

(h) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period.*

Capacity Obligation Capacity Auction Charges True-up Payment

4.7J.7 The *capacity obligation* charge true-up *settlement amount* for *capacity market participant* ‘k’ at *delivery point* ‘m’ in the relevant *obligation period* (“$CACT^m_k$”) shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which the *capacity market participant* has a *capacity obligation*. The *capacity obligation* charge true-up *settlement amount* shall be calculated as follows:

$$CACT^m_k = -1xMin\ (0, (\sum_H TD_{C,k,h}{}^m + \sum_H TD_{P,k,h}{}^m))$$

Where:

(a) $TD_{C,k,h}{}^m$ is the total dollar value of all *settlement amounts* ‘C’ for *capacity market participant* ‘k’ at *delivery point* ‘m’ in *settlement hour* ‘h’ in the relevant *obligation period*, where:

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

(b) $TD_{P\ k,h}{}^m$ is the total dollar value of all *settlement amounts* ‘P’ for *capacity market participant* ‘k’ at *delivery point* ‘m’ in *settlement hour* ‘h’ in the relevant *obligation period*, where:

a. ‘P’ is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1 and 4.7J.6

(c) ‘H’ is the set of all *settlement hours* ‘h’ within the *availability window* of the relevant *obligation period*.

Capacity Auction Uplift

4.7J.8 The *capacity auction* uplift *settlement amount* for *market participant* ‘k’ at *delivery point* ‘m’ in the *energy market billing period* (“CAU^m_k”) will be calculated and collected from or disbursed to *market participants* for load facilities, as defined in Ontario Regulation 429/04, for each *energy market billing period*. The *capacity auction* uplift *settlement amount* shall be determined in accordance with sections 4.7J.8.1 and 4.7J.8.2. In calculating the *capacity auction* uplift *settlement amount* in this section 4.7J.8, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

(a) ‘H’ is the set of all *settlement hours* ‘h’ in the relevant *energy market billing period;*

(b) ‘M’ is the set of all *delivery points* ‘m’ of *market participant* ‘k’;

(c) ‘Class B Load’ as defined in the applicable *market manual*;

(d) ‘$EGEI_k$’ as defined in the applicable *market manual.*

4.7J.8.1 for *market participants* that are classified as a ‘Class A Market Participants’ in respect of the relevant load facility, as defined in Ontario Regulation 429/04, in accordance with *applicable law,* the *capacity auction* uplift *settlement amount* for such load facility shall be calculated as follows:

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

Where:

(a) ‘$TD_{C,k,h}{}^m$’ is total dollar value of all *settlement amounts* ‘C’ for *capacity market participant* ‘k’ at *delivery point* ‘m’ in *settlement hour* ‘h’ in the relevant *energy market billing period*, where:

(i) ‘C’ is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(b) ‘PDF_k’ is the Peak Demand Factor for ‘Class A Market Participant’ or Distributor ‘k’ for the relevant *energy market billing period*, as determined in accordance with *applicable law,* where if the ‘Class A Market Participant’ or Distributor ‘k’ ceases to be a ‘Class A Market Participant’ in respect of the relevant load facility during the relevant *energy market billing period,* the PDF_k shall be pro-rated accordingly.

4.7J.8.2 for *market participants* that are classified as ‘Class B Market Participants’ in respect of the relevant load facility, as defined in Ontario Regulation 429/04, in accordance with *applicable law,* the *capacity auction* uplift *settlement amount* for such load facility shall be calculated in accordance with the following:

(a) for Fort Frances Power Corporation Distribution Inc.:

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

Where:

(i) '$TD_{C,k,h}{}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(ii) '$TD_{C1350,k,h}{}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

(iii) 'EEQ' as defined in the applicable *market manual;*

(b) *market participants* that are classified as 'Class B Market Participants' in respect of the relevant load facility in accordance with *applicable law*:

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

Where:

(i) '$TD_{C,k,h}{}^{m}$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(ii) '$TD_{C1350,k,h}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

(iii) '$GA\_AQEW_{g,k,h,M}^{m,t}$' as defined in the applicable *market manual*.

(iv) '$PGS_{h,M}$' as defined in the applicable *market manual*.

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.14;

4.8.1.7 [Intentionally left blank – section deleted]

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 [Intentionally left blank – section deleted]

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 3.5.6;

4.8.2.7 [Intentionally left blank – section deleted]

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 [Intentionally left blank – section deleted]

4.8.2.13 any recovery of payments made by the *IESO* under section 3.5.9;

4.8.2.14 any proceeds from the day-ahead *generator* withdrawal charge under section 3.8F;

4.8.2.15 any recovery of payments made by the *IESO* under section 3.5.10;

4.8.2.16 any recovery of payments made by the *IESO* under sections 4.7B.4A, 4.7D.7 or 4.7D.8;

4.8.2.17 any recovery of payments made by the *IESO* under section 3.5.7A; and

4.8.2.18 any recovery of payments made by the *IESO* under section 3.5.11.

4.8.3 The *IESO* shall, at the end of each *energy market billing period,* recover from *market participants,* in the manner specified in the applicable *market manual,* the following amounts:

4.8.3.1 [Intentionally left blank – section deleted];

4.8.3.2 [Intentionally left blank – section deleted];

4.8.3.3 any compensation for *capacity market participants* paid in that *energy market billing* period by the *IESO* pursuant to section 4.7J.

4.8.3.4 any funds borrowed by the *IESO* and any associated interest costs incurred by the *IESO* in the preceeding *energy market billing period* pursuant to section 6.16.6.2.

4.8.4 The *IESO* shall distribute to *market participants*, in the manner specified in the applicable *market manual*, the following amounts:

4.8.4.1 [Intentionally left blank – section deleted];

4.8.4.2 [Intentionally left blank – section deleted];

4.8.4.3 any adjustments to *capacity market participant* payments pursuant to section 4.7J.

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 By November 1 of each year, the *IESO* shall *publish* the *IESO Settlement Schedule & Payments Calendar* or *SSPC* for the following calendar year showing the dates referred to in sections 6.3.2 to 6.3.23 as fixed dates within such calendar year.

6.2.2 If the *IESO* becomes aware of any change required to the *SSPC*, the *IESO* shall *publish* an updated *SSPC* to reflect the necessary changes. The *IESO* shall use reasonable efforts to provide *market participant*s with at least two weeks' notice of any changes to the *SSPC*.

6.2.3 The *SSPC* is *published* by the *IESO* for *market participant* ease of reference and the applicable dates that are binding on the *IESO* and *market participant*s are the dates determined in accordance with sections 6.3.1 to 6.3.23. Notwithstanding anything to the contrary, any reference in these *market rules* to the *SSPC* shall be deemed to be references to the dates specified in accordance with sections 6.3.1 to 6.3.23.

6.3 Settlement Cycles

6.3.1 Subject to section 6.3.24 to 6.3.33, section 6.3.2 to 6.3.23 set out the applicable dates for the *settlement process* and issuance of *settlement statements* and *invoices*.

TR auctions

6.3.2 The *preliminary settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued two *business days* after the *trading day*.

6.3.3 After the *preliminary settlement statement* referred to in section 6.3.2 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.4 The *final settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued six *business days* after the *trading day*.

6.3.5 After the *final settlement statement* referred to in section 6.3.4 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.6 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a) or as otherwise required, *recalculated settlement statements* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued at the following times:

a. the first *recalculated settlement statement* shall, where applicable, be issued on the last *business day* of the month immediately following the month of the *trading day* to which the *recalculated settlement statement* relates;

b. the *final recalculated settlement statement* shall be issued on the last *business day* of the month that is 22 months after the month of the *trading day* to which the *final recalculated settlement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement*; and

c. notwithstanding the foregoing, and at the *IESO*'s sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlement statement* referred to in section 6.3.6(a)-(b), an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* in the preceding 23-month period.

6.3.7 After a *recalculated settlement statement* referred to in section 6.3.6 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.8 The *IESO* shall issue one invoice to each *market participant*, covering all *trading days* within a *billing period*, on the same business day it issues the *final settlement statement* for the last *trading day* of that *billing period*.

6.3.9 The *market participant payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.10 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant*'s payments in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.11 The *IESO payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* after the corresponding *market participant payment date*.

6.3.12 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant* in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach each *market participant*'s *settlement account* no later than the *close of banking business* (of the bank at which the *market participant*'s *settlement account* is held) on the *IESO payment date*.

Real-Time Markets

6.3.13 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 6.3.2, shall be issued ten *business days* after the *trading day*.

6.3.14 After the *preliminary settlement statement* referred to in section 6.3.13 is issued, each *market participant* shall have six *business day*s to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.15 The *final settlement statement* for each *trading day* in the *real-time market*s and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the issuance of the *preliminary settlement statement* for that *trading day*.

6.3.16 After the *final settlement statement* referred to in section 6.3.15 is issued, each *market participant* shall have six *business day*s in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.17 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a), or as otherwise required, *recalculated settlement statements* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued at the following times:

a. the first *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is one month after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the first *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

b. the second *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is two months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the second *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

c. the third *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is five months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the third *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

d. the fourth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eight months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fourth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

e. the fifth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eleven months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fifth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

f. the sixth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is seventeen months after the month which contains the trading day to which the *recalculated settlement statement* relates. For greater certainty, the sixth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

g. the *final recalculated settlement statement* shall be issued on the same date as the *invoice* for the month that is 23 months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement statement* and the *final recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month; and

h. notwithstanding the foregoing, and at the *IESO*'s sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlements statements* referred to in section 6.3.17(a)-(g), an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement statement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* that was first invoiced in the preceding 23-month period.

6.3.18 After a *recalculated settlement statement* referred to in section 6.3.17 is issued, other than in respect of a *final recalculated settlement statement*, each *market participant* shall have six *business day*s in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.19 The *IESO* shall issue one *invoice* to each *market participant*, covering all *trading day*s within a *billing period*, and such other information specified in accordance with section 6.12.1, on the same day it issues the *preliminary settlement statement* for the last *trading day* of that *billing period*.

6.3.20 The *market participant payment date* for each *real-time market billing period* and for each *TR market billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.21 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant*'s payments for each *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*.

6.3.22 The *IESO payment date* for each *real-time market billing period* and for each *TR market billing period* shall be the second *business day* after the *market participant payment date*.

6.3.23 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant*, *forecasting entity*, and to each *transmitter* for each *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*.

Delays

6.3.24 The *IESO* may delay the issuance of *settlement statement*s for a *trading day* to a date later than that provided for in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, where, in the *IESO*'s opinion significant inaccuracies exist in the *settlement statements* such as to justify such delay.

6.3.25 Where the *IESO* delays the issuance of one or more *settlement statement*s for a *trading day* pursuant to section 6.3.24:

6.3.25.1 the issuance of *settlement statement*s for any immediately succeeding *trading day*s that would otherwise be required pursuant to sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, to be issued prior to the date referred to in section 6.3.26.1 shall be delayed to that date or to such later date(s) as may be determined and published by the *IESO*; and

6.3.25.2 the date by which *market participant*s must notify the *IESO* of errors or omissions in any delayed *settlement statement*s for each of the *trading day*s referred to in section 6.3.25.1 shall be delayed by the same number of days which the *settlement statement* to which the date relates is delayed.

6.3.26 Where the *IESO* delays the issuance of a *settlement statement* for a *trading day* pursuant to section 6.3.24, the *IESO* shall publish notice of such delay, which notice shall indicate:

6.3.26.1 the date on which such *settlement statement* shall be issued in lieu of the date referred to in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be;

6.3.26.2 the date by which *market participants* must notify the *IESO* of errors or omissions in such *settlement statement*s, determined in accordance with section 6.3.25.2; and

6.3.26.3 whether the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27.

6.3.27 Where the *IESO* determines that it will be unable to issue *invoice*s calculated in accordance with section 6.12.1 in respect of a given *energy market billing period* on or within one *business day* of the applicable date determined in accordance with section 6.3.8 or 6.3.19, the *IESO* shall, within two *business days* of the applicable date, issue to each *market participant* an estimated *invoice* for such *energy market billing period* in a net amount determined in accordance with section 6.3.29.

6.3.28 Where the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27 or to delay the issuance of *invoice*s pursuant to section 6.3.33, the *IESO* shall *publish* a notice indicating whether the *IESO* intends, in accordance with section 6.3.31, to delay each of the *market participant payment date* and the *IESO payment date* associated with such *invoice*s or estimated *invoice*s.

6.3.29 The amount of an estimated *invoice* issued to a *market participant* pursuant to section 6.3.27 shall, subject to section 6.3.30, be equal to the aggregate of:

6.3.29.1 the net total amount for that *market participan*t for all *trading day*s that occurred during the *energy market billing period* prior to the date on which the issuance of *preliminary settlement statements* commenced to be delayed pursuant to section 6.3.24 or 6.3.25.1, as the case may be;

6.3.29.2 for each *trading day* in the *energy market billing period* that occurred subsequent to the date referred to in section 6.3.29.1, the net total amount for that *market participant* as set forth in the *final settlement statement*s 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 statement*s equal to the number of *trading day*s in the current *energy market billing period* occurring subsequent to the date referred to in section 6.3.29.1; and

6.3.29.3 for greater certainty, any net total amount for that *market participant* reflected on a *recalculated settlement statement* which would have otherwise been included on the *invoice* for the relevant *energy market billing period* shall not be reflected on the estimated *invoice*.

6.3.30 Where the data required to determine the amount of an estimated *invoice* in accordance with section 6.3.29 is not readily available at the relevant time, the *IESO* shall issue to each applicable *market participant* an estimated *invoice* in an amount equal to:

6.3.30.1 the net amount of the *invoice* issued to the *market participant* for the preceding *energy market billing period* minus any amounts on such *invoice* included on a *recalculated settlement statement*; or

6.3.30.2 zero, if no *invoice* was issued to the *market participant* for the preceding *energy market billing period*.

6.3.31 Where the *IESO* issues estimated *invoice*s pursuant to section 6.3.28 or delays the issuance of *invoice*s pursuant to section 6.3.33 in respect of a given *energy market billing period*, the *IESO* may, where the delay resulting in the need to issue an estimated *invoice* or to delay the issuance of the *invoice*s has or is likely to have an adverse effect on the operation of the *IESO settlement clearing account*, delay each of the *market participant payment date* and the *IESO payment date* associated with such estimated *invoice* or delayed *invoice* by one *business day* relative to the periods referred to in sections 6.3.9 or 6.3.15, or sections 6.3.11 or 6.3.17, respectively.

6.3.32 Where the *IESO* issues to a *market participant* an estimated *invoice* in respect of a given *energy market billing period* pursuant to section 6.3.27, the *IESO* shall adjust the *invoice* issued to the *market participant* for the next *energy market billing period* to reflect any net difference between the amount of the estimated *invoice* and the amount that would have been set forth on the *market participant*'s *invoice* had the *invoice* been calculated in accordance with section 6.12.1 rather than estimated in accordance with section 6.3.27, including adding any net amounts reflected on any *recalculated settlement statement*s for the same *energy market billing period*.

6.3.33 Where the *IESO* determines that:

6.3.33.1 it will be unable to issue *invoice*s calculated in accordance with section 6.12.1 in respect of a given *energy market billing period* on the applicable date specified in the accordance with sections 6.3.8 or 6.3.19 by reason of the delay in issuance of *settlement statement*s referred to in section 6.3.24 or 6.3.25.1, or for any other reason; and

6.3.33.2 it is able to issue such *invoice*s within one *business day* of the applicable date specified in accordance with sections 6.3.8 or 6.3.19 such that the estimated *invoice* procedure referred to in sections 6.3.27 to 6.3.32 does not apply,

the *IESO* may delay the issuance of such *invoice*s for such *energy market billing period* for a period of up to one *business day* relative to the applicable date specified in accordance with sections 6.3.8 or 6.3.19, as the case may be.

6.4 Settlement Statement Process

6.4.1 The *IESO* shall issue *settlement statement*s to each *market participant* to cover each trading day in accordance with section 6.5, section 6.6 and section 6.7, and shall provide the *settlement* data included in such *settlement statements* into the *settlement process*.

6.4.2 For each *settlement statement*, the *IESO* shall calculate a net *settlement amount* for each *market participant* for the *trading day*. The net *settlement amount* shall be comprised of:

6.4.2.1 the aggregate of the trading amounts from each transaction in each *settlement hour* in the *trading day*; and

6.4.2.2 the aggregate of the amounts for the purchase or sale of *TR*s in all rounds of any *TR auction* that is concluded on the *trading day*,

adjusted to reflect any fees payable by the *market participant* and any other adjustment amounts payable or receivable pursuant to these *market rules.*

6.4.3 The net *settlement amount* referred to in section 6.4.2 shall be a positive or negative dollar amount for each *market participant* and:

6.4.3.1 where the net *settlement amount* for a *market participant* is negative, the absolute value of the *settlement amount* shall be an amount payable by the *market participant* to the *IESO*; or

6.4.3.2 where the net *settlement amount* for a *market participant* is positive, the *settlement amount* shall be an amount receivable by the *market participant* from the *IESO*.

6.4.4 *Settlement statements* shall be considered issued to *market participant*s when issued in accordance with the applicable *market manuals.*

6.4.5 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive a *preliminary settlement statement*, *final settlement statement*, or *final recalculated settlement statement* on the date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in section 6.3.25.1 and 6.3.26. Each *market participant* shall be deemed to have received such *settlement statements* on the relevant date specified in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, unless it notifies the *IESO* to the contrary within two *business days* of date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23.

6.4.6 In the event that a *market participant* notifies the *IESO* that it has failed to receive a *settlement statement* on the date specified for that *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, the *IESO* shall re-send such *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 Settlement 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 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,

6.5.1.3 any adjustments which may be required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10,

6.5.1.4 in accordance with the timelines set forth in sections 6.3.2, 6.3.13, 6.3.24 and 6.3.25.1, as may be applicable.

6.5.2 *Preliminary settlement statements* related to each *market participant* for all rounds of any *TR auction* that is concluded on a given *trading day* shall include, in electronic format, for each *settlement hour* of the relevant *trading day* or for each such *TR auction*, as the case may be, referenced by applicable *charge type*:

6.5.2.1 the *hourly Ontario energy price* in that *settlement hour*;

6.5.2.2 the payment for the *settlement hour*, either from the *market participant* to the *IESO*, or from the *IESO* to the *market participant*;

6.5.2.3 all fees, charges, credits and payments applicable to the *market participant* in respect of the purchase or sale of a *TR* in all rounds of such *TR auction*; and

6.5.2.4 for each type of charge listed, the total *trading day's* charges and a *billing period*-to-date total.

6.5.3 *Preliminary settlement statements* related to each *market participant* for the *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 6.5.4, presented as follows:

6.5.3.1 for each hourly *settlement amount* referred to in section 3, by *metering interval* or *settlement hour*, as the case may be, depending upon the manner of calculation of the *settlement amount* as described in section 3;

6.5.3.2 for each non-hourly *settlement amount* referred to in section 4 or 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 amount*s shall be included only in the *preliminary settlement statement* issued in respect of the last *trading day* of a *billing period*; and

6.5.3.3 for each non-hourly *settlement amount*, other than those referred to in section 6.5.3.2, by *metering interval*, *settlement hour*, or *trading day*, as the case may be, depending upon the time period over or with respect to which the relevant *settlement amount* is required to be calculated pursuant to section 4, or 5.

6.5.4 The *preliminary settlement statement*s referred to in section 6.5.3 shall be in electronic format and shall set forth, for the *market participant* to whom the *preliminary settlement statement* is issued and referenced by applicable charge type:

6.5.4.1 the *energy* injected or withdrawn by each of that *market participant*'s *registered facilities* as determined in each of the *market schedule* and the *real-time schedule*.

6.5.4.2 the allocated quantities of *energy* withdrawn or injected by each of that *market participant*'s *registered facilities*.

6.5.4.3 the aggregate quantity of each class of *operating reserve* provided by each of that *market participant*'s *registered facilities* as determined in each of the *market schedule* and the *real-time schedule*.

6.5.4.4 the aggregate quantities or capacities, as the case may be, of each *contracted ancillary service* scheduled and provided from each of that *market participant*'s *registered facilities*;

6.5.4.5 the *physical bilateral contract quantities* for that *market participant*;

6.5.4.6 the availability payments to be made in each *billing period* under *reliability must-run contracts* to each of that *market participant*'s *reliability must-run resources*;

6.5.4.7 details of performance incentive payments or penalties applicable to the *market participant*;

6.5.4.8 the *energy market price* applying to each of that *market participant*'s *registered facilities*;

6.5.4.9 the applicable 5-minute price for each class of *operating reserve* for each of that *market participant*'s *registered facilities*;

6.5.4.10 detailed calculations of applicable *transmission services charges*, and the *market participant*'s share of these;

6.5.4.11 the total of each type of *contracted ancillary service* charges, and the *market participant*'s share of these;

6.5.4.12 all *real-time market* fees, charges and payments applicable to the *market participant* and the basis for deriving those fees, charges or payments;

6.5.4.13 for each type of charge listed, the total *trading day*'s charges and a *billing period*-to-date total; and

6.5.4.14 all *TR market* fees, charges, credits and payments applicable to the *market participant*.

6.6 Final Settlement Statement Coverage

6.6.1 The *IESO* shall issue to each *market participant* separate *final settlement statements* to cover:

6.6.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*;

6.6.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.6.1.1; and

6.6.1.3 adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10,

6.6.1.4 in accordance with the timelines set forth in sections 6.3.4, 6.3.14, 6.3.24, and 6.3.25.1, as may be applicable.

6.6.2 The *final settlement statement* shall be in the same form as the *preliminary settlement statement* and shall include all of the information provided in the *preliminary settlement statement*, as amended following the validation procedure set forth in section 6.8 and 6.9, where applicable.

6.6.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, *final settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *final settlement statement*.

6.6.4 Each *market participant* that receives a *final settlement statement* is required to pay any net debit amount shown in the *final settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *final settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of such debit or credit.

6.7 Recalculated Settlement Statement Coverage

6.7.1 The *IESO* shall, when applicable, issue to each *market participant* separate *recalculated settlement statements* to cover adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10 in respect of:

6.7.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.7.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.7.1.1,

6.7.1.3 accordance with the timelines set forth in sections 6.3.6, 6.3.17, 6.3.24, 6.3.25.1, as may be applicable.

6.7.2 The *recalculated settlement statement* shall be in the same form as the *final settlement statement* and shall include all of the information provided in the most recently issued *settlement statement* for the *trading day* for which the *recalculated settlement statement* relates, as amended following the validation procedure set forth in section 6.8 and 6.9 and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, where applicable.

6.7.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, where applicable, *recalculated settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *recalculated settlement statement*.

6.7.4 Each *market participant* that receives a *recalculated settlement statement* is required to pay any net debit amount shown in the *recalculated settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *recalculated settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of such debit or credit.

6.8 Market Participant Validation of Settlement Statements

6.8.1 Each *market participant* shall review all of its *settlement statements* upon receipt. Subject to the terms of this section 6.8, a *market participant* may register a disagreement with the *IESO* with respect to any *settlement statement* other than a *final recalculated settlement statement* by filing a *notice of disagreement* in accordance with the timelines set forth in sections 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be.

6.8.2 Subject to section 6.8.12, if a *market participant* disagrees with any item or calculation set forth in a *preliminary settlement statement* that it has received, or considers that there is an omission in such *preliminary settlement statement,* it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4.

6.8.3 Subject to section 6.8.12, if a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* or a *recalculated settlement statement*, other than a *final recalculated settlement statement*, that:

a. differs in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag;

b. is an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag; or

c. the *market participant* considers that there is an omission in such *settlement statement*, including where the *IESO* does not issue a *recalculated settlement statement* because it has determined an adjustment is not necessary and the *market participant* disagrees with such determination, it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4. For greater certainty, a *market participant* shall not provide a *notice of disagreement* to the *IESO* if the item or calculation on a *final settlement statement* or *recalculated settlement statement* with which the *market participant* disagrees is not captured by sections (a) or (b) above.

6.8.4 *Notices of disagreement* shall relate to only one *settlement statement* and shall include at least the following information:

6.8.4.1 the date of issuance of the *settlement statement* in question;

6.8.4.2 the *dispatch day* in question;

6.8.4.3 the item(s) or omission(s) in question;

6.8.4.4 clearly state, with supporting material, the reasons for the disagreement;

6.8.4.5 where applicable and with supporting material, the proposed adjustment to the data used to calculate any relevant *settlement amount* on the *settlement statement*; and

6.8.4.6 where applicable and with supporting material, the proposed correction to any calculation of the relevant *settlement amount* on the *settlement statement.*

6.8.5 Where a *notice of disagreement* includes a proposed adjustment to:

6.8.5.1 *physical bilateral contract data*; or

6.8.5.2 any data of a comparable nature which may be identified by the *IESO* from time to time,

the *IESO* shall notify any other *market participant* to whom items 6.8.5.1 or 6.8.5.2 relates of such proposed adjustment prior to taking any action under section 6.8.9.

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

6.8.7 The issuance of a *notice of disagreement* shall not remove the obligation of the *market participant* to settle any *invoice* based on the *preliminary settlement statement*, *final settlement statement* or *recalculated settlement statement*.

6.8.8 Subject to section 6.8.12 the *IESO* shall use the information provided in and with a *notice of disagreement*, and any other information available to the *IESO,* to consider the subject-matter of the disagreement and determine the necessary corrections, if any.

6.8.9 Following the determination described in section 6.8.8, the *IESO* shall inform the *market participant* of its determination, provide the *market participant* the opportunity to respond within ten *business days*, and, after considering any such response, take one of the following actions:

6.8.9.1 if the *IESO* concludes that no adjustment or correction is required in the *settlement statement,* it shall take no further action; or

6.8.9.2 if the *IESO* concludes that an adjustment or correction is required, take one of the following actions:

a. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement.* For clarity, where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; or

c. if the *notice of disagreement* is with respect to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement*.

6.8.10 If the *IESO* does not make its determination before the date for issuing any subsequent *settlement statements,* as applicable, the *IESO* shall issue such *settlement statements* without taking into account the disagreement.

6.8.11 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.8 shall, subject to section 6.18.3, be included as:

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

6.8.11.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period* *allocation* to a *recalculated settlement statement,* or a subsequant *preliminary settlement statement* where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

6.8.12 No *market participant* may submit a *notice of disagreement*, and any such *notice of disagreement* shall not be valid and any adjustment resulting from such *notice of disagreement* shall be void, if the *notice of disagreement*:

6.8.12.1 is submitted to the *IESO* after the time specified in 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be;

6.8.12.2 relates to an issue which falls outside the permitted scope of such *notice of disagreement* outlined in sections 6.8.2 or 6.8.3, as the case may be;

6.8.12.3 relates to a *final recalculated settlement statement*;

6.8.12.4 relates to a compliance and enforcement action described in section 6 of Chapter 3, or matters relating to section 3.5.6B, section 3.5.6C, section 3.5.6D, section 3.5.6G, section 3.5.9, section 3.8.1, section 3.8.2, or section 4.7E of Chapter 9, section 2.2B.2 of Chapter 7 or Appendix 7.6 of Chapter 7;

6.8.12.5 relates to a dispute referred to in section 2.1A.6A of Chapter 9;

6.8.12.6 relates to an adjustment made on a *settlement statement* reflecting a dispute outcome;

6.8.12.7 relates to a matter described in the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10;

6.8.12.8 relates to the calculation of:

a. the 5-minute *energy market* price for any *dispatch interval* in a given settlement hour;

b. the 5-minute *market price* for any class of *operating reserve* for any *dispatch interval* in a given *settlement hour*; or

c. the hourly Ontario energy price for a given *settlement hour*; or

6.8.12.9 relates to a matter which the *market participant* has already submitted a *notice of disagreement*, including in regards to an earlier *settlement statement*.

6.8.13 Subject to the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, *market participants* that fail to submit a *notice of disagreement* in accordance with section 6.8 in regards to a *settlement statement* shall have no further recourse in regards to the amount of any *settlement amount* contained on such *settlement statement*.

6.8.14 Nothing in section 6.8.12 shall prevent a *market participant* from submitting, or the *IESO* from making a determination in regards to, a *notice of disagreement* that relates to the manner in which any of the elements noted in sections 6.8.12.8 have been applied for purposes of the calculation of the *market participant's* net *settlement amount.*

6.8.15 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.8.9 or the *IESO* has not made its determination prior to the earlier of either (i) the date that is 23 months after the date on which the relevant *trading day* was first *invoiced*; or (ii) twelve months after the date the *notice of disagreement* was issued by the *market participant*, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1. Additionally, if a *market participant* disagrees with an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1.

6.9 IESO Validation of Settlement Statements

6.9.1 Subject to section 6.9.2, if the *IESO* becomes aware of a possible error within an *IESO* system or *settlement process* that a *market participant* would not have reasonably been able to identify and address through section 6.8 and which may result in *settlement amounts* being calculated incorrectly, the *IESO* shall use the information available to the *IESO* to consider the possible error and take one of the following steps:

6.9.1.1 if the *IESO* concludes that no material adjustment or correction is required, it shall take no further action; and

6.9.1.2 if the *IESO* concludes that a material adjustment or correction is required, take one or more of the following actions:

a. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statements*. For clarity, where the correction relates to a trading date prior to the *IESO* commencing the issuance of *recalculated settlement statements*, the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; and

c. if the correction is with respect to an item or calculation on any other *settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statement*.

6.9.2 Notwithstanding section 6.9.1 and commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amounts* which were invoiced, or should have been invoiced, more than 23 months before the day on which the *IESO* issues the *settlement statement* referred to in section 6.9.1.2. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amount* if a limitation period applicable to such *settlement amount* prescribed in *applicable law* has lapsed.

6.9.3 If the *IESO* does not make its determination before the date for issuing the any *settlement statements*, as applicable, the *IESO* shall issue such *settlement statements* without taking into account the error being considered.

6.9.4 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.9 shall, subject to section 6.18.3, be included as:

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

6.9.4.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period allocation,* to a *recalculated settlement statement,* or a subsequant *preliminary settlement statement* where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a *current period adjustment* to a subsequent *preliminary settlement statement.*

6.9.5 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.9.1.2, the *market participant* may pursue their disagreement through the *market participant* validation procedure described in section 6.8, or, if the adjustment is made on a *final recalculated settlement statement* or on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued, through the dispute resolution procedure described in section 6.10.1.

6.9.6 Notwithstanding the foregoing, nothing in this section 6.9 limits the *IESO*'s ability to apply an adjustment related to matters described in section 6.8.12.4, including as a *current period adjustment* to a *preliminary settlement statement* issued more than two years after the *invoice* for the relevant *trading day* was issued.

6.10 Dispute Resolution

6.10.1 Subject to section 6.10.2, if a *market participant* wishes to initiate a dispute in regards to matters described in section 6.8.15, section 6.9.5, section 6.8.12.4, or in regards to a *final recalculated settlement statement,* it may submit the matter to the dispute resolution process set forth in section 2 of Chapter 3.

6.10.2 In regards to matters described in section 6.10.1, no *market participant* may submit a *notice of dispute*, and any such *notice of dispute* shall not be valid, if:

6.10.2.1 in regards to disputes pertaining to *settlement statements* other than a *final recalculated settlement statement,* the *notice of dispute* relates to a matter which, pursuant to section 6.8.2, section 6.8.3, or section 6.8.12, except for section 6.8.12.4, is not an item or calculation for which the the *market participant* is permitted to submit a *notice of disagreement*, unless the only reason that a *market participant* is not permitted to submit a *notice of disagreement* is because the new or adjusted item or calculation is not identified as associated with an adjustment flag;

6.10.2.2 in regards to disputes pertaining to a *final recalulated settlement statement,* the *notice of dispute* relates to a matter:

a. which does not differ in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day*;

b. is not an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day*;

c. is not an item or calculation which the *market participant* considers that there is an omission in such *settlement statement*; or

d. described in sections 6.8.12.5 to 6.8.12.9.

6.10.2.3 subject to section 2.5.1B of Chapter 3, the *notice of dispute* was submitted by the *market participant*:

a. in regards to matters described in section 6.8.15 where the *IESO* has made its determination, more than twenty *business days* after either the *IESO* notifies the *market participant* in accordance with section 6.8.9.1 or issues the relevant *settlement statement* in accordance with section 6.8.9.2, as the case may be;

b. in regards to matters described in section 6.8.15 where the *IESO* has not made its determination, prior to the date referred to in section 6.8.15;

c. in regards to matters described in section 6.9.5 where the adjustment is made on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued, more than twenty *business days* after the *IESO* issues the ad hoc *recalculated settlement statement;*

d. in regards to disputes pertaining to a *final recalculated settlement statement*, more than twenty *business days* after the *IESO* issues the *final recalculated settlement statement*;

e. in regards to matters described in section 6.8.12.4, except for a compliance and enforcement action described in section 6 of Chapter 3, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed;

f. in regards to a compliance and enforcement action described in section 6 of Chapter 3, outside of the applicable timeline set forth in section 2.5.1A of Chapter 3; and

g. in regards to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed.

6.10.3 Following the resolution of a dispute, the *IESO* shall arrange to have the *dispute outcome* carried out as soon as is reasonably practicable following the resolution of the dispute, subject to the availability of data and of the *IESO's* resources.

6.10.4 To implement a *dispute outcome*, the *IESO* shall:

6.10.4.1 for the *market participant* that originally filed the *notice of dispute* that resulted in the *dispute outcome*, reflect the amounts to be debited or credited in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits on the next scheduled *recalculated settlement statement*; or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on the *final recalculated settlement statement*, the *IESO* shall reflect such credits or debits on a subsequent *preliminary settlement statement* issued for the *market participant*.

6.10.4.2 ensure any credit adjustment made to such *market participant*, being a refund of payments already made, shall include interest at the *default interest rate* from the date the overpayment was received to the time that the repayment is credited to the relevant *market participant settlement account*;

6.10.4.3 arrange to have all net adjustments for each *market participant*, and any interest on such net adjustments, placed into the *IESO adjustment account*; and

6.10.4.4 for any other *market participant* affected by the *dispute outcome*, reflect the incremental dollar amount determined in section 6.10.4.1 as a debit or credit in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as an *adjustment period allocation* on the next scheduled *recalculated settlement statement.* If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement;* or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as a c*urrent period adjustment* on a subsequent *preliminary settlement statement* issued for the *market participant.*

6.10.4.5 Notwithstanding the section 6.10.4.1(a) and 6.10.4.4(a), where *dispute outcome* requires an adjustment within a specified time period and the next scheduled *recalculated settlement statements* follows such time period, the *IESO* shall issue an ad hoc *recalculated settlement statements* to reflect such adjustments within the required timeframe.

6.11 Responsibility of the IESO

6.11.1 In carrying out its *settlement* responsibilities, the *IESO* shall operate in a non-discriminatory manner.

6.11.2 The *IESO* shall not be a counter-party to any trade transacted through the *real-time markets*.

6.12 Settlement Invoices

6.12.1 Unless the *IESO* has invoked the estimated *invoice* procedure pursuant to section 6.3.27, each *invoice* issued by the *IESO* to a *market participant* shall be based on all of the *settlement statements* issued to the *market participant* since their last *invoice* was issued except for any that may pertain to the next *billing period*, as more particularly described in the applicable *market manual*. In each *invoice*, other than an estimated *invoice* issued pursuant to section 6.3.27:

6.12.1.1 each line item shall correspond to a distinct commodity or service bought or sold over the *billing period*; and

6.12.1.2 the *charge type* appearing on the *invoice* shall allow *invoice* line items to be cross-referenced to the relevant *settlement statements.*

6.12.2 The *IESO* shall, on the days specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33, issue an *invoice* to each *market participant* showing:

6.12.2.1 the dollar amounts which are to be paid by or to the *market participant*, according to *settlement statements* as specified in section 6.12.1 or as estimated pursuant to section 6.3.27;

6.12.2.2 the *market participant payment date* by which such amounts (if any) are to be paid by the *market participant* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account*);

6.12.2.3 the *IESO payment date* by which the *IESO* is to make payments (if any) to the *market participant* no later than the *close of banking business* (of the bank at which the *market participant settlement account* is held); and

6.12.2.4 details of the *IESO settlement clearing account*, including the bank name, account number and *electronic funds transfer* instructions, to which any amounts owed by the *market participant* are to be paid in accordance with section 6.12.2.2.

6.12.3 *Invoices* shall be considered issued to *market participants* when issued by the *IESO* in accordance with the applicable *market manuals*.

6.12.4 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive an *invoice* on the date specified for the issuance of such *invoice* accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33. Each *market participant* shall be deemed to have received its *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* unless it notifies the *IESO* to the contrary.

6.12.5 In the event that a *market participant* notifies the *IESO* that it has failed to receive an *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* the *IESO* shall re-send the appropriate *invoice* and the *invoice* shall be considered received on the date the re-sent *invoice* is sent to the *market participant.*

6.13 Payment of Invoices

6.13.1 Subject to section 6.13.2, each *market participant* shall pay the full net *invoice* amount by the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31 and 6.3.33, regardless of whether or not the *market participant* has initiated or continues to have a dispute respecting the net amount payable.

6.13.2 A *market participant* may pay at an earlier date than the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33 in accordance with the following:

6.13.2.1 notification must be given to the *IESO* before submitting such prepayment or before converting an existing overpayment by the *market participant* into a prepayment;

6.13.2.2 the prepayment notification shall specify the dollar amount prepaid;

6.13.2.3 a prepayment shall be made by the *market participant* into the *IESO prepayment account* designated by the *IESO*;

6.13.2.4 on any *market participant payment date,* the *IESO* may initiate the transfer of necessary funds from the *IESO prepayment account* to the *IESO settlement clearing account* to discharge, up to the amount of the prepayment, that *market participant*'s outstanding payment obligations arising in relation to that *market participant payment date;* and

6.13.2.5 subject to 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.*

6.13.3 With respect to *transmission services charges*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *transmitter's transmission services settlement account* sufficient funds to pay in full the *transmission services charges* falling due to that *transmitter* on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33.

6.13.4 With respect to the *IESO administration charge*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account sufficient funds to pay in full the *IESO administration charge* falling due on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 in priority to any other payments to be made on that *IESO payment date* or on subsequent days out of the *IESO settlement clearing account.*

6.13.5 With respect to the smart metering charge*,* the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account only those funds that were received in the *IESO settlement clearing account* in payment of the smart metering charge*.* The smart metering charge is the fee approved by the *OEB* to recover costs incurred by the *IESO* solely as a result of the *IESO* acting as the Smart Metering Entity and its responsibilities related to the smart metering initiative.

6.13.6 The *IESO* shall, on the *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* determine the amounts available in the *IESO settlement clearing account* for distribution to *market participant*s or the *forecasting entity*, and shall, if necessary, borrow funds in accordance with the provisions of section 6.16 if necessary to enable the *IESO settlement clearing account* to clear no later than 11:00 am on the *IESO payment date*.

6.14 Funds Transfer

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

6.14.2 All payments by the *IESO* to *market participants* in respect of settlement matters shall be made to each *market participant's market participant settlement account* or to each *transmitter's transmission services settlement account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.3 In the event of failure of any *electronic funds transfer* system affecting the ability of either a *market participant* or the *IESO* to make payments, the affected party shall arrange for alternative means of payment so as to ensure that payment is effected by the dates and times specified in this Chapter.

6.14.4 No *market participant* shall include in any *electronic funds transfer* amounts attributable to more than one *invoice* or prepayment, unless such *electronic funds transfer* is in such form as may be specified in the applicable *market manual.*

6.14.5 The *IESO* shall be entitled to and shall rely on the information contained in or accompanying an *electronic funds transfer* received pursuant to section 6.14.4 for the purpose of allocating the aggregate amount of an *electronic funds transfer* referred to in that section and, notwithstanding section 13 of Chapter 1:

6.14.5.1 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 6.14.6.1; or

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2; and

6.14.5.2 the *market participant* providing the *IESO* with such information shall indemnify and hold harmless the *IESO* in respect of any claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation by the *IESO* of:

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

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2.

6.14.6 Where a *market participant* that initiates an *electronic funds transfer* to which section 6.14.4 applies fails to provide the information contained in or accompanying an *electronic funds transfer* referred to in section 6.14.4, the *IESO* shall allocate:

6.14.6.1 the aggregate amount of the *electronic funds transfer;* and

6.14.6.2 the entire amount of any associated overpayment or underpayment,

to that *market participant*.

6.15 Confirmation Notices

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

6.16 Payment Default

6.16.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account*.

6.16.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.

6.16.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.13.2**,** the provisions of section 6.3 of Chapter 3 shall apply and *default interest* shall accrue on all amounts outstanding.

6.16.4 If the *market participant's invoice* includes a *settlement amount* owing for the smart metering charge under section 6.13.5 and the *market participant*

a. fails to remit the full *invoice* amount due by the *market participant payment date*; and

b. does not direct the *IESO* how to apportion the payment between the smart metering charge and all other *settlement amounts* on the *invoice* prior to the *IESO payment date*, the *IESO* shall allocate the payment made by the *market participant* first to satisfying any *settlement amounts* due under the *market rules* before being applied to the smart metering charge.

6.16.5 The *IESO* shall be authorized to borrow short-term funds to clear the credits in any settlement cycle only if the following conditions are met:

6.16.5.1 there are insufficient funds remitted into the *IESO settlement clearing account* or *TR clearing account* to pay all applicable *market creditors* due for payment from the funds in the *IESO settlement clearing account* or *TR clearing account,* and clear the *IESO settlement clearing account* or *TR clearing account* on a given *IESO payment date*, due to:

a. payment default by one or more *market participants* in the *real-time markets*; or

b. the circumstances referred to in section 4.19.2 or 4.19.6 of Chapter 8;

6.16.6 If the *IESO* borrows short-term funds pursuant to section 6.16.5, it shall recover this borrowing:

6.16.6.1 where the insufficient funds were due to a payment default referred to in section 6.16.5.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules,* including, if necessary, by imposing the *default levy* in accordance with section 8 of Chapter 2; or

6.16.6.2 where the insufficient funds were due to the circumstances referred to in section 6.16.5.1 (b), in the manner referred to in sections 4.19.3 and 4.19.5 of Chapter 8 and then, if necessary, by recovering from *market participants* proportionately based on *transmission service charges* paid during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.16.6.2.1 Where a *market participant* has paid provincial *transmission service charges*, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *RWMs* excluding *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.2.2 Where a *market participant* has paid export *transmission service* charges, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *intertie metering points* during all intervals and *settlement hours* within the *energy market* *billing period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.3 The portion of any short-term funds borrowed by the *IESO* to be recovered from *market participant* 'k' in the current *energy market billing period* shall be calculated as follows:

For market participants that have paid provincial transmission service charges in the current energy market billing period:

$$TRCAC_k = TRCAD_L \text{ x } \sum_H^{M,T} [(AQEW_{k,h}^{m,t}) / \sum_{K,H}^{M,T} (AQEW_{k,h}^{m,t})$$

For market participants that have paid export *transmission service charges* in the current energy market billing period**:**

$$TRCAC_k = TRCAD_E \text{ x } \sum_H^{I,T} [(SQEW_{k,h}^{i,t}) / \sum_{K,H}^{I,T} (SQEW_{k,h}^{i,t})]$$

Where:

$$TRCAD_L =(\sum_K TD_C / \sum_K TD_{C,C1}) \text{ x } TRCAR$$

$$TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \text{ x } TRCAR$$

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

6.16.7 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participant*s or to the circumstances referred to in section 6.16.5.1 (b), the *IESO* shall borrow funds in accordance with section 6.16.5 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date*.

6.16.8 If the *IESO* has exhausted credit availability contemplated by section 6.16.5, then the *IESO* shall pay *real-time market creditors* on a pro rata basis in proportion to the amounts owed to each *market creditor*. Any amounts that remain owing to *real-time market creditors* shall bear interest at the *default interest rate* until paid.

6.16.9 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default* *levy*, the *IESO* shall first repay all existing lines of credit and other banking facilities, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *market creditors* owed amounts pursuant to section 6.16.8.

6.17 Payment Errors, Adjustments, and Interest

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

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

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

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

6.17.1.4 the *IESO* shall be entitled to treat the overpayment and any interest accruing thereon as an unpaid amount to which section 6.16 applies; and

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

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

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

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

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

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

6.17.4.3 the *market participant* may request that the overpaid amount be either refunded or treated as a prepayment pursuant with section 6.13.2; and

6.17.4.4 any related administration and transaction costs incurred by the *IESO* in managing and resolving the over-payment shall be charged to the account of the *market participant* involved.

6.17.5 If the *IESO* underpays any *market participant* on any *IESO payment date*:

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

6.17.5.2 if the *IESO* determines or becomes aware of the underpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly; and

6.17.5.3 the *IESO* shall use all reasonable endeavours to promptly correct any underpayments, including interest thereon at the *default interest rate*.

6.17.6 If the *IESO* is underpaid by a *market participant* on any *market participant payment date,* the provisions of section 6.16 or of section 4.20 of Chapter 8 shall apply.

6.17.7 If the *IESO* borrows funds in accordance with section 6.16.5 because a payment due from a *market participant* was received too late to be credited to the *IESO settlement clearing account* by *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* when such payment was due, then such remittance when it does arrive shall be used to repay the borrowed funds. Any such late payments shall be charged the *Canadian prime interest rate* plus 2%.

6.17.8 If the *IESO* holds or has under its control after five *business days* from receipt in the *IESO settlement clearing account* amounts which it ought properly to have paid to *market participant*s, such *market participant*s shall be entitled to interest on such amounts at the *default interest rate* from the date on which the *IESO* commenced to improperly hold or have such amounts under its control to the date on which such amounts are paid to the relevant *market participants.*

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

6.17.10 Where an amount is payable to a former *market participant* as a result of a *settlement* adjustment, the *IESO* shall endeavor to distribute the amount as specified in the applicable *market manual*. If the *IESO* cannot distribute the amount to the former *market participant* as specified in the applicable *market manual*, such amount shall be used to offset the *IESO administration charge*.

6.18 Settlement Financial Balance/Maximum Amount Payable by IESO

6.18.1 The *IESO* shall provide and operate a *settlement* control process to monitor the financial balance of the calculated charges and payments so as to ensure that, subject to section 6.18.3:

6.18.1.1 for *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

6.18.1.2 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*.

6.18.2 Subject to the provisions of section 6.16, the *IESO* shall not be liable to make payments in excess of the amount it receives for transactions in the *real-time markets*.

6.18.3 If there is an aggregate imbalance for all transactions for a given *trading day* or *billing period,* the *IESO* shall, in accordance with section 6.18.4 or by such other means as the *IESO* determines appropriate, recover that portion of the imbalance that arises by virtue of the rounding of *settlement amounts* or of an adjustment to the *settlement statement* of one *market participant* that is too small to be reflected in corresponding *settlement statement* of other *market participants* provided that:

6.18.3.1 the manner of calculation of that portion of the imbalance can be evidenced in a manner satisfactory for purposes of the audit referred to in section 6.19; and

6.18.3.2 that portion of the imbalance has accumulated to an amount which is sufficient to permit recovery.

6.18.4 The *IESO* may recover the portion of an aggregate imbalance referred to in section 6.18.3 by means of an adjustment to a *settlement statement* applied:

6.18.4.1 to *market participants* to whom *hourly uplift* may be allocated pursuant to these *market rules*;

6.18.4.2 in the same manner as *hourly uplift;* and

6.18.4.3 in respect of all *settlement hours* of the last day of the *billing period* in which the portion of such aggregate imbalance is determined to arise and be recoverable pursuant to section 6.18.3.

6.19 Audit

6.19.1 The audit of *settlement* functions referred to in this section 6.19 shall serve to examine and evaluate compliance with management control objectives and operational effectiveness of *settlement process*es and procedures.

6.19.2 The audits referred to in section 6.19.3 shall be performed by an external, independent auditing firm.

6.19.3 Unless otherwise directed by the *IESO Board*, the *IESO* shall every two years, on the anniversary of the *market commencement date*, direct a comprehensive external audit on the *settlement process*es and procedures. The audit shall include the following tasks:

6.19.3.1 gauge the performance of the *settlement process* in meeting the objectives of these *market rules;*

6.19.3.2 review the accuracy and timeliness of the production of *settlement statements*, including *settlement* calculations and financial allocations;

6.19.3.3 review the accuracy and timeliness of the production of *invoice*s and supporting market and system information;

6.19.3.4 review the *reliability* and integrity of the market and system operational data used in the *settlement process*es and procedures;

6.19.3.5 review the *reliability* and security of the information technology system infrastructure used to measure, validate, classify, compute and report *settlement* information;

6.19.3.6 review the adequacy of *settlement processes* and procedures to safeguard *confidential information*; and

6.19.3.7 review the adequacy and effectiveness of risk management controls of the *settlement process*es and tools, including the effectiveness of the *disaster recovery plan.*

6.19.4 *Settlement statements*, financial *settlement* records and any documentation pertaining to the *IESO's settlement* activities shall, subject to sections 2.11.1 to 2.11.3, be kept in secure storage for a period of at least seven years and made available for auditing purposes.

6.19.5 An audit report shall be prepared by the auditors in respect of each audit conducted pursuant to this section 6.19 and shall be commissioned on the basis that the audit report must be provided to the *IESO* within one month after completion of the audit activities.

6.19.6 Each audit report prepared pursuant to this section 6.19 shall be made available to a *market participant* upon request, subject to such measures as may be required to be taken to safeguard any *confidential information* contained in such audit report.

6.20 Settlement Accounts

6.20.1 The *IESO* shall establish and maintain the *settlement accounts* described in this section 6.20 for the operation of its *settlement* and billing systems.

6.20.2 The *IESO* shall obtain lines of credit and other banking facilities it deems necessary for the operation of the *settlement accounts* described in this section 6.20, which lines of credit and other banking facilities shall not exceed an aggregate amount approved by the *IESO Board*.

6.20.3 The *IESO* may establish *settlement accounts* in addition to those referred to in this section 6.20 as may be necessary to implement the *settlement* and billing processes outlined in this Chapter. *Market participant*s shall be notified 60 *business days* prior to any such additional *settlement accounts* becoming *operational*.

6.20.4 The *IESO* shall open and maintain the *IESO settlement clearing account* as a single bank account to and from which all *settlement* payments shall be made in accordance with the provisions of this Chapter and the details of which shall appear in the *invoice*s sent by the *IESO* to *market participant*s as provided in section 6.12.2.4**.**

6.20.5 The *IESO* shall open and maintain the *IESO adjustment account*, which *account* shall operate as follows:

6.20.5.1 the *IESO adjustment account* shall be a single bank account established to receive and disburse payments related to penalties, damages, fines and payment adjustments arising from resolved *settlement* disputes, and to reimburse the *IESO* for any associated costs or expenses;

6.20.5.2 any amounts paid into the *IESO adjustment account* by *market participant*s shall first be applied to reimburse the *IESO* in respect of any costs or expenses described in section 6.20.5.1 which it has or will incur. Any remaining amount shall be credited to the *IESO adjustment account;* and

6.20.5.3 the *IESO Board* shall review, at least annually, the allocation of any credit balance of the *IESO adjustment account*, and may:

a. establish an amount to be retained in the *IESO adjustment account*;
b. direct that some or all of the credit balance be applied to special education projects or initiatives; and/or
c. direct that some or all of the balance be distributed to *market participants* on a basis to be determined by the *IESO board*.

6.20.6 The *IESO* shall open and maintain the *IESO prepayment account,* which *account* shall operate as follows:

6.20.6.1 the *IESO prepayment account* shall be a bank account established for *market participants* to deposit prepayments at an earlier date than the specified *market participant payment date*; and

6.20.6.2 the arrangements for making the prepayment and transferring funds from the *IESO prepayment account* to the *IESO settlement clearing account* shall be in accordance with the provisions of section 6.13.2.

6.20.7 The *IESO* shall open and maintain the *TR clearing account*, which *account* shall operate in the manner described in sections 4.18 and 4.19 of Chapter 8.

6.20.8 Unless otherwise specified, the *IESO* shall recover all banking costs reasonably incurred in opening and operating the *IESO's settlement accounts* through the *IESO administration charge.*

6.20.9 The *IESO* shall maintain its *settlement accounts* at a bank or financial institution in the Province of Ontario approved by the *IESO Board*.

6.20.10 Each *transmitter* shall be required to open and maintain a *transmission services settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.11 Each *transmitter* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *transmitter's transmission services settlement account*.

6.20.12 Each *market participant* shall be required to open and maintain a *market participant settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.13 Each *market participant* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *market participant's market participant settlement account*.

6.20.14 The *settlement accounts* referred to in this section 6.20 may be changed or closed as follows:

6.20.14.1 the *IESO* may change the bank or the details of any of its *settlement accounts*, on the condition that the bank or financial institution is reasonably acceptable to the *IESO Board* and that all *market participant*s are notified by the *IESO* in writing at least 60 *business days* before the change takes effect; and

6.20.14.2 any *transmitter* or *market participant* may change its bank or the details of its *settlement account*, on the condition that the *IESO* is notified in writing at least 60 *business days* before the change takes effect.