Interjurisdictional Energy Trading

IESO Training

Revised: January, 2014

Introduction to Interjurisdictional Energy Trading

AN IESO TRAINING PUBLICATION

This document has been prepared to assist in the IESO's training of market participants and has been compiled from extracts from the market rules or documents posted on the web site of Ontario's Independent Electricity System Operator. Users are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this document, even if such obligations are not specifically referred to herein. While every effort has been made to ensure the provisions of this document are accurate and up to date, users must be aware that the specific provisions of the market rules or particular document shall govern.

The Independent Electricity System Operator
Box 4474, Station A
Toronto, Ontario
M5W 4E5

Reception: (905) 855-6100
Fax: (905) 403-6921
Customer Relations: (905) 403-6900
Toll Free: 1-888-448-7777

Website: www.ieso.ca

Table of Contents

1. Introduction

The IESO-controlled grid is connected to five neighbouring jurisdictions with intertie transmission lines. These lines allow Ontario to import and export energy. This workbook introduces the basic concepts of Interjurisdictional Energy Trading (IJT) in the IESO-administered markets.

NOTE: This workbook does not include information on interjurisdictional energy trading under the Day-Ahead Commitment Process (DACP). For information on the DACP, please refer to:

- DACP recorded presentations, available on the Training web pages
- 'Guide to the Day-Ahead Commitment Process', available on the Training web pages
- Market Manuals 9.0 through 9.5 concerning the DACP, available on the Rules, Manuals and Forms web pages

Prerequisite

To benefit from this module, you need an understanding of how Ontario's physical markets work. You can gain this understanding by reading *Introduction to Ontario's Physical Markets,* available on the Training home page.

Objectives

After completing this course you will be able to:

- List the markets in which importers and exports can participate
- List the three types of import/export transactions and relate them to transactions within Ontario
- Distinguish between Ontario prices and prices used for imports and exports
- Explain the impact imports and exports have on Ontario prices
- Explain how prices are set for imports and exports
- Explain how imports and exports are scheduled
- Explain how congestion management settlement credits are calculated for intertie transactions
- Calculate intertie offer guarantee (IOG) payments
- Explain the application of the net interchange schedule limit
- Discuss the settlements process and associated charge types
- Explain schedule compliance requirements and potential failure charges

2. Interjurisdictional Energy Transactions

Moving energy across intertie transmission lines to or from other control areas is referred to as interjurisdictional energy trading (IJT). Market participants wishing to conduct IJT can participate in both the real-time energy and operating reserve markets in Ontario. While interjurisdictional transactions are similar to transactions within Ontario, there are significant differences. These differences will be explained in this document.

Objectives

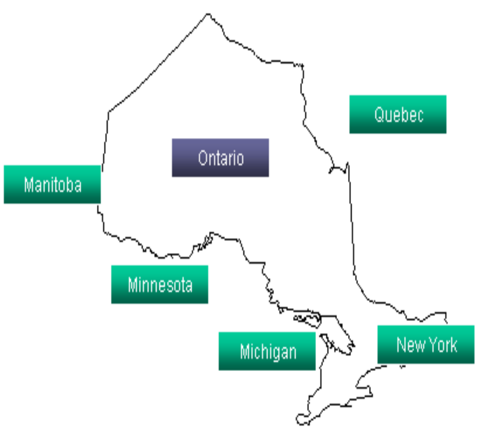
When you have completed this chapter you will be able to:

- List the adjacent control areas available for interjurisdictional trade
- Explain the types of interjurisdictional transactions
- Explain when interchange schedules are determined and why this is different from when schedules for facilities within Ontario are set

Interties

Ontario is interconnected with five other jurisdictions (or “control areas”):

- Manitoba
- Minnesota
- Michigan
- New York
- Quebec



Interties are transmission lines that allow energy to move between adjacent balancing authorities. Like any transmission line, interties can carry only so much energy. Exceeding this level can result in reliability issues such as overheating. Ontario’s IESO and our interconnected partners work together to keep flows across the interties within these limits. Intertie flows are also managed by the IESO to ensure the stable operation of the electricity grid within Ontario.

Types of Interjurisdictional Energy Trading

There are three types of interjurisdictional energy transactions. A participant can:

- import energy or operating reserve from another control area into Ontario
- export energy from Ontario to another control area
- move energy from one jurisdiction, through Ontario, to a different jurisdiction (called "wheeling")

In order for an intertie transaction scheduled in Ontario to flow, there must be a matching transaction scheduled in the neighbouring jurisdiction. For example, an import from New York scheduled in the Ontario market must having a matching export scheduled in the New York market. It is the responsibility of the market participant to ensure that appropriate matching transactions are scheduled by meeting the requirements of the neighbouring jurisdiction.

Import

An import involves moving energy from another control area into Ontario for use by consumers within Ontario. An import acts much like an internal generator in that it helps meet Ontario energy demand. As with internal generators, a participant wishing to complete an import transaction must make a supply offer in the IESO-administered market. Import offers are considered along with all other offers received from suppliers. An import offer is accepted and scheduled if:

- it is required to meet demand,
- it is economic in comparison to other supply, and
- it can be physically accommodated by the intertie and the IESO-controlled grid.

Export

Exports are treated in much the same way as internal dispatchable load. In order to export energy, a participant must place a bid in the IESO-administered market to purchase energy at the intertie. An export will be scheduled if the bid is economic and the intertie and IESO-controlled grid can physically accommodate the transaction.

Wheel-Through

A wheel-through allows a participant to move energy from one jurisdiction through Ontario to another jurisdiction. For example, a participant may want to move energy from New York to Minnesota through Ontario. This movement is achieved by transacting both an import to Ontario and an export from Ontario during the same period.

In the simplest form of wheel-through, a participant makes an offer to import energy and a bid to export energy during the same period. If both the bid and offer are accepted, the energy will flow into and out of Ontario at the same time. Importantly, in this form of wheel-through the two transactions (import and export) are totally independent from each other. The success of one transaction has no influence on the success of the other. Therefore, if one leg fails, the other may still flow. This may present a risk to the participant.

This risk can be avoided by "linking" the two legs of the wheel-through. This ensures that if one leg of a wheel-through is curtailed or fails, the other leg will also be curtailed.

Linking a wheel-through is achieved by:

- Offering the import leg of the transaction at between -$50 and negative maximum market clearing price (i.e., -$2,000)
- Bidding the export leg at maximum market clearing price (i.e., $2,000)
- Submitting the NERC tags for each leg in a particular format (see the section "Placing Bids and Offers" below)[1]

Operating Reserve

Operating reserve is stand-by power or demand reduction that the IESO must have available in case of a contingency on the grid such as the loss of a generator. If a contingency occurs, operating reserve is activated, re-establishing the balance between supply and demand and thereby maintaining system reliability. The IESO purchases operating reserve on behalf of the market. The cost is then charged back to loads (including exports) through an uplift.

Market participants involved in imports and exports can offer 10 minute non-spinning and 30 minute operating reserve. In order to offer operating reserve you must:

- be able to provide the energy when called upon within the time frame specified by the class of operating reserve involved (either 10 minutes or 30 minutes)
- be able to supply the energy for up to one hour (the neighbouring jurisdiction must allow this to occur)
- have a bid or offer in the energy market for an amount greater than or equal to the quantity of your operating reserve offer

---

[1] Please see *Market Manual 4.2: Submission of Dispatch Data In the Real-time Energy and Operating Reserve Markets* on the Rules, Manuals and Forms web pages for more details on wheel-throughs

Placing Bids and Offers

Placing an offer or bid at an intertie is very similar to placing one within Ontario:

- Bids and offers are placed using the Energy Market Graphical User Interface Workspace.[2]
- Scheduling is independent of any bilateral contracts. All transactions must clear the market economically. No preference is given to those covered under contractual agreements.
- No physical transmission rights are required. Once a transaction is scheduled, the participant has access to Ontario's transmission system.

There are two primary differences, however, between bids and offers within Ontario and those at the interties:

- A participant bidding or offering in Ontario has to indicate the location of the desired transaction (i.e., where the energy will either be injected into or taken out of the IESO-controlled grid). This information is required by the IESO computer algorithm so that it can evaluate the effects of any physical system constraints when considering the transaction. Knowing the location of the transaction is also critical information for settlement purposes. Participants indicate their transaction's location by entering a resource name with their bid or offer. A resource name is a unique identifying reference which is associated with a facility (e.g., a generator or load).
- With intertie transactions, the IESO needs to know where the energy is going to (if an export) or coming from (if an import). However, intertie bids and offers are not associated with a facility registered within Ontario. Therefore, a boundary entity resource is used to indicate an intertie transaction's location.[3] In addition to the resource, the participant must also indicate which intertie they plan to use.

---

[2] Please see the *Energy Market Graphical User Interface Workspace Training Manual* available on the Training home page for more information on entering, revising and cancelling offers and bids.

[3] Please see *Market Manual 4.2: Submission of Dispatch Data in the Real-time Energy and Operating Reserve Markets* on the Rules, Manuals and Forms web pages for a complete listing of boundary entity resources.

- The market participant must enter a NERC tag with their export bid or import offer.[4] Participants are responsible for updating the tag if the quantity of energy that clears the market is different from the quantity indicated in the originally submitted NERC tag (see the next section for timing).[5] The Ontario portion of the transaction should be designated as FIRM "7F". Quebec transactions should use the control area HQT. If entering a linked wheel-through:
  - The import leg tag should be in the format:

    WI_Source Control Area_ _ _ _ _Sink Control Area
  - The export leg tag should be in the format:

    WX_Source Control Area_ _ _ _ _Sink Control Area

Scheduling Interjurisdictional Trade

The IESO uses a computer algorithm called the Dispatch Scheduling Optimizer (DSO) to determine prices and schedules.[6] It is run in two timeframes:

- Hourly in "pre-dispatch" to determine projected prices, projected schedules for dispatchable facilities within Ontario, and projected and actual interchange schedules
- Every five minutes in "real-time" to determine actual dispatch schedules for facilities within Ontario, and settlement prices

Participants with dispatchable facilities in Ontario receive dispatch instructions every five minutes. Dispatch instructions tell the participant what quantity of energy they should be injecting or withdrawing by the end of the five-minute interval during which the instruction was received.

The IESO cannot issue dispatch instructions every five minutes in real-time to facilities located outside of Ontario. Instead, interjurisdictional trade is co-ordinated between the IESO and other balancing authorities, using hourly interchange schedules. Imports and exports are scheduled on an economic basis within the physical security limits of the intertie and of the IESO-controlled grid. Which imports or exports are accepted for a particular dispatch hour is determined by the pre-dispatch run of the DSO during the preceding hour (for example, the schedule for noon to 1:00 p.m. is determined between 11:00 a.m. and noon). This schedule is then confirmed with our neighbouring

---

[4] NERC (North American Electric Reliability Council) tags are participant-selected codes that identify intertie transactions. For more information on NERC Tags, please see the NERC web site: www.NERC.com and Market Manual 4.2, *Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets* available on the IESO Rules, Manuals and Forms web page.

[5] Except for transactions with New York, where the sink balancing authority will make any required changes for you. Please see *Market Manual 4.2: Submission of Dispatch Data in the Real-time Energy and Operating Reserve Markets* on the Rules, Manuals and Forms web pages

[6] See the *Introduction to Ontario's Physical Markets* workbook available on the Training web pages

jurisdictions to determine if matching transactions have been scheduled. Once this is confirmed, transactions become fixed for the dispatch hour. This means that they do not change during the hour (unless a change is needed for reliability reasons). Further, no additional intertie transactions can be made to flow during the hour using market mechanisms. Therefore, intertie transactions compete economically in pre-dispatch in order to be scheduled, but are then fixed for the hour in real-time. This has an important effect on pricing and settlements, which will be explained in later sections.

Participants use the IESO Reports site to retrieve their interchange schedules before the dispatch hour. For example, the interchange schedule for the hour starting at 9:00 a.m. eastern standard time (EST) is determined by a run of the IESO algorithm starting at 8:07 a.m. This interchange schedule should be available by 8:20 a.m. Participants are required to supply valid NERC tags at least 30 minutes prior to the dispatch hour (35 minutes if Transmission Load Relief has been declared).

Summary

Market participants who wish to import energy must make an offer to inject into the IESO-controlled grid. An import offer is placed using the Energy Market Graphical User Interface in much the same way as a generator in Ontario places an offer.

Market participants who wish to export energy must make a bid to withdraw energy from the IESO-controlled grid. An energy bid is placed using the Energy Market Graphical User Interface in much the same way as a dispatchable load in Ontario places a bid.

Import offers and export bids are evaluated by the DSO algorithm, taking into consideration both the economic competitiveness of the bid or offer, and the physical ability of the intertie and of the IESO-controlled grid to accommodate the transaction.

Interjurisdictional transactions are scheduled by the last pre-dispatch run of the algorithm before the dispatch hour. They are then fixed for the dispatch hour at the quantity determined hour ahead.

Skill Check

1) List the five adjacent control areas.

   a)
   b)
   c)
   d)
   e)

2) Importers and exporters may provide operating reserve in which two classes?

   a)
   b)

3) True or False:
   If the IESO accepts an import offer and schedules the import, the participant is guaranteed access to the intertie, the IESO-controlled grid, and to facilities in neighbouring control areas.

4) In order to ensure a successful wheel-through, the market participant must:

   a) Make a successful offer to import and a successful bid to export
   b) Link the export and import legs
   c) Successfully navigate the affected neighbouring jurisdictions
   d) a) and c)
   e) a), b) and c)

5) Select the 2 correct statements:

   a) Imports and exports are scheduled for 5-minute blocks
   b) Interchange schedules are for 1-hour time periods
   c) Having a physical bilateral contract guarantees that your transaction will be scheduled
   d) If the IESO cuts one leg of a non-linked wheel-through, it will not automatically cut the other leg

Skill Check: Answers

1) List the five intertie points with adjacent control areas.

    a) Manitoba
    b) Minnesota
    c) Michigan
    d) New York
    e) Quebec

2) Importers and exporters may provide operating reserve in which two classes?

    a) 10 minute non-spinning
    b) 30 minute

3) True or **False**:
    If the IESO accepts an import offer and schedules the import, the participant is guaranteed access to the intertie, the IESO-controlled grid, and to facilities in neighbouring control areas.
    Comment: The participant must still navigate the neighbouring jurisdiction and ensure their NERC tags are valid.

4) In order to ensure a successful wheel-through, the market participant must:

    a) Make a successful offer to import and a successful bid to export
    b) Link the export and import legs
    c) Successfully navigate the affected neighbouring jurisdictions
    d) a) and c)
    e) a), b) and c)

    Comment: The likelihood of a wheel-through being successfully scheduled is not increased by linking the two legs. Doing so only ensures that if one leg fails, the other will be cut.

5) Select the two correct statements:

    a) Imports and exports are scheduled for 5-minute blocks.
    b) Interchange schedules are for 1-hour time periods
    c) Having a physical bilateral contract guarantees that your transaction will be scheduled
    d) If the IESO cuts one leg of a non-linked wheel-through, it will not automatically cut the other leg

3. Pricing and Scheduling of Interjurisdictional Trade

Imports are paid the price in the zone through which they are importing while exports pay the price in the zone through which they are exporting. Intertie zone prices may be higher, lower, or the same as the price used to settle transactions occurring in the Ontario zone. Differences between the Ontario and intertie zone prices are caused by congestion.

When you have completed this chapter, you will be able to:

- Define “intertie congestion price” (ICP)
- Given a set of bids and offers, determine the Ontario market clearing price (MCP) and an intertie zone price in a situation with congestion and in a situation without congestion
- Explain the impact on settlements of scheduling imports and exports an hour ahead

Prices and Constraints

As discussed in Section 2, the IESO uses the Dispatch Scheduling Optimizer (DSO) algorithm to determine prices and schedules. It is run in two time frames:

- Hourly in “pre-dispatch” to determine projected prices, projected schedules for dispatchable facilities within Ontario, and projected and actual interchange schedules
- Every five minutes in “real-time” to determine actual dispatch schedules for facilities within Ontario, and settlement prices

The DSO is run in both an unconstrained and constrained mode in both the pre-dispatch and real-time timeframes:

- The unconstrained mode determines prices and market schedules with limited reference to the physical limitations of the electricity system
- The constrained mode determines dispatch schedules taking the physical system into consideration[7]

[7] For more information on DSO modes, please see the *Introduction to Ontario’s Physical Markets* workbook, available on the Training web pages

The DSO determines prices for Ontario as well as for a number of intertie zones:

Control Area	Code(s)
Ontario	ONZN
Manitoba	MBSI
Minnesota	MNSI
Michigan	MISI
New York	NYSI
Quebec	PQBE
	PQDA
	PQDZ
	PQHA
	PQHZ
	PQPC
	PQQC
	PQXY
	PQAT

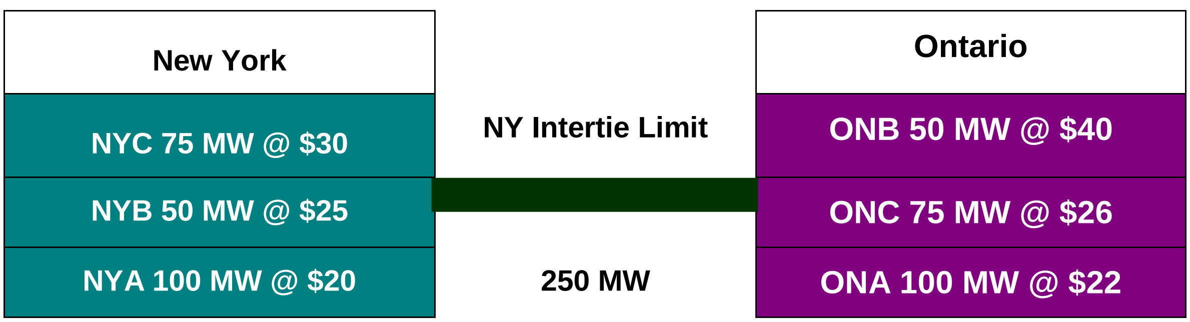
Imports are paid the price in the intertie zone while exports pay the price in the zone. Intertie zone prices can be higher, lower, or the same as the price used to settle transactions occurring in the Ontario zone. Differences between the Ontario and intertie zone prices are caused by congestion. But what is congestion in this context? As with any transmission line, the interties that connect Ontario to neighbouring control areas have a maximum allowable flow limit. Scheduling transactions in excess of this limit can result in reliability issues, such as overheating. A maximum flow limit can be referred to as a "constraint" as it constrains the ability of the DSO to schedule transactions. Because of these flow limits, there can be more energy trying to move in a given direction across an intertie than can be physically accommodated. When this occurs, the DSO may not be able to schedule all of the transactions that have an economic bid or offer. Instead, because energy can only be scheduled up to the maximum flow limit, energy that is otherwise economic may be left unscheduled. When this occurs the "constraint" is said to be "binding" due to congestion.

A binding intertie constraint impacts both scheduling (by the constrained mode of the DSO) and pricing (by the unconstrained mode). This is because the unconstrained mode takes into account the limitations of the interties (although it ignores transmission limitations within Ontario).

Let's look at some simplified examples to illustrate the potential scheduling and pricing impact of intertie constraints.

Pre-Dispatch

In this example, there are three generator offers in Ontario and three import offers in the New York zone. The intertie can accommodate up to 250 megawatts (MW) of flow either into or out of Ontario. Demand in Ontario is 225 MW. There are no exports bid in the New York zone.



The DSO looks for the most economic combination of resources that can satisfy demand and that can be accommodated within the physical limitations of the system. Therefore, the pre-dispatch offer stack used by the DSO to satisfy Ontario demand includes offers from Ontario resources as well as imports. Importantly, however, imports are included only to the extent that the intertie can physically transfer the energy. In this example, the intertie can accommodate up to 250 MW of imports. Since there are only 225 MW of import offers, all of the New York import offers will be included in the pre-dispatch offer stack and considered for scheduling. This is illustrated below:

Given Ontario demand of 225 MW, the Ontario zone price would be set by an offer from the NY intertie (NYB) of $25. The resulting Market (unconstrained) schedules would be:

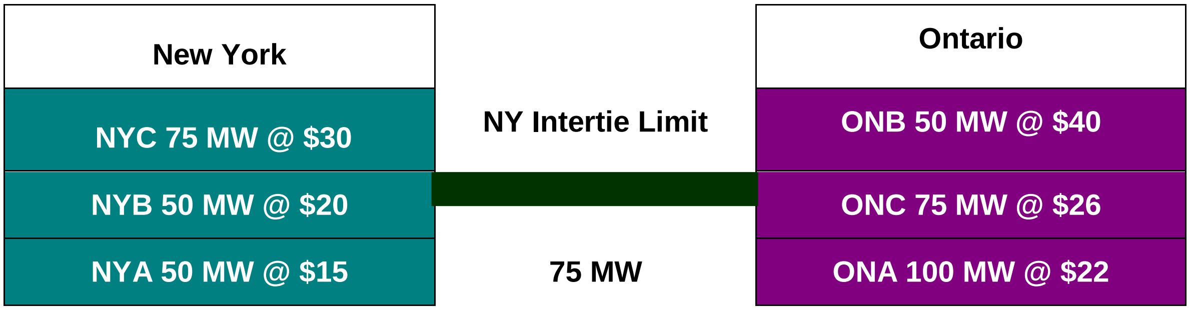
- NYA: 100 MW
- ONA: 100 MW
- NYB: 25 MW

What is the price in the New York intertie zone? Price in an intertie zone is determined by calculating the cost of satisfying one additional megawatt (MW) of non-dispatchable demand in that zone.

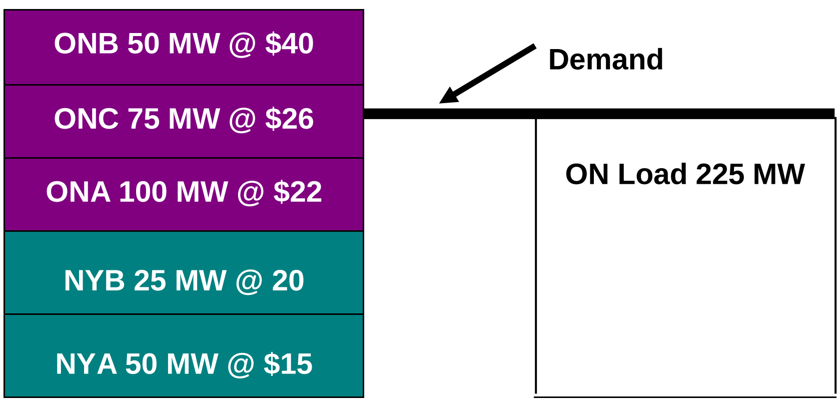
In the above example, what was the demand in the NY zone before the application of this additional MW? It was the total energy scheduled for import to Ontario, or 125 MW. Given this, what would the cost be to satisfy one additional MW of non-dispatchable demand in the NY zone? In this case, the most economical method would be to use NYB's offer at $25. Therefore, the price in the intertie zone and the price in the Ontario zone are the same, indicating a lack of congestion (i.e., there is no binding constraint affecting price).

What happens if a constraint is binding? Intertie congestion is said to occur when the physical limitations of the intertie restrict the movement of otherwise economic energy to and/or from another control area. When intertie congestion occurs, transactions that might otherwise have been accepted cannot be scheduled. The unconstrained mode of the algorithm, which is used for price setting, includes the physical limitations of the interties. Therefore, intertie congestion has a price impact.

We can see the impact of this congestion on both intertie and Ontario zone prices by revisiting our previous example. All of the offers are the same and Ontario demand remains at 225 MW. This time, however, the intertie limit is only 75 MW.



In this example, the unconstrained mode of the algorithm can only consider the most economic 75 MW from the New York zone (which will come from NYA's offer of 50 MW at $15 and NYB's offer of 50MW at $20) when setting the Ontario price. The resulting offer stack is shown below. With this offer stack, ONC becomes the marginal (i.e., price-setting) unit. The Ontario zone price becomes $26 instead of the $25 set by NYB in the previous example:



The resulting Market (unconstrained) schedules in this scenario would be:

- NYA: 75 MW
- NYB: 25 MW
- ONA: 100 MW
- ONC: 50 MW

What is the price in the New York zone? Remember that this price is set based on the cost of satisfying one additional MW of non-dispatchable demand in the intertie zone. In this case, how can we best satisfy a 76th MW of demand?

NYA offered 50 MW at $25 and NYB offered 50 MW at $20 only 75 MW of which could be included in the Ontario stack. This offer is the most economical way to satisfy NY zonal demand. Therefore, the price in the NY zone would be $20. The price in the New

York zone was lower than the Ontario zone price of $26 because the intertie could not physically transfer all of the energy that was economic from the NY zone into Ontario. This means that the intertie was "import-congested". Conversely, an intertie is "export congested" if there are more economic export bids than can be accommodated by the intertie. When this happens, the price in the intertie zone is higher than the Ontario zone price.

The difference between the Ontario zone price and the intertie zone price reflects the cost of congestion on that interface. For example, if the intertie zone price was $50 and the Ontario zone price was only $20, the cost of congestion was $30.

Real-Time

"Real-time" refers to the actual dispatch period during which energy is flowing. In real-time, the MW quantity of scheduled imports and exports are fixed for the hour based on the transactions selected in pre-dispatch. This means that even if real-time demand or price is different than anticipated in pre-dispatch, the schedule for intertie transactions cannot change during the hour.[8] For example, assume that only 50 MW of a 100 MW import offer was scheduled. Even if conditions in real-time meant that the full offer would be economic, no additional energy can be scheduled. Similarly, the import can't be reduced, even if the price in real-time falls below its offer price. Further, offers or bids that weren't selected in pre-dispatch can't be allowed to flow during the dispatch hour even if they would have now been economic.

The quantity of transactions scheduled in pre-dispatch to run in real-time is limited by the transfer limits of the interties. In other words, the total scheduled to flow in real-time can be no greater than the intertie's maximum capacity. Because the schedule can't exceed the maximum flow limit, there can be no congestion on the interties in real-time to cause price differences between intertie zones and the Ontario zone. However, as seen above, there may have been congestion-caused price differences in pre-dispatch. If real-time prices don't respect the cost of this congestion, settlements may be inappropriate.

So how are real-time prices determined for imports and exports that respect the impacts of congestion? This is done this by adding an "intertie congestion price" (ICP) to each of the 5-minute real-time prices in Ontario during the dispatch hour. The ICP reflects the difference between the intertie zone price and the Ontario zone price as determined in pre-dispatch:

[8] Except in limited circumstances for reliability reasons. See *Market Manual 7.4, IMO-Controlled Grid Operating Policies,* available on the IESO Rules, Manuals and Forms web page.

Intertie Congestion price (ICP) = Pre-dispatch Intertie Zone Price - Pre-dispatch Ontario Price

For example, if we have a price in the Ontario zone of $24 and a price in the NY intertie zone of $25 in the hour prior to dispatch, the ICP would be:

ICP = $25 - $24 = $1

The price used to settle imports and exports, therefore, is a combination of the real-time five-minute market clearing price (MCP) in Ontario and the pre-dispatch ICP.[9]

Real-Time Intertie Zone Price = Ontario MCP + ICP

If the real-time price in Ontario is the same as the last pre-dispatch projected price for that hour, by adding the ICP, the intertie zone settlement price will equal the pre-dispatch intertie zone price. Continuing our example from above, if the real-time Ontario price comes in at $24 (as projected in pre-dispatch), adding the $1 ICP to it will result in an intertie settlement price of $25 (which was the pre-dispatch projected price in the NY intertie zone):

Real-Time NY Intertie Zone Price = Ontario MCP + ICP

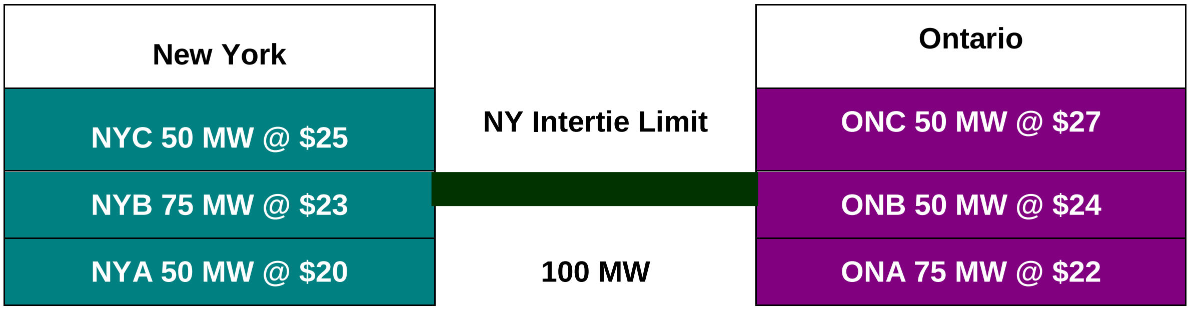
Real-Time NY Intertie Zone Price = $24 + $1

Real-Time NY Intertie Zone Price = $25

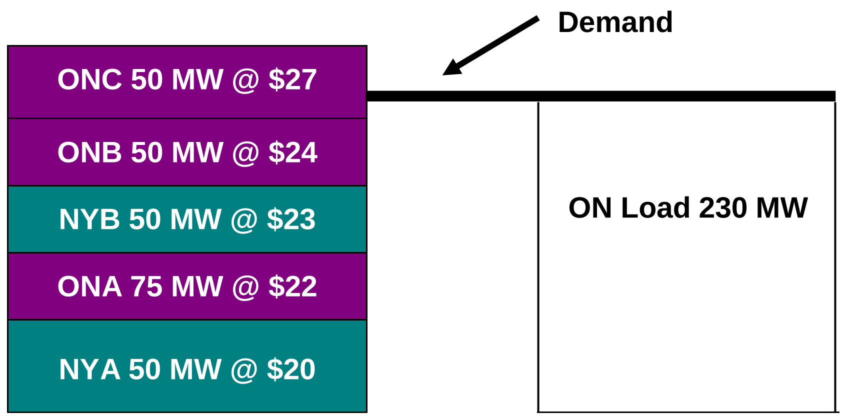
This method of setting real-time intertie zone settlement prices presents a price risk for those conducting intertie transactions because the Ontario MCP in real-time can be different than the pre-dispatch projection of price. The following example illustrates the risk:

Here we have three offers in the NY zone and three offers in the Ontario zone. Demand in Ontario is 230 MW and the intertie has a capacity of 100 MW:

[9] Note: This may not be the case where prices are administered. As well, prices cannot exceed the maximum market clearing price.


New York
NYC 50 MW @ $25
NYB 75 MW @ $23
NYA 50 MW @ $20
NY Intertie Limit
100 MW
Ontario
ONC 50 MW @ $27
ONB 50 MW @ $24
ONA 75 MW @ $22

In pre-dispatch, the offer stack would look like this:



Remember that NYC cannot be considered even though its offer price is lower than ONC's because the intertie can transfer only 100 MW. NYA and NYB have lower offer prices than NYC, so are considered first. Given this stack, the price in Ontario would be $27.

What would the price in the NY zone be? Remember that the price in the intertie zone is set based on the cost of satisfying one additional MW of non-dispatchable demand in that zone. NYB offered 75 MW at $23. Only 50 MW could be taken across the intertie, however. Therefore, NYB still has 25 MW of energy available at $23. Therefore, the price in the NY zone would be $23.

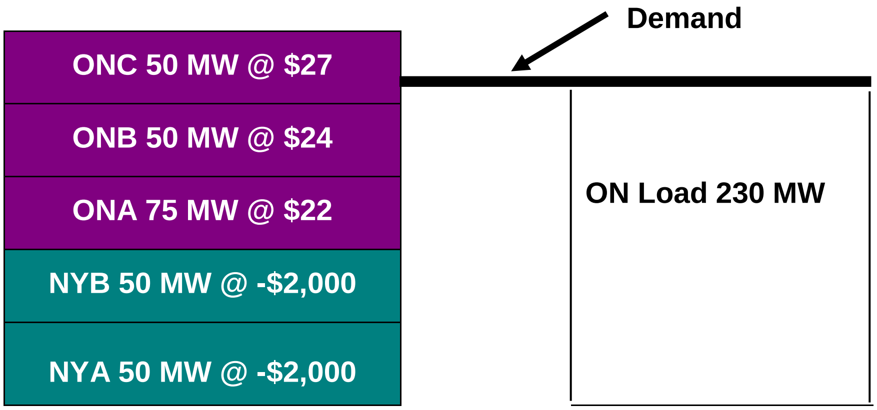
Given a $23 NY zone price and an Ontario zone price of $27, the intertie congestion price would be:

ICP = Pre-dispatch Intertie Zone Price - Pre-dispatch Ontario Price

= $23 - $27 = - $4

In real time, the DSO treats imports and exports as non-dispatchable resources, as their quantity cannot be changed. It does this by assuming that all scheduled imports were offered at negative maximum market clearing price (-$2,000) and that all scheduled exports were bid at positive maximum market clearing price ($2,000). In other words, it assumes that imports and exports are willing to pay up to $2,000/MW (the maximum price in the market) for the ability to flow.

In our example then, the DSO assumes that the scheduled offers from the NY intertie were offered at negative $2,000. Given this, if demand is unchanged at 230 MW, the Ontario MCP would remain at the pre-dispatch value of $27, as illustrated below:



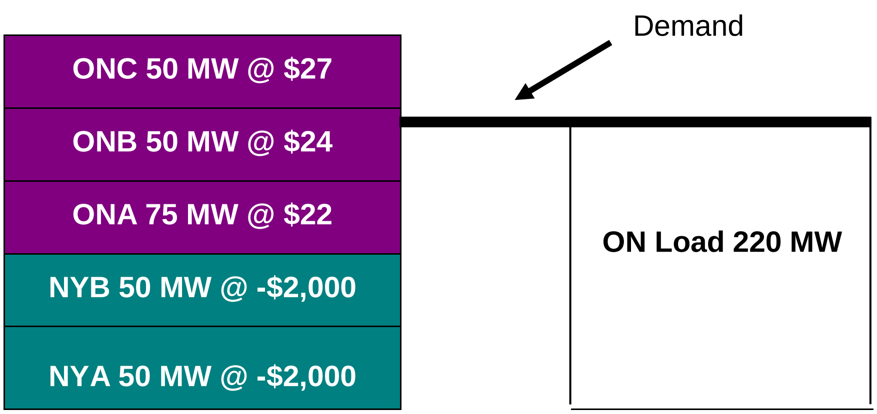
Therefore, the real-time intertie zone price would be:

Real-Time Intertie Zone Price = Ontario MCP + ICP

= $27 + (-$4) = $23

This is the same price as was projected in pre-dispatch. Therefore, both NYA and NYB achieve in real-time the operating profit they anticipated achieving in pre-dispatch. (Operating profit is the difference between a participant's offer price and the intertie zone price. See page 25 for more information on operating profit.)

However, the real-time Ontario MCP can be different from the pre-dispatch projection. This can occur, for example, if demand in real-time is different than what was projected in pre-dispatch. Let's assume that the real-time demand in our example is 220 MW instead of the 230 MW projected in pre-dispatch.



If this were to occur, the Ontario zone price in real-time would be $24. This would mean a real-time settlement price in the intertie zone as follows:

Real-Time Intertie Zone Price = Ontario MCP + ICP

= $24 + (-$4) = $20

This is $3 lower than the intertie zone price of $23 that was projected in pre-dispatch. Further, this price is below the $23 offer price of NYB. There is a price risk, then, for participant's transacting at the interties caused by the fact that transactions are scheduled based on pre-dispatch projections but are settled based on real-time prices. We will discuss how this price risk is mitigated for importers in *Section 5: Intertie Offer Guarantee.*

Summary

When there is no congestion, the MCP (market clearing price) for an intertie zone will be the same as the Ontario zone MCP. If there is import congestion the price in the intertie zone will be lower than the price in the Ontario zone. If there is export congestion, the intertie zone price will be higher than the Ontario zone MCP.

Imports and exports are scheduled based on the pre-dispatch results during the hour prior to the actual dispatch hour. The price used to settle the transaction is a combination of the intertie congestion price (ICP) from pre-dispatch, and the twelve 5-minute real-time Ontario prices during the dispatch hour.

Skill Check

1. True or False:
   A binding constraint is one that limits the ability of the DSO to schedule all energy that is economic.

2. Given a $30 NY zone price and an Ontario zone price of $24, the intertie congestion price would be:
   a. $6
   b. $3
   c. -$6

3. True or False
   The physical limitations of the interties have no impact on the price in Ontario.

4. Select the 2 correct statements:
   a. Imports and exports can be adjusted for economics during a dispatch hour
   b. In real-time, the DSO assumes that all scheduled imports were offered at negative maximum market clearing price (-$2,000) and that all scheduled exports were bid at positive maximum market clearing price ($2,000)
   c. The price in an intertie zone is set based on the cost of satisfying one more MW of demand in the zone.
   d. If there is intertie congestion, the price in the intertie zone will be the same as the Ontario price

5. What is the price in the Michigan zone and the price in Ontario, given Ontario demand of 350 MW, a Michigan intertie capacity of 150 MW, and the following offers:

Michigan Import Offers	Ontario Offers
MIA 100 MW at $25	ONA 150 MW at $37
MIB 75 MW $35	ONB 100 MW at $45
MIC 50 MW at $40	ONC 100 MW at $50

Skill Check: Answers

1. **True** or False:
   A binding constraint is one that limits the ability of the DSO to schedule all energy that is economic.

2. Given a $30 NY zone price and an Ontario zone price of $24, the intertie congestion price would be:
   a. **$6**
   b. $3
   c. -$6

3. True or **False**
   The physical limitations of the interties have no impact on the price in Ontario.

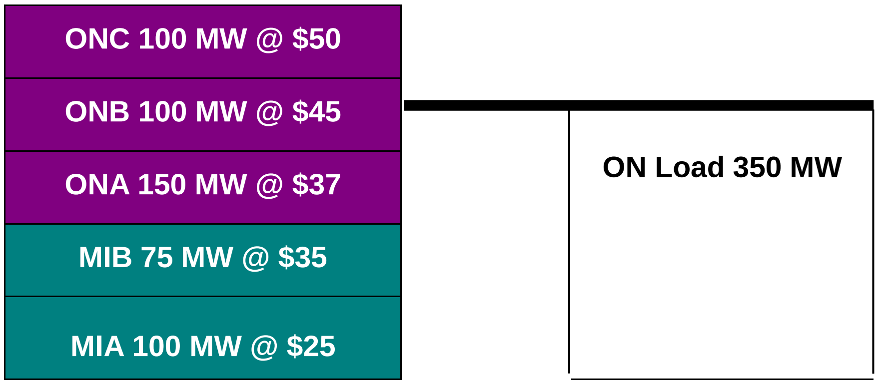
4. Select the 2 correct statements:
   a. Imports and exports can be adjusted for economics during a dispatch hour
   b. **In real-time, the DSO assumes that all scheduled imports were offered at negative maximum market clearing price (-$2,000) and that all scheduled exports were bid at positive maximum market clearing price ($2,000)**
   c. **The price in an intertie zone is set based on the cost of satisfying one more MW of non-dispatchable demand in the zone**
   d. If there is intertie congestion, the price in the intertie zone will be the same as the Ontario price

5. What is the price in the Michigan zone and the price in Ontario, given Ontario demand of 350 MW, a Michigan intertie capacity of 150 MW, and the following offers:

Michigan Import Offers	Ontario Offers
MIA 100 MW at $25	ONA 150 MW at $37
MIB 75 MW $35	ONB 100 MW at $45
MIC 50 MW at $40	ONC 100 MW at $50

See next page for answer:

Ontario offer stack



MIC would not be included in the stack as the intertie can only take 150 MW. Therefore, the price in Ontario is $45.

The price in Michigan would be $35 as set by MIB.

4. Congestion Management and Interjurisdictional Trade

Market schedules and prices are determined by the unconstrained mode of the DSO whereas dispatch (interchange) schedules are determined using a constrained mode. Because these two modes consider different factors, there can be a difference between a participant's market schedule and their interchange schedule. Such a difference can result in a change in operating profit. If this occurs, congestion management settlement credits (CMSC) return the participant to their market schedule operating profit.

Chapter 9 of the market rules, *Settlements and Billing*, outlines the use of CMSC. The *Introduction to Ontario's Physical Markets* workbook explains CMSC as it is generally applied in the IESO-administered markets. In this section we will discuss how CMSC specifically relates to imports and exports.

Objectives

After completing this section you will be able to:

- Explain the differences between the market schedule and the interchange schedule
- Calculate operating profit
- Calculate CMSC for imports and exports

Schedules, Dispatch Instructions, and Interchange Schedules

As discussed in the *Introduction to Ontario's Physical Markets*, the unconstrained mode of the algorithm determines prices and market schedules while the constrained mode determines dispatch schedules. The table below summarizes the different inputs used by these two modes:

Unconstrained Algorithm Inputs	Constrained Algorithm Inputs
• Flow limitations on interties • Hourly facility ramp rates based on MP input (energy market only) • Last scheduled point for the facility	• Flow limitations on interties • Limitations on the IESO-controlled grid • Limitations provided by the MP, including actual ramp rates • Last actual operating point

While there are a number of circumstances under which a participant's market (unconstrained) and dispatch (constrained) schedules will be different, congestion on an intertie itself is not one of them. Constraints on the intertie are considered in both the unconstrained and constrained mode of the DSO. Therefore, both modes are affected to the same degree by intertie congestion. For intertie transactions, the most common reason for CMSC is congestion on the IESO-controlled grid that restricts the ability of the grid to accommodate the transaction. Consistent with the limit on the settlement price for export transactions the amount of CMSC paid to both constrained on and constrained off exports is limited to result in the same resultant CMSC consistent with what the transaction is settled at.

Please note that linked wheel-through transactions are not eligible for CMSC.

CMSC and Operating Profit

If a participant's dispatch schedule is different from their market schedule, their operating profit may be affected. Operating profit for an importer is the difference between the revenue received for the energy sold and the cost of supplying the energy, as represented by their offer price. For an exporter, operating profit is the difference between the cost of purchasing the energy, and the benefit they realize by using the energy, as represented by their bid price (see *Introduction to Ontario's Physical Markets*). Therefore:

- For imports: Operating Profit = (MCP – Offer Price) x Quantity
- For exports: Operating Profit = (Bid Price – MCP) x Quantity

MCP for intertie transactions is the market clearing price in the intertie zone.

CMSC returns a participant to their market schedule operating profit when their market and dispatch schedules are different. This is done because the market rules reflect the principle that no participant should be unduly benefited or harmed because of their physical location in relation to the transmission grid. The general formula for CMSC is:

CMSC = **operating profit (market schedule)** **-** **operating profit (dispatch schedule)**

We can illustrate the calculation of CMSC payments with an example:

Transbord offers to import 100 MW into Ontario if the price is $22 or higher. The pre-dispatch price in Ontario is $25. As there is no congestion on the intertie, the pre-dispatch intertie zone price in this example is also $25. Therefore, ICP = $25 - $25 = $0.

Transbord's market (unconstrained) schedule would be the full 100 MW offered because their offer price is less than the intertie zone price and there is no intertie congestion.

In this example, let's assume that there is a system constraint on the IESO-controlled grid that prevents the constrained mode from accepting any of the energy from Transbord. Therefore, Transbord's dispatch schedule is 0 MW. (Remember that the unconstrained mode does not recognize constraints *within* Ontario so the market schedule was not impacted by the constraint.)

Let's further assume that the Ontario zone MCP in real-time comes in at $25 for all intervals. ICP was $0, so the real-time intertie zone MCP is also $25. Given this, Transbord's market schedule operating profit would be:

Market Schedule OP = (MCP – Offer Price) x Market Schedule Quantity

= ($25 – $22) X 100 MW

= $300

However, their dispatch schedule operating profit would be:

Dispatch Schedule OP = (MCP – Offer Price) x Dispatch Schedule Quantity

= ($25 – $22) X 0 MW

= $0

Therefore, instead of a $300 operating profit, as per the market schedule, Transbord now stands to receive a $0 operating profit because of a system constraint that was beyond their control.

The market rules were designed so that no participant unduly suffers or benefits by their location relative to the IESO-controlled grid. The participant's constrained schedule was different from their unconstrained schedule because of a constraint on the IESO-controlled grid. Therefore, Transbord would receive a CMSC payment sufficient to return them to their market schedule operating profit. This effectively compensates them for the effect of the constraint on their profitability:

CMSC = Operating Profit Unconstrained – Operating Profit Constrained

= $300 - $0

= $300

Negative CMSC Payments

Congestion management settlement credits are intended to restore participants to the operating profit they would have had under their market schedule. While this is normally a payment, there are circumstances under which CMSC is a debit. This occurs if the participant's dispatch schedule leads to a higher operating profit than they would have received under their market schedule. In these cases, a CMSC payment *from* the participant is required in order to restore their operating profit to their market schedule level. This type of situation can occur with intertie transactions because of the timing of the scheduling process. An example will illustrate:

In pre-dispatch, Exbord places a bid to export 120 MW at the New York intertie zone if the price is $30 or less. In pre-dispatch, the New York zone price is determined to be $28, the same as the Ontario price. Therefore, the ICP for the New York intertie zone is zero. In this scenario, Exbord would receive a market schedule for all 120 MW.

Assume that a system constraint inside Ontario prevents this transaction from being scheduled by the constrained mode. Exbord's dispatch schedule would be 0 MW.

Assume that in real-time the average price over the hour in both the Ontario and New York zones is $42.50 (ICP = $0). This is substantially higher than Exbord's export bid of $30. Because their dispatch schedule was 0 MW, Exbord is not flowing in real-time. However, Exbord did receive a market schedule. Therefore, we have to determine their real-time market schedule operating profit and compare it to their real-time dispatch schedule operating profit (which is $0 because they are not flowing).

The table below shows the twelve 5-minute real-time prices for Ontario and for the New York zone, as well as the market schedule operating profit for Exbord for each interval:

Market Schedule – Real-time

Interval	Ontario MCP $	New York Zone Price $	Offer $	Operating Profit $/MWh	Energy MWh[10]	Total Operating Profit $
1	26	26	30	4	10	40
2	26	26	30	4	10	40
3	29	29	30	1	10	10
4	29	29	30	1	10	10

[10] The offer was for 120 MW for one hour. This translates to an energy quantity of 120 MWh in one hour. Dividing by 12 intervals means 10 MWh per interval.

5	50	50	30	-20	10	-200
6	50	50	30	-20	10	-200
7	50	50	30	-20	10	-200
8	50	50	30	-20	10	-200
9	50	50	30	-20	10	-200
10	50	50	30	-20	10	-200
11	50	50	30	-20	10	-200
12	50	50	30	-20	10	-200

In total, Exbord's market schedule would result in a negative operating profit (i.e., a loss) of $1,500. However, because they were constrained-off and not allowed to flow, Exbord avoided incurring this loss.

What does this mean for CMSC? Remember that CMSC is designed to return the participant to their market schedule operating profit. Therefore:

CMSC = Market Schedule Operating Profit – Dispatch Schedule Operating Profit

= -$1,500 - $0

= -$1,500

In this example, Exbord would be required to pay $1,500 in CMSC in order to restore it to the negative operating profit (loss) that it would have incurred had it not been constrained off.

Exbord's market schedule would have resulted in a loss because of the timing of when the transaction was scheduled. An intertie transaction is scheduled during the hour before the actual dispatch hour based on pre-dispatch prices. It is settled, however, based on real-time prices. In this example, the average price in real-time was $42.50, whereas the pre-dispatch price was $28. Exbord's bid was $30. If they had not been constrained off in pre-dispatch, Exbord would have been scheduled to flow in real-time. They would have then been fixed for the hour, and unable to respond to the higher price in real-time. Therefore, because of the price difference between pre-dispatch and real-time, Exbord would have lost money had they not been constrained off.

Without a CMSC adjustment to return Exbord to their negative market schedule operating profit, they would not incur the loss they should have incurred. CMSC is used to ensure that participants are not unduly harmed *or benefited* by their location on the grid. Avoiding an operating profit loss because of a constraint is a benefit. CMSC is most often a payment to a participant. However, in some cases, as in this example, CMSC can be a charge to the participant.

(For additional information on negative CMSC payments, please see the topic "IOG and Negative CMSC" in *Section 5: The Intertie Offer Guarantee*.)

Skill Check

1. Which of the following statements is false:
    a. The market schedule is determined by the unconstrained mode of the algorithm
    b. The dispatch schedule is determined by the constrained mode of the algorithm
    c. The unconstrained mode of the algorithm ignores flow limitations on the interties
    d. The constrained mode of the algorithm includes flow limitations on the interties

2. What would Borgpower's operating profit be if it was scheduled for 200 MW with an offer price of $45 and the price in the intertie zone was $56 for each interval:
    a. $2,200
    b. $220
    c. $26,400
    d. $2,400

3. What would the CMSC payment be, given the following:
    a. Offer 150 MW at $35
    b. Market schedule = 150 MW
    c. Dispatch schedule = 0 MW
    d. Real-time intertie zone price = $30

Skill Check: Answers

1. Which of the following statements is false:
    a. The market schedule is determined by the unconstrained mode of the algorithm
    b. The dispatch schedule is determined by the constrained mode of the algorithm
    c. The unconstrained mode of the algorithm ignores flow limitations on the interties
    d. The constrained mode of the algorithm includes flow limitations on the interties

2. What would Borgpower's operating profit be if it was scheduled for 200 MW with an offer price of $45 and the price in the intertie zone was $56 for each interval:
    a. $2,200
    b. $220
    c. $26,400
    d. $2,400

3. What would the CMSC payment be, given the following:
    a. Offer 150 MW at $35
    b. Market schedule = 150 MW
    c. Dispatch schedule = 0 MW
    d. Real-time intertie zone price = $30

CMSC = Market Schedule Operating Profit – Dispatch Schedule Operating Profit

= ($30 - $35) X 150 MW – ($30 - $35) X 0 MW

= -$750

5. The Intertie Offer Guarantee

Import transactions are locked in for the hour based on pre-dispatch prices. However, these transactions are settled using real-time prices. As a result, those conducting imports face a settlement price risk due to the scheduling process.

A key market design principle is that the market must not adversely affect the adequacy of supply. Acting on input from stakeholders, the IESO introduced intertie offer guarantee (IOG) payments which reduce price risk for importers. These IOG payments are intended to encourage imports, helping to ensure adequate supply in Ontario.

Objectives

After completing this section you will be able to:

- Explain the purpose of the intertie offer guarantee
- Calculate an intertie offer guarantee payment
- Discuss the impact of implied wheel-throughs on the intertie offer guarantee
- Explain the relationship between negative CMSC and the intertie offer guarantee

Calculation of the Intertie Offer Guarantee

The IOG ensures that, over the course of an hour, an importer will receive revenue at least equal to their market schedule times their average offer price. By doing this, the IOG ensures that an importer does not suffer a negative operating profit over the course of an hour. In other words, they are assured that they will receive at least a $0 operating profit. The IOG is calculated as follows:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

We can illustrate how the IOG works with some examples:

Example One

Assume Transbord offers to import 120 MW if the price is $20 or greater.

In pre-dispatch, the Ontario MCP and the intertie zone MCP are both $24 (ICP = $0). Transbord receives a market schedule for the full 120 MW.

In real-time the Ontario MCP comes in at $15 for each interval of the hour. Because the ICP is zero, the transaction is settled at an intertie zone price of $15. At this price, Transbord would have a negative operating profit:

Operating Profit = (MCP – Offer Price) X Market Schedule Quantity

= ($15 – $20) X 120 MW

= -$600

The IOG is intended to ensure that an importer does not suffer a negative operating profit over the course of an hour. In this example, therefore, the IOG would be:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

= -1 X (($15 - $20) X 120 MW)

= -1 X (-$5 X 120 MW)

= -1 X (-$600)

= $600

The total of the energy payment ($15/MWh) and the IOG payment means that Transbord was paid its offer price of $20 for the scheduled import quantity:

Offer Price Settlement = $20 X 120 MW = $2,400

Total Settlement With IOG = $15 X 120 MW + $600 = $1,800 + $600 = $2,400

Example Two

In our previous example, the real-time price was constant during the dispatch hour. Let's look at what happens if the price fluctuates during the hour.

In this example, assume Transbord offers to import 120 MW from Michigan if the price is $20 or greater.

In pre-dispatch, the Ontario MCP and the Michigan zone price are both $24 (ICP = $0). As a result, Transbord receives a market schedule for the full 120 MW.

In real-time, the Ontario MCP (and therefore the Michigan zone MCP because ICP = $0) is:

- $28 for the first 6 intervals of the hour
- $18 for the remaining 6 intervals of the hour

In real-time, Transbord's operating profit will vary as the real-time MCP varies:

Interval	Ontario MCP $	Michigan Zone Price $	Offer $	Operating Profit $/MWh	Energy MWh[11]	Total Operating Profit $
1	28	28	20	8	10	80
2	28	28	20	8	10	80
3	28	28	20	8	10	80
4	28	28	20	8	10	80
5	28	28	20	8	10	80
6	28	28	20	8	10	80
7	18	18	20	-2	10	-20
8	18	18	20	-2	10	-20
9	18	18	20	-2	10	-20
10	18	18	20	-2	10	-20
11	18	18	20	-2	10	-20
12	18	18	20	-2	10	-20

Transbord's total operating profit over the hour would be:

($80 X 6) + (-$20 X 6)

= $480 - $120

= $360

[11] The schedule is for 120 MW for one hour. This translates to an energy quantity of 120 MWh in one hour. Dividing by 12 intervals means 10 MWh per interval.

An IOG payment is made only if an importer's total operating profit *over an hour* is negative. It is not paid to restore the operating profit for individual intervals. In this case, because the positive operating profit of the first six intervals more than compensated for the negative operating profit of the last six intervals, no IOG is payable.

Example Three

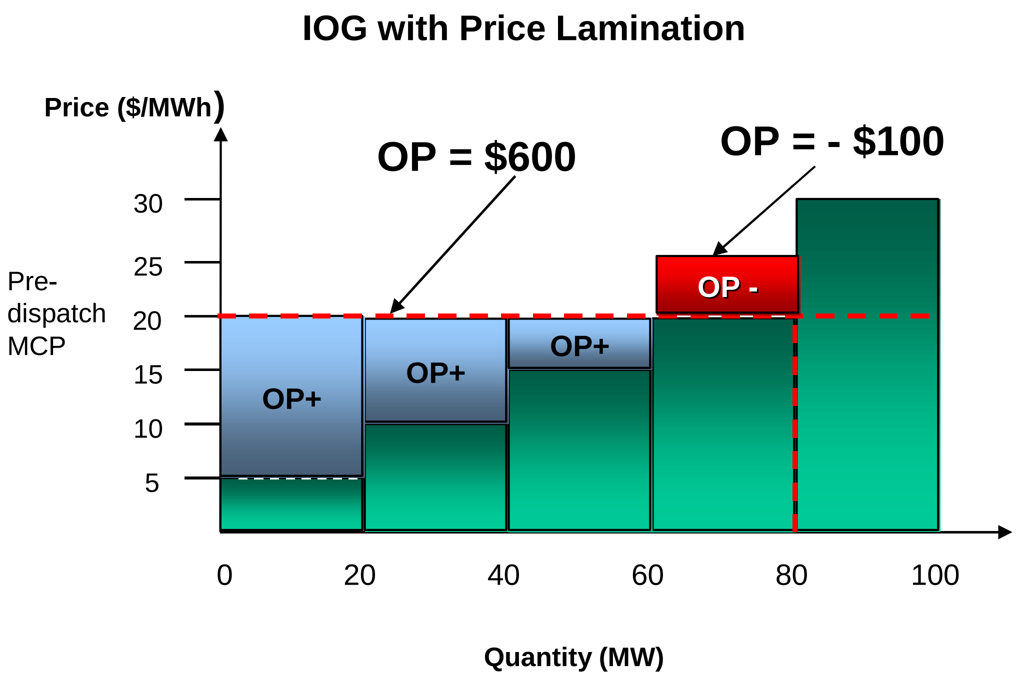
So far the examples have used offers that were for a set quantity at one price. Importers can, however, submit multiple price/quantity pairs. If they do submit more than one price/quantity pair, each pair will have its own operating profit. This can affect IOG payments.

In this example, assume that Transbord makes the following offer to import from New York:

- first 20 MW at $5
- next 20 MW at $10
- next 20 MW at $15
- next 20 MW at $25
- next 20 MW at $30

In pre-dispatch, the Ontario and the New York zone prices are both $25. Transbord is scheduled for 80 MW of its 100 MW offer (the last 20 MW were offered at a price higher than the zone price).

In real-time, the actual price in both Ontario and the intertie zone is $20 for each interval. At this price, Transbord will have a positive operating profit for the first 60 MW it supplies to Ontario, but will incur a loss on the last 20 MW.



Operating Profit = (MCP – Offer Price) X Quantity

= (($20 - $5) X 20 MW) + (($20 - $10) X 20 MW) + (($20 - $15) X 20 MW) +
(($20 - $25) X 20 MW)
= $300 + $200 + $100 - $100
= $500

Transbord has a positive operating profit for the transaction as a whole. Again, no IOG payment will be made. Even though one price/quantity pair had a negative operating profit over the hour, the other three price/quantity pairs generated more than enough operating profit to compensate.

Wheel-Throughs

All of the above examples deal with importing power into Ontario. It is also possible to wheel energy through Ontario, that is, to have both an import and an export scheduled in the same hour. The IOG was implemented as a reliability measure to ensure that imports would be available to help Ontario meet its demand for electricity. A wheel-through of energy does not add to reliability because the increased supply represented by the import is offset by the increased demand resulting from the export. As a result, the import leg of a wheel-through is not eligible for the IOG. This applies to both linked and implied wheel-throughs (where the two legs are not formally linked – see *Section: 2 Interjurisdictional Energy Transactions*).

In order to exclude IOG payments from wheel-throughs, the IESO nets total exports against total imports in the same hour for a participant before determining if an IOG is payable. For example, assume that Transbord:

- Offers to import 120 MW from New York if the price is $20 or greater
- Bids to export 50 MW to Michigan if the price is $30 or less
- Bids to export 50 MW to Manitoba if the price is $35 or less

In pre-dispatch, the Ontario price and all intertie zone prices are determined to be $25. As a result, Transbord is scheduled for 120 MW of imports as well as 100 MW of exports. Even though the exports are not formally linked to the import, they reduce the net quantity of imports for Transbord in this hour from 120 MW to 20 MW. If an IOG becomes due, Transbord will receive payment based only on the 20 MW of imports that did not have an offsetting export.

IOG and Negative CMSC

The IOG will often work to offset a negative CMSC because the IOG is based on the market (unconstrained) rather than the dispatch (constrained) schedule. An example:

Transbord offers to import 100 MW from New York at $25. In pre-dispatch, the Ontario price is $130 and the New York zone price is $30. ICP is -$100.

Transbord is given a market schedule for all 100 MW. However, a constraint on the IESO-controlled grid prevents any of the energy from being scheduled by the constrained mode. Therefore, their dispatch schedule is 0 MW.

In real-time, the price in Ontario is $40 for all intervals. The price in the New York zone, therefore, is negative $60 (Ontario MCP of $40 plus the ICP of -$100).

CMSC for Transbord in this situation would be:

CMSC = Operating Profit Unconstrained – Operating Profit Constrained

= [(-$60 - $25) X 100] - [(-$60 - $25) X 0]

= -$8,500

Transbord would owe the IESO $8,500. However, Transbord is also eligible for an IOG that would entirely offset the negative CMSC in this example:

IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

= -1 X ((-$60 - $25) X 100 MW)

= -1 X (-$8,500)

= $8,500

Skill Check

1. True or False
   The intertie offer guarantee applies to exports as well as imports.

2. What would the IOG be for Genbord assuming the following:
   - Offered 100 MW at $35
   - Pre-dispatch intertie zone price and Ontario price of $40
   - 100 MW market schedule
   - Intertie zone price in real-time of $25

3. What would the IOG be for Transbord assuming the following:
   - Offered 150 MW at $40
   - Pre-dispatch intertie zone price and Ontario price of $45
   - 150 MW market schedule.
   - Intertie zone price in real-time of $50 for the first 8 intervals and $30 for last 4 intervals

4. True or False
   The intertie offer guarantee will normally offset a negative congestion management settlement credit.

5. True or False
   The intertie offer guarantee is paid on total imports during the hour regardless of exports also scheduled during the hour.

Skill Check: Answers

1. True or **False**
   The intertie offer guarantee applies to exports as well as imports

2. What would the IOG be for Genbord assuming the following:
   - Offered 100 MW at $35
   - Pre-dispatch intertie zone price and Ontario price of $40
   - 100 MW market schedule
   - Intertie zone price in real-time of $25

   IOG = -1 X ((Intertie Zone MCP – Offer) X Market Schedule Quantity)

   = -1 X (($25 - $35) X 100 MW)

   = -1 X (-$1,000)

   = $1,000

3. What would the IOG be for Transbord assuming the following:
   - Offered 150 MW at $40
   - Pre-dispatch intertie zone price and Ontario price of $45
   - 150 MW market schedule.
   - Intertie zone price in real-time of $50 for the first 8 intervals and $30 for last 4 intervals

   IOG would be $0 as the positive operating profit from the first 8 intervals ($50 - $40 = $10 for 8 intervals) more than offsets the negative operating profit from the last 4 intervals ($30 - $40 = -$10 for 4 intervals)

4. **True** or False
   The intertie offer guarantee will normally offset a negative congestion management settlement credit.

5. True or **False**
   The intertie offer guarantee is paid on total imports during the hour regardless of exports also scheduled during the hour.

6. Limitations on CMSC Payments

Congestion management settlement credits (CMSC) are designed to return a market participant to its market schedule operating profit in situations where the dispatch schedule is different from the market schedule. Underlying this is the assumption that the market participant offered energy at its marginal cost, or bid for energy at its marginal benefit. If this is the case, the payment of CMSC ensures that the market participant does not suffer an actual loss as a result of being constrained on or off. Over time, several circumstances have been identified under which this assumption of marginal cost/benefit bidding could not be supported.[12] In response, the IESO has instituted a number of market rule changes placing restrictions either on the payment of CMSC, or on how the IESO analyzes transactions which result in CMSC. This section explains these rules as they relate to intertie transactions.[13]

Objectives

After completing this section you will be able to:

- Discuss how CMSC is calculated for constrained-off imports with negative offer prices
- Explain reference prices
- Define an uncontested intertie
- Explain how reference prices are used when considering CMSC paid for constrained-off exports at uncontested interties

CMSC for Constrained-Off Imports with Negative Offers

The market rules allow importers to offer energy at a price as low as negative $2,000. Offering in this way virtually guarantees that the import will be scheduled in the unconstrained (or market) schedule (assuming sufficient intertie capacity). However, conditions on the IESO-controlled grid may result in the import being constrained off. Let's look at an example:

- Borgpower offers to import 100 MW from Michigan at -$1,000
- Borgpower receives a market schedule for all 100 MW
- However, due to a system constraint within Ontario, Borgpower is constrained-off and receives a 0 MW dispatch schedule
- Michigan market clearing price in real-time is $20 for all intervals

---

[12] For example, see the report "Constrained-Off Payments and Other Issues in the Management of Congestion" available on the Market Surveillance Panel pages of the Ontario Energy Board web site.

[13] Note: The procedures described also apply to transactions by generators and loads within Ontario, where applicable.

Therefore:

CMSC = Operating Profit Unconstrained – Operating Profit Constrained

= (($20 - -$1000) x 100 MW)) - (($20 - -$1000) x 0 MW)

= $102,000

This kind of payment is not truly consistent with the underlying CMSC assumption of marginal cost offers. It is highly unlikely that the actual marginal cost to a supplier would ever be less than $0. As a result, if CMSC is payable for a constrained-off import that was offered at a negative price, the IESO recalculates the CMSC so that the market participant receives payments as if they had offered at $0.

Looking at our example again, the CMSC payment for this market participant would be recalculated as follows:

CMSC = (($20 - $0) x 100 MW) - (($20 - $0) x 0 MW)

= $2,000

CMSC and Reference Prices

The IESO examines all instances where a material amount of CMSC has been paid. This is to ensure that such payment did not result from the application of market power.[14] Payments may be reduced if investigations reveal that CMSC resulted from inappropriate circumstances.

One of checks the IESO performs is to compare the offer or bid made by the market participant at the time the CMSC was incurred against two reference prices:

- The market clearing price for the interval or intervals during which the CMSC was incurred, and
- The resource's historical reference price. The historical reference price is the average offer or bid by the participant that was accepted in the market schedule over the 90-day period prior to when the CMSC was incurred. Two historical reference prices are used: One for the period 7:00 to 23:00 EST on business days, and another for all other times.

[14] Materiality for this purpose is defined in *Market Manual 2.12, Treatment of Local Market Power, Appendix C.4* available on the IESO Rules, Manuals and Forms web page.

When evaluating an incident, a "safe-harbour" of acceptable offers or bids is established around the MCP and the historical reference price:

- The upper limit is 110% to 150% of the price
- The lower limit is 70% to 90% of the price

These limits are adjusted based on such factors as the duration over which the current CMSC payment was made, and the number of times CMSC was incurred by the market participant over the last 90 days.

Let's look at an example of how reference prices might be used. Assume:

- A CMSC payment was incurred at a time when the market clearing price was $24.
- The market participant involved has a calculated historical reference price of $44.
- Based on the factors mentioned above, the range around the prices is set at a low of 75% of the price and a high of 125% of the price
- As a result, the range of acceptable prices is from 75% of $24 (the lowest price) to 125% of $44 (the highest price).

Therefore, the price range in this example would be:

- $24 x 75/100 = $18
- $44 x 125/100 = $55

If the bid or offer the market participant made at the time the CMSC was incurred was more than $18 for a constrained-off import or a constrained-on export, or was less than $55 for a constrained-on import or constrained-off export, the IESO will cease investigating. If otherwise, the IESO will continue to examine the incident. If it is determined that action is required, the IESO will recalculate the CMSC payment substituting the appropriate high-end or low-end price for the market participant's bid or offer as follows:

The high-end price (in this example, $55) would be used if:

- The incident involved a constrained-on import, and the offer exceeded the market clearing price, or
- The incident involved a constrained-off export, and the bid exceeded the market clearing price.

A low-end price (in this example, $18) is used if:

- The incident involved a constrained-off import; offer was below the market clearing price, or
- The incident involved a constrained-on export; bid was below the market clearing price.

CMSC, Reference Prices and Constrained-Off Exports at Uncontested Interties

The above describes the standard use of reference prices for evaluating CMSC. The market rules have a provision that affects how reference prices are used in cases of constrained-off exports at uncontested interties.

An intertie is defined as uncontested for exports if:

- At least 90% of the withdrawals over the intertie in the previous 90-day period were accomplished by one market participant, or
- The IESO finds reasonable grounds to believe that one or more participants effectively control the level of CMSC payments from export transactions on a particular intertie (see *Market Manual 2-12: Treatment of Local Market Power, Appendix E* for specific criteria).

As stated above, one of the assumptions underlying CMSC is that market participants bid for energy at their marginal benefit. In other words, if you bid $100 for energy, it is assumed that you derive a benefit of $100 by consuming that energy.

However, for exports, this is not always the case. A market participant may bid a high price in order to increase the likelihood of their transaction being scheduled. As long as the intertie is uncongested, they will pay only the Ontario market clearing price.

Congestion is much more likely to occur on a contested intertie than on an uncontested one. On uncontested interties, competition does not exist to a sufficient extent. As a result, a market participant can consistently bid a high price in order to increase the likelihood of being scheduled in the knowledge that there is little or no possibility that the intertie will become export-congested. Therefore, they know that they are almost certain to pay only the Ontario MCP and not their high bid price (see *Section 3: Pricing and Scheduling of Interjurisdictional Trade*).

While bidding in this manner is allowable under the market rules, it has two potential impacts on CMSC:

- If the transaction is constrained-off, a high CMSC payment will occur
- This bidding behaviour creates a high historical reference price because it is based on the market participant's own accepted bids over the last 90 days. An artificially high reference price can limit the effectiveness of the IESO's investigations.

In order to counter these effects, only the current zonal market clearing price is used as a reference price when the IESO analyzes CMSC payments at uncontested interties. The historical reference price is not used. Therefore, the IESO will further assess market participants operating at uncontested interties if the market participant bid for energy outside of the acceptable range around the current zonal market clearing price.

The designation of intertie zones as uncontested can change over time. The IESO monitors conditions at each designated intertie, and if it is determined that an intertie is no longer uncontested, the designation is revoked. Additionally, any market participant can request that the designation be revoked as long as they provide information supporting the request.

As of the date of this document, the PQHZ and PQAT intertie zones with Quebec have been designated as uncontested. The criteria for designating an intertie as uncontested and for revoking such designation are explained in the following documents, available on the IESO Rules, Manuals and Forms web page:

- Section 1.3.3.4 of *Appendix 7.6* of the market rules
- *Market Manual 2.12; Treatment of Local Market Power, Appendix E*

Skill Check

1. True or False:
   Limitations on CMSC payments were placed because the Market Surveillance Panel identified situations in which the underlying assumption of marginal cost/benefit bidding did not hold

2. What would Transbord's CMSC payment be assuming the following:
   - Transbord offered to import 200 MW from New York at -$100
   - Their market schedule is 200 MW, but a constraint inside Ontario reduces their dispatch schedule to 0 MW
   - New York zone price is $35 for all intervals in real-time

3. Which of the following are **not** used as reference prices when examining constrained-off exports at uncontested interties:
   a) The market clearing price for the interval or intervals during which the CMSC was incurred
   b) The price in the neighbouring control area at the time the CMSC was incurred
   c) The resource's historical reference price
   d) The price in the zone during the last hour in which the participant could have entered a bid to export

4. Which of the following is a criteria for establishing that an intertie is uncontested for exports:
   a) At least 90% of the withdrawals over the intertie in the previous 60-day period were accomplished by one MP
   b) At least 90% of the withdrawals over the intertie in the previous 90-day period were accomplished by one MP
   c) If the IESO finds reasonable grounds to believe that one or more participants effectively control the level of CMSC payments from export transactions on a particular intertie

Skill Check: Answers

1. **True** or False:
   Limitations on CMSC payments were placed because the Market Surveillance Panel identified situations in which the underlying assumption of marginal cost/benefit bidding did not hold

2. What would Transbord's CMSC payment be assuming the following:
   - Transbord offered to import 200 MW from New York at -$100
   - Their market schedule is 200 MW, but a constraint inside Ontario reduces their dispatch schedule to 0 MW
   - New York zone price is $35 for all intervals in real-time

   CMSC = (($35 - $0) x 200 MW) - (($35 - $0) x 0 MW)

   = $7,000

3. Which of the following are **not** used as reference prices when examining constrained-off exports at uncontested interties:
   a) The market clearing price for the interval or intervals during which the CMSC was incurred
   b) The price in the neighbouring control area at the time the CMSC was incurred
   c) The resource's historical reference price
   d) The price in the zone during the last hour in which the participant could have entered a bid to export

4. Which of the following is a criterion for establishing that an intertie is uncontested for exports:
   a) At least 90% of the withdrawals over the intertie in the previous 60-day period were accomplished by one MP
   b) At least 90% of the withdrawals over the intertie in the previous 90-day period were accomplished by one MP
   c) If the IESO finds reasonable grounds to believe that one or more participants effectively control the level of CMSC payments from export transactions on a particular intertie

7. Net Interchange Schedule Limit

The direction and volume of net energy flow on an intertie is the result of the combination of imports and exports scheduled for the hour. For example, 1,000 MW of imports and 1,000 MW of exports scheduled for the same hour results in a 0 MW net flow. Having too great a change in intertie flow from one hour to another can adversely affect reliability in Ontario. To prevent this, the IESO imposes a net interchange schedule limit.

Objectives

After completing this section you will be able to:

- Explain why a net interchange schedule limit must be used
- Explain how the net interchange schedule limit is applied, both automatically and manually
- Given a net schedule for one hour, calculate the acceptable interchange schedule range for the next hour
- Discuss when CMSC may be affected by the net interchange schedule limit

Why Limit Changes in the Interchange Schedule?

Interchange schedules are for one hour periods starting at the beginning of an hour. As a result, the net flows across the interties can change across the top of the hour each and every hour.

Changes in intertie flow are achieved by ramping resources within Ontario either up or down. This either draws energy into Ontario or moves energy out. Resource ramping is achieved over a ten-minute period starting five minutes before the dispatch hour and ending five minutes after the start of the dispatch hour. The larger the net change in intertie flow from one hour to the next, the more difficult it is for resources within Ontario to accommodate the change. For example, a 1,000 MW increase in net exports would need to be ramped at a rate of 100 MW/min over the ten-minute period. This could require 20 generation units to each ramp up at a rate of 5 MW/min.

Responding to large hourly interchange schedule changes can have an adverse impact on the reliability of the IESO-controlled grid. To prevent these problems, Ontario's IESO limits the change in the net interchange schedule from hour-to-hour by imposing a net interchange schedule limit (also referred to as the “inter-hour ramp limit”).

Typically the IESO limits the net change from one hour to the next to 700 MW.[15] This change can be in either direction (i.e., either 700 MW more into or out of the province). For example, if the net schedule in one hour is 600 MW of imports, in the next hour the

[15] Unless respecting this limit would negatively impact reliability, such as during a supply shortfall

schedule could be for up to 1300 MW of imports or 100 MW of exports (i.e., 600 MW currently flowing plus 700 MW or minus 700 MW). This limiting of interchange transaction schedules occurs automatically within the Dispatch Scheduling Optimizer (DSO), or, if necessary, manually through IESO intervention. Both processes are discussed below.

Automatic Process

The DSO attempts to schedule transactions that in combination do not violate the 700 MW net interchange schedule limit. In achieving this, transactions that would otherwise have been economic may not be fully scheduled or may not be scheduled at all. Alternatively, the DSO may respect the limit by scheduling transactions that might not otherwise have been selected. As with all scheduling decisions, the DSO uses an economic basis to determine how to ensure compliance with the net interchange schedule limit.

We can illustrate this process with an example. For the sake of simplicity, we will assume there is only one intertie zone with no congestion.

Assume that in Hour Ending (HE) 1, the total net interchange schedule is 500 MW coming into the province (i.e., imports). The allowable net change from this schedule is plus or minus 700 MW. Therefore, the total net interchange schedule for the next hour must be within the range of:

- 1200 MW of net imports (500 MW of current net imports plus 700 MW of additional imports) or
- 200 MW of net exports (500 MW of current net imports plus 700 MW of exports).

Assume that during the pre-dispatch process for HE 2, the IESO-administered market receives the following bids and offers:

Transbord	Import 1300 MW @ $30
Pinepower	Import 300 MW @ $35
Expbord	Export 100 MW @ $50
Genbord	Export 300 MW @ $34

In pre-dispatch, the MCP for Ontario is $38 and there is no congestion on the intertie. With an MCP of $38, the import offers by Transbord and Pinepower and the export bid by Expbord are all economic. The export bid by Genbord is not economic (Genbord is only willing to pay $34/MW for its 300 MW export and the MCP is $38). If all of the economic transactions were allowed to flow, the net interchange schedule would be:

Transbord	Pinepower	Expbord

1300 MW import + 300 MW import - 100 MW export = 1500 MW of imports

However, as explained above, the total net interchange schedule for HE 2 can be no greater that 1200 MW of imports. Additional imports would violate the net interchange schedule limit. In order to respect the limit, the DSO must reduce the 1500 MW to 1200 MW. This can be achieved by either scheduling 300 MW less of imports, or by scheduling 300 MW of additional exports. How will the DSO decide which measure to take?

The DSO attempts to maximize gain from trade across the market when scheduling transactions. Gain from trade is the sum of supplier and consumer operating profit:

- Supplier operating profit is the difference between the supplier's offer price and the revenue they receive (i.e., MCP, less their offer).
- Consumer operating profit is the difference between what they are willing to pay for energy and what they are required to pay (i.e., their bid, less MCP).

One alternative open to the DSO in the example is to schedule 300 MW of exports. This would reduce the net interchange schedule to the required 1200 MW of imports.

Genbord bid to export 300 MW of energy if the price was $34 or less. The MCP was $38. If Genbord's export were scheduled to allow the DSO to respect the net interchange schedule limit, Genbord would lose $4/MW. Therefore, scheduling Genbord would result in a $1,200 reduction in consumer operating profit (and thereby, a reduction in the gain from trade in Ontario).

($34 - $38) X 300 MW = -$1,200

There is another way the DSO could respect the limit. It could reduce imports by 300 MW. There were two import offers in this example: One from Pinepower and one from Transbord. Which should the DSO consider reducing?

Transbord offered at $30 and Pinepower offered at $35. MCP was $38. This means that for each MW scheduled, Transbord has an operating profit of $8 ($38 - $30) against Pinepower's $3 ($38 - $35). Because its operating profit is less, the DSO will consider reducing Pinepower in preference to reducing Transbord because doing so has less of an impact on supplier operating profit (and thereby gain from trade for the market).

Pinepower offered 300 MW. Reducing this import to 0 MW will allow the DSO to satisfy the net interchange schedule limit. This action would lower the gain from trade to the market as a whole by all of Pinepower's potential operating profit:

($38 - $35) x 300 MW = $900

Scheduling Genbord's export would reduce the gain from trade by $1,200. Therefore, the DSO in this example would reduce Pinepower's import to meet the net interchange schedule limit. The resulting interchange schedule for HE 2 would be:

Transbord	Import 1300 MW @ $30
Expbord	Export 100 MW @ $250
Pinepower	Import 0 MW
Genbord	Export 0 MW

Manual Process

In the above example, the DSO was able to use available bids and offers to avoid violating the 700 MW net interchange schedule limit. What happens if insufficient bids or offers are available? When this occurs, the DSO can't create a schedule that does not violate the limit. Therefore, the IESO has to act manually to ensure that the limit is respected in order to support system reliability.

If it is determined more than five hours prior to the dispatch hour that the potential exists for a violation of the net interchange schedule limit that the DSO can't avoid, the IESO will attempt to avoid the violation by sending messages to the market via the System Status Report. These messages request that participants voluntarily adjust their bids and offers to help correct the problem.

If the situation persists, or if it is initially identified less than five hours in advance, the IESO must directly intervene. The IESO will manually adjust intertie schedules in the hour before the hour with the violation in order to avoid the problem. If manual adjustments are required, the following principles are used to guide the IESO's actions:

- Only transactions that contribute to the net interchange schedule limit violation are reduced (i.e., transactions that changed from the previous hour, excluding linked wheel-through transactions)
- To the extent possible, transactions are reduced in the most economic order
- When two or more transactions have the same price, each transaction will be reduced on a pro-rated basis

We can see how this works through an example.

The IESO receives the following offers to import energy from New York:

Import Offers				
Hour Ending	1	2	3	4
Transbord	400 MW @ $75	400 MW @ $75	400 MW @ $75	400 MW @ $75
Powerport	600 MW @ $65	600 MW @ $65	700 MW @ $65	No offer
Borgpower	No offer	700 MW @ $60	700 MW @ $60	No offer
Total Net Intertie Schedule	1,000 MW	1,700 MW	1,800 MW	400 MW
Change from previous hour	N/A	700 MW	100 MW	1400 MW

Assume that the Ontario MCP and the price in the New York zone are above $100 for each of the four hours. In this case, all offers would be economic as they were all below $100. Assume further that the zone price is the same as the price in Ontario for each hour (i.e., ICP = $0).

We can see that a problem exists from HE 3 to HE 4. There is a 1400 MW hour-to-hour change. However, 700 MW is the most that can be allowed. The DSO would normally use the bids and offers available in the hour to find a combination that would respect the limit. However, there is only one offer in HE 4. Cutting the offer would not improve the situation as the net interchange schedule change would actually go up, not down as needed. The DSO can't constrain on Powerport or Borgpower, either, as they have withdrawn their offers. Ideally, the DSO would change the schedules in HE 3 in order to avoid problems in HE 4 when the two import offers are withdrawn. However, the DSO is not capable of doing this on its own. It can only look out one hour when scheduling. Therefore, when setting the schedules for HE 3 during HE 2, the DSO doesn't recognize that there is a problem in HE 4. As a result, the IESO would have to take manual action in HE 3 to prevent the limit violation in HE 4.

In order to respect the net interchange schedule limit, the IESO must ensure that the import total in HE 3 is no more than 1100 MW. This is arrived at by adding the 700 MW limit to the 400 MW of imports that will be available in HE 4.

How is this to be accomplished? The first decision-making principle cited above states that only those transactions that contribute to the problem should be affected. In this example, who contributed to the problem? Transbord has the same offer in HE 4 that it had in HE 3, whereas both Powerport and Borgpower withdrew their offers in HE 4.

Therefore, only Powerport and Borgpower contribute to the problem. Only their transactions will be considered for reduction in HE 3.

The second principle cited above is that transactions will be reduced in economic order. Powerport has a lower operating profit than Borgpower because Powerport's offer was higher. Therefore, Powerport would be reduced before Borgpower.

As stated above, the IESO has to reduce net imports from 1800 MW to 1100 MW in HE 3. This can be achieved by reducing Powerport's HE 3 schedule to 0 MW:

Hour	1	2	3	4
Transbord	400 MW @ $75	400 MW @ $75	400 MW @ $75	400 MW @ $75
Powerport	600 MW @ $65	600 MW @ $65	0 MW	No offer
Borgpower	No offer	700 MW @ $60	700 MW @ $60	No offer
Total	1,000 MW	1,700 MW	1,100 MW	400 MW
Change from previous hour	N/A	700 MW	- 600 MW	- 700 MW

The 700 MW limit is now respected in all hours.

Congestion Management Settlement Credits (CMSC) and the Net Interchange Schedule Limit

The net interchange schedule limit is applied in the same way in both the unconstrained and constrained modes of the DSO. This means that CSMC cannot be caused directly by the application of the net interchange schedule limit.

However, the starting conditions for the constrained and unconstrained modes may differ. This is typically because of transmission congestion within Ontario. This means that even though the net interchange schedule limit is applied in the same way in both modes, the outcomes of this application can differ because the starting conditions differed. In some circumstances, this difference may result in CMSC payments.

The following example illustrates the interaction of internal transmission limits and the net interchange schedule limit. Assume:

In **Hour One**:

- There is a single offer from Transbord to import 700 MW of energy at $10/MW

- Internal constraints limit the actual allowable flow to 500 MW
- MCP is $50
- The market schedule is a net import of 700 MW
- The dispatch schedule is a net import of 500 MW

In Hour One, there will be a CMSC payment to Transbord based on the lost operating profit from the 200 MW that did not flow due to internal constraints. (CMSC in this case is $8,000, which is $40 lost operating profit per megawatt, times 200 MW.)

In **Hour Two**:
Even though both the constrained and unconstrained modes of the algorithm use the exact same net interchange schedule limit of 700 MW, they have different starting points when determining an acceptable net schedule for Hour Two. The constrained mode uses the actual operating point from the previous period, whereas the unconstrained mode uses the last market schedule.

Applying the net interchange schedule limit of 700 MW means that in Hour Two:

- The unconstrained mode will allow a net interchange schedule range of 1400 MW of imports to 0 MW of flow (that is, the previous hour's 700 MW market schedule, plus or minus 700 MW)
- The constrained mode will allow a net interchange schedule range of 1200 MW of imports to 200 MW of exports (that is, the previous hour's dispatch schedule of 500 MW, plus or minus 700 MW)

What does this mean for our example? Assume that in Hour Two:

- There are no import offers
- Borgpower enters a new bid to export 200 MW of energy at $75/MW
- MCP is $50

The unconstrained mode will only allow a net interchange schedule range of 1400 MW of imports to 0 MW of flow. Allowing Borgpower's export would result in a net flow of 200 MW out of the province, or a total net interchange schedule change of 900 MW. Although Borgpower's bid is economic, the net interchange schedule limit would not allow the export. Borgpower would receive a 0 MW market schedule.

The constrained mode, however, has an allowable net interchange schedule range of 1200 MW of imports to 200 MW of exports. This is because its starting point from Hour One was 500 MW of imports, not the 700 MW of imports assumed by the unconstrained mode. As a result, Borgpower would receive a dispatch schedule allowing it to export all 200 MW.

Because of these different schedules, Borgpower would have an operating profit under its dispatch schedule, but not under its market schedule. CMSC is used to ensure that a participant is held to the operating profit that they would have received under their market schedule. In this case, there would be a negative CMSC payment, or a charge, to Borgpower:

CMSC = ((\$75 - \$50) x 0 MW) - ((\$75 - \$50) x 200 MW)

= -\$5,000

The negative CMSC payment is the result of the different starting points used by the unconstrained and constrained modes of the algorithm. If there had been no congestion in Hour One, the starting points would have been the same for both modes, and, since both use the same net interchange schedule limit, there would have been no CMSC payment.

Note, however, that Borgpower does not have a negative operating profit even with this charge. Combining the negative CMSC payment and the cost of the 200 MW export gives a total transaction cost to that is equivalent to Borgpower's original bid price of \$75/MW:

Cost of export: 200 MW @ \$50/MW = \$10,000

Negative CMSC: = \$ 5,000

Total: = \$15,000

Bid price: 200 MW @ \$75/MW = \$15,000

Skill Check

1) If the current hour has a net interchange schedule of 450 MW of exports, the allowable range for the next hour is:
   a) 700 MW of exports to 700 MW of imports
   b) 1150 MW of exports to 250 MW of imports
   c) 1150 MW of exports to a 0 MW net flow
   d) 1150 MW of exports to 700 MW of imports

2) Which of the following is **not** a principle used when the IESO manually intervenes to respect the net interchange schedule limit:
   a. Only transactions that contribute to the net interchange schedule limit violation are reduced (i.e., transactions that changed from the previous hour, excluding linked wheel-through transactions)
   b. To the extent possible, transactions are reduced in the most economic order
   c. When two or more transactions have the same price, each transaction will be reduced on a pro-rated basis
   d. The more consecutive hours a transaction was scheduled the less likely it is to be reduced

3) Assume that in Hour Ending (HE) 1, the total net interchange schedule is 300 MW going out of the province (i.e., exports). Also assume that during the pre-dispatch process for HE 2, the IESO-administered market receives the following bids and offers.

Transbord	Export 1000 MW @ $50
Pinepower	Import 100 MW @ $30
Expbord	Import 400 MW @ $54
Genbord	Export 300 MW @ $44

If the market clearing price is $36, how would the DSO schedule these transactions?

Skill Check: Answers

1) If the current hour has a net interchange schedule of 450 MW of exports, the allowable range for the next hour is:
   a. 700 MW of exports to 700 MW of imports
   b. 1150 MW of exports to 250 MW of imports
   c. 1150 MW of exports to a 0 MW net flow
   d. 1150 MW of exports to 700 MW of imports

2) Which of the following is not a principle used when the IESO manually intervenes to respect the net interchange schedule limit:
   a. Only transactions that contribute to the net interchange schedule limit violation are reduced (i.e., transactions that changed from the previous hour, excluding linked wheel-through transactions)
   b. To the extent possible, transactions are reduced in the most economic order
   c. When two or more transactions have the same price, each transaction will be reduced on a pro-rated basis
   d. The more consecutive hours a transaction was scheduled the less likely it is to be reduced

3) Assume that in Hour Ending (HE) 1, the total net interchange schedule is 300 MW going out of the province (i.e., exports). Also assume that during the pre-dispatch process for HE 2, the IESO-administered market receives the following bids and offers.

Transbord	Export 1000 MW @ $50
Pinepower	Import 100 MW @ $30
Expbord	Import 400 MW @ $54
Genbord	Export 300 MW @ $44

If the market clearing price is $36, how would the DSO schedule these transactions?

With a market clearing price of $36 the following transactions would be economic:

Transbord	**Export 1000 MW @ $50**
Pinepower	**Import 100 MW @ $30**
Genbord	**Export 300 MW @ $44**

This would result in a net interchange schedule of:

1000 MW export - 100 MW import + 300 MW export = 1200 MW of exports

Given the net schedule of 300 MW of exports in HE 1, this would violate the limit of 1000 MW of exports. The DSO needs to cut 200 MW of exports or schedule an additional 200 MW of imports. The DSO would make this determination based on which option had the least impact on the gain from trade. The DSO has three options:

a) **It could reduce Transbord's export by 200 MW. This would reduce the gain from trade as follows: (50 – 36) X 200 = $2,800**
b) **It could schedule 200 MW of imports from Expbord. Because Expbord offered at higher than the market clearing price, scheduling its transaction would cause a loss in gain from trade as follows: (36 – 54) X 200 = -$3,600**
c) **It could reduce Genbord's export by 200 MW. This would reduce the gain from trade as follows: (44 – 36) X 200 = $1,600**

Given that reducing Genbord by 200 MW has the least impact on the gain from trade (a reduction in gain from trade of $1,600 versus $2,800 or $3,600), the DSO would select this option. The final schedule would be:

Transbord	**Export 1000 MW @ $50**
Pinepower	**Import 100 MW @ $30**
Genbord	**Export 100 MW @ $44**

8. Operating Reserve

As discussed in the *Introduction to Ontario's Physical Markets* workbook (available on the Training web pages), operating reserve (OR) is essentially stand-by power or demand reduction that can be called upon with short notice to deal with an unexpected mismatch between generation and load. OR helps the IESO ensure the reliability of the grid by forming a pool of additional energy that can be accessed quickly to boost supply if needed.

There are three classes of operating reserve, determined by the time required to bring the energy into use and the physical behaviour of the facilities that can provide it:

- 10 minute spinning (synchronized)
- 10 minute non-spinning (non-synchronized)
- 30 minute

The IESO administers a market for all three types of operating reserve. This allows the IESO to purchase this service in the most efficient manner possible. Those dispatchable market participants who wish to supply OR offer it to the market. Dispatchable suppliers offer to provide additional energy, and dispatchable consumers offer to reduce their demand if called upon. A market clearing price for each class of operating reserve is set based on the requirement for each class (as set by the IESO based on industry reliability standards), and the cost of the offers submitted.

The market rules allow the IESO to obtain non-spinning OR from imports and exports. However, this is restricted to interties where the IESO has the agreement of the neighbouring control area that these transactions can be treated as OR. (NOTE: Even where this agreement exists, intertie transactions cannot be offered as synchronized reserve).

Additionally, participants cannot export OR from Ontario to another jurisdiction.

9. Settlement

Intertie transactions are settled on the same timelines and with the same processes as those used for physical transactions within Ontario.

Objectives

After completing this section you will be able to:

- Explain settlement timelines
- Identify constraints that cause CMSC to be paid
- List common uplift charges
- Explain an importer's role with regard to the Harmonized Sales Tax (HST)

Timing of Settlement Statements and Invoices

Recall from *Section Two: Interjurisdictional Energy Transactions* that imports are essentially the same as generators within Ontario and exports are generally the same as loads within Ontario. This is also true for the settlement process. The timing for settlement in the physical market is outlined below. (Please see the recorded presentation *Commercial Reconciliation* or the *Settlement Statements and Invoices* workbook for more information on the settlement process. Both are available on the Training web pages).

Transactions occur in the IESO-administered markets 24-hours a day, 365 days a year. Therefore, every day is a trade day that must be settled. For each trade day:

- A preliminary settlement statement is issued 10 business days after the trade day.
- A final settlement statement is issued 10 business days after the preliminary settlement statement, or 20 business days after the trade day.

Invoices in the physical markets are issued for a calendar month, 10 business days after the last trade day of the month.

Those who owe the market (e.g., net exporters) must make payments to the IESO within two business days of invoices being issued.

The IESO, in turn, makes payments within four business days of invoices being issued to those participants who are owed by the market (e.g., net importers).

The totals on statements and invoices are divided into categories referred to as charge types (please see the *Charge Types and Equations* document available on the Technical Interfaces web page for more details). For example, imports and exports are settled in charge type 100, Net Energy Settlement for Dispatchable Market Participants (recall that intertie transactions are considered dispatchable prior to the hour in which they actually flow).

The settlement amount for imports and exports is based on the appropriate intertie zone price and the scheduled flow (assuming that the transaction does not fail). NERC tags are not used to determine settlement amounts. (NERC tags may be used during follow-up investigations if there is uncertainty or disagreement on actual flows.)

Operating reserve purchased by the IESO from importers and exporters is settled in charge type 203 (ten-minute non-spinning) and charge type 208 (30-minute).

Intertie offer guarantee (IOG) payments are made in charge type 130. Recall that these payments are made only on net imports. They do not apply to wheel-through transactions, whether linked or unlinked. If an IOG payment is calculated on the import leg of a wheel-through, there will be a balancing IOG offset amount in charge type 130 which will bring the net IOG to zero. This adjustment is made on the last preliminary settlement statement for the month.

Congestion Management Settlement Credits (CMSC)

As discussed in Section 4, the IESO uses CMSC to remove the impact on participant's operating profit of constraints on the IESO-controlled grid. CMSC is not payable when schedules are affected by constraints on an intertie or in another control area.

CMSC is covered in charge type 105 (recall that CMSC can be negative, requiring a payment to the IESO).

Participants can retrieve a data file along with their preliminary settlement statement. The schedule section of the data file (begins with the letter S) identifies transactions that were limited by internal or external constraints. Constraints that were internal to Ontario (i.e., on the IESO-controlled grid) are flagged with a TLRi code while external constraints are identified with TLRe. CMSC is paid only where the constraint was internal.

Congestion payments for operating reserve appear in charge type 107 (ten-minute non-spinning) and charge type 108 (30 minute).

Uplift

The IESO is a revenue neutral organization. Revenues received from energy consumers must equal payments to suppliers, plus expenses. Overhead, reliability expenses, and losses are recovered by tariffs and uplift charges. Those withdrawing energy pay virtually all of these costs (the only exception being a default levy which can be used to recover losses from ALL participants, including suppliers, if a participant defaults on payments to the IESO-administered markets).

Exports withdraw energy from the IESO-controlled grid and are, therefore, subject to tariffs and uplift charges. Some uplifts are calculated hourly, while others are calculated monthly.

Hourly uplifts include:

- 150: Net Energy Management Settlement Credit
- 155: Congestion Management Settlement Credit
- 250, 252, 254: Three classes of operating reserve

The total of all hourly uplifts is estimated an hour after the trade hour, and is posted on the Today's Market page of the IESO web site.

Monthly uplifts include:

- 450, 452, 454: Monthly Ancillary Services
- 9990: IESO Administration Charge
- 653: Export Transmission Service Charge

The *Settlement Statements and Invoices* workbook provides more detail on common charges. A complete list of all possible charges is contained in the IESO document, *IESO Charge Types and Equations* available on the Rules, Manuals and Forms web page.

There are some uplifts which do not apply to exports. Exports do not pay the Debt Retirement Charge, the Rural and Remote Settlement Credit, or the Global Adjustment. In addition, there is a separate transmission tariff for exports (Charge Code 653).

Information on historical uplift charges can be found in the *Market Summaries* posted on the IESO's website.

Harmonized Sales Tax (HST)

Statements and invoices include charge codes for the HST:

- Charge Code 950 for HST amounts due to the IESO from the participant
- Charge Code 900 for HST owed from the IESO to the participant

The HST is intended to be a tax on consumption within Canada. Therefore, the HST:

- is not charged on exports of energy to non-Canadian jurisdictions (i.e., New York, Michigan and Minnesota)
- is payable by the IESO to participants importing to Ontario from the United States

For more information on the HST in the IESO-administered markets including the responsibilities of importers and exporters, please see the *HST Guide for IESO Transactions* available on the Rules, Manuals and Forms page of the IESO web site.

Notice of Disagreement (NOD)

If a participant believes that an error has occurred on their preliminary settlement statement, they can file a notice of disagreement. The filing deadline is 4 business days from when the statement was made available. Please note that filing a NOD does not change the time period for paying an invoice. For more information on the process for filing a NOD, please see the *Settlement Statements and Invoices* workbook available on the Training web pages.

NOTE: For information on the Day-Ahead Intertie Offer Guarantee, please see:

- The Guide to the Day-Ahead Commitment Process
- The Intertie Transactions recorded presentation available on the Day-Ahead Commitment Process Training page
- Market Manual 9.5: Settlement for the Day-Ahead Commitment Process available on the Rules and Manuals page

Skill Check

1) Which of the following statements are False:
    a. Preliminary settlement statements are available 10 business days after each trade day.
    b. Final settlement statements are available 10 days after the trade day.
    c. You can file a Notice of Disagreement against your final settlement statement.
    d. If a TLRi code is seen in a data file, CMSC is payable for that transaction.

2) How often must importers remit HST?
    a. Biannually
    b. Every 2 months
    c. Monthly
    d. Quarterly

3) True or False:
   There will be an offsetting intertie offer guarantee charge in charge type 130 for implied wheel-throughs.

4) How many days does a participant have to file a NOD?
    a. 2 business days after the preliminary settlement statement is made available
    b. 10 business days after the preliminary settlement statement is made available
    c. 4 business days after they retrieve the preliminary settlement statement
    d. 4 business days after the preliminary settlement statement is made available

Skill Check: Answers

1) Which of the following statements are False:
    a. Preliminary settlement statements are available 10 business days after each trade day.
    b. Final settlement statements are available 10 days after the trade day.
    c. You can file a Notice of Disagreement against your final settlement statement.
    d. If a TLRi code is seen in a data file, CMSC is payable for that transaction.

2) How often must importers remit HST?
    a. Biannually
    b. Every 2 months
    c. Monthly
    d. Quarterly

3) **True** or False:
    There will be an offsetting intertie offer guarantee charge in charge type 130 for implied wheel-throughs.
    NOTE: The offset will appear on statements for the last trade day of the month.

4) How many days does a participant have to file a NOD?
    a. 2 business days after the preliminary settlement statement is made available
    b. 10 business days after the preliminary settlement statement is made available
    c. 4 business days after they retrieve the preliminary settlement statement
    d. 4 business days after the preliminary settlement statement is made available

10. Compliance with IESO Interchange Schedules

If an interchange transaction fails to flow for a reason that was within the participant's control, that participant is subject to a settlement charge. In some cases, there may also be compliance actions, including penalties.

Objectives

After completing this section you will be able to:

- Explain why interchange failures are significant
- Calculate both an import and an export failure settlement charge

Interchange Failures

Interchange transactions fail to flow for a variety of reasons. Some of these reasons are beyond a participant's control, such as being cut by a system operator. However, participants can avoid others, including:

- Not entering a valid NERC tag
- Not successfully scheduling the transaction in the neighbouring jurisdiction

Interchange failures to flow can have a significant impact on IESO-controlled grid operations and on IESO-administered markets:

- The IESO may have to replace a failed import by taking actions that increase market costs, either through increased uplift or higher prices
- For failed exports, the IESO may have to constrain off generation, leading to increased congestion management settlement credit payments. Such actions may lower the real-time price. Failed exports can also have operational impacts during low demand periods.

Because of these negative effects of failed interchange transactions, an automatic settlement charge is applied to a participant who fails to flow an interchange transaction if the reason for failure was within the participant's control.

Real-time Import Failure Charges: Formula and Example

There is a settlement charge formula for failed import transactions, and one for failed export transactions.

> **Real-Time Import Failure Charge** =
>
> Minimum of:
>
> [Maximum [0,(Real-time Ontario Price + Price Bias Adjustment Factor – Pre-dispatch Ontario Price) X MWh failed],
>
> Maximum (0, Real-time Ontario Price) X MWh failed]

That is, the import failure charge is the lesser of two terms:

- The greater of zero or the real-time Ontario market clearing price adjusted by a Price Bias Adjustment Factor minus the pre-dispatch Ontario market clearing price times the MWh failed
- The greater of zero or the real-time Ontario market clearing price times the MWh failed

The 'price bias adjustment factor' compensates for systematic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time. For example, pre-dispatch is an hourly calculation that projects future prices using expected demand for the hour whereas in real-time, prices are set every five minutes based on actual demand.

The Price Bias Adjustment Factor page of the IESO web site lists the factors.

The real-time import failure settlement charge is applied if:

- An import fails in whole or in part for a reason that was within the participant's control, and
- The real-time price in Ontario is higher than the last pre-dispatch price for that hour. The last-pre-dispatch price is the one calculated by the final pre-dispatch run before the start of the hour during which the energy should have flowed. For example, the last pre-dispatch price for hour ending 5 would have been determined by the 3:07 pre-dispatch run.

The second term of the formula means that the real-time import failure settlement charge cannot be more than an amount equal to the real-time Ontario price times the MWh failed.

Assume:

- Pre-dispatch Ontario price = $35
- Real-time Ontario price = $45
- 10 MWh failed in hour ending 6 on September 3, 2012
- Price bias adjustment factor = $2.74

Real-Time Import Failure Charge:

= Minimum of

[Maximum [0,(Real-time Ontario Price + Price Bias Adjustment Factor – Pre-dispatch Ontario Price) X MWh failed],

Maximum (0, Real-time Ontario Price) X MWh failed]

= Min [Max [0,($45 + $2.74 – $35) X 10], Max(0, $45) X 10]

= Min [$127.40, $450]

= $127.40

Therefore, this participant owes a real-time import failure charge of $127.40.

Real-time Export Failure Charges: Formula and Example

Real-Time Export Failure Charge =

Minimum of

[Maximum [0,(Pre-dispatch Ontario Price – Real-time Ontario Price – Price Bias Adjustment Factor) X MWh failed],

Maximum (0, Pre-dispatch Ontario Price) X MWh failed]

That is, the export failure charge is the lesser of two terms:

- The greater of zero or the pre-dispatch Ontario market clearing price less the real-time price in Ontario less a Price Bias Adjustment Factor times the MWh failed,
- The greater of zero or the pre-dispatch Ontario market clearing price times the MWh failed

The real-time export failure settlement charge is applied if:

- An export fails in whole or in part for a reason that was within the participant's control, and
- The real-time price in Ontario is lower than the last projected pre-dispatch price for that hour

The second term of the formula means that the real-time export failure settlement charge is capped at an amount equal to the pre-dispatch Ontario price times the MWh failed.

Assume:

- Pre-dispatch Ontario price = $55
- Real-time Ontario price = $40
- 40 MWh failed in HE 24 on August 22, 2012
- Price Bias Adjustment Factor = $1.40

Real-Time Export Failure Charge:

= Minimum of

[Maximum [0,(Pre-dispatch Ontario Price – Real-time Ontario Price – Price Bias Adjustment Factor) X MWh failed],

Maximum (0, Pre-dispatch Ontario Price) X MWh failed]

= Min [Max [0,($55 – $40 – $1.40) X 40], Max(0, $55) X 40]

= Min [$544.00, $2200]

= $544.00

Therefore, this participant would owe a real-time export failure charge of $544.40.

NOTE: Import, export and wheel through transactions scheduled by the Day-Ahead Commitment Process that fail to flow in real-time can be subject to a day-ahead failure charge. Please see:

- The Guide to the Day-Ahead Commitment Process
- The Intertie Transactions recorded presentation available on the Day-Ahead Commitment Process Training page
- Market Manual 9.5: Settlement for the Day-Ahead Commitment Process available on the Rules and Manuals page

Compliance Penalties

If an interchange failure is considered 'egregious' (i.e., flagrant), the IESO can:

- Issue a letter of non-compliance
- Impose a financial penalty
- Withhold or claw back payments related to the failed transaction.[16]

A participant who disagrees with the application of a financial penalty or with the withholding or clawback of payments can file a notice of dispute.[17]

A participant who does not agree with the outcome of the dispute can appeal to the Ontario Energy Board.

[16] Please see *Market Rules Chapter 3, section 6.6.10A*

[17] For more details, see the Dispute Resolution pages of the IESO web site

Skill Check

1) Which of the following is true:
   A failed import is a concern because it can cause:
   a) Lower prices
   b) Higher prices
   c) Higher uplift charges
   d) Lower uplift charges

2) The real-time import failure charge is applied if:
   a) The real-time price in Ontario is lower than the last pre-dispatch price for that hour
   b) The real-time price in Ontario is higher than the last pre-dispatch price for that hour
   c) The transaction failed because it was cut by another jurisdiction
   d) The failure was within the participant's control

3) Which of the following are true
   a) The price bias adjustment factor:
   b) Is needed because the calculation of the real-time price is biased to be lower than the pre-dispatch price
   c) Compensates for systemic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time
   d) Is available on our web site
   e) Is only applied when calculating the real-time import failure charge

4) Assume the following:
   - Pre-dispatch Ontario price = $30
   - Real-time Ontario price = $40
   - 20 MWh import failed in hour ending 18 on February 16, 2011
   - Price bias adjustment factor = $4.84

   Given these factors, the real-time import failure charge be:

   a) $327.55
   b) $800.00
   c) $296.80
   d) $326.52

Skill Check - Answers

1) Which of the following is true:

   A failed import is a concern because it can cause:

   a) Lower prices
   b) Higher prices
   c) Higher uplift charges
   d) Lower uplift charges

2) The real-time import failure charge is applied if:
   a) The real-time price in Ontario is lower than the last pre-dispatch price for that hour
   b) The real-time price in Ontario is higher than the last pre-dispatch price for that hour
   c) The transaction failed because it was cut by another jurisdiction
   d) The failure was within the participant's control

3) Which of the following are true:
   The price bias adjustment factor:
   a) Is needed because the calculation of the real-time price is generally biased to be lower than the pre-dispatch price
   b) Compensates for systemic differences between how prices are calculated in pre-dispatch and how they are calculated in real-time
   c) Is available on the IESO web site
   d) Is only applied when calculating the real-time import failure charge

4) Assume the following:

   - Pre-dispatch Ontario price = $30
   - Real-time Ontario price = $40
   - 20 MWh import failed in hour ending 18 on February 16, 2011
   - Price bias adjustment factor = $4.84

   Given these factors, the real-time import failure charge be:

   a) $327.55
   b) $800.00
   c) $296.80
   d) $326.52