Prices in Ontario’s Electricity Markets

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1. Introduction

This document is intended to provide a foundational understanding of key electricity market pricing concepts. Its purpose is to educate the reader at a high level on how prices are formed, applied, and settled within the market framework. Specifically, this document explains how locational marginal prices (LMPs) are calculated and identifies the individual components that make up the price charged to non-dispatchable loads. It also outlines how intertie prices are established, how zonal prices are determined for the settlement of virtual transactions, and how operating reserve prices are set. Finally, the document describes the criteria and rules governing price-setting eligibility. Together, these topics offer a comprehensive overview of the mechanisms that drive price formation and settlement in the market.

Energy Price Basis	Applicable to
Locational Marginal Price (LMP)	Dispatchable resources, self-scheduling and intermittent suppliers and price-responsive loads
Ontario Energy Market Price (Day-Ahead Ontario Zonal Price (DA-OZP) + the Load Forecast Deviation Adjustment (LFDA))	Non-dispatchable loads (NDL)
Intertie Price	Intertie Transactions
Virtual Zone Price	Virtual Transactions

1.1 Learning Objectives

- UNDERSTAND at a high level how locational marginal prices are calculated
- UNDERSTAND the components of the price which will be charged to non-dispatchable loads
- UNDERSTAND intertie prices
- UNDERSTAND how zonal prices are determined for virtual transaction settlement
- UNDERSTAND how operating reserve prices will be set
- UNDERSTAND price setting eligibility

2. Locational Marginal Pricing for Energy

2.1 Introduction

Ideally, the price for a product should cover the cost to produce and deliver it. In an electricity market, this means the price should reflect:

- The cost to have the energy available. That is, it should recover sufficient funds from consumers to pay suppliers for the energy itself;
- The cost of losses on the system. Some electricity is lost as it moves through the grid from a point of supply to a point of consumption. As a result, additional energy must be injected so consumers receive all of the energy they need; and
- The costs resulting from congestion. The transmission lines and other elements which comprise the grid cannot carry an unlimited amount of energy. At times, this means that the least cost suppliers are unable to cover all of the energy needs of consumers. When this happens, more expensive supply may be required to fill the gap.

Locational Marginal Prices (LMPs) are used in Ontario's physical markets as the price for electricity.

An LMP includes:

- A reference price, which is the price of energy at a specific location on the grid called the 'reference bus';
- The cost of congestion, which reflects the impact on system congestion of serving an additional increment of demand at a pricing location with supply from the reference bus; and
- The cost of losses, which reflects the impact on system losses of serving an additional increment of demand at a pricing location with supply from the reference bus.

LMPs are determined using an ex-ante (before-the-fact) constrained calculation for each consumer and supplier connection point to the IESO-controlled grid. Ontario-based resources active in the market are settled using LMPs directly. This includes dispatchable resources, self-scheduling and intermittent suppliers and price-responsive loads (PRLs). Non-dispatchable loads[1] and virtual transactions[2] are settled using zonal prices which average the LMPs in the applicable zone. Intertie transactions are settled using prices calculated for each intertie zone and include the LMP on the Ontario side of the interconnection.

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[1] Price responsive loads (PRLs) are a wholesale consumer resource type. PRLs bid into the day-ahead market, and, if scheduled, secure a day-ahead LMP for their expected real-time consumption. They are not required to bid in pre-dispatch or real-time, nor do they receive IESO dispatch instructions. Instead, they consume in real-time as desired, like a non-dispatchable load. PRLs are settled for their day-ahead schedule using their day-ahead LMP. If their real-time consumption deviates from their day-ahead schedule, the difference will be settled at their real-time LMP.

[2] Virtual transactions allow a registered virtual trader to bid or offer energy in the day-ahead market, receive a schedule, be settled for that quantity at the day-ahead price, and also be settled for the opposite transaction at the real-time price. Virtual transactions help converge day-ahead and real-time prices. See Section 5: Virtual Transaction Pricing.

Locational marginal pricing is the most accurate way to align settlement prices with the incremental cost of energy at a given location. An accurate price signal encourages efficient responses from participants who are active in the electricity market. Compensating supply resources using locational energy prices that reflect system conditions encourages them to submit offers based on their short-run marginal costs[3]. This, in turn, will result in more efficient dispatch, helping to support reliability and reducing the long-run cost of operating the system. Accurate location-based price signals can also encourage active consumers to reduce their consumption when local prices are high, lowering demand and putting downward pressure on prices in their region.

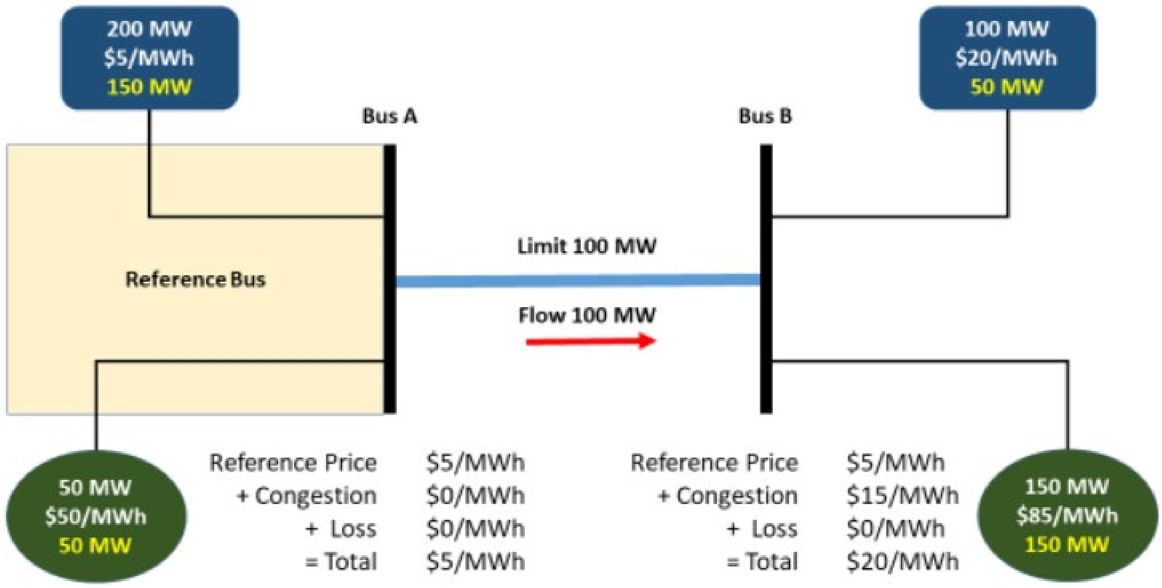
This enables cost reductions for the responding consumers and for other consumers in the region. Importantly, an accurate price signal also encourages dispatchable market participants to respond to dispatch instructions with a much reduced need for out-of-market uplift payments like the current congestion management settlement credits (CMSC).

2.2 Reference Price

The reference price forms the basis of all prices on the system. It is the marginal cost of energy at the reference bus. To calculate the reference price, losses and system limits are considered when determining the supply available to meet demand at the reference bus. The reference price, however, is solely the price of energy – that is, the incremental cost to supply incremental demand. Because of this, the physical location of the reference bus on the system does not matter. Relocating the reference bus does not change LMPs, as the reference price, loss and congestion components adjust to reflect the conditions relevant to the new location.

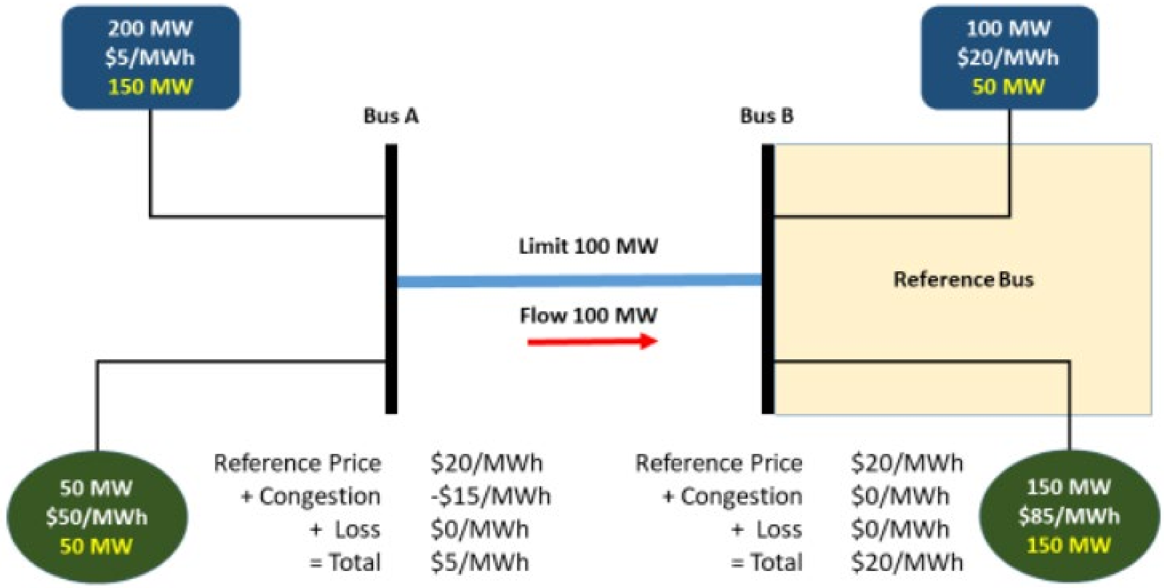
Let's look at two simplified examples to demonstrate the concept. On the next page we have a diagram of a two bus system with no losses (to keep things as clear as possible). In the first instance, Bus A is the reference bus. There is 200 MW of supply at this bus with an offer price of $5/MWh. At Bus A, there is also dispatchable demand of 50 MW bid at $50/MWh. At Bus B, there is 100 MW of supply offered at $20/MWh and dispatchable demand of 150 MW bid at $85/MWh. There is a line limited to 100 MW linking the two buses.

[3] Short-run marginal costs refer to costs that increase when a resource provides additional amounts of energy or operating reserve, e.g., costs for fuel used by the resource.



In this scenario, the Bus A supplier would be the most economic. As such, it would provide the 50 MW for the consumer at its bus as well as 100 MW to partially serve the consumer at Bus B, for a total schedule of 150 MW. Because of the 100 MW line limit, it can't supply any more to Bus B. The remaining 50 MW of demand at Bus B can be served by the supply at that location. The cost of energy at Bus A, and therefore the reference bus price is $5. At Bus B the LMP is $20 since the incremental supply at this location has to come from the supplier located there. This means that the cost of congestion at Bus B is $15 since the cost of energy there is $15 higher than the reference price.

In the example below, the reference bus changes to Bus B. The schedules for the resources do not change, since all relevant factors are still the same. Bus A still serves the 50 MW of demand at its location, and it provides 100 MW towards the demand at Bus B. The remaining Bus B demand is served from the supply at that location for $20. Now, however, because Bus B is the reference bus, the reference price is $20, and the congestion cost at Bus B is $0. The LMP at Bus A is still $5, but now the congestion cost component is -$15 since its price is $15 lower than the reference bus.



2.3 Cost of Congestion

Energy takes all available paths from a point of supply to a point of consumption (see Section 2.5, "Why Consider Impacts on Multiple Paths?"). Energy flows are kept within acceptable limits primarily by adjusting the magnitude of active supply and demand. Congestion can occur when the ability of the most economic energy to serve demand is restricted due to the need to manage system limits. This can result in higher prices at locations on one side of a flow limiting constraint compared to the other, if higher priced resources must be used to serve demand in that area.

Congestion costs are established within the dispatch engine by incrementally relaxing each constraint, one at a time, and then determining the resulting change in total system costs from re-dispatch. The congestion cost for a pricing location is the sum of the individual incremental congestion costs for each constraint affected to at least a pre-determined degree by the flow from the reference bus to the pricing location. This is determined using calculated "shift factors" which indicate the degree to which changes in flows between the reference bus and the pricing location affect a given constraint. The total incremental congestion cost for a pricing location is:

- Positive when flows are limited away from the reference bus towards the pricing location.
- Negative when flows are limited towards the reference bus from the pricing location.
- Zero when there are no binding constraints.

2.4 Cost of Losses

Electricity is lost as it moves from one point on a transmission system to another, mostly through conversion to heat. When the system is dispatched, supply must be included to replace losses in addition to meeting the demand created by consumers and exports.

The cost of losses is a function of the marginal loss factor at a given location and the reference price. A location's marginal loss factor reflects the transmission losses incurred on the system from meeting an additional increment of demand at that location with one additional MW of supply from the reference bus. Similar to the cost of congestion, the impact on losses on all paths affected to a certain degree is considered.

In general, the loss factor for a resource is a function of its electrical distance from the reference bus and the prevailing transmission system flows. Loss factors for specific resources are typically greater the further the resource is from the reference bus.

The cost of losses also increases as the reference price increases. If all else is equal, the greater the cost of marginal transmission losses to a particular location relative to the reference bus, the lower the LMP will be at that bus. Losses can be modelled through either static or dynamic loss factors. Static loss factors reflect the cost of losses within a historical sample set. Historically, the IESO has used static loss factors to determine the cost of losses. This was satisfactory in the previous market as the HOEP did not include the cost of losses, so any imprecision associated with using static factors did not directly affect the settlement price. However, the cost of losses can directly impact LMPs. Using dynamic loss factors is producing prices that better reflect the cost of meeting demand at a given bus.

Dynamic loss factors are ones determined closer to actual dispatch. These can be calculated daily, hourly, by interval, or on some other basis which brings the calculation near to real-time. The more often the calculation is done, the more accurate it will be. However, there are downsides to calculating loss factors frequently, such as every five minutes – doing so can add significant dispatch algorithm processing time and can result in more price fluctuations. Therefore, the IESO has settled on using hourly loss factors. These will reflect relatively near-term system conditions in the cost of losses but will have a lower impact on processing times and will reduce potential price volatility.

2.5 Why Consider Impacts on Multiple Paths?

In general terms, energy will take every available path between a point of supply and a point of consumption.

The direction and magnitude of energy flows on a transmission system are influenced by several factors, including:

- The location and magnitude of demand,
- The location and magnitude of supply, and
- The relative impedance of the various paths.

Impedance refers to relative opposition to power flow. It is a major factor which influences how energy moves around a grid. A higher impedance path indicates more opposition to power flow and greater losses. Impedance will be lower where there are:

- Shorter transmission lines,
- More parallel paths,
- Higher voltage, and
- Fewer series transformers.

Therefore, the algorithm must consider the impact on multiple lines when determining the costs of congestion and losses, as well as account for the physical nature of the transmission elements on the path. What increases the flow on one path may decrease the flow on another by "pushing" against the general direction of flow. This means that the same supply to meet the incremental demand at a pricing location may simultaneously increase congestion and losses in one place and reduce them in another. The impacts across all affected paths added together, to at least a specified minimum degree, are aggregated to determine the final congestion or loss cost used in calculating a location's LMP.

2.6 Energy Price Floors and Caps

A price cap represents the highest price that can be used to settle the market. Conversely, a price floor is the lowest the price can be. In the Market a range between the Maximum Market Clearing Price (MMCP) and the negative MMCP, i.e., must be no higher than $2,000 and no lower than negative $2,000, which are used for bid and offer prices.

However, a floor price for energy settlement of negative $100/MWh is applied in the market. This applies in both the DAM and real-time market for energy injections and withdrawals. This does not affect the ability for resources to offered or bid at prices as low as today's negative MMCP[4]. This design results in efficient price signals and appropriate settlement outcomes, while allowing resources to submit offers or bids across the full price range, from positive to negative MMCP, if desired.

[4] Except for those such as dispatchable variable generators or flexible nuclear resources which have specific offer floors. Please see Market Rules Chapter 7 section 3.5.5 and Market Manual 4.1: Submitting Dispatch Data in the Physical Market, section 2.1.1.1

3. Non-Dispatchable Load Prices

3.1 Introduction

The overall goal of non-dispatchable load (NDL) energy market settlement is to collect monies in keeping with the costs incurred to serve its demand. As such, the price charged to NDLs needs to reflect as closely as possible the cost of supply. This means the price has to include costs created across both the day-ahead and real-time markets. An uplift is also needed to account for differences in the LMPs paid to suppliers and those charged to consumers.

3.2 Non-dispatchable Load Settlement Price

In the market, resources scheduled to meet demand will be settled using LMPs through a two-settlement system. Here, LMPs determined by the DAM will be used to settle day-ahead schedules. Real-time LMPs will be used to settle deviations between day-ahead schedules and real-time actual operations.

Because NDLs do not submit bids, the IESO forecasts their expected real-time demand for use in day-ahead, pre-dispatch and real-time processes. As such, NDLs do not directly participate in the two-settlement system. Instead, NDLs are settled for their real-time consumption using a uniform price. However, costs associated with serving their demand will be generated across both the day-ahead and real-time markets. To account for this, the price charged to NDLs will have two components: The Day-Ahead Ontario Zonal Price (DA-OZP) and the Load Forecast Deviation Adjustment (LFDA).

3.2.1 Day-Ahead Ontario Zonal Price (DA-OZP)

The DA-OZP is the hourly, load-weighted average of the day-ahead LMPs calculated for each NDL[5]. Since LMPs reflect the cost of delivering energy to a specific location on the grid, this allows the total day-ahead cost of serving NDLs to be spread across all NDL market participants.

Since NDLs are charged based on their real-time consumption, why are day-ahead prices used instead of real-time ones? It's because under a two-settlement system, most energy supply will be scheduled in the DAM. This means that the largest proportion of NDL costs to the market will be accumulated there.

[5] LMPs will be calculated for NDLs but will not be charged directly to each individual market participant

3.2.2 Load Forecast Deviation Adjustment (LFDA)

NDL real-time consumption is forecasted by the IESO for use in the DAM. Since most demand is NDL, this forecast is an essential input used by the DAM to decide how much supply to secure for the next day. Resources scheduled day-ahead are given financially binding schedules. If actual NDL real-time consumption is different than what was forecast, the market will have secured too little, or too much, supply day-ahead for which it will pay day-ahead prices. These real-time deviations from DAM schedules will be settled at real-time prices. As such, simply applying a day-ahead price to real-time consumption won't accurately reflect NDL costs to the market. Instead, the financial impact of forecast deviations must be accounted for. This is done through calculating and adding the LFDA to the DA-OZP before applying the result to NDL real-time consumption.

The LFDA is the hourly sum of two components (positive or negative), allocated across all NDLs, the:

- DAM Volume Factor Cost/Benefit, and the
- Real-Time Purchase Cost/Benefit.

The DAM Volume Factor Cost/Benefit represents the total hourly cost or benefit to all NDLs arising from DAM load forecast deviations as assessed in the DAM. It's calculated on an hourly basis as follows:

DAM-OZP x (DAM forecasted load – RT energy withdrawn + RT energy injected)

This determines the charge/credit at the day-ahead price for the difference between the energy consumption forecast day-ahead and what was actually withdrawn in real-time.

The Real-Time Purchase Cost/Benefit represents the total hourly cost or benefit to all NDLs resulting from DAM load forecast deviations as assessed in the real-time market. It's calculated for each five-minute interval of an hour for each NDL settlement point and then summed for the hour as follows:

Sum of [RT-LMP x (RT energy withdrawn – RT energy injected – DAM forecasted load)/12]

This determines the charge/credit at the real-time price for the difference between the energy actually withdrawn and the amount forecast day-ahead.

NDL Settlement Price Calculation Example:

The following are simplified examples of DA-OZP and LFDA calculations.

1. Day-Ahead Ontario Zonal Price

As stated above, the DA-OZP will be the load-weighted average of all DAM LMPs calculated for NDLs in Ontario. For example, assume there are only three NDLs across the province with the following DAM forecasted consumption:

NDL A = 5,000 MW

NDL B = 2,000 MW

NDL C = 3,000 MW

So, the total forecast is 10,000 MW.

Assume the following DAM LMP's for each NDL:

NDL A = $40/MWh

NDL B = $50/MWh

NDL C = $30/MWh

As mentioned earlier, although LMPs are calculated for NDLs, they are not directly applied for settlement. Instead, they will be used to arrive at an average price which will serve as the basis of NDL settlement.

In this example, the DA-OZP would be:

DA-OZP = ((5,000/10,000) x 40) +((2,000/10,000) x 50) +((3,000/10,000) x 30))

= 20 + 10 + 9

= $39.00/MWh

2. Load Forecast Deviation Adjustment (LFDA)

As stated above, the LFDA is a price adjustment applied to the DA-OZP to reflect the two-settlement nature of the renewed market. Let's look at an example.

Continuing from above, the DAM-OZP was $39/MWh. Let's assume:

- The real-time LMPs for the three resources were $30, $55 and $31 in all intervals, and
- None of the resources injected energy in real-time (so the term RT energy injected = 0)

NDL	DAM-OZP ($/MWh)	RT-LMP ($/MWh)	DAM Forecast (MW)	Actual Consumption (MW)	Real-Time Purchase Cost/Benefit	DAM Volume Factor Cost/Benefit
NDL A	$39	$30	5,000	4,750	-$7,500	$9,750
NDL B	$39	$55	2,000	2,100	$5,500	-$3,900
NDL C	$39	$31	3,000	3,225	$6,975	-$8,775
TOTAL			10,000	10,075	$4,975	-$2,925

For NDL A:

- The Real-Time Purchase Cost/Benefit is

Sum of [RT-LMP x (RT energy withdrawn – RT energy injected – DAM forecasted load)/12]

= Sum of [$30 x (4,750 – 5,000)/12]

= Sum of [$30 x (-250) /12]

= -$625 x 12 (since the LMP was the same for each interval, and there are 12 intervals in the hour)

= -$7,500

The DAM Volume Factor Cost/Benefit is

DAM-OZP x (DAM forecasted load – RT energy withdrawn + RT energy injected)

= $39 x (5,000 – 4,750)

= $39 x 250

= $9,750

If we do the same calculations for the other two NDLs, the total Real-Time Purchase Cost/Benefit is $4,975, the total DAM Volume Factor Cost/Benefit is -$2,925, and the total real-time demand was 10,075 MW. So, in this example,

LFDA = (Real-Time Purchase Cost/Benefit + DAM Volume Factor Cost/Benefit) / RT energy withdrawn

= ($4,975 + (- $2,925)) / 10,075

= $0.20/MWh

With this LFDA, the total price used to settle NDLs in this hour will be:

DAM-OZP + LFDA = $39/MWh + $0.20/MWh = **$39.20/MWh**

Charging this rate for real-time consumption ensures that NDLs are settled appropriately for their market costs. To illustrate that, let’s look at the above example in a different way:

- Forecast demand for NDL 1 was 5,000 MW. With a DA-OZP of $39, that would result in a total charge of $195,000. However, NDL 1’s real-time consumption was actually 250 MW less than that. In keeping with a two-settlement system, the difference is accounted for at the real-time price. With a $30 real-time LMP, this results in a charge reduction of 250 MW x $30, or $7,500.
- NDL 2’s real-time consumption was higher than forecast by 100 MW. At a real-time LMP of $55, an additional $5,500 (i.e., 100 MW x $55) is required over and above what would have been collected based on the DA-OZP and the day-ahead forecasted quantity.
- Lastly, NDL 3’s real-time consumption was 225 MW higher than forecast, and its LMP was $31. This results in a needed adjustment of 225 MW x $31, or $6,975.

NDL	DAM DA-OZP	DAM Forecast (MW)	Actual Consumption (MW)	Difference DAM to RT (MW)	Real-Time LMP	Market Revenue Required Change
NDL A	$39	5,000	4,750	-250	$32	-$7,500
NDL B	$39	2,000	2,100	100	$55	$5,500
NDL C	$39	3,000	3,225	225	$31	$6,975
TOTAL		10,000	10,075			**$4,975**

So overall, the total revenue required to cover these NDLs costs to the market is $394,975 (i.e., the DAM Cost of $390,000 plus the Market Revenue Required Change of $4,975). If the IESO settled the NDLs at the DA-OZP of $39 for their real-time consumption of 10,075 MW, they would only be charged $392,925. The DA-OZP has to be adjusted to ensure the correct market charges. Given real-time consumption, the required price is $394,975 / 10,075 MW = $39.20/MWh. Since the DA-OZP was $39.00, this makes the LFDA, as in the earlier calculations, 0.20.

Pricing in the Event of a DAM Failure

The DAM is designed to operate every day of the year. There is the small possibility, however, that issues may arise that preclude DAM completion. If this occurs, NDLs will be settled using the real-time Ontario Zonal Price. This is calculated as the load-weighted average of NDL real-time energy LMPs.

3.3 Residuals

Because of differences in the LMPs paid to suppliers and those charged to consumers, an uplift charge to settle 'residual' monies will be needed to balance the market. LMPs include congestion and loss components which are unique to each location on the grid. This means that LMPs applied to consumers (including NDLs collectively) will not be exactly the same as those paid to suppliers. These price differences create two forms of residual:

- Congestion Rents: Congestion rents result from price differentials created by binding transmission constraints. Binding constraints mean that lower priced supply on one side of a constraint cannot fully serve demand on the other side. This demand must be served for their remaining requirement by higher priced supply. The consumers will be charged the higher price for all of their demand. However, the suppliers who provided part of the consumers' required energy will be paid a lower price, since they were on the lower-priced side of the constraint. The difference is congestion rent.
- Loss Residuals: Transmission losses occur when electricity flows across a transmission system. The difference between the amount paid for losses by consumers through their LMPs and the amount paid for losses to generators through theirs results in the "loss residual."

Settlement occurs monthly through the Internal Congestion and Residual Loss charge type (CT 1116).

4. Intertie Pricing

4.1 Introduction

Ontario is directly interconnected with five neighbouring jurisdictions. This allows energy to be transacted into and out of the province. Energy imports and exports are conducted in the market through intertie zones. These zones are Ontario market constructs which represent the jurisdiction with which the energy is being transacted. These are used for scheduling and pricing purposes within the calculation engines.

The Ontario market supports hourly intertie transactions. As such, intertie transactions are scheduled to flow by the last pre-dispatch run before the start of the hour[6]. They are then passed to the real-time scheduling and pricing calculation engine as fixed supply (if imports) or demand (if exports). As such, real-time does not schedule intertie transactions.

4.2 Intertie Pricing

Given this, how are intertie transactions priced? Firstly, it's important to note that Intertie transactions are settled using the two-settlement system.

Intertie prices will be made up of the **Intertie Border Price (IBP)** plus the **Intertie Congestion Price (ICP)**.

The IBP is the LMP at the Ontario side of an intertie. As such, it includes the Ontario reference price plus the costs of congestion and losses between the reference bus and the intertie with the external jurisdiction.

The ICP reflects external congestion as determined in the last pre-dispatch before the start of the dispatch hour and also includes the congestion cost associated with the Net Intertie Scheduling Limit (NISL).

NISL is included in the DAM and pre-dispatch calculation engines to limit the net allowable change in intertie schedules across the top of an hour. As mentioned, intertie schedules are for one hour blocks. Changes in schedules from one hour to the next are achieved by dispatching facilities within Ontario either up (to achieve net exports) or down (to accommodate net imports) to account for the total intertie schedule change across all interties. This ramping takes ten minutes, starting five minutes before the hour and ending five minutes after the start of the hour. NISL is respected to ensure Ontario resources can satisfy hour-to-hour ramping needs without adversely impacting reliability. NISL is normally set to plus or minus 700 MW, unless changed by the IESO to support reliability.

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[6] Final schedules are subject to confirmation with our neighbouring control areas, and may be adjusted from the last pre-dispatch results, if necessary.

NISL in the Market

To respect NISL in the DAM and PD calculation engines may reduce or increase imports and exports that would have otherwise been economically scheduled. When doing so, they take the impact on cost into consideration.

As an example, assume an Hour 1 net import schedule of 500 MW. For Hour 2, assume the pre-dispatch intertie price is $38 and that the following are the available import offers and export bids:

Transaction	Hour 2 Offers and Bids
Import A	1,300 MW@ $30
Import B	300 MW@ $35
Export C	100 MW@ $50
Export D	300 MW@ $34

With an intertie price of $38, Imports A and B and Export C would be economic. Export D would be uneconomic. If the three economic transactions were all scheduled in full, the resulting net schedule would be imports of 1,500 MW (1,300 MW plus 300 MW, less 100 MW). However, because Hour 1's net schedule was 500 MW of imports, the net import schedule for Hour 2 must be limited to 500 MW plus the 700 MW NISL, or 1200 MW.

To produce a net import schedule of 1200 MW in hour 2, the DAM and pre-dispatch calculation engines would evaluate the following options to determine what the impact on cost would be:

- The algorithm could choose not to schedule Import B. With an offer price of $35 and an intertie price of $38, it had been scheduled to 300 MW. Not scheduling this transaction would represent a cost of $38 less $35, or $3/MWh, or $900 in total. This is the amount that the import stood to benefit by if it had flowed. Not receiving it would, therefore, be a cost to be considered.
- Alternatively, the algorithm could schedule Export D. with a bid price of $34 and a price of $38, it had not been previously scheduled to flow. If Export D was now scheduled, it would be required to pay a price higher than it's bid. The difference between its bid and what it would be required to pay given the intertie price is $4/MWh. This represents a total cost of $12

Option	Economic Schedule	Schedule to Respect NISL	Offer/Bid Price	Cost [(Intertie Price – Offer/Bid Price) x Schedule Change to Respect NISL
Do not schedule Import B	300 MW	0 MW	$35	($38 - $35) x 300 MWh = $900
Schedule Export D	0 MW	300 MW	$34	($38 - $34) x 300 MWh = $900

Therefore, the calculation engines will choose not to schedule Import B (and to leave Export D unscheduled) as this is the least cost solution to respect NISL.

The cost of NISL is also incorporated into the intertie price. To calculate the NISL congestion component for the intertie price, the DAM and pre-dispatch calculation engines will determine the savings resulting from expanding the NISL constraint by 1 MW. To determine this, the calculation engines will look at all possible solutions, including whether Import A and Export D could help. Import A cannot as it is already fully scheduled. Export D cannot because it is uneconomic and is not required to be scheduled to respect NISL. This makes Export D unavailable.

Transaction	Offers/Bids	Schedule to Satisfy 700 MW NISL	Eligible to Satisfy next MW (i.e., 701 MW NISL)?	Savings (Difference Between IBP and Eligible Offer/Bid)
Import A	1,300 MW@ $30	1,300 MW	No	N/A
Import B	300 MW @ $35	0 MW	Yes	$38 - $35 = $3
Export C	100 MW @ $50	100 MW	Yes	$38 - $50 = -$12
Export D	300 MW @ $34	0 MW	No	N/A

Import B could flow 1 MW if the NISL constraint were relaxed by a megawatt. The savings associated with this would be the $3 difference between its offer price and the Intertie Border Price.

Because Export C bid at $50, it was fully scheduled while respecting the 700 MW NISL limit. If Export C was reduced by 1 MW to allow for additional import flow, there would be a cost of $12 since Export C was willing to pay up to $50 to export.

Therefore, the NISL price is set at Import B's $3 savings since it is the most economic outcome.

The intertie price, then, would be the Intertie Border Price of $38 plus an ICP of -$3 (assuming no congestion due to the intertie limit) which equals $35. The NISL congestion price is negative because it is binding in the import direction.

That the price in this example dropped due to NISL congestion makes sense in terms of market dynamics – reducing the intertie price by $3 makes transacting imports less attractive and makes it more attractive to export. This is what one would want to have happen to resolve an import-congested intertie.

5. Virtual Transaction Pricing

5.1 Introduction

'Virtual trader' is a market participant type in the market. Virtual transactions allow registered market participants to be settled on zonal price differences between the day-ahead and real-time markets.

The market uses a two-settlement process: Transactions scheduled in the DAM are settled at day-ahead prices while deviations from day-ahead schedules in real-time operations are settled at real-time prices. Prices in the two markets can be different. An efficient two-settlement system will tend to have prices in day-ahead and real-time which are relatively close. Having day-ahead and real-time prices that are relatively close reduces the risk to a participant of failing to deliver day-ahead schedules. This incentivizes participants to offer and bid their expected capability in day-ahead as accurately as possible. This allows the IESO to schedule the lowest cost resources to meet demand, improving the efficiency of DAM scheduling and commitments.

Virtual transactions allow registered participants to bid or offer energy in the DAM, receive a schedule, be settled for that MW quantity at the day-ahead price, and then be settled for the opposite transaction at the real-time price. No physical delivery or consumption of energy is required.

This structure helps to converge prices and reduce the difference between day-ahead and real-time prices. For example, if one is buying at the day-ahead price and selling at the real-time price, it is likely they are assuming the price in real-time will be higher than the price day-ahead. However, by buying day-ahead, they are increasing demand for energy day-ahead which will contribute to a higher day-ahead price – one which may be closer to the real-time price.

5.2 Virtual Trading Zones

For the purposes of virtual trading, the IESO has designated nine virtual trading zones within Ontario. These are effectively the ten Ontario electrical zones, with the southwest and Bruce zones combined into one[7]. There is one source resource (for offers to sell energy) and one sink resource (for bids to buy energy) per virtual trading zone. These are used to specify the location of a bid or offer.

Virtual Zone	East	Essa	Northeast	Northwest	Ottawa	Southwest	Toronto	West
Electrical Zone	East	Essa	Northeast	Northwest	Ottawa	Southwest & Bruce	Toronto	West

[7] There are no virtual trading zones at the interties.

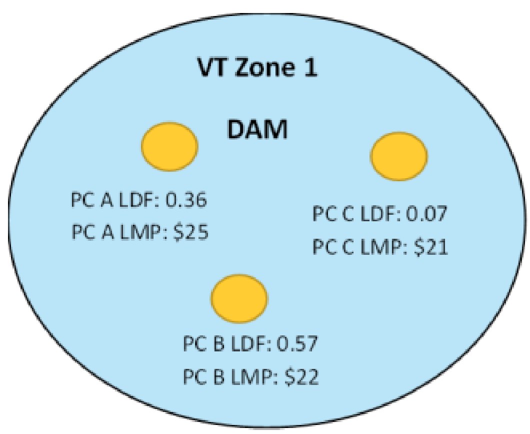
5.3 Virtual Transactions and Price Convergence

Virtual transactions are assigned by the DAM calculation engine to specific load locations for the purpose of determining schedules and prices. The distribution is done using Load Distribution Factors (or LDFs), which represent each physical load's share of total demand. By distributing virtual transactions to specific locations and including them in the calculation of DAM LMPs they are able to contribute to price convergence. Virtuals do this by moving LMPs higher or lower than they would have been otherwise, reflecting the market's expectations about real-time prices. So, as stated above, if a trader expects prices to be higher in real-time than in the DAM, they will buy day-ahead. This has the effect of increasing demand day-ahead, moving prices upwards – that is, more in line with expected higher real-time prices. Virtuals are not included in price and schedule determination in real-time, as real-time is effectively a reliability run which is focused on meeting physical demand.

5.4 Virtual Zone Prices

The zonal prices used to settle virtual transactions will be calculated as the load-weighted average of the locational marginal prices at all load points within the zone. LDFs are used to determine the weighting to give to each applicable locational marginal price in the virtual trading zone. Like with other prices, DAM and real-time virtual zonal prices will be calculated and used for settlement; pre-dispatch zonal prices will be provided for information purposes only.

As an example, assume in the DAM there are three consumers in Virtual Transaction Zone 1. Physical Consumer A has an LDF of 0.36 and an LMP of $25; Physical Consumer B has an LDF of 0.57 and an LMP of $22; and Physical Consumer C has an LDF of 0.07 and an LMP of $21

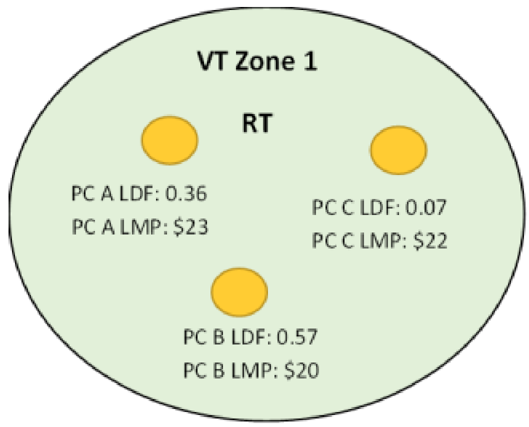


Therefore, Virtual Transaction Zone 1 DAM Price

= (\$25 x 0.36) + (\$22 x 0.57) + (\$21 x 0.07)

= \$23.01

Assume in real-time that Physical Consumer A has an LMP of \$23, Physical Consumer B has an LMP of \$20, and Physical Consumer C has an LMP of \$22.



Therefore, Virtual Transaction Zone 1 RT Price

= (\$23 x 0.36) + (\$20 x 0.57) + (\$22 x 0.07)

= \$21.22

So if a trader sold 100 MW day-ahead in this example, they would receive in total the day-ahead zone price less the real-time price times the quantity sold; or (\$23.01 - \$21.22) X 100 MW. This means that they would be paid \$179.

However, if a trader bought 100 MW day-ahead, they would be charged \$179 because they sold at a price which was lower than the price at which they had made their purchase; or (\$21.22 - \$23.01) X 100 MW.

6. Operating Reserve Pricing

6.1 Operating Reserve LMPs for Internal Pricing Nodes

The energy and operating reserve markets are co-optimized by the calculation engines, meaning that resources are scheduled and prices are set simultaneously based on all submitted offers, while maximizing gains from trade across both markets and for each scheduled resource[8].

In the renewed market, the operating reserve LMPs for each type of operating reserve[9] are made up of two components:

- An Operating Reserve Reference Price: This is the marginal cost of satisfying an additional increment added to the province-wide requirement for that class of operating reserve. Similar to the energy Reference Bus Price, the same Operating Reserve Reference Price is included in all operating reserve prices.
- A Congestion Component: Congestion costs in the operating reserve market is not determined for each pricing location. Instead, these will be determined as the congestion cost associated with the operating reserve area in which the resource is located.

Operating Reserve Price = Operating Reserve Reference Price + Operating Reserve Congestion Component

Operating Reserve Congestion

An operating reserve area is a portion of the grid for which the IESO can ensure deliverability of activated reserve by entering minimum or maximum operating reserve requirements. Reserve area boundaries are usually defined by transmission interfaces and their associated system operating limits.

Minimum reserve area requirements are used to ensure that at least a certain amount of operating reserve is scheduled in an area because transmission restricts the delivery of sufficient activated reserve into that area. Maximum reserve area limits are used to prevent over-scheduling of operating reserve in areas where there is limited transmission capability to export activated reserve out of the area to serve needs elsewhere. Congestion occurs when these constraints are binding – that is, when insufficient operating reserve is available in an area with a minimum constraint or too much economic

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[8] The gain from trade for the market is the difference between the total price of scheduled bids and the total price of scheduled offers. Gain from trade is maximized at the price where the quantity generators are willing to sell is equal to the quantity customers are willing to purchase. The gain from trade for a resource which offers operating reserve is the difference between their offer price and the operating reserve market clearing price.

[9] Operating reserve is classified as one of three types: 10-minute Synchronized (or Spinning), 10-minute Non-Synchronized (or Non-Spinning) and 30-minute Reserve. The time periods indicate how quickly a resource must meet its dispatch target if activated. Synchronized reserve must be scheduled from resources currently synchronized to the grid, whereas non-synchronized and 30-minute reserve can come from resources which are not currently synchronized to the grid.

operating reserve is available in an area with a maximum constraint. If there is no congestion, the price in an operating reserve area is the same as the Operating Reserve Reference Price.

6.2 Operating Reserve LMPs for Intertie Zones

Intertie zone operating reserve LMPs is the same for all transactions in the same intertie zone. In the DAM and pre-dispatch calculation engines, determining intertie zone operating reserve LMP's is similar to the calculation of LMPs for internal resources. The difference is that intertie zone OR LMPs also account for binding net import constraints, since these, limit the amount of operating reserve that can be imported. The formula for DAM and PD operating reserve LMPs is:

Operating Reserve Price = Operating Reserve Reference Price + Operating Reserve Congestion Component + Operating Reserve Import Congestion Component

The calculation of real-time operating reserve prices for intertie zones is similar, except the import congestion component is determined by the last pre-dispatch calculation before the start of the dispatch hour, and not by real-time. This is because real-time does not evaluate intertie transactions; it is given intertie schedules by pre-dispatch. These schedules can't cause congestion since pre-dispatch only schedule transactions which don't exceed the intertie's limit.

6.3 Operating Reserve Minimum and Maximum Prices

Operating reserve offers and prices are capped at the Maximum Operating Reserve Price of $2,000 and may not fall below $0.

7. Price Setting Eligibility

An LMP is set by an offer or bid which can satisfy an additional increment of demand. For an offer or bid to be selected, the resource for which it was submitted must have the actual remaining operational range to allow it to physically meet the demand. For example, if a supplier is currently fully dispatched, it would not have any additional capability to increase its output. As such, it could not set price.

Beyond being fully dispatched, there are several other limitations on the ability of a resource to meet incremental demand and, therefore, its ability to set prices. The following describes some of these constraints:

- Offers from a non-quick start resource will only be eligible to set energy or operating reserve prices in the DAM or pre-dispatch if the resource is committed and is scheduled to at least its minimum loading point.
- If a resource has entered a maximum daily energy limit (MaxDEL), it's considered by the DAM and pre-dispatch calculation engines to be energy-limited. Such a resource can set price in these runs only if it has remaining energy below its maximum cap.
- A resource which entered a maximum number of starts per day as a dispatch data parameter will only be able to set price in the DAM and pre-dispatch to the extent that it can start. For example, pre-dispatch will not use a resource to set price in a future hour if it is offline coming into the hour and it has no remaining starts.
- There are several dispatch data parameters which can be entered by a hydroelectric resource which will affect its ability to set price:
  - Minimum Hourly Output (MHO): Only offers above the MHO[12] will be eligible to set energy or operating reserve prices in the DAM and pre-dispatch. As such, the resource will only be eligible to set price in these calculation engines when it is scheduled at or above its MHO.
  - Minimum Daily Energy Limit (MinDEL): Resources that have not reached their MinDEL[13] can't set prices in the DAM or pre-dispatch. The DAM calculation engine will consider MinDEL still binding (and the resource ineligible to set price) if the sum of the energy scheduled throughout the day is less than or equal to the MinDEL limit. It's similar in the pre-dispatch engine, except:
    - If the look-ahead period covers only the current dispatch day, the amount of energy already provided during the dispatch day before the particular predispatch run will be considered.
    - If the look-ahead period covers the remainder of the dispatch day and the next dispatch day, pre-dispatch will use the MinDEL limit for the next dispatch day.

- Shared Maximum Daily Energy Limit (Shared MaxDEL): Hydroelectric resources registered to the same forebay are ineligible to set price for an hour in the DAM if the sum of energy scheduled up to that point plus operating reserve scheduled in the final hour is more than or equal to the shared MaxDEL.14 It's similar in the pre-dispatch engine, except:
  - If the look-ahead period covers only the current dispatch day, the amount of energy provided during that dispatch day before the particular pre-dispatch run is considered.
  - If the look-ahead period covers the remainder of the dispatch day and the next dispatch day, pre-dispatch will use the shared MaxDEL limit for the next dispatch day.
- Shared Minimum Daily Energy Limit (Shared MinDEL): Hydroelectric resources registered to the same forebay are ineligible to set price for an hour in the DAM if the sum of energy scheduled throughout the day is less than or equal to the shared MinDEL.15 It's similar in the pre-dispatch engine, except:
  - If the look-ahead period covers only the current dispatch day, the amount of energy provided during that dispatch day before the particular pre-dispatch run is considered.
  - If the look-ahead period covers the remainder of the dispatch day and the next dispatch day, pre-dispatch will use the shared MinDEL limit for the next dispatch day.

8. Additional Resources

Training resources can be found on the Marketplace Training and Participant Tool Training web pages:

- Workbooks:
  - Introduction to Ontario's Physical Markets
  - Interjurisdictional Energy Trading
  - Revenue Metering
- Guides:
  - Introduction to Virtual Trading
  - Price Responsive Loads
  - Guide to IESO Market Calculation Engines

Market Rules and Manuals can be found on the Renewed Market Rules and Manuals Library web page:

- Market Rules:
  - Market Rules Chapter 7 – System Operations and Physical Markets
  - Market Rules Chapter 9 – Settlements and Billing
- Market Manuals:
  - Market Manual 4.1 – Submitting Dispatch Data in the Physical Markets
  - Market Manual 4.2 – Operation of the Day-Ahead Market
  - Market Manual 4.3 – Operation of the Real-Time Markets
  - Market Manual 5.5 – IESO-Administered Markets Settlement Amounts

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