Ontario’s Physical Markets

IESO Training

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Connecting Today.
Powering Tomorrow.

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1. Introduction

This workbook explains the basic rules and processes for trading energy within Ontario. You will learn how participants buy and sell energy products in Ontario's IESO-administered markets, how energy prices are set, and how we dispatch facilities to meet the demand for electricity.

We begin with a discussion of:

- A brief history of the electricity market in Ontario
- Types of market participants
- How participants offer to supply electricity or bid to buy electricity
- Energy bids and offers

Once we have explained bids and offers, we move on to:

- How we determine the prices of electricity in Ontario
- How the amount of electricity participants supply or consume is determined

The last chapter explains operating reserve (i.e., 'stand-by' energy).

We end with a section listing 'Additional Information'. Please refer to this section for sources of in-depth explanations of some of the topics covered in this introductory workbook.

Note: This workbook deals only with energy sales and purchases within Ontario. For details on imports and exports, see the Interjurisdictional Energy Trading workbook, available on the Training web page.

2. Ontario's IESO

The IESO is a not-for-profit, regulated corporation without share capital. The Ontario Energy Board (OEB) regulates the IESO, and the Ontario government appoints its directors. The IESO's fees and licences to operate are set by the Ontario Energy Board. In fulfilling its role as the province's reliability coordinator, the IESO complies with, oversees and enforces reliability standards and processes set by several regulatory bodies within and outside of Ontario. The IESO delivers key services across the electricity sector including managing the power system in real-time, planning for the province's future energy needs, enabling conservation, contracting for new supply, operating a capacity auction and maintaining and updating the electricity marketplace to support sector evolution.

Objectives

After completing this section, users will be able to:

- Describe the roles of the IESO
- Understand the various responsibilities of the IESO

2.1 Roles of the IESO

Overseeing the IESO-Administered Markets

The IESO administers a set of rules (the Market Rules) that govern the operation of the electricity markets. The IESO monitors market activity to ensure compliance with these rules and performs surveillance of market activity to ensure fair market competition. In addition to the rules, to support market operations, the IESO has produced procedures, forms, standards and policies. The market manuals provide the details of these procedures and policies.

The IESO itself does not buy or sell electricity in the energy market. It administers the markets by authorizing market participants, publishing system forecasts and market information, producing statements and invoices, and performing financial settlement transactions for the markets.

The IESO also runs the energy market. Based on consideration of expected demand and system conditions and of participant bids and offers, the IESO determines the price for energy as well as the schedules and dispatch instructions required to maintain reliability.

Ensuring the Reliability of the Integrated Power System

The IESO and all market participants are jointly responsible for ensuring the reliability of the power system.

The IESO gathers real-time information on voltage levels, power flows, and equipment status. Trained and certified IESO staff monitor this information and manage the security and adequacy of the power system 24 hours a day, every day of the year.

From its system control centre, Ontario’s IESO manages the power system. The IESO ensures the system adheres to reliability standards like those set by standards authorities such as the North American Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC). In addition, the IESO provides input to both reliability organizations to ensure that appropriate reliability standards are set.

Planning for the Future

To ensure the province’s electricity system can meet these needs, the IESO uses demand and supply forecasts to inform future infrastructure planning and supply procurement. These forecasts consider many variables, including: the impact weather could have on demand, the sector’s ability to make - and deliver - enough power to Ontario’s communities and future electricity demand drivers, such as the opening of new manufacturing plants, electric vehicle uptake and economic sector growth. These forecasts are regularly updated as new information becomes available to signal new project and investment opportunities.

The IESO also plans and coordinates the construction of Ontario's high-voltage transmission lines that transport electricity from suppliers to Ontario's communities. This includes coordination between local, regional and provincial electricity system planning, engagement with Indigenous communities, municipalities, individuals and business groups and integration of different forms of electricity supply, weighing the best mix of available options to ensure affordability and reliability.

These roles are important in ensuring an adequate and reliable electricity system.

3. Ontario's Physical Power System

Ontario's well-established electric power system is made up of a network that transmits electricity from suppliers (e.g., generators) to consumers (loads). To explore more of Ontario's physical power system, please see the IESO's Interactive Ontario Electricity System Map.

Objectives

After completing this section, users will be able to:

- Describe the role of transmission system
- Recognize the role of the IESO-Controlled Grid in the physical power system
- Recall key terms such as electricity supply, demand and electricity flow

3.1 Ontario's Transmission System

Electric power is transmitted across the province on approximately 30,000 kilometres of high-voltage transmission lines, which includes 115 kilovolt (kV), 230 kV, and 500 kV transmission lines. Hydro One owns most of the transmission system.

Step-down transformers are used to link electric power from the high-voltage lines to low-voltage lines. Local distribution companies then distribute the electric power at lower voltages to end-use customers.

Ontario's high-voltage lines interconnect with lines from Manitoba, Quebec, New York, Michigan and Minnesota. These interconnection lines (or interties) allow electricity to be imported into and exported out of Ontario. They can also provide critical support when needed to maintain system reliability.

Ontario currently has the installed capacity to generate more than 35,000 megawatts of electric power. The available capacity changes throughout the day and year according to how many facilities are undergoing maintenance or are in forced outage or derate. Ontario Power Generation Inc. (OPG) is the largest provider of generating capacity to the Ontario market. OPG's generating plants include nuclear, hydroelectric, biomass, oil and natural gas-fired stations. In addition, multiple independently owned suppliers provide power to the system.

3.2 The IESO-Controlled Grid

The portion of the Ontario transmission system managed by the IESO is called the 'IESO-controlled grid'. It includes all transmission lines equal to or greater than 50 kilovolts. These are not the lines that go directly into your home. They are the high voltage transmission lines that provide electricity to large industrial consumers, and to distributors who then provide electricity at the retail level.

The IESO-controlled grid lies within the Ontario Control Area, which also includes the distribution lines and energy consumers (loads) within Ontario.

The IESO is responsible for balancing the supply and demand of energy so that supply always adequately satisfies demand.

Energy Supply

Energy is supplied to the market by generators and electricity storage facilities located within Ontario and by imports from neighbouring jurisdictions.

Energy Demand

Consumers of energy in Ontario are referred to as loads. There is also demand from neighbouring jurisdictions for the export of energy produced in Ontario. Some loads provide forms of demand response, where their consumption can be lowered to reduce overall demand on the system.

Measuring the Flow of Energy

Meters are used to measure the flow of energy at any point where energy flows into or out of the IESO-controlled grid. These meters must be capable of measuring energy at specific time intervals. The resulting readings are the basis of settling energy charges and revenues in the wholesale market.

4. Day-Ahead Market

A Day-Ahead Market (DAM) for electricity is where market participants submit bids and offers a day in advance of operations to secure schedules and prices for the following day. A DAM is a standard component of many electricity markets in North America and around the world. In these markets, most of the supply is scheduled in the DAM and the real-time market is used to balance any deviations that occur between day-ahead and real-time.

A DAM for energy and operating reserve (OR) encourages efficient market participation by providing market participants with an opportunity to lock in a day-ahead price for their day-ahead schedules.

Objectives

After completing this section, you will be able to:

- Explain the objectives and processes of the DAM calculation engine, including the production of financially binding schedules, commitment decisions, and locational marginal prices.
- Describe the two-settlement process, including day-ahead settlement and real-time balancing settlement.

4.1 Two Settlement Process

Day-ahead scheduled transactions are settled at day-ahead prices meaning they are "financially binding". Day-ahead schedules and prices, however, are based on forecasts of next day demand and system conditions, both of which can change by the time real-time comes along. As such, actual real-time operations may need to be different than what was scheduled day-ahead. Real-time, therefore, serves as a balancing market to settle deviations between day-ahead schedules and actual real-time operations. This process of settling both the DAM and the RTM is called "two-settlement."

The DAM is settled on an hourly basis, so schedules and prices are for an entire hour. The general formula for DAM energy settlement for suppliers, dispatchable loads and price responsive loads is the day-ahead quantity times the resource's day-ahead locational marginal price:

DAM Quantity Scheduled X DAM LMP

The RTM operates on a five-minute basis, so it's prices and schedules are determined for each of the 12 five-minute periods in an hour. The general formula for RTM energy settlement for suppliers, dispatchable loads and price responsive loads is the difference between the quantity produced/consumed in real-time less the quantity scheduled in day-ahead times the five-minute real-time locational marginal price:

(RTM Quantity Actually Produced/Consumed – DAM Quantity Scheduled) X RTM LMP

The quantity actually produced/consumed in an interval is multiplied by 12, then the DAM quantity is subtracted from the result. This number is divided by 12 to get the result for the interval. This process minimizes rounding of the schedule quantity for an interval which could impact the payment received for the scheduled MW. This process is repeated for each of the 12 intervals in a clock hour.

The outcome of the two settlements (DAM and RTM) represents the outcome of the two-settlement process for any given hour.

4.2 DAM Calculation Engine

The DAM calculation engine uses a number of inputs from both market participants and the IESO. The engine runs on the day before the dispatch day (the "pre-dispatch day") and consists of three passes executed sequentially. The DAM calculation engine achieves the following objectives for the next day:

- Produce financially binding day-ahead energy and OR schedules for most resources
- Generate commitment decisions for eligible non-quick start (NQS) resources
- Provide locational marginal prices (LMPs) that will be used to settle the day-ahead market
- Prevent the potential exercise of market power by performing the ex -ante market power mitigation process.

4.3 Market Power Mitigation (MPM)

When market participants posses market power, they have the ability to raise prices and to maintain them above the level that would prevail under competition. Market Power Mitigation refers to the actions necessary to prevent market participants from exercising market power.

There are several forms of MPM which are used in the market. Before-the-fact or 'ex-ante' mitigation is applied within the day-ahead market calculation engine to prevent attempts to exercise market power from significantly impacting day-ahead prices and schedules. This assessment is conducted by the day-ahead market calculation engine using a conduct and impact methodology which assesses the following:

1. Did any resources have market power?
2. For those resources, did any of them submit dispatch data at prices significantly above the relevant reference level value?
3. Were market prices significantly higher using the too-high prices than would have been the case if reference level values were used in place of the too-high prices?

If the answer to all three questions is yes, then the relevant resources' dispatch data are replaced with reference level values to determine prices and schedules in the day-ahead market calculation engine. Reference level values are offer prices pre-determined by the IESO with input from the market participant, which reflect how they would have offered in the face of competition.

4.4 Availability Declaration Envelope (ADE)

In order for dispatchable generation resources, dispatchable loads[1], hourly demand response resources, and dispatchable electricity storage resources to operate in the RTM, they must establish an Availability Declaration Envelope (ADE). They do this by submitting energy offers or bids in the DAM for every hour they in which they wish to participate in the RTM. If they do not establish an ADE, the resource is unable to operate in the RTM, unless approved by the IESO under certain, specific circumstances.

Market participants have the option to increase their offered or bid quantity in the RTM from their day-ahead ADE as long as the increase is within a materiality threshold of the lesser of 15% of the ADE or 10 MW. Energy bid or offer quantity changes which exceed the availability declaration envelope quantity for a given hour by more than this must be approved by the IESO.

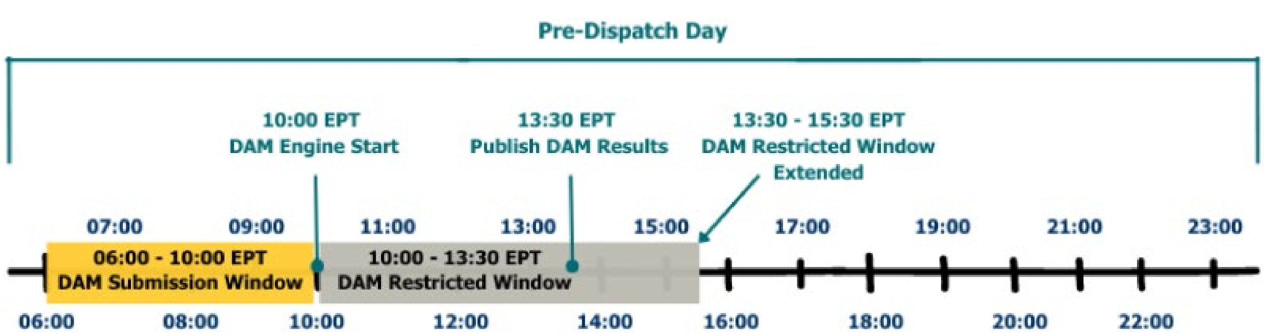
The requirement to establish an ADE does not apply for PRLs, self-scheduling generation, intermittent generators, and non-dispatchable storage resources. However, these market participants must still submit dispatch data for each hour real-time where they intend to inject or consume energy.

4.5 Day-Ahead Market Timeline

The DAM operates in Eastern Prevailing Time (EPT). On each pre-dispatch day, market participants submit dispatch data between 06:00 EPT and 10:00 EPT, which is also known as the DAM submission window. Once the DAM submission window closes at 10:00 EPT, the DAM calculation engine starts running.

From 10:00 EPT to 13:30 EPT, with limited exceptions, market participants cannot make any revisions to their dispatch data submissions for the next dispatch day. This is known as the DAM restricted window. This allows sufficient time for the calculation of schedules and prices to be completed. IESO approval is required for any new submissions or revisions to dispatch data for the next dispatch day within the restricted window. Such requests are only approved in the rare case of an IESO tool failure that prevents the IESO from receiving dispatch data submissions. If such a tool failure occurs, an advisory notice will be posted on the IESO advisory notice webpage.

Figure 1 | DAM Market Timeline



[1] Note that dispatchable loads must establish an ADE if they intend to operate as dispatchable in real-time. They are allowed, however, to operate as non-dispatchable if they either do not bid, or if they bid at the maximum market clearing price. Please see the Dispatchable Loads Quick Take on the Marketplace Training pages of the IESO website.

By approximately 13:30 EPT, hourly schedules, commitments and locational marginal prices are produced for the 24 hours of the next dispatch day as an output of the DAM. The results are published in the form of reports.

There is a possibility that process issues may delay publication of DAM results to 15:30 EPT. If results cannot be published by 15:30 EPT, a DAM failure will be declared.

5. Pre-dispatch

Pre-dispatch provides an updated view of real-time schedules and prices between the completion of the DAM and real-time itself. The first pre-dispatch that looks out for the next day starts at 20:00 EST. Pre-dispatch optimizes over the hours of its look-ahead period to produce such outcomes as pre-dispatch advisory schedules, pre-dispatch generator offer guarantee eligible non-quick start resource commitments, and reports.

Objectives

After completing this section, you will be able to:

- Identify what information is passed from the DAM to be used in pre-dispatch
- Recognize the outputs of the pre-dispatch calculation engine

5.1 Information Passed from DAM to Pre-dispatch

Certain information is passed from the day-ahead market for use by pre-dispatch, including:

- Offers, bids and submitted non-dispatchable supply schedules. These are passed to pre-dispatch as entered by the market participant. This means that offers which were mitigated in the DAM are passed in their unmitigated values. Pre-dispatch will do its own evaluation of offers and may or may not mitigate the same or different offers, depending on the outcome of its process.
- Day-ahead market generator offer guarantee eligible non-quick start operational commitments– these become minimum operational constraints in pre-dispatch to ensure they are respected by it in scheduling and pricing calculations.
- Day-ahead market import and export schedules.

Financially bindings schedules are not passed on from the DAM. Pre-dispatch is not required to respect these when it determines its look-ahead schedules.

5.2 Pre-dispatch Calculation Engine

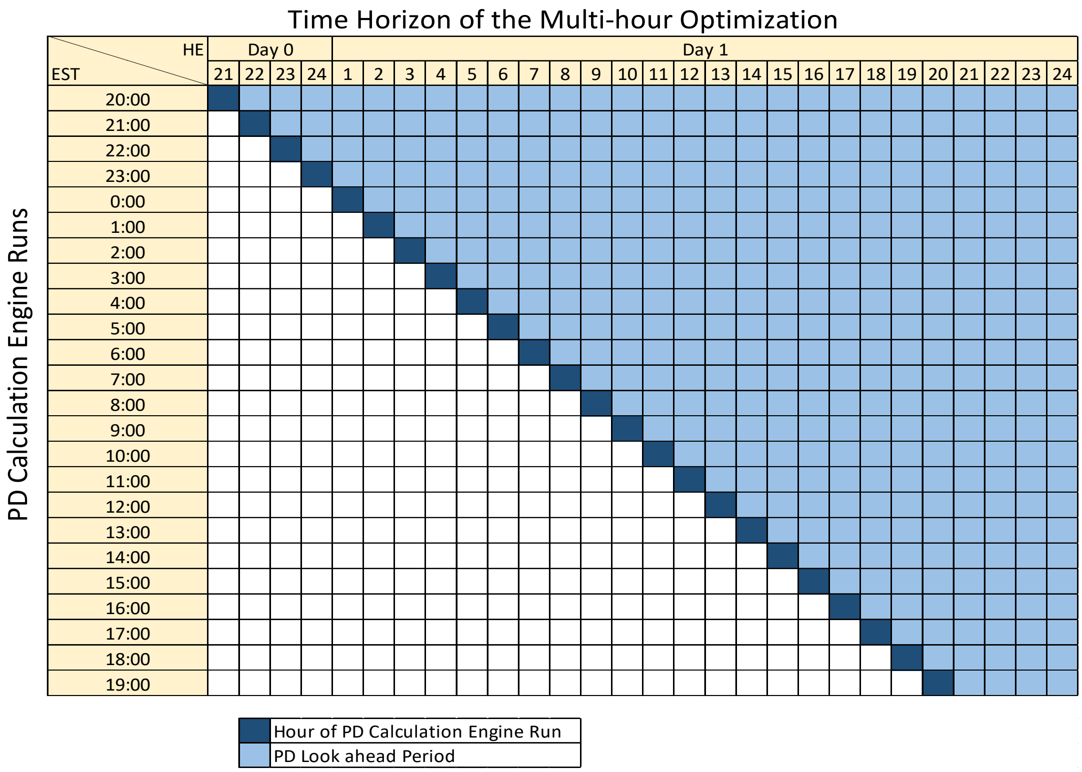
The pre-dispatch calculation engine runs hourly and executes one pass to:

- Apply operational commitments from the day-ahead market
- Generate new commitment decisions, and advance a DAM commitment or extend DAM or pre-dispatch commitment decisions (if applicable)
- Perform ex-ante market power mitigation
- Exclude non-DAM imports and exports from calculations until 2 hours prior to real-time
- Produce next hour import/export dispatch schedules
- Produce hourly advisory schedules and prices

- Issue start-up notices (if applicable)

The first pre-dispatch for a trade day begins at 20:00 EST and looks out 27 hours. Each subsequent run reduces its look-ahead period by an hour until 20:00 EST the next day is reached, at which point the cycle repeats. The figure below is an overview of the time horizon for multi-hour optimization by the pre-dispatch calculation engine run.

Figure 2 | Pre-dispatch Time Horizon



5.3 Pre-dispatch Operational Commitments

For non-quick start resources eligible for a Generator Offer Guarantee (GOG), pre-dispatch can issue new operational commitments or can add additional hours to a day-ahead market or pre-dispatch commitment.

Pre-dispatch can do the following:

- Advance a day-ahead market commitment, meaning it would add additional time to the start of a DAM commitment without changing its end-time
- Issue a stand-alone, pre-dispatch commitment
- Extend a day-ahead market or pre-dispatch commitment by adding more time to the end of an existing commitment

Pre-dispatch also issues start-up notices for all committed resources to indicate when they will need to start-up in order to be at their minimum loading points by the start of a commitment.

6. Real-Time

Real-time uses multi-interval optimization to determine both energy dispatch instructions and operating reserve (OR) schedules every five minutes. Real-time is also the balancing market for energy and OR.

Objectives

After completing this section, you will be able to:

- Identify what information is passed from pre-dispatch to real-time
- Recognize the outputs of the real-time calculation engine

6.1 Information Passed from PD to Real-Time

The last pre-dispatch run before the start of an hour provides the real-time calculation engine with several key data sets for that hour, such as:

- Dispatch data including reference level values which were substituted for offers to which pre-dispatch had applied mitigation (this is because real-time does not itself perform market power mitigation)
- Non-quick start operational commitments
- Hourly demand response activation schedules
- Actual intertie schedules
- Hydroelectric resource hourly must-run amounts and binding minimum daily energy limits

6.2 Real-Time Calculation Engine

The real-time calculation engine performs multi-interval optimization that allows it to consider the following ten five-minute intervals when determining real-time dispatch instructions for the dispatch interval.

The real-time calculation engine considers resource and system constraints to determine:

- Five-minute energy and operating reserve dispatch instructions and advisory schedules for dispatchable resources, and
- Settlement-ready locational marginal prices and zonal prices (for settlement of the interties, virtual transactions and non-dispatchable loads)

7. Types of Market Participants

The term "market participant" refers to any company participating in any of the IESO-administered markets.

Objectives

After completing this section, users will be able to:

- Identify the different types of participants in the physical markets
- Distinguish between dispatchable and non-dispatchable participants

7.1 Market Participants

To become a market participant, organizations must register with the IESO and pay an application fee. There may be additional registration requirements depending on which role they wish to play in the markets. Market participants can have more than one market role. For example, a company could be both a generator and an energy trader.

While companies may choose to participate in the markets, a company must become a market participant if it:

- Has equipment directly connected to the IESO-controlled grid
- Plans to convey electricity into, through or out of the grid

Participants with physical facilities can either be directly connected or 'embedded'. Embedded participants are connected to a local distribution company (LDC) and not to the IESO-controlled grid.

There are also participants who may not have any physical facilities, such as energy traders and virtual traders.

7.2 Dispatchable vs. Non-dispatchable Participants

A participant's classification indicates how they interact with the IESO – that is, whether they are 'dispatchable' or 'non-dispatchable'.

7.2.1 Dispatchable participants

Dispatchable participants:

- Submit bids and/or offers:
- **An offer** tells the IESO how much energy a supplier would like to sell, when they would like to sell it, and what price they want to receive for it
- **A bid** tells the IESO how much energy a consumer wants to purchase, when they would like to purchase it, and what price they are willing to pay for it

- Respond to dispatch instructions:
- The IESO uses dispatch data such as bids and offers, demand forecasts and transmission system information to determine when and how much energy a dispatchable supplier should provide or a dispatchable consumer should consume.
- The IESO then sends dispatch instructions to the participant indicating what their operating point (target MW) should be. We determine dispatch instructions for each 5-minute interval of the day, 24 hours a day, 365 days a year.

Dispatchable generators provide most of the energy produced in Ontario. Most directly connected generators over 10 megawatts (MW) are dispatchable. A generator producing over 1 MW connected to a distribution system (i.e., one that is ‛embedded’) can also choose to register as dispatchable. Nuclear, large natural gas, and hydroelectric facilities are examples of dispatchable generators.

Directly connected and embedded loads over 1 MW that can respond to five-minute dispatch can choose to be dispatchable.

Dispatchable participants play an essential role in maintaining the reliability of the grid. Adjusting the operating point of dispatchable facilities is our primary method of ensuring the continuing balance between supply and demand, while respecting transmission security limits.

7.2.2 Non-dispatchable participants

Non-dispatchable participants do not submit bids and offers in the market and do not receive dispatch instructions. Instead, they accept the market price at the time they produce or consume energy, regardless of what the market price is.

Both generators and loads (consumers) can be non-dispatchable.

7.2.2.1 Non-dispatchable generators

There are two types of non-dispatchable generators:

- Self-scheduling generators submit schedules to the IESO indicating the amount of energy they will be providing and when they expect to provide it. Self-scheduling generators are restricted by size. To be classified as self-scheduling, a generator must be rated between 1 and 10 megawatts. (‛Cogeneration’ facilities are producers of another form of energy, such as steam, with electricity as a by-product. Facilities of this type larger than 10 MW may be self-scheduling if the IESO determines that allowing them to do so will not negatively impact system reliability.)
- Intermittent generators operate intermittently due to factors outside the operators’ control. As a result, they have limited ability to know in advance the amount of energy they will generate. Intermittent generators enter forecasts that estimate the energy they will provide and predict when they will be producing.

7.2.2.2 Non-dispatchable loads

Non-dispatchable loads simply draw electricity from the grid as needed. They pay the market price for electricity at the time of consumption, regardless of what the price might be. We determine market prices for non-dispatchable loads on an hourly basis.

Examples of market participants who are non-dispatchable loads include directly connected loads such as large industrial facilities and local distribution companies (LDCs).

Non-dispatchable loads account for most of the energy consumed in Ontario.

7.2.2.3 Price Responsive Loads

Price Responsive Loads (PRL) are a third type of load. PRL's submit energy bids into the Day-Ahead Market (like a dispatchable resource) but do not need to follow dispatch instructions in real-time. This allows them to be settled primarily on day-ahead prices for their real-time consumption.

7.2.3 Transmitters

Although they are not active participants in terms of the energy markets, transmitters are key market participants. They provide the paths for energy to flow from producers to consumers and their actions have significant impact on reliability and the markets. Transmitters own and maintain the equipment that makes up the grid, which physically connects generators and loads throughout the province and to other jurisdictions (e.g., Quebec and New York).

7.3 Market Participants Without Physical Facilities

Many companies participate in the markets without having physical facilities that either produce or consume electricity.

7.3.1 Energy Traders

The IESO-controlled grid is connected through intertie transmission lines to five neighbouring jurisdictions: Quebec, Manitoba, Michigan, Minnesota and New York. These lines allow Ontario to benefit from the import and export of energy – what is referred to as Interjurisdictional Trade (IJT). Energy traders are market participants who are authorized to participate in this trade. They can transact both energy and operating reserve.

7.3.2 Virtual Traders

Virtual traders bid or offer virtual energy in the day-ahead market, receive a schedule, are settled for that megawatt quantity at the day-ahead price, and are also settled for the opposite transaction at the real-time price. That is, they can be charged for a purchase in the day-ahead market and be credited for a sale of equal quantity at the real-time price, or they can do the opposite and sell virtual megawatts in the day-ahead market and get charged for a purchase of equal quantity at the real-time price. As the name implies, no physical energy transactions happen. No energy backs up sales, and no real energy is bought. Virtual traders participate in the market with the aim of identifying profit opportunities by leveraging the differences between Day-Ahead Market (DAM) prices and Real-Time Market (RTM) prices. In turn, their activities help converge day-ahead and real-time prices, to the broader benefit of the market.

7.4 Energy Market Participant Summary

In the Ontario electricity market, there are:

- Generators that are directly connected to the high voltage grid
- Transmission companies that own, operate and maintain the high voltage grid
- Consumers who are directly connected to the high voltage grid
- Energy Traders who act as importers and exporters
- Virtual traders participate in the market with the aim of leveraging the differences between Day-Ahead Market (DAM) prices and Real-Time Market (RTM) prices
- Local distribution companies (LDCs) who take electricity from the high voltage grid, step it down to lower voltages, and then distribute it to retail customers
- Embedded generators and large consumers. These can choose to enter the electricity market if they qualify (e.g., they must be at least 1 MW in size and install wholesale metering). Even if they do not become market participants, generators and large consumers within distributor networks are settled using the market price

8. Knowledge Check One

8.1 Questions

1. Select the two correct statements:
    a) You can be a market participant even if you have no physical facilities.
    b) All market participants must be directly connected to the grid.
    c) All companies with equipment that is directly connected to the grid must be market participants.
    d) A company may play only one role in the markets.

2. Match the correct term from Column B to the statement in Column A

Letter	Column A	Column B	
	Supply most of the energy in Ontario	a.	Transmitters
	Account for most of the energy consumed in Ontario	b.	Distributors
	Supply energy to retail customers	c.	Dispatchable Generators
	Own the equipment that makes up the IESO-controlled grid	d.	Non-dispatchable Generators
	Not directly connected to the grid	e.	Dispatchable Loads
	Must be able to adjust power consumption in response to our instructions	f.	Non-dispatchable Loads
	Consume energy regardless of the market price	g.	Embedded Facilities

8.2 Answers

1. Select the two correct statements:

   a) You can be a market participant even if you have no physical facilities.

   b) All market participants must be directly connected to the grid.

   c) All companies with equipment that is directly connected to the grid must be market participants.

   d) A company may play only one role in the markets.

2. Match the correct term from Column B to the statement in Column A

Letter	Column A	Column B	
c	Supply most of the energy in Ontario	a.	Transmitters
d	Account for most of the energy consumed in Ontario	b.	Distributors
b	Supply energy to retail customers	c.	Dispatchable Generators
a	Own the equipment that makes up the IESO-controlled grid	d.	Non-dispatchable Generators
g	Not directly connected to the grid	e.	Dispatchable Loads
e	Must be able to adjust power consumption in response to our instructions	f.	Non-dispatchable Loads
f	Consume energy regardless of the market price	g.	Embedded Facilities

9. Virtual Traders

Virtual traders are a market participation type. The key role that virtual traders provide is to help drive price convergence between the DAM and the RTM. Virtual traders also increase liquidity in the DAM, which enhances the financial and operational certainty that the DAM provides. Virtual traders participate in the DAM with bids and offers for energy like physical resources. However, unlike physical resources, virtual traders do not deliver or consume energy in the RTM. They are settled on the difference between DAM prices and RTM prices as described in the Settlements section below. The trader may receive a profit or a loss on their transaction depending on whether their prediction of the directional difference between DAM and RTM prices was accurate, or not.

Objectives

After completing this section, you will be able to:

- Explain the key functions of virtual traders in the DAM and RTM
- Understand how virtual traders can profit or incur losses based on DAM and RTM price differences

Note: Virtual Traders are not eligible to participate in the Operating Reserve (OR) market

9.1 Virtual Trading Zones

When virtual traders enter a bid or offer, they must indicate which virtual transaction zone they wish the transaction to occur in. There are nine such zones which largely correspond to the 10 Ontario electrical zones (Bruce and Southwest are combined into one Southwest virtual transaction zone).

Table 1 | Virtual Trading & Electrical Zones

<table>
<tr><td>Virtual Zones</td><td>East</td><td>Essa</td><td>Niagara</td><td>Northeast</td><td>Northwest</td><td>Ottawa</td><td colspan="2">Southwest</td><td>Toronto</td><td>West</td></tr>
<tr><td>Electrical Zones</td><td>East</td><td>Essa</td><td>Niagara</td><td>Northeast</td><td>Northwest</td><td>Ottawa</td><td>Bruce</td><td>Southwest</td><td>Toronto</td><td>West</td></tr>
</table>

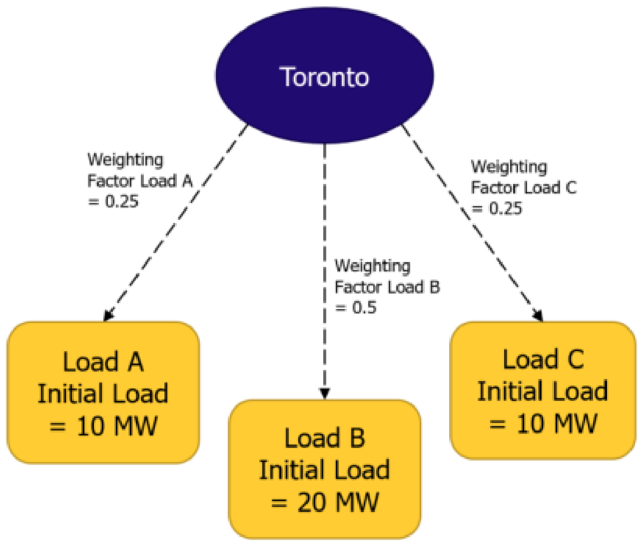
Virtual traders may offer into multiple trading zones for the same hour. Like for other market participants who enter financial dispatch data, virtual bids and offers must be at least 1 MW each. There are several limits applying to virtual trades which assure that the market is protected from potential virtual trader defaults, and that the efficiency of DAM calculation engine operations is maintained. Please see the Introduction to Virtual Trading training guide for more information.

9.2 DAM Scheduling and Pricing

DAM energy schedules for virtual transactions are produced for every hour of the dispatch day. Corresponding virtual zonal prices for energy are also produced hourly as a weighted average of the locational marginal prices (LMPs) for each non-dispatchable load location within each virtual zone. These DAM schedules and corresponding virtual zonal prices are used as inputs to settle virtual transactions.

The example below demonstrates how virtual transactions are scheduled and priced in the DAM.

Figure 3 | Scheduling Virtual Transactions



In this example, assume the Toronto virtual transaction zone contains three non-dispatchable load resources. To determine virtual zonal prices and the distribution of the net schedules for each virtual transaction zone, weighting factors are calculated by the engine.

Step 1: Calculate the weighting factors

Weighting Factor Load A:

= Load A Initial Load ÷ Total Load in the Virtual Zone

= 10 MW ÷ 40 MW

= 0.25

Weighting Factor Load B:

= Load B Initial Load ÷ Total Load in the Virtual Zone

= 20 MW ÷ 40 MW

= 0.50

Weighting Factor Load C:

= Load C Initial Load ÷ Total Load in the Virtual Zone

= 10 MW ÷ 40 MW

= 0.25

9.2.1 DAM Scheduling Outcomes

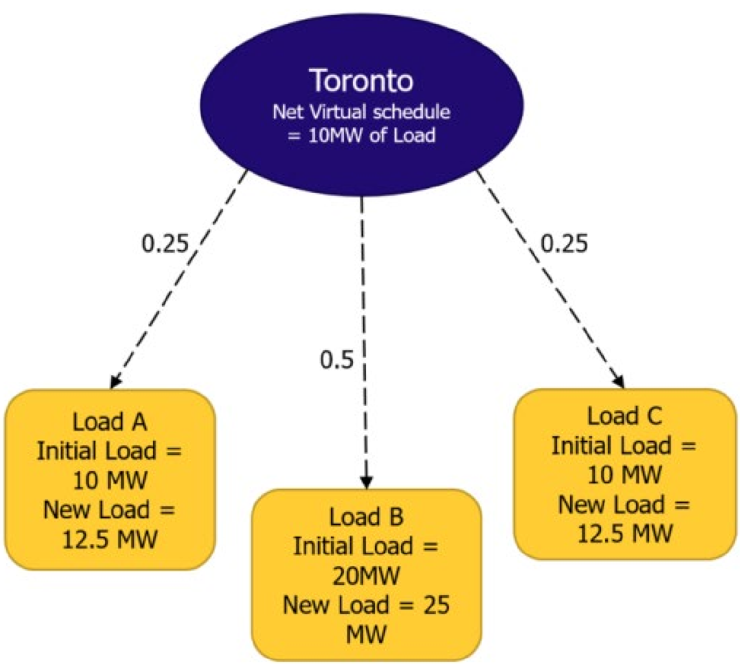
Assume the following virtual transactions have been scheduled in the Toronto virtual transaction zone:

TORONTO_OFFER:HUB = 20 MW (Supply)

TORONTO_BID:HUB = 30 MW (Load)

Net Virtual Schedule = 10 MW of Load

Figure 4 | DAM Scheduling Example



To calculate the virtual load to distribute to each of the load resources, multiply the Net Virtual Schedule of the virtual zone by the weighting factor calculated for each load under Step 1, and then add the initial load to the respective load resources.

Step 2: Calculate the load distribution

Load Distribution for Load A:

= 10 MW * 0.25 + 10 MW

= 12.5 MW

Load Distribution for Load B:

= 10 MW * 0.5 + 20 MW

= 25 MW

Load Distribution for Load C:

= 10 MW*0.25 + 10 MW

= 12.5 MW

Corresponding virtual zonal prices for energy are produced hourly as the weighted average of the locational marginal prices for each non-dispatchable load location within the virtual zone.

Step 3: Calculate the Toronto virtual transaction zonal price

Using the example above, the virtual zonal price for Toronto is calculated as follows:

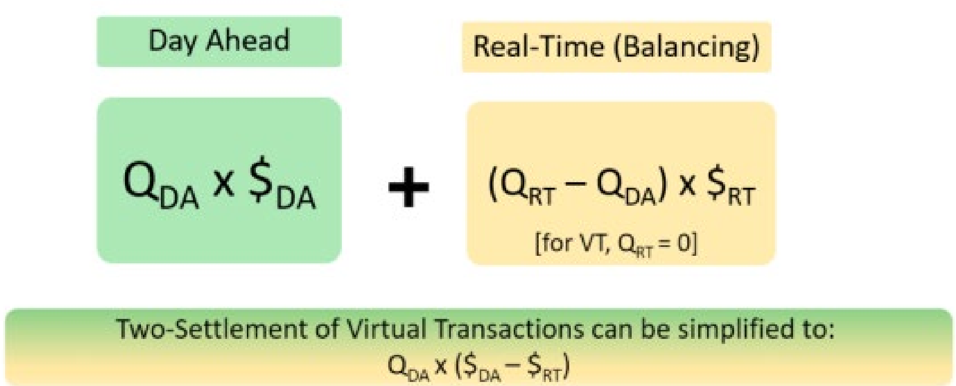
Virtual Zonal Price = ($20*0.25) + ($15*0.5) + ($30*0.25)

= $20

9.3 Settlement

Since virtual traders do not participate in the RTM, the two-settlement process formula can be simplified as below. The simplified formula demonstrates the opportunity for a virtual trader, since they may make a profit (or loss) based on the difference between the price of electricity in the DAM and the RTM multiplied by the quantity they cleared in the DAM.

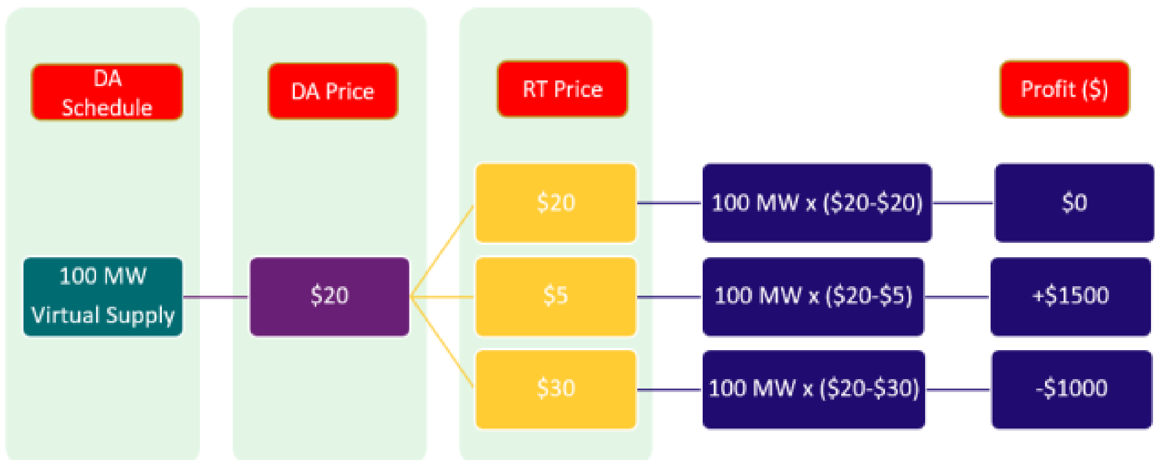
Figure 5 | Two-settlement Process Formula



9.3.1 Profit/Loss Examples for Scheduled Offers

Virtual traders can submit either a bid or an offer to the DAM, which they are financially committed to if scheduled by the DAM. Virtual offers scheduled in the DAM will benefit when the day-ahead price is greater than the real-time price. Virtual bids scheduled in the DAM will benefit when the day-ahead price is less than the real-time price. The examples below demonstrate this concept.

Figure 6 | Profit/Loss Example for Scheduled Offers



Three scenarios are illustrated. In each, a virtual trader has had a 100MW offer scheduled in the DAM and the DAM price cleared at $20.

In the first scenario, the real-time price also clears at $20. Because there is no difference between the DAM and RTM prices, there is no profit or loss to the virtual trader.

In the second scenario, the real-time price is $5, which is less than the DAM price; therefore, the virtual trader receives a profit of $1500.

In the last scenario, the real-time price is $30, which is more than the DAM price; therefore, the virtual trader must pay $1000.

10. Price Responsive Load

Price Responsive Load (PRL)[2] status is available to new load resource applicants and currently registered non-dispatchable loads and dispatchable loads.[3]

Price Responsive Loads submit energy bids into the day-ahead market (DAM). If they are economic, they receive a financially binding day-ahead schedule. Their bids are not considered in real-time, and they are free to consume as they wish.

PRL participation allows loads that were previously non-dispatchable to take a more active role in managing their energy costs by locking in day-ahead prices while not being required to be dispatchable in the real-time market. It also benefits day-ahead operations since it results in increased DAM participation, yielding more efficient outcomes.

Objectives

After completing this section, you will be able to:

- Define price responsive load and its eligibility criteria
- Explain the timelines for changing bid/offer type from a price-responsive load to a non-dispatchable load and vice versa
- Recognize how PRLs are charged and settled based on DAM and real-time locational marginal prices (LMPs)

10.1 Changing to Bid/Offer Type

MPs are able to change their bid/offer type from a price responsive load to a non-dispatchable load and vice versa. There are limitations on the frequency with which these changes can occur, however.

Figure 7 | NDL/PRL Status Change Timelines

[2] For more information, please see the Price Responsive Load guide available on the Marketplace Training pages of the IESO website.
[3] Note: A registered PRL can be used to satisfy an Hourly Demand Response (HDR) capacity obligation in the energy market.

If changing from a non-dispatchable load to a price responsive load, or vice versa, the request must be submitted at least 75 calendar days prior to the requested effective date.

The advanced notice period is required to allow time for the IESO to assess and implement naming convention and delivery point configuration changes as needed in the network model to accommodate the change.

Once a participant becomes a PRL, there is no requirement that they stay one for any set minimum period of time. A participant can choose to switch back to being a non-dispatchable load at any time. However, once they have reverted to NDL status, they must wait for at least one year before changing to a PRL. This is to support fairness by limiting the ability of MPs to take advantage of short-term price differentials between nodal and Ontario zonal prices to the detriment of other MPs.

If a dispatchable load is changing to a PRL, the request is to be submitted at least 75 days prior to the requested effective date. If a PRL (or a non-dispatchable load) is changing to a dispatchable load, the request is to be submitted at least 180 days before the requested effective date.

10.2 Settlement

The two-settlement process is applied to PRLs meaning that they are settled on both their DAM schedules and hourly LMPs and on their actual real-time market consumption and 5-minute LMPs (see section 13).

11. Dispatch Data

Dispatch data is a collective term referring to bid, offer, daily dispatch data and schedule information submitted by MPs to represent their operational intentions under different economic conditions. It is used to determine schedules, commitments, dispatch instructions and to calculate prices. The two main types of dispatch data are daily and hourly. Daily data provides the calculation engines with important information about a resource's operational capabilities while hourly dispatch data provides information about the market participant's minimum operational costs and required energy or operating reserve prices.

Objectives

After completing this section, users will be able to:

- Recall the difference between daily and hourly dispatch data
- Identify and describe the main data and information included in a bid or offer

11.1 Daily and Hourly Dispatch Data Overview

Market participants enter their dispatch data into the Energy Market Interface (EMI). Daily dispatch data (DDD) is used by the IESO to understand a resource's operational capability. The type of DDD varies by resource type. Daily dispatch data is submitted once per day and persists for that day until replaced, withdrawn or expired.

Hourly dispatch data may be submitted daily for each hour of the day. Hourly dispatch data includes three main elements: Price/quantity pairs, ramp rates and resource IDs. GOG-eligible non-quick start resources also submit their start up and speed no-load costs. This data provides the IESO with information regarding the resource and its price sensitivity.

11.2 Hourly Energy Bids and Offers in the Ontario Electricity Markets

Dispatchable market participants, including PRLs[4], energy and virtual traders submit energy bids and offers.

- Dispatchable suppliers submit offers to sell energy
- Dispatchable and price responsive loads submit bids to buy energy

11.2.1 Price /Quantity Pairs

Price/quantity pairs indicate:

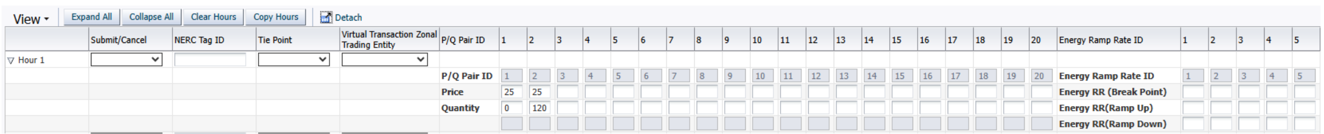
- The minimum price a supplier will accept for producing a quantity of energy
- The maximum price a load is willing to pay for a quantity of energy

[4] As stated earlier in this workbook PRL's submit bids in the Day-Ahead Market only

For example:

- A generator might want to sell 120 MW of energy if the price is $25 or higher. In that case, they would enter a price/quantity pair of (25,120). Below is an example of how this would appear within the EMI system. There is a minimum of two price/quantity pairs required. The first quantity must always be zero.

Figure 8 | EMI Price/Quantity Pair Example



- A load might want to buy 50 MW of energy if the price is $1900 or less. In this case, their price/quantity pair would be entered as (1900,50).

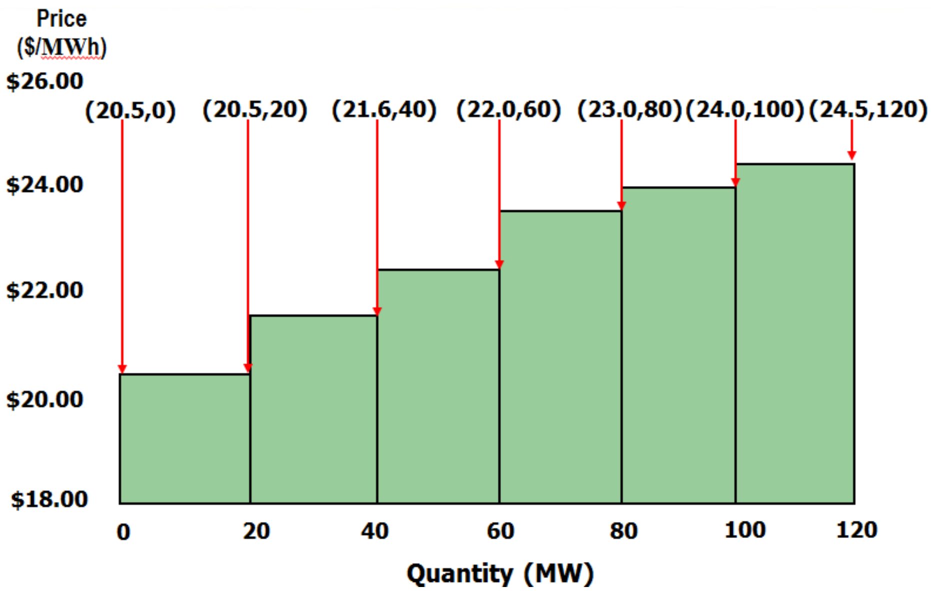
Participants may include up to 20 price/quantity pairs within a single energy bid or offer. Multiple price/quantity pairs allow the participant to reflect their variable costs (generator) or benefits (load) at different dispatch levels.

For example:

Generator A is willing to provide:

- Up to 20 MW of electricity if the price is $20.5 or higher
- Up to 40 MW if the price is $21.6 or higher
- Up to 60 MW if the price is $22 or higher
- Up to 80 MW if the price is $23 or higher
- Up to 100MW if the price is $24 or higher
- Up to 120MW if the price is 24.5 or higher

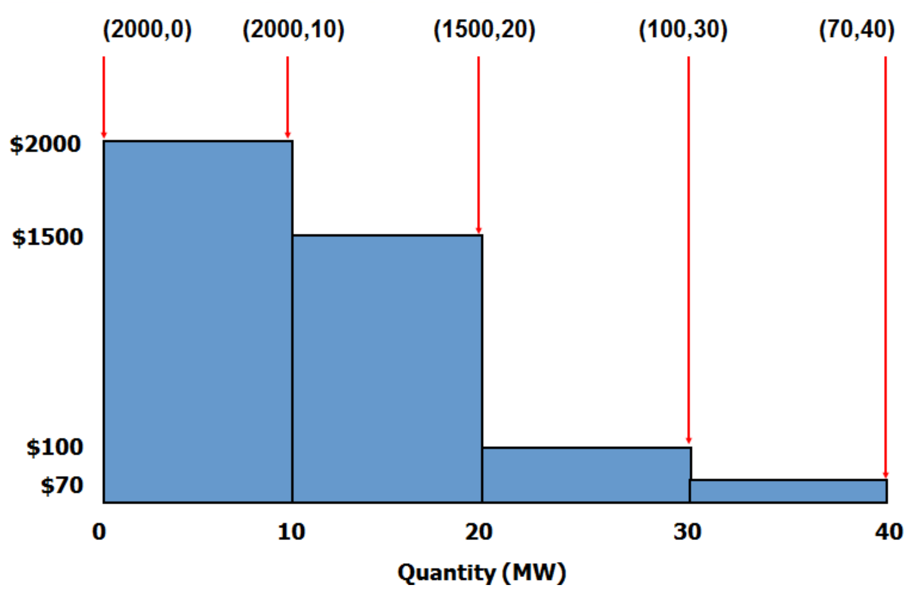
Figure 9 | Generator PQ Pair Example



Load A will consume:

- Up to 10 MW if the price is no higher than $2000
- Up to 20 MW if the price is no higher than $1500
- Up to 30 MW if the price is no higher than $100
- Up to 40 MW if the price is no higher than $70

Figure 10 | Load PQ Pair Example



11.2.2 Ramp Rates

Ramp rates are also part of dispatch data. Ramp rates tell us:

- How quickly a generator can increase or decrease the amount of energy it is producing
- How quickly a load can increase or decrease the amount of energy it is consuming

We will not dispatch a facility to move faster than its submitted ramp rate.

Ramp rates are submitted using megawatt breakpoints; each breakpoint represents the level at which there is a change in the facility's ramping capability. The format is (breakpoint, ramp rate up, ramp rate down). The breakpoints do not have to align with MW quantity levels in the price-quantity pairs.

For example, submitting the following ramp rates tells the IESO, for DAM calculations, that the facility can:

- Ramp up in the range from 0 to 20 MW at 0.3 megawatts per minute and ramp down in the range from 20 to 0 MW at 10 megawatts per minute.
- Ramp up in the range from 20 MW to 75 MW at 5 megawatts per minute and ramp down in the range from 75 to 20 MW at 10 megawatts per minute.

Figure 11 | Ramp Rate Example

Daily Energy Ramp ID	1	2	3	4	5
Daily Energy RR(BreakPoint)	20	75			
Daily Energy RR(Ramp Up)	0.3	5			
Daily Energy RR(Ramp Down)	10	10			

Types of Ramp Rates

There are two types of ramp rates that are submitted as dispatch data:

- Daily Ramp Rate: These values are for use in the DAM and Pre-Dispatch calculations to ensure that the schedule produced by the DAM and the schedule changes from one hour to the next are feasible.
- Hourly Ramp Rate: Is used in real-time for dispatch instructions.

Both types of ramp rates can include up to five sets of ramp rates. This allows dispatchable facilities to ensure that their dispatch instructions reflect the facility's actual ramp capability.

11.2.3 Resource ID

Bids and offers also include the resource's Resource ID. This is a unique reference that identifies where the facility connects to the grid. This location information allows the calculation engines to evaluate the impact of scheduling an injection or withdrawal by the facility. This influences what schedules and dispatch instructions will be determined for the facility.

The Resource ID also identifies that the market participant has been registered for a particular market activity such as:

- Capacity Auction obligation submission
- Virtual Trade
- Price Responsive Load

12. Knowledge Check Two

12.1 Questions

1. Which of the following is NOT a main element of hourly dispatch data in the Ontario electricity markets? (Select the correct answer)
   a) Price/Quantity Pairs
   b) Ramp Rates
   c) Resource ID
   d) Locational Marginal Price

2. Ramp rates indicate how quickly a generator can increase or decrease the amount of energy it is producing, but they do not apply to loads. (Select True or False)
   a) True
   b) False

3. What does a Resource ID indicate in the context of bids and offers in the Ontario electricity markets? (Select the correct answer)
   a) The price at which energy is sold or bought
   b) The unique reference identifying where the facility connects to the grid
   c) The ramp rate of a generator or load
   d) The quantity of energy being dispatched

12.2 Answers

1. Which of the following is NOT a main element of hourly dispatch data in the Ontario electricity markets? (Select the correct answer)

   a) Price/Quantity Pairs

   b) Ramp Rates

   c) Resource ID

   d) **Locational Marginal Price**

2. Ramp rates indicate how quickly a generator can increase or decrease the amount of energy it is producing, but they do not apply to loads. (Select True or False)

   a) True

   b) **False**

3. What does a Resource ID indicate in the context of bids and offers in the Ontario electricity markets? (Select the correct answer)

   a) The price at which energy is sold or bought

   b) **The unique reference identifying where the facility connects to the grid**

   c) The ramp rate of a generator or load

   d) The quantity of energy being dispatched

13. Determining Market Prices

Locational Marginal Prices (LMPs) form the basis for the prices used to settle the markets. This section explains the basic concepts behind how market prices are determined. A later section will look at how the IESO determines the operating instructions we send to dispatchable participants (i.e., "dispatch instructions").

Objectives

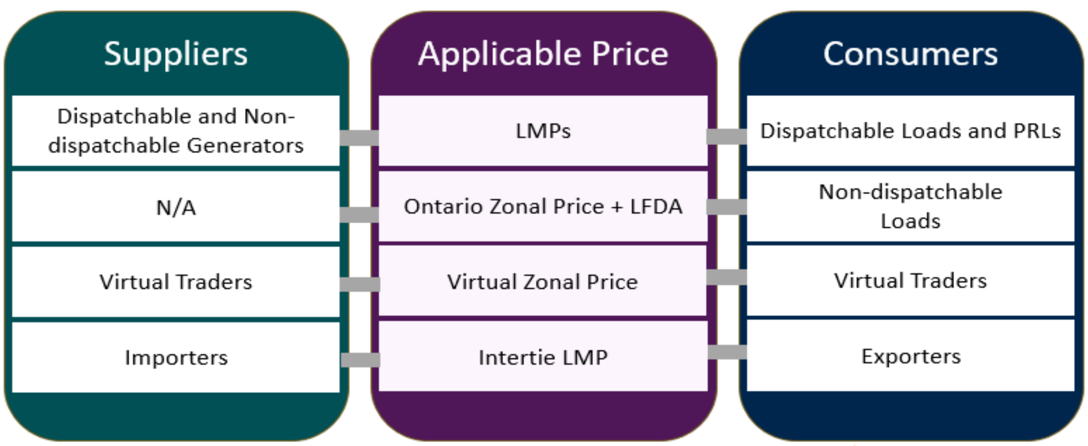
After completing this section, users will be able to:

- Identify the applicable energy prices for different participant types
- Recognize how the LMP for a given hour in the Day-Ahead Market and a given interval in the Real-time Market are derived
- Understand how the Ontario Zonal Price for a given hour is determined
- Identify components of supply and demand in Ontario

13.1 Energy Price Applicability

The following figure identifies which market price are applied to specific participant types.

Figure 12 | Applicable Energy Price



13.2 Pricing Principles

The price charged for a product should cover what it costs to produce as well as deliver it. In an electricity market, this means the price should reflect the following:

- The cost to have the energy available. That is, the price should recover sufficient funds from consumers to pay suppliers for the cost to produce the energy;

- The cost of losses on the system. The reason for this is that 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 the energy they need to their consumption needs; and
- The costs resulting from congestion. Congestion happens because transmission lines and other elements which comprise the grid cannot carry an unlimited amount of energy. At times, this means that system "constraints" or bottlenecks appear where the additional movement of energy is restricted. This can lead to price differences on one side of a constraint versus another if the least cost suppliers are unable to cover of the energy needs of consumers. When this happens, more expensive supply may be required to fill the gap.

13.3 Locational Marginal Pricing for Energy

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[5]. 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 reduced need for out-of-market payments.

LMPs are determined using an ex-ante (before-the-fact) 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 and virtual transactions are settled using zonal prices which average the LMPs in the applicable zone.

13.3.1 LMP Components

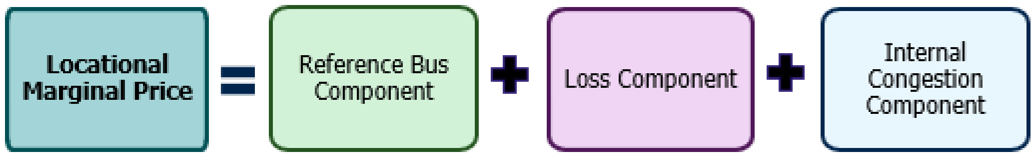
An LMP includes:

- 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

[5] 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.

- 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.

Figure 13 | LMP Components



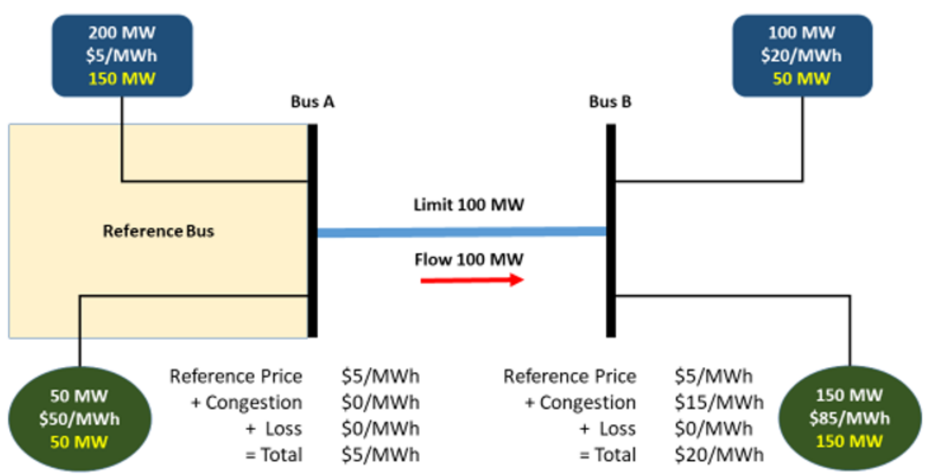
Reference Price

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, it is the incremental cost to supply incremental demand. Because of this, where the reference bus is on the system does not matter – all LMPs will still be the same if it is moved elsewhere because the reference price, loss and congestion components will adjust to reflect conditions relevant to the new location.

Let's look at two simplified examples to demonstrate the concept:

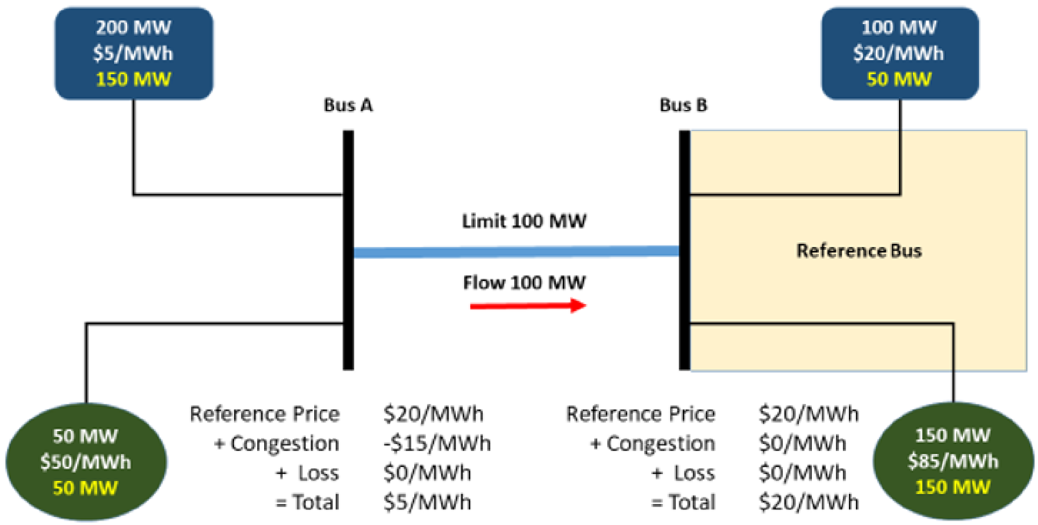
Example 1 Reference Bus Price + Congestion



In our first example we have a diagram of a two-bus system with no losses (just 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.

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 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 must 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.

Example 2 Reference Bus Price + Congestion



In Example Two 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 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

Cost of Congestion

Energy takes all available paths from a point of supply to a point of consumption. 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 limits. This can result in higher prices for locations on one side of a flow limiting constraint versus the other if higher priced resources must be used to serve demand in that area.

Congestion costs are established within a calculation engine by relaxing each constraint in turn by an incremental amount and then determining the impact on overall system costs of re-dispatching the system as a result. 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.

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.

13.4 Non-Dispatchable Load Prices

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. With the renewed market, this means the price must include costs created across both the day-ahead and real-time markets.

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

Because NDLs do not submit bids, the IESO will forecast their expected real-time demand for use in day-ahead, pre-dispatch and real-time processes. As such, NDLs don’t directly participate in the two-settlement process. Instead, NDLs are settled for their real-time consumption using a uniform price. However, costs associated with serving their demand are generated across both the day-ahead and real-time markets. To account for this, the price charged to NDLs has two components:

- Day-Ahead Ontario Zonal Price (DA-OZP)
- Load Forecast Deviation Adjustment (LFDA).

13.4.1 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. 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 process, most energy supply is scheduled in the DAM. This means that the largest proportion of NDL costs to the market is accumulated there.

13.4.2 Load Forecast Deviation Adjustment (LFDA)

NDL real-time consumption is forecast 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 forecasted, 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 are 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 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 RTM. 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 withdrawn and the amount forecast day-ahead.

NDL Settlement Price Calculation Example

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

Day-Ahead Ontario Zonal Price Example

As stated above, the DA-OZP is 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 are used to arrive at an average price which serves 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/MW

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 with the example 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).

Table 2 | NDL Example

NDL	DAM-OZP ($/MWh)	RT-LMP ($/MWh)	DAM Forecast (MW)	Actual Consumption (MW)	Real-Time Purchase Cost/Benefit	DAM Volume Factor Cost/Benefit
NDL 1	\$39	\$30	5,000	4,750	-\$7,500	\$9,750
NDL 2	\$39	\$55	2,000	2,100	\$5,500	-\$3,900
NDL 3	\$39	\$39	3,000	3,225	\$6,975	-\$8,775
TOTAL			**10,000**	**10,075**	**\$4,975**	**-\$2,925**

For NDL 1:

- 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 is:

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 250 MW less than that. In keeping with a two-settlement process, 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.

Table 3 | NDL Example Continued

NDL	**DAM-OZP ($/MWh)**	**DAM Forecast (MW)**	DAM Cost	**Actual Consumption (MW)**	**Difference DAM to RT (MW)**	**Real-Time LMP**	**Market Revenue Required Change**
NDL 1	$39	5,000	$195,000	4,750	-250	$32	-$7,500
NDL 2	$39	2,000	$78,000	2,100	100	$55	$5,500
NDL 3	$39	3,000	$117,000	3,225	225	$31	$6,975
TOTAL		**10,000**	**$390,000**	**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 must 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 are settled using the real-time Ontario Zonal Price. This is calculated as the load-weighted average of NDL real-time energy LMPs.

13.5 Virtual Transactions and Price Convergence

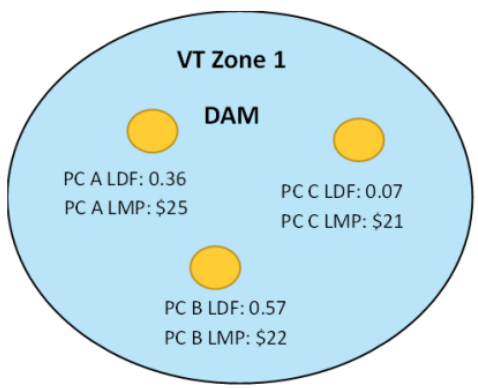
Virtual transactions are assigned by the DAM calculation engine to specific load locations for the purpose of determining schedules and prices. The distribution is done using Load Distribution Factors (or LDFs), which represent each physical load's share of total demand. By distributing virtual transactions 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.

13.5.1 Virtual Zone Prices

The zonal prices used to settle virtual transactions are 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 are calculated and used for settlement; pre-dispatch zonal prices are provided for information purposes only.

Virtual Zone Pricing Example

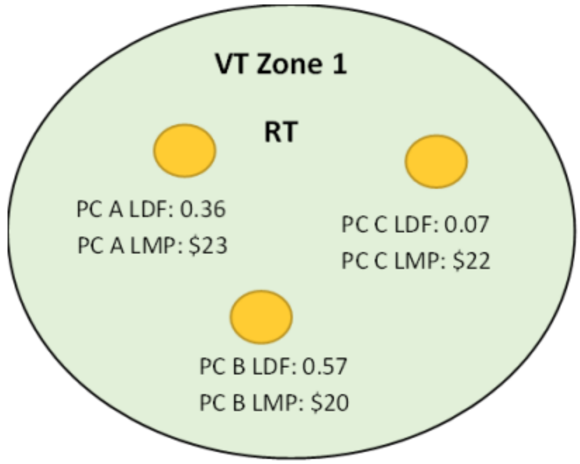
As an example, assume in the DAM there are three consumers in Virtual Transaction Zone 1. Physical Consumer A has an LDF of 0.36 and an LMP of $25; Physical Consumer B has an LDF of 0.57 and an LMP of $22; and Physical Consumer C has an LDF of 0.07 and an LMP of $21.



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.

13.6 Price Setting Eligibility

LMP considers the offer or bid which can satisfy an additional increment of demand when determining the reference bus price as part of the LMP components. 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 are only 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 is only 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 affect its ability to set price:
- Minimum Hourly Output (MHO): Only offers above the MHO are 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 can't set prices in the DAM or pre-dispatch. The DAM calculation engine considers MinDEL 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 pre-dispatch run is considered.
- If the look-ahead period covers the remainder of the dispatch day and the next dispatch day, pre-dispatch uses 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. 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 uses 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. 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 pre-dispatch run is considered.
- If the look-ahead period covers the remainder of the dispatch day and the next dispatch day, pre-dispatch uses the shared MinDEL limit for the next dispatch day.

14. Knowledge Check Three

14.1 Questions

1. What components are included in the calculation of Locational Marginal Pricing (LMP)? (Select the correct answer)
    a) Reference price, cost of distribution, and cost of maintenance
    b) Reference price, cost of congestion, and cost of losses
    c) Reference price, cost of storage, and cost of transportation
    d) Reference price, cost of marketing, and cost of administration

2. What conditions must be met for a non-quick start resource to be eligible to set energy or operating reserve prices in the DAM or pre-dispatch? (Select the correct answer)
    a) The resource must be offline and have remaining starts.
    b) The resource must be committed and scheduled to at least its minimum loading point.
    c) The resource must have reached its maximum daily energy limit.
    d) The resource must be fully dispatched.

3. How is the Day-Ahead Ontario Zonal Price (DA-OZP) calculated for non-dispatchable loads (NDLs)? (Select the correct answer)
    a) As the average of all locational marginal prices within the zone.
    b) As the highest locational marginal price within the zone.
    c) As the load-weighted average of the day-ahead locational marginal prices calculated for each NDL.
    d) As the lowest locational marginal price within the zone.

4. A resource that has entered a maximum number of starts per day as a dispatch data parameter will be able to set price in the DAM and pre-dispatch only if it has remaining starts. (Select True or False)
    a) True
    b) False

5. Virtual transactions contribute to price convergence by moving locational marginal prices higher or lower than they would have been otherwise, reflecting the market's expectations about real-time prices. (Select True or False)

    a) True

    b) False

6. What are the two components included in the price charged to non-dispatchable loads (NDLs) in the renewed market? (Select the correct answer)

    a) Day-Ahead Ontario Zonal Price (DA-OZP) and Real-Time Ontario Zonal Price (RT-OZP)

    b) Day-Ahead Ontario Zonal Price (DA-OZP) and Load Forecast Deviation Adjustment (LFDA)

    c) Real-Time Ontario Zonal Price (RT-OZP) and Load Forecast Deviation Adjustment (LFDA)

    d) Day-Ahead Ontario Zonal Price (DA-OZP) and Congestion Rent

14.2 Answers

1. What components are included in the calculation of Locational Marginal Pricing (LMP)? (Select the correct answer)

    a) Reference price, cost of distribution, and cost of maintenance

    b) Reference price, cost of congestion, and cost of losses

    c) Reference price, cost of storage, and cost of transportation

    d) Reference price, cost of marketing, and cost of administration

2. What conditions must be met for a non-quick start resource to be eligible to set energy or operating reserve prices in the DAM or pre-dispatch? (Select the correct answer)

    a) The resource must be offline and have remaining starts.

    b) The resource must be committed and scheduled to at least its minimum loading point.

    c) The resource must have reached its maximum daily energy limit.

    d) The resource must be fully dispatched.

3. How is the Day-Ahead Ontario Zonal Price (DA-OZP) calculated for non-dispatchable loads (NDLs)? (Select the correct answer)

    a) As the average of all locational marginal prices within the zone.

    b) As the highest locational marginal price within the zone.

    c) As the load-weighted average of the day-ahead locational marginal prices calculated for each NDL.

    d) As the lowest locational marginal price within the zone.

4. A resource that has entered a maximum number of starts per day as a dispatch data parameter will be able to set price in the DAM and pre-dispatch only if it has remaining starts. (Select True or False)

    a) True

    b) False

5. What are the two components included in the price charged to non-dispatchable loads (NDLs) in the renewed market? (Select the correct answer)

    a) Day-Ahead Ontario Zonal Price (DA-OZP) and Real-Time Ontario Zonal Price (RT-OZP)

b) Day-Ahead Ontario Zonal Price (DA-OZP) and Load Forecast Deviation Adjustment (LFDA)

c) Real-Time Ontario Zonal Price (RT-OZP) and Load Forecast Deviation Adjustment (LFDA)

d) Day-Ahead Ontario Zonal Price (DA-OZP) and Congestion Rent

6. Virtual transactions contribute to price convergence by moving locational marginal prices higher or lower than they would have been otherwise, reflecting the market's expectations about real-time prices. (Select True or False)

   a) True

   b) False

15. Determining Dispatch Instructions

Now that we have discussed the concepts behind determining electricity prices, we can examine how dispatchable participants receive their dispatch instructions. A dispatch instruction is sent from the IESO to a dispatchable participant and indicates the target energy level to be achieved (in MW) at the end of the dispatch interval at a rate equal to the ramp rate provided by the market participant as dispatch data. These dispatch instructions consider both economics and physical limitations. It's important to recognize that dispatch instructions are sent only if there is a required change. Additionally, dispatch instructions can be refused for reasons of public or worker safety, equipment damage, or legal requirements

Objectives

After you have completed this section, you will be able to:

- Recognize why dispatch instructions are sent and the importance of actively following them
- Explain how the calculation engine determines dispatch instructions by considering economic factors, operational capabilities, and system limitations

15.1 The Calculation Engine

The calculation engine must consider the actual physical characteristics of the grid, or else system reliability will be compromised. To determine dispatch instructions, it considers a resource's economics and operational capabilities as well as broader system limitations. The capabilities and limitations considered include:

- Limitations on how much electricity can be moved through the transmission lines, while respecting security limits
- The ability of facilities to change their operating point (i.e., their ramp rate)

As mentioned, the calculation engine determines dispatch instructions for every 5-minute interval. They are sent at the start of an interval and indicate the energy operating point that the facility should achieve by the end of interval.

The IESO sends dispatch instructions to participants' dispatch workstations. A dispatch workstation is a dedicated computer that is used solely to manage dispatch instructions.

We send dispatch instructions only if there is a required change in operating point. If a facility does not receive an instruction for a particular interval, it means that they are to maintain an operating point according to the last instruction received.

Due to the essential role that dispatchable facilities play in maintaining system reliability, facilities must comply with dispatch instructions as closely as possible. There are exceptions, however. You can refuse dispatch instructions for reasons of public or worker safety, equipment damage, or legal requirements.

15.2 Dispatch Compliance

Dispatch compliance is discussed in an Interpretation Bulletin (IB) and a Statement of Approach on the compliance pages of the IESO website. The IB explains that dispatch instructions must be followed within a particular range in order for the market participant to have been compliant with the market rules. The particular range, or "deadband", depends upon the size of the facility:

- If the facility is greater than 30 MW, it shouldn't depart more than the greater of ± 15 MW or ± 2% of the dispatch instruction.
- If the facility is less than 30 MW, it shouldn't depart more than the greater of ± 10 MW or ± 2% of the dispatch instruction.

16. Knowledge Check Four

16.1 Questions

1. What are the primary reasons for sending dispatch instructions to market participants? (Select the correct answer)
   a) To ensure participants are aware of market trends.
   b) To achieve the target energy level required at the end of the dispatch interval and maintain system reliability.
   c) To provide participants with financial updates.
   d) To inform participants about upcoming maintenance schedules.

2. What factors does the calculation engine consider when determining dispatch instructions? (Select the correct answer)
   a) Market trends and participant preferences.
   b) Physical characteristics of the grid, including transmission line limits and ramp rates of facilities.
   c) Financial performance of market participants.
   d) Historical energy consumption data.

3. Dispatch instructions must be actively followed by facilities, but they can be refused for reasons such as public or worker safety, equipment damage, or legal requirements. (Select True or False)
   a) True
   b) False

16.2 Answers

1. What are the primary reasons for sending dispatch instructions to market participants? (Select the correct answer)

   a) To ensure participants are aware of market trends.

   b) **To achieve the target energy level required at the end of the dispatch interval and maintain system reliability**.

   c) To provide participants with financial updates.

   d) To inform participants about upcoming maintenance schedules.

2. What factors does the calculation engine consider when determining dispatch instructions? (Select the correct answer)

   a) Market trends and participant preferences.

   b) Physical characteristics of the grid, including transmission line limits and ramp rates of facilities.

   c) Financial performance of market participants.

   d) Historical energy consumption data.

3. Dispatch instructions must be actively followed by facilities, but they can be refused for reasons such as public or worker safety, equipment damage, or legal requirements. (Select True or False)

   a) **True**

   b) False

17. Timelines

Now that we have discussed how we set the market price and how we determine dispatch instructions, we can look at the timing of the market.

Objectives

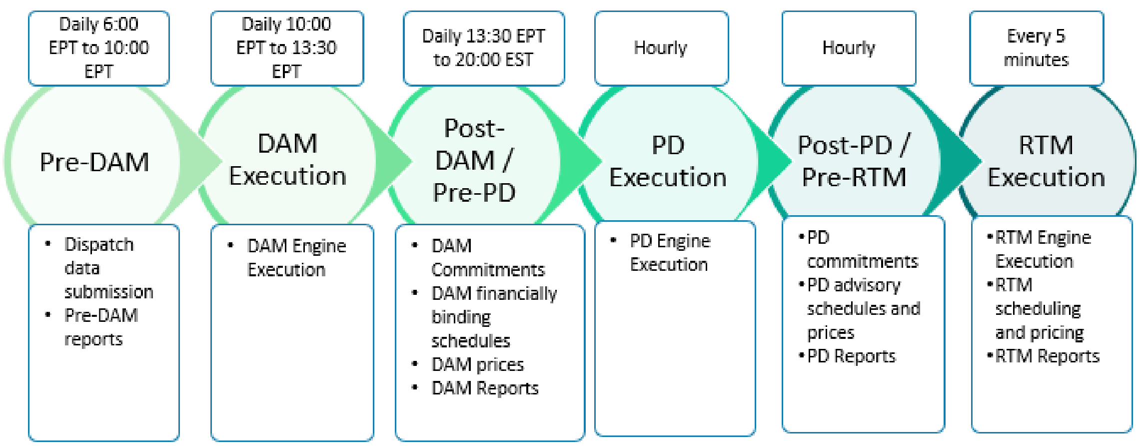
After you have completed this section, you will be able to:

- Identify the window for submitting bids and offers
- Explain the differences between a standing and a daily bid or offer
- Recognize the differences between the difference market timelines

17.1 Market Timelines Overview

Within the market there are distinct timeframes where different calculation engines and outcomes will be applicable. The figure below shows these timeframes and some key outcomes and timing.

Figure 14 | Market Timelines Overview



The market has three separate calculation engines referenced in the figure above; DAM, pre-dispatch and real-time. Each have distinct outcomes and reports.

17.2 Types of Bids and Offers

There are two basic types of bids and offers.

17.2.1 Normal bids and offers

Normal bids and offers apply for only one day. The window for entering Normal bids and offers opens at 6:00 EPT the day before the energy will flow (i.e., the day before the 'dispatch day'). For example, market participants can start entering bids and offers Tuesday at 6:00 EPT for transactions they want to happen on Wednesday.

17.2.2 Standing Bids and offers

There are also standing bids and offers. Standing bids and offers apply for more than one day. They stay in our system until changed or withdrawn, or until you enter an expiry date. Standing bids and offers are best used if you expect your price sensitivity to remain the same from day-to-day or from week-to-week.

Standing bids and offers convert to daily bids and offers at 6 a.m. EPT the day before the dispatch day. You can adjust your daily or standing bids and offers as more information about the specific hour becomes available.

18. Operating Reserve

Operating reserve (OR) provides a 'cushion' of energy we can call upon quickly in the event of an unexpected shortfall of energy. This energy can be supplied by a supplier increasing its output or by a load reducing its demand.

Objectives

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

- Identify the three classes of operating reserve
- Explain how we determine payments for operating reserve

18.1 What is Operating Reserve?

OR is stand-by power that can be called on with short notice to deal with an unexpected mismatch between supply and demand. We purchase OR from participants through an OR market.

The IESO determines the required quantity of scheduled OR in accordance with reliability standards established by standards authorities like the North American Electricity Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

18.1.1 Classes of operating reserve

There are three classes of operating reserve, determined by the time required to bring the energy into use. The three classes are the following:

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

We must have enough 10-minute operating reserve to cover the largest single contingency that is likely to occur given the current grid configuration. Typically, this is the loss of the single largest generation unit. If the largest generator on the grid is 900 MW, we must schedule an equal quantity of megawatts of operating reserve from facilities whose energy can be made available within 10 minutes of the loss of that unit.

Normally, 25% of this 10-minute capacity must be 'spinning' or 'synchronized'. Spinning operating reserve comes from generators and loads that are already synchronized to the grid. Generators, dispatchable storage, and dispatchable loads can offer 10-minute spinning reserve.

The remaining portion of 10-minute operating reserve does not have to be spinning. We can use dispatchable loads, dispatchable generators, dispatchable storage, imports and exports to satisfy 10-minute non-spinning reserve requirements.

We must also maintain 30-minute operating reserve over and above the 10-minute requirement. There must be enough 30-minute reserve to cover one half of the second largest likely single contingency on the grid. We can use dispatchable loads, dispatchable generators, dispatchable storage, imports and exports to satisfy 30-minute operating reserve requirements.

18.1.2 Operating reserve markets

The IESO operates a market for each of the three types of operating reserve. This allows us to purchase OR efficiently.

Dispatchable facilities can place offers for operating reserve, just as they place bids and offers for energy. An offer of operating reserve can only be made if the participant has entered a corresponding bid or offer for energy. For example:

- A load could bid for 150 MW of energy in total and offer up to 150 MW of operating reserve.
- If the participant is dispatched to consume 100 MW of energy and is scheduled for 25 MW of 10-minute operating reserve, this means that, if called upon, the facility must reduce their consumption by 25 MW (from 100 to 75 MW) within 10 minutes.

Similarly:

- A generator might offer up to 200 MW of energy.
- They can, at the same time, offer up to 200 MW of operating reserve. If the participant is dispatched to 150 MW and is scheduled for 25 MW of 10-minute operating reserve, they must be able to produce 25 additional MW within 10 minutes of being called upon to do so.

The calculation engine simultaneously determines schedules for both energy and operating reserve through a process called 'joint optimization'.

Participants who are scheduled for operating reserve receive a payment at the market price (LMP) for the class of operating reserve. They receive this stand-by payment for all intervals during which they are scheduled to supply operating reserve.

Scheduled operating reserve suppliers may be 'activated'. If they are, they must then actually provide the energy. This must be done within the ramp period for the product activated.

- If activated for 10-minute reserve, a facility has 10 minutes to provide the energy.
- If activated for 30-minute reserve, a facility has 30 minutes to provide energy.

How the energy is provided depends on the type of resource:

- If a supplier is activated, they must inject additional energy at least equal to the amount of OR activated.
- If a load is activated, they have to consume less energy. The reduced consumption must be at least equal to the amount of OR activated.

How do we settle activated participants?

Operating reserve settlement follows the same basic principles as energy settlement: OR LMPs are determined in the DAM and the RTM which are used to settle the participant using a two-settlement process.

19. Knowledge Check Five

19.1 Questions

1. What is the difference between a standing bid or offer and a normal bid or offer in the electricity market? (Select the correct answer)

   a) Standing bids and offers apply for only one day, while normal bids and offers apply for more than one day.

   b) Standing bids and offers apply for more than one day and stay in the system until changed or withdrawn, while normal bids and offers apply for only one day.

   c) Standing bids and offers are submitted in real-time, while normal bids and offers are submitted day-ahead.

   d) Standing bids and offers are used only for non-dispatchable loads, while normal bids and offers are used for dispatchable loads.

2. What are the primary functions of the Day-Ahead Market (DAM) calculation engine? (Select the correct answer)

   a) Producing financially binding day-ahead energy and operating reserve schedules, generating operational commitments for eligible non-quick start resources, performing ex-ante market power mitigation, and calculating DAM LMPs for settlement.

   b) Generating real-time dispatch instructions, performing ex-post market power mitigation, and calculating real-time LMPs for settlement.

   c) Producing hourly advisory schedules and prices, issuing start-up notices, and generating new commitment decisions.

   d) Managing the physical delivery of energy, performing real-time market power mitigation, and calculating real-time zonal prices.

3. The pre-dispatch calculation engine runs hourly and executes one pass to apply operational commitments from the day-ahead market, generate new commitment decisions, and produce next hour import/export dispatch schedules. (Select True or False)

   a) True

   b) False

4. What are the three classes of operating reserve, and how are they determined? (Select the correct answer)

a) 10-minute spinning, 10-minute non-spinning, and 30-minute; determined by the time required to bring the energy into use.

b) 5-minute spinning, 10-minute non-spinning, and 15-minute; determined by the cost of energy production.

c) 10-minute spinning, 20-minute non-spinning, and 30-minute; determined by the market demand.

d) 5-minute spinning, 10-minute non-spinning, and 30-minute; determined by the location of the facilities.

5. How is the total quantity of scheduled operating reserve determined? (Select the correct answer)

   a) By the market demand and supply.

   b) In accordance with reliability standards established by authorities like NERC and NPCC.

   c) By the financial performance of market participants.

   d) Based on historical energy consumption data.

6. Participants who are scheduled for operating reserve receive a payment at the market price (OR LMP) for the class of operating reserve for all intervals during which they are scheduled to supply operating reserve. (Select True or False)

   a) True

   b) False

7. What happens when a scheduled operating reserve supplier is activated? (Select the correct answer)

   a) They must provide the energy within the ramp period for the product activated (10 minutes for 10-minute reserve, 30 minutes for 30-minute reserve).

   b) They receive an additional payment for the energy provided.

   c) They can choose whether or not to provide the energy.

   d) They must reduce their energy consumption immediately.

19.2 Answers

1. What is the difference between a standing bid or offer and a normal bid or offer in the electricity market? (Select the correct answer)

   a) Standing bids and offers apply for only one day, while normal bids and offers apply for more than one day.

   b) **Standing bids and offers apply for more than one day and stay in the system until changed or withdrawn, while normal bids and offers apply for only one day.**

   c) Standing bids and offers are submitted in real-time, while normal bids and offers are submitted day-ahead.

   d) Standing bids and offers are used only for non-dispatchable loads, while normal bids and offers are used for dispatchable loads.

2. What are the primary functions of the Day-Ahead Market (DAM) calculation engine? (Select the correct answer)

   a) **Producing financially binding day-ahead energy and operating reserve schedules, generating operational commitments for eligible non-quick start resources, performing ex-ante market power mitigation, and calculating DAM LMPs for settlement**.

   b) Generating real-time dispatch instructions, performing ex-post market power mitigation, and calculating real-time LMPs for settlement.

   c) Producing hourly advisory schedules and prices, issuing start-up notices, and generating new commitment decisions.

   d) Managing the physical delivery of energy, performing real-time market power mitigation, and calculating real-time zonal prices.

3. The pre-dispatch calculation engine runs hourly and executes one pass to apply operational commitments from the day-ahead market, generate new commitment decisions, and produce next hour import/export dispatch schedules. (Select True or False)

   a) **True**

   b) False

4. What are the three classes of operating reserve, and how are they determined? (Select the correct answer)

   a) **10-minute spinning, 10-minute non-spinning, and 30-minute; determined by the time required to bring the energy into use**.

b) 5-minute spinning, 10-minute non-spinning, and 15-minute; determined by the cost of energy production.

c) 10-minute spinning, 20-minute non-spinning, and 30-minute; determined by the market demand.

d) 5-minute spinning, 10-minute non-spinning, and 30-minute; determined by the location of the facilities.

5. How is the total quantity of scheduled operating reserve determined? (Select the correct answer)

   a) By market demand and supply.

   b) **In accordance with reliability standards established by authorities like NERC and NPCC**.

   c) By the financial performance of market participants.

   d) Based on historical energy consumption data.

6. Participants who are scheduled for operating reserve receive a payment at the market price (OR LMP) for the class of operating reserve for all intervals during which they are scheduled to supply operating reserve. (Select True or False)

   a) **True**

   b) False

7. What happens when a scheduled operating reserve supplier is activated? (Select the correct answer)

   a) **They must provide the energy within the ramp period for the product activated (10 minutes for 10-minute reserve, 30 minutes for 30-minute reserve)**.

   b) They receive an additional payment for the energy provided.

   c) They can choose whether or not to provide the energy.

   d) They must reduce their energy consumption immediately.

20. Additional Resources

This workbook introduces you to Ontario's Physical Markets. For more detailed information on some of the topics mentioned in the workbook, please refer to:

- IESO Academy: eLearning resources - IESO Academy
- IESO Training Materials: Website - Training Materials
- IESO Participant Tool Training: Website - Participant Tool Training
- Market Rules and Manuals: Renewed Market Rules & Manuals Library

4.

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