Utilizing Shadow Prices In the Ontario Electricity Market

July 20, 2007

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Introduction

Shadow prices are generated by the Independent Electricity System Operator (IESO) market systems for most nodes on the Ontario transmission system. They are published for energy and three classes of operating reserve for every 5-minute interval. However, since they are not used for any settlements calculations their value to dispatchable participants is often overlooked.

This document focuses on a generator's role in the electricity market, and explains how energy offers, operating reserve offers and shadow prices can be used to determine a generator's dispatch instructions. This would be useful to new generators wishing to develop a first-time bidding strategy, or to existing generators wishing to fine-tune their offers in order to improve their operational efficiencies through more desirable dispatches. It can also be used by non-dispatchable generators that are considering becoming dispatchable in order to have their production coincide better with higher energy prices and to enter the operating reserve market. A technique is shown that uses joint optimization to determine dispatch quantities, market schedules and settlements credits using the historical shadow price data. Finally, the Sygration Generation Market Simulator service is introduced as a commercial alternative to parties considering implementing these techniques in-house.

This document is intended for readers that are familiar with the Ontario electricity market and have dispatchable generators, or are considering becoming dispatchable.

Background

The Ontario wholesale electricity market uses a uniform market price for wholesale purchases and sales of electricity. The wholesale price to distributors and participants that are not dispatched by the IESO is based on the average Hourly Ontario energy price (HOEP), while the price to generators and large industrial customers that are dispatched by the IESO is the 5-minute Market Clearing Price (MCP) [1]. In both cases, this wholesale market price is always the same for all locations throughout the province and does not truly reflect the effects of such things as transmission losses, congestion and actual generator ramping limitations. This was the intention of the original designers of the Ontario electricity market and they used the postage stamp analogy where everyone pays the same price to send a letter anywhere in the country. It is referred to as the Unconstrained Market Model, and is used to determine the market prices by ignoring many real-life transmission system constraints or inflating unit ramping capabilities.

System constraints cannot be ignored when it comes to operating the electricity system, including the dispatch of generators or large industrial loads (dispatchable). Not only does this result in a safer operation of the transmission system (by keeping transmission flows within safe limits), it also results in a more efficient energy exchange by factoring in transmission losses. The dispatch of electricity is based on the Constrained Model that recognizes the impact of:

- Transmission losses
- Transmission operating limits
- Resource ramping capabilities
- Limits placed on how much operating reserve can come from specific areas of the grid
- Multi-interval optimization that looks ahead at changes in supply and demand

Of course, both the Constrained Model and Unconstrained Market Model operate on the bids and offers for energy and operating reserve that are submitted by generators and dispatchable consumers. Every five minutes, the IESO’s Dispatch Scheduler and Optimizer balances these bids and offers along with the current and forecast demand to arrive at individual market schedules (using the Unconstrained Market Model) and dispatch instructions (using the Constrained Model). The constrained model runs first and uses the most recent demand predictions in determining the dispatches for the interval, while the unconstrained run actually runs after the interval and uses actual demand and supply values sample during the interval. The end of both processes is the creation of a single set of market prices for the entire province and the 13 intertie zones, as well as individual shadow prices for most major connections (“nodes”) to the system.

[1] The final price for energy may actually regulated for some users, or include global adjustments, uplifts and tariffs. All of these are beyond the scope of this document.

Market prices are important because they are used as the basis of energy and operating reserve settlements. However, the shadow prices tell where there is a greater or lesser need for energy, as well as how generators and consumers are being dispatched throughout the province. Shadow prices can also be used to work backwards from trial bids and offers to determine how a unit would have been dispatched had these bids been used for real.

Bids and Offers

Dispatchable participants submit bids to buy or offers to sell energy to the IESO for every hour of the day. If they are capable (and authorized) to sell operating reserve, they may optionally submit offers for operating reserve[2] for the same hours. For generators, these offers are assumed to represent their cost to produce energy, or in the case of operating reserve their cost to be on stand-by to provide energy upon short notice. The Ontario market employs a Dispatch Scheduler and Optimizer (DSO) which evaluates all of the bids and offers for both energy and the three classes of operating reserve simultaneously in a process called Joint Optimization. The market schedules and dispatches produced by the DSO balances the demand and supply for both energy and operating reserve, with the objective of maximizing the economic gain to both individual generators and consumers.

Simple Energy Offer:

1-7,,{(30,0),(30,200),(45,300)},{(300,3.0,10.0)};
8-19,,{ (30,0),(30,200),(45,300),(50,450),(75,500) },{ (200,3.0,10.0),(500,5.0,10.0) };
20-24,,{(30,0),(30,200),(45,300)},{(300,3.0,10.0)};

Breakdown of offer using Line 2:

8-19	**Line is for hours 8 through 19 (7:00AM – 7:00PM EST) only**
(30,0),(30,200),(45,300),(50,450),(75,500)	**Price Quantity Pairs (5 of maximum 20 pairs used):** - **0 – 200 MW, price must be at least $30/MWh** - **200 – 300 MW, price must be at least $45/MWh** - **300 – 450 MW, price must be at least $50/MWh** - **450 – 500 MW, price must be at least $75/MWh**
(200,3.0,10.0),(500,5.0,10.0)	**Normal Maneuvering Ramp Rates (2 of maximum 5 sets used):** - **0 – 200 MW, ramp up @ 3.0 MW/minute, ramp down @ 10.0 MW/minute** - **200 – 500 MW, ramp up @ 5.0 MW/minute, ramp down @ 10.0 MW/minute**

Energy offers includes multiple MW quantities and the prices ($/MWh) the generator expects to receive to produce energy within that range, as well as the ramp-rates (MW/min) which the generator can normally maneuver up or downward.

[2] The Ontario market includes 10-Minute Spinning, 10-Minute Non-Spinning and 30-Minute Operating Reserve. Both Generators and Dispatchable Loads can participate in these markets, however Dispatchable Loads are restricted from offering 10-Minute Spinning Operating Reserve. This restriction is under review by the IESO and NPCC.

Maximizing the Gain from Trade

In balancing the supply and demand for electricity every 5 minutes the DSO selects the quantities of energy and operating reserve from each bid and offer in such a way that the cost to the market is optimal – the prices are just enough and not any more or less than they need to be to satisfy both buyers and sellers. This is said to result in a maximizing the economic gain from trade, where the common price for electricity allows generators to produce and consumers to consume with an optimal operating profit.

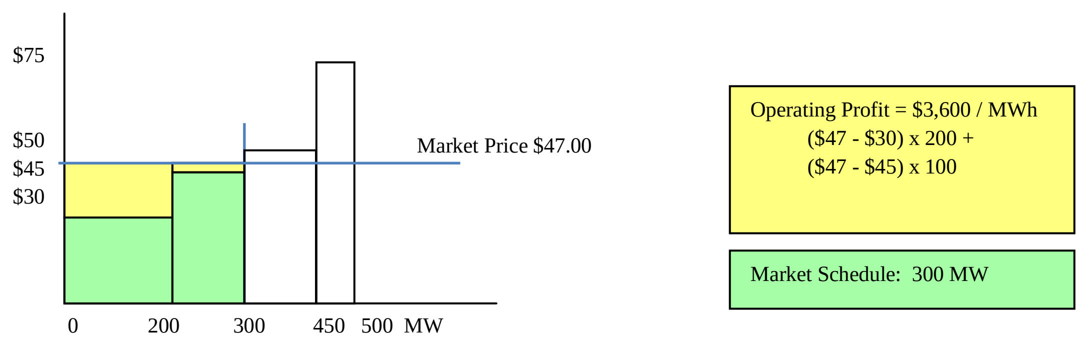
To a generator, this operating profit is determined by their electricity revenue (Market Price x MWh) less their production costs. Since their energy and operating reserve offers are assumed to represent their production costs, the operating profit can be calculated as the area between the price and their offer, up to the scheduled quantity. See examples 1 through 3 for an illustration of this. In the simple case where a generator is only offering energy, the quantity scheduled by the DSO would only include offered quantities at or below the market price. At that market price, if a lesser quantity was scheduled it would not be optimal to the generator as it was willing to sell more energy for a greater profit. It would also be non-optimal to the market since it would be holding back energy from loads that were willing to consume more at that price. A key concept here is that such optimization occurs at both the market level and at the individual resource level. While dispatch quantities and prices are the consequence of the joint optimization process, these historical prices can also be applied against the offers to determine the expected dispatch quantities.

Calculating Economic Gain:

The price-quantity pairs of the generator's offer can be shown as laminations on a bar chart. Since these offers represent the cost of energy production for generators, the economic gain or operating profit is the difference between the market price and the offer prices up to the scheduled quantity.

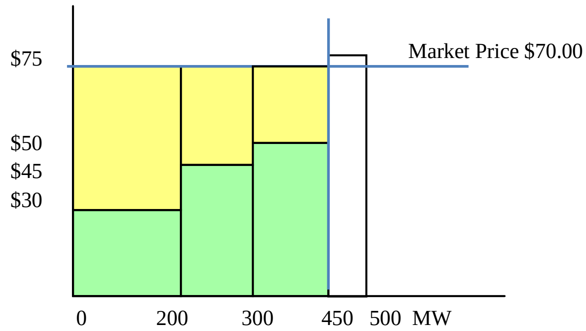
Example 1: Market Price = $47.00

Using the simple energy offer above for hours 8-19: an energy price of $47 would result in a schedule of 300MW and an operating profit of $3,600/MWh (yellow area). Any quantity higher or lower than 300MW would result in a reduction of operating profit (not maximized). This leaves an additional 200MW of energy unscheduled.



Example 2: Market Price = $70.00

Again using the simple energy offers from above for hours 8-19: An energy market price of $70 would result in a market schedule of 450MW and an economic gain of $13,500/MWh (yellow area) . The remaining 50MW of energy is left unscheduled.

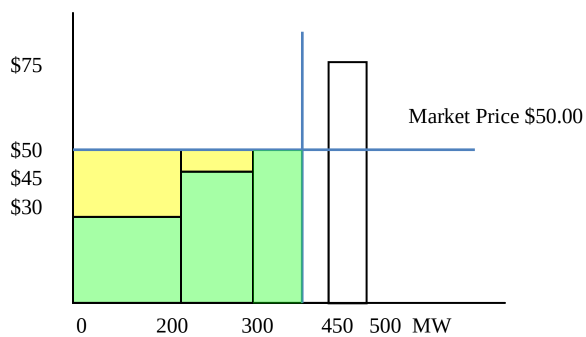


Operating Profit = $13,500 / MWh
($70 - $30) x 200 +
($70 - $45) x 100 +
($70 - $50) x 150

Market Schedule: 450 MW

Example 3: Market Price = $50.00 (same as an offered lamination)

Here, the market price is the same as the generator's third price-quantity lamination. This can occur when that generator is the one responsible for setting the market price and is "on the margin". When this occurs the scheduled quantity can be anywhere within the lamination range of 300 MW – 450 MW, with the exact amount chosen to meet demand. The generator is indifferent to where it is operating within this range because its operating profit remains unchanged at $4,500/MWh.



Operating Profit = $4,500 / MWh
($50 - $30) x 200 +
($50 - $45) x 100 +
($50 - $50) x ?

Market Schedule between 300 and 450 MW

Market Prices vs. Shadow Prices

The previous examples show how economic gain (or operating profit) is calculated for an offer set given an energy market price. This is for illustration only as the Ontario electricity market is a little more complex. The spot market price for electricity is the same for all resources; all loads pay and all generators are paid the same energy price. However, the market schedule MW is not necessarily the quantity that each resource is actually dispatched. Instead, the quantity that the DSO will dispatch each resource is based on the constrained market model, which as a by-product also generates several hundred nodal prices called shadow prices.

The DSO uses the same fundamental algorithm and objective function for the unconstrained market schedule and constrained dispatch. The DSO first executes the constrained run using all of the real-life restrictions in order to determine each unit dispatch. It then relaxes most of these restrictions (constraints) for a second run in order to calculate the market schedules and market clearing prices.

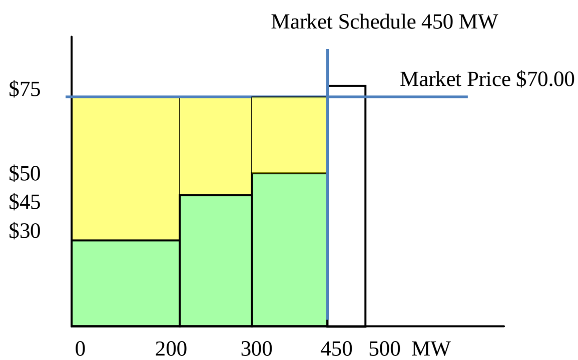
The shadow prices at each node are consistent with the actual dispatch quantity of any resource at that node. That is to say, given a set of offers and a set of shadow prices you can determine the dispatch quantity in the same manner as in examples 1 – 3. The calculation of operating profit using shadow prices is still valid in establishing the dispatch quantities, however, it is not used directly in any settlements calculations. No payments are based on shadow prices. Instead, the market price is used on three occasions to determine three operating profit calculations based on 1) the market schedule quantity, 2) the constrained dispatch quantity and 3) the quantity that was actually provided (using revenue metering data). A Congestion Management Settlement Credit (CMSC) is an adjustment calculated by the IESO Settlements system to ensure the operating profit for each interval is kept true to the operating profit that would have been received based on the market schedule.

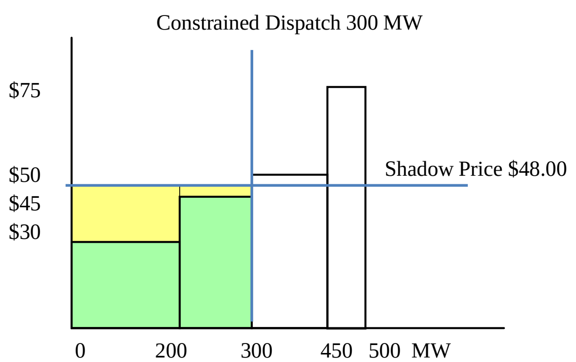
$$CMSC = OP_{\text{Market Schedule}} - MAX(OP_{\text{Dispatch Quantity}}, OP_{\text{Actual Quantity}})$$

Since the adjustment uses the maximum of the Operating Profits based on Dispatch Quantity and Actual Quantity, this effectively claws-back any Operating Profit the participant might have received by over-generating. The CMSC is effectively a constrained-on or constrained-off payment, and is an incentive to the participant to follow the constrained dispatch instructions. It is calculated separately for Energy and each class of Operating Reserve and can be a negative value.

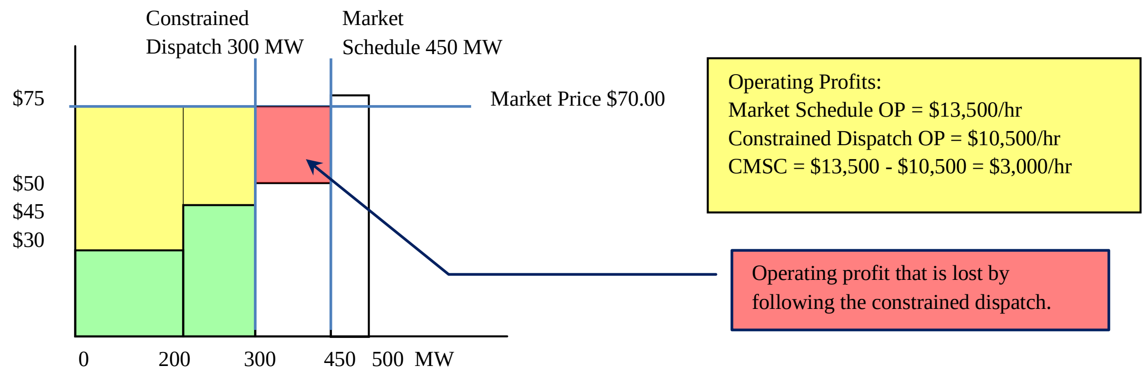
CMSC Calculation:

The energy offer is shown twice, first with the Market Price and then with the Shadow Price. Each price would result in a different energy quantity for the market schedule and the constrained dispatch. The energy Shadow Price is lower than the Market Price, indicating that there may be an oversupply of energy in the area resulting in the need to constrain down generation or constrain up loads.





The Constrained Dispatch of 300 MW is 150 MW lower than the Market Schedule. To hold the participant true to the market operating profit, the generator will be compensated for any difference in operating profit.



If the generator follows its dispatch instruction exactly, it will be compensated for the reduced operating profit by CMSC of $3750/hr or $312.50 for the single 5-minute interval. This amount is an upper-limit and may be reduced if the actual MW output is not the same as the dispatch instruction. Any variance from the dispatch instruction will not be rewarded with increased CMSC and may actually be reduced, or become negative if the generator's output exceeds 450 MW.

Joint Optimization

The DSO does not evaluate energy and operating reserve offers and demands in isolation of each other. Instead, it uses joint optimization to assess energy and the three classes of operating reserve simultaneously and by doing so, meets the demand for energy and the requirements for operating reserve at an optimal cost to the market. [3]

Joint optimization can have a significant effect on generator dispatches as any quantity of operating reserve provided must be done so at the expense of energy (and vice versa). This can sometimes result in what appears as strange behavior by the DSO; if the need for operating reserve is high, then a generator's energy may be passed over even if the offer was "in the money" (when the market price was higher than the offered price). In this case the reduction in scheduled energy results in a reduction in economic gain, however, it will be offset more so (or at least kept neutral) by the increase in economic gain that results from the increase in scheduled operating reserve. Dispatchable loads are a slightly different situation since they can provide operating reserve only when consuming energy. However, joint optimization still applies and a dispatchable load may be scheduled to consume energy in order to have it provide its operating reserve even if the price was higher than its energy bid price.

The quantity of energy and operating reserve selected from each generator or dispatchable load is determined by the overall demand for these products, their economic value based on the bids and offers, and their availability based on the constraints. The value of these products assigned to the market are published by the DSO in the form of market prices and shadow prices. They are optimized across the

[3] Refer to IESO Quick Take on Joint Optimization for a detailed explanation of this and a comparison with sequential optimization.

market as a whole, meaning the price is not unnecessarily high or low in order to meet the supply and demand for energy and operating reserve. They are also optimized across each individual unit's offer set, meaning the MW quantities scheduled or dispatched for a generator will result in the maximum quantity at that price considering the economic gain of *both* energy and operating reserve.

Example 4A shows how Joint Optimization is applied using an energy offer and operating reserve offer. You can see in the example that the energy market price was higher than the generator's energy offer price for a significant portion, yet the quantity was still not scheduled. It might appear at first glance that the DSO made an error by passing over the quantity of energy that had a positive economic gain. A closer look shows that it did this so it could schedule some operating reserve and the overall selection resulted in an even higher economic gain. Example 4B shows how these quantities were assessed and chosen.

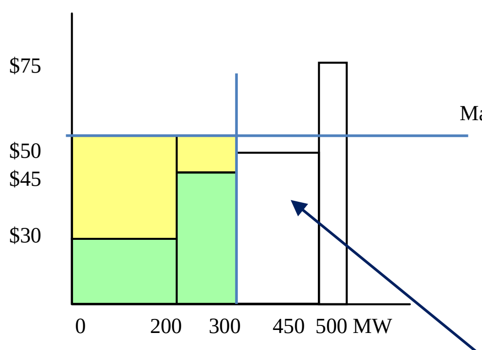
Example 4A: Joint Optimization

Market Prices: Energy $55/MWh, 10-Min Non-Spin OR $20/MWh, 30-Min OR $5/MWh

The earlier energy offer for hours 8-19 is used here. However, additional offers for 10-Minute Non-Spinning Operating Reserve and 30-Minute Operating Reserve have also been submitted. Even though individual offer quantities appear to be "in the money", not all quantities are scheduled. Instead, the joint optimization finds that maximum economic gain occurs through scheduling a mix of energy and operating reserve:

Energy: 300 MW Scheduled
10-Minute Spinning OR: 100 MW Scheduled
30-Minute OR: 100 MW Scheduled

Energy Offer / Schedule

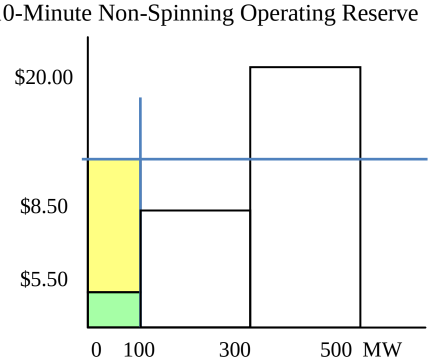


Market Price $55.00. Scheduled Quantity 300 MW

Economic Gain:
0 – 200 MW $25.00/MWh ✓ scheduled
200 – 300 MW $10.00/MWh ✓ scheduled
300 – 450 MW $5.00/MWh X not scheduled
450 – 500 MW -$20.00/MWh X not scheduled

The energy offer of range 300 – 450MW @ $50/MWh appeared "in the money" but was not chosen because its economic gain would be less than either operating reserve offers.

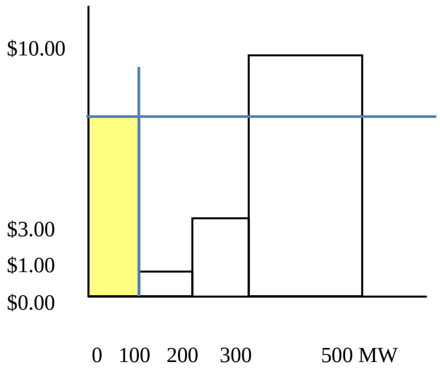
10-Minute Non-Spinning Operating Reserve



Market Price $15.00 Scheduled Quantity 100 MW

Economic Gain:
0 – 100 MW $9.50/MWh ✓ scheduled
100– 300 MW $6.50/MWh X not scheduled
300 – 500 MW -$5.00/MWh X not scheduled

30-Minute Operating Reserve



Market Price $7.00 Scheduled Quantity 100 MW

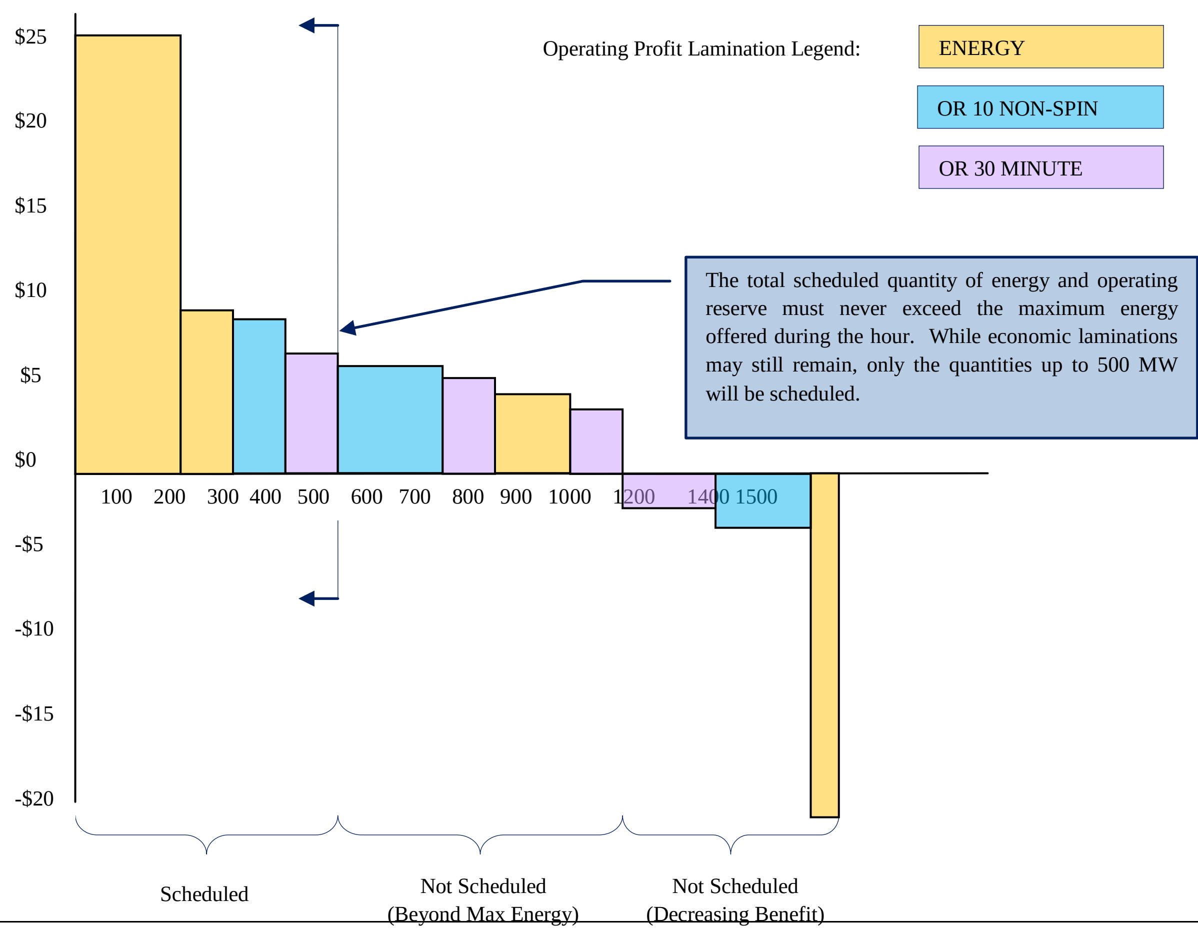
Economic Gain:

0 – 100 MW	$7.00/MWh	√ scheduled
100– 200 MW	$6.00/MWh	X not scheduled
200 – 300 MW	$4.00/MWh	X not scheduled
300 – 500 MW	-$3.00/MWh	X not scheduled

To show how the various quantities of energy and operating reserve were scheduled, determine how much operating profit each lamination quantity would contribute. These operating profit laminations can then be sorted from highest to lowest $/MWh to establish their economic priority. Sum up the total quantities from left to right that 1) result in an increase in operating profit as the laminations are positive, and 2) are at or below the maximum energy offered within the hour.

Example 4B: Operating Profit Laminations

Using the offers and prices shown in Example 4A, we can order the Operating Profit laminations from highest to lowest to determine what quantities from energy and operating reserve would result in the greatest operating profit.

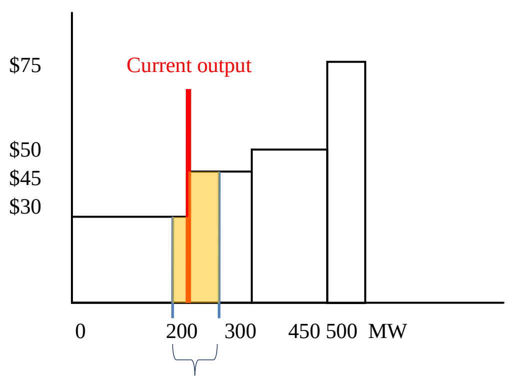


Ramp-Rate Constraints

Ramp-rates are submitted by participants within their energy offers and tell the IESO how each resource can maneuver under normal operating conditions. Dispatch instructions sent to the participant will follow these ramp-rates to ensure the technical operating limits of the units are respected. A separate operating reserve ramp-rate is also submitted by the participant to indicate how quickly a unit can increase its energy under short notice in response to unexpected outages, demand or other contingencies. The previous examples ignored the effect of ramp rates on the joint optimization and assumed that all energy and operating reserve was available for the interval. In reality, the DSO constantly tracks where the resource is currently operating and factors in the ramp-rates to establish upper and lower energy boundaries for the next 5-minute interval. Similarly, the operating reserve ramp-rate (provided separately in the energy bid/offer) is used to establish a maximum upper boundary for 10-minute and 30-minute operating reserve. Regardless of how much of the offer is in the money, a unit's next dispatch will always be within this range.

Submitted Ramp Rates: (200,3.0,10.0),(500,5.0,10.0)

Current Output 200MW
Minimum Constrained Dispatch = 200 MW – 3.0 MW/min x 5 minutes = 185 MW
Maximum Dispatch = 200 MW + 10.0 MW/min x 5 minutes = 250 MW



Next dispatch interval is ramp-rate constrained to between 185 MW and 250 MW

The DSO handles energy ramp rates differently for the constrained dispatch and market schedule. While the constrained dispatch respects the ramp rates at face value, the market schedule currently uses a multiplier of 12 times ramp-rate[4] when calculating the upper and lower energy boundaries. In this example the market schedule would be ramp-rate limited between 20 MW (200 – 3 x 5 x 12) and 800 MW (200 + 10 x 5 x 12) for the next 5-minute interval.

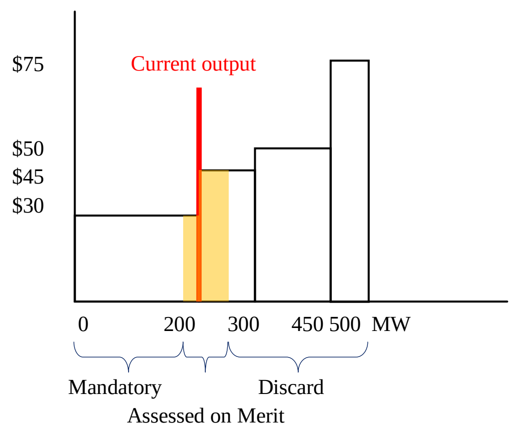
If a resource will be participating in the operating reserve market, a separate operating reserve ramp rate is also provided (within the energy bid body) for use with all operating reserve offers. This ramp-rate indicates the MW/minute rate a unit can increase its energy output should operating reserve be activated.

[4] In early 2007, the IESO Board of Directors proposed changing the 12-times ramp rate in the market schedule to 3-times. This was challenged by the Association of Major Power Consumers of Ontario (AMPCO) to the Ontario Energy Board, but was denied. AMPCO has since filed an appeal in the Superior Court of Justice, Divisional Court [Source: Stikeman Elliott LLP].

For establishing the maximum operating reserve allowed, the DSO multiplies this ramp-rate by either 10 minutes (for 10-Minute spinning and non-spinning operating reserve) or 30 minutes (for 30-minute operating reserve). Unlike the energy ramp-rates, the DSO does not implement any multiplier in determining the maximum operating reserve for the unconstrained market schedule.

In example 4B, the operating profit laminations for energy and operating reserve were determined then sorted from highest to lowest $/MWh. It treated each of these laminations as being optional where the quantities would be chosen if they resulted in a positive additional operating profit, up the maximum energy offered. Because of the ramp-rates, two things happen for each interval. First, portions of the laminations may have to be discarded if the energy or operating reserve cannot be reached during the target timeframe (5-minute energy, 10-minute OR or 30-minute OR). Second, portions of the energy laminations may be mandatory and must be scheduled regardless if they result in positive or negative operating profit, if the unit cannot ramp down energy quickly enough to achieve 0 MW output.

Energy Offer Laminations evaluated for Constrained Dispatch:
Current Output 200 MW. Ramp-rates limit next interval to between 185 MW and 250 MW
0-185 MW lamination becomes mandatory. 185-250 MW will be assessed on merit. Above 250 MW must be discarded.



The trajectory calculations above assume that a unit has been following its dispatch instructions to get to its current output. In spring 2004 the IESO implemented a feature of their Multi-Interval Optimization project to continually track how well certain units (some non-quick start generators) were following their dispatch instructions. Logic was added to the DSO to accelerate the ramp-rate when a unit is falls behind their dispatch instructions when loading up. This was done in order to reduce or eliminate the “Stutter Step” by allowing these units to catch up to their target output levels when they momentarily fall behind. Refer to IESO Quick Take Issue 13 for a full explanation.

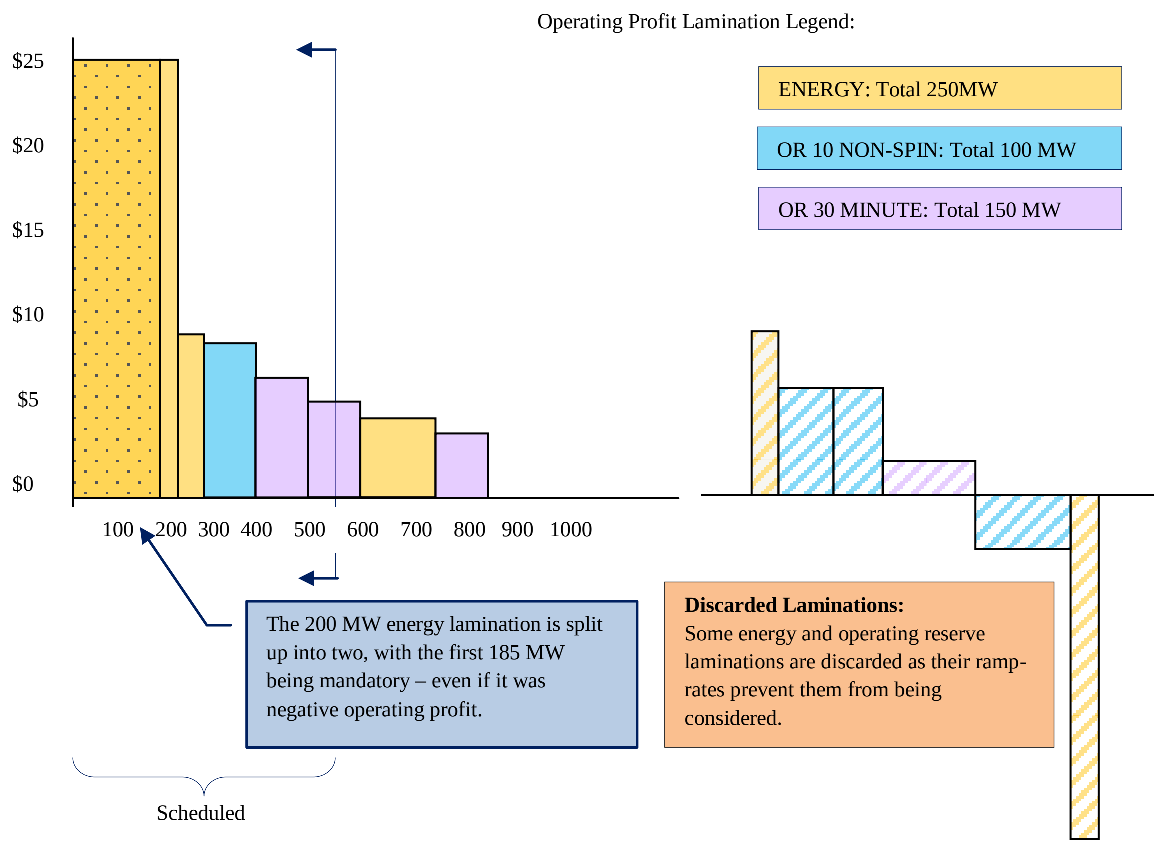
Hourly Pre-dispatch Shadow Prices

Pre-dispatch Shadow Prices for each delivery point are also published hourly with data also on an hourly granularity, not 5-minute. You can apply most of the steps described in this document for determining your generator's dispatch instructions. However, the pre-dispatch data is hourly data and each run is always a best effort forecast which may not actually occur. The shadow prices are based on peak energy requirements expected within the hour and not the average energy requirements, and will tend to reflect a higher price for energy than in the dispatch intervals. Ramp-rates should continue to be factored in, however, values should be multiplied by 12 to establish the hourly ramp rate.

Example 4C: Including Ramp-Rate Constraints

Current Energy Output: 200 MW
Operating Reserve Ramp-Rate: 10 MW/minute

As a result of energy and operating reserve ramp-rate constraints on the next 5-minute interval, the first 185MW of energy becomes mandatory. Energy laminations above 250MW becomes discarded, as does 10-Minute Spinning OR above 100MW and 30-Minute OR above 300 MW. Remaining laminations are shifted to the left for further consideration.



Totaling up the laminations, the final dispatch will be Energy 250MW, OR 10-Minute Non-Spin 100 MW and OR 30-Minute 150 MW.

Reserve Loading Point

The reserve loading point is another MW value provided by resources that participate in the operating reserve market, and is included in the operating reserve offer. Separate values are provided within each offer and they must meet certain validation rules defined by the IESO. It was intended to allow the generator to reliably achieve a minimum output before having to worry about the possibility of being activated to supply operating reserve energy for system contingencies. In reality, the DSO implements a linear algorithm which restricts (but does not entirely prevent) the amount of operating reserve scheduled unless the dispatched energy will also be beyond the reserve loading point.

Resource Dispatch Filter

The Resource Dispatch (RD) Filter is used by the IESO to block numerous small changes to the dispatch instructions that would otherwise result in units constantly moving up or down by small increments. It is set to block any energy dispatches where the change from the previous dispatch instruction is less than 2% of the maximum generation offer up to a maximum of 10MW. The RD Filter is turned off for the 1st and 7th interval to ensure these dispatch instructions are allowed to be issued on the hour and half-hour.

The IESO Market Manual[5] states the RD Filter also does not filter dispatches when that dispatch is attempting to bring a unit to its low operating limit or its high operating limit. These limits may be different than the minimum and maximum offered quantities (i.e. they are maintained in the IESO Participant Life Cycle system). As a result, it is understood that the RD filter will allow all new dispatches through when they are within 2% or 10 MW (whichever is less) of these limits and if the new dispatch is directing the unit towards the limit.

The RD Filter is applied to the energy dispatch and only after the DSO has applied its optimization. Operating Reserve schedules may still be dispatched. As a result, there may be times when the total energy and operating reserve slightly exceed the total energy offered, or leave small amounts of operating reserve unscheduled even if it was economic.

[5] Market Manual 4.3 Real Time Scheduling and Physical Markets, Section 1.8.1

Steps in Reverse-Engineering Shadow Prices

Maximizing the economic gain from trade is the objective function which the DSO attempts to optimize across the market. Understanding this and knowing that it also applies to each resource is key in working backwards from the shadow prices in determining the energy and operating reserve dispatches. Similarly, individual market schedules can be determined by applying the market prices against each offer set. While market schedules are not intended to be followed as the dispatch instructions are, determining them is still important as they are used in the calculation of CMSC, which can be very significant payments to a dispatchable resource.

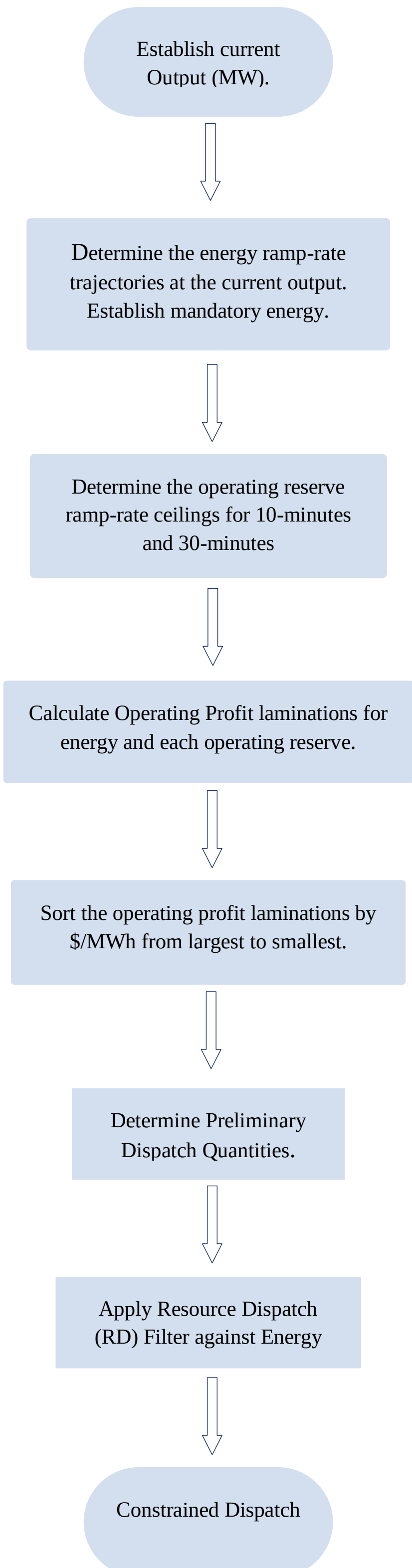
To start the reverse-engineering process, two similar sets of calculations are first required to determine how the historical prices would result in the Constrained Dispatch and the Market Schedule. This must be done using the 5-minute shadow price and 5-minute market price data published by the IESO and not the hourly data (average shadow prices or HOEP). Any simulation should use the shadow prices that are at or close to the location of the generator as these reflect the physical constraints that would occur in normal operations.

A third step is required to calculate the dispatch operating profit (based on the constrained dispatch using the market prices) and CMSC payment for the interval.

> The IESO publishes Shadow Prices for over 280 delivery points, which are nodes on the IESO controlled grid. Prices are given for energy and each of the three operating reserve markets. The dispatch data is in 5-minute resolution and bundled into hourly data files, published shortly after the hour.

> Note: These steps are not to be confused with those taken by the DSO for determining the Constrained Dispatch and Market Schedules. Instead, we are working backwards starting with the results of the DSO output (Shadow Prices and Market Prices) to determine how these would apply to trial bids and offers. This also assumes that the new or revised offers would have no impact on the final DSO results, which in reality may not be the case.

Reverse-Engineering Step 1 – Constrained Dispatch Calculations



Regardless of how economic the offers for energy or operating reserve may be, the next 5-minute dispatch will always depend on the unit's current energy output. If you are running a simulation that assumes you will follow the dispatch quantity, your current output will be the final constrained dispatch from the previous 5-minute interval.

Using the ramp-rates, establish the floor (minimum) and ceiling (maximum) energy that the next dispatch must be within. Energy quantities below the minimum level become mandatory, so the next dispatch must include at-least this much energy. Discard the offer quantities to exclude any MW beyond the ceiling level. You will likely need to split the offer laminations to separate mandatory and discarded quantities.

Using the operating reserve ramp-rate (not the energy ramp rates), calculate how much maximum operating reserve can be scheduled within 10-minute and 30-minute timeframes. Discard any operating reserve offer laminations (or portions) that are beyond the maximum amounts.

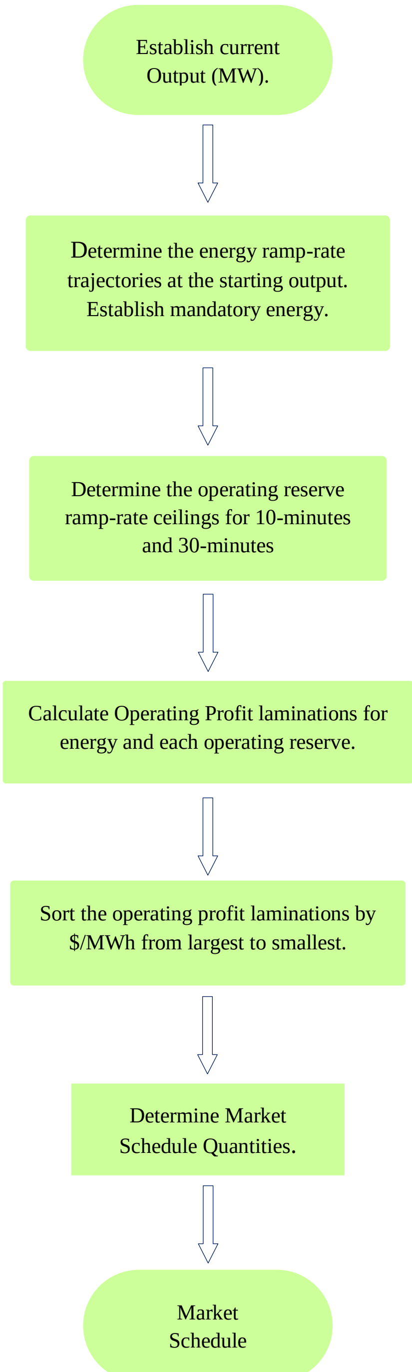
With the 5-minute shadow prices for energy and the three operating reserves, calculate the operating profit laminations ($/MWh) using the energy and operating reserve offers and the Shadow Prices for each of these.

Place the Mandatory Energy lamination(s) first, followed by the remaining sorted laminations. Discard any operating profit laminations beyond the maximum energy offered for that hour. Discard any remaining laminations that have a negative operating profit.

Using the remaining operating profit laminations, sum up the MW quantities for each energy and operating reserve products.

The RD Filter blocks any energy dispatches where the change from the previous dispatch is less than 2% of the maximum generation offer up to a maximum of 10MW. The RD Filter is not applied on the 1st and 7th interval in each hour.

Reverse-Engineering Step 2 – Market Schedule Calculations



As with the Constrained Dispatch, the process for determining the Market Schedule starts with the current energy output. Again, the simulation can assume this is the previous interval's constrained energy dispatch. Do not use the previous energy Market Schedule.

Using the ramp-rates multiplied by 12x (later to be 3x), establish the floor (minimum) and ceiling (maximum) energy that the next dispatch must be within. Energy quantities below the minimum level become mandatory and must be scheduled. Discard the offer quantities to exclude any MW beyond the ceiling level. You will likely need to split the offer laminations to separate mandatory and discarded quantities.

Using the operating reserve ramp-rate (not the energy ramp rates), calculate how much maximum operating reserve can be scheduled within 10-minute and 30-minute timeframes. Discard any operating reserve offer laminations (or portions) that are beyond the maximum amounts. No multiplier is used for the OR ramp-rates.

With the 5-minute prices for energy and the three operating reserves, calculate the operating profit laminations ($/MWh) using the energy and operating reserve offers and the Market Prices for each of these.

Place the Mandatory Energy lamination(s) first, followed by the remaining sorted laminations. Discard any operating profit laminations beyond the maximum energy offered for that hour. Discard any remaining laminations that have a negative operating profit.

Using the remaining operating profit laminations, sum up the MW quantities for each energy and operating reserve products. These are the final Market Schedules as the RD filter is not applied.

Reverse-Engineering Step 3 – Settlements and CMSC Calculations

Generators are paid the market price for the energy they inject, as well as the market price for each operating reserve quantity scheduled. They are also paid CMSC whenever their constrained dispatch differs from the market schedule. While shadow prices were used in determining the dispatch quantities, they have no role in any further settlements calculations.

Determine Energy and Operating Reserve Credits.

Assuming the dispatch quantity is followed exactly:

$$Energy\ Credit = \frac{\text{Dispatch Energy x Market Price Energy}}{12}$$

$$OR\ 10s\ Credit = \frac{\text{Dispatch OR10 Spin x Market Price OR10 Spin}}{12}$$

$$OR\ 10n\ Credit = \frac{\text{Dispatch OR10 Nonspin x Market Price OR10 Nonspin}}{12}$$

$$OR\ 30\ Credit = \frac{\text{30 min Spin Schedule x Market Price OR30}}{12}$$

Each credit is divided by 12 since these calculations are for 5-minutes.

Determine the Dispatch Operating Profits for energy and each operating reserve.

Using the Constrained Dispatch Quantities and the Market Prices (not the Shadow Prices), determine each Operating Profit (OP) realized by the dispatch. Some may even be negative.

Determine the Market Schedule Operating Profits for energy and each operating reserve.

Using the Market Schedules and the Market Prices, determine each Market Schedule Operating Profit. This is what your Operating Profit would have been if you were dispatched based on the unconstrained market schedule (which you are not).

Calculate the CMSC for energy and each operating reserve.

Assuming you follow your dispatch exactly, the CMSC credits are:

$\text{CMSC}_{\text{Energy}} = \text{OP}_{\text{Energy Market}} - \text{OP}_{\text{Energy Dispatch}}$

$\text{CMSC}_{\text{OR 10 Spin}} = \text{OP}_{\text{OR 10 Spin Market}} - \text{OP}_{\text{OR 10 Spin Dispatch}}$

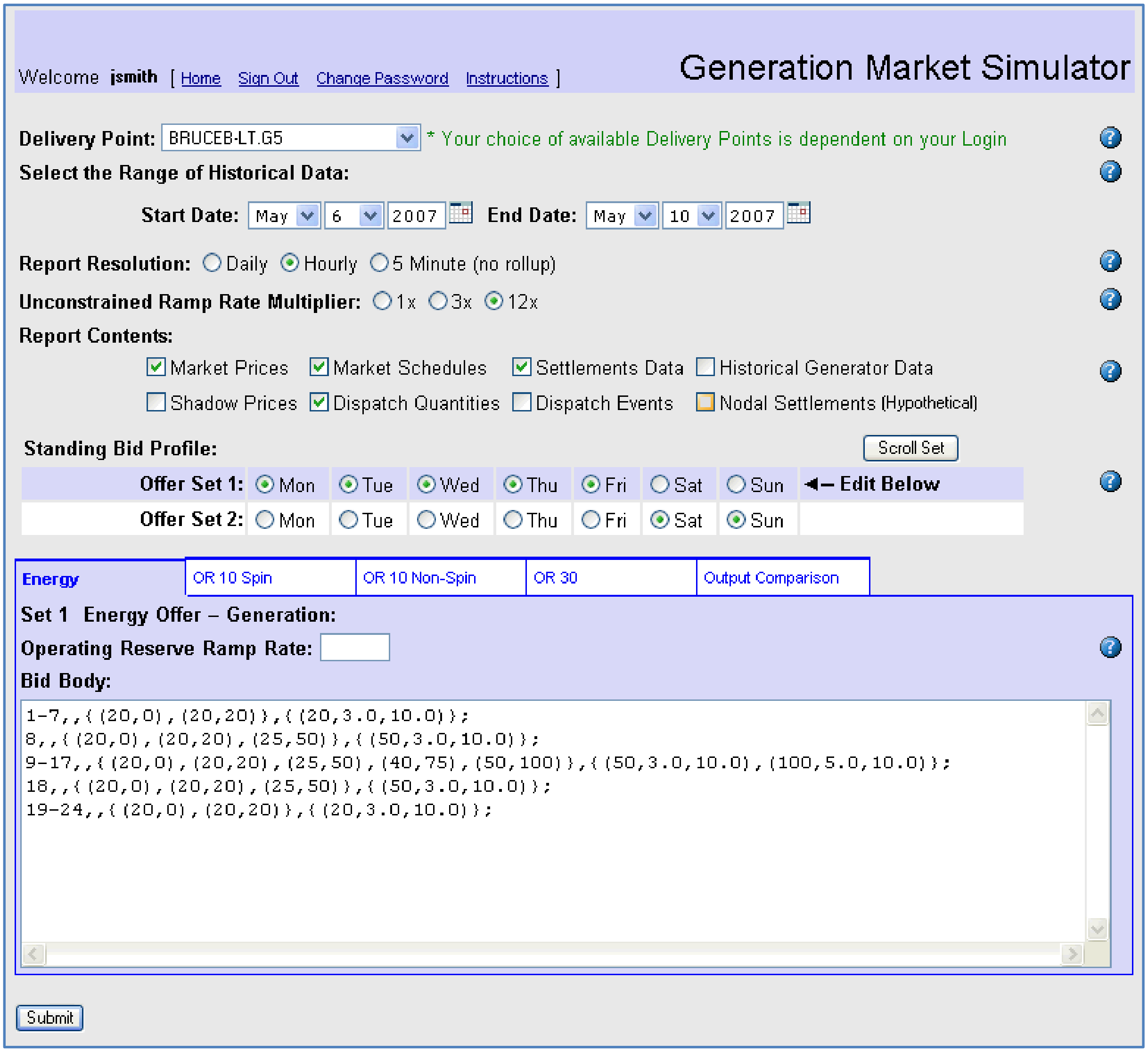
$\text{CMSC}_{\text{OR 10 Non-Spin}} = \text{OP}_{\text{OR 10 Non-Spin Market}} - \text{OP}_{\text{OR 10 Non-Spin Dispatch}}$

$\text{CMSC}_{\text{OR 30}} = \text{OP}_{\text{OR 30 Market}} - \text{OP}_{\text{OR 30 Dispatch}}$

These credits can individually be negative, but as a set they are generally positive or are offset by higher energy and OR credits.

Sygration Generation Market Simulator

The Sygration Generation Market Simulator is a subscription-based service based on the design described above. It validates the submitted energy and operating reserve offers just as the IESO system does, then processes every 5-minutes of historical data to generate dispatch and settlements reports. The service allows market participants to test various bid strategies or fine-tune their offers using the historical analysis. The user selects the delivery point and timeframe of interest, and submits offers for energy and each of the three classes of operating reserve just as they would for the IESO.



The simulator has implemented the algorithm described earlier[6], along with some additional rules for marginal bids and indifferent market choices (when incremental operating profit is the same for energy and operating reserve). The service accesses a large database of historical shadow and market prices and

[6] The Reserve Loading Point is not implemented exactly as in the DSO. Instead, it is applied as the minimum generation level that must be scheduled in the prior interval before operating reserve can be scheduled in the next interval. Low and high operating limits, used in the RD filter, have also not been implemented.

calculates the dispatch quantities, market schedules, settlements credits and CMSC as if the offers had been used for real.

DATE TIME	$ MCP	$MP-OR10S	$MP-OR10N	$MP-OR30	DQSI	DQ-OR10S	DQ-OR10N	DQ-OR30	$ NEMSC	$SC-OR10S	$SC-OR10N	$SC-OR30	$CMSC-
01-JUL-2005 00:00	55.25	0.32	0.20	0.20	45.0	2.1	0.0	0.0	2379.99	0.65	0.00	0.00	267.76
01-JUL-2005 01:00	44.02	0.58	0.20	0.20	50.0	0.0	0.0	0.0	2200.92	0.00	0.00	0.00	0.00
01-JUL-2005 02:00	38.13	0.62	0.20	0.20	40.0	10.0	0.0	0.0	1513.21	6.09	0.00	0.00	143.54
01-JUL-2005 03:00	35.81	2.33	0.20	0.20	50.0	0.0	0.0	0.0	1790.54	0.00	0.00	0.00	0.00
01-JUL-2005 04:00	36.68	0.37	0.20	0.20	50.0	0.0	0.0	0.0	1834.12	0.00	0.00	0.00	0.00
01-JUL-2005 05:00	36.85	0.37	0.20	0.20	50.0	0.0	0.0	0.0	1842.29	0.00	0.00	0.00	0.00
01-JUL-2005 06:00	35.58	0.37	0.20	0.20	26.2	23.8	0.0	0.0	942.15	8.75	0.00	0.00	243.06
01-JUL-2005 07:00	39.45	0.36	0.20	0.20	83.3	15.8	0.0	0.0	3316.96	5.73	0.00	0.00	112.37
01-JUL-2005 08:00	49.19	0.20	0.20	0.20	93.8	5.4	0.0	0.0	4658.08	1.08	0.00	0.00	27.52
01-JUL-2005 09:00	63.74	0.20	0.20	0.20	100.0	0.0	0.0	0.0	6374.08	0.00	0.00	0.00	0.00
01-JUL-2005 10:00	72.77	0.20	0.20	0.20	100.0	0.0	0.0	0.0	7277.17	0.00	0.00	0.00	0.00
01-JUL-2005 11:00	74.54	0.20	0.20	0.20	100.0	0.0	0.0	0.0	7454.00	0.00	0.00	0.00	0.00
01-JUL-2005 12:00	67.33	0.20	0.20	0.20	100.0	0.0	0.0	0.0	6732.58	0.00	0.00	0.00	0.00
01-JUL-2005 13:00	68.56	0.20	0.20	0.20	100.0	0.0	0.0	0.0	6856.42	0.00	0.00	0.00	0.00
01-JUL-2005 14:00	65.30	0.20	0.20	0.20	100.0	0.0	0.0	0.0	6530.00	0.00	0.00	0.00	0.00
01-JUL-2005 15:00	69.77	0.20	0.20	0.20	93.8	0.0	0.0	0.0	6633.40	0.00	0.00	0.00	52.02
01-JUL-2005 16:00	46.80	0.20	0.20	0.20	64.6	0.0	0.0	0.0	3012.44	0.00	0.00	0.00	81.08
01-JUL-2005 17:00	37.40	0.20	0.20	0.20	50.0	0.0	0.0	0.0	1869.88	0.00	0.00	0.00	0.00
01-JUL-2005 18:00	36.01	0.20	0.20	0.20	62.5	0.0	0.0	0.0	2263.81	0.00	0.00	0.00	36.65
01-JUL-2005 19:00	36.35	0.20	0.20	0.20	50.0	0.0	0.0	0.0	1817.67	0.00	0.00	0.00	0.00
01-JUL-2005 20:00	35.37	0.20	0.20	0.20	50.0	0.0	0.0	0.0	1768.67	0.00	0.00	0.00	0.00
01-JUL-2005 21:00	35.22	0.20	0.20	0.20	50.0	0.0	0.0	0.0	1761.04	0.00	0.00	0.00	0.00
01-JUL-2005 22:00	35.71	0.20	0.20	0.20	50.0	0.0	0.0	0.0	1785.46	0.00	0.00	0.00	0.00
01-JUL-2005 23:00	39.03	0.20	0.20	0.20	50.0	0.0	0.0	0.0	1951.58	0.00	0.00	0.00	0.00
02-JUL-2005 00:00	31.59	2.33	0.20	0.20	45.0	5.0	0.0	0.0	1432.98	11.65	0.00	0.00	21.48
02-JUL-2005 01:00	28.29	2.33	0.20	0.20	20.0	30.0	0.0	0.0	565.73	69.90	0.00	0.00	98.60
02-JUL-2005 02:00	24.32	2.33	0.20	0.20	20.0	30.0	0.0	0.0	486.33	69.90	0.00	0.00	35.73
02-JUL-2005 03:00	28.73	0.39	0.20	0.20	37.5	12.5	0.0	0.0	1078.56	4.89	0.00	0.00	45.69
02-JUL-2005 04:00	19.10	2.33	0.20	0.20	20.0	30.0	0.0	0.0	382.00	69.90	0.00	0.00	0.00
02-JUL-2005 05:00	9.43	2.33	0.20	0.20	14.4	25.0	0.0	0.0	164.70	58.25	0.00	0.00	23.96
02-JUL-2005 06:00	14.35	2.40	0.20	0.20	17.9	27.5	0.0	0.0	270.30	66.00	0.00	0.00	30.05
02-JUL-2005 07:00	32.36	0.38	0.20	0.20	63.3	30.4	0.0	0.0	2070.02	11.48	0.00	0.00	120.98

Timestamps (Hourly summary selected) | Market Prices Energy & OR | Constrained Dispatch (MW) | Settlement Credits including CMSC

Calculations are always based on the 5-minute historical pricing data. However, the output can be summarized to show the hourly average and totals (as shown above) or daily average and totals. In addition, a Monthly Summary and Hourly Profile report is generated.

Monthly Summary Results

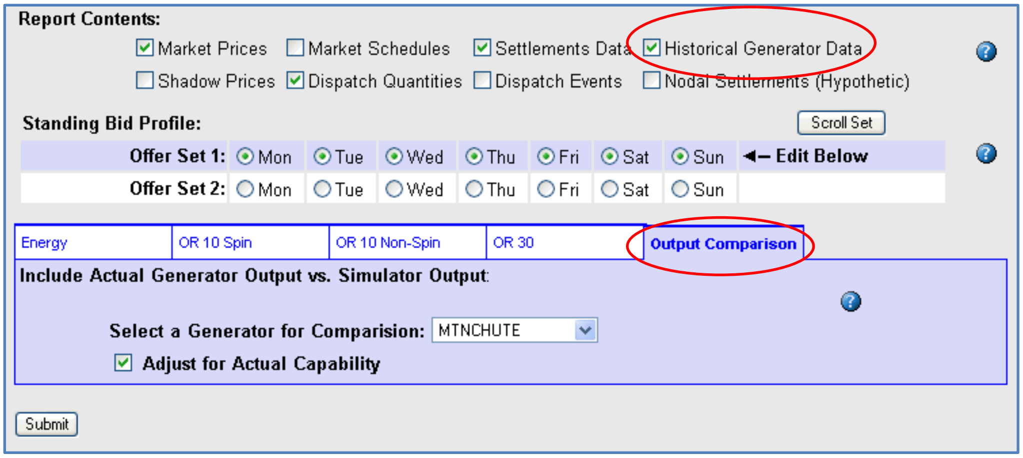
DATE TIME	$ MCP	$MP-OR10S	$MP-OR10N	$MP-OR30	DQSI	DQ-OR10S	DQ-OR10N	DQ-OR30	$ NEMSC	$SC-OR10S	$SC-OR10N	$SC-OR30	$CMSC-
June 2005	78.12	2.31	1.17	1.17	71.2	2.8	0.0	0.0	285774.79	383.90	0.00	0.00	5244.52
July 2005	68.31	2.71	0.23	0.23	67.5	4.4	0.0	0.0	2048344.37	5513.93	0.00	0.00	52927.09

Hourly Profile Results

DATE TIME	$ MCP	$MP-OR10S	$MP-OR10N	$MP-OR30	DQSI	DQ-OR10S	DQ-OR10N	DQ-OR30	$ NEMSC	$SC-OR10S	$SC-OR10N	$SC-OR30	$CMSC-
Hour 01	51.12	2.91	0.20	0.20	47.2	2.5	0.0	0.0	2415.97	7.06	0.00	0.00	70.30
Hour 02	40.82	2.36	0.20	0.20	44.3	5.7	0.0	0.0	1870.22	11.27	0.00	0.00	27.87
Hour 03	35.39	2.22	0.20	0.20	41.6	7.7	0.0	0.0	1531.98	14.42	0.00	0.00	30.80
Hour 04	37.34	2.21	0.20	0.20	45.4	4.2	0.0	0.0	1729.04	7.17	0.00	0.00	22.49
Hour 05	35.92	2.50	0.20	0.20	43.5	6.4	0.0	0.0	1605.35	15.93	0.00	0.00	36.80
Hour 06	34.44	2.32	0.20	0.20	41.0	7.7	0.0	0.0	1513.55	18.60	0.00	0.00	28.73
Hour 07	42.94	3.25	0.20	0.20	39.2	10.0	0.0	0.0	1817.15	28.90	0.00	0.00	89.93
Hour 08	57.77	3.69	0.20	0.20	86.4	10.7	0.0	0.0	5217.37	33.01	0.00	0.00	121.85
Hour 09	65.99	3.40	0.20	0.20	88.4	8.9	0.0	0.0	6092.79	27.25	0.00	0.00	81.37
Hour 10	77.64	3.25	0.20	0.20	89.1	7.6	0.0	0.0	7004.66	32.37	0.00	0.00	313.64
Hour 11	88.14	3.14	0.20	0.20	92.2	6.1	0.0	0.0	8436.03	18.57	0.00	0.00	65.06
Hour 12	90.04	3.22	0.20	0.20	90.0	4.5	0.0	0.0	8278.18	11.17	0.00	0.00	278.21
Hour 13	98.02	3.54	0.37	0.37	93.7	3.0	0.0	0.0	9269.24	13.05	0.00	0.00	271.89
Hour 14	100.48	3.97	0.27	0.26	94.0	4.4	0.0	0.0	9292.98	26.41	0.00	0.00	500.14
Hour 15	91.40	2.64	0.48	0.47	96.0	2.0	0.0	0.0	8837.80	9.25	0.00	0.00	129.81
Hour 16	87.65	2.73	1.04	1.04	96.5	0.6	0.0	0.0	8571.90	3.61	0.00	0.00	34.38
Hour 17	96.25	3.39	1.43	1.43	93.4	1.0	0.0	0.0	9205.07	3.52	0.00	0.00	119.79
Hour 18	92.05	3.27	0.76	0.76	86.2	1.2	0.0	0.0	8362.55	4.02	0.00	0.00	246.96
Hour 19	82.86	2.65	0.36	0.36	86.1	4.5	0.0	0.0	7403.03	23.42	0.00	0.00	282.24
Hour 20	79.44	2.75	0.20	0.20	49.0	0.0	0.0	0.0	3909.06	0.00	0.00	0.00	37.36
Hour 21	87.30	2.46	0.20	0.20	49.6	0.1	0.0	0.0	4328.25	0.04	0.00	0.00	26.23
Hour 22	69.79	0.73	0.20	0.20	46.5	1.1	0.0	0.0	3283.78	1.31	0.00	0.00	117.36
Hour 23	67.55	0.60	0.20	0.20	45.9	0.2	0.0	0.0	3161.76	0.97	0.00	0.00	113.27
Hour 24	60.76	0.60	0.20	0.20	46.2	0.3	0.0	0.0	2864.76	1.63	0.00	0.00	77.55

The Simulator also includes options to select the Market Schedule ramp-rate multiplier (1x , 3x or 12x) or to run the simulator using the Shadow Prices as a Nodal Prices in the settlements calculations[7], as generally used in other electricity markets.

There is also an option to compare the simulator output against actual generator output, which is useful in developing a theory on how a competing generator is bidding. When using the Output Comparison mode, you can ask the simulator to automatically adjust offer quantities downward when it detects a drop in the target generator's capability.



Simulators like this are not without limitations. It is not a full transmission model and does not have a complete offer curve for all generators to determine the exact effect of new or revised generation offers. Instead, it is a purely historical model that assumes that changes to the energy and operating reserve offers will have no impact on the shadow prices or market prices. It also assumes the generation dispatch will be followed exactly, which rarely happens in real life given that the IESO allows a compliance "dead band" for dispatchable resources. Therefore the simulator uses the previous interval's dispatch as the starting point for the next interval.

Subscribers are given access to the delivery point they require with data going back to market opening. Guest users can still try out the Simulator by applying offers against a limited amount of data (2 weeks) and an arbitrary delivery point.

The Sygration Generation Market Simulator (and its little brother the Dispatchable Load Market Simulator) is accessible at http://www.sygration.com/bidsimulator

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[7] There is no upper or lower limit to the values of the shadow prices. When generating the Nodal Settlements, the current minimum market clear prices and maximum market clearing prices are applied to the settlements calculations. If Ontario was to change to a location-based market for settlements, it is reasonable to expect changes to bid/offer strategies that would result in changes to future shadow prices.

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