An Overview of the Operation of Ontario's Electricity Market

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***Abstract*— The Ontario electricity market, which opened on May 1, 2002, consists of physical markets for energy and operating reserves as well as a financial market for transmission rights, administered by the Independent Electricity Market Operator (IMO). Bids for energy and operating reserves from inside Ontario are settled based on a uniform pricing mechanism; however, import/export of electricity and applicable operating reserves through 12 intertie zones from/to New York, Michigan, Minnesota, Manitoba and Quebec control areas are priced differently. Energy and operating reserves markets are designed based on two time-frames, pre-dispatch and real-time, as well as two optimization procedures, unconstrained and constrained. Financial transmission rights are auctioned for short-term (one month) and long-term (one year), and provide a limited risk-hedging mechanism for holders. In this paper an overview of the market structure, basic features and the operational aspects of the Ontario market is discussed.**

***Index Terms*— Deregulation, Electricity markets, Ontario power industry, electricity market design, transmission rights.**

I. Introduction

THE electric power sector of the province of Ontario in Canada went through a process of transition from a government-owned vertically integrated power system to a competitive wholesale electricity market on May 1, 2002 [1], two years after the originally scheduled date. In the erstwhile structure, Ontario Hydro along with some small municipal utilities generated, transmitted and distributed electrical energy to their customers across the province and electricity price was regulated by the provincial government. Based on the Ontario Electricity Act of 1998, Ontario Hydro was unbundled to Hydro One Inc., a regulated company that owns and maintains most of the transmission and distribution network; Ontario Power Generation (OPG) Inc., which owns more than 75% of the total installed capacity[1]; and the Independent Electricity Market Operator (IMO), which is a nonprofit company that is mainly responsible for ensureing fair competition for market participants and maitaining the power grid reliability and security. The Electrical Safety Authority (ESA) and the Ontario Electricity Financial Corporation (OEFC) also emerged out of Ontario Hydro.

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[1]The Market Power Mitigation Agreement has been made between the Ontario government, the Market Design Committee and OPG in order to mitigate OPG's market power.

The transmission system has remained regulated, and the Ontario Energy Board determines the transmission and distribution tariffs [2], which cover the investment and expansion, maintenance and operational costs for the transmission and distribution system. The average transmission charge for the period May 2002-April 2003 was $8.58/MWh. Hydro One Inc., wholly owned by the Government of Ontario, is the major transmission company in Ontario that possesses and operates 28,600 km of the 28,900 km Ontario's transmission network, as well as having a distribution network that spans 75% of Ontario. The Ontario's high voltage transmission system has interconnections with Manitoba, Quebec, New York, Michigan and Minnesota control areas through 12 lines. These high voltage interconnection lines, usually referred to as interties, allow 4,000 MW of electrical energy to be exported out of and imported into Ontario, and each intertie is considered as a price zone.

Ontario has a total installed generation capacity of 30,548 MW comprising 4 nuclear power stations (total 10,836 MW), 59 hydroelectric stations (total 7,615 MW), 5 coal-fired stations (total 7,546 MW), 24 oil/natural gas stations (total 4,485 MW) and 66 MW of miscellaneous capacity. Ontario demand is supplied through the local generation capacity available and imports; and the highest summer peak was recorded on August 13, 2002 at 25,414 MW.

The IMO has the responsibility of authorizing market participation; receiving the supply and demand bids; determining the energy and operating reserve prices and the quantity of power to be traded; dispatching the system; monitoring the system operation; maintaining the reliability standards; publishing the forecasts and information to markets participants and the public; producing statements and invoices; and performing financial settlement transactions under the Ontario market rules.

The Ontario electricity market consists of the real-time physical energy and operating reserves markets and a financial transmission rights (FTR) market, while a financial day-ahead forward market is under development. Furthermore, market participants may choose to buy or sell energy through physical bilateral contracts. A market participant having bilateral contracts with other parties may either inform the IMO of the contract data for financial settlement or they may do the settlements on their own. Physical bilateral contracts have a small share in the whole electricity trading in Ontario and are not part of the actual scheduling and dispatch of energy, while physical bilateral contracts are a part of the dispatching process in most of other markets (*e.g.* New York).

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Ancillary services are being procured by the IMO, to ensure the reliability of the system, either through physical markets (*e.g.* operating reserves) or through contracts with eligible service providers (*e.g.* reactive support). Three separate operating reserves classes, determined by the North American Electric Reliability Council (NERC), and the Northeast Power Coordinating Council (NPCC), are used in the Ontario market, namely, 10 minute synchronized reserve (also called 10 minute spinning or 10S), 10 minute non-synchronized reserve (also called 10 minute non-spinning or 10N), and 30 minute non-synchronized reserve (30R). Only dispatchable generators are authorized to offer the 10S, while for the other two types of reserves, dispatchable generators, dispatchable loads and boundary entities (power importers/exporters) can participate. The IMO paid $76 Million to operating reserves providers for the period May 2002-October 2003.

Market participants may either have a physical connection to the grid, such as large loads, generators and distributors, or be without a physical connection, such as power traders or boundary entities who import/export power to/from Ontario. Generators and loads are grouped into dispatchable, those who receive dispatch commands every five minutes to reach a specified level of generation or consumption, and non-dispatchable, those who accept to produce or consume power at real-time and be paid or charged at the hourly price prevailing at that time. Most of the loads in Ontario are non-dispatchable, and most of generation facilities are dispatchable.

The Ontario electricity market has 282 market participants (Oct. 2004) which mainly consists of generation companies, large industrial loads, distribution companies and power traders. Wholesale prices apply to most of the electricity consumers having more than 25,000 kWh/year of electricity consumption, while at the retail level, prices are capped and fixed by the Ontario government at 4.7 cents for the first 750 kWh consumed each month and 5.5 cents for monthly consumption beyond 750 kWh, as of April 2004. Specially designated large-volume consumers such as schools, universities, hospitals, farms and specified charities also pay the same fixed rates; however this will end on 2005.

The market clearing price (MCP) is determined every five minutes and the hourly average of five minute MCPs is defined as the Hourly Ontario Energy Price (HOEP). For financial settlements, MCP applies to dispatchable participants and HOEP is the base of settlement invoices for non-dispatchable loads and generators. Imports and imports are settled based on the pre-dispatch and real-time prices. Energy and each class of operating reserves are traded at a uniform price for the entire province, whereas most of the existent neighboring markets, such as New York and PJM electricity markets, use locational marginal prices (LMPs) to calculate market price for each load or generation zone.

The rest of this paper is organized as follows. Section II reviews the market price fluctuations for energy and operating reserves for the first two years of market operation. The operational aspects of the physical energy and operating reserves market, including market time-line, energy and operating reserves MCP, hour ahead dispatchable load program, the spare generation on-line program, contracted ancillary services, interjurisdictional energy trading and market uplift are described in Section III. The FTR market is explained briefly in Section IV. Some concluding remarks are given in Section V.

II. Two years of Ontario electricity market operation

Ontario market prices has been volatile since its inception. Although price volatility decreased during the second year in comparison with the first year, market prices are still unusually high at some hours, as shown in Fig. 1. This figure also illustrates the Ontario market demand and displays how market demand was also unstable during the first months of market operation.

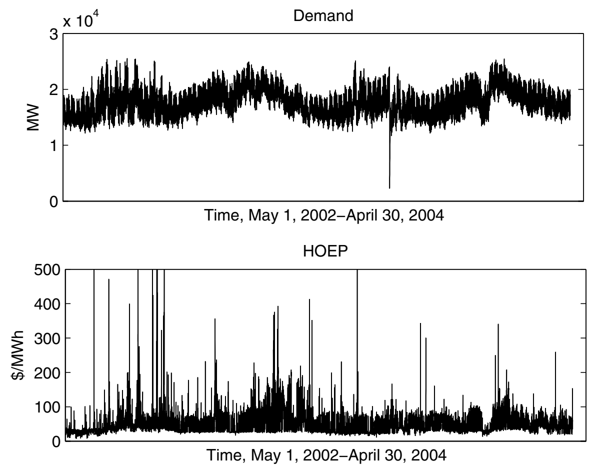

Fig. 1. The Ontario market demand and HOEP, May 1, 2002-April 30, 2004.

The monthly average wholesale electricity prices are shown in Fig. 2. This figure shows a decreasing trend in price behavior. Furthermore, the yearly average wholesale price of electricity from May 2003 to April 2004 was $50.7/MWh, about 30% lower than the yearly average price for May 2002-April 2003 period which was $72.34/MWh [3]. However, it cannot be generally said at this point that electricity prices have progressively declined during the first two years of the market operation.

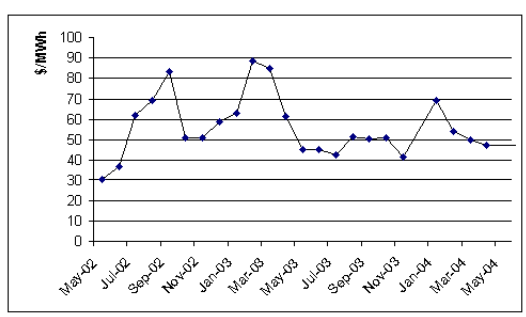

Fig. 2. Monthly average wholesale prices, May 2002-April 2004, [3].

Electricity market demand is one of the main driving factors which determines the general trend of the market price behavior, as shown in Fig. 3, which is associated with the fact that the demand in Ontario is rather inelastic. Moreover, several other factors can also potentially influence the market price fluctuations, such as sudden weather changes, unplanned generation outages, failed import/export transactions and energy price in neighboring markets.

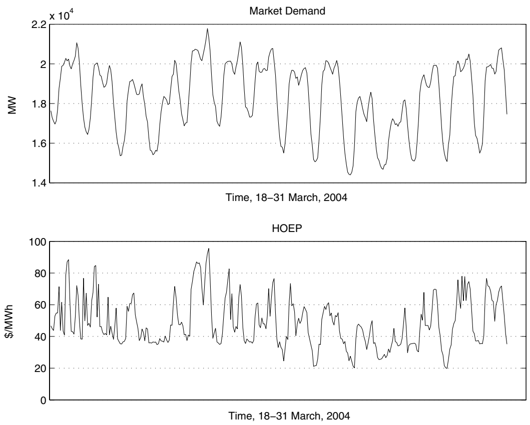

Fig. 3. The Ontario market demand and HOEP, March 18-31, 2004.

The 10S class of operating reserve has been the most expensive one, with a peak of \$65.17/MWh in early September 2002 and an average of \$6.39 /MWh for the first two years of the market operation. Yearly averages of the operating reserve MCPs for the three classes of operating reserves over the period of May 2002-April 2004 are shown in Table I.

TABLE I

YEARLY AVERAGE PRICES (\$/MWh) FOR THE THREE CLASSES OF THE OPERATING RESERVES, MAY 2002-APRIL 2004.

Period	10S	10N	30N
May 2002-April 2003	6.8	3.75	3.1
May 2003-April 2004	5.95	4.58	3.87

III. PHYSICAL MARKET OPERATION

The dispatch scheduling and pricing software (DSPS) determines the schedules, prices for energy and operating reserves and dispatch decisions in Ontario, as well as for the 12 intertie zones. The objective of the DSPS optimization algorithm is to maximize the economic gain from trade, which is defined as the difference between the value of the electricity produced and the cost of producing that electricity.

The DSPS consists of several system and data analysis blocks, with a dc-based security-constrained optimal power flow block as its heart, and is described in more detail in [4], [5]. Several penalty functions and violation variables are also defined to allow the DSPS to automatically violate system constraints when there would not be any solution otherwise. A separate ac power flow is run to calculate the transmission loss, which is incorporated in the power balance requirements constraint using appropriate penalty factors.

The DSPS solves the economic gain maximization problem for energy and operating reserves for a dispatch hour "simultaneously", using the following objective function:

$$\begin{aligned} \text{Economic Gain} &= \sum_j DB_j \times DBP_j \times PFD_j \\ &- \sum_i SB_i \times SBP_i \times PFS_i - \sum_{k,c} ORB_{k,c} \times ORBP_{k,c} \\ &- \text{Violation Variables} - \text{Tie Breaking} \qquad (1) \end{aligned}$$

where DB and SB are demand bid and supply bid blocks respectively; DBP and SBP are the prices associated with the DB and SB; PFD and PSF are the defined loss penalty factors associated with each demand or supply bid; $ORB_{k,c}$ is a bid block for class c of operating reserves with a price $ORBP_{k,c}$; the Violation Variables are defined to represent the cost of violating respective constraints; and the Tie Breaking function deals with the bids that have the same price. The algorithm determines the best trade-off between energy and operating reserves using appropriate constraints and operational functions, which are beyond the scope of this paper.

The algorithm is run in two time-frames, the pre-dispatch and real-time (dispatch), and in two modes: unconstrained and constrained. The pre-dispatch run is used to provide the market participants with the "projected" schedules and prices for advisory purposes in advance, while the final schedules and prices for financial settlement are determined in the real-time run. In the "unconstrained" algorithm, the economic gain is optimized based on supply and demand bids, but most of the physical power system constraints are neglected except for some of the operational constraints, such as intertie energy trading limits and ramping constraints. In the "constrained" algorithm, however, certain system security limits and a representation of the Ontario transmission network model are also included.

A. Market Time-line

Hourly supply and demand bids as well as operating reserves bids for a dispatch day are submitted to the IMO between 6:00 and 11:00 on the pre-dispatch day. The bids may be revised up until two hours prior to the dispatch hour without any restriction. Furthermore, the "quantity" of bids can be revised up until 10 minutes before dispatch hour (for imports and exports 60 minutes prior the dispatch hour) with the permission of the IMO.

From 11:00 of the pre-dispatch day, the pre-dispatch version of DSPS is run hourly for the remaining hours of the pre-dispatch day and for 24 hours of the dispatch day. It uses the unconstrained algorithm to determine the market clearing prices for energy and operating reserves and the unconstrained schedules. The resulting schedules are then analyzed for any network constraint violations iteratively until all violations are resolved. If violations exist, the corresponding constraint equations are incorporated in the constrained algorithm. In the constrained algorithm, the economic gain is optimized and new schedules are generated. The new pre-dispatch schedules are then sent to each market participant.

The pre-dispatch run covers a range of 37 hours (at 11:00 on the pre-dispatch day) to 14 hours (at 10:00 on the dispatch day), and provides a first glance on future schedules and prices. Every hour after 11:00 on the pre-dispatch day, revised pre-dispatch schedules and prices are derived for the rest of the pre-dispatch day and/or dispatch day, until 11:00 on the dispatch day, which then becomes the pre-dispatch day for tomorrow (see Fig. 4). The results for energy prices and total market demand at each pre-dispatch run are publicly available by the end of the hour or during the next hour.

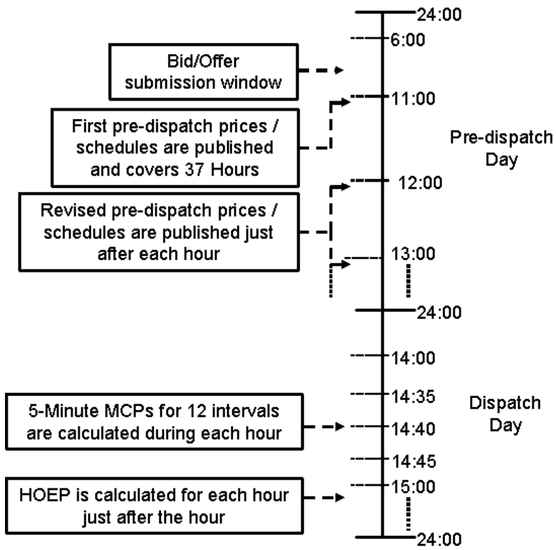

Fig. 4. Market time line, pre-dispatch and dispatch days.

In real-time, the dispatch version of DSPS is run every five minutes to derive prices, schedules and dispatch instructions for each interval. Both the constrained and unconstrained algorithms start at the beginning of each interval. The constrained algorithm provides real-time schedules and dispatch instructions for the next interval[2], while the unconstrained algorithm determines the market schedule and prices for the interval that just passed, based on real-time supply and consumption (see Fig. 5). Schedules and prices obtained in real-time are the basis of all financial settlements.

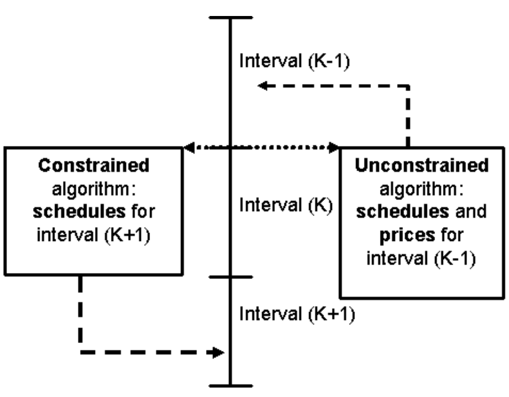

Fig. 5. Unconstrained and constrained algorithm in real time.

[2]For the next interval plus 4 other intervals during the hour, after implementation of the Multi-Interval Optimization project in June 2004.

B. Ontario MCP for Energy and Operating Reserves

1) Pre-dispatch: The IMO forecasts the aggregate non-dispatchable Ontario demand and estimates the amount of generation capacity available from non-dispatchable generators for the dispatch hour. Non-dispatchable loads and generators are "price-taker" market participants who consume/generate the amount of energy they need/can regardless the market price. Therefore, the predicted amount of price-taker demand is considered as a energy buying bid with the price of maximum market clearing price (MMCP) and the aggregated predicted generation capacity available as an energy sell bid with the price of -MMCP.

All price-sorted energy buying bids for inside Ontario and exports are stacked in decreasing order and all price-sorted supply bids from generators inside Ontario and import bids are stacked in increasing order. Operating reserve offers from inside Ontario and boundary entities for the three classes are also stacked in increasing order, and the operating reserves requirements are specified by the IMO for each hour. The point of intersection between energy supply and demand bids stacks, while honoring all applicable constraints, determines the uniform Ontario energy MCP (see Fig. 6 for a simple illustration). The projected price of each class of operating reserves are also calculated, while the algorithm determines the best trade-off between energy and operating reserves.

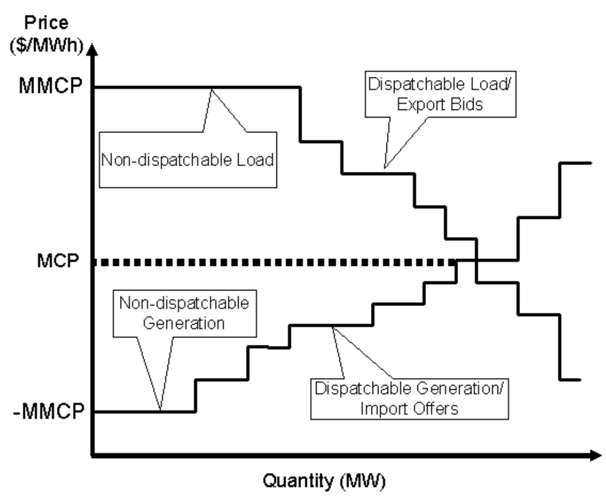

Fig. 6. Determining energy MCP in pre-dispatch.

2) Real-time: In real-time, the dispatch version of the unconstrained algorithm is run to determine the Ontario MCP for the past 5-minute interval. This version is basically the same as pre-dispatch unconstrained algorithm except the differences in inputs and time horizon. For example, the import/export quantities for energy and operating reserves cleared in the one-hour ahead pre-dispatch run are assumed constant and are treated as supply/demand bids with the prices of -MMCP/MMCP rspectively. Furthermore, actual primary demand, as measured by the operational meters, as well as the system losses for the previous interval are used as an energy bid with the price of MMCP (see Fig. 7).

Displacement of import and export bids along with other factors, such as unplanned generation or transmission line

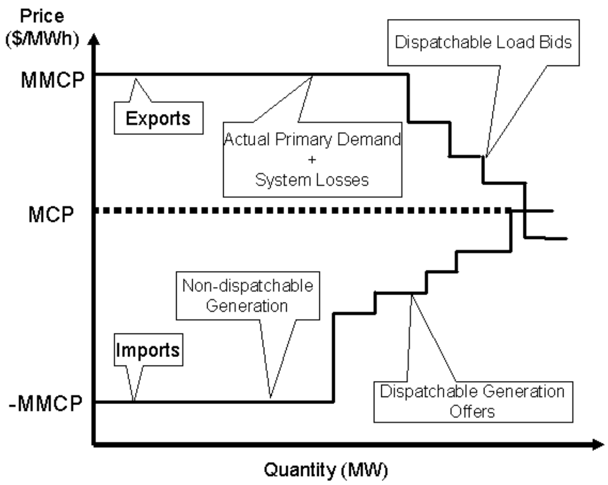

Fig. 7. Determining energy MCP in real-time.

outages and sudden change in weather condition causes the real-time prices to deviate from the pre-dispatch prices. This deviation is sometimes high and could affect price-sensitive loads and interjurisdictional traders. Figure 8 depicts this deviation for Jan. 12 to March 31, 2004.

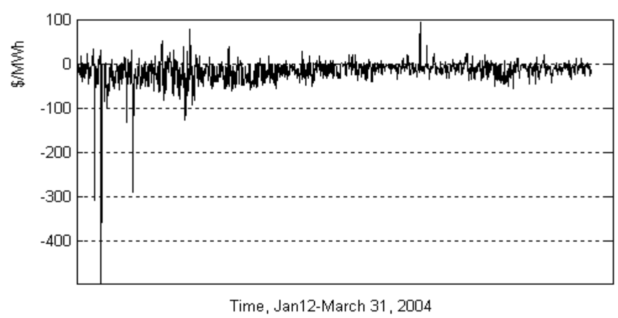

Fig. 8. HOEP and pre-dispatch hourly price difference, Jan. 12, March 31, 2004.

C. Hour Ahead Dispatchable Load (HADL) Program

Most of the load in Ontario is non-dispatchable and therefore they do not respond to high market prices in real-time. To make non-dispatchable loads more price-responsive and to allow the IMO to include future load reductions in the scheduling process, as well as to encourage load curtailment during high-peak operating hours, the IMO launched the HADL program in July 2003.

In most cases, non-dispatchable loads have a limit for energy costs in their production process and if electricity price exceeds a specific cap, the load would agree to shut down its production. Non-dispatchable loads who wish to participate in HADL program offer their price cap to the IMO and the quantity of demand that should be cut. If the three-hour ahead pre-dispatch HOEP is higher than the load offer, the IMO will send dispatching instructions to the load to reduce its demand by the amount of its HADL offer. If the real-time HOEP turns out to be equal or more than the loads price cap, there will not be any payment. However, if the real-time HOEP is lower than the loads price cap, the load would have been better off to operate than shutting down its processes. In this situation, there would be a lost operating profit and the *hour ahead dispatchable load offer guarantee* (HADLOG) is payable to the load to bring it to the same operating profit as it would have been gained when operating. The HADLOG is calculated as follows:

$$\text{HADLOG} = \max\{0, \text{(PC-HOEP)} \times \text{Q}\} \qquad (2)$$

where Q is the quantity of demand that is offered to be cut and PC is the load price cap. For example, Load A bids to cut 100 MW of its demand if the three-hour ahead pre-dispatch energy price is more than \$45/MWh. If in the three-hour ahead pre-dispatch run, the energy price for the dispatch hour clears at \$50/MWh; therefore, dispatch commands are sent to Load A by the IMO to cut its load by 100 MW. If in real-time, the HOEP clears at \$40/MWh, a HADLOG payment of \$500 will be credited to Load A by the IMO in this case, as per equation 2.

D. The Spare Generation On-line Program (SGOL)

Fossil-based generation units usually require a long and expensive start-up process and their minimum up-time and minimum generation limit must be respected. During the off-peak periods, these units are exposed to the risk of not being scheduled, while they incur the start-up costs. Even if they are scheduled, they might be dispatched off before their minimum up-time period is over, which can lead to some technical problems. Hence, such generation capacities may decide not to put bids for the risky off-peak periods. On the other hand, if during the off-peak period, a large decrease in supply or increase in demand occurs, the IMO has to buy power from more expensive units or import expensive power. To increase the reliability of the IMO-controlled grid and to reduce price volatility, the IMO launched the SGOL program in August 2003, which offers eligible generators a guarantee of start-up and minimum costs. Eligible generators submit their minimum loading point, minimum up-time and combined guaranteed costs to the IMO. If an eligible generator registered in the SGOL submits a supply bid and is scheduled to run, but the revenue earning over its minimum up-time is lower than its combined guaranteed costs, it will receive compensation from the IMO to cover its minimum combined guaranteed costs. The IMO recovers the SGOL payments through monthly uplift charges to loads.

E. Contracted Ancillary Services

The IMO procures five different ancillary services through contracts with various service providers in addition to the three classes of operating reserves discussed earlier; these are:

- Regulation/Automatic Generation Control Service
- Reactive Support and Voltage Control
- Black Start Service
- Emergency Demand Response Load
- Reliability Must-Run Resources

The IMO contracts with eligible generators to provide regulation service for the period beginning May 1 of each year to April 30 of the following year. Minimum requirements are calculated by the IMO and control signals are sent to the generators under contract to raise or lower their output as required.

Reactive support and voltage control is considered to ensure that the IMO is able to maintain the voltage level of the its grid within acceptable limits. This service can be provided by (but not limited to) capacitors, Static VAR Compensators (SVC), reactors, synchronous generation facilities, and synchronous condensers.

Black start service is contracted to meet the requirements of restoring Ontario's power system after a major contingency. Generators that wish to provide this service must meet specific requirements determined by the IMO. Emergency demand response loads are referred to the loads that can be called upon by the IMO to cut their demand on short notice in order to maintain the reliability of the IMO-controlled grid; this service is envisaged for an emergency operating state. The IMO paid about \$38 million for the 2002-2003 period, and about \$55 million for the 2003-2004 period for the above four ancillary services through yearly contracts.

Whenever sufficient resources to provide physical services in a reliable way are not available, the IMO may need to call registered facilities, excluding non-dispatchable loads, to maintain the reliability of the grid through reliability must-run resources contracts. For the past two years, there has been no contracts for providing this service.

F. Interjurisdictional Energy Trading

Although most of the Ontario market regulations are the same for import/export bids and supply/demand bids from inside Ontario, the scheduling and pricing procedure is different for import/export bids. When dealing with import/export bids, the net interchange schedule limit (NISL) is also considered by the DSPS, in addition to the intertie physical capacity limits. Furthermore, as previously described in Section III-B.1, imports/exports are scheduled in the one-hour ahead pre-dispatch run; whereas, they are financially settled based on real-time prices.

1) NISL: Sharp changes in import/export schedules during subsequent hours can expose the IMO-controlled grid to reliability risks. To prevent this possibility, the net interchange schedule (NIS) is defined as the total imports minus total exports, and the net change in NIS is limited to 700 MW for two subsequent hours.

The dispatch algorithm automatically respects this limit when scheduling imports and exports by reducing exports or increasing imports. Due to the NISL, there might be some uneconomical supply/demand bids scheduled (or economical supply/demand bids not being scheduled) which should not have been scheduled (should have been scheduled) in the absence of NISL. If there is insufficient import bids and export bids for the algorithm to come up with a feasible solution, the IMO asks importers and exporters to change their import/export bids.

2) Intertie Congestion Price (ICP): In the one-hour ahead pre-dispatch run, the Ontario MCP and zonal MCPs for the 12 intertie zones are determined as described in Section III-F.3 bellow. The ICP is calculated as the difference between the one-hour ahead pre-dispatch zonal MCP and the pre-dispatch Ontario MCP, as follows:

$$\text{ICP} = \text{MCP}_{PD}^{Zone} - \text{MCP}_{PD}^{ON} \tag{3}$$

where PD indicates pre-dispatch, MCP^{Zone} is the zonal MCP and MCP^{ON} is the Ontario MCP.

The ICP is used in real-time to determine the real-time energy price for intertie transactions, as follows:

$$\text{MCP}_{RT}^{Zone} = \text{ICP} + \text{MCP}_{RT}^{ON} \tag{4}$$

where RT indicates real-time. A similar process is used to determine zonal MCP for 10N and 30N classes of operating reserve.

In fact, the absolute value of the ICP amounts to the projected cost of congestion for the Ontario market. Therefore, when the intertie is export congested (ICP>0), the exporters have to pay a price higher than the Ontario MCP for the energy purchased from the Ontario market. On the other hand, when the intertie is import congested (ICP<0), the importers receive a price lower than the Ontario MCP for the energy sold to the Ontario market. This price difference is referred to as the congestion rent (CR), which can be written as:

$$\text{CR=ICP} \times \text{Q}_c \tag{5}$$

where Q_c is the quantity of power that actually crosses the intertie.

The ICPs for energy and operating reserves for the 12 interties are zero most of the time; Table II shows the maximum and minimum energy ICPs for the period of January 12 to October 31, 2004 for the Manitoba, Michigan, Minnesota and New York interties.

TABLE II
ENERGY ICPS (\$/MWh): JANUARY 12 TO OCTOBER 31, 2004.

	Manitoba	Michigan	Minnesota	New York
Max	4.54	177.62	55.8	167.33
Min	-56.83	-825	-91.99	-5.497

3) Zonal MCP for the Interties: The DSPS passes the import/export bids to the Ontario bids stacks while honoring both physical capacity limits and NISL. If all economic bids from an intertie can be used in the Ontario market without violating both limits, or the economic bids cannot be used due to NISL, there is no congestion in the intertie and the zonal MCP is equal to the Ontario MCP, otherwise the intertie is assumed congested.

If only physical capacity limits are violated, the marginal price of energy in the intertie zone is considered as zonal MCP. For example, assume the New York intertie physical limit for import is 1000 MW and there are 1500 MW of import bids, all with prices under \$300/MWh, and the NISL is met. Up to 1000 MW of bid blocks are being passed to the Ontario supply bids stack, and the Ontario MCP clears at \$300/MWh (see Fig. 9). In this case, since the next MWh not scheduled is valued

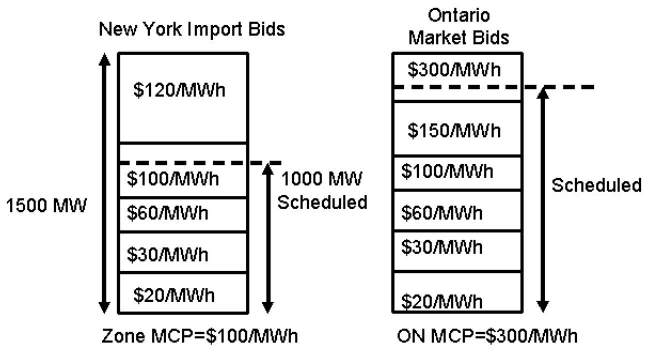

Fig. 9. Determining zonal MCP

at $100, the zonal MCP is $100. If the intertie limit were 1001 MW, one more MWh would be supplied from the $100 import bid, instead of using the $300 Ontario bid; therefore, the congestion has cost the Ontario market $200/ MWh.

When the NISL is violated and the intertie is congested, relaxing the physical limit for an intertie leads to decreasing the physical limit for another intertie. In this situation, the global cost of congestion from both the increase and decrease of the interties capacity is calculated for determination of the intertie ICP. For example, assume relaxing the congested intertie with one MW will save the market $300 and at the same time, decreasing another intertie limit by one MW, to meet NISL, costs the market $200. Therefore the total cost of the intertie congestion, or the ICP, is $100.

4) Intertie Offer Guarantee (IOG): To ensure adequate supply and encourage power imports to Ontario, the IOG mechanism is designed to pay the power importers at least the average price of their bid and prevent importers from incurring negative operating profit. One of the main assumptions in the Ontario market design is that supply and demand bids are based on marginal costs and marginal benefits. It means that if the MCP for a given interval is equal to a bid price, the operating profit of the respective market participant is zero and it would not be better off either scheduled or not.[3] Therefore, if under any circumstances the actual operating profit for a power importer is negative, the IOG payments return it to zero. Of course, this payment does not hedge the risk of having a lower operating profit in real-time than what was expected in pre-dispatch.

For example, assume the pre-dispatch Ontario MCP is equal to $25/MWh and the ICP is zero. The expected operating profit for a 100 MW power import at the bid price of $20/MWh for a given hour would be:

$$\text{OP=100MWh} \times (\text{\$25/MWh-\$20/MWh}) = \$500 \qquad (6)$$

where OP is the operating profit.If in real-time the Ontario MCP turns out to be equal to $15/MWh, the actual operating profit would be:

$$\text{OP=100MWh} \times (\text{\$15/MWh-\$20/MWh}) = -\$500 \qquad (7)$$

[3]This assumption is not necessarily true in an entirely competitive market in which the market participants design their bidding strategies to maximize profit.

In this case an IOG payment equal to $500 will be made by the IMO to the power importer to return it to zero operating profit.

G. Congestion Management Settlement Credit (CMSC)

In the Ontario electricity market, real-time unconstrained prices and schedules are the basis of the financial settlements. If power system constraints force a market participant to generate/consume more/less than what it was supposed to do in the unconstrained schedule, the market participant is treated as constrained on/off, and the CMSC is used to provide the market participant with the same operating profit as it would gain in the absence of power system constraints.

For example, assume generator A bids to generate 100 MW of energy at a price of $20/MWh for a given hour. Also assume the Ontario MCP is equal to $30/MWh, and generator A is scheduled by the unconstrained algorithm for its entire bid for all intervals of the hour. In this case the "operating profit" of generator A would be:

$$\text{OP} = 100\text{MWh} \times (\text{\$30/MWh} - \text{\$20/MWh}) = \$1000 \qquad (8)$$

But if in the constrained algorithm run the generator is scheduled to inject only 50 MW at all intervals, the actual operating profit would be:

$$\text{OP} = 50\text{MWh} \times (\text{\$30/MWh} - \text{\$20/MWh}) = \$500 \qquad (9)$$

and the lost profit is $500. In such a case, a $500 CMSC payment will be given to generator A to bring it to the same level of operating profit as obtained from the unconstrained schedule.

When a market participant has gained some profit or prevented loss in real time as the result of being constraint on/off, it has to pay the extra operating profit to the IMO as CMSC. For example, an exporter is scheduled to export 100 MW during the next hour in the pre-dispatch unconstrained run, but network constraints force the exporter not to export at all; if, its bid price is $40/MWh, the ICP is equal to zero and the real-time MCP is $60/MWh for the all intervals of the hour, it would lost $2000 if it were not constrained off. Therefore, the exporter has to pay $2000 to the IMO as CMSC.

H. Market Uplift

The Ontario electricity market has been designed such that the consumers of electricity pay for all costs associated with operating the market in a reliable way. The operating costs are recovered through market uplifts, which are categorized under hourly and monthly uplifts and are collected from the loads based on their share of the total demand. Congestion management costs, operating reserve costs, IOG payments and the costs associated with system losses are measured hourly, while other costs including contracted ancillary services, IMO administration fee and miscellaneous charges are calculated monthly. Some costs are regulated by the Ontario energy authorities and have a fixed price per MWh; for example, the IMO administration fee is $0.959/MWh. Market uplifts appear in the customer's monthly invoice under separate charge types.

IV. Financial Market Operation

Transmission rights and day-ahead forward markets are the two financial markets envisaged in the IMO administered electricity market. To date, FTR is the only financial market activated and is operated on a long-term and short-term auction basis. The FTR product is defined by the FTR time structure and the path (injection zone- withdrawal zone). For instance, a 100 MW FTR is sold for hours from 9:00 to 16:00 for all days of November for transmitting power from Ontario to New York. In the Ontario market, holding a FTR does not guarantee the right to transmit energy on an intertie, while in some other markets a FTR is a firm right for energy transmission. Furthermore, FTR does not protect the holder from all risk associated with the business. The FTR market is funded through the money raised in the FTR auctions and the collected congestion rents.

There are two types of FTR, short-term (valid for a month) and long-term (valid for a year). Available short-term and long-term FTRs are sold in separate auctions and the auction MCP is applicable to all winning FTR bids. Market participants who wish to participate in the FTR auction must follow the FTR market regulations to put their bids one business day prior to the FTR auction. The MCP for a particular FTR is the lowest bidding price of all winning bids for that particular FTR. Winning bids will be charged by the amount of FTR awarded multiplied by the FTR MCP through the financial market settlement. Reselling FTRs is not allowed yet.

In real-time physical market, FTR holders are paid by transmission rights settlement credits (TRSC). The TRSC is calculated as follows:

$$\text{TRSC=max}\left\{0,\text{ICP}\right\}\times\text{FTR} \tag{10}$$

Obviously, the TRSC is greater than zero only if Ontario is export congested.

The FTR provides a limited mechanism for mitigating the risks associated with exporting power out of Ontario. For example, assume a power exporter has bought a Q_i^{FTR} MW FTR through FTR auction at the price of P_i^{FTR}\$/MW for the path $i \in 1,\ldots 12$, for a specific hour. In real-time operation, it actually exports Q_i^{Ex} MW power through the path i during the hour. For that hour, the exporter would receive a total TRSC payment of:

$$\text{TRSC} = \sum_i \text{Q}_i^{FTR}\times\text{max}\left\{0,\text{ICP}_i\right\} \tag{11}$$

where ICP_i is the ICP associated with the intertie i. Moreover, assume the Ontario MCP remains constant during the hour; in this case, the exporter has to pay the total price of the exported power (TPEP) as:

$$\text{TPEP} = \sum_i \left(\text{MCP}_{RT}^{ON}+\text{ICP}_i\right)\times\text{Q}_i^{Ex} \tag{12}$$

It also should be noted that the exporter has already paid the cost of buying FTR in the FTR auction (FTR_{cost}), which is:

$$\text{FTR}_{cost} = \sum_i \text{Q}_i^{FTR}\times\text{P}_i^{FTR} \tag{13}$$

The total revenue (TR) of the exporter can be written as:

$$\text{TR} = \text{SR}+\text{TRSC}-\text{TPEP}-\text{FTR}_{cost} \tag{14}$$

where SR is the exporter's revenue from selling the exported power to a third party. This total revenue is not necessarily always grater than zero. Specifically, when the MCP_{RT}^{ON} turns out to be grater than the exporter's bid price, there is no mechanism to compensate for the associated revenue losses.

V. Conclusion

In this paper, the operational aspects of the Ontario electricity market have been discussed. Electricity market participants who have a dynamic interaction with the market need to predict the future (short-term and long-term) market price behavior in order to be able to design their bidding strategies; this fact, requires a profound understanding of the rules, regulations and operational features of the market. This paper provides the reader with an overall view of the most important procedures and practices that are in place to make the electricity trade in Ontario reliable and competitive.

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