The Operation of Ontario's Competitive Electricity Market: Overview, Experiences, and Lessons

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***Abstract*— Competitive electricity markets have been operating in various countries for more than a decade, with every single electricity market presenting its own unique characteristics and features. This paper provides a comprehensive overview of the operational aspects of the Ontario electricity market, its unique features, and its outcomes for the first four years of operation. Several programs implemented in the Ontario market to improve efficiency, transparency, and competitiveness are analyzed, and the effectiveness of these programs are discussed.**

***Index Terms*— Deregulation, Ontario electricity market, Market outcome analysis.**

ACRONYMS

ADE Availability Deceleration Envelope
CAOR Control Action Operating Reserve
CMSC Congestion Management Settlement Credit
DACP Day-Ahead Commitment Process
DAIOG Day-Ahead Intertie Offer Guarantee
DAGCG Day-Ahead Generation Cost Guarantee
DSPS Dispatch Scheduling and Pricing Software
EDRP Emergency Demand Response Program
ELRP Emergency Load Reduction Program
HADL Hour-Ahead Dispatchable Load
HOEP Hourly Ontario Energy Price
ICP Intertie Congestion Price
IESO Independent Electricity System Operator
IOG Intertie Offer Guarantee
MCP Market Clearing Price
MIO Multi-Interval Optimization
MMCP Maximum Market Clearing Price
MPMA Market Power Mitigation Agreement
NIS Net Interchange Schedule
NISL Net Interchange Schedule Limit
OEB Ontario Energy Board
OP Operating Profit
OPG Ontario Power Generation Inc.
PDP Pre-dispatch Price
SGOL Spare Generation On-Line
10N 10 Minute Non-Synchronized Operating Reserve
30R 30 Minute Non-Synchronized Operating Reserve
10S 10 Minute Synchronized Operating Reserve

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I. INTRODUCTION

WHILE deregulation of the electricity sector has been accepted and adopted by many countries and utilities around the globe, every market has its own unique characteristics and specific features. The Ontario electricity market is unique because of various reasons; for example, even after deregulation, about 75% of generation capacity is held by one single entity, and there exist various kinds of price and revenue caps for wholesale market participants as well as for retail customers. Moreover, Ontario is a single-settlement real-time market, unlike the other four adjacent North American electricity markets- the New York, New England, Midwest, and PJM markets- which are two-settlement ones. Finally, the Ontario power network is directly connected to the New York and Midwest electricity markets and indirectly connected to the New England and PJM markets. It is also connected to the regulated utilities in Quebec and Manitoba, both having significant energy transactions with other utilities in the United States. In view of this, the operation of the Ontario electricity market can significantly impact the North American North-East and Mid-West power interconnections, and hence its structure, operation and outcomes need close examination.

In the Ontario electricity sector prior to deregulation, Ontario Hydro along with some small municipal utilities generated, transmitted, and distributed electricity to their customers across the province. In that era, electricity prices were regulated by the provincial government. The Ontario Electricity Act of 1998 reorganized Ontario Hydro into five companies [1], and on April 1, 1999, these new companies were created, namely, the Independent Market Operator (IMO), Hydro One Inc., Ontario Power Generation Inc. (OPG), the Electrical Safety Authority (ESA), and the Ontario Electricity Financial Corporation (OEFC). The ESA is responsible for the electric industry standards, and the OEFC manages financial services of the erstwhile Ontario Hydro and its successors.

Since the initial restructuring of the Ontario electricity market in 1999, many changes have been implemented. Thus, in this paper, a general overview of the current competitive electricity market in Ontario is presented, and the operational aspects of this market are reviewed. More specifically, the procedures of clearing the energy and operating reserves markets, pre-dispatch and real-time dispatch of the supply and demand sides, inter-jurisdictional energy trading, and procurement of ancillary services are discussed in detail. In addition, the main market outcomes, namely, pre-dispatch energy prices, real-time energy prices, and operating reserve prices are briefly studied for the first four years of market operation, i.e. from May 1, 2002 to April 30, 2006. The programs introduced by the Ontario Independent Electricity System Operator (IESO) to enhance market operation are also analyzed and their effectiveness is discussed.

The rest of this paper is organized as follows: The operational aspects of the physical markets for energy and operating reserves are described in Section II. The programs implemented to enhance the operation of Ontario's market are presented in Section III. In Section IV, the Ontario market outcomes over the first four operating years are discussed, and concluding remarks are presented in Section V.

II. The Physical Market for Energy and Operating Reserves

A. An Overview

The Ontario wholesale competitive electricity market opened on May 1, 2002. This market consists of a real-time physical market for energy and operating reserves, and a Financial Transmission Rights (FTR) market [2]. The Electricity Act of 2004 [3], renamed the IMO as the IESO, which is a non-profit company regulated by the Ontario Energy Board (OEB) and its core responsibility is to operate the Ontario wholesale electricity market.

Hydro One Inc., wholly owned by the Government of Ontario, is the major transmission company that owns and operates Ontario's transmission network. The transmission system has remained regulated and the OEB determines the transmission and distribution tariffs. The distribution system is also regulated by the OEB, with 91 local distribution companies delivering electricity to the retail customers. The Ontario's high voltage transmission system has interconnections with Manitoba, Quebec, New York, Michigan and Minnesota through 12 lines with 4000 MW capacity.

OPG owns about 75% of the 30,662 MW installed generation capacity in Ontario. The province's total generation capacity consists of: 11,397 MW of nuclear power plants (37.2%); 7,855 MW of hydro and other renewable resources (25.6%); 6,434 MW of coal-fired generation facilities (21%); and 4,976 MW of oil/gas-fired power stations (16.2%). Energy imports from the neighboring areas are also an important part of Ontario's supply portfolio. The highest Ontario summer peak demand was recorded in August 2006 at 27,005 MW, an approximately 3% increase with respect to the previous peak demand recorded in July 2005 at 26,160 MW.

The supply and demand side entities within the province having direct connection to the transmission network must participate in the Ontario electricity market [4]. This group of entities consists of generation companies, large industrial loads, and local distribution companies. Other parties with physical assets which are connected to the distribution network, referred to as "embedded" facilities, can choose to either participate in the market or buy/sell power through contracts with power retailers. There are, however, other market participants without a physical connection, such as power traders, or boundary entities who import/export power to/from Ontario, which may participate in the physical or financial markets.

Energy market participants in Ontario can also choose to buy or sell energy through bilateral contracts. However, bilateral contracts not necessarily need to be reported to the IESO, and are not considered in the scheduling and dispatching process. Bilateral contracts have a small share in the whole electricity trading in Ontario, compared to other electricity markets. This may be attributed to the unique structure of the market and lack of diversity in the supply side in Ontario.

Market participants are grouped into dispatchable and non-dispatchable. Dispatchable market participants actively bid into the market and receive dispatch commands every five minutes to reach a specified level of generation or consumption. In contrast, non-dispatchable market participants are "price-takers" 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 the generation facilities are dispatchable. Generators with the capability to follow IESO's dispatch instructions must register as dispatchable generators, while the rest are allowed to register as non-dispatchable. Non-dispatchable generators are either small (less than 10 MW) self-scheduling units, such as run-off-the-river hydro plants, or intermittent generators such as wind farms. On the demand side, only the loads with a capacity of more than 1 MW and having the capability to follow IESO's dispatch instructions are allowed to register as dispatchable loads.

A uniform, province-wide, Market Clearing Price (MCP) is determined for Ontario every five minutes. The hourly average of these five-minute MCPs is defined as the Hourly Ontario Energy Price (HOEP). For financial settlements, the MCP applies to dispatchable market participants, whereas the HOEP is applicable to non-dispatchable participants. Zonal MCPs are also calculated for each of the 12 intertie zones. The pre-dispatch and real-time Ontario MCPs and real-time zonal MCPs are the basis of settling the imports and exports.

The Ontario electricity market has 289 market participants (May 2006). Wholesale prices apply to most of the electricity consumers having more than 250 MWh/year of electricity consumption, whereas, prices are capped at the retail level. The capped prices are determined based on the Regulated Price Plan (RPP) which was initiated by the Electricity Act of 2004. Residential customers pay 5.8 cents for the first 600 kWh per month and 6.7 cents for the consumption over this threshold, as of May 2006. Designated large-volume consumers such as schools, universities, hospitals, farms and specified charities also pay the RPP rates.

The physical market is jointly optimized for energy and operating reserves. Three separate operating reserve classes are used in the Ontario market, namely, 10 Minute Synchronized Operating Reserve (10S), 10 Minute Non-Synchronized Operating Reserve (10N) and 30 Minute Non-Synchronized Operating Reserve (30R). Only dispatchable generators are authorized to offer the 10S reserve, while dispatchable generators and loads, and boundary entities can participate in the market for 10N and 30R reserves.

B. Optimizing the Physical Market

The physical market for energy and operating reserves is optimized to maximize the market's "Economic Gain," which is conceptually the same as social welfare. The market optimization program, referred to as Dispatch Scheduling and Pricing Software (DSPS), consists of several system and data analysis blocks based on an "incremental" dc-power-flow security analysis [5], [6]. Several penalty functions and violation variables are also defined to allow the DSPS to automatically violate system constraints when a solution is not found otherwise. A separate ac power flow is run to calculate the loss factors, which are incorporated in the power balance constraints using appropriate penalty factors.

The market Economic Gain is defined as the difference between the perceived worth of the electricity produced and the cost of producing that electricity, when considering the cost of operating reserves, as follows:

$$\begin{aligned}\text{Economic Gain} &= \sum_j \rho_{D,j} \times P_{D,j} \times PF_{D,j} \\ &- \sum_i \rho_{S,i} \times P_{S,i} \times PF_{S,i} - \sum_{k,c} \rho^{OR}_{k,c} \times P^{OR}_{k,c} \\ &- C_{VIOL} \qquad (1)\end{aligned}$$

where $P_{D,j}$ and $P_{S,j}$ are demand bid and supply bid blocks respectively; $\rho_{D,j}$ and $\rho_{S,j}$ are the prices associated with the $P_{D,j}$ and $P_{S,j}$; PF_D and PF_S are the defined loss penalty factors associated with each demand or supply bid; $P^{OR}_{k,c}$ is a bid block for class c of operating reserves with a price $\rho^{OR}_{k,c}$; and C_{VIOL} represents the cost of violating respective constraints.

The DSPS is run in two time-frames, i.e. the pre-dispatch and real-time (dispatch), and in two modes, i.e. unconstrained and constrained. The pre-dispatch run is used to provide the market participants with the "projected" schedules and prices in advance for advisory purposes only, while the final schedules and prices for financial settlement are determined in the real-time run.

In the "unconstrained" algorithm, the Economic Gain is maximized based on supply and demand bids, but most of the physical power system constraints are neglected except for some operational constraints, such as intertie energy trading limits and ramping constraints. The solution of this algorithm defines the "unconstrained" schedules and the energy and operating reserve MCPs.

In the "constrained" algorithm, system security limits together with a representation of the Ontario transmission network model are considered, and it works as follows: It starts with a security analysis of the "unconstrained" operation schedules, i.e. these schedules are analyzed for any network constraint violations. If violations exist, the associated constraint equations are generated and incorporated in the Economic Gain maximization model, and the optimization problem is solved again. The iterative procedure continues until all violations are resolved; at this point, the Economic Gain is maximized one last time and final "constrained" schedules are generated. Observe that the constrained schedules may differ from the unconstrained ones, which in turn may result in lost/extra profit for some of the participants, since the MCPs are defined by the unconstrained model; this issue is discussed in more detail in Section II-E.

C. Market Time-line

Hourly supply and demand bids as well as operating reserves bids for a dispatch day must be submitted to the IESO between 6:00 and 11:00 hours 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 IESO.

1) Pre-dispatch: 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. 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. The results for energy prices and total market demand at each pre-dispatch run are publicly available at the end of the hour or during the next hour.

2) Real-time: 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 unconstrained and constrained algorithms start at the beginning of each interval. The unconstrained algorithm determines energy and operating reserves MCPs and "unconstrained" schedules for the interval that just passed based on real-time supply and consumption, and supply and demand offers/bids. The constrained algorithm provides final schedules and dispatch instructions for the next interval. The market is financially settled based on actual generation and consumption MWs, and the real-time MCPs.

It is to be noted that after June 2004, a Multi-Interval Optimization (MIO) algorithm was implemented by the IESO, thereby the constraint algorithm derives real-time schedules for an interval while also considering four other advisory intervals. The MIO project is described in more detail in Section III-E.

D. Clearing Energy and Operating Reserves Markets

In order to clear market prices for energy and operating reserves, two different versions of the unconstrained algorithm are used in pre-dispatch and real-time. The differences between the pre-dispatch and dispatch (real-time) versions are mostly on the time frame and the type of inputs used, but the core algorithms remain the same.

In pre-dispatch, the IESO forecasts the aggregate non-dispatchable Ontario demand and estimates the amount of generation capacity available from non-dispatchable generators for a dispatch hour. Recall that non-dispatchable loads and generators consume/generate the amount of energy they need/can regardless of the market price. Therefore, the predicted amount of price-taker demand is considered as an energy buying

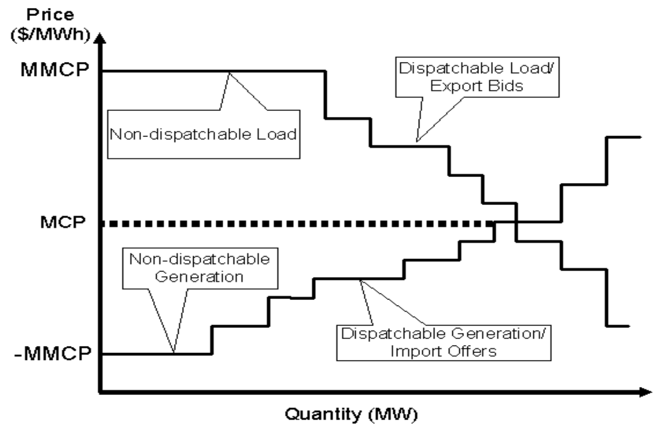

Fig. 1. Energy MCP in pre-dispatch.

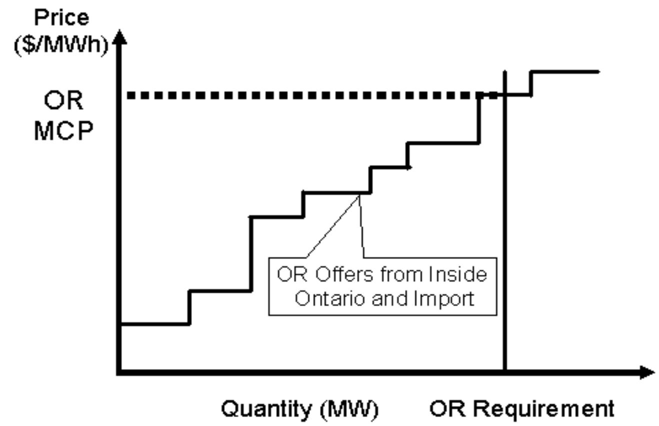

Fig. 2. Operating reserve (OR) MCP in pre-dispatch.

bid at the Maximum Market Clearing Price (MMCP), and the aggregate predicted non-dispatchable generation capacity available is considered as an energy sell at -MMCP. The MMCP is currently $2000/MWh.

In real-time however, the inputs and the time frame of the algorithm are different. For example, the import/export quantities for energy and operating reserves cleared in the one-hour ahead pre-dispatch run are assumed constant and treated as supply/demand bids with the prices of -MMCP/MMCP. Furthermore, actual metered non-dispatchable "primary" demand as well as the system losses for the previous 5-minute interval are used as energy bids with the price of MMCP. Also, the non-dispatchable generators' capacity forecast is assumed as a supply bid with the price of -MMCP, similar to the pre-dispatch run. Observe that the pre-dispatch version of the unconstrained algorithm is run, once per hour, to determine Pre-Dispatch Prices (PDPs), while the dispatch version is run every five minutes to determine the energy and operating reserves MCPs.

The process of clearing market prices for energy and operating reserves can be explained as follows: all price-sorted energy buying bids are stacked in decreasing order, and all price-sorted supply offers in increasing order. Operating reserve offers for each reserve class are also stacked in increasing order with the hourly gross operating reserve requirements being specified by the IESO for each class. The unconstrained algorithm basically determines the energy MCP as the intersection of demand bids and generation offers stacks, while the intersection of the offer stack for each class of operation reserve and the respected hourly requirement defines the corresponding reserve MCP. Observe that energy and operating reserves MCPs are calculated jointly and the algorithm determines the best trade-off between energy and operating reserves. A simple visualization of the process is presented in Fig. 1 and Fig. 2 for pre-dispatch.

E. Congestion Management Settlement Credit

As described in the previous section, operation schedules are first determined by the unconstrained algorithm, but final dispatch instructions are based on schedules determined by the constrained algorithm. If power system constraints force a market participant to generate/consume more/less than what it was supposed to in the unconstrained schedule, the market participant is treated as "constrained on/off," and the Congestion Management Settlement Credit (CMSC) is used to provide the market participant with the same operating profit as it would have gained in the absence of power system constraints.

For example, assume that generator A bids to generate 100 MW of energy at a price of $20/MWh for a given hour. Assume also that the Ontario MCP is equal to $30/MWh, and generator A is scheduled by the unconstrained algorithm for its entire bid for all 5-minute intervals of the hour. In this case the Operating Profit (OP) of generator A would be:

$$\text{OP} = 100\text{MWh} \times (\$30/\text{MWh} - \$20/\text{MWh}) = \$1000 \quad (2)$$

However, if the constrained algorithm schedules generator A to supply only 50 MW at all 5-minute intervals, the actual operating profit would be:

$$\text{OP} = 50\text{MWh} \times (\$30/\text{MWh} - \$20/\text{MWh}) = \$500 \quad (3)$$

and hence the lost profit is $500. In such a case, a $500 CMSC payment will be made to generator A to bring it to the same level of operating profit as obtained from the unconstrained schedule. Similarly, when a market participant has made 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 IESO as CMSC.

It was observed by the IESO that in the cases when the offer prices were negative, constrained-off payments could be very high and unjustifiable. Therefore, changes were made to the financial settlement algorithm in June 2003 to use $0/MWh offer prices in such cases.

F. Inter-jurisdictional Energy Trading

Figure 3 shows the interconnections between Ontario power system and its neighboring areas. Energy transactions take place among all these interconnected control areas. Imports and exports to and from Ontario are treated in the same manner as the local supply and demand, in many aspects. However, there are two major exceptions: First, as previously

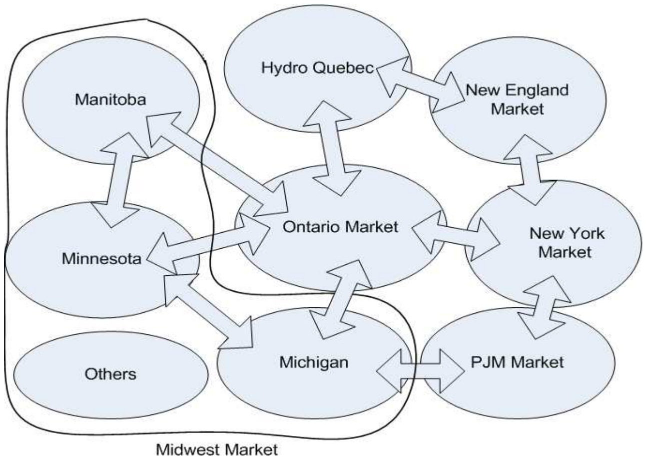

Fig. 3. Ontario's interconnections with other areas.

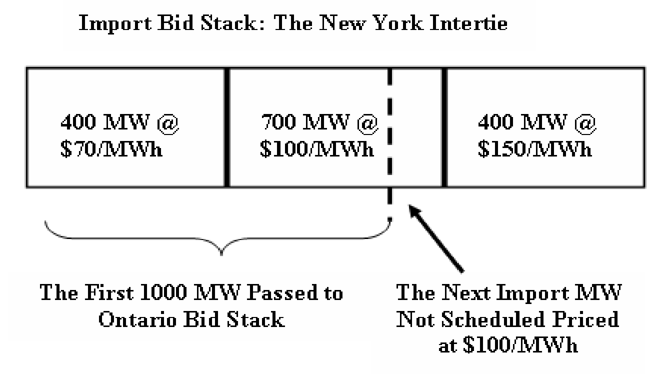

Fig. 4. Determining zonal MCP

described in Section II-D, imports and exports are scheduled in the 1-hour-ahead pre-dispatch run and they are considered as constant supply offers and demand bids in real-time. Second, physical intertie limitations, as well as the Net Interchange Schedule Limit (NISL) are honored by the DSPS when scheduling the imports and exports. The NISL is discussed next, followed by the process of finding zonal MCPs for the interties.

1) Net Interchange Schedule Limit: Sharp changes in import/export schedules during consecutive hours can expose the IESO-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 change in NIS across two consecutive hours is limited to 700 MW. This limitation is referred to as the NISL and is automatically respected by the dispatch algorithm. Because of 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 the NISL. If there is insufficient import bids and export bids for the algorithm to come up with a feasible solution, the IESO asks importers and exporters to change their import/export bids.

2) Zonal MCPs in Pre-dispatch: In order to find the zonal MCPs, the DSPS passes the import/export bids to the Ontario bid stacks while honouring both physical capacity limits and the NISL. If all economic bids from an intertie can be used in the Ontario market without violating both limits, or if the economical bids cannot be used due to the NISL, there is no congestion in the intertie, and the zonal MCP is equal to the Ontario MCP; otherwise, the intertie is assumed congested and the marginal price of energy in the intertie zone is considered as the zonal MCP. For example, assume that 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 (see Fig. 4), and the NISL is met. Thus, up to 1000 MW of bid blocks are being passed to the Ontario supply bid stack. Further assume that Ontario MCP clears at $300/MWh. In this case, the zonal MCP is $100/MWh (not $300/ MWh) since the next MWh not scheduled due to intertie limit is valued at $100.

3) Zonal MCPs in Real-time: In real-time, the zonal MCPs are calculated based on real-time Ontario MCP and an Intertie Congestion Price (ICP), which is determined based on pre-dispatch zonal and Ontario MCPs. The ICP is conceptually defined as the net costs incurred by the Ontario market because of congestion in an intertie. The ICP is determined in pre-dispatch considering the following two scenarios.

In the first scenario, where only the physical intertie capacity limits the scheduling of intertie offers/bids, the ICP is calculated as the difference between the 1-hour-ahead pre-dispatch zonal MCP and the pre-dispatch Ontario MCP, as follows:

$$\mathrm{ICP} = \mathrm{MCP}_{PD}^{Zone} - \mathrm{MCP}_{PD}^{ON} \tag{4}$$

where PD indicates pre-dispatch, MCP^{Zone} is the zonal MCP and MCP^{ON} is the Ontario MCP. For the example in Section II-F.2, 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 would cost the Ontario market $200/MWh, i.e. ICP=-$200/MWh.

In the second scenario, both the physical intertie capacity and the NISL constrain the scheduling of intertie offers/bids. It is to be noted that 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 scenario, the global cost of congestion from both the increase and decrease of the intertie capacities is calculated for determination of the intertie ICP. For example, let assume that an export congested intertie is relaxed by one MW which will save the market $300; at the same time, assume that decreasing another intertie limit by one MW, to meet the NISL, will cost the market $200. This is the total cost of the intertie congestion or, ICP=$100/MWh.

The real-time zonal MCPs are determined as follows:

$$\mathrm{MCP}_{RT}^{Zone} = \mathrm{ICP} + \mathrm{MCP}_{RT}^{ON} \tag{5}$$

where RT indicates real-time; a similar process is used to determine zonal MCP for 10N and 30N operating reserve classes. It should be noted that when an intertie is export congested, the exporters should pay a price higher than the Ontario MCP for the energy purchased from the Ontario market and hence ICP$>$0. On the other hand, when the intertie is import congested, the importers should receive a price lower than the Ontario MCP for the energy sold to the Ontario market and thus ICP<0.

G. Contracted Ancillary Services

Ancillary services are required to ensure the reliability of the IESO-controlled grid. Ancillary services may be procured either through physical markets, such as operating reserves or through contracts with eligible service providers. The IESO 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: The IESO 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 IESO and control signals are sent to the generators under contract to raise or lower their output as required.
- Reactive Support and Voltage Control: Reactive support and voltage control is contracted to ensure that the IESO is able to maintain the voltage level of its grid within acceptable limits. Generation facilities are the major provider of this service in Ontario.
- Black Start Service: 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 IESO.
- Emergency Demand Response Service: Emergency demand response loads are the loads that can be called upon by the IESO to cut their demand on short notice in order to maintain the reliability of the IESO-controlled grid; this service is envisaged for emergency operating conditions.
- Reliability Must-Run Resources: Whenever sufficient resources to provide physical services in a reliable way are not available, the IESO may need to call registered facilities, excluding non-dispatchable loads, to maintain the reliability of the grid through Reliability Must-run Resources contracts.

H. Market Uplift

Electricity consumers of electricity pay for all costs associated with operating the market in a reliable way. The operating costs are categorized under hourly and monthly components and recovered through market uplift. The market uplift is collected from the loads based on their share of the total demand. Congestion management costs, operating reserve costs and the costs associated with system losses are the hourly components of the market uplift. However, other components of the market uplift, including contracted ancillary services, IESO administration fees 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 IESO administration fee is \$0.909/MWh (2006). The market uplift appears in the customers" monthly invoice under separate charges.

III. Programs to Improve Market Operation

Subsequent to the opening of the Ontario electricity market, several programs have been introduced by the IESO in order to improve its reliability, efficiency, and transparency. These programs are briefly discussed in this section.

A. Intertie Offer Guarantee

To ensure adequate supply and encourage power imports to Ontario, given the supply limitations within the province, the Intertie Offer Guarantee (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. 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:

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

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:

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

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

B. Hour-Ahead Dispatchable Load Program

The Hour-Ahead Dispatchable Load (HADL) program was launched in June 2003 for three main reasons: to make non-dispatchable loads more price-responsive; to allow the IESO to include future load reductions in the scheduling process; and to encourage load curtailment during peak operating hours.

The non-dispatchable loads would have an upper limit on the energy costs associated with their production process in most cases. If electricity price exceeds a specific upper cap, the load would choose to shut down its production. Non-dispatchable loads who wish to participate in the HADL program offer their price cap to the IESO and the quantity of demand that would be curtailed. If the 3-hour-ahead PDP is higher than the price cap offered by the load, the IESO 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 load's 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:

$$\text{HADLOG} = \max\{0, (\text{PC-HOEP}) \times \text{Q}\} \tag{8}$$

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 3-hour-ahead PDP for energy is more than \$45/MWh. If in the 3-hour-ahead pre-dispatch run the energy price for the dispatch hour clears at \$50/MWh, dispatch commands are sent to Load A by the IESO to cut its load by 100 MW. If in real-time, the HOEP clears at \$40/MWh, an HADLOG payment of \$500 will be credited to Load A by the IESO in this case, as per equation (8).

C. The Spare Generation On-Line

Fossil-based generation units usually require a long and expensive start-up process, and thus they require a reasonably long operation period in order to recover the start-up costs. During the off-peak periods, these units are exposed to the risk of not being scheduled for a long enough period, and hence, they 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 IESO has to buy power from more expensive units or import expensive power; these lead to unusually high price spikes.

To increase the reliability of the IESO-controlled grid and to reduce price volatility, the IESO launched the Spare Generation On-Line (SGOL) program in August 2003, which offers eligible generators a guarantee of their start-up costs. Eligible generators submit their minimum loading point, minimum up-time and combined guaranteed costs to the IESO. If an eligible generator registered in the SGOL program 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 IESO to cover its minimum combined guaranteed costs. The IESO recovers the SGOL payments through monthly uplift charges to loads.

D. Control Actions Operating Reserves

Under the Ontario market rules, the IESO is allowed to use out-of-market control actions when there is not sufficient operating reserve offered in the market. These control actions include a 3% voltage reduction, a 5% voltage reduction, and a reduction of 30R requirements. In the initial Ontario market design, the market operator manually put in place these actions to maintain system reliability in stressed situations. This “free” service could affect integrity of the price signals sent to the supply side, putting unrealistic downward pressure on the HOEP. Furthermore, out-of-market control actions have been recognized as one of the main sources of discrepancy between pre-dispatch and real-time prices.

To mitigate potential implications of the “free” out-of-market control actions, the Control Action Operating Reserve (CAOR) was introduced in the market in August 2003. The first 200 MW CAOR was priced at \$30/MWh as 10N operating reserve, and at \$30.1/MWh as a reduction in 30R operating reserve requirements. In October 2003, an additional 200 MW CAOR was implemented in the market with the same pricing scheme. This 400 MW CAOR resulted in a significant reduction in the rate of out-of-market control actions. An additional 400 MW CAOR was later brought into the market in November 2005 at the price of \$75/MWh for the first 200 MW and \$100/MWh for the next 200 MW. Although it is expected that the CAOR result in slightly higher HOEPs, it would provide more realistic price signals during stressed conditions.

E. Multi-Interval Optimization Project

The MIO project was implemented in two stages. The initial stage was implemented in March 2004, by which a change was made to the DSPS to recognize “effective unit ramp rates”. Before this stage, the DSPS assumed that generators can only operate under their offered ramp rates. If a unit could not reach the dispatched level for a specific interval for any reason, dispatch instructions for next intervals could be undesirably affected; this problem is referred to as the “stutter step” by the Ontario market participants. On the other hand, it was observed that some non-quick start generators can ramp up higher than their offered ramp rates for a short period of time. Therefore, in order to prevent some undesirable dispatch instructions, the DSPS was modified to use effective unit ramp rate, which is the lesser of the offered ramp rate for the interval multiplied by 1.2, and the maximum registered ramp rate. For example, if the maximum registered ramp rate of a facility is 4 MW/min, and the offered ramp rate for a given interval is 2.0 MW/min, the effective ramp rate that is used by the DSPS is 2.4 MW/min.

In the initial DSPS, dispatch instructions were derived for each interval independently. This caused some dispatching difficulties because the IESO had to dispatch generators on and off to maintain system reliability. However, frequent ramp up and down instructions are costly. In order to address this issue of dispatch volatility, the second stage of MIO was implemented in June 2004 [7], through which dispatch instructions for a given interval are calculated considering four other advisory intervals. These four intervals are selected out of a rolling 11-interval “study period” based on some pre-defined selection criteria. These criteria are designed with the intention of providing the most efficient optimal solution, as well as providing the unit operators with an insight into the upcoming operating instructions. The four advisory intervals are not necessarily the same for each study period, and unit operators are provided with advisory dispatch targets for these intervals. The new MIO algorithm is further expected to improve system reliability, market efficiency, and market transparency.

F. Demand Response Programs

1) Emergency Demand Response Program: The Emergency Demand Response Program (EDRP), announced in June 2002, is intended to enhance system reliability by providing the IESO with a control action option prior to non-dispatchable load shedding. Terms and conditions of the EDRP are agreed upon by the IESO and the interested market participant through a 18-month contract. In case the IESO anticipates an emergency situation, it will give the EDRP participants a notice indicating the possibility of EDRP activation. EDRP participants are required to inform the IESO whether they intend to curtail their load. It should be noted that curtailing their load in response to IESO's notification is not mandatory for EDRP participants. If EDRP participants reduce their demand in practice, they will receive financial compensation for the costs they incurred in responding to the IESO's request, based on the contract rates. Of the several occasions that the EDRP participants were given notice for EDRP activation (e.g. during the summer of 2003, the winter of 2004, and the summer of 2005), there was only one actual load reduction.

2) Emergency Load Reduction Program: In view of the EDRP experience and feedback from stakeholders, and to address the reliability concerns arisen from the shortage of supply during summer 2005, the Emergency Load Reduction Program (ELRP) was approved for launching on June 15, 2006. The ELRP is intended to provide Ontario market participants with an opportunity to improve the reliability of the electricity grid during stressed system conditions, particularly in the summer. If the program can attract a dependable amount of the demand side, it will enable the IESO to reduce usage of other more costly control actions, such as emergency energy purchases and voltage reductions.

Market participants with capability to reduce their consumption for at least 1 MW during a minimum 2-hour time window can participate in the ELRP program. The ELRP is implemented in three steps. In the notification step, market participants are informed that the ELRP will be implemented for a given day. The notice may be issued a day ahead or on the dispatch day, and can be for any number of hours within the program's window. In the offering step, the interested market participants notify the IESO by submitting their MW offer of load reduction. Although participating in the ELRP is not mandatory, a market participant is committed to reduce its specified load upon submitting an ELRP offer to the IESO. In the activation step, the IESO contacts ELRP participants to reduce their consumption, and non-compliance penalties may apply in case of under performance of greater than 20%.

ELRP participants will receive two types of financial compensations. A standby fee of $15 per MW per hour will be paid for participating in the program up until the activation hour. Upon activation, the participants will receive a load reduction payment based on the greater of the HOEP and the applicable following options:

- $400/MWh, for 2 hours of consecutive load reduction,
- $500/MWh, for 3 hours of consecutive load reduction,
- $600/MWh, for 4 hours of consecutive load reduction.

G. Mitigating OPG's Market Power

In order to limit OPG's market power, the Market Power Mitigation Agreement (MPMA) was put in place by the Ontario government before opening the market in May 2002. According to the MPMA, OPG had to pay the IESO a rebate if the HOEP exceeded $38/MWh. However, it was observed that the MPMA seriously affected OPG's efficiency and led to financial problems; it cost OPG about $100 million per month, as it was not able to recover the overall costs of producing electricity.

The Electricity Act of 2004 replaced the MPMA with a new plan that sets capped prices and revenue for most of OPG's generation facilities. Effective April 1, 2005, generation from OPG's base load hydroelectric and nuclear facilities, referred to as regulated assets, was capped at $33/MWh, and $49.5/MWh, respectively; these regulated assets represent about 40% of the Ontario's total generation capacity. Furthermore, OPG's revenues from about 85% of its unregulated assets, i.e. non-base load hydroelectric, coal and gas-fired stations, were set at an upper limit of $47/MWh; these unregulated assets represent about 33% of the total generation capacity in Ontario.

It is worth mentioning that the Market Surveillance Panel, an independent body directed by the OEB, has not found any exercise of market power or gaming by OPG or any other Ontario market participants for the time period covered by the present paper [8].

H. Day-Ahead Commitment Process

The idea of a day-ahead market with nodal pricing was investigated by the IESO, and was eventually rejected because of various political, economical, regulatory, and design issues. Instead, a Day-Ahead Commitment Process (DACP) with reliability guarantees was approved in September 2005. The fundamental targets of designing the DACP are to address frequent real-time failure of import transactions, and to optimally manage next-day available energy resources.

Dispatchable generators/loads who intend to participate in next day's real-time market must submit their operational data to the IESO by 11:00 on the pre-dispatch day. Dispatchable facilities are also required to submit an Availability Deceleration Envelope (ADE). The ADE specifies the hours, energy, and capacity limits within which a dispatchable facility intends to operate during real-time. Although the dispatchable facilities are allowed to change offered prices, quantity of bids have to remain within the limits specified in the ADE. Importers are not obliged to submit import data into the DACP; however, they must do so in order to be qualified for the DACP financial incentives. The importer participating in the DACP will have to pay a day-ahead import failure charge if they do not follow their DACP obligations. It is to be noted that under the pre-DACP data submission rules, market participants were allowed to make any change to their submitted data, up to two hours before real-time.

A Day-Ahead Generation Cost Guarantee (DAGCG) is offered to dispatchable generators to ensure they recover certain combined costs if they have not recovered their costs through market revenues. The DAGCG is the day-ahead version of the SGOL, except it also covers eligible maintenance and operation costs. A Day-Ahead Intertie Offer Guarantee (DAIOG) is also offered to imports to guarantee their "as-offered" costs, and is basically the day-ahead version of the

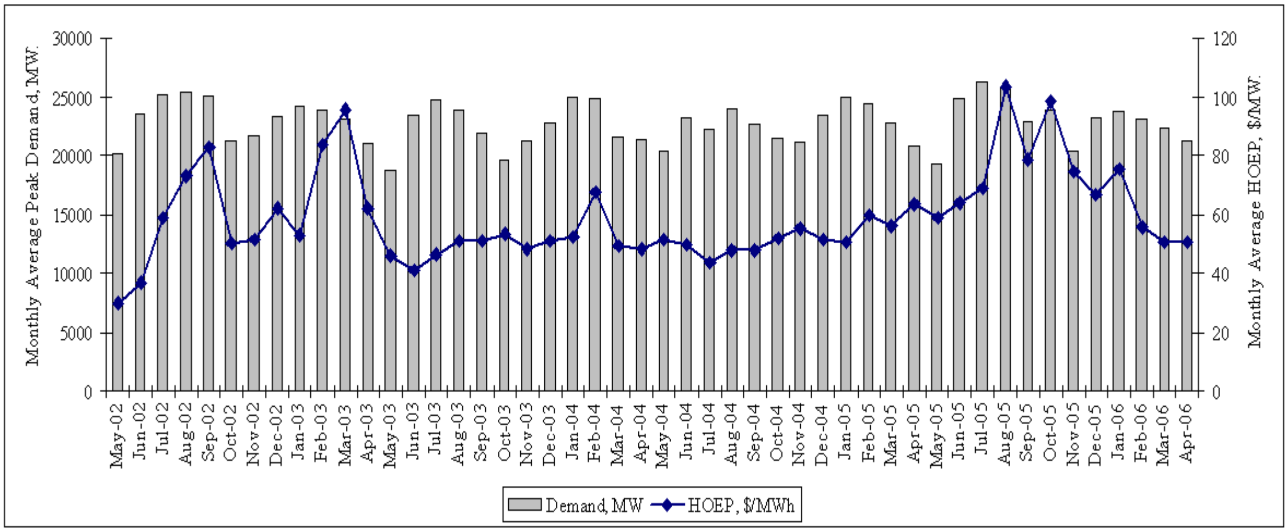

Fig. 5. Monthly weighted HOEP averages and peak demands, 2002-2006

IOG. Aside from some minor differences in the way the DAGCG and the DAIOG are calculated and financially settled, they are basically the same as the real-time SGOL and the IOG payments, respectively. If a market participant is entitled to both day ahead (DAGCG and DAIOG) and real-time (SGOL and IOG) credits, only the higher one will be credited. The costs of paying the DAGG and DAIOG will be recovered through market uplifts.

The existing pre-dispatch algorithm, discussed earlier, is the calculation engine for the DACP. The first four runs of the pre-dispatch algorithm after 11:00 on the pre-dispatch day are used to generate DACP schedules. The first three runs are to generate initial schedules and necessary reliability refinements are carried out. Also, energy limited generators can change their submitted data during the first three runs. The 4^{th} run starts at 14:00 and produces final schedules, referred to as the Pre-dispatch of Record, which is the basis for financial guarantees, and may be rejected by the committed participants by hour 15:15.

IV. Analysis of Market Outcomes and Discussion

A. Energy Price

The monthly averages of Ontario peak demand and the HOEP for the period of May 1, 2002 to April 30, 2006 are shown in Fig. 5. The Ontario market experienced a record high demand during summer 2002, which coincided with some supply limitations. Similarly, winter 2003 was extremely cold, resulting in an increase in demand, with marginal costs of producing electricity soaring as a result of unusually high natural gas prices; furthermore, some of the gas/oil stations were not available to the market operator, as they experienced difficulties in their fuel procurement systems. Thus, the conjunction of high demand and limited supply availability resulted in high energy prices during these two time periods.

The average HOEPs remained steady until summer 2005, when high temperature and humidity levels led to a record peak demand. On the other hand, reliance on gas-fired stations during this period was increased as a result of reduced hydro-electric outputs and the shutdown of a large coal-fired station. Furthermore, since natural gas prices were high during this period, some generators preferred to sell their gas contracts in the natural gas spot markets rather than producing electricity. Hence, the costs of producing electricity in Ontario as well as in the neighboring areas increased, resulting in high and volatile HOEPs.

Energy prices in Ontario on average have been in the same order as the wholesale energy prices in New York and PJM. However, New England prices have been persistently higher than Ontario prices. Michigan, Manitoba and Minnesota control areas have joined the Mid-West electricity market, which open in April 2005, with the energy prices being always lower than the HOEP. It is usually expected that in a fully competitive environment, arbitrage results in elimination of the price differences in the neighboring areas; however, transmission line constraints, different scheduling protocols, and physical power flow rules have limited the ability of power traders to arbitrage away the price differences.

The HOEP has been in general highly volatile, varying from as low as $4/MWh to as high as $1,028.4/MWh during the 4-year period. About 82% of the hours, the HOEP has remained in the range of $20/MWh to $80/MWh, and for about 15% of the hours, the HOEP has varied in the $80/MWh-$200/MWh range. Furthermore, during the first four years, there have been 196 hours at which the HOEP has exceeded $200/MWh. Finally, for about 2% of the hours, prices have been low, in the range of $4/MWh to $20/MWh.

It is to be noted that analyses of market price volatility in [9], [10] reveal that Ontario's prices are significantly more volatile than the day-ahead market prices in the New England, New York, and PJM markets . From these comparative studies, it can be argued that the high price volatility in Ontario is driven by the real-time nature of this market, and hence, introduction of a day-ahead market might be a possible way to reduce price volatility.

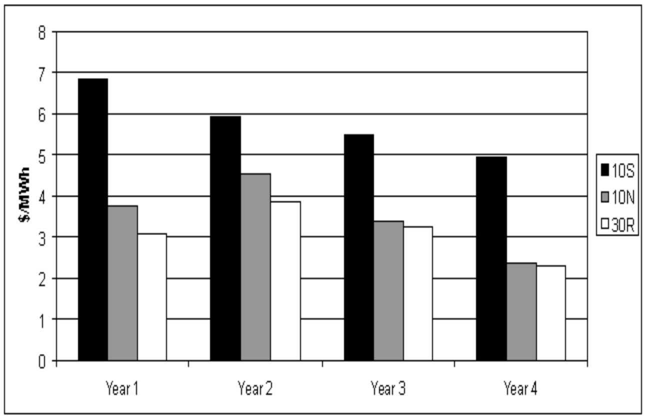

Fig. 6. Yearly operating reserve (OR) price averages

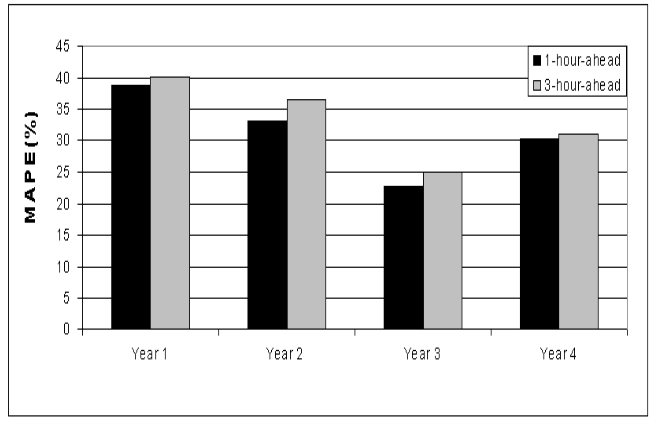

Fig. 7. Yearly MAPE of the discrepancy between the HOEP and PDPs.

B. Operating Reserve Prices

The yearly average prices of the three classes of operating reserves are shown in Fig. 6. Unlike the energy prices, operating reserves prices have declined over the 4-year period. It was observed that the operating reserve prices were as high as energy prices on a few days during September 2003, because of a series of unusual events; these unusually high prices interrupted the reducing pattern of the 10N and 30R prices during the second year. Reduction in operating reserve prices can be attributed to the fact that about 600 MW of dispatchable load has emerged in the market. This group of load is allowed to offer 10N and 30R into the market, resulting in a more competitive and lower 10N and 30R prices. It should be noted that despite the high energy prices during the summer of 2005, the 10S prices have continued to decline; these low 10S prices can be explained by the fact that the limited water supply due to drought during this period shifted some of the hydroelectric units from energy production to providing 10S reserve.

C. Discrepancy between the HOEP and the PDPs

The PDPs are generated based on the most recent available market information in order to provide the market participants with an estimate of the real-time HOEPs. However, it has been consistently observed that there is a large discrepancy between the PDPs and the HOEP [11]. Thus, let define the yearly Mean Absolute Percentage Error (MAPE) of the PDPs as:

$$\text{MAPE} = \frac{100}{N} \times \sum_{t=1}^{N} \frac{|\text{HOEP}_t - \text{PDP}_t|}{\text{HOEP}_t} \tag{9}$$

where HOEP_t and $\text{PDP}_{a,t}$ are the values of the HOEP and PDP for hour t, respectively, and N is the number of hours in a year. The yearly MAPEs of the 1-hour-ahead and 3-hour-ahead PDPs for the first four years of market operation are depicted in Fig. 7. One can observe from this figure that the discrepancy between the HOEP and PDPs has declined, to some extent, through the first three years. Moreover, the highest discrepancies happened during the first year of market operation, mainly because of the volatile prices during the summer of 2002, and probably due to market immaturity. Note that the deviation of HOEP from the PDPs has increased in the 4^{th} year, which is because of the unstable and unusually high prices during the summer of 2005.

The high discrepancy between the HOEP and the PDPs can be explained by operational aspects of the Ontario market. The real-time nature of this market makes it vulnerable to unpredictable events. The generation offer curve in Ontario is “hockey-stick” shaped [11]. Consequently, demand over-forecasting, demand under-forecasting, errors in forecasting the output of self-scheduling generators, and import/export failures oblige the market operator to commit expensive units on the “blade” portion of the offer curve, or to de-commit some of the already committed units and move back on the “shaft” portion of the offer curve. This requirement puts upward or downward pressure on the HOEP, leading to price spikes and deviation of HOEP from the PDPs. Furthermore, out-of-market control actions affect the consistency between the real-time and pre-dispatch market clearing procedures, leading to deviation of the HOEP from the PDPs.

The improvement in consistency between the HOEP and PDPs is basically a matter of market maturity, and are partially attributed to changes and enhancements gradually implemented in the market [11]. Specifically, the Panel’s analyses point out that the modifications made to the processes of forecasting Ontario load and forecasting self-scheduling generation availability, and the introduction of CAOR program have contributed to this improvement.

Deviation of the HOEP from the PDPs has many implications, and seriously affects market efficiency. For example, analysis of PDP data for the first four years of market operation shows that for about 81% of the hours, real-time HOEPs have been less than the corresponding 1-hour-ahead PDPs. For such hours, eligible importers are entitled to IOG payments, recalling the fact that imports are scheduled based on 1-hour-ahead PDPs. Furthermore, too many imports are scheduled while the cheap local supply is dispatched off, and too few exports are scheduled while the demand side in the neighboring areas are willing to pay more for Ontario energy. Another example is the HADL program which is also designed based on the 3-hour-ahead PDPs. If the real-time HOEPs turn out to be lower than the 3-hour-ahead PDPs, which has been the case for about 79% of the hours for the first four years of the market operation, the HADL program participants may be eligible for HADLOG payments.

D. Effectiveness of the Market Improvement Programs

Each of the programs discussed in Section III are designed to deal with specific operational issues. Some of these issues are shown to be addressed by the designated programs, however, in most cases either the envisaged goals of each program have not been entirely reached, or the programs have led to other issues. Briefly, the following conclusions can be reached from publicly available data and reports, particularly [11]:

1) The HADL program was implemented to boost load responsiveness to price signals, which could lead to an economic benefit to the market. Observe that the benefit of HADL program to the market basically comes from not dispatching the extremely expensive units or imports when the demand is expected to be very high. The cost of the HADL program is the HADLOG which is paid to the program participants if the real-time prices are lower than what were expected in 3-hour-ahead pre-dispatch. Analyses of market data have revealed that the overall benefit to the market form the HADL program has been minimal, given the high discrepancy between the HOEP and the 3-hour-ahead PDPs. Furthermore, only a total of 240 MW load participated in the program, and the participants have been scheduled for load reduction for 110 hours. This indicates that the program has not been very successful in attracting a large share of the demand.
2) The SGOL program was mainly designed to improve market reliability. While this objective has been met, market efficiency has been reduced by the payment of more than $33 million to eligible generators.
3) By using the MIO and looking-ahead scheduling, the use of out-of-market control actions is reduced. However, the problem of dispatch volatility, which was one of the main objectives to be addressed by the MIO program, still exists.
4) The MPMA program was designed to improve market efficiency by mitigating OPG's obvious market power. However, it resulted in inefficient operation of OPG and subsidized electricity prices for the consumers. Considering the dominant share of OPG in Ontario supply, these side effects are against market efficiency and transparency. On the other hand, non-utility generators (NUGs) have been holding long-term power purchase agreements with the Ontario government that have excluded them from openly competing in the market. Also, the Ontario Power Authority has been assigned to manage generation and load management contracts with supply and demand side entities in order to ensure availability of reliable power for Ontario. These contracts are refereed to as the "Request for Proposal" (RFP) contracts. Under the RFP contracts, while the generators sell their output into the market, they will be provided with guaranteed revenue to ensure they can recover their costs. The generators will be financially settled based on the net revenue they received from the market, and the revenues agreed upon in the RFP contract. Given the NUG and RFP contracts, and the new capped prices and revenues over most of OPG's output, only about 25% of the total Ontario generation capacity is truly open to compete in the market.
5) Despite the reduction in the deviation of the HOEP from the PDPs, the discrepancy between the two and the overall price volatility is still high. The highly volatile pre-dispatch and real-time prices during the summer of 2005 highlighted the limited effectiveness of the implemented market programs in maintaining consistency between the pre-dispatch and real-time prices.
6) There are 600 MW of dispatchable loads biding into the market. However, these loads usually bid high prices compared to the normal range of the HOEP, and demand-side involvement in market enhancement programs has not been very significant. This high level of load inelasticity affects market efficiency in general.

V. CONCLUSIONS

This paper presents a comprehensive overview of the operation of the Ontario electricity market, along with an analytical discussion of the market's outcomes. The Ontario electricity market is the only single-settlement market in North America, and it is interconnected with the New England, New York, PJM, and Midwest competitive electricity markets, as well as the regulated power systems of Quebec and Manitoba. The physical system is not fully considered in the process of clearing the market prices, and a province-wide uniform price applies to all market participants. Most of the load in Ontario is not price-responsive, which has adversely affected the load management programs initiated by the Ontario IESO. Various programs have been and are being implemented by the IESO to improve market operation; however, some of the challenges motivating the implementation of these programs have yet to be fully addressed.

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