Ontario Energy Board **Commission de l'énergie de l'Ontario**

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2008 – April 2009

PUBLIC

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Ontario Energy Board

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Ontario

July 29, 2009

The Honourable Howard I. Wetston, Q.C.
Chair & Chief Executive Officer
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Mr. Wetston:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Don McFetridge and Tom Rusnov, I am pleased to provide you with the Panel's 14th semi-annual Monitoring Report of Ontario's wholesale electricity market, the IESO-administered markets.

This report, covering the period November, 2008 to April, 2009, is submitted pursuant to Article 7.1.1 of Ontario Energy Board By-law #3.

Best Regards,

Neil Campbell
Chair, Market Surveillance Panel

Enclosure

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Executive Summary

Overall Assessment

Ontario's IESO-administered wholesale electricity market once again performed reasonably well according to its design over the six-month period November 2008 to April 2009. Spot market prices generally reflected demand and supply conditions. The Market Surveillance Panel (MSP) did not find gaming or abuse of market power to be occurring, with the possible exception of one matter that is still being assessed. As in previous reports, there were occasions where actions by market participants or the IESO led to inefficient market outcomes. The MSP identified four potential opportunities to improve the efficiency of the market which are reflected in the recommendations summarized below.

Market Prices and Uplift

The average Hourly Ontario Energy Price (HOEP) for the period November 2008 to April 2009 was $40.98/MWh, which is 16.6 percent lower than last winter. Average on-peak HOEP was 18.1 percent lower and off-peak HOEP 14.5 percent lower. Market prices in March and April were especially low, primarily due to improved baseload supply, lower natural gas prices, reduced domestic demand, and transmission constraints limiting exports this winter.

In contrast, the effective load-weighted HOEP increased this winter compared to the previous winter period by $3.69/MWh (6.8 percent) to $58.08/MWh, as payments for the Global Adjustment continued to increase. Total hourly uplift payments charged declined by $29 million (14 percent) this winter compared to last year. Less (Intertie Offers Guarantee (IOG) payments and lower payments for transmission losses more than offset the 136 percent increase in operating reserve (OR) payments due to a higher OR requirement and fewer resources supplying OR this winter compared to a year ago.

Demand and Supply Conditions

Ontario Demand totalled 76.9 TWh this winter, down by 4.6 percent relative to last winter. With the exception of January, total demand fell in all months with the largest decline occurring in February 2009 at 9.2 percent compared to the same month one year ago. Exports (excluding linked wheel transactions) declined this winter by 0.30 TWh, or 3.5 percent to 8.16 TWh with 52 percent of these exports destined for PJM through the Michigan interface. The primary reason for the decline in exports was transmission line outages at the New York intertie reducing flows to New York (and simultaneously Michigan) resulting in a 54 percent decline in exports in April 2009 relative to 2008.

Planned outage rates over the latest winter showed similar seasonal patterns to previous periods. The planned outage rate (including OPG's planned CO_2 outages) for coal-fired generation was slightly higher relative to other winters as it remained at or above 20 percent of capacity with the exception of January 2009, a month where no CO_2 outages were taken. The forced outage rate for most generation types fluctuated between 10 and 15 percent this winter, which is consistent with forced outage rates since the beginning of 2006. However, the forced outage rate for coal-fired units was above 30 percent between December 2008 and April 2009, the highest monthly rates since early 2005.

High-priced and Low-priced Hours

Over the recent winter, there were 8 hours when the HOEP exceeded $200/MWh. In contrast, there were 219 hours (all but 5 hours of which occurred in March and April) when the HOEP fell below $0/MWh, easily surpassing the total from any previous six-month period.[1] The recent winter period produced both the highest and lowest HOEP values since the market opened in May 2002:

- The highest priced hour occurred on February 18, 2009 in delivery hour 12 (HE 12) when the HOEP reached $1,891.14/MWh.
- The lowest priced hour this period occurred for three hours on March 29, 2009 in HE 2-4 at minus $51.00/MWh.

[1] These hours are discussed in more detail in Chapter 2.

While these outcomes are mostly explainable by reference to supply and demand conditions existing at the particular time, some of these extreme outcomes were also influenced by elements of the market design that the Panel previously recommended should be changed.

Increased Exports from Ontario to PJM

Since the NYISO obtained a prohibition on the scheduling of certain linked-wheel transactions in July 2008 from Federal Energy Regulatory Commission (FERC), including scheduled linked-wheels originating in New York and destined for PJM (through Ontario and MISO), Ontario export volumes to PJM have steadily increased and reached a monthly peak of 1.02 TWh in March 2009. The NYISO actions were taken because unscheduled flows (the difference between the scheduled and actual flows) were leading to high congestion costs imposed on New York consumers primarily as a result of increased west-to-east internal New York transmission congestion. The Panel continues to monitor the situation in Ontario to determine if there are issues requiring attention in the Ontario market. It has observed that the increased Ontario exports to PJM through MISO have induced a significant portion of parallel path flow (loop flow) from west to east within Ontario and on the Ontario-New York intertie. Chapter 3 includes a detailed discussion on how the parallel flow is induced and its impacts on internal congestion and intertie congestion. The preliminary findings continue to show that unscheduled flows resulting from Ontario exports to PJM are not leading to significant amounts of internal congestion and therefore, Ontario has not experienced the type of adverse impacts that incurred in New York last year. However, further review is still needed to assess congestion at the New York intertie itself. The Panel has asked the MAU to continue monitoring and assessing these issues.

New Payment Structure for Prescribed Assets

As of December 1, 2008, the regulated pricing mechanism for OPG's prescribed assets (its baseload nuclear and hydroelectric generation) was modified.[2] The new regulated payment structure for its baseload hydroelectric generation relies primarily on the market price as the driver for production decisions.[3] This should make OPG's generating units more responsive to market prices and improve market efficiency. In an initial review of OPG's production profile under the new payment structure up to the end of April 2009, OPG has shifted more hydroelectric production from off-peak hours to on-peak hours. The Panel estimates that the water shifting has led to increased efficiency amounting to approximately $1.5 million dollars between December 2008 and April 2009.

Recommendations

The Panel makes several suggestions for potential changes to the present IESO-administered markets based on its analysis of observed market outcomes over the past six months. These are summarized below:

<u>Recommendation 3-1 (Chapter 3, section 2.2)</u>

To address the Minister of Energy's May 2008 Declaration regarding the reduction of CO_2 emissions from OPG's coal-fired generating stations, OPG released the details of its implementation strategy in November 2008. The strategy was discussed by the Panel in its previous Monitoring Report and certain aspects were identified as potentially inefficient. Specifically, the Panel raised concerns regarding OPG's use of Not Offered but Available (NOBA) designation and "CO_2 outages" as they are likely to be less efficient because they result in capacity being removed on a block basis rather than being available to respond to price signals.

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[2] OPG's non-prescribed asset agreement (which covers peaking hydroelectric and coal units) ended in April 2009, implying that market prices will become more of a driver for production from these assets. The market implications of this change will be examined in the Panel's summer 2009 report.

[3] For a detailed review of OPG's new prescribed asset agreement, see Chapter 3, section 3.3.

Consistent with its implementation strategy, OPG has used a combination of planned CO_2 outages, NOBA designations, and an environmental emissions adder (which was subsequently eliminated in the middle of March due to declining Ontario Demand). Over the first four months this year, there have been 39 days when at least one coal unit was on NOBA. While a large proportion of these occurred during the relatively low-priced days between mid-March and April, high prices during some of the NOBA events indicate that some inefficiencies are occurring. The Panel continues to hold the view that NOBA's and planned CO_2 outages are not the most efficient means of achieving OPG's emission targets and these targets could be met more efficiently if OPG were to rely solely on an appropriate emissions adder.

The combination of these mechanisms along with other factors such as declining demand have led to very low production levels from OPG's coal-fired generators this year. By the end of June 2009, coal production was only half of last year's total over the same months, and it appears very unlikely that OPG will come close to exceeding their annual target of 19.6 Mt of CO_2 emissions. If OPG continues to use NOBA's and CO_2 planned outages to reduce coal-fired production, the Panel would need to assess whether this constitutes withholding and contributes to market inefficiencies. The Panel Recommends:

(i) Ontario Power Generation (OPG) should discontinue the use of Not Offered but Available (NOBA) designations and CO_2 outages in excess of regular planned outages for the remainder of 2009 since they do not appear to be necessary to meet its 2009 CO_2 emission target, and

(ii) To the extent that OPG forecasts a need to reduce coal-fired generation in order to comply with its CO_2 emissions limit, the Panel recommends OPG should employ a strategy that utilizes an emissions adder alone as the most efficient way to offer an energy-limited resource into the market at the times when it has the most economic value.

Recommendation 3-2 (Chapter 3, section 3.1)

The Spare Generation On-line (SGOL) and Day-Ahead Commitment Process (DACP) programs provide generators a cost guarantee that is unit-based, although the units at combined-cycle gas turbine (CCGT) generators are not operated independently of each other (since waste heat from one or more gas turbines is used to provide the energy to drive a steam turbine). While current market rules and procedures do not specify how costs should be allocated across the gas and steam units for purposes of SGOL and DACP cost guarantees, different allocation methods used by a station can lead to different revenue outcomes, some well in excess of the costs for each unit and well above the revenue requirement for the entire station as a whole.

In Chapter 3, section 3.1, the Panel performed a comparison of cost guarantee payments using a unit-based approach and a station-based approach. It estimated that cost guarantee payments during 2007 and 2008 would have been reduced by more than 50 percent under the SGOL program and 20 percent under the DACP program. The Panel believes that since CCGT participants run their gas and steam units as a group, their costs and revenues should similarly be aggregated across all units at the station. This will be more consistent with the objectives of the SGOL and DACP programs, reduce unnecessary program payments, and eliminate some inefficient generator starts. The Panel therefore recommends:

The IESO should improve the mechanisms for aligning submitted costs and associated revenue streams at combined cycle stations for its Spare Generation On-line and Day-Ahead Commitment Process generation cost guarantee programs, in the context of the other changes taking place to these programs. The preferred mechanism is to determine guarantee payments on an aggregate basis for all units at a station. Alternatively, the IESO should eliminate allocations that result in over-compensation (for example, by requiring allocation of submitted costs among units in proportion to the revenue they generate during the period associated with those costs).

Recommendation 3-3 (Chapter 3, section 3.2)

The Daily Energy Limit (DEL) represents the maximum amount of energy that can be scheduled at a specified hydroelectric generation facility for a given day. Although the DEL is submitted on a voluntary basis, the IESO applies the limit in its pre-dispatch scheduling tools, scheduling the energy in hours it is economic until the limit has been reached. However, the IESO real-time dispatch tool does not apply this limit, leading to possible discrepancies in the pre-dispatch and real-time schedules. If the submitted DEL differs from the actual amount of energy available at a hydroelectric unit, market efficiency can be reduced. For example, if DEL is lower than actual, the pre-dispatch which sees no energy remaining at the hydroelectric unit, may schedule more imports and/or fewer exports, or possibly more fossil-fired generators online.

Between January 2008 and April 2009, underestimated DEL from hydroelectric units led to 234 GWh of energy (and OR) scheduled in real-time but not in pre-dispatch due to a binding DEL limit. A binding DEL when understated occurred in 2,622 hours during the period (22 percent of the all hours) with an estimated average increase in supply between pre-dispatch and real-time of 89 MW over these hours. The Panel recommends:

Given the frequency and impact on the market of incorrect Daily Energy Limit (DEL) submissions for hydroelectric generators, the Panel recommends that the IESO should discontinue the use of the DEL feature in the pre-dispatch schedules (including the Day-Ahead Commitment Process pre-dispatches) until an Enhanced Day-Ahead Commitment process is introduced which is specifically designed to optimize resources over 24 hours using accurate estimates of energy limits for hydroelectric resources. Alternatively, if the IESO considers that the DEL is currently useful for reliability reasons, the IESO should require submission of DELs from all hydroelectric generators, and strengthen the compliance provisions in the Market Rules to incent participants to submit more accurate forecasts of DEL.

Recommendation 3-4 (Chapter 3, section 3.4)

Over the recent winter period, there was an increase in the frequency of Surplus Baseload Generation (SBG) events, meaning that there is more "baseload" generation available than is needed to meet the total Ontario load and net exports.[4] Between November 2008 and April 2009 there were 200 hours when the IESO experienced SBG conditions (the majority in March and April 2009), which is dramatically higher than the previous record of 24 hours with SBG conditions set during the 2005/2006 winter months. The increase was due to a combination of factors including reduced Ontario Demand, reduced outages to nuclear units, planned outages to transmission lines at the Ontario-New York intertie, increased wind generation, and large amounts of commissioning gas-fired generation.

SBG events are typically accompanied by low, indeed often negative, market prices. Low, and especially negative, market prices should incent generators and importers to reduce supply and consumers and exporters to increase demand. However, a large portion of Ontario generators have contractual or regulated pricing arrangements, which make the incentive of the market price less important in their production decisions.[5] Consistent with previous recommendations, the Panel encourages relevant agencies to continue their efforts to improve contracts, programs and/or procedures to allow the market to better respond to low-price conditions.[6] The Ontario Power Authority (OPA) has the responsibility to develop and negotiate new programs and contracts for generation in Ontario, while the Ontario Electricity Financial Corporation (OEFC) administers existing non-utility generation (NUG) contracts). This is especially important in anticipation of more SBG events in the future as the amount of renewable and nuclear generation capacity is increased, consistent with the passing of the *Green Energy and Green Economy Act, 2009*.

[4] The IESO defines SBG as the condition *"when the amount of baseload generation (which may largely consist of a supply mix of high minimum load fossil, nuclear and run-of-the-river hydroelectric resources) exceeds the market demand" (*IESO Internal Procedures*).*

[5] For a detailed analysis of how various types of generators respond to low market prices, see Chapter 3, section 3.4.

[6] See section 2 of Chapter 4 for a fuller discussion of the issue and market-friendly steps for reducing SBG.

The Panel recommends:

In order to improve the price responsiveness of generation to low market price and Surplus Baseload Generation conditions, the Panel recommends that when Non-Utility Generation contracts are renewed and renewable energy (primarily wind-power) contracts are designed, the Ontario Power Authority and Ontario Electricity Financial Corporation should design the contracts in a way to motivate these generators to respond to the market price, at least when it is negative.

In past reports we have grouped recommendations under four categories – price fidelity, dispatch, transparency, and uplift payments.[7, 8] The recommendations from this report are grouped in the table below. There were no recommendations to improve transparency.

Summary of Recommendations

CATEGORY	RECOMMENDATION	SUBJECT	RELEVANT ENTITIES
Price Fidelity	**3-3**	**Daily Energy Limit for Hydroelectric Generation**	**IESO**
Dispatch	**3-1**	**OPG's Co_2 Emissions Strategy**	**OPG**
	3-4	**NUG and Renewable Energy Contracts**	**OPA OEFC**
Uplift Payments	**3-2**	**Cost Guarantees**	**IESO**

[7] Prioritization was introduced in response to a suggestion of the IESO's Stakeholder Advisory Committee.
[8] Uplift recommendations in the past have been associated with hourly uplift payments; The current recommendations relates to a non-hourly uplift payment.

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Chapter 1: Market Outcomes November 2008-April 2009

1. Highlights of Market Indicators

This Chapter provides an overview of the results of the IESO-administered markets over the period November 1, 2008 to April 30, 2009, with comparisons to the same period a year earlier and in many instances a review of trends over several years. For ease of reference, the November to April period is sometimes referred to as the 'winter period'.

1.1 Pricing

The average Hourly Ontario Energy Price (HOEP) was $40.98/MWh this winter, representing a reduction in HOEP of 16.6 percent from $49.16/MWh the prior winter. The two lowest monthly average HOEP's recorded by the market since its inception in 2002 occurred in March and April 2009 at $28.88/MWh and $18.40/MWh respectively.

Although HOEP was decreasing this period, the effective prices, which include the Global Adjustment and OPG Rebate, actually increased from $54.39/MWh last winter to $58.08/MWh (6.8 percent), with the Global Adjustment almost as large as the average HOEP in March, and almost $20/MWh (106 percent) higher than the average HOEP in April.

1.2 Demand

Ontario Demand was 76.90 TWh this winter, down by 3.55 TWh (4.6 percent) compared to one year ago. There were declines in every month compared to last year with the exception of January, with the largest monthly percentage declines of 6 percent or higher during the last three months of the winter period.

Exports (excluding linked wheel transactions) declined slightly this winter by 0.30 TWh, (3.5 percent) to 8.16 TWh with the majority of exports destined for PJM via Michigan.

The primary reason for the lower export volume this year was the 54 percent drop in April, which was induced by transmission line outages at the New York intertie reducing flows to both NY and Michigan.

1.3 Supply

More combined cycle generation was added this winter. This included new stations – St. Clair Energy Centre, Sithe Goreway– as well as additions to an existing station – Portlands. Smaller amounts of new wind generation also came in-service, with the largest of these being the Enbridge Ontario wind-farm and the Amaranth/Melancthon wind-farm. These additions in supply represent approximately 12 percent of average hourly demand during the winter period.

1.4 Imports and Exports

Net exports increased to 5,423 GWh this winter, which is 1,340 GWh (33 percent) higher than last winter. On-peak exports grew more this year than off-peak (54 percent versus 21 percent), but the off-peak portion remains larger, at almost 60 percent of the total. This increase in net exports was induced by the above noted small drop in exports coupled with a significant decrease in import levels, which fell to 2,737 GWh, a decrease of 1,631 GWh or 37 percent compared to last winter (after adjusting for the linked wheels).

2. Pricing

2.1 Ontario Energy Price

Table 1-1 presents the monthly average HOEP for November to April 2007/2008 and 2008/2009. The average HOEP declined by $8.18/MWh (16.6 percent) during the winter 2008/2009 months relative to the same months one year earlier. On-peak average prices fell by 18.1 percent this winter while off-peak prices declined 14.5 percent. Although year-over-year average prices were higher in November and January, there were considerable declines in March and April (decreases of 49.2 percent and 62.4 percent respectively).

Table 1-1: Average HOEP, On-peak and Off-peak, November–April 2007/2008 & 2008/2009 ($/MWh)

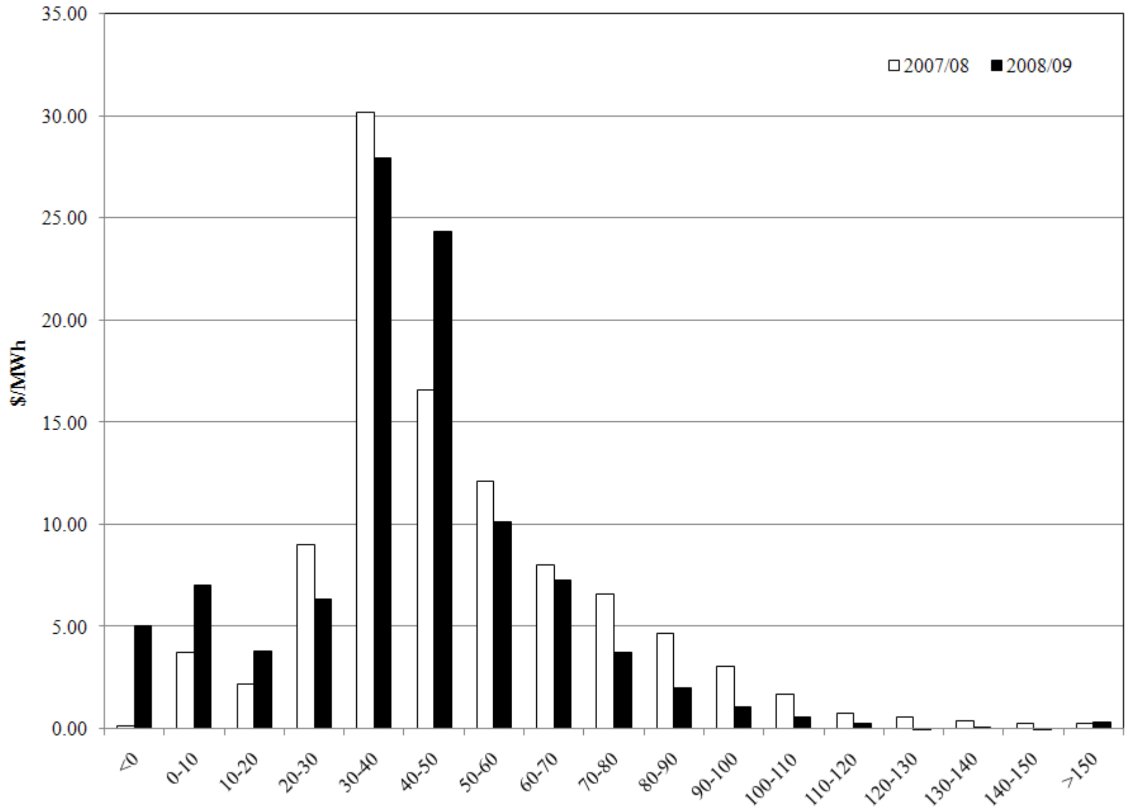
	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2007/ 2008	**2008/ 2009**	**% Change**	**2007/ 2008**	**2008/ 2009**	**% Change**	**2007/ 2008**	**2008/ 2009**	**% Change**
November	46.95	51.78	10.3	56.35	59.98	6.4	37.96	45.22	19.1
December	49.08	46.34	(5.6)	62.96	57.67	(8.4)	39.48	37.02	(6.2)
January	40.74	53.22	30.6	50.89	62.32	22.5	31.62	45.73	44.6
February	52.38	47.24	(9.8)	67.48	57.78	(14.4)	39.52	38.53	(2.5)
March	56.84	28.88	(49.2)	68.60	36.65	(46.6)	48.72	21.90	(55.0)
April	48.98	18.40	(62.4)	63.61	28.62	(55.0)	34.99	10.22	(70.8)
Average	49.16	40.98	(16.6)	61.65	50.50	(18.1)	38.72	33.10	(14.5)

Numerous factors contributed to the low prices in March and April 2009 including improved baseload supply conditions, low demand levels, falling natural gas prices (there was a 27 percent decline in the Henry Hub Spot price this winter) and transmission constraints limiting export volumes. Average hourly baseload supply output increased by 2.2 GW (19 percent) in March and 0.5 GW (4.3 percent) in April 2009 versus 2008 as presented in Table 1-30 in section 4.3. Improved baseload output was a contributing factor to the high frequency of Surplus Baseload Generation (SBG) events in March and April 2009 that are discussed in more detail in Chapter 3 section 3.4.

Low energy prices this winter were also indicative of low demand levels, primarily a result of slightly higher average temperatures and weakened economic activity. With the exception of January, total market demand was lower in all months this winter relative to the same months last winter as shown later in Table 1-27. The most extreme declines on a monthly basis occurred in February through April 2009 where total market demand declined by 0.61 GWh to 1.70 GWh (or 4.3 to 12.8 percent). A major reason for the falling demand in these months was the reduction in export volumes relative to last year (total exports fell by 9.5 percent in February and 54.3 percent in April compared to the prior winter).

Figure 1-1 presents the frequency distributions of HOEP over the last two winter periods. It shows a general shift in prices from higher to lower levels. There was a large increase in the percentage of low-price hours this winter as the frequency of hours when HOEP fell below $20/MWh increased from 261 hours in 2007/08 to 689 hours in 2008/09, an increase of 164 percent. The HOEP fell below $0/MWh in only 0.1 percent of all hours in the earlier winter period but this increased to 5.0 percent of all hours this winter. There was also a large increase in hours when HOEP was between $40-50/MWh, from 16.6 percent of all hours last winter to 24.4 percent this winter. Finally, compared to last year, there was a decline in the frequency of occurrences for all categories between $50/MWh and $150/MWh (down from 1,660 hours last winter to only 1,095 hours this winter).

Figure 1-1: Frequency Distribution of HOEP, November–April 2007/2008 & 2008/2009 (% of total hours in $10/MWh price ranges)



2.1.1 Load-weighted HOEP

Table 1-2 reports the load-weighted HOEP by load type for the last two winter periods. Load-weighted HOEP provides a more accurate representation of the actual price paid by loads since it is weighted by hourly demand. Similar to the decline in the unweighted HOEP, the load-weighted HOEP over all loads declined compared to last winter by $7.78/MWh or 15.2 percent. The load-weighted HOEP for dispatchable load declined the most by $9.02/MWh (18.9 percent) while that for other wholesale loads fell by $7.15/MWh (14.5 percent). Dispatchable loads can also earn revenue from the operating reserve market. During the recent winter period, dispatchable load operating reserve revenue was $1.07/MWh (8.7 percent higher than operating reserve revenue earned last winter) primarily a result of very high operating reserve prices this winter period.

Table 1-2: Load-Weighted Average HOEP and Dispatchable Load Operating Reserve Revenue, November–April 2007/2008 & 2008/2009 ($/MWh)

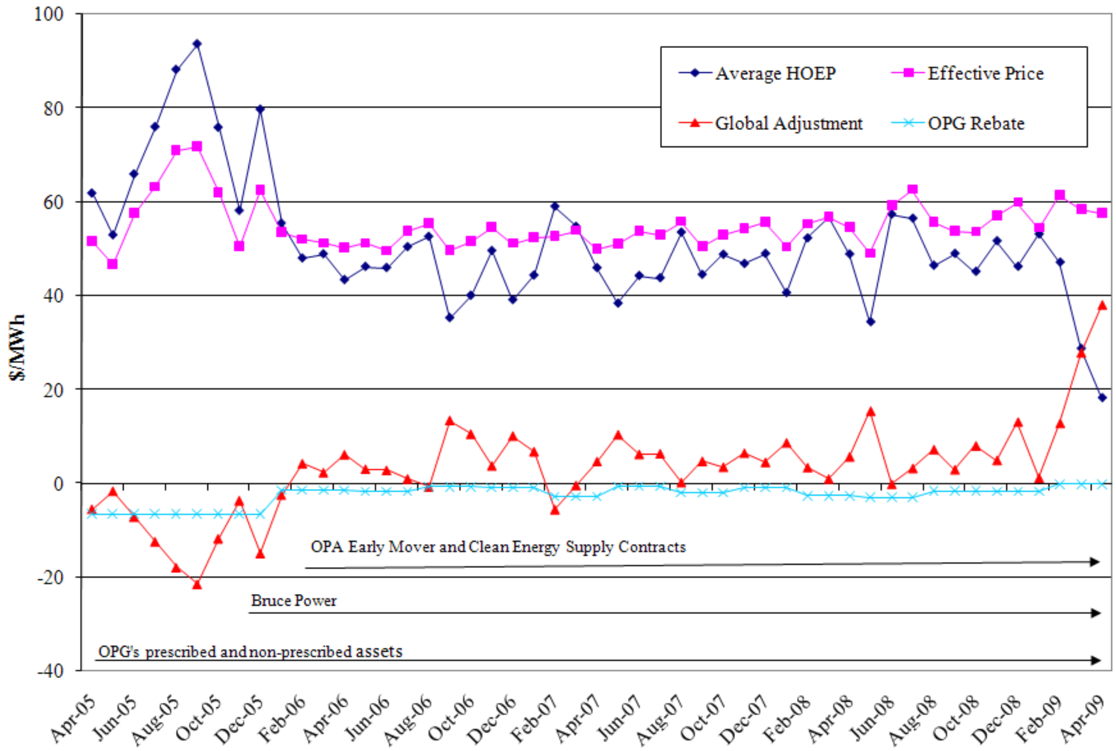
Year	Unweighted HOEP	Load-weighted HOEP[9]			Dispatchable Load Operating Reserve Revenue
		All Loads	Dispatchable Load	Other Wholesale Loads	
2007/2008	49.16	51.09	47.67	49.20	0.98
2008/2009	40.98	43.31	38.65	42.05	1.07
Difference	(8.18)	(7.78)	(9.02)	(7.15)	0.09
% Change	(16.6)	(15.2)	(18.9)	(14.5)	8.7

2.1.2 Impact of the Global Adjustment and the OPG Rebate on the Effective Price

Figure 1-2 plots the monthly average HOEP and effective HOEP between April 2005 and April 2009 as well as payments made through the Global Adjustment (GA) and OPG Rebate. The GA and OPG Rebate tend to moderate the effective HOEP by lowering (increasing) the net payments to generators when the average HOEP is high (low) during a month. Between early 2006 and mid-2008, the effective HOEP generally remained between $50/MWh and $55/MWh. However over the last 12 months, the effective price has gradually increased. Since May 2008, the effective HOEP climbed above $55/MWh in eight months and above $60/MWh in two months including July 2008 and February 2009. The Global Adjustment dramatically increased in March and April 2009 to $27.79/MWh and $37.96/MWh respectively in large part due to extremely low market prices.[10] Low prices pushed the OPG Rebate down to $0/MWh during March and April 2009.[11]

[9] Unadjusted – like the unweighted HOEP, the load-weighted HOEP does not include the impact of the Global Adjustment or the OPG Rebate.
[10] For most price-guaranteed generation procured into the system by the Ontario Power Authority, the Global Adjustment covers the gap between the HOEP and the guaranteed contract price.
[11] As indicated in the IESO Participant News Release dated May 21, 2009, the OPG Rebate was discontinued after April 30, 2009. The announcement can be found on the IESO's website at: http://www.ieso.com/imoweb/news/newsItem.asp?newsItemID=4693

Figure 1-2: Monthly Average HOEP Adjusted for OPG Rebate and Global Adjustment, April 2005–April 2009 ($/MWh)



The effect of these price movements was that in March, the Global Adjustment was almost as large as the average HOEP (in April, the GA was 6 percent larger than HOEP). Therefore, for hours in March and April when the HOEP fell as low as minus $27/MWh and minus $37/MWh respectively, an Ontario consumer that is charged HOEP would still have paid for incremental energy consumption due to the greater offsetting effect of the Global Adjustment, as opposed to being paid (as implied by the negative HOEP).

Although many of Ontario's business and industrial customers are exposed to the wholesale rate for electricity, almost half of electricity consumed in the province is covered by the Regulated Price Plan (RPP) prices as set, on a forecast basis, by the Ontario Energy Board (OEB) every six months (prices adjusted on May 1st and October 31st each year). As of May 1, 2009, the RPP was established at 5.7 cents/KWh up to 600

KWh each month and 6.6 cents/KWh after that, which represented an increase of 0.1 cents/KWh relative to the previous six-month period.[12]

Table 1-3 reports the average six-month HOEP relative to the load-weighted HOEP with and without the Global Adjustment and OPG Rebate over the last two winter periods. As mentioned above, the average OPG Rebate plus Global Adjustment increased substantially more than four times than last year, primarily due to low market prices towards the end of the current winter period. Although the load-weighted HOEP fell by $7.78/MWh this winter, the offsetting effect of the Global Adjustment and OPG rebate led to an increase in the effective load-weighted HOEP of $3.69/MWh, or 6.8 percent.

Table 1-3: Impact of Adjustments on Weighted HOEP, November–April 2007/2008 & 2008/2009 ($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate[13]	Effective Load-Weighted HOEP
2007/2008	49.16	51.09	(3.30)	54.39
2008/2009	40.98	43.31	(14.77)	58.08
Difference ($)	(8.18)	(7.78)	(11.47)	3.69
% Change	(16.6)	(15.2)	348.0	6.8

2.2 Price Setters

Over the six months this winter, real-time price-setting shares were almost unchanged relative to last winter across fuel categories, but this was due to considerable off-setting shifts in some months and between on-peak and off-peak periods. For example, coal-fired units set price more often than a year ago on-peak but less often off-peak, as overall prices fell and on-peak prices were in the coal-range more often. For pre-dispatch, the price-setting share for imports dropped quite significantly, as a result of the much lower levels of imports this winter.

[12] http://www.oeb.gov.on.ca/OEB/Documents/Press+Releases/press_release_rpp_prices_20090415.pdf
[13] A negative value represents a payment from consumers to generators.

2.2.1 Real-time Price Setters

Table 1-4 presents the average share of the real-time MCP set by resource type.[14] The table shows that average shares by resource type were almost identical over the last two winter periods, although the subsequent tables show this reflects off-setting shifts across the months.[15] Coal units continued to be the most frequent price setter in real-time at 58 percent of all intervals during the 2008/09 winter months, unchanged from last year. The most notable change in the period was that nuclear resources set the real-time MCP 3 percent of the time this winter, compared to in only one interval (represented as 0 percent in Table 1-4) last year, due to the abundance of Surplus Baseload Generation in March and April 2009. Hydro units set the price 21 percent of all intervals, down 2 percent from last winter.

Table 1-4: Average Share of Real-time MCP set by Resource Type, November–April 2007/2008 & 2008/2009 (% of Intervals)

	2007/2008	2008/2009	Difference
Coal	58	58	0
Hydro	23	21	(2)
Oil/Gas	19	18	(1)
Nuclear	0	3	3
Total	100	100	0

Tables 1-5 to 1-7 report the monthly share of real-time MCP set by resource type for the last two winter periods for all intervals, on-peak, and off-peak intervals respectively. Table 1-5 shows that coal's share of setting the real-time MCP increased in four months but these were offset mostly by a 27 percent decrease in April, corresponding to the much lower market demand. The tables also show that in April both hydro and nuclear price setting shares increased sharply from 25 percent to 41 percent for hydro and from 0 to 11 percent for nuclear, which in the following tables can be seen as mostly off-peak increases for nuclear.

[14] Dispatchable loads are also able to set the real-time MCP but are removed from Tables 1-4 to 1-7 since they do so infrequently. For example, between November 2008 and April 2009, dispatchable loads only set the real-time MCP in 0.04 percent of all intervals.
[15] Monthly shares for the previous winter period may be slightly different than those reported in the July 2008 MSP report. The formula used to calculate shares was slightly modified to accommodate multiple fuel types being able to set the real-time MCP. The calculation for the Oil/Gas category was also changed to recognize the steam portion of the combined-cycle plants.

Table 1-5: Monthly Share of Real-Time MCP set by Resource Type, November–April 2007/2008 & 2008/2009 (% of Intervals)

	Coal		Oil/Gas		Hydro		Nuclear	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	55	59	24	24	21	17	0	0
December	47	60	28	19	26	20	0	1
January	69	61	13	26	18	13	0	0
February	59	69	20	19	21	12	0	0
March	59	63	15	8	26	26	0	3
April	62	35	13	13	25	41	0	11
Average	58	58	19	18	23	21	0	3

During the on-peak intervals, Table 1-6 shows that coal's share increased from 44 percent to 50 percent overall, with the largest monthly increases occurring in February (15 percent) and March 2009 (28 percent). The table also shows that the oil/gas and hydro shares dropped in the recent six-month period. Oil/gas resources set the MCP less often in all months this winter with the exception of January, when demand increased and HOEP was up by almost 23 percent during on-peak hours as reported in Table 1-1. Hydro resources also set the MCP less often this winter on-peak in five of the six months, the exception being April where the share increased from 19 percent in 2008 to 32 percent in 2009.

Table 1-6: Monthly Share of Real-Time MCP set by Resource Type, On-Peak, November–April 2007/2008 & 2008/2009 (% of Intervals)

	Coal		Oil/Gas		Hydro		Nuclear	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	33	47	41	41	26	12	0	0
December	32	44	45	37	23	19	0	0
January	59	44	25	46	16	10	0	0
February	41	56	37	33	22	11	0	0
March	39	67	29	14	32	19	0	0
April	58	44	23	23	19	32	0	1
Average	44	50	33	32	23	17	0	0

During the off-peak hours, Table 1-7 shows that over the last winter period, coal units set the MCP 64 percent of the time, down from 70 percent last winter but still larger than coal's share during the on-peak intervals. Oil/gas and hydro resources off-peak share remained relatively unchanged overall, but showed some monthly fluctuations. Nuclear resources set the off-peak MCP in 4 percent of all intervals during the latest six-month period, up from zero percent one year earlier. In April 2009, nuclear units set the real-time MCP 19 percent of the time, which is reflective of the high frequency of off-peak SBG events in the month. The low demands and high availability of generation in April also led to an increase of 17 percent for hydro and reduction of 37 percent for coal price-setting shares.

Table 1-7: Monthly Share of Real-Time MCP set by Resource Type, Off-Peak, November–April 2007/2008 & 2008/2009 (% of Intervals)

	Coal		Oil/Gas		Hydro		Nuclear	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
November	75	69	8	10	17	21	0	0
December	56	73	16	5	28	21	0	1
January	78	75	2	10	20	15	0	0
February	75	79	4	7	21	14	0	0
March	72	59	6	3	22	32	0	6
April	65	28	4	5	31	48	0	19
Average	70	64	7	7	23	25	0	4

2.2.2 Pre-dispatch Price Setters

Historically, imports and exports have played a large role in setting pre-dispatch prices. Table 1-8 shows the percentage of hours that the one-hour pre-dispatch price was set by resource type on a monthly basis this winter compared to last winter.[16] Overall, there was a noticeable decline of 16 percentage points for imports setting the pre-dispatch price this winter. The decline is consistent with lower import volumes, as total scheduled imports (not including the import leg of linked-wheels) declined from 4.4 TWh last winter to 2.8 TWh this year, a decrease of 37 percent (see Table 1-35 below). With a small change for the period in exports setting the price, generation consequently set the pre-dispatch price more often increasing from 41 percent last winter to 56 percent this winter. Monthly

[16] The table excludes the very small (on the order of 0.1 percent) contribution from Dispatchable Loads.

shares for both imports and exports setting the pre-dispatch price were lower in March and April 2009 because intertie outages in those months reduced the intertie trade allowed, as noted earlier in section 2.1.

Table 1-8: Monthly Share of Pre-dispatch Price set by Resource Type, November–April 2007/2008 & 2008/2009 (% of Hours)

	Imports		Exports		Generation	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	39	36	21	21	40	43
December	39	24	16	25	46	52
January	34	24	16	23	50	53
February	40	27	20	20	40	53
March	41	14	23	17	36	69
April	40	11	24	22	37	67
Average	39	23	20	21	41	56

2.3 One-Hour and Three-Hour Ahead Pre-dispatch Prices and HOEP

Production and consumption decisions are improved when market participants have accurate pre-dispatch prices. Therefore, the differences between one-hour ahead and three-hour ahead pre-dispatch prices and HOEP are important statistics to monitor as the improved accuracy of the pre-dispatch price signals will translate into real-time dispatch efficiencies.

2.3.1 One-hour Ahead Pre-dispatch Price

Table 1-9 presents the differences between the one-hour ahead pre-dispatch price and the HOEP for November 2008 through April 2009 relative to the same months a year ago. There was a significant improvement in the average and absolute average differences. The average difference fell from $9.15/MWh last winter to $3.92/MWh this year while the absolute average difference decreased from $13.00/MWh to $9.72/MWh. The positive arithmetic averages indicate that pre-dispatch prices are generally higher than real-time prices, with the averages in each month relative to the corresponding month last winter. Over the recent six-month period, the average hourly difference as a percentage of average monthly HOEP fell by almost half from 18.6 to 9.6 percent and were largest in March and April 2009.

Table 1-9: Measures of Differences between One-Hour Ahead Pre-Dispatch Prices and HOEP, November–April 2007/2008 & 2008/2009 ($/MWh)

	Average Difference		Absolute Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of Average HOEP[17]	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	7.50	4.81	10.52	8.99	56.65	42.90	(58.16)	(67.71)	12.91	11.81	16.0	9.3
December	7.37	3.08	10.74	9.92	52.08	83.79	(52.54)	(177.65)	13.32	18.12	15.0	6.6
January	9.41	7.42	11.25	12.44	64.78	1,925.02	(66.65)	(379.76)	13.52	73.97	23.1	13.9
February	11.28	0.18	15.06	11.29	107.12	60.23	(485.46)	(1,846.87)	25.08	81.92	21.5	0.4
March	10.87	4.35	15.00	7.87	77.36	66.62	(124.21)	(125.82)	18.68	13.35	19.1	15.1
April	8.46	3.66	15.41	7.82	77.91	57.88	(143.82)	(80.80)	21.38	11.89	17.3	19.9
Average	9.15	3.92	13.00	9.72	72.65	372.74	(155.14)	(446.44)	17.48	35.18	18.6	9.6

2.3.2 Three-hour Ahead Pre-dispatch Price

Table 1-10 reports the differences between the three-hour ahead pre-dispatch price and the HOEP for November through April 2007/2008 and 2008/2009. The average difference between the three-hour ahead pre-dispatch price and HOEP three-hours ahead also dropped in the latest winter period. In fact, the average price difference fell below $0/MWh in February 2008 suggesting on average, the HOEP was higher than the three-hour pre-dispatch price for the month. In absolute terms, the average price difference also fell from $13.11/MWh to $9.11/MWh this winter. In part, this result was influenced by the two high-priced hours on February 18, 2009, which are discussed in more detail later in Chapter 2. (These two high prices also affected the statistics for the one-hour ahead prices in Table 1-9, where the average difference remained slightly above zero, $0.18/MWh.)

[17] In previous MSP Reports, the average difference as a percentage of HOEP statistics found in the last column of Tables 1-9 and 1-10 was calculated hourly and then averaged over the month. However, given the high frequency of HOEP around $0/MWh (and sometimes a HOEP equal to $0/MWh leading to an undefined result), the statistic was being driven up (or down) by some very large outliers. To minimize this outlier effect, the calculation has been revised as the average price difference as a percentage of the average HOEP in each month (denominator being the monthly average HOEP reported in Table 1-1). Results from the 2007/2008 winter period have also been adjusted.

Table 1-10: Measures of Differences between Three-Hour Ahead Pre-Dispatch Prices and HOEP, November–April 2007/2008 & 2008/2009 ($/MWh)

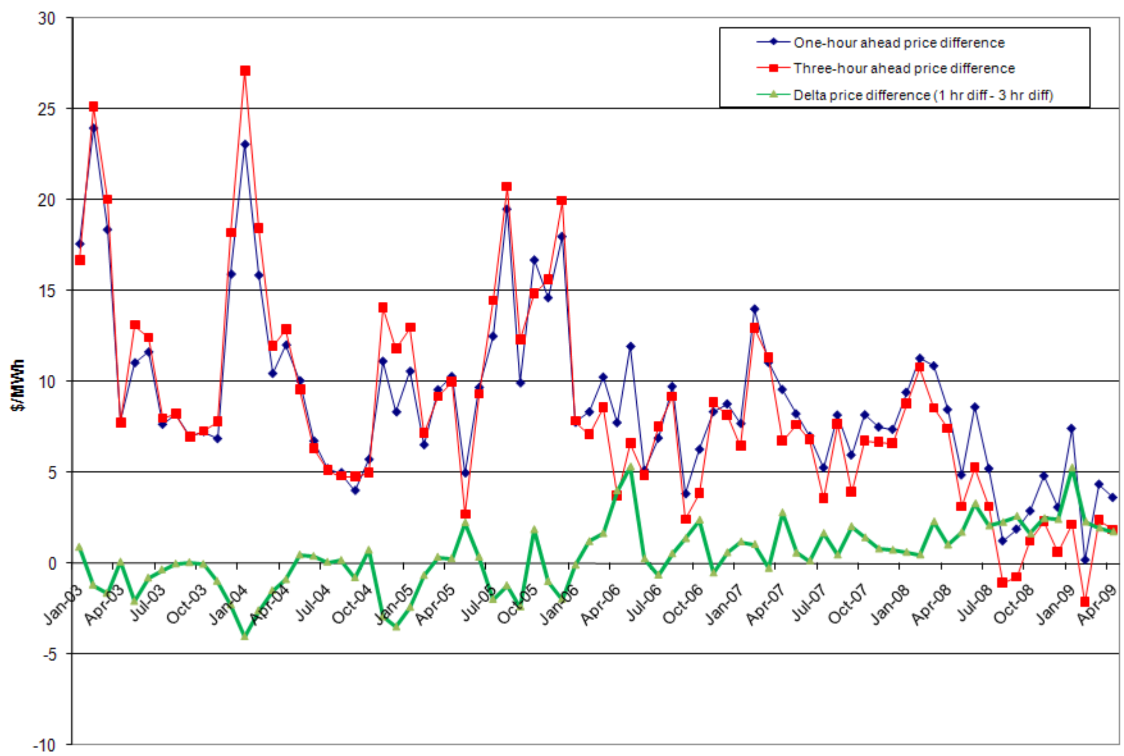
	Average Difference		Absolute Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	6.68	2.31	10.16	8.87	50.18	43.57	(54.74)	(78.83)	13.48	12.73	14.2	4.5
December	6.62	0.64	11.29	10.01	48.05	52.07	(50.61)	(184.42)	14.24	19.11	13.5	1.4
January	8.78	2.13	11.46	9.30	63.38	52.48	(84.51)	(411.27)	14.28	24.17	21.6	4.0
February	10.79	(2.13)	14.89	10.94	68.85	42.49	(505.62)	(1,853.34)	25.50	82.19	20.6	(4.5)
March	8.55	2.38	15.19	7.66	77.36	68.23	(125.90)	(142.18)	20.29	13.43	15.0	8.2
April	7.42	1.86	15.67	7.85	82.12	42.11	(145.17)	(81.83)	22.34	12.68	15.2	9.9
Average	8.14	1.20	13.11	9.11	64.99	50.16	(161.09)	(458.65)	18.36	27.39	16.6	2.9

Figure 1-3 plots the average monthly difference between the one and three-hour ahead pre-dispatch versus real-time prices between January 2003 and April 2009. The figure shows that the average monthly difference between the one-hour ahead pre-dispatch price and HOEP continues to be larger than the three-hour ahead pre-dispatch differences, as has been the case since early 2006. Overall, both the one-hour ahead and three-hour ahead price differences have declined since 2003 and generally remained less than $5/MWh in all months over the current winter period.

Figure 1-3 also demonstrates that there has been a persistent and widening gap between one-hour and three-hour ahead price differences. As represented by the green line, the three-hour ahead price difference has been smaller than the one-hour ahead price difference in all months since April 2007. Furthermore, the three-hour ahead difference has been at least $2.00/MWh lower than the one-hour ahead difference in 15 months since 2003, with most (11) of those months occurring after April 2007. Finally, in the most recent six months, average monthly differences for the three-hour ahead price has been $1.20/MWh compared to the average of $3.92/month for the one-hour, or $2.72/MWh less.

The reasons for this are not entirely clear, but one factor which in part may explain this trend relates to the timing of export bids. Many imports and exports have their offers finalized as late as possible, in order to benefit from the most recent market information. This means that bids and offers are finalized after the three-hour ahead pre-dispatch run. Since there has been an increasing tendency towards Ontario being a net exporter in recent years, more exports than imports would be showing-up in the last two hours. This would tend to increase the market demand in the last two pre-dispatches, and increase the difference between one-hour ahead pre-dispatch prices relative to three-hour ahead, everything else being equal.

Figure 1-3: Average Pre-dispatch to HOEP Price Differences
One and Three-Hour Ahead,
January 2003–April 2009
($/MWh)



2.3.3 Reasons for Differences

To date, the Panel has identified four main factors that lead to discrepancies between pre-dispatch and real-time prices:[18]

- Demand forecast error;
- Performance of self-schedulers and intermittent (primarily wind) generators;
- Failure of scheduled imports and exports; and
- Frequency that imports (or exports) set the pre-dispatch price.

Table 1-11 presents the average and absolute average differences for each of the first three factors listed above for the latest six-month period. Monthly averages and absolute averages provide some indication as to which of the factors are most important in leading to discrepancies between pre-dispatch and real-time prices. However, any one of these factors can lead to significant price discrepancies in a given hour.

Overall, the largest absolute average errors appear to result from demand forecast error. Although peak-to-peak average hourly error was 32 MW, the absolute average error was 182 MW (and peak-to-average deviation magnitudes were even higher). Both average and absolute average net export failures and self-scheduling and intermittent errors were similar in magnitude over the recent six-month period.

[18] Pre-dispatch and real-time scheduling also differ in the magnitude of control action operating reserve (CAOR) incorporated, although this tends primarily to affect operating reserve price differences, with an indirect and smaller influence on energy prices. Up to September 2008 there were 400 MW of CAOR available in pre-dispatch and 800 MW in real-time. Subsequently, the 400 MW in pre-dispatch was dropped. See the Panel's January 2009 Monitoring Report, pp. 191-193.

Table 1-11: Average and Absolute Average Hourly Error by Discrepancy Factor, November 2008–April 2009 (MW)

Discrepancy Factor	Average Error (MW)	Absolute Average Error (MW)	Average Error as % of Ontario Demand	Absolute Average Error as % of Ontario Demand
Peak-to-Peak Demand Forecast Error	32	182	0.19	1.08
Peak-to-Average Demand Deviation	258	310	1.53	1.84
Self-Scheduling and Intermittent Error	37	82	0.22	0.49
Net Export Failures	31	87	0.18	0.51

*Average hourly Ontario Demand for the six-month period was 16,886 MW

2.3.3.1 Demand Forecast Error

Table 1-12 reports the one-hour and three-hour ahead mean absolute demand forecast error on a monthly basis over the 2007/08 and 2008/09 winter months. There were slight increases this winter in both one-hour ahead and three-hour ahead average peak-to-peak demand forecast errors and peak-to-average demand deviations. The one-hour ahead measurements were lower in all months relative to the three-hour ahead measurements. This is an expected result as conditions affecting demand are more predictable one-hour ahead. Average peak-to-average demand deviation grew from 1.90 percent to 2.08 percent three-hours ahead and from 1.73 percent to 1.86 percent one-hour ahead. Peak-to-peak forecast error increased from 1.19 percent to 1.32 percent three-hours ahead and from 0.98 percent to 1.07 percent one-hour ahead.

Table 1-12: Demand Forecast Error, November–April 2007/2008 & 2008/2009 (%)

	Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand			
	Three-Hour Ahead		One-Hour Ahead		Three-Hour Ahead		One-Hour Ahead	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	1.81	1.96	1.76	1.85	1.02	1.13	0.88	0.96
December	1.94	2.22	1.74	1.98	1.41	1.40	1.12	1.10
January	2.01	2.20	1.79	1.94	1.12	1.32	0.88	1.06
February	1.87	1.92	1.70	1.74	1.13	1.17	0.96	0.94
March	1.97	2.11	1.73	1.81	1.34	1.51	1.06	1.20
April	1.80	2.07	1.68	1.81	1.13	1.41	0.95	1.15
Average	1.90	2.08	1.73	1.86	1.19	1.32	0.98	1.07

Improvements in the magnitude of demand forecast error levels have been observed since market opening. Figure 1-4 reports monthly one-hour ahead absolute demand forecast error between January 2003 and April 2009. In 2003 and 2004, absolute average demand forecast error was typically above 1.2 percent. Since mid-2006, the average absolute error has remained relatively stable fluctuating between 0.8 percent and 1.2 percent and only exceeding 1.2 percent in two months (August 2007 and June 2008). The winter six-month average has increased slightly in the last two years, from a low of 0.89 percent November 2006 to April 2007, to the current winter value of 1.07 percent.

Figure 1-4: Absolute Average One-Hour Ahead Forecast Error, January 2003–April 2009 (% of Peak Demand)

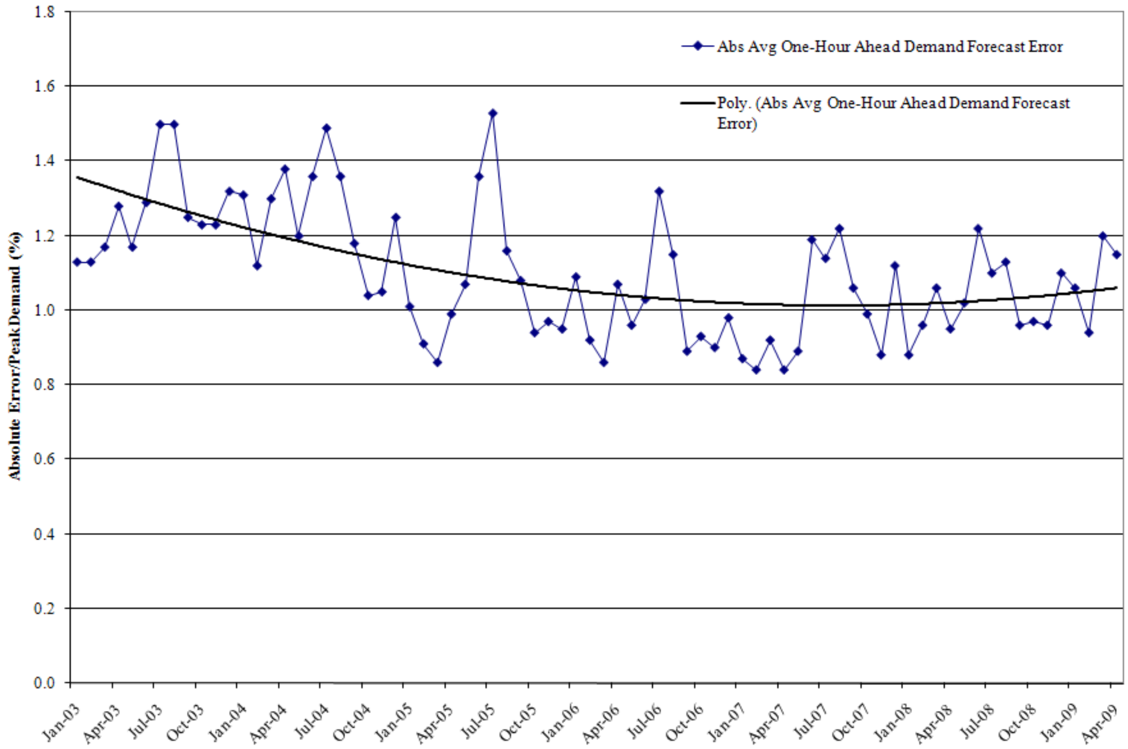
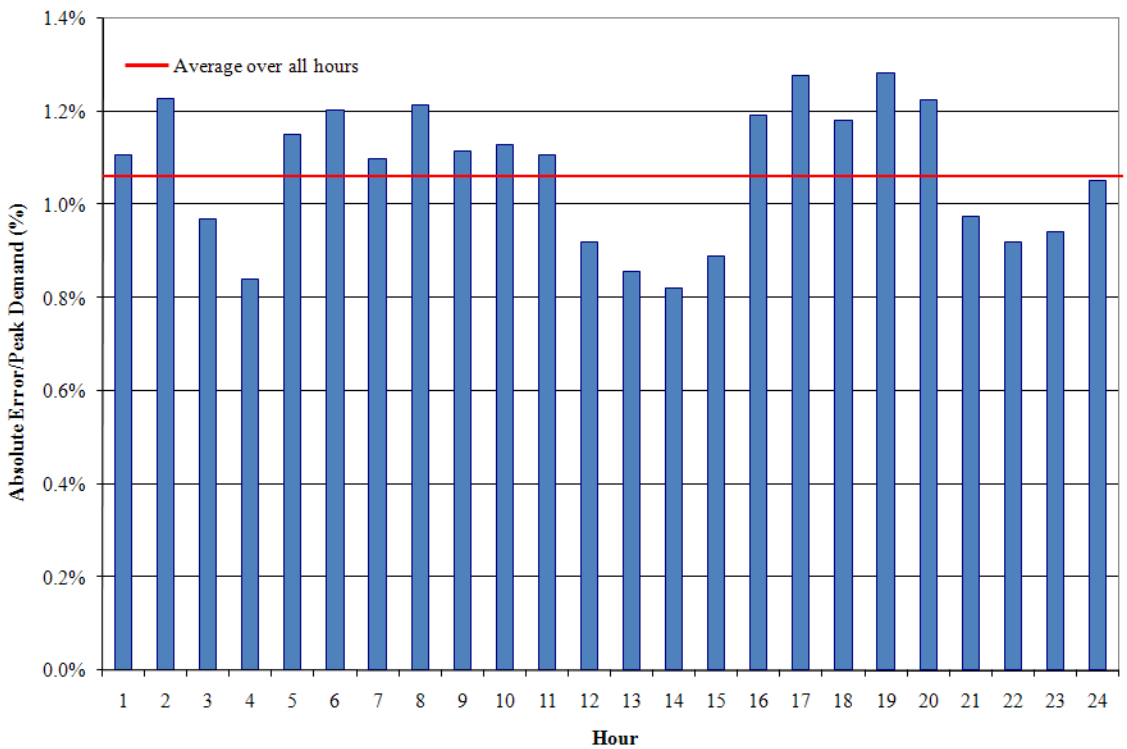


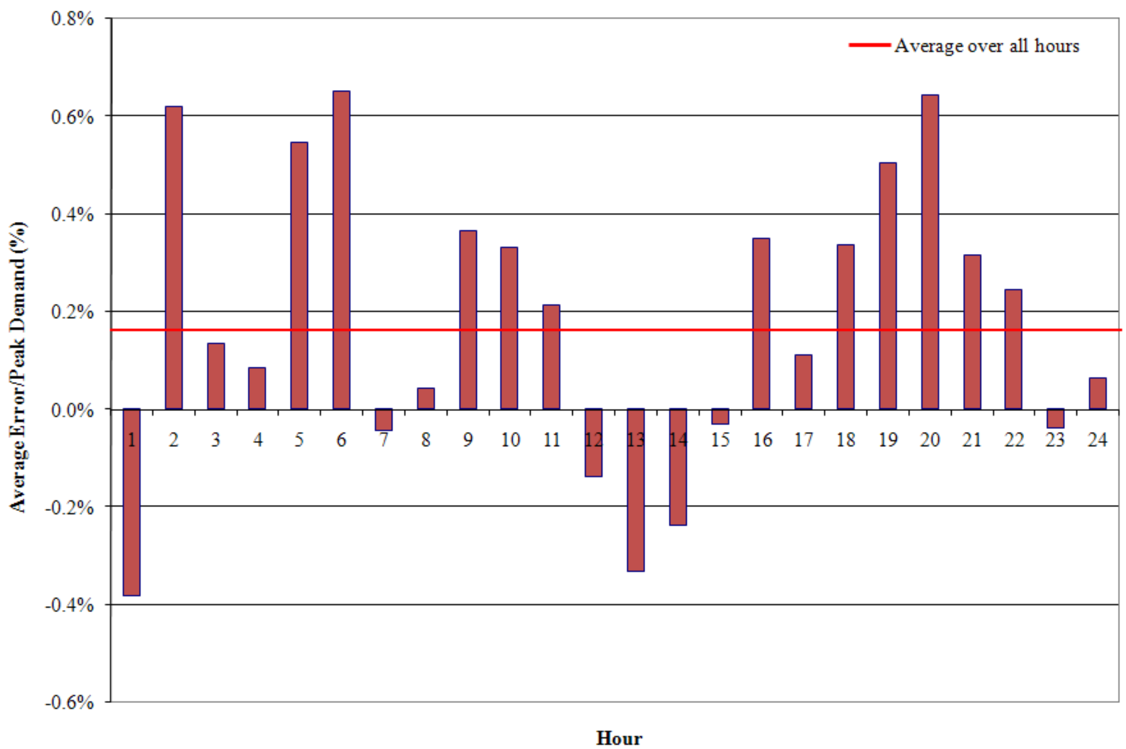
Figure 1-5 plots the one-hour ahead absolute average peak-to-peak forecast error by hour of the day over the latest winter period. The average forecast error over the six-month period was 1.07 percent and is represented by the red horizontal line. On average, forecast errors tended to be highest during the early morning hours up to the morning peak hours and also during the evening peak hours. On the other hand, forecast errors were lowest during the mid day hours, specifically hours 12 to 15.

Figure 1-5: Absolute Average One-Hour Ahead Forecast Error by Hour, November 2008-April 2009 (% of Peak Demand)



Although the absolute average provides some perspective on the magnitude of the demand forecast errors, the arithmetic average as presented in Figure 1-6 shows the bias of the error which can be positive or negative. The average one-hour ahead forecast error was slightly positive over the recent six-month period at 0.18 percent indicating that pre-dispatch forecasts were slightly higher than actual peak demand. The figure shows that the largest over-forecasts occurred in a few early morning hours and the evening peak hours. Conversely, demand was under-forecast mostly during the mid-day hours along with hour 1.

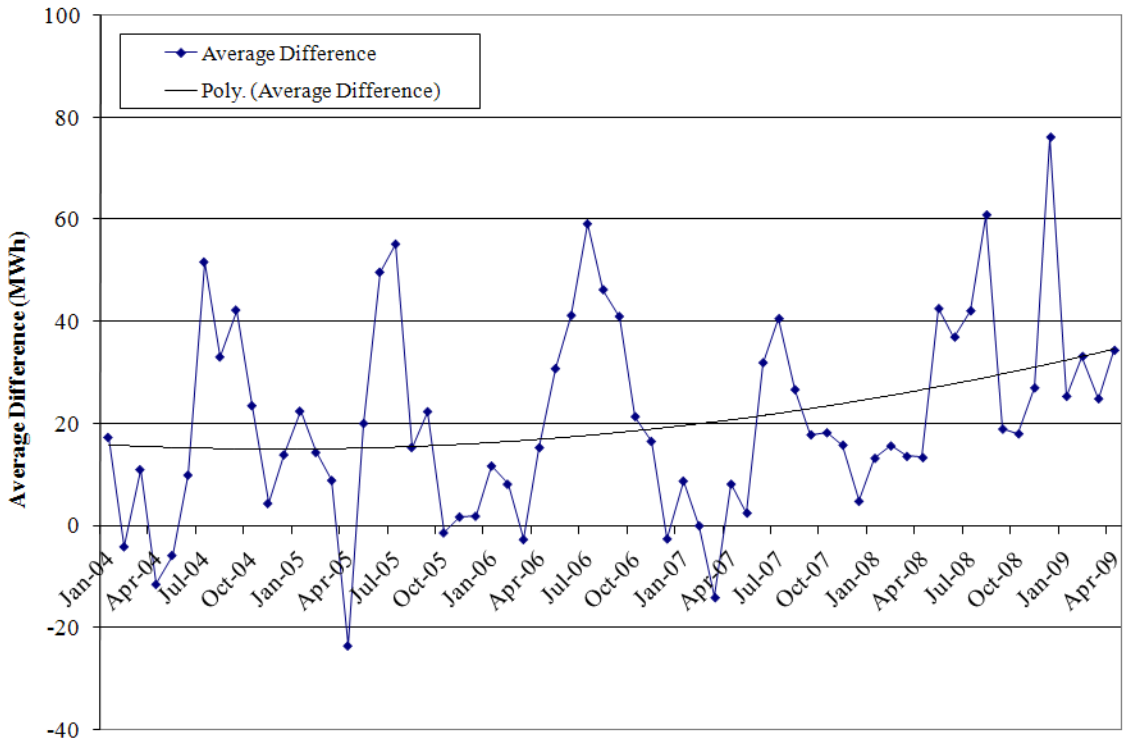
Figure 1-6: Arithmetic Average One-Hour Ahead Forecast Error by Hour, November 2008-April 2009 (% of Peak Demand)



2.3.3.2 Performance of Self-Scheduling and Intermittent Generation

Figure 1-7 plots the monthly average difference between the amount of energy self-scheduling and intermittent generator forecast and the amount of energy they actually deliver in real-time. Historically, the largest peaks in self-scheduling and intermittent generation error have occurred during the summer months. However average error reached a peak of 76 MW in December 2008, the largest monthly value since 2004. Furthermore, error levels were higher this winter compared to any other winter over the last five years. Increased wind generating resources and a large volume of commissioning units over the recent winter (typically new gas-fired units) placed upward pressure on error levels.

Figure 1-7: Average Difference between Self-Scheduling and Intermittent Generator Forecasted and Delivered Energy, January 2004–April 2009 (MWh)



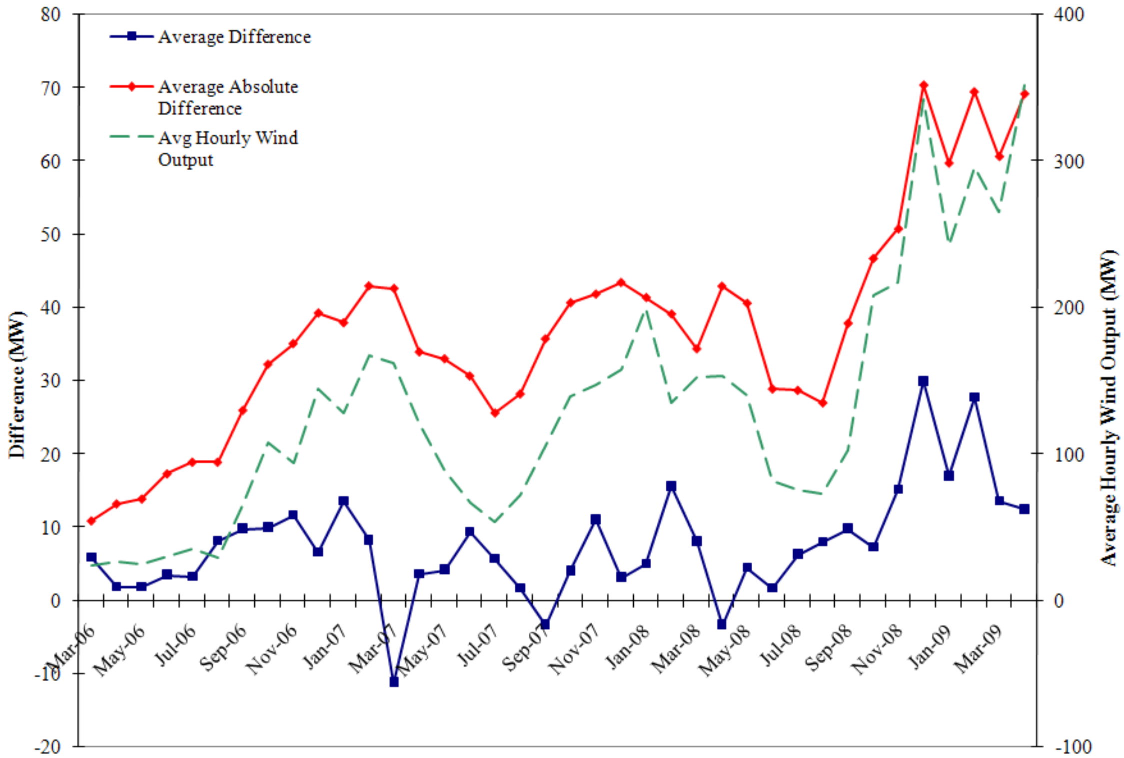
Since early 2006, the amount of wind generating resources entering the market has steadily increased. As of April 2009, there was a combined name-plate capacity of 887 MW, based on the sum of the large wind projects currently operational in Ontario.[19] Figure 1-8 presents the average and absolute average difference between wind generators' forecasted and delivered energy. Average hourly wind output is also plotted and represented by the green dashed line.[20] Figure 1-8 shows that both the average and absolute average wind forecast error has been increasing since 2006 and the magnitude of the error has climbed as wind output has increased. Absolute average wind error reached as high as 70 MW in December 2008 and all observations this winter were higher than the previous peak of 46 MW observed in October 2008. Previously in the January 2009

[19] See the OPA's Wind-power webpage for details on wind projects that are currently operational and those under development at: http://64.34.71.254/Page.asp?PageID=924&SiteNodeID=234

[20] In previous MSP Reports, nameplate capacity was plotted to show that amount of wind available in a given month. However, using average hourly wind output provides a better measure of actual wind generation performance in a given month as outages and other factors constraining wind generation at specific facilities are reflected in actual output levels but not in the nameplate capacity value. Average hourly wind output is also used to deflate average and absolute average wind error in Figure 1-8.

MSP Report, the Panel recommended that efforts to efficiently accommodate new renewable energy resources should be investigated including the consideration of centralized wind forecasting to help reduce wind forecast error from directly connected and demand forecast error from embedded wind resources.[21] This is especially important in light of the passage of the Ontario government's *Green Energy and Green Economy Act, 2009*, *(GEA)* in May 2009, which among other things is aimed at increasing investment in renewable energy projects such as wind generation.[22]

Figure 1-8: Average and Absolute Average Difference between Wind Generator Forecasted and Delivered Energy and Average Hourly Wind Output, March 2006–April 2009 (MW)

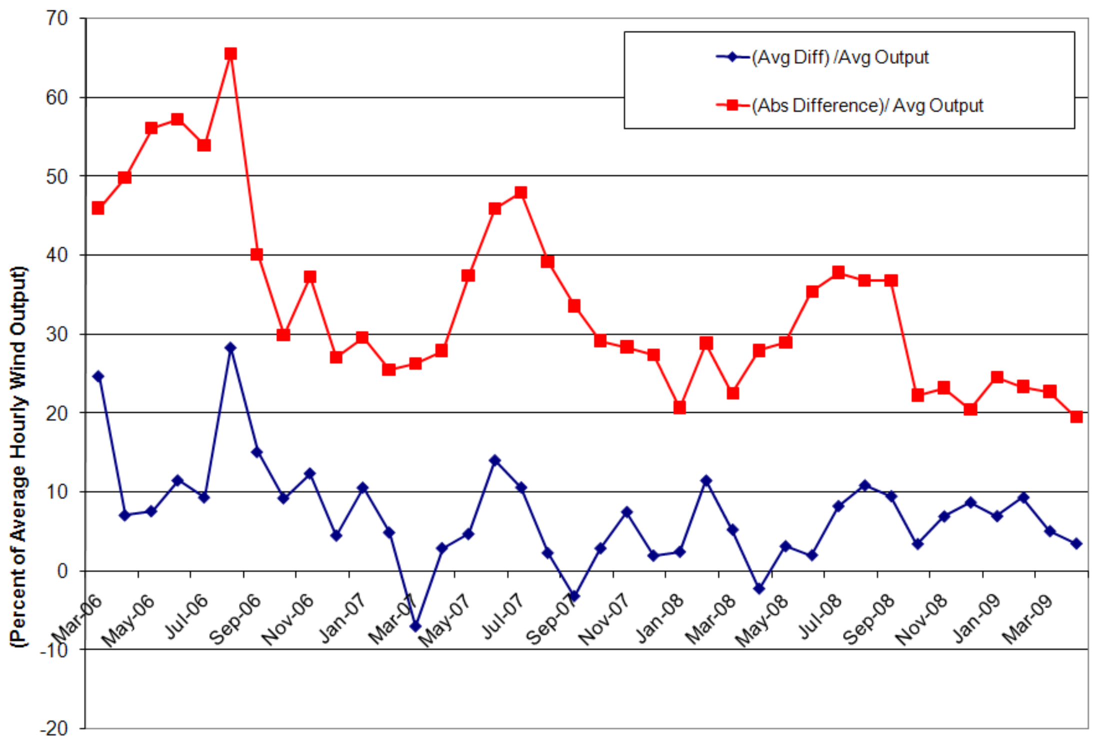


The Figure above shows that average and absolute average differences have increased since early 2006 and peaked in the 2008/2009 winter months. However when these error measurements are normalized by hourly average wind output, little trend is apparent. Figure 1-9 plots the average and absolute average difference between wind generators'

[21] See Recommendation 4-1 in Chapter 4 of the January 2009 MSP Report, p 256.
[22] For more information on the Green Energy Act, see the Ministry of Energy and Infrastructure's GEA webpage at: http://www.mei.gov.on.ca.wsd6.korax.net/english/energy/gea/

forecasted energy and actual energy produced normalized using hourly average wind output since March 2006. Normalized absolute average difference as a percentage of hourly wind output ranged between 20 to 25 percent over the latest winter period while the average difference remained below 10 percent of the hourly average wind output in most months. Normalized average differences has been roughly stable since the end of 2006, while there appears to be a slight downward trend for the normalized absolute average differences as wind output has increased. However, absolute average differences of this magnitude (greater than 20 percent as shown in Figure 1-9) is significant and should be addressed as more wind generation is currently under development.

Figure 1-9: Normalized Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy, March 2006-April 2008 (Difference/Wind Capacity)



2.3.3.3 Real-Time Failed Intertie Transactions

Failed import and export transactions are also a contributing factor leading to differences in pre-dispatch prices and HOEP. In real-time, import failures represent a loss of supply while export failures represent a decline in demand, both of which result in pre-dispatch to real-time price discrepancies.

Export Failures

Table 1-13 reports statistics on the frequency and magnitude of failed export transactions over the latest winter periods. Overall, the number of hours when exports failed declined this winter by 582 hours, from 2,712 hours to 2,130 hours. Similarly, the failure rate declined from 5.93 percent last winter to 3.64 percent this winter. Average hourly export failures were down in five of the six months with the exception of March where average export failures increased from 154 MW to 168 MW.

Table 1-13: Frequency and Average Magnitude of Failed Exports from Ontario, November–April 2007/2008 & 2008/2009

	Number of Hours when Failed Exports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	363	314	876	552	171	131	6.10	2.93
December	431	386	857	1,645	186	176	5.87	4.62
January	508	434	1,142	965	207	133	5.62	3.07
February	498	340	1,150	675	265	134	8.20	3.28
March	401	337	774	1,815	154	168	4.83	3.79
April	511	319	843	900	179	108	4.96	4.13
Total/Average	2,712	2,130	940	1,092	194	142	5.93	3.64

* The incidents with less than 1 MW and linked wheel failures are excluded
** Based on those hours in which a failure occurs
*** Total failed export MWh divided by total scheduled export MWh (less the export leg of linked wheels) in the unconstrained schedule in a month

Import Failures

Table 1-14 compares the frequency and rate of import failures over the 2007/08 and 2008/09 winter months. The number of hours when failed imports occurred dropped slightly by 38 hours this winter, corresponding to the decline in scheduled imports this winter compared to last year. However, the import failure rate increased from 4.3 percent last winter to 6.0 percent this winter, an increase of 1.7 percent.

Table 1-14: Frequency and Average Magnitude of Failed Imports to Ontario, November–April 2007/2008 & 2008/2009

	Number of Hours when Failed Imports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	210	282	677	730	136	152	2.80	5.13
December	170	220	597	812	129	143	2.19	7.17
January	261	287	843	600	156	143	5.86	5.99
February	233	145	550	800	139	158	4.97	5.26
March	221	163	786	575	155	98	6.10	5.70
April	190	150	450	425	132	108	4.07	7.00
Total/Average	1,285	1,247	651	657	141	134	4.33	6.04

* The incidents with less than 1 MW and linked wheel failures are excluded
** Based on those hours in which a failure occurs
*** Total failed import MWh divided by total scheduled import MWh (less the import leg of linked wheels) in the unconstrained schedule in a month

Causes of Failures

Figures 1-10 and 1-11 plot export and import failure rates beginning in January 2005. Failures are separated by those under the market participants' control (labelled MP failures) and those under the control of a system operator (labelled ISO curtailments).[23,24] The failure rate is determined as a percentage of failed to total exports (or imports) in MWh per month (linked-wheel failures are not included).

[23] Data prior to 2005 is not considered given the introduction of the intertie failure charge in June 2006
[24] The IESO Compliance database that separates failures into ISO curtailments and market participant failures does so for constrained schedule failures only. Therefore, failure rates vary slightly from the statistics reported in Tables 1-13 and 1-14, which report unconstrained schedule failures in aggregate.

The export failure rate, as illustrated in Figure 1-10, has been declining for both MP caused failures and ISO curtailments. The failure rate for exports curtailed under an ISO's control reached its lowest level since 2005 in February 2009 at 0.48 percent and, with the exception of April, remained below 2 percent for all months this winter. Similarly, the MP caused failure rate was lower than failure rates observed last winter and fluctuated between 2 to 4 percent.

Figure 1-10: Monthly Export Failures as a Percentage of Total Exports by Cause, January 2005–April 2009
(%)

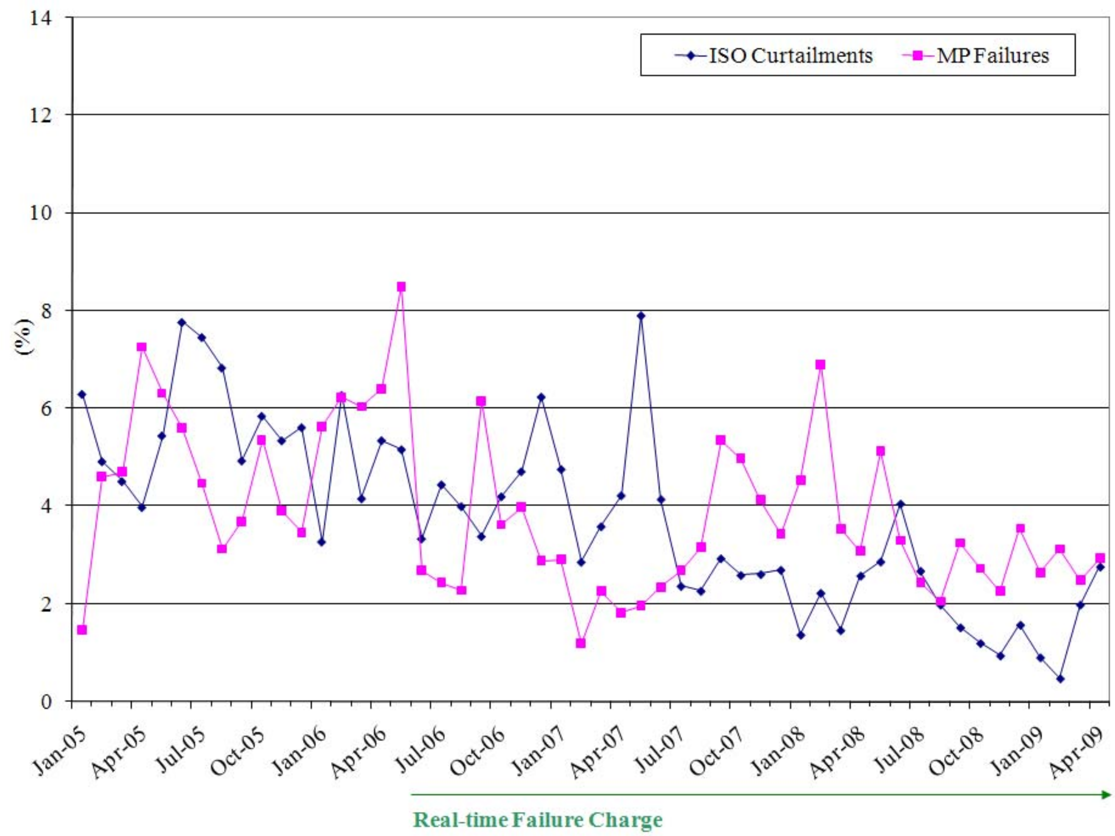
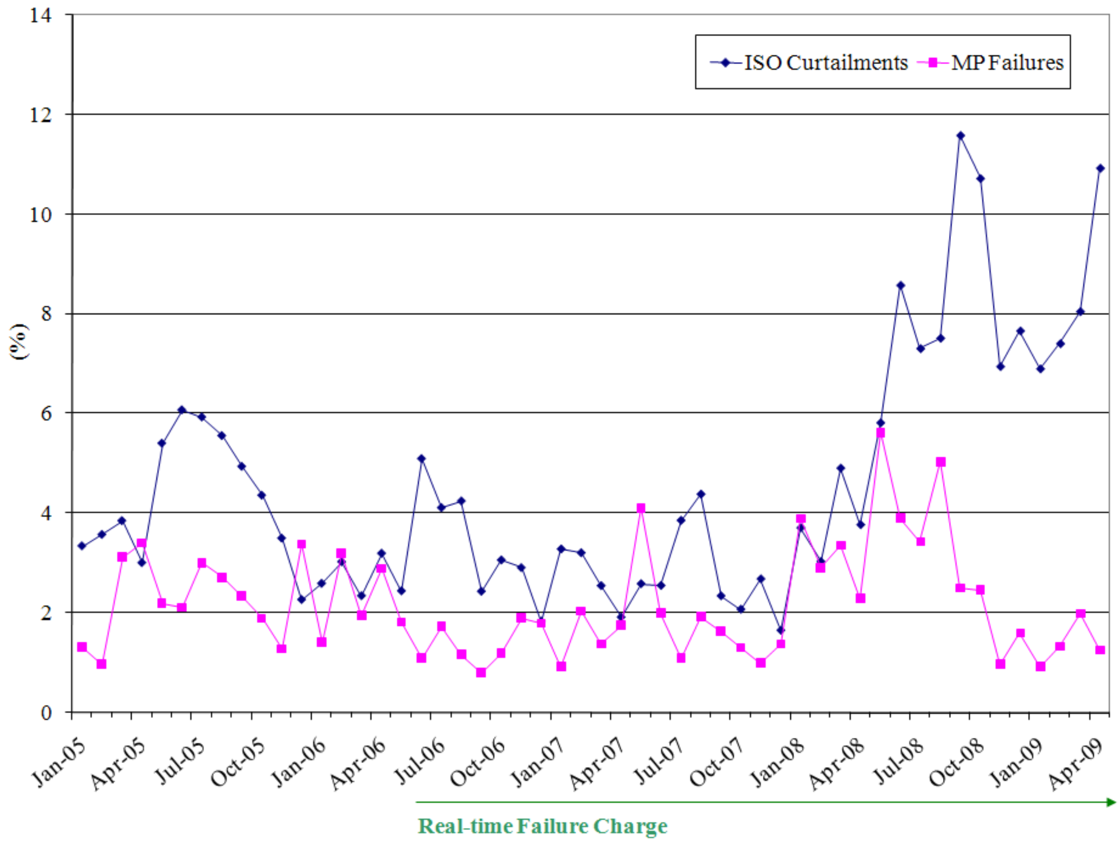


Figure 1-11 plots the import failure rate by cause between January 2005 and April 2009. In the previous MSP Report, the Panel noted a significant increase last summer in the import failure rate for imports not under the MP's control. The ISO controlled import failure rate remained high this winter relative to previous winter periods since 2005. The failure rate was in the 8 percent range this winter, with the exception of April 2009 when it rose back to the 11 percent level experienced last summer.

Figure 1-11: Monthly Import Failures as a Percentage of Total Imports by Cause, January 2005–April 2009
(%)



<u>Failures by Intertie Group</u>

Tables 1-15 and 1-16 report average monthly export and import failures by intertie group and cause for the period November 2008 to April 2009. Exports failures at the Michigan intertie accounted for almost half (44.6 percent) of all ISO export failures. The failure rate for ISO controlled export failures was highest at the Minnesota intertie at 10.2 percent, largely due to high levels of internal congestion in the northern areas of MISO. New York destined export failures made up the majority of participant controlled export failures (82.8 percent) with an associated failure rate of almost 6 percent, the highest of all intertie groups. Participant failures are highest at the New York intertie since participants selling into New York must place offers to sell the energy in real-time which allows for the possibility that transactions are not economic and not scheduled in New York even when scheduled in Ontario. The potential for mismatched economic scheduling with NYISO (also for imports) is unique among the jurisdictions directly connected to Ontario. This distinction also applies for imports to Ontario.

Table 1-15: Average Monthly Export Failures by Intertie Group and Cause, November 2008–April 2009 (GWh and % Failures)

	Average Monthly Exports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
NYISO	547	3.6	19.7	32.2	82.8	0.7	5.9
Michigan	717	8.2	44.6	6.3	16.2	1.1	0.9
Manitoba	24	0.7	3.7	0.1	0.1	2.9	0.4
Minnesota	41	4.2	22.7	0.1	0.4	10.2	0.2
Quebec	48	1.7	9.4	0.2	0.4	3.5	0.4
Total	1,376	18.4	100.0	38.9	100.0	1.3	2.8

Table 1-16 reports average monthly import failures by intertie and cause for the period November 2008 to April 2009. Average monthly Michigan imports totaled 346 GWh, or about three-quarters of total imports over the latest winter period. Therefore it is not surprising that the magnitude of both ISO controlled import failures and participant controlled failures were the highest at the Michigan intertie at 31.5 GWh (91 percent of all ISO controlled failures) and 2.9 GWh (52 percent of all participant controlled failures) respectively. The failure rate for ISO controlled failures of 9.1 percent was materially higher than on other intertie groups.[25] However, for participant controlled failures, the Michigan rate was less than 1 percent compared with 5.3 percent in New York. This high participant failure rate for New York was also noted above for exports.

[25] ISO-controlled import failures were identified in the previous Panel report as having increased because of some changes in MISO procedures. For a more detailed discussion on the reasons for the increase in ISO curtailments, see the January 2009 MSP Monitoring Report, p 27.

Table 1-16: Average Monthly Import Failures by Intertie Group and Cause, November 2008–April 2009 (GWh and % Failures)

	Average Monthly Imports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
NYISO	45	0.4	1.2	2.4	42.4	0.9	5.3
Michigan	346	31.5	91.2	2.9	52.0	9.1	0.8
Manitoba	15	0.7	2.2	0.1	1.2	4.7	0.7
Minnesota	17	1.1	3.2	0.1	2.5	6.5	0.6
Quebec	38	0.8	2.2	0.1	2.0	2.1	0.3
Total	461	34.6	100.0	5.7	100.0	7.5	1.2

2.3.3.4 Imports or Exports Setting Pre-dispatch Price

Another factor identified by the Panel that leads to discrepancies between pre-dispatch and real-time prices is the frequency of imports and exports setting the pre-dispatch MCP. An increased frequency of imports or exports setting the pre-dispatch price will lead to an increased divergence between pre-dispatch and real-time prices.

Currently the unconstrained schedule does not allow imports or exports to set the MCP in real-time, as imports are essentially moved to the bottom of the offer stack and exports to the top of the bid stack.[26] When an import sets the pre-dispatch price in a given hour, a lower priced generating unit's offer will typically set the price in real-time because of lower average demand in real-time than the forecast peak demand in pre-dispatch. Similarly, exports are eligible to be marginal in pre-dispatch but are unable to set the real-time MCP so the next closest generator offer will set the price. The result is a discrepancy between pre-dispatch and real-time MCP.

[26] In effect, the net export modifies the total demand.

Table 1-17 shows the frequency of hours that imports and exports set the pre-dispatch price for the last two winter periods. The number of hours fell from 2,428 hours to 1,913 hours with the largest monthly declines occurring in March and April 2009 when the capability of the interties at New York (and indirectly limiting the export capability at the Michigan interties) were restricted.

Table 1-17: Frequency of Imports or Exports Setting the Pre-Dispatch Price, November–April 2007/2008 & 2008/2009 (Number of Hours and % of Hours)

	2007/2008		2008/2009		Difference	
	Hours	%	Hours	%	Hours	% Change
November	416	58	411	57	(5)	(1)
December	388	52	361	49	(27)	(3)
January	354	48	352	47	(2)	(1)
February	393	56	319	47	(74)	(9)
March	450	60	232	31	(218)	(29)
April	428	59	238	33	(190)	(26)
Total	2,428	56	1,913	44	(515)	(12)

2.4 Analyzing Year-Over-Year Changes in the HOEP

Table 1-18 presents the results from the estimated econometric model of HOEP using monthly data over the time period January 2003 to April 2009 to identify the relative importance of changes in different factors on the HOEP.[27] There are 76 months of observations in the sample. The dependent variable in the model is the HOEP. The independent variables are: nuclear generation in Ontario, self-scheduled generation in Ontario, Ontario non-dispatchable load, New York integrated demand, the Henry-hub natural gas price (in Canadian dollars), and eleven monthly dummy variables.

[27] For more information on the methodology of the econometric model, see the December 2006 MSP Monitoring Report (pp. 21-25)

Table 1-18: Estimation Results of the Updated Econometric Model, January 2003–April 2009

Variable	All Hours		On-peak Model		Off-peak Model	
	Coefficient	P-value	Coefficient	P-value	Coefficient	P-value
Constant	-22.39	0.000	-27.68	0.000	-18.66	0.000
LOG(Nuclear Output)	-0.76	0.000	-0.73	0.000	-0.75	0.000
LOG(Self Scheduler output)	-0.25	0.042	-0.14	0.196	-0.38	0.023
LOG(Ontario NDL)	1.74	0.000	1.29	0.000	2.45	0.000
LOG(New York Integrated Load)	1.72	0.001	2.56	0.000	0.73	0.311
LOG(Natural Gas Price)	0.51	0.000	0.56	0.000	0.43	0.000
R-squared	0.830		0.871		0.761	
Adjusted R-squared	0.784		0.836		0.696	
LM test of Serial Correlation	Normal		Normal		Normal	
JB test of normality of residuals	Absent		Absent		Absent	
Number of observations	76		76		76	

The signs of the parameter estimates are intuitive and, for the most part, statistically significant. The two exceptions are the self-scheduled generation variable in on-peak hours and New York integrated load in off-peak hours. The main difference from the results presented in the previous Panel report is that the quality of self-scheduled generation as an explanatory variable has deteriorated.

The self-scheduled generation variable in determining the HOEP during on-peak hours was statistically insignificant, although the negative coefficient estimate suggests that directionally, it may have a negative impact on the HOEP. Likewise, the statistical insignificance of the New York Integrated load during off-peak hours suggests that demand in New York is not an important indicator of the HOEP likely to prevail in Ontario during off-peak periods.

Table 1-19 presents a decomposition analysis using the regression model results presented above in Table 1-18. This analysis estimates what the monthly average HOEP would have been over the period November 2008 to April 2009 had the values of the explanatory variables observed one year earlier been used in place of the actual 2008/2009 observations. That is, we changed the value of one explanatory variable at a time in order to estimate the marginal effects (in dollars) of each of these variables on the calibrated HOEP (the price that the model predicts). The difference between the actual HOEP and the calibrated HOEP for the 2008/2009 winter months represents the unexplained residual.

Table 1-19: Price Effect of Setting 2008/2009 Factors Equal to 2007/2008 Factors All hours, On-peak hours and Off-peak hours January 2003-April 2009 ($/MWh)

	Month	Nuclear Generation	Self Scheduler Generation	Ontario Load	New York Load	Natural Gas Price	2008/2009 HOEP	
							Actual	Calibrated
All Hours	November	3.41	0.24	2.59	0.93	-3.93	51.78	43.95
	December	0.84	1.98	1.06	0.99	-0.62	46.34	40.55
	January	-1.15	0.42	-1.60	-2.31	4.07	53.22	45.97
	February	0.59	1.79	3.37	1.14	8.30	47.24	36.91
	March	4.03	2.71	3.28	1.21	11.57	28.88	31.57
	April	2.95	2.33	2.30	0.58	12.62	18.40	22.60
	Average	**1.78**	**1.58**	**1.83**	**0.42**	**5.33**	**40.98**	**36.92**
On-peak Hours	November	3.64	-0.19	1.98	1.06	-5.49	59.98	55.87
	December	1.12	0.97	1.08	1.87	-0.89	57.67	52.27
	January	-1.61	-0.01	-0.84	-3.00	5.51	62.32	56.09
	February	0.87	1.09	3.18	2.36	11.72	57.79	46.65
	March	4.59	1.51	2.99	2.74	15.82	36.65	38.37
	April	4.11	1.35	1.99	1.67	18.99	28.62	30.01
	Average	**2.12**	**0.79**	**1.73**	**1.12**	**7.61**	**50.51**	**46.54**
Off-peak Hours	November	2.98	0.51	1.73	-0.15	-2.65	45.22	34.47
	December	0.60	2.41	2.29	0.62	-0.40	37.02	30.35
	January	-0.76	0.64	-3.25	-1.25	2.78	45.73	36.93
	February	0.39	2.11	3.64	0.28	5.66	38.53	29.89
	March	3.20	3.21	5.29	0.77	7.68	21.90	25.11
	April	1.93	2.81	1.84	-0.14	7.45	10.22	16.15
	Average	**1.39**	**1.95**	**1.92**	**0.02**	**3.42**	**33.10**	**28.81**

The signs on the reported price effects in Table 1-19 reflect two factors: the direction of the year-over-year change of underlying variable, and the sign of the respective coefficient estimate from the HOEP econometric model presented in Table 1-18. Consider for example, average hourly nuclear generation over all hours was 8.5 GW in November 2007 and 9.4 GW in November 2008. If the November 2007 value of 8.5 GW was realized in November 2008 (in essence replacing the 9.4 GW value), the decomposition analysis estimates that the HOEP would have been $3.41/MWh higher in November 2008. This is intuitive since less available baseload generation should, on average, have the effect of increasing market prices.

2.5 Hourly Uplift and Components

Table 1-20 reports the monthly total hourly uplift charge for the last two winter periods. Total hourly uplift charges dropped from $201 million in 2007/2008 to $172 million in 2008/2009, a reduction of 14 percent. The only uplift category that showed an increase was payments towards operating reserve.

- IOG Payments - There were large declines in the amount of IOG's paid to importers as total IOG fell from $27 million last winter to $7 million this winter and declined in all months relative to last winter. Lower IOGs resulted from smaller pre-dispatch to HOEP prices differences, as well as the fewer imports that occurred this winter.
- Losses - Total payments for losses declined by $19 million (21 percent) this winter, with almost $17 million of the decline realized in March and April 2009. This is consistent with the period HOEP that was lower by 17 percent (as seen in Table 1-1), with March and April contributing most to HOEP reductions. This result is intuitive since the total cost of transmission losses is directly related to the level of payments to the generators that satisfy this component of the total demand, and the magnitude of the losses.

- CMSC payments - CMSC payments also declined this winter by $8 million (11 percent), mostly due to lower CMSC paid to Dispatchable Loads.[28] As a percentage of total uplifts, CMSC payments remained relatively stable (up from 35.3 percent last winter to 36.6 percent this winter).
- Operating reserve payments - operating reserve payments increased from $13 million in 2007/2008 to $31 million in 2008/2009 (a 136 percent change) and increased in every month compared to one year ago as operating reserve prices continue to rise for reasons discussed later in section 2.8.

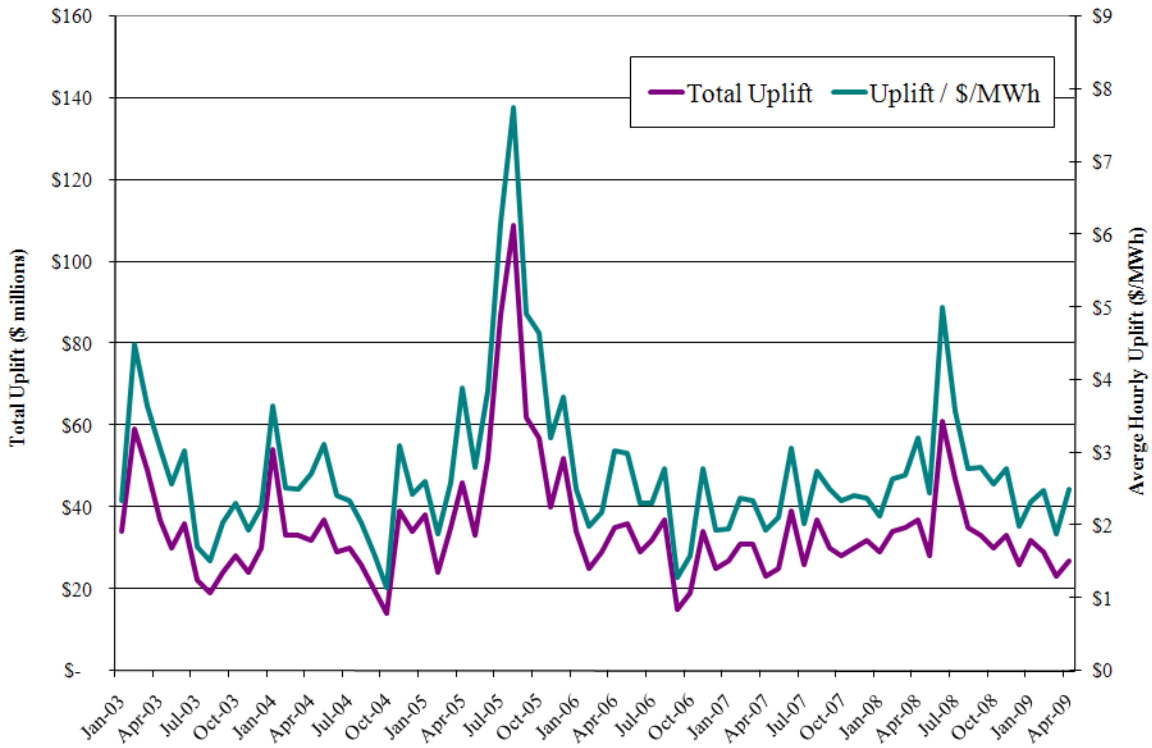
Table 1-20: Monthly Total Hourly Uplift Charge by Component and Month, November–April 2007/2008 & 2008/2009 ($ millions and %)

	Total Hourly Uplift		IOG		CMSC		Losses		Operating Reserve	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	30.7	33.8	4.2	2.3	11.7	15.5	13.4	11.9	1.5	4.1
December	32.9	26.1	4.2	1.4	11.4	6.3	16.2	15.9	1.1	2.5
January	30.0	32.4	4.1	1.2	9.4	9.8	14.2	15.2	2.3	6.2
February	34.1	29.0	6.0	1.0	11.3	7.9	14.6	13.3	2.3	6.8
March	35.6	23.8	4.2	0.8	12.8	10.4	17.2	8.4	1.4	4.2
April	37.4	27.0	4.3	0.3	14.3	13.1	14	6	4.8	7.6
Total	200.8	172.1	27.0	7.0	70.9	63.0	89.5	70.7	13.3	31.4
% of Total	100.0	100.0	13.4	4.1	35.3	36.6	44.6	41.1	6.6	18.2

Figure 1-12 plots hourly uplift charges in millions of dollars and in $/MWh between January 2003 and April 2009. The long-term trend shows that total uplift payments and uplift per MWh of production have remained relatively stable since the beginning of 2006 with the exception of June 2008. In March 2009, total uplift charges on a $/MWh basis were $1.89/MWh, which is the lowest monthly amount since the fall of 2006.

[28] A large portion of the CMSC payments to dispatchable loads is self-induced and recovered. A change in the Settlement recovery process in January 2008, led to a different accounting for the CMSC payments calculated here. Note, that the CMSC totals in Table 1-20 include all CMSC payments including those to Dispatchable loads while those referenced in Table 1-22 and Figure 1-14 exclude these.

Figure 1-12: Total Hourly Market Uplift and Average Hourly Market Uplift, January 2003–April 2009 ($ millions and $/MWh)



2.6 Internal Zonal Prices and CMSC Payments

Table 1-21 presents average nodal prices for the 10 internal Ontario zones for each six month period for the last three six-month periods.[29] Figure 1-13 shows the same average nodal prices graphically for each zone for the recent winter period. The average nodal price for a zone, also referred to here as the internal zonal price, is calculated as the average of the nodal prices for generators in the zone.[30]

For most zones in the south, the table shows that current internal zonal prices are lower than each of the previous two six month periods. Current winter values are about 22 to 24 percent below the previous winter. These price movements in the southern zones are largely related to generally lower demand and increased supply in southern Ontario,

[29] See the IESO's "Ontario Transmission System" publication for a detailed description of the IESO's ten zone division of Ontario at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2005jun.pdf
[30] All nodal and zonal prices have been modified to +$2,000 (or -$2,000) when the raw interval value was higher (or lower). This is a refinement in the calculation which previously truncated prices on an hourly basis, and has resulted in the currently reported zonal prices for Nov07-Apr08 differing slightly from those in previous Monitoring Reports.

which is also seen as a decrease in the Richview nodal prices.[31] The average Richview nodal price was $45.10/MWh over the recent winter which is $12.86/MWh, or 22.2 percent, lower than the 2007-2008 winter period.

Table 1-21: Internal Zonal Prices, November 2007–April 2009 ($/MWh and %)

Zone	Nov 07-Apr 08	May08 – Oct 08	Nov 08 – Apr 09	% Change from Nov 07 – Apr 08 to Nov 08 – Apr 09
Bruce	56.82	59.99	43.42	(23.6)
East	58.36	57.69	43.53	(25.4)
Essa	57.06	59.76	43.44	(23.9)
Northeast	49.18	38.40	22.97	(53.3)
Niagara	56.01	59.62	43.18	(22.9)
Northwest	(43.86)	(96.61)	(272.34)	(520.9)
Ottawa	60.51	61.58	45.70	(24.5)
Southwest	57.22	60.41	43.86	(23.3)
Toronto	58.55	62.11	45.24	(22.7)
Western	57.53	61.23	44.60	(22.5)
Richview Nodal Price	57.96	63.15	45.10	(22.2)

For the Northwest particularly, and also the Northeast to some degree, higher levels of losses and more frequent congestion in the zone (either at the interface with the rest of the system, or in more remote locations for example in the far Northeast area near James Bay) continue to drive the nodal prices significantly below prices in the south.

As observed for previous periods, congestion in the Northwest is the primary reason for the average prices there to be so low. This winter’s average zonal price dropped to -$272.34/MWh, which is more than five times lower than the -$48.36/MWh average from last winter. This is the lowest six-month average seen for the zone. The reduction in demand has been more acute in the Northwest with the larger portion of industrial load

[31] Between January 21 and Feb 25, 2009, there may have been an error in calculated nodal prices associated with applied loss factors, which could have affected zonal price averages by up to about 7 percent, for that 36 day period, with some zonal prices slightly higher and some slightly lower than would have been expected. The overall impact on the six-month averages would be considerably smaller. The IESO is reviewing this.

there.[32] Coupled with abundant supply of very low-priced water in the Northwest, including energy available from imports, the low demand has created surpluses in the area which have driven prices much lower than previously, as generators attempt to avoid being constrained off, which can mean spilling water at hydroelectric stations. For about a two week period at the end of March and early April, the outage of the transmission lines from the Northwest to the rest of the province, also contributed to increased congestion in the area.

The Northeast also had a large amount of hydroelectric supply, but experienced less surplus and less congestion than the Northwest. However, prices in the Northeast declined by 53 percent relative to the previous winter, which reflects continued abundant hydroelectric supply, lower demand this year and occasional transmission outages in the area all leading to lower prices offered in order to minimize spill.

[32] For example, in April 2009 Ontario Demand was lower by almost 7 percent compared to April 2008 (see Table 1-26), while Northwest Demand was down about 25 percent. Northeast Demand reduction was also greater than the provincial decline, with a reduction of about 10 percent for April this year compared to last year.

Figure 1-13: Average Internal Zonal Prices November 2008–April 2009 ($/MWh)

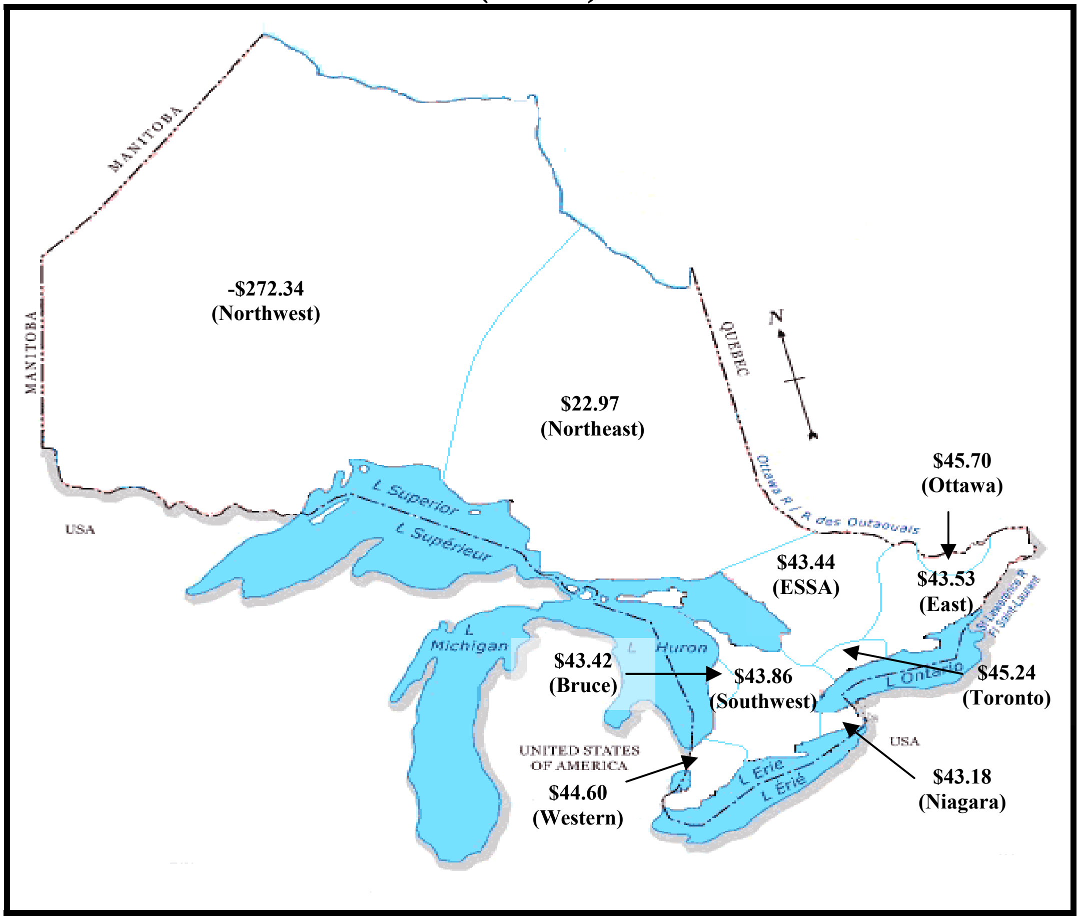


Figure 1-14 provides a summary of congestion payments (CMSC) across the same 10 zones for the last winter period. For each zone, there is a total for CMSC paid for constraining off generation or imports (into the zone) or constraining on exports from the zone. The data has been aggregated in this manner since constraining on exports is an alternative to constraining off supply when supply is bottled (oversupply in zone), and so this amount is an indicator of the bottling of supply in the zone. A second total shows the CMSC for constrained on generation or imports, or constrained off exports. This is a measure of the need for additional or out-of merit supply in a zone (undersupply in zone).[33] However, not all CMSC is induced by transmission (including losses) or

[33] CMSC paid to dispatchable load is omitted here since the largest portion of those payments are self-induced, as opposed to being related to congestion, losses or other system requirements.

security. For example, the 3-times ramp rate or slow ramping of fossil units can induce CMSC, so the total CMSC is not entirely a measure of congestion or losses.
Of the total $31.6 million, the majority ($17.7 million or 56 percent) of the CMSC for constrained off supply or constrained on exports occurred in the Northwest zone, primarily as the result of the East-West flow limits which bottle the low-cost supply in the area. Another $4.6 million or 15 percent of this CMSC was paid to generation and exports in the Northeast, where additional low-cost (hydroelectric) supplies were bottled due to limits on flows to the south. For both of these zones significant and extended transmission outages contributed to some of the flow limitations and resulting CMSC.

The $21.8 million CMSC for constrained on supply or constrained off exports was more evenly distributed across the province. Flows East Toward Toronto (FETT), a sometimes limiting transmission interface, contributed to the $8.8 million CMSC paid in the East and Toronto zones, representing 40 percent of the total for these payments. Another significant portion of the $8.8 million was the result of the need to constrain on generation to satisfy total system operating reserve requirements. Another $5.6 million (or about 24 percent of the total for this category) was paid in the Western zone, primarily for generation constrained on under the DACP and SGOL programs, and for constrained on imports or constrained off exports to Michigan. Another $3.4 million was paid in the Niagara zone mostly to imports and exports, but also to generators in the area including generation needed in the Niagara 25 Hz sub-system.[34]

[34] It is notable that the last generation on the sub-system was shut-down on April 30, 2009 consistent with a recommendation by the Panel in its report "Constrained Off Payments and Other Issues in the Management of Congestion" July 2003, pp. 7-8.

Figure 1-14: Total CMSC Payments by Internal Zone, November 2008–April 2009 ($ millions)

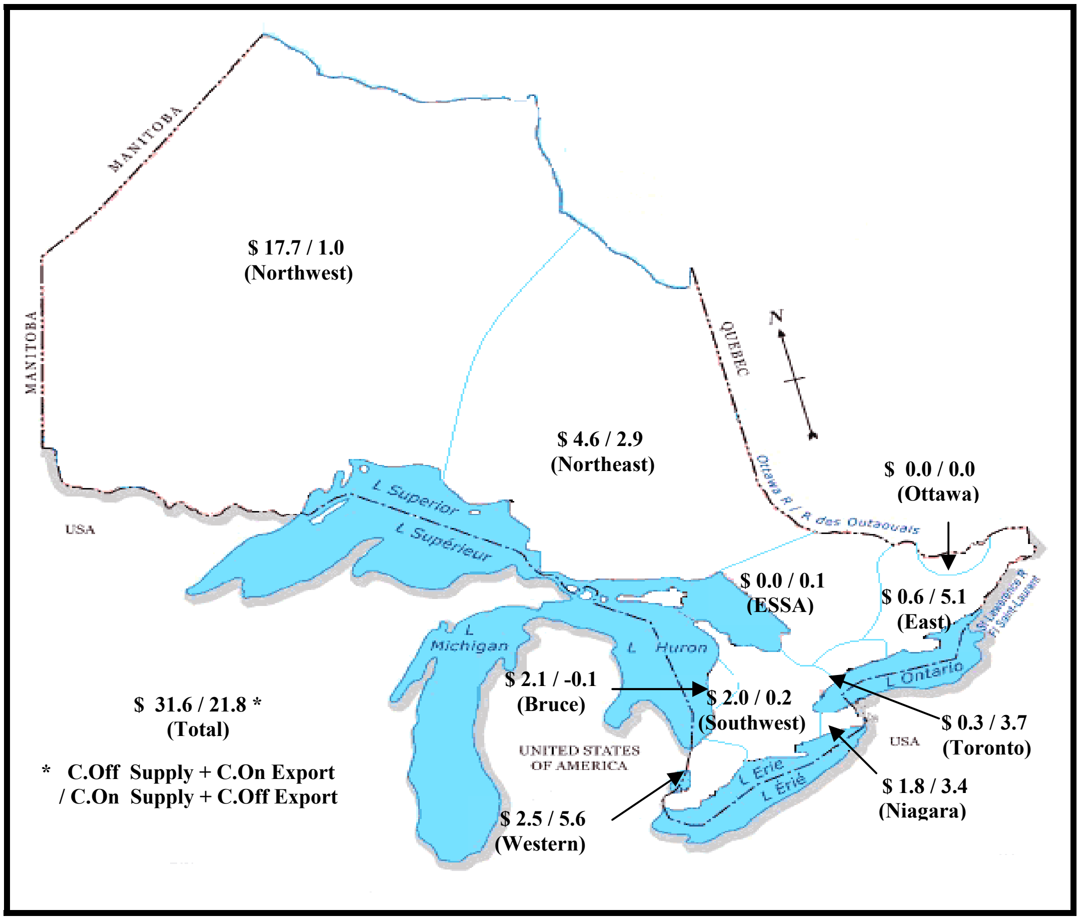


Table 1-22 provides similar data on a comparative basis relative to the prior winter period. While there are some notable proportional shifts in some regions relative to last year, the changes were small in absolute terms (less than $0.6 million per zone) for payments to constrained off supply plus constrained on exports. On an overall basis such payments only experienced a 2 percent increase. The $2.4 million or 9.9 percent decline in constrained on supply plus constrained off export payments was the result of decreases of $1.0 to $1.8 million (or 23 percent to 62 percent relative to the previous winter) in the Northwest, Niagara, and Western zones, offset somewhat by the $1.5 million (or 68 percent) increase in Toronto.

Table 1-22: Total CMSC Payments by Internal Zone, November–April 2007/2008 & 2008/2009 ($ millions)

Zone	Constrained off Supply plus Constrained on Exports			Constrained on Supply plus Constrained off Exports		
	2007/2008	2008/2009	% Change	2007/2008	2008/2009	% Change
Bruce	2.0	2.1	5.0	0.0	-0.1	n/a
East	0.3	0.6	100.0	4.6	5.1	10.9
Essa	0.1	0.0	(100.0)	0.1	0.1	0.0
Northeast	4.1	4.6	12.2	2.7	2.9	7.4
Niagara	1.2	1.8	50.0	4.4	3.4	(22.7)
Northwest	18.1	17.7	(2.2)	2.6	1.0	(61.5)
Ottawa	0.0	0.0	0.0	0.0	0.0	0.0
Southwest	2.4	2.0	(16.7)	0.2	0.2	0.0
Toronto	0.2	0.3	50.0	2.2	3.7	68.2
Western	2.6	2.5	(3.8)	7.4	5.6	(24.3)
Total	31.0	31.6	1.9	24.2	21.8	(9.9)

2.7 A Comparison of HOEP and Richview Nodal Price

This section reports summary statistics comparing the HOEP and Richview nodal prices. Table 1-23 presents the average and median prices for each and the number of hours these prices fell below $20/MWh or exceeded $200/MWh.[35]

The average HOEP was $40.98/MWh, which was $4.12/MWh lower than the Richview price this winter. Both the average HOEP and the Richview nodal price fell this winter, by 16.6 percent and 22.2 percent respectively. Similarly the median values fell for both price measures by 5.6 percent for HOEP and 7.8 percent for the Richview price.

[35] For the MCP within particular intervals, the Richview nodal price has been modified to +$2,000/MWh (or -$2,000/MWh) when the raw interval value was higher (or lower). The HOEP is based also on similar price caps. Interval values were averaged to provide an hourly Richview price for comparison with the HOEP.

Table 1-23: HOEP and Richview Nodal Price Summary Statistics, November– April 2007/2008 & 2008/2009 ($/MWh and Hours)

	HOEP			Richview Nodal Price			Richview - HOEP	
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009
Average ($/MWh)*	49.16	40.98	(16.6)	57.96	45.10	(22.2)	8.80	4.12
Median ($/MWh)*	42.32	39.95	(5.6)	45.49	41.94	(7.8)	3.17	1.99
# of Hours Price < $20/MWh	261	689	164.0	286	672	135.0	25	(17)
# of Hours Price > $200/MWh	2	8	300.0	66	24	(63.6)	64	16

The HOEP fell below $20/MWh in 689 hours this winter, up from 261 hours over the same months last year (164 percent). However 409 of these hours occurred between March 24 and April 17, 2009, which represents the period when the planned outages to two major transmission lines on the New York interface led to the net export capability to be reduced to 0 MW.[36] The Richview price also demonstrated a similar pattern as instances of less than $20/MWh increased by 135 percent, from 286 hours to 672 hours this winter, most of which occurred during the same period.

The number of hours when HOEP was higher than $200/MWh increased from 2 hours last year to 8 hours this year. By comparison, the Richview price exceeded $200/MWh only 24 hours this winter compared to 66 hours last winter. The fact that high-price hours occur more frequently in the Richview price than the HOEP reflects the generally downward pressure on the HOEP from bottled resource offers in the Northwest and Northeast regions.

2.8 Operating Reserve Prices

Prices for all types of operating reserve increased this winter compared to last winter. Various factors have contributed to this, causing either an increase in operating reserve requirements or a decrease in available operating reserve resources.

[36] Factors that led to the high frequency of HOEP below $20/MWh during this period are discussed in further detail in Chapter 2, section 2.2.

Tables 1-24 presents average monthly operating reserve prices during the on-peak hours over the last two winter periods. On-peak prices have more than doubled on average for the period, with increases between 124 percent to 160 percent for the different operating reserve classes. Average 10-minute spinning reserve (10S) prices grew from $4.68/MWh last winter to $11.31/MWh this year. The largest percentage increase occurred in the 10-minute non-spinning reserve (10N) class, as 10N prices moved up almost to the level of the 10S prices in all months. The largest proportional changes occurred in November and February, ranging from 226 percent up to 297 percent, depending on operating reserve class. Only in April did the price drop for 30-minute reserve (30R), by a marginal amount of 6 percent.

Table 1-24: Operating Reserve Prices On-Peak, November–April 2007/2008 & 2008/2009 ($/MWh)

	10S			10N			30R		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
November	2.15	7.40	244.2	1.96	7.37	276.0	1.74	6.90	296.6
December	2.21	4.85	119.5	1.77	4.84	173.4	1.77	4.67	163.8
January	4.77	12.23	156.4	4.59	12.23	166.4	4.49	11.35	152.8
February	5.97	19.47	226.1	5.28	19.47	268.8	5.08	17.65	247.4
March	3.96	8.37	111.4	3.35	8.32	148.4	3.18	6.82	114.5
April	9.01	15.54	72.5	8.96	15.14	69.0	8.44	7.91	(6.3)
Average	4.68	11.31	141.7	4.32	11.23	160.0	4.12	9.22	123.7

Tables 1-25 presents average monthly operating reserve prices during the off-peak hours over the last two winter periods. Off-peak prices have not moved as much as on-peak prices in either absolute values or percentage terms. 10S prices rose from $1.63/MWh last year to $2.61/MWh, an increase of 60 percent, while prices for 30R, the lowest priced class of OR, grew from $0.83/MWh to $1.62/MWh, or 95 percent. Because of the much lower prices off-peak last year, monthly changes this year were more volatile. For example, the increase in the 10N price from $0.44/MWh last year to $2.49/MWh this year represented a jump of 466 percent, although there were a few examples, in December and April, where monthly average OR prices fell relative to the same month last year.

Table 1-25: Operating Reserve Prices Off-Peak, November–April 2007/2008 & 2008/2009 ($/MWh)

	10S			10N			30R		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
November	1.84	2.83	53.8	0.48	1.22	154.2	0.47	1.22	159.6
December	1.37	0.99	(27.7)	0.40	0.51	27.5	0.40	0.51	27.5
January	0.98	2.21	125.5	0.69	2.21	220.3	0.62	2.09	237.1
February	0.84	2.50	197.6	0.44	2.49	465.9	0.40	2.14	435.0
March	0.87	1.85	112.6	0.33	1.34	306.1	0.33	1.33	303.0
April	3.87	5.25	35.7	3.61	2.76	(23.5)	2.78	2.42	(12.9)
Average	1.63	2.61	59.8	0.99	1.76	77.3	0.83	1.62	95.0

Table 1-26 presents monthly averages for the total operating reserve requirements, for the winter period last year and this year. It shows that total operating reserve required increased from 1,371 MW to 1,523 MW, an increase of 153 MW or 11 percent. The total operating reserve requirement equals the first largest contingency plus half the next largest contingency minus a contribution for Regional Reserve Sharing. In this recent winter period operating reserve was often increased due to larger first contingency events (the largest loss of resources due to a single event). There were several causes contributing to the increased operating reserve requirement:

- Transmission line outages, which led to two large nuclear units representing about twice the typical single contingency;
- High flows from Northeastern Ontario representing the single largest contingency;
- A new large fossil-fired plant being treated as single contingency because of the possible simultaneous loss of all units;
- Following a double contingency at a generating station, the outage of two units at the plant being treated as a somewhat larger single contingency on a regular basis;
- Outages at the New York interties preventing IESO relying on 100 MW of Regional Reserve Sharing (RRS).

Table 1-26: Average Monthly Operating Reserve Requirement November–April 2007/2008 & 2008/2009 (MW)

	2007/ 2008	2008/ 2009	% Change
November	1,399	1,534	10
December	1,341	1,511	13
January	1,317	1,519	15
February	1,318	1,470	12
March	1,320	1,455	10
April	1,333	1,556	17
Average	1,371	1,523	11

In addition to the increased operating reserve demand there was a reduction of operating reserve resources available. This included:

- lower consumption by some dispatchable loads limiting operating reserve provided (by almost 130 MW on average);
- withdrawal by some generation from participating in the operating reserve market for most of the period;
- the IESO no longer accepting import operating reserve offers; [37] and
- less operating reserve offers available from coal-fired units. There was a 36 percent reduction in operating reserve offers from coal-fired units this winter compared to last winter, partly due to a change in the market participant's operating reserve offer strategy during the summer to more closely match their average ramping capability[38] as well as fewer coal-fired units on-line this year due primarily to lower market demands.[39]

Figure 1-15 shows monthly average operating reserve prices since 2003. With increasing generation coming on-line, as well as CAOR being introduced, operating reserve prices had been falling until about the middle of 2008. Since then prices have been rising, affected by the demand and supply factors noted above.

[37] As of April 24, 2009, the IESO began to reduce operating reserve import transactions for thirty minute reserve that originate from PJM or MISO to 0 MW as the IESO was unable to activate these transactions due to market timing issues in both markets.
[38] This was previously noted in the Panel's January 2009 Monitoring Report p. 221.
[39] Although less coal operating reserve offers were available this winter, more coal operating reserve was selected, since other sources of operating reserve were not available for the reasons described.

Figure 1-15: Monthly Operating Reserve Prices by Class, January 2003–April 2009 ($/MWh)

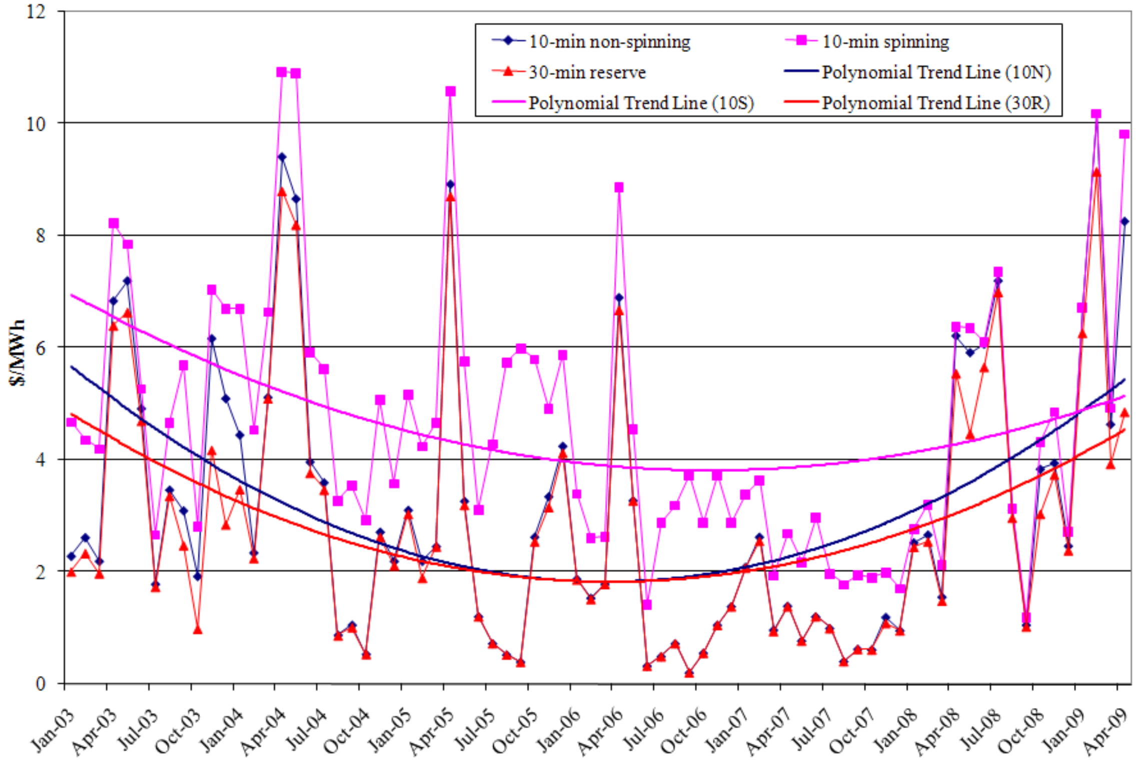
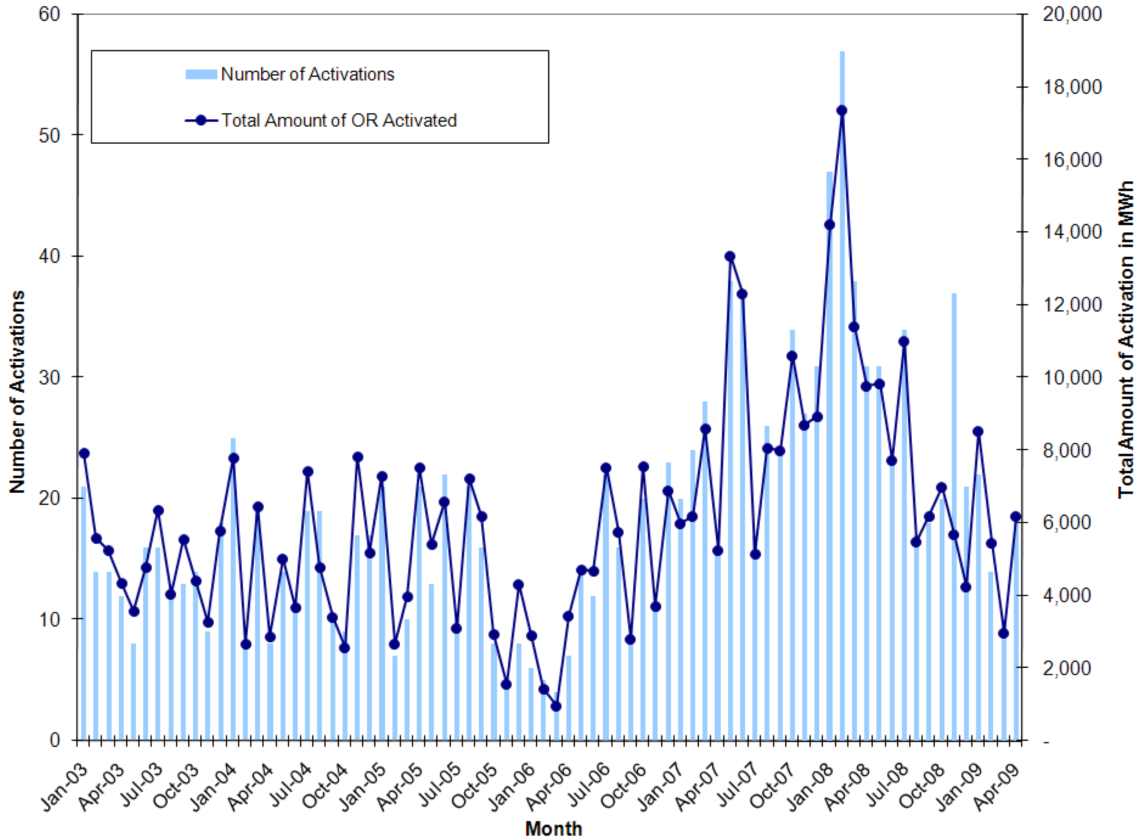


Figure 1-16 shows operating reserve activations, again since 2003. As noted in the previous Panel report [40] activations dropped in early 2006 followed by large increases until early 2008. Since then activations have fallen once more, to roughly the range observed in earlier years.

Figure 1-16: Monthly Operating Reserve Activations, January 2003–April 2009 (Frequency and Cumulative MW)



[40] See the Panel's August 2008 Monitoring Report, pp. 42-44 and. 192-203 and Panel's January 2009 Monitoring Report, pp. 45-47.

3. Demand

3.1 Aggregate Consumption

Table 1-27 compares total monthly energy demand and exports for the 2007/08 and 2008/09 winter periods. Ontario Demand fell by 3.55 TWh, or 4.6 percent, this winter compared to last winter and declined in every month with the exception of January. The largest monthly declines in percentage terms occurred during the second half of the 2008/09 winter period, with declines of 6 percent or higher.

Exports (excluding linked wheel transactions) declined slightly this winter by 3.5 percent, or 0.3 TWh. Over the recent winter period, 52 percent of these exports were scheduled transactions originating in Ontario, destined for PJM.[41] Although export volumes increased in four of the six months, there was a 54 percent drop in exports in April 2009 compared to April 2008 in large part due to the reduced export capability at the New York interties this spring, simultaneously reducing flows over the Michigan interties due to parallel flow effects.

The sum of Ontario Demand and export volumes is known as 'total market demand'. Similar to the decline in Ontario Demand, total market demand also fell by 3.86 TWh, or 4.5 percent this winter. The decline in Ontario Demand and export volumes in April led to a 12.8 percent drop in total market demand in April 2009 relative to the same month one year earlier.

[41] The implications of the increased exports from Ontario to PJM are discussed in more detail in Chapter 3, section 2.1.

Table 1-27: Monthly Energy Demand, Market Schedule, November–April 2007/2008 & 2008/2009 (TWh)

	Ontario Demand*			Exports (excluding Linked Wheels)			Total Market Demand (excluding Linked Wheels)		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
November	12.39	11.85	(4.4)	0.96	1.36	41.7	13.35	13.21	(1.0)
December	13.45	13.09	(2.7)	1.29	1.40	8.5	14.74	14.49	(1.7)
January	13.63	13.75	0.9	1.77	1.82	2.8	15.40	15.57	1.1
February	12.90	11.71	(9.2)	1.48	1.34	(9.5)	14.38	13.05	(9.2)
March	13.01	12.18	(6.4)	1.22	1.44	18.0	14.23	13.62	(4.3)
April	11.52	10.77	(6.5)	1.75	0.80	(54.3)	13.27	11.57	(12.8)
Total	76.90	73.35	(4.6)	8.46	8.16	(3.5)	85.37	81.51	(4.5)
Average	12.82	12.23	(4.6)	1.41	1.36	(3.5)	14.23	13.59	(4.5)

* Non-dispatchable loads plus dispatchable loads

3.2 Wholesale and LDC Consumption

Figure 1-17 plots the monthly total energy consumption separate for wholesale load and Local Distribution Companies (LDC's) between January 2003 and April 2009. There are clear seasonal fluctuations in LDC demand. Typically, LDC consumption is highest during the December/January and July/August months. Over the latest six-month period, LDC demand peaked in January 2009 at 11,300 GWh, the highest monthly total since January 2005, and a low of 8,650 GWh in April 2009, the lowest monthly total since the market opened in May 2002.

The relatively poor economic conditions this winter appears to be contributing to the continuing decline in wholesale electricity consumption this winter as it reached its lowest level in April 2009 at slightly less than 1,700 GWh of consumption. This is about one-third less than typical monthly consumption seen in 2004. Total monthly wholesale demand levels also fell in all six months this winter below the previous monthly low of approximately 2,100 GWh set in October 2008.

Figure 1-17: Monthly Total Energy Consumption, LDC and Wholesale Loads, January 2003–April 2009 (GWh)

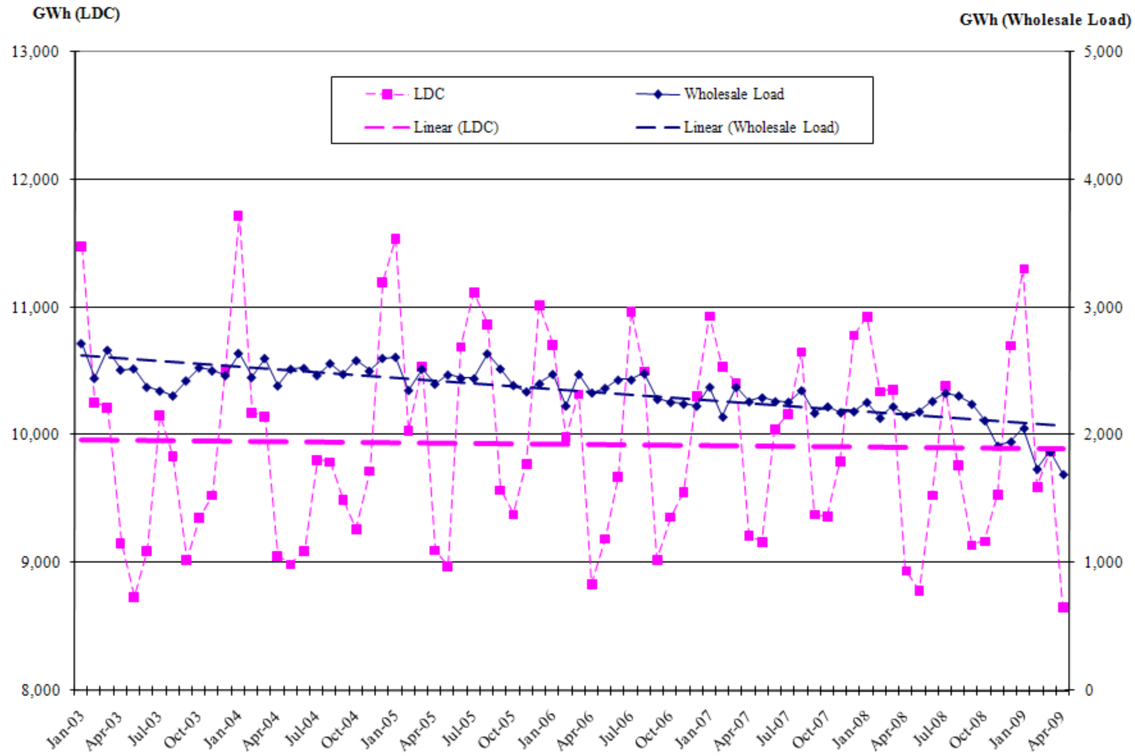
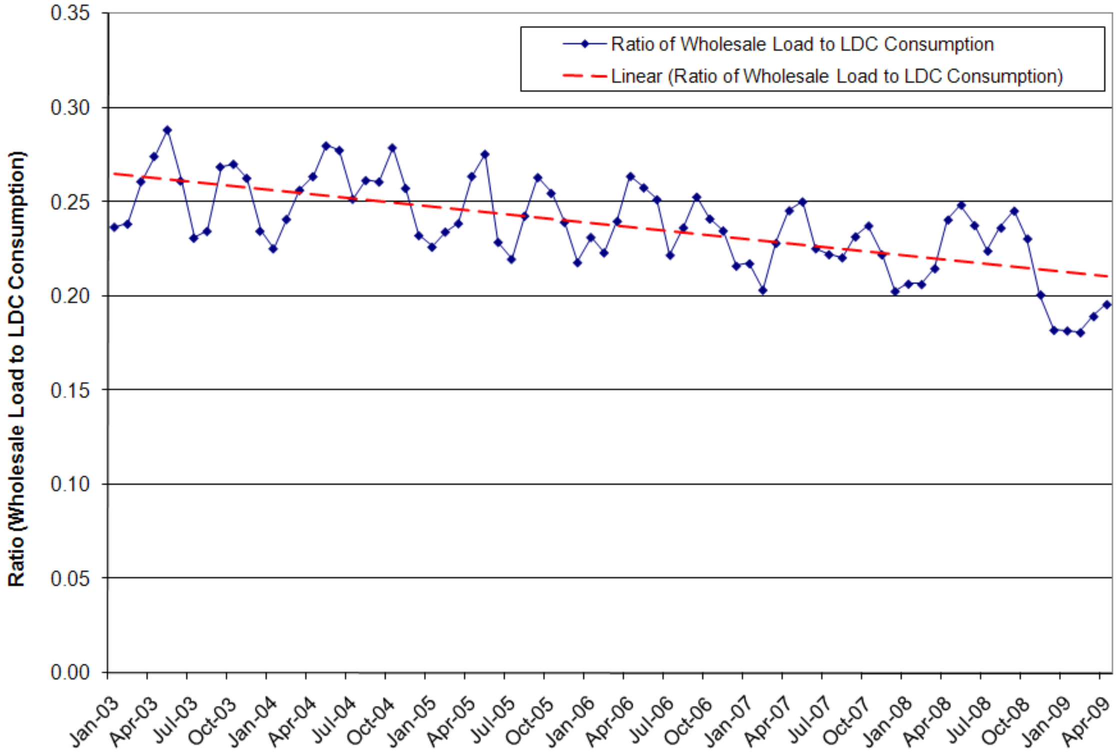


Figure 1-18 presents the ratio of wholesale load to LDC consumption since January 2003. The decrease in the ratio is consistent with the decline in wholesale load presented above and shows that the rate of decline in wholesale load is falling more quickly relative to the decline in LDC consumption. For the first time since 2003, the ratio fell below 0.20 in five of the six months during the current winter period.

Figure 1-18: Ratio of Wholesale Load to LDC Consumption, January 2003–April 2009 (Wholesale Load:LDC Consumption)



4. Supply

4.1 New Generating Facilities

Over the latest six-month period, several new gas-fired generating units and two new wind generation facilities became fully operational.[42] St. Clair Energy Centre, a 577 MW natural gas-fired combined-cycle generating facility located in Sarnia, Ontario was being commissioned throughout most of the winter, becoming fully dispatchable at the end of March 2009. Sithe Goreway commissioned several units at its combined-cycle plant, for a total of 839 MW, while the Portlands plant added 244 MW from its steam units.

[42] The capacity data and operational dates came from the OPA's Electricity Contracts website at: http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=123

Two new wind generating facilities began operating with a combined nameplate capacity of 313.5 MW. The Melancthon II Wind Plant, located in Amaranth/Melancthon Township, became operational in November 2008 with a capacity of 132 MW. In December 2008, the Enbridge Ontario Wind Farm in Bruce County with a capacity of 181.5 MW began operating its facility.

4.2 The Supply Cushion

Tables 1-28 and 1-29 present monthly summary statistics on the pre-dispatch total and real-time domestic supply cushion respectively for the last two winter periods. The pre-dispatch supply cushion measure includes all sources of supply (including imports) while the real-time domestic supply cushion focuses only on supply from internal generation.[43]

Overall, the pre-dispatch supply cushion worsened slightly this winter while the real-time measure improved. The average pre-dispatch supply cushion fell from an average of 16.5 percent in 2007/2008 to 15.7 percent in 2008/2009 while the real-time average supply cushion increased significantly from an average of 16.1 percent last winter to 18.9 percent this winter. Although the average pre-dispatch supply cushion worsened this winter, the frequency of hours when the pre-dispatch supply cushion fell below 10 percent improved slightly by 13 hours (i.e. fell from 1,262 hours last winter to 1,249 hours this winter). Similarly, the number of hours when the real-time supply cushion fell below 10 percent significantly dropped by 823 hours (57 percent), from 1,440 hours last winter to 617 hours this winter. These results are consistent with more internal supplies this year and fewer imports.

[43] In pre-dispatch, all dispatchable resources (including imports and exports) are able to set the projected price, while in real-time imports and exports are fixed and cannot set price..

Table 1-28: Pre-Dispatch Total Supply Cushion, November–April 2007/2008 & 2008/2009 (% and Number of Hours under Certain Levels)

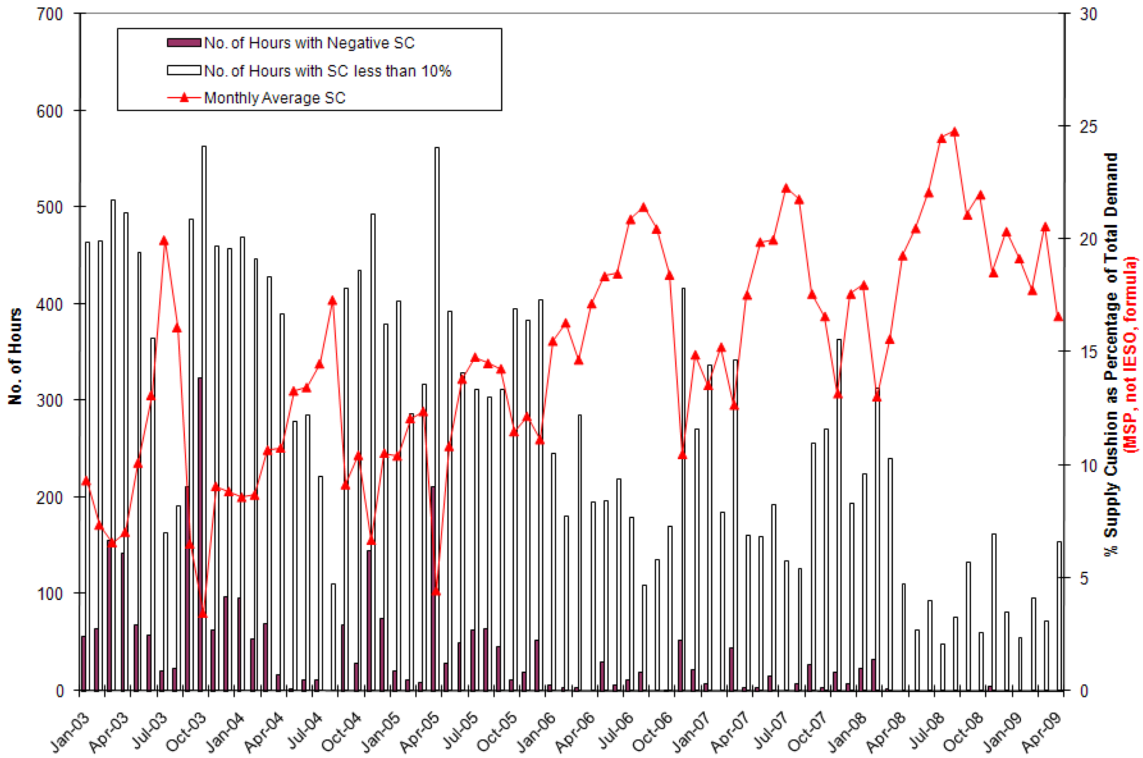
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2007/ 2008	2008/ 2009	2007/ 2008	%	2008/ 2009	%	2007/ 2008	%	2008/ 2009	%
November	17.6	18.6	0	0.0	0	0.0	164	22.8	127	17.6
December	19.6	17.2	0	0.0	0	0.0	93	12.5	170	22.8
January	16.0	14.4	0	0.0	0	0.0	271	36.4	262	35.2
February	15.7	13.5	0	0.0	0	0.0	208	29.9	261	38.8
March	17.2	13.8	0	0.0	0	0.0	143	19.2	279	37.5
April	12.7	16.7	6	0.8	0	0.0	383	53.2	150	20.8
Total	16.5	15.7	6	0.1	0	0.0	1,262	28.9	1,249	28.8

Table 1-29: Real-time Domestic Supply Cushion, November–April 2007/2008 & 2008/2009 (% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2007/ 2008	2008/ 2009	2007/ 2008	%	2008/ 2009	%	2007/ 2008	%	2008/ 2009	%
November	13.2	18.5	20	2.8	5	0.7	362	50.3	162	22.5
December	17.6	20.4	7	0.9	0	0.0	193	25.9	81	10.9
January	18.0	19.2	23	3.1	0	0.0	223	30.0	54	7.3
February	13.1	17.8	33	4.7	0	0.0	312	44.8	95	14.1
March	15.6	20.6	2	0.3	0	0.0	240	32.3	71	9.5
April	19.3	16.6	0	0.0	0	0.0	110	15.3	154	21.4
Total	16.1	18.9	85	1.9	5	0.1	1,440	33.0	617	14.2

Figure 1-19 plots real-time domestic supply cushion summary statistics between January 2003 and April 2009. The long-term trend appears to show that the real-time supply cushion has consistently been improving since 2003, although falling slightly from the peak levels observed last summer. The number of hours when the supply cushion fell below 10 percent has fallen since 2003 and the number of hours when it was negative fell to 5 hours this winter, well below any six-month totals from previous winter periods.

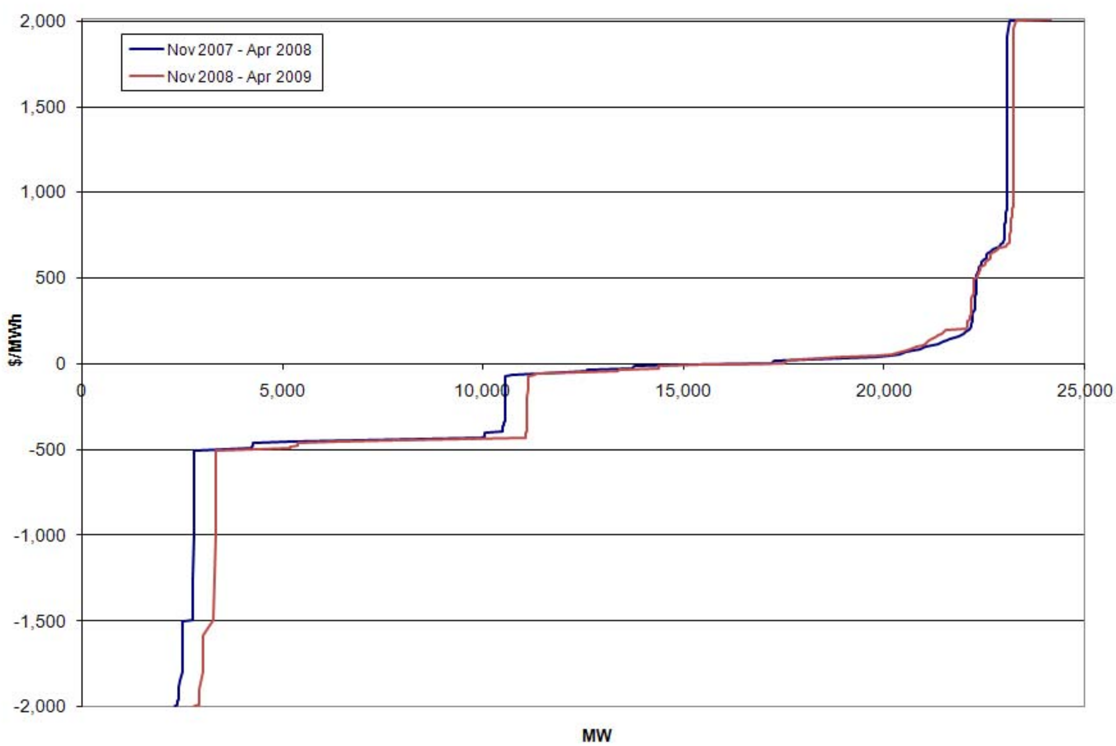
Figure 1-19: Monthly Real-time Domestic Supply Cushion Statistics, January 2003–April 2009 (% and Number of Hours under Certain Levels)



4.3 Average Supply Curves

Figure 1-20 plots the average domestic offer curve for the last two November to April periods. The average offer curve this winter shifted to the right for offers below $0/MWh as a result of an increase in offers from nuclear and self-scheduling and intermittent generation this year. These trends are consistent with the year-over-year increases in production for these two components of domestic supply as shown in Table 1-30 below.[44] The increase in these two categories more than offsets the small decline in non-baseload hydroelectric offers below $0/MWh this period. The average offer curves also show a decrease in offers above $0/MWh this winter, which is primarily due to a decline in submitted offers from coal-fired generators due to increased coal outages relative to last winter.

Figure 1-20: Average Domestic Offer Curve, November–April 2007/2008 & 2008/2009 ($/MWh)



[44] In previous reports, offers from self-scheduling and intermittent generators were not included when constructing the domestic offer curve. In this report, this increasingly significant component of domestic generation is included in the average offer curve.

Table 1-30 presents average monthly hourly market schedules by baseload generation category and the total domestic baseload supply. Average hourly baseload supply increased to a total of 13.4 GW this winter, up from 12.5 GW (7 percent increase) last winter. Total baseload supply remained the same in January and increased in all other winter months this year compared to the same months last year. Improved baseload supply resulted from better performance from nuclear generating units (0.5 GW, or 5 percent higher) and increased self-scheduling supply (0.4 GW, or 44 percent higher). The last two columns in Table 1-30 shows that over the recent winter period, baseload supply made up 81 percent of average hourly Ontario non-dispatchable demand, up from 73 percent last year.

Table 1-30: Average Hourly Market Schedules by Baseload Generation Type and Ontario Demand, November–April 2007/2008 & 2008/2009 (GW)

	Nuclear		Baseload Hydro		Self-Scheduling Supply		Total Baseload Supply		Ontario Demand (Non-Dispatchable Load)		Total Baseload Supply as a % of Ontario Demand	
	2007/ 2008	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**
November	8.5	9.4	2.1	2.0	0.9	1.1	11.5	12.5	16.7	16.1	68.9	77.6
December	10.3	10.6	1.9	2.1	0.9	1.4	13.1	14.1	17.6	17.3	74.4	81.5
January	11.0	10.6	1.9	2.0	0.9	1.2	13.8	13.8	17.8	18.1	77.5	76.2
February	10.0	10.2	2.1	2.1	0.9	1.3	13.0	13.6	18.0	17.1	72.2	79.5
March	8.7	10.3	2.3	2.2	0.8	1.5	11.8	14.0	16.9	16.0	69.8	87.5
April	8.6	8.6	2.3	2.1	0.8	1.5	11.7	12.2	15.4	14.6	76.0	83.6
Average	9.5	10.0	2.1	2.1	0.9	1.3	12.5	13.4	17.1	16.5	73.1	81.2

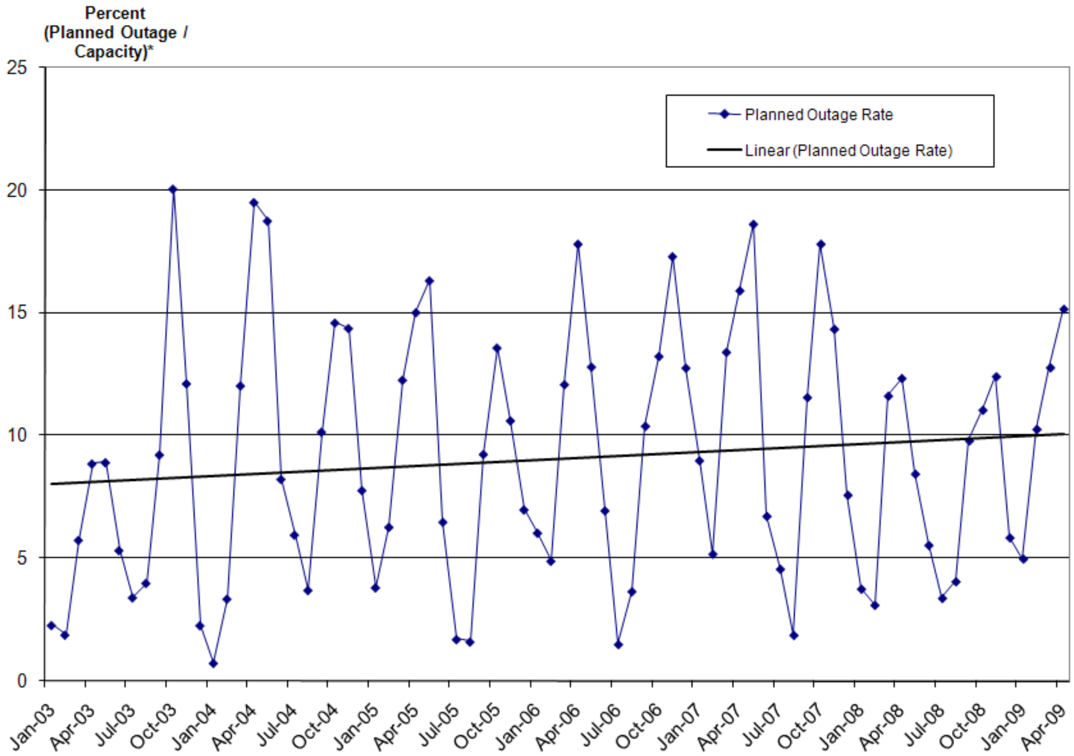
4.4 Outages

Effective planned outage management together with minimized forced outages can lead to increased generator output (and revenues) and can improve the supply situation in the province. Both planned and forced outages also have an upward effect on market prices because supply is removed from the market. The following sections report on planned and forced outage rates by fuel type since January 2003.

4.4.1 Planned Outages

Planned outages are typically taken during the low demand periods in the spring and fall months. Figure 1-21 plots monthly planned outages as a percentage of capacity. Planned outage rates over the latest winter period showed seasonal fluctuations that were reasonably in line with previous winter periods.

Figure 1-21: Planned Outages Relative to Capacity, January 2003–April 2009 (% of Capacity)



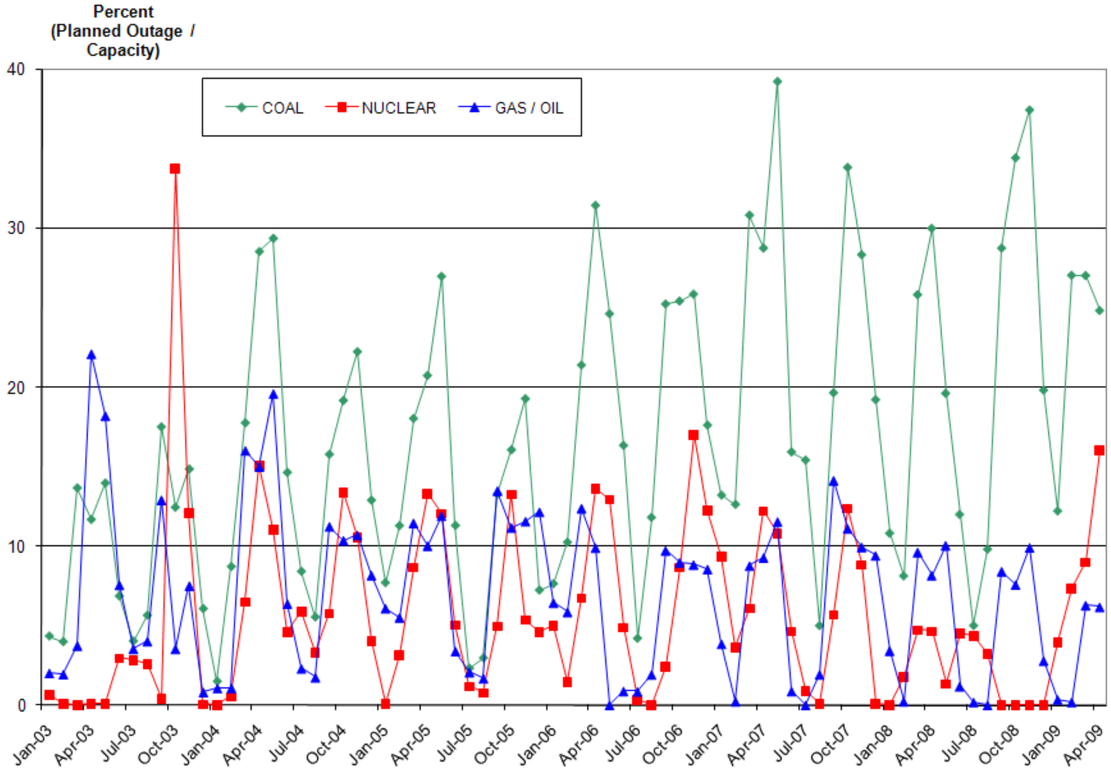
*Includes Nuclear, Coal, and Oil/Gas units.

Figure 1-22 presents planned outage rates as a percentage of total capacity for coal, nuclear, and oil/gas resources. Similar to the aggregated planned outage rate presented above, planned outages for each fuel type show similar seasonal patterns. For the purposes of our outage statistics, we classify OPG's CO_2 outages as planned outages rather than forced outages as done by the IESO. [45] Furthermore, the capacity that was

[45] OPG has used the existing planned outage process to designate certain planned outages as CO_2 outages. An important feature of these CO_2 outages is that they provide assurance that they will not be recalled before all other planned outages due to IESO reliability concerns. The IESO achieves this assurance by classifying them as forced outages. As of April 30, 2009, there have been 3 CO_2 outages, the first beginning at the end of January 2009.

removed from the market by designating units as NOBA is not reflected in either the planned or forced outage statistics.[46] Over the last five years, coal-planned outage rates have typically been at or above 20 percent of capacity during the spring and fall months, which represents low demand months, and this spring is no exception when treating the CO_2 outages as planned outages.[47]

Figure 1-22: Planned Outages Relative to Capacity by Fuel Type, January 2003–April 2009 (% of Capacity)

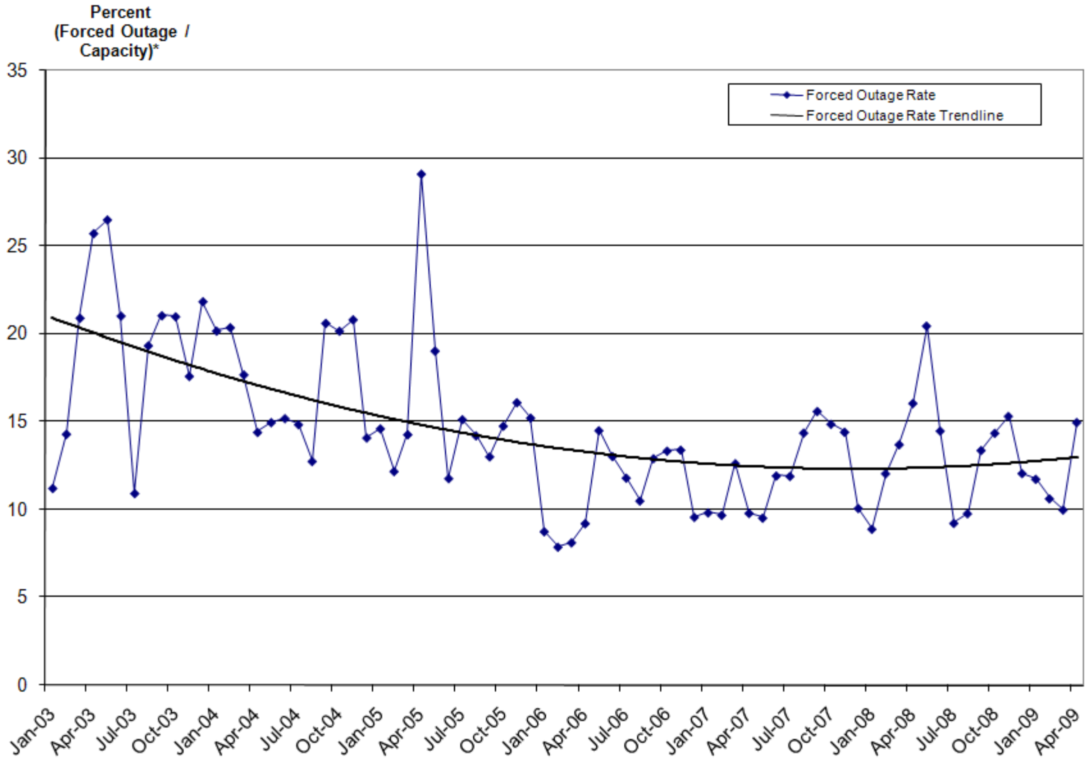


[46] OPG has designated certain coal units as NOBA (Not Offered But Available) as part of their CO_2 Reduction Strategy. Between February and April 2009, there have been 53 unit-days designated as NOBA (all but two were in March and April 2009). Had these NOBA's been classified as planned outages, the coal-planned outage rate would have increased to slightly above 30 percent in March and April 2009. OPG's CO_2 Reduction Strategy is discussed in more detail in Chapter 3, section 2.2.
[47] During March and April 2009, the planned outage rate for coal units would have been below 10 percent if CO_2 outages were classified as forced outages as done by the IESO outage management system.

4.4.2 Forced Outages

Unlike observed patterns in planned outage, forced outages are unexpected and tend to be less seasonal in nature. Figure 1-23 plots forced outages as a percentage of capacity between January 2003 and April 2009. Since the summer of 2006, the aggregated forced outage rate has mainly fluctuated between 10 and 20 percent, an improvement from frequent observations above 20 percent between 2003 and 2005.

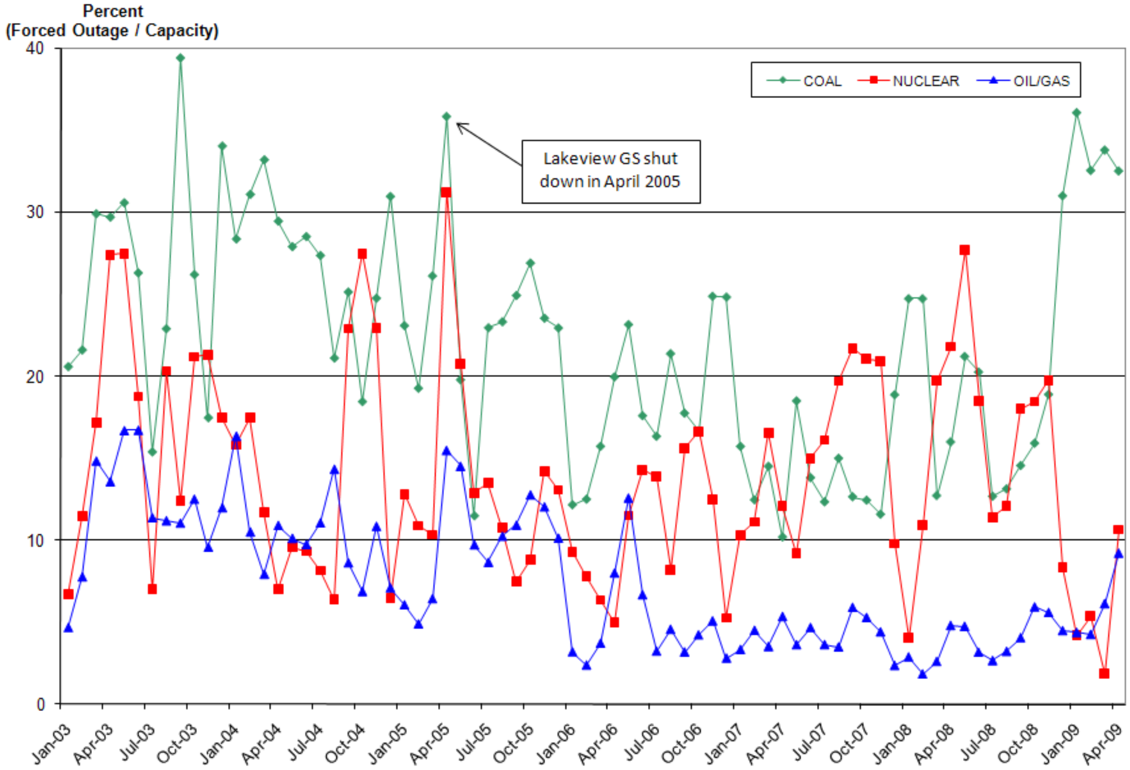
Figure 1-23: Forced Outages Relative to Capacity,*
January 2003–April 2009
(% of Capacity)



* Includes Nuclear, Coal, and Oil/Gas units.

Figure 1-24 separates forced outage rates by fuel type since 2003. The forced outage rate for coal units noticeably increased during the winter 2008/2009 months and remained above 30 percent between December 2008 and April 2009 indicating poor coal performance during these months. The coal outage rate reached a peak of 36 percent in January 2009, coming close to the previous peak outage rate of 39 percent set in September 2003.[48]

Figure 1-24: Forced Outages Relative to Total Capacity by Fuel Type, January 2003–April 2009 (% of Capacity)



While coal outages appear to have increased this winter, the nuclear forced outage rate was relatively low compared to previous periods and fell below 5 percent in 3 of the six months this winter. In March 2009, the nuclear forced outage rate reached a low of slightly under 2 percent, easily surpassing the previous low of 5 percent in April 2006.

[48] If our coal forced outage rate included OPG's CO_2 outages, consistent with the IESO's classification, the rate would have been much higher this spring and would have reached almost 50 percent in March 2009.

Finally, the gas-forced outage rate remained below 10 percent for all months this winter, although it reached a high of 9 percent in April 2009, the highest level since May 2006.

4.5 Changes in Fuel Prices

Tables 1-31 and 1-32 presents average monthly coal and natural gas spot prices over the last two winter periods. Based on the six-month averages, coal prices demonstrated a significant increase this winter while natural gas prices declined.[49] In general, fuel prices declined throughout the recent winter months in contrast to the 2007/2008 winter months where prices were steadily increasing throughout the period.[50]

4.5.1 Coal Prices

Average monthly Central Appalachian (CAPP) and Powder River Basin (PRB) Coal spot prices are presented in Table 1-31 for the last two winter periods. In percentage terms, both types of coal appreciated in price relative to last year, however there was a larger increase in CAPP coal over PRB coal. CAPP coal prices increased by 38 percent this winter, increasing from an average of $2.92/MMBtu in 2007/2008 to $4.03/MMBtu in 2008/2009. PRB coal prices increased 16.9 percent, from $0.71/MMBtu last winter to $0.83/MMBtu this winter. Although the six-month average prices for both types of coal increased this winter, prices were falling steadily from November 2008, such that by April 2009, prices had fallen within the period by 36 percent, and were lower than one year earlier prices by 6.6 percent for CAPP coal and 24.7 percent for PRB coal.

[49] Spot prices are converted using the daily noon USD-CAD exchange rate published on the Bank of Canada's website at: http://www.bank-banque-canada.ca/en/rates/exchange.html
[50] Fuel prices are indexed by the applicable heat rate to allow for a consistent comparison between fuel types.

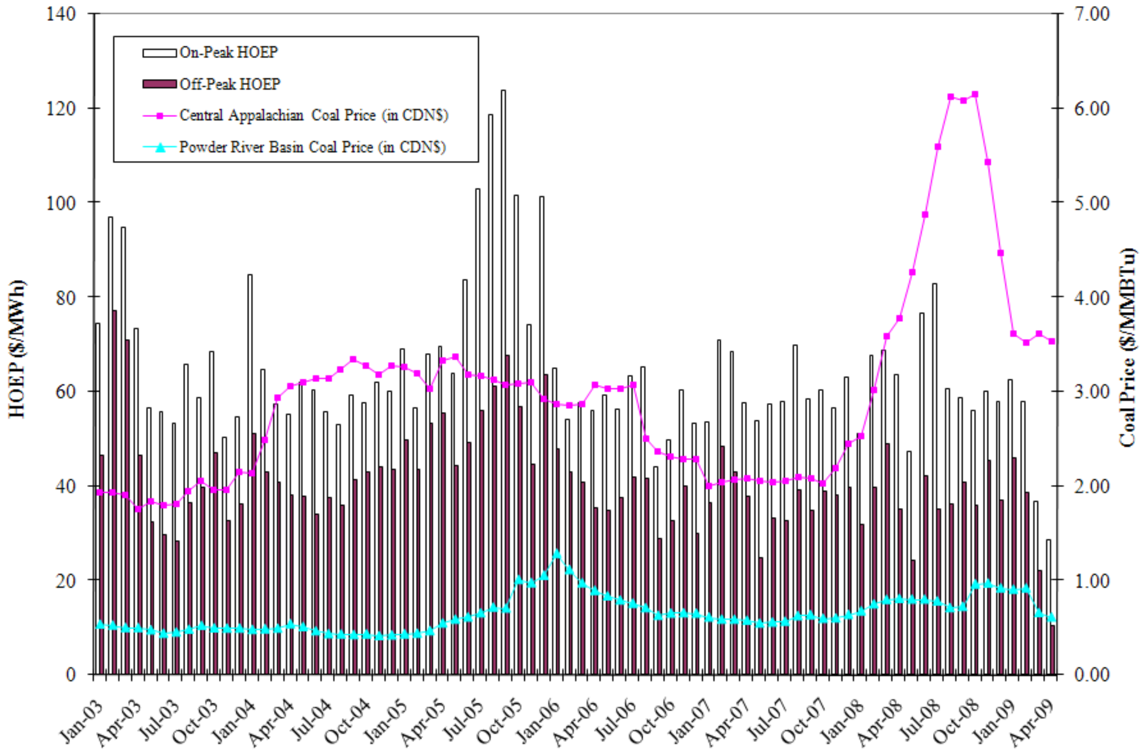
Table 1-31: Average Monthly Coal Prices by Type, November–April 2007/2008 & 2008/2009 ($CDN/MMBtu)

	Central Appalachian Coal (CAPP) Spot Price			Powder River Basin (PRB) Coal Spot Price		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
November	2.18	5.44	149.5	0.60	0.97	61.7
December	2.44	4.47	83.2	0.64	0.92	43.8
January	2.52	3.61	43.3	0.68	0.90	32.4
February	3.02	3.52	16.6	0.75	0.92	22.7
March	3.59	3.61	0.6	0.80	0.66	(17.5)
April	3.77	3.52	(6.6)	0.81	0.61	(24.7)
Average	2.92	4.03	38.0	0.71	0.83	16.9

Source: EIA Coal News and Market Reports

Figure 1-25 plots the monthly average CAPP and PRB coal prices, along with the on-peak and off-peak HOEP prices. Since 2003, there does not appear to be a close correlation between the HOEP and CAPP and PRB coal prices. Although there was a significant spike in coal prices during the 2008 summer months and a subsequent decline in the fall and winter months, on-peak and off-peak average HOEP's showed little similarity in price movements.

Figure 1-25: Central Appalachian Coal Spot Price and HOEP, January 2003–April 2009 ($/MWh and $/MMBtu)



4.5.2 <u>Natural Gas Prices</u>

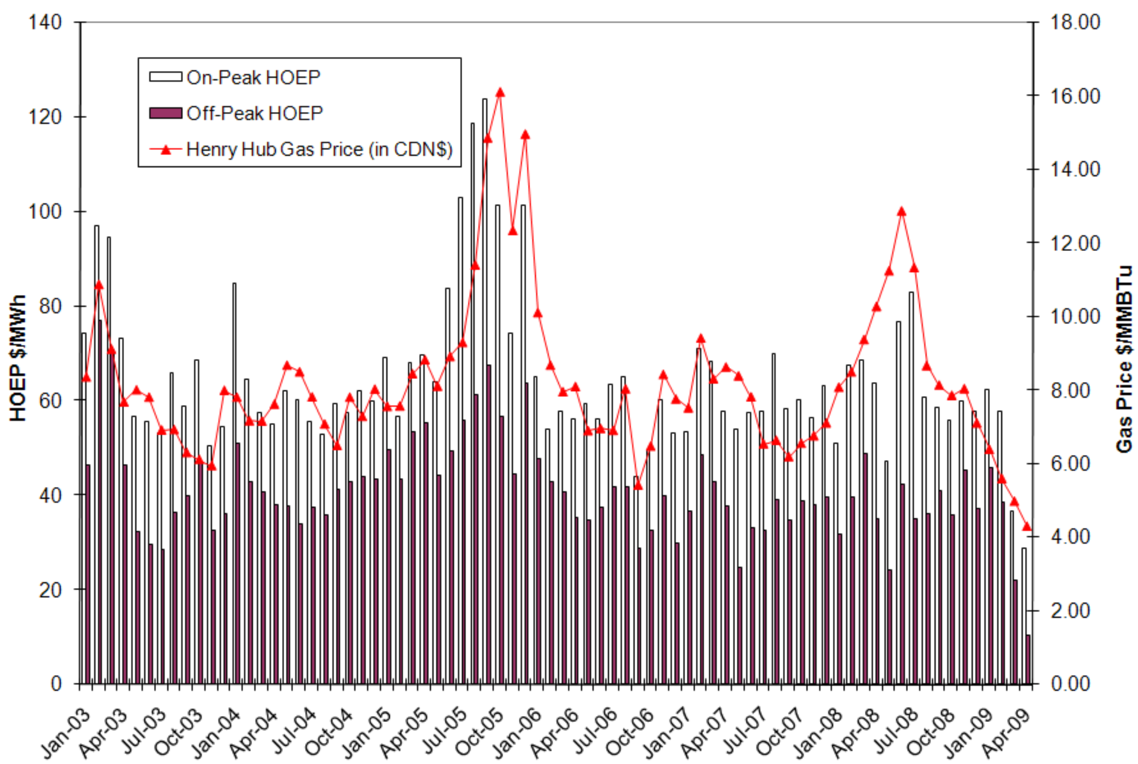
Natural gas prices, measured by the Henry Hub Spot and Dawn Daily Gas prices are presented in Table 1-32. Based on the six-month averages, prices for both types of natural gas fell relative to last winter although began the winter period higher than last winter. The Henry Hub price declined by $2.27/MMBtu (27.3 percent) while the Daily Dawn price fell by $2.11/MMBtu (24.1 percent) year-over-year. In November 2008, gas prices were higher than November 2007, but just as there was a steady rise in gas prices every month last year, there was a steady drop in gas prices every month this winter. By April 2009, both Henry Hub and Daily Dawn prices had fallen about 43 percent relative to November 2008 prices, which mean they were some 56 to 58 percent lower than April 2008 prices.

Table 1-32: Average Monthly Natural Gas Prices by Type, November–April 2007/2008 & 2008/2009 ($CDN/MMBtu)

	Henry Hub Spot Price			Dawn Daily Gas Price		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
November	6.76	8.04	18.9	7.21	8.43	16.9
December	7.11	7.11	(0.1)	7.56	7.80	3.2
January	8.06	6.39	(20.7)	8.25	7.26	(12.0)
February	8.50	5.60	(34.2)	8.73	6.15	(29.6)
March	9.38	4.98	(46.9)	9.89	5.40	(45.4)
April	10.28	4.30	(58.2)	10.84	4.78	(55.9)
Average	8.35	6.07	(27.3)	8.75	6.64	(24.1)

Figure 1-26 plots the monthly average Henry Hub spot price along with the on-peak and off-peak HOEP prices. Movements in the gas price appear to roughly coincide with movements in the HOEP.

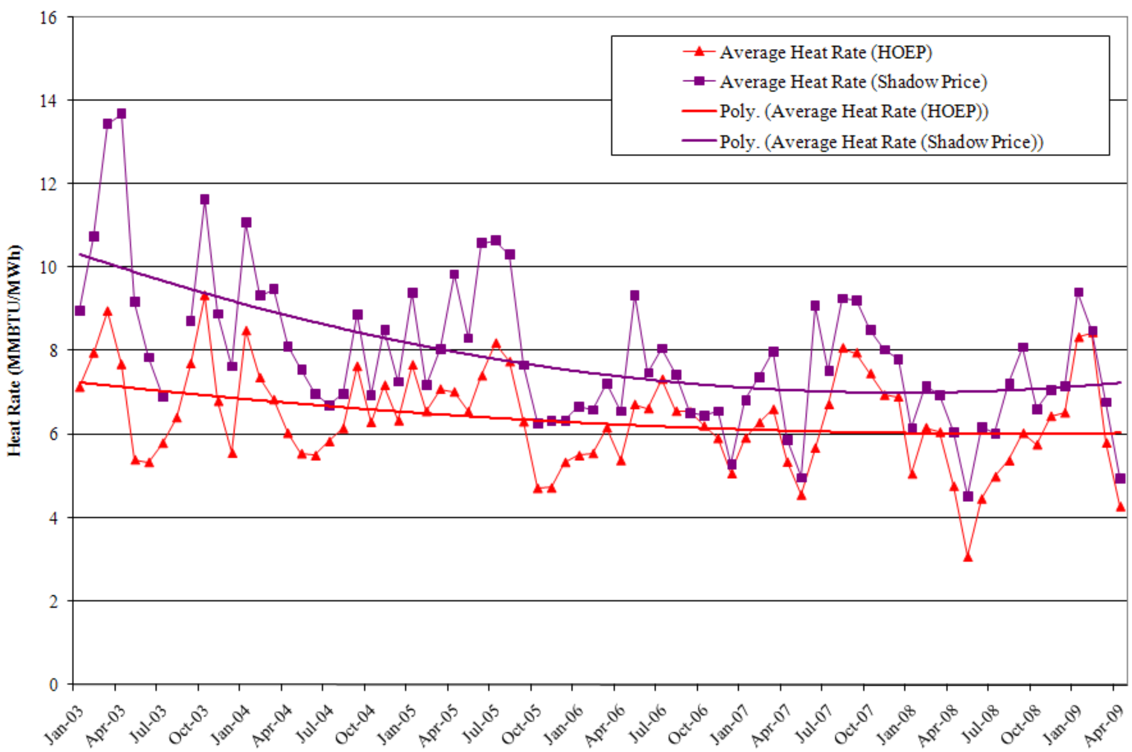
Figure 1-26: Henry Hub Natural Gas Spot Price and HOEP, January 2003–April 2009 ($/MWh and $/MMBtu)



4.5.3 Energy Price Equivalent Heat Rate

Figure 1-27 plots the estimated energy price equivalent heat rate since January 2003. The energy price equivalent heat rate is calculated by taking the average HOEP (or Richview Shadow Price) in a month divided by the average natural gas price measured by the Henry Hub spot price converted to Canadian dollars. This estimated equivalent heat rate can be useful for a couple of reasons, although this may be less the case under current lower demand conditions and ample supply. First, the heat rate equivalent is relevant when gas-fired generators are marginal or near marginal. The heat rate equivalent indicates the efficiency level an existing gas-fired generator needs in order to recover its incremental costs through market revenue. Secondly, it provides potential investors information on the efficiency required from a gas-fired generator to recover its incremental costs. The figure suggests that a hypothetical 7,000 MMBtu combined-cycle gas-fired generating unit would have been unable to recover its costs from the market over the last few years with the exception of a few months in 2007. The same analysis using the Richview shadow price shows that, a 7,000 BTU heat rate generator in the constrained sequence may be close to cost recovery. This simple analysis highlights a major reason why most of Ontario's new generation operates under some form of contract, which compensates them for losses in the market.

Figure 1-27: Estimated Monthly Average Energy Price Equivalent Heat Rate using HOEP and the Richview Shadow Price, January 2003–April 2009 (MMBtu/MWh)



4.6 Net Revenue Analysis

Similar to previous MSP reports, we use a standardized model developed by the Federal Energy Regulatory Commission of the United States (FERC) to help assess whether there are sufficient market revenues for a typical new gas-fired generator in Ontario to make an adequate rate of return on their investment.[51]

Table 1-33 reports net revenue estimates (in CDN$) for the past six annual May to April periods.[52] Estimated net revenues for the more efficient combined-cycle generator have fluctuated between a low of $47,174/MW-year between May 2004 and April 2005 and a maximum of $83,053/MW-year between May 2005 and April 2006. The average net

[51] For details, see FERC 2004 State of the Markets Report, Docket MO05-4-000.
[52] See the Panel's January 2009 MSP Monitoring Report, pp. 64-65, for the most recent annual results based on annual periods measured on a November-October basis.

revenue over the last six annual periods is $60,848/MW-year. Net revenues for the less efficient combustion turbine generator are much lower ranging between $8,314/MW-year and $24,633/MW-year with an average at $15,134/MW-year over the last six years. FERC estimates that a combined cycle generator would require approximately US$80,000-90,000/MW-year (approximately CDN$89,000-$100,000/MW-year at current exchange rates) and a combustion turbine unit US$60,000-70,000/MW-year (approximately CDN$67,000-$78,000/MW-year at current exchange rates) in order to meet debt and equity requirements. For all annual periods except 2005/2006, the estimated net revenue for the combined-cycle units are well below the FERC requirement and estimated net revenues for the combustion gas turbine are below FERC's estimate of requirements for all annual periods.

Table 1-33: Yearly Estimated Net Revenue Analysis for Two Generator Types, May 2003–April 2009 (CDN$/MWh)

Generator Type	7,000 Btu/KWh of Combined-cycle with variable O&M cost of US$1/MWh	10,500 Btu/KWh of Combustion turbine with variable O&M cost of US$3/MWh
May 2003 – April 2004	73,349	17,609
May 2004 – April 2005	47,174	8,314
May 2005 – April 2006	83,053	24,633
May 2006 – April 2007	49,924	9,786
May 2007 – April 2008	62,439	16,322
May 2008 – April 2009	49,151	14,141
Average	60,848	15,134

5. Imports and Exports

5.1 Overview

Table 1-34 presents that monthly net exports during both on-peak and off-peak hours significantly increased this winter relative to last winter by a total of 1,340 GWh (33 percent). Of this total, net exports during on-peak hours increased by 789 GWh (54 percent) this winter while off-peak net exports increased by 552 GWh (21 percent).

Table 1-34: Net Exports (Imports) from (to) Ontario Off-peak and On-peak, November–April 2007/2008 & 2008/2009 (GWh)

	Off-Peak			On-Peak			Total		
	2007/2008	2008/2009	% Change	2007/2008	2008/2009	% Change	2007/2008	2008/2009	% Change
November	80	363	353.8	(115)	200	273.9	(35)	562	1,705.7
December	241	553	129.5	70	441	530.0	311	994	219.6
January	672	634	(5.7)	425	546	28.5	1,097	1,180	7.6
February	541	585	8.1	319	348	9.1	860	932	8.4
March	478	657	37.4	210	516	145.7	688	1,173	70.5
April	615	387	(37.1)	547	195	(64.4)	1,161	582	(49.9)
Total	2,627	3,179	21.0	1,456	2,245	54.2	4,083	5,423	32.8

Imports and exports are also reported in Table 1-35 and 1-36, showing totals for each intertie for the total winter period last year and this year. The tables also show totals at each intertie, net of linked wheels at that intertie. Total imports, shown in Table 1-35, dropped to 2,737 GWh, a decrease of 1,631 GWh or 37 percent compared to last winter.[53] The decrease in total exports, as seen in Table 1-36 was only 284 GWh, or 3.4 percent. The reduction in imports was largest in March and April when Ontario experienced a combination of intertie outages that limited trade, and very low HOEP which reduced the opportunity for profitable imports to Ontario.

[53] Linked wheels between November 2007 and April 2008 amounted to 1,850 GWh, but were much lower, only 16 GWh, for the current period.

Table 1-35: Imports to Ontario by Intertie, November–April 2007/2008 & 2008/2009 (GWh)

	Total			Total Excluding Linked Wheels		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
Manitoba	568	510	(10.2)	568	510	(10.2)
Michigan	2,441	1,718	(29.6)	2,424	1,713	(29.3)
Minnesota	140	146	4.3	140	146	4.3
New York	2,548	232	(90.9)	875	220	(74.9)
Quebec	525	149	(71.6)	361	148	(59.0)
Total	6,222	2,755	(55.7)	4,368	2,737	(37.3)

Table 1-36: Exports from Ontario by Intertie, November–April 2007/2008 & 2008/2009 (GWh)

	Total			Total Excluding Linked Wheels		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
Manitoba	26	76	192.3	26	76	192.3
Michigan	3,744	4,457	19.0	1,983	4,445	124.2
Minnesota	130	77	(40.8)	112	77	(31.3)
New York	5,912	3,279	(44.5)	5,831	3,275	(43.8)
Quebec	494	289	(41.5)	494	289	(41.5)
Total	10,305	8,178	(20.6)	8,446	8,162	(3.4)

When the market opened in 2002, Ontario was a net importer of energy but over the years it has become a net exporter as favourable supply conditions in the province made it less dependent on imports to meet internal energy needs. As can be seen in Figure 1-28, the trend toward increasing net exports has continued into the current winter period, with net exports during the on-peak and off-peak hours in the recent winter comparable to those in the previous summer months.

Figure 1-28: Net Exports (Imports) from Ontario, On-peak and Off-peak, January 2003–April 2009 (GWh)

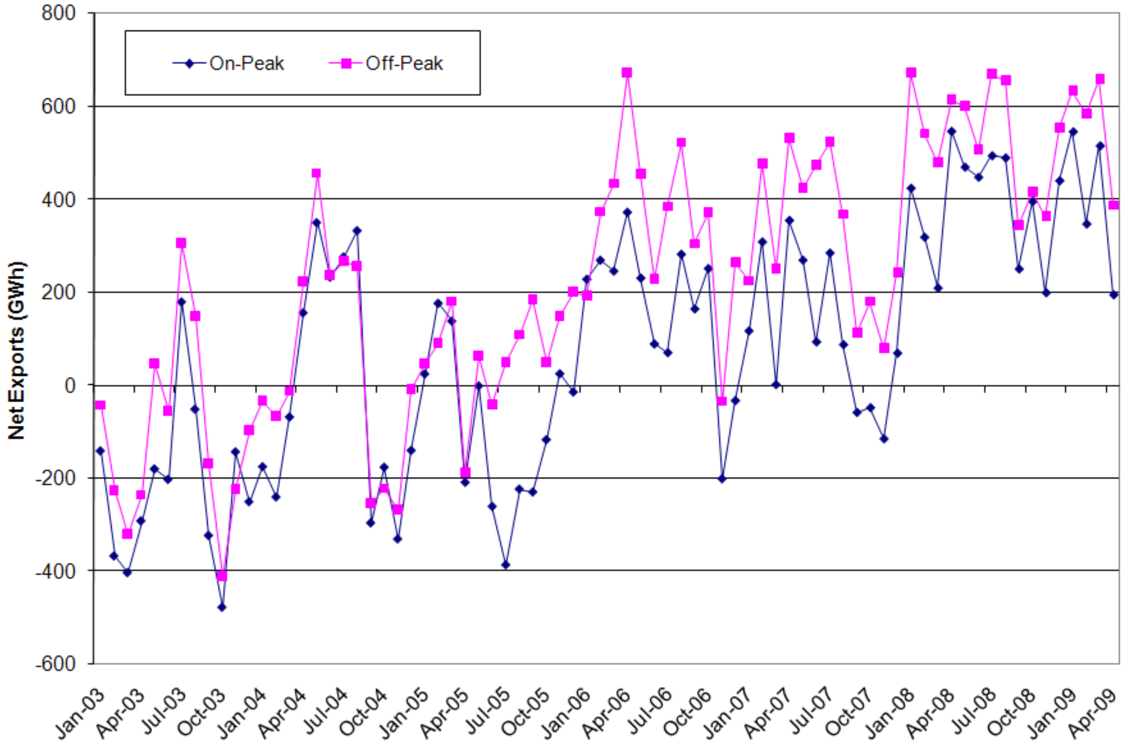


Table 1-37 presents total net exports by neighbouring intertie group for the 2007-2008 and 2008-2009 winter months. Table 1-34 and Figure 1-28 report total provincial net exports, therefore linked wheel volumes are not relevant to these since each linked wheel includes a simultaneous injection and withdrawal of energy, thus netting to zero. However, linked wheel volumes have been included in the net exports by intertie group since the import and export leg are scheduled at different intertie groups (ie. they do not net to zero at a given intertie).

Historically, Ontario has been a net importer of energy at the Michigan intertie but that has been slowly shifting. As of last winter, Ontario became a net exporter at the Michigan interface, with 1,303 GWh of net exports, and this has risen even further to 2,739 GWh this winter, an increase of 1,436 GWh (110 percent). Last year the exports were large mostly because of the linked wheels flowing out at Michigan, which as noted above amounted to 1,850 GWh, with the vast majority flowing from New York to PJM through

MISO. For this winter there have been only 16 GWh of such linked wheels. However, this winter's exports from Ontario through Michigan to PJM have risen markedly to a total of almost 3,200 GWh, while imports from Michigan have dropped by 723 GWh or almost 30 percent compared with last winter.[54] Because imports last year at New York included 1,850 GWh of linked wheels, this means there were fairly large shifts in other trade with New York. Most noteworthy was the drop in exports to New York, falling by about 2,633 GWh or 45 percent compared to last winter, in large part due to the reduced export capability in March and April. (Refer to Tables 1-35 and 1-36 for import and export statistics at individual interties.) It is also noteworthy that for the winter period, total exports to Michigan exceeded exports to New York. This represents the first six-month reporting period when this has occurred when looking at total exports absent the export leg of linked-wheels. Net exports at the other interties were mostly unchanged.

Table 1-37: Net Exports (Imports) from (to) Ontario by Neighbouring Intertie Group
November–April 2007/2008 & 2008/2009
(GWh)

	Manitoba		**Michigan**		**Minnesota**		**New York**		**Quebec**		**Total**	
	2007/ 2008	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**	**2007/ 2008**	**2008/ 2009**
November	(117)	(160)	(624)	47	(16)	(38)	733	647	(11)	67	(35)	562
December	(107)	6	(442)	345	(17)	18	791	562	87	63	311	993
January	(79)	(45)	604	300	23	(24)	550	902	(1)	47	1,097	1,180
February	(61)	(96)	519	533	5	(22)	502	537	(105)	(19)	860	932
March	(90)	(69)	489	1011	3	(16)	293	260	(6)	(14)	688	1173
April	(87)	(70)	758	505	(8)	12	495	140	3	(4)	1,161	582
Total	(542)	(434)	1,303	2,739	(10)	(70)	3,364	3,048	(32)	140	4,083	5,423

5.2 Congestion at Interties

Congestion refers to economic trade at an intertie being limited by the capacity of that intertie to support the flow of energy. In general, intertie congestion levels tend to increase at Ontario's interties as the volume of inter-jurisdictional transactions increase or

[54] For more discussion on the increase in Ontario to PJM export transactions, see Chapter 3, section 2.1.

intertie capability decreases.[55] During the winter 2008/2009 period, overall import congestion levels increased in the Northwest and decreased in the South.

5.2.1 Import Congestion

Table 1-38 reports the number of occurrences of import congestion by month and intertie group over the last two winter periods. At the three interties in the southern part of Ontario - Michigan, New York and Quebec - import congestion fell to near-zero levels. This corresponds to the significant decrease in imports at each intertie (by 30 percent to 91 percent below winter 2007/2008 levels, as observed in Table 1-35), and the simultaneous increase in exports at the Michigan intertie, which contributed to alleviating import congestion at the Michigan interties. In the Northwest, the number of congestion hours increased significantly at the Manitoba intertie (about a 4-fold increase) but much less at Minnesota. As observed in the Panel's previous Monitoring Report,[56] the change at Manitoba is due to more aggressive competition among the small number of traders competing at the intertie.

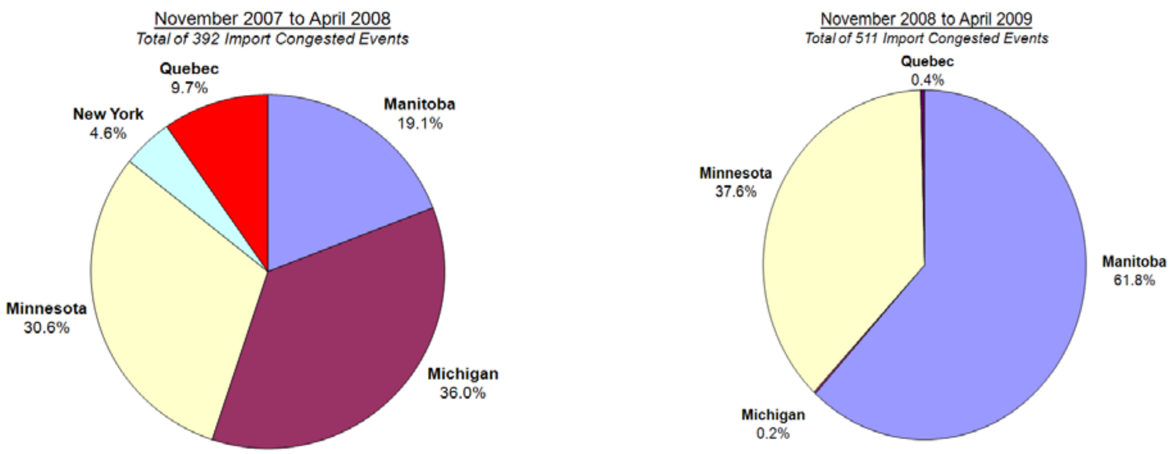
Table 1-38: Import Congestion in the Market Schedule by Intertie, November–April 2007/2008 & 2008/2009 (Number of Hours)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	5	80	80	1	25	54	0	0	9	1
December	38	14	56	0	6	21	0	0	6	0
January	0	33	0	0	19	10	12	0	9	0
February	17	121	9	0	55	58	2	0	4	0
March	9	61	0	0	12	26	4	0	3	0
April	6	7	0	0	3	23	0	0	4	1
Total	75	316	145	1	120	192	18	0	35	2

[55] In this section we focus on intertie congestion which occurs in the unconstrained schedule and leads to intertie prices diverging from the HOEP. This is different from congestion in the constrained schedule at interfaces internal to Ontario, which can lead to imports or exports being constrained on or off and receiving CMSC payments.
[48] See the Panel's January 2009 MSP Monitoring Report, p. 69.
[57] It is possible to have more than one intertie import (export) congested during the same hour and for the purposes of the pie charts above (and in the export congestion section), these are treated as individual import (export) congestion events.

Figure 1-29 compares the number of hours of import congestion by intertie group as a percentage of total import congestion events for the 2007/2008 and 2008/2009 winter months.[57] The largest source of import congestion has shifted from Michigan last year to Manitoba this year. Import congestion at Minnesota was the next most pronounced in each period.

Figure 1-29: Percentage of Import Congestion Events in the Market Schedule by Intertie, November–April 2007/2008 & 2008/2009 (%)



[57] It is possible to have more than one intertie import (export) congested during the same hour and for the purposes of the pie charts above (and in the export congestion section), these are treated as individual import (export) congestion events.

5.2.2 Export Congestion

Table 1-39 provides the frequency of export congestion by month and intertie group for the 2007-2008 and 2008-2009 winter months. Increased export volumes at Michigan have led to increased export congestion (45 percent higher) there, while lower exports volumes at Minnesota contributed to reduced export congestion (31 percent lower) at that intertie. Part of the increased congestion at Michigan was associated with the transmission outages at the New York intertie between late March and early April, which required lowering the export capability at Michigan as well.

Exports to or through Michigan (e.g. ultimately to PJM) flow partly across the Michigan intertie and partly across the New York intertie because of the nature of parallel path flows in a transmission grid. Thus to control the flows across the New York intertie induced by exports to or through Michigan, the Michigan export limit was also reduced. With exports to PJM being economic, the reduced limit led to increased competition for the reduced transmission resource and more congestion. The reduced import and export limit at New York had the opposite effect, i.e. reduced congestion, because with limits of zero in each direction, traders avoided trading at that intertie. (The Panel has previously commented on the implications of congestion and wheeling transactions.[58] In Chapter 3, section 2.1 we further discuss congestion and exports from Ontario to PJM).

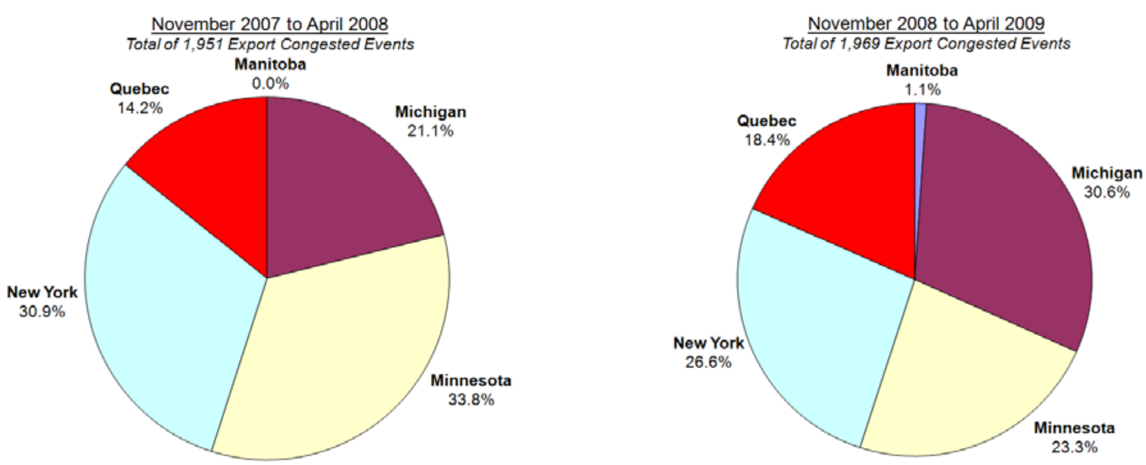
[58] MSP Monitoring Report, January 2009, p. 196 As long as such transactions pay for their share of the intertie congestion they contribute, they are receiving the appropriate pricing signal. As long as internal congestion is small there is also little concern.

Table 1-39: Export Congestion in the Market Schedule by Intertie, November–April 2007/2008 & 2008/2009 (Number of Hours)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	0	0	0	40	21	18	62	103	0	37
December	0	12	1	54	47	102	141	82	0	31
January	0	0	175	6	193	9	34	258	94	71
February	0	0	23	1	238	12	111	50	14	27
March	0	3	90	205	146	80	29	27	131	46
April	0	6	127	297	17	238	229	4	37	150
Total	0	21	416	603	662	459	606	524	276	362

Figure 1-30 compares the percentage of export congestion events by intertie group for the last two winter periods. Over the last two winters, the largest source of export congestion has shifted from Minnesota last year to Michigan this year. Export congestion at New York was next most prevalent in each period.

Figure 1-30: Percentage of Export Congestion Events in the Market Schedule by Intertie, November–April 2007/2008 & 2008/2009 (%)



5.2.3 Congestion Rent

Congestion rent occur as the result of different prices faced by importers and Ontario load, or exporters and Ontario generation. These price differences are induced by congestion at the interties, with importers and exporters receiving or paying the intertie price, and Ontario generators and loads receiving or paying the uniform Ontario price (either the interval MCP or HOEP). When there is export congestion and exporters are competing for the limited intertie capability, the intertie price rises above the Ontario price, and congestion rent is collected from the exporters. When there is import congestion, the intertie price falls below the Ontario price, and congestion rent is the result of the lower price paid to importers, relative to the uniform price.

Tables 1-40 and 1-41 report the congestion rent for the five intertie groups in winter 2008/2009 compared to winter 2007/2008. Congestion rent is calculated as the MW of net import or net export that actually flows (i.e. the constrained schedule) multiplied by the price difference between the congested intertie zone in Ontario and the uniform price. This represents a cost to traders, either in the form of a congestion price premium paid for exports or the reduction in the payment for imports. However, traders that have transactions in the opposite direction to the congested flow may actually benefit from these differentials. For example, an import on an export congested intertie would receive a higher payment than HOEP because of the higher intertie price. Similarly, an export on an import congested intertie would pay a lower price than the HOEP. Such counter-flows in the constrained schedule can induce negative components in the congestion rent as occasionally observed below.

Table 1-40: Import Congestion Rent by Intertie, November–April 2007/2008 & 2008/2009 ($ thousands)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON		Total	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	15	1	731	1	(13)	(20)	0	0	10	2	743	(16)
December	0	2	829	0	(1)	3	0	0	1	0	829	5
January	0	17	0	0	(10)	8	29	0	20	0	39	25
February	0	(11)	86	0	(45)	8	(1)	0	1,203	0	1243	(3)
March	(3)	(25)	0	0	(5)	(21)	3	0	1,346	0	1341	(46)
April	2	6	0	0	(4)	(4)	0	0	82	0	80	2
Total	14	(10)	1,646	1	(78)	(26)	31	0	2,662	2	4,275	(33)

Table 1-41: Export Congestion Rent by Intertie, November–April 2007/2008 & 2008/2009 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	0	0	0	467	27	10	654	952	0	51	681	1,480
December	0	68	18	718	58	424	2,680	2,600	0	39	2,756	3,849
January	0	0	2,844	27	518	20	498	4,098	79	43	3,939	4,188
February	0	0	435	5	437	6	1,622	427	7	16	2,501	454
March	0	1	1,419	3,238	473	95	508	219	78	48	2,478	3,601
April	0	1	3,631	4,164	17	174	3,485	23	46	119	7,179	4,481
Total	0	70	8,347	8,619	1,530	729	9,447	8,319	210	316	19,534	18,053

Total congestion rent for import congestion events dropped to virtually zero this winter, compared with total rent of $4.3 million last winter, corresponding to the near-zero levels of import congestion in southern Ontario. For the two interties which showed significant and increased import congestion as shown in Table 1-38 (Manitoba and Minnesota), congestion rent was negative. This negative rent highlights the fact that the Northwest had bottled supply for most of the period, which led to constraining off imports and constraining on exports. Thus in the unconstrained pre-dispatch sequence, imports appeared large and congested the intertie, but actual imports flows based on the constrained schedule were lower, often zero, leading to little or no congestion rent. Meanwhile, constrained on exports in those hours led to negative congestion rent.

Although congestion rent may be lower or negative as the result of constraining on or constraining off transactions, because CMSC payments are also tied to the congested intertie price, lower CMSC made to these transactions offsets the reduced congestion rent to some extent.[59]

Total congestion rent for export congestion events were moderately lower this winter, at $18.0 million, a reduction of $1.5 million or 7.6 percent, with rent at some interties increasing and others decreasing, roughly corresponding to the increased or decreased similar frequency of export congestion on the intertie. In addition to the numbers of hours of congestion, reduction in intertie capability also contributed to some lowering of congestion rent.

The magnitude of monthly congestion rent relates only in part to the hours of congestion at the intertie. There are several factors which can influence congestion rent since it is based on both the magnitude of actual imports or exports at the intertie and the Intertie Congestion Price (ICP). ICP is the difference between the uniform Ontario price and the intertie zonal price and depends on the price of the marginal import or export at the intertie, relative to the marginal resource within Ontario in the unconstrained scheduling process. The magnitude of the actual import or export flow is dependent on:

i) the maximum capability of the intertie,
ii) temporary reductions in the intertie capability,
iii) loop flows, which use up part of, or add to, the intertie capability,
iv) import or export failures, and
v) constrained on or constrained off imports or exports.

Congestion rent can be viewed as the risk that an importer may be paid less than the Ontario uniform price or an exporter may pay more than the uniform price. To hedge the risk, the IESO makes available Transmission Rights (TR) which will compensate the TR

[59] For example, with a HOEP of $50/MWh and an intertie price of $30/MWh due to import congestion, a 100 MW constrained off import with an offer price of $20/MWh would receive CMSC of 100 * (30 -20) = $1,000. This is less than the CMSC payment if there was no congestion, 100 * (50 – 20) = $3000. The CMSC is lower by $2000 because of the congested price, which corresponds to the congestion rent 100 * (50 – 30) = $2,000 lost because the transaction was constrained of f and did not flow.

holder for differences in the intertie and uniform price. In previous reports the Panel has observed that TR payments generally exceed congestion rent received by the IESO.[60]

Tables 1-42 and 1-43 show TR payments by intertie for each month of the 2007/2008 and 2008/2009 winter periods, separately for import congestion events and export congestion events. The total TR Payments for imports were $1.4 million, which is only about 20 percent of the $7.0 million payment last year, but contrasts with the slightly negative congestion rent of minus $0.033 million (see Table 1-40) for the period. The total TR Payments for exports were $23.1 million, which is 36 percent lower than last year's TR payment of $36.3 million. However, the TR payment was $5.0 million or 28 percent higher than the export congestion rent (see Table 1-41) for the recent winter period.

Table 1-42: Monthly Import Transmission Rights Payments by Intertie, November–April 2007/2008 & 2008/2009 ($ thousands)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON		Total	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	45	526	1,043	1	45	93	0	0	33	3	1,165	623
December	225	47	747	0	4	30	0	0	11	0	987	77
January	0	71	0	0	30	19	474	0	31	0	535	90
February	47	293	107	0	84	65	71	0	1,213	0	1,522	358
March	39	252	0	0	9	27	34	0	2,565	0	2,647	279
April	24	26	0	0	5	16	0	0	152	0	181	27
Total	379	1,214	1,897	1	177	250	579	0	4,005	3	7,037	1,454

[60] See the Panel's January 2009 Monitoring Report, p.75.

Table 1-43: Monthly Export Transmission Rights Payments by Intertie, November–April 2007/2008 & 2008/2009 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007 / 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	0	0	0	740	31	70	737	1,005	0	70	768	1,884
December	0	81	8	2,665	63	944	2,853	5,523	0	40	2,925	9,254
January	0	0	7,520	49	1,192	45	679	3,541	108	47	9,498	3,683
February	0	0	710	4	1,232	36	3,918	465	11	18	5,871	523
March	0	8	2,986	5,327	1,240	206	835	256	114	129	5,175	5,925
April	0	2	4,109	993	26	533	7,948	5	57	317	12,140	1,849
Total	0	90	15,332	9,777	3,783	1,835	16,970	10,795	290	622	36,376	23,119

Part of the reason for lower total TR payments was the reduced quantity of TRs which were sold at the Michigan and New York interties. Because of known planned outages and uncertainty regarding the level of outages at the New York intertie, and their impact on both New York and Michigan transactions, fewer TRs were sold at these interties throughout the winter period. The much lower TR payments for imports correspond to fewer TRs sold and the much lower levels of congestion this year. Overall TR payments for exports were lower, largely due to the fewer TRs sold (about 45 percent fewer were sold at both New York and Michigan). The less frequent export congestion at the New York intertie further helped reduce TR payments there, while increased congestion at the Michigan intertie (see Table 1-39) partially offset the effect of the reduced TRs sold.

Tables 1-44 and 1-45 provide the absolute value of monthly average Intertie Congestion Prices (ICPs) by intertie for imports and exports respectively.[61] The absolute ICP represents the difference in the intertie price and the uniform price, which is the basis for both congestion rent and TR payments (averages are taken across hours where there is congestion, with imports and exports congestion averaged separately). The ICPs for imports were generally lower this winter compared to last, particularly at the interties in southern Ontario, where imports have decreased and import congestion decreased significantly, while ICPs in the Northwest, where import congestion increased compared with last winter, were about $17/MWh, roughly unchanged year-over-year. ICPs for

[61] Monthly observations denoted as ‘n/a’ represent months where there was no congestion on the intertie.

exports for the Michigan and New York interties were $24.83/MWh and $19.22/MWh respectively, representing marginal increases of 18 percent and 8 percent respectively, compared with the previous winter.

Table 1-44: Monthly Average Import Congested Prices by Intertie, November–April 2007/2008 & 2008/2009 ($/MWh for hours congested)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	44.17	24.63	7.98	1.08	21.04	19.79	n/a	n/a	6.07	2.51
December	23.26	12.76	11.60	0.08	7.65	16.88	n/a	n/a	6.32	0.08
January	n/a	11.45	n/a	n/a	18.42	22.51	24.82	n/a	5.69	n/a
February	15.67	12.85	6.14	n/a	17.91	16.71	22.09	n/a	536.92	n/a
March	24.70	22.07	n/a	n/a	9.29	15.58	6.14	n/a	2,059.87	n/a
April	24.72	16.58	n/a	n/a	21.41	10.50	n/a	n/a	118.44	n/a
Average	23.22	17.53	9.29	0.58	17.36	17.02	20.36	n/a	255.57	0.89

Table 1-45: Monthly Average Export Congested Prices by Intertie, November–April 2007/2008 & 2008/2009 ($/MWh for hours congested)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	n/a	n/a	n/a	18.95	10.44	27.64	6.18	9.26	n/a	19.00
December	n/a	25.96	7.23	63.49	10.05	67.46	10.29	64.98	n/a	16.67
January	n/a	n/a	21.86	5.90	44.10	35.78	10.16	12.48	11.46	6.59
February	n/a	n/a	15.40	1.52	36.98	28.42	18.08	7.50	7.57	6.80
March	n/a	16.67	16.18	22.69	60.66	24.32	17.60	7.97	8.71	28.13
April	n/a	1.51	24.70	22.22	10.78	20.87	26.50	4.08	18.25	23.73
Average	n/a	16.91	21.10	24.83	40.94	32.35	17.76	19.22	10.87	18.68

Both TR payments and congestion rent increase with the (absolute) ICP. However, unlike congestion rent, TR payments are influenced only by the magnitude of TR's sold in the auction and the ICP. There is a large tendency for actual net imports and net exports, and thus congestion rent, to be less than the full capability of the intertie, and the TR's sold. Consequently the TR payments continue to exceed the congestion rent in aggregate.

As noted earlier and by comparing totals from Table 1-40 and 1-41, it can be seen that there was no net offset of overall import TR payment of $1.4 million since total import congestion rent was slightly negative this winter. The comparison of TR payments and congestion rent for exports can be seen in Table 1-46, which shows export TR payments less congestion rent by intertie. Export TR payments exceeded rent by $5.1 million in the 2008-2009 winter, representing a 70 percent reduction, compared with $16.8 the previous winter. The excess of TR payment over congestion rent is much lower this year, primarily as a result of the smaller TR payments at both Michigan and New York interties.

Table 1-46: Monthly Export TR Payments less Congestion Rent by Intertie, November–April 2007/2008 & 2008/2009 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009	2007/ 2008	2008/ 2009
November	0	0	0	272	3	60	83	53	0	19	86	404
December	0	13	(9)	1,947	7	521	172	2,923	0	1	170	5,405
January	0	0	4,676	22	674	25	181	(557)	29	4	5,559	(505)
February	0	0	275	(1)	795	30	2,297	38	4	2	3,370	70
March	0	6	1,567	2,089	766	111	327	36	36	82	2,697	2,324
April	0	0	478	(3,171)	9	359	4,463	(18)	11	197	4,961	(2,632)
Total	0	20	6,986	1,158	2,254	1,106	7,523	2,476	80	306	16,844	5,066

5.3 Analysis of the Determinants of Exports from Ontario to New York and Michigan

This section reports elasticity estimates from the demand for exports model for exports from Ontario to both New York (NYISO) and Michigan (MISO). The econometric approach makes use of two-stage least squares methodology.[62] These models test whether the average hourly volume of exports from Ontario to New York and Michigan, respectively, are decreasing functions of the HOEP and increasing functions of the neighbouring jurisdictions' prices, and to what degree.

[62] The variables we use to instrument for the HOEP are: Ontario nuclear and self-scheduled output; Ontario non-dispatchable and New York integrated load; the Henry Hub natural gas price (in Canadian dollars); and monthly dummy variables.

Table 1-47 presents estimates for all hours, on-peak hours only, and off-peak hours only for exports from Ontario to New York. With respect to the price variables, all results are statistically significant. In particular, for all hours, we find that a 1 percent increase of the HOEP leads to a 4.55 percent decrease of export volume, while a 1 percent increase of the New York West zonal price leads to a 4.59 percent increase of export volumes. These results are economically intuitive and conform to the expectations stated above. The elasticity estimates are, in absolute value, greater on-peak and lower off-peak than the all hours estimates.

Table 1-47: New York Export Model Estimation Results, January 2003–April 2009

Variable	All Hours		On-peak		Off-peak	
	Coef.	P-value	Coef.	P-value	Coef.	P-value
Constant	6.04	0.000	7.14	0.000	6.01	0.000
Log(HOEP)	-4.55	0.000	-5.69	0.000	-2.12	0.037
Log(New York West Price)	4.59	0.000	5.43	0.001	2.24	0.030
January	0.17	0.200	0.35	0.119	0.07	0.490
February	0.12	0.422	0.10	0.649	0.12	0.367
March	0.25	0.237	-0.02	0.911	0.27	0.218
April	-0.27	0.172	-0.41	0.136	-0.20	0.245
May	0.12	0.538	-0.17	0.660	0.14	0.325
June	0.13	0.535	0.10	0.578	0.07	0.664
July	-0.09	0.723	0.14	0.570	-0.11	0.664
August	-0.23	0.414	-0.15	0.660	-0.17	0.558
September	-0.20	0.237	-0.28	0.230	-0.16	0.171
October	-0.27	0.243	-0.23	0.345	-0.36	0.147
November	0.01	0.917	-0.01	0.965	-0.10	0.507
Model Diagnostics						
Correlation between actual and fitted values	0.798		0.832		0.817	
Number of observations	76		76		76	

Table 1-48 presents similar result for exports from Ontario to Michigan (MISO) for all hours, on-peak hours only, and off-peak hours only. As with New York, all estimates with respect to price variables are statistically significant and economically intuitive. For example, in the case of all hours, a 1 percent increase in the HOEP leads to a 6.2 percent decrease of exports to Michigan, while a 1 percent increase in the Michigan Hub price leads to a 6.0 percent increase of exports to Michigan.

Table 1-48: MISO Export Model Estimation Results, April 2005–April 2009[63]

Variable	All Hours		On-peak		Off-peak	
	Coef.	P-value	Coef.	P-value	Coef.	P-value
Constant	6.26	0.080	10.03	0.003	1.86	0.753
Log(HOEP)	-6.20	0.011	-4.49	0.002	-6.63	0.006
Log(Michigan Hub Price)	6.03	0.032	3.43	0.013	7.56	0.016
January	-0.40	0.626	-0.35	0.604	-0.13	0.891
February	0.26	0.716	0.79	0.271	0.59	0.518
March	-0.59	0.323	-0.17	0.757	-0.88	0.101
April	-0.92	0.196	-0.25	0.702	-1.39	0.134
May	-0.61	0.306	-0.38	0.452	-0.17	0.854
June	-0.61	0.158	-0.45	0.320	-0.09	0.920
July	-0.57	0.284	0.02	0.953	-0.78	0.276
August	-0.64	0.315	-0.02	0.969	-0.93	0.158
September	-0.69	0.398	-0.73	0.304	-0.19	0.879
October	-0.65	0.187	-0.34	0.512	-0.91	0.082
November	-0.59	0.355	-0.70	0.192	-0.22	0.814
Correlation between actual and fitted values	0.871		0.902		0.839	
Number of observations	49		49		49	

5.4 Wholesale Electricity Prices in Neighbouring Markets

5.4.1 Price Comparisons[64]

Table 1-49 provides average market prices for Ontario and neighbouring jurisdictions over the last two winter periods. In an attempt to make these prices more comparable, they have been converted to Canadian dollars using the daily noon exchange rate published by the Bank of Canada. For several years, energy prices in Ontario have been generally lower than energy prices in most neighbouring jurisdictions. Over the latest six-month period, this continued as prices in Ontario were lower when analysed over all

[63] MISO's market opened in April 2005. As a result, data before this date is not considered.
[64] Some caution should be used when comparing market prices across jurisdictions due to their differing market designs and payment structures. For example in Ontario, the Global Adjustment and various uplift charges represent actual charges not reflected in the average HOEP. Other jurisdictions, such as ISO New England-, New York ISO, and PJM have various capacity market designs that require consumers to pay capacity charges.

hours as well as on-peak and off-peak hours. The average HOEP was $40.98/MWh this winter while the next highest priced jurisdiction was Michigan (MISO-Ontario Hub price) at $42.79/MWh. Average prices for the other areas were considerably higher, between $50 and $65/MWh. Although not higher than New England's prices, PJM - the destination of the majority of exports from Ontario – offered prices for Ontario (known as the PJM-IMO interface price) sourced energy which, on average, were $12 - $13/MWh higher than Ontario HOEP on-peak and off-peak.

Table 1-49: Average HOEP Relative to Neighbouring Market Prices, November–April 2007/2008 & 2008/2009 ($CDN/MWh)

	All Hours			On-peak Hours			Off-peak Hours		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
Ontario - HOEP	49.16	40.98	(16.6)	61.65	50.50	(18.1)	38.72	33.10	(14.5)
MISO – ONT	52.48	42.79	(18.5)	67.73	50.50	(25.4)	39.75	36.34	(8.6)
NYISO – Zone OH	53.58	50.71	(5.4)	64.56	56.28	(12.8)	44.56	46.32	4.0
PJM – IMO	61.93	54.89	(11.4)	74.32	62.33	(16.1)	51.53	48.99	(4.9)
New England – Internal Hub	80.52	64.94	(19.4)	89.59	70.40	(21.4)	72.98	60.35	(17.3)
Average	59.54	50.86	(14.6)	71.57	58.00	(19.0)	49.51	45.02	(9.1)

Figures 1-31 to 1-33 compare monthly average prices for Ontario's neighbouring jurisdictions for the latest winter period, for all hours, on-peak hours, and off-peak hours respectively. The comparison of HOEP in relation to neighbouring prices applies equally well to Richview shadow prices, also included in the figures. Most noticeable in these figures is the strong downward trend in prices following the January peak prices. With winter temperatures moderating through to the spring, a downward trend after February is normal, however, the steepness of the current decline would appear to be more economic than weather related, as we have observed in Ontario. On-peak and off-peak trends were similar.

The data also show that even though the six-month average HOEP was lower than other prices in all these neighbouring jurisdictions, there were three months - November, January and February - when the HOEP was higher than the MISO price. It was the unusually low prices in Ontario in March and April that led to the overall lower six-month average relative to MISO.

It appears from these figures that the drop in prices in Ontario between January and April was more precipitous than in the other jurisdictions. There was a decline over those months of about 65 percent in Ontario, while average prices elsewhere did not drop more than 50 percent, even in off-peak hours. This underlines the effect that factors other than the weather and the economy played in suppressing Ontario prices, especially off-peak, in those months. It is interesting, however, that as seen in Table 1-49 year-to-year average price declines this winter were not as large for Ontario (at 16.6 percent) as MISO's Ontario hub price or New England's Internal Hub (both of which showed declines close to of 19 percent). This suggests that by January year-over-year prices in MISO and New England were already more suppressed than for Ontario, in which case subsequent declines from January to April were not as significant in those areas as in Ontario.

Figure 1-31: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, All Hours, November 2008–April 2009 ($CDN/MWh)

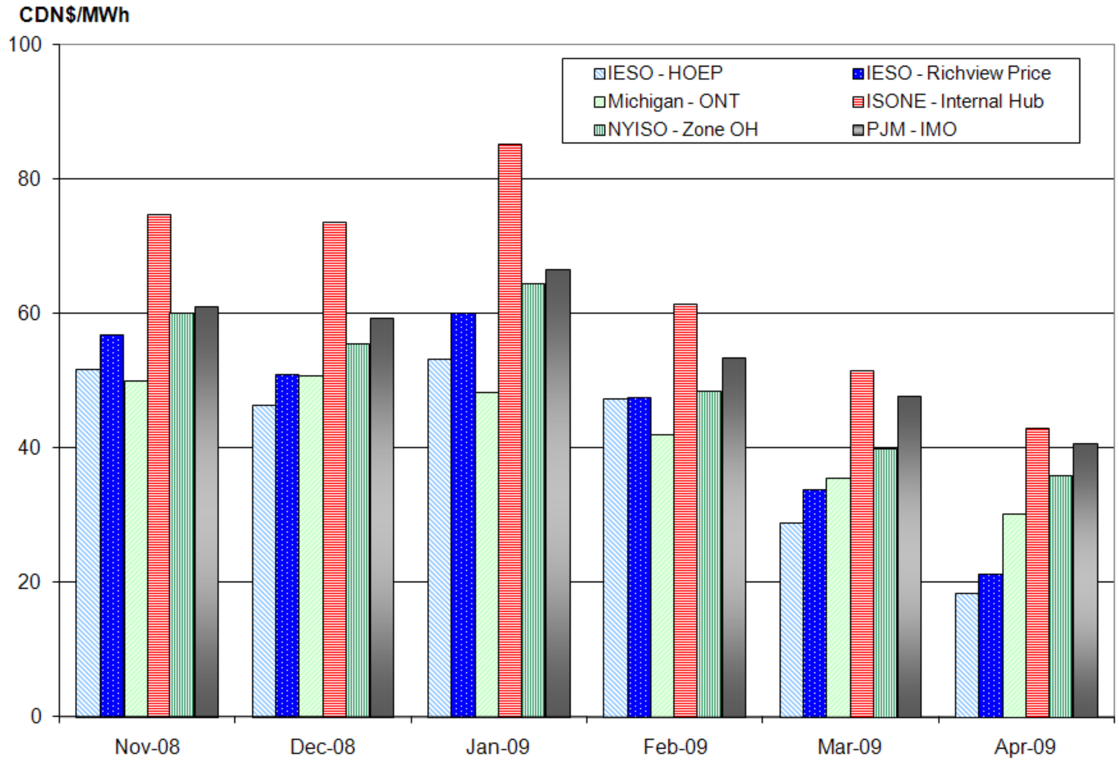


Figure 1-32: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, On-Peak, November 2008–April 2009 ($CDN/MWh)

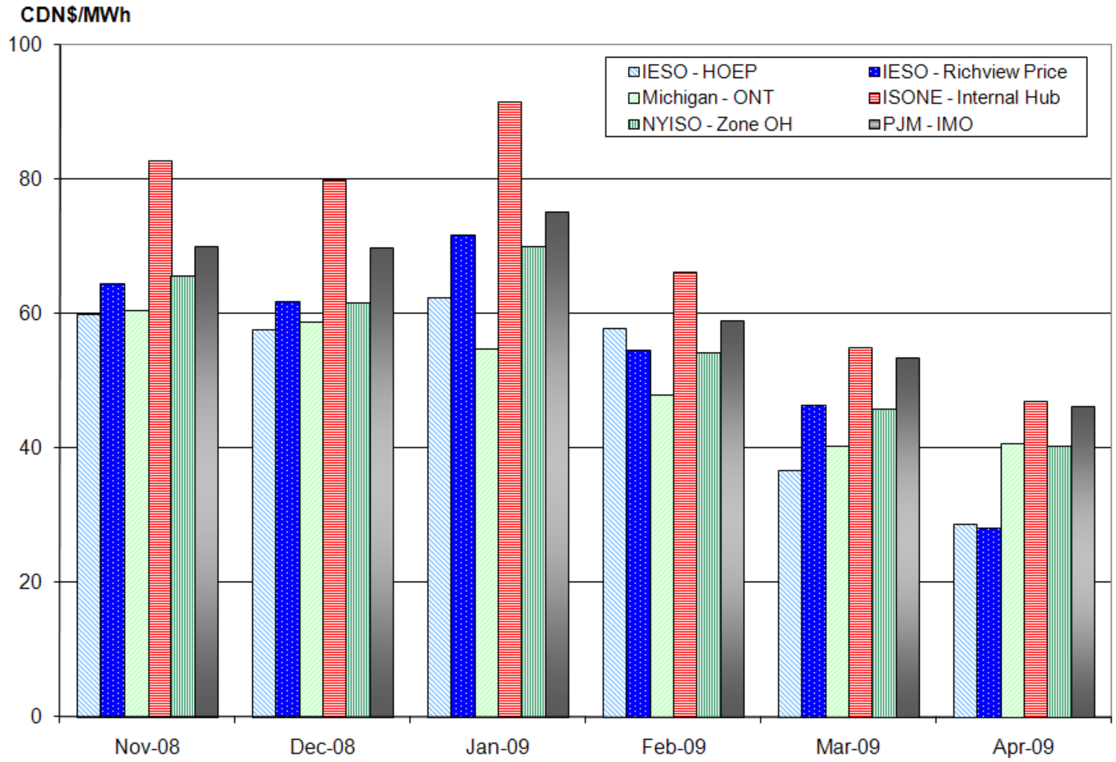
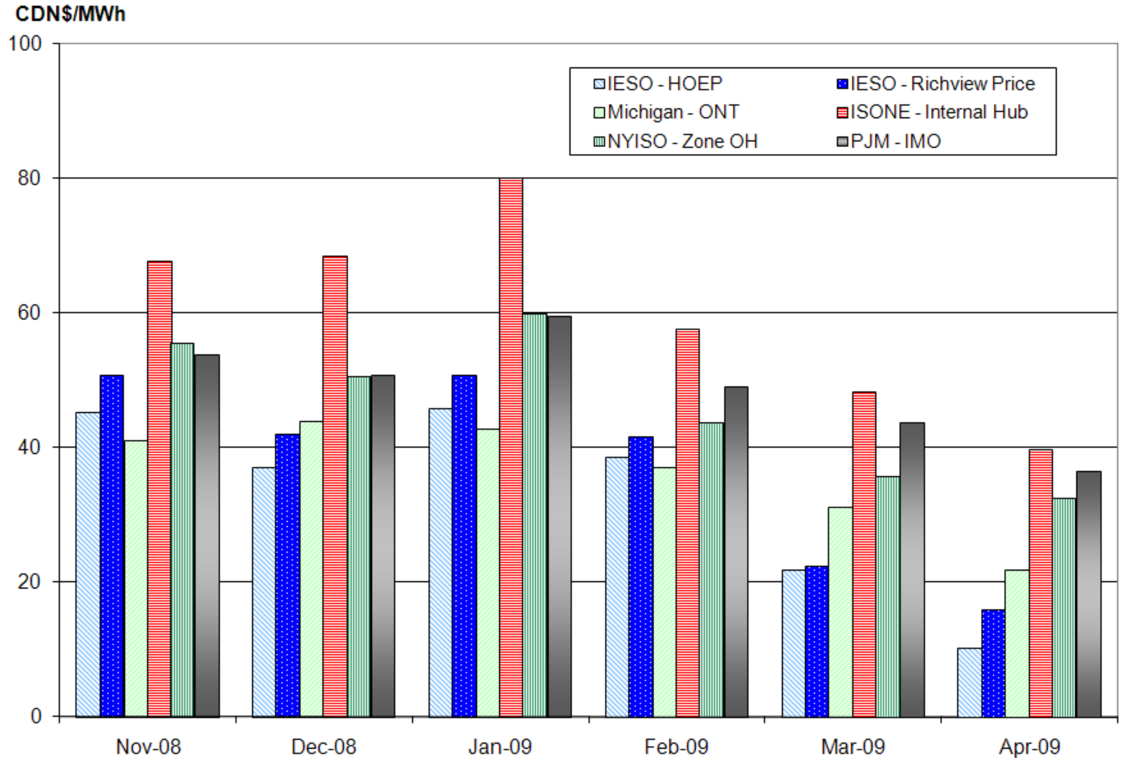


Figure 1-33: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, Off-Peak, November 2008–April 2009 ($CDN/MWh)



Chapter 2: Analysis of Market Outcomes

1. Introduction

The Market Assessment Unit (MAU), under the direction of the Market Surveillance Panel (MSP), monitors the market for anomalous events and behaviour. Anomalous behaviours are actions by market participants (or the IESO) that may lead to market outcomes that fall outside of predicted patterns or norms.

The MAU monitors and reports to the Panel both high and low-priced hours as well other events that appear to be anomalous given the circumstances. The Panel believes that the explanations of these events provides transparency on why certain outcomes occur in the market and leads to learning by all market participants. As a result of this monitoring, the MSP may recommend changes to Market Rules or the tools and procedures that the IESO employs.

Daily, the MAU reviews the previous day, not only to discern anomalous events but also to review:

- changes in offer and bid strategies, both price and volume;
- the impact of forced and extended planned outages;
- import/export arbitrage opportunities as well as the behaviour of traders;
- the appropriateness of uplift payments;
- the application of IESO procedures; and
- the relationship between market outcomes in Ontario and neighbouring markets.

This daily review may lead to identifying anomalous events that may be discussed with the relevant market participants and/or the IESO.

During the current reporting period, with respect to these observed anomalous events, the Panel did not identify any gaming or abuse of market power by market participants. However, the review has led the Panel to reiterate some of its past recommendations to the IESO to take certain actions to improve market efficiency.

The Panel defines high-priced hours as all hours in which the HOEP is greater than $200/MWh and low-priced hours as all hours in which the HOEP is less than $20/MWh,[65] including negative-priced hours.

There were 8 hours during the review period November 2008 through April 2009 where the HOEP was greater than $200/MWh. Section 2.1 of this Chapter examines the factors contributing to the relatively high HOEP in each instance.

In this review period, there were 689 hours in which the HOEP was less than $20/MWh including 219 hours where the HOEP was negative. Section 2.2 of this Chapter reviews the factors typically driving prices to low levels in these hours.

In its last report, the Panel redefined anomalous uplift as payments in excess of $500,000/hour for Congestion Management Settlement Credits (CMSC) or Intertie Offer Guarantees (IOG) and $100,000/hour for OR payments. Daily payments of $1,000,000 for CMSC or IOG in the intertie zones are also considered anomalous.[66]

During the study period, there were no hours with an IOG greater than $500,000, four hours with OR payments greater than $100,000, one hour with a CMSC payment greater than $500,000 and no days in which the total CMSC or IOG exceeded $1,000,000 on any interface. There were occasional small negative CMSC payments but there was one day in which the total CMSC was -$3 million. We discuss these incidents of anomalous uplift in section 3 of this Chapter.

[65] $200/MWh is roughly an upper bound for the cost of a fossil generation unit while $20/MWh is an approximate lower bound for the cost of a fossil unit.
[66] See the Panel's January 2009 Monitoring Report, pp. 178-184.

2. Anomalous HOEP

2.1 Analysis of High Price Hours

The MAU reviews all hours where the HOEP exceeds $200/MWh. The objective of this review is to understand the underlying causes that led to these prices and determine whether any further analysis of the design or operation of the market or any further investigation of the conduct of market participants is warranted.

Table 2-1 depicts the total number of hours with a HOEP greater than $200/MWh by month. There were 8 hours with a high HOEP in the most recent winter period, in contrast to 2 hours in the same period one year ago.

Table 2-1: Number of Hours with a High HOEP
November – April, 2007/2008 and 2008/2009

	Number of Hours with HOEP >$200	
	2007/08	2008/09
November	0	0
December	0	2
January	0	3
February	1	2
March	0	1
April	1	0
Total	2	8

In previous reports, we have noted that a HOEP greater than $200/MWh typically results in hours when at least one of the following occurs:

- real-time demand is much higher than the pre-dispatch forecast of demand;
- one or more imports fail real-time delivery; and/or
- one or more generating units that appear to be available in pre-dispatch become unavailable in real-time as a result of a forced outage or derating.

In addition, a significant increase in net exports from one hour to the next can also lead to a sharp increase in MCP in the first few intervals and thereby increase the HOEP for the hour. Increases in the MCP in the first few intervals of an hour in which net exports increased became more marked after the assumed ramp rate in the unconstrained sequence was reduced from 12 to 3 in September 2007. The change in the assumed ramp rate removed some of the fictitious energy supply that the unconstrained sequence had perceived to be 'available' to meet increased export demand at the beginning of the hour. This led to higher MCPs in the first intervals of hours in which net exports are increasing.[67]

Each of the factors discussed above has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. Spikes of the HOEP above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[68]

2.1.1 December 9, 2008 HE 12

Prices and Demand

Table 2-2 lists the real-time and pre-dispatch information for HE 11 and 12 on December 9, 2008. The MCP in HE 11 gradually increased from $87.50/MWh interval 1 to $137.86/MWh in interval 12, as real-time demand kept increasing. The peak Ontario Demand in the hour came in about 600 MW (or 3.0 percent) above forecast, but this was partially offset by 300 MW of net export failure. The HOEP in HE 11 was $109.34/MWh.

The HOEP in HE 12 rose to $233.52/MWh, in contrast to a pre-dispatch price of $55.87/MWh (or 319 percent higher). The average demand in the hour was 20,349 MW, with a peak of 20,404 MW, which was 825 MW (or 4.2 percent) greater than the forecast in pre-dispatch. There were 100 MW of net export failure, partially offsetting the impact of the demand under-forecast.

[67] For more details, see the Panel's July 2008 Monitoring Report, pp. 134-140.
[68] In the Panel's March 2003 Monitoring Report (pp. 11-16), we noted that a supply cushion lower than 10 percent was more likely to be associated with a price spike. The Panel began reporting a revised supply cushion calculation in its July 2007 Monitoring Report. It remains the case, however, that when the supply cushion is below 10 percent, a price spike becomes increasingly likely.

Table 2-2: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch, December 9, 2008 HE 11 and 12

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
11	1	87.50	59.95	27.55	20,037	19,700	1,228	1,528
11	2	89.48	59.95	29.53	20,048	19,700	1,228	1,528
11	3	90.18	59.95	30.23	20,076	19,700	1,228	1,528
11	4	93.56	59.95	33.61	20,115	19,700	1,228	1,528
11	5	96.12	59.95	36.17	20,180	19,700	1,228	1,528
11	6	98.12	59.95	38.17	20,222	19,700	1,228	1,528
11	7	100.50	59.95	40.55	20,199	19,700	1,228	1,528
11	8	100.50	59.95	40.55	20,233	19,700	1,228	1,528
11	9	125.75	59.95	65.80	20,279	19,700	1,228	1,528
11	10	154.59	59.95	94.64	20,294	19,700	1,228	1,528
11	11	137.86	59.95	77.91	20,282	19,700	1,228	1,528
11	12	137.86	59.95	77.91	20,287	19,700	1,228	1,528
Average		**109.34**	**59.95**	49.39	**20,187**	**19,700**	**1,228**	**1,528**
12	1	229.21	55.87	173.34	20,285	19,579	1,455	1,555
12	2	280.09	55.87	224.22	20,386	19,579	1,455	1,555
12	3	229.21	55.87	173.34	20,383	19,579	1,455	1,555
12	4	229.21	55.87	173.34	20,364	19,579	1,455	1,555
12	5	229.21	55.87	173.34	20,401	19,579	1,455	1,555
12	6	212.32	55.87	156.45	20,306	19,579	1,455	1,555
12	7	280.09	55.87	224.22	20,404	19,579	1,455	1,555
12	8	229.21	55.87	173.34	20,367	19,579	1,455	1,555
12	9	229.21	55.87	173.34	20,360	19,579	1,455	1,555
12	10	229.21	55.87	173.34	20,374	19,579	1,455	1,555
12	11	212.92	55.87	157.05	20,317	19,579	1,455	1,555
12	12	212.31	55.87	156.44	20,246	19,579	1,455	1,555
Average		**233.52**	**55.87**	177.65	**20,349**	**19,579**	**1,455**	**1,555**

Day-ahead Conditions

Total energy scheduled day-ahead during the DACP run was 19,499 MW for HE 12. Eighteen, out of 29 fossil fired units that were expected to be available for the day, were scheduled for a combined supply of 2,600MW. With no imports/exports scheduled in DACP, the day-ahead supply cushion for HE 12 was 41 percent.

Pre-dispatch Conditions

Table 2-3 illustrates the successive changes in forecast demand, the projected price and scheduled imports/exports for HE 12. The forecast demand was only slightly adjusted during the sequential pre-dispatch runs. The final one-hour ahead pre-dispatch price was $55.87/MWh, with 1,555MW of net exports scheduled.

Table 2-3: Prices, Ontario Demand and Exports/Imports December 9, 2008, HE 12

Hours Ahead	Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
DACP (22)	37.08	19,499	0	N/A	0
10	42.58	19,653	473	1,707	1,234
5	45.74	19,846	673	1,700	1,027
4	45.41	19,812	673	1,700	1,027
3	49.10	19,795	673	1,800	1,127
2	55.00	19,546	400	1,976	1,576
1*	55.87	19,579	400	1,955	1,555
Real-Time Average	233.52	20,349	400	1,855	1,455
Notable Events	*A nuclear unit experienced boiler problems 30 minutes ahead of real-time				

The one-hour ahead supply cushion was 10.7 percent.

Real-time Conditions

Thirty minutes ahead of real-time, 100 MW of exports to NYISO were curtailed for reliability concerns in NYISO. All other intertie transactions were successful in real-time. The failure of 100 MW exports had the effect of partially mitigating the price spike resulting from the nuclear unit outage described below.

In HE 11 interval 6, a market participant notified IESO that one of its nuclear units appeared to have boiler problems and needed to shutdown within 30 minutes if the problems could not be fixed quickly. In HE 12 interval 1, the unit was shut down with a 435 MW loss of generation capacity.

Ahead of the full shutdown of the nuclear unit, the IESO manually increased schedules at a few hydro generators by 167 MW for HE 12 interval 2 and by 180 MW for interval 3 for ACE control. These manual actions eliminated the possibility of a negative ACE following the loss of the nuclear unit. As a result, there was no OR activation in the hour and no reduction in the OR requirement.

Self-scheduling and intermittent generation collectively produced 186 MW (12.5 percent) less than they projected. About 130 MW of this amount was due to two wind generation stations.

Real-time Ontario Demand also came in heavier than predicted, with an average of 20,349 MW and a peak of 20,404 MW which was 825 MW (or 4.2 percent) greater than the forecast in final pre-dispatch. The real-time supply cushion was 0.6 percent at the beginning of the hour, indicating very tight demand/supply conditions.

Assessment

The spike in HOEP in HE 12 was largely a consequence of real-time demand exceeding the pre-dispatch forecast (825 MW) and the loss of a nuclear unit (435 MW). The under-production of self-scheduling and intermittent generators also contributed to the price spike, while the export failure had a mitigating effect.

Because the outage at the nuclear unit was foreseen, the IESO took precautionary actions ahead of its shutdown. This obviated the need for other control actions such as OR activation. As a result, the HOEP was properly reflective of the tight supply and demand conditions.[69]

[69] Otherwise the loss of the nuclear units might have led to an activation of operating reserve and consequently a reduction in the operating reserve requirement. The result of such a control action would have been a counter-intuitive HOEP, i.e. a reduction in the operating reserve requirement would have suppressed the HOEP. The Panel has previously recommended that the IESO should maintain the operating reserve requirement when operating reserve is activated in response to ACE. For more details, see the Panel's July 2007 Monitoring Report, pp. 192-202.

The MCP was set by a unit at a hydroelectric station which is typically used as a peaking generator in the afternoon. As a result, it is offered at a price that is high enough to be out of the money in the morning so that it is not scheduled for energy (but is available for OR) until the afternoon. Given the conditions on this particular day, it was partially dispatched for energy in HE 11 and 12 and set the MCP.

2.1.2 December 19, 2008 HE 12

Prices and Demand

Table 2-4 lists the real-time and pre-dispatch information for HE 11 and 12. The HOEP in HE 11 was only slightly above $40/MWh even though the peak Ontario Demand was 920 MW (or 4.5 percent) greater than forecast one-hour ahead. In HE 12, however, the HOEP rose to $211.01/MWh, or $158.00/MWh (298 percent) greater than the final PD price for the hour. The average Ontario Demand in the hour was 20,953MW, with a peak of 21,030 MW, which was 733 MW or (3.6 percent) greater than the forecast in final pre-dispatch. There were 55 MW of net import failure.

Table 2-4: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch, December 19, 2008 HE 11 and 12

Delivery Hour	Interval	RT MCP	PD MCP	Diff (RT-PD)	RT Ontario Demand	PD Ontario Demand	RT Net Exports	PD Net exports
11	**1**	39.22	37.48	1.74	20,587	19,956	1,229	1,425
11	**2**	39.36	37.48	1.88	20,624	19,956	1,229	1,425
11	**3**	39.47	37.48	1.99	20,648	19,956	1,229	1,425
11	**4**	40.08	37.48	2.60	20,684	19,956	1,229	1,425
11	**5**	40.10	37.48	2.62	20,688	19,956	1,229	1,425
11	**6**	40.42	37.48	2.94	20,764	19,956	1,229	1,425
11	**7**	40.70	37.48	3.22	20,830	19,956	1,229	1,425
11	**8**	41.01	37.48	3.53	20,876	19,956	1,229	1,425
11	**9**	40.72	37.48	3.24	20,842	19,956	1,229	1,425
11	**10**	40.75	37.48	3.27	20,854	19,956	1,229	1,425
11	**11**	41.01	37.48	3.53	20,885	19,956	1,229	1,425
11	**12**	40.70	37.48	3.22	20,817	19,956	1,229	1,425
Average		**40.30**	**37.48**	**2.81**	**20,758**	**19,956**	**1,229**	**1,425**
12	**1**	207.97	53.01	154.96	20,931	20,297	1,712	1,657
12	**2**	191.53	53.01	138.52	20,899	20,297	1,712	1,657
12	**3**	211.79	53.01	158.78	20,885	20,297	1,712	1,657
12	**4**	196.14	53.01	143.13	20,903	20,297	1,712	1,657
12	**5**	215.75	53.01	162.74	20,998	20,297	1,712	1,657
12	**6**	215.41	53.01	162.40	20,930	20,297	1,712	1,657
12	**7**	215.41	53.01	162.40	20,959	20,297	1,712	1,657
12	**8**	215.41	53.01	162.40	20,945	20,297	1,712	1,657
12	**9**	215.75	53.01	162.74	21,018	20,297	1,712	1,657
12	**10**	215.75	53.01	162.74	21,030	20,297	1,712	1,657
12	**11**	215.75	53.01	162.74	21,009	20,297	1,712	1,657
12	**12**	215.46	53.01	162.45	20,927	20,297	1,712	1,657
Average		**211.01**	**53.01**	**158.00**	**20,953**	**20,297**	**1,712**	**1,657**

Day-Ahead Conditions

Total energy scheduled day-ahead during the DACP run was 19,444 MW for HE 12. Twenty out of 30 fossil-fired units that were expected to be available for the day were scheduled for a combined supply of 2,600 MW. With no imports/exports scheduled in DACP, the day-ahead supply cushion for HE 12 was 46 percent.

Pre-dispatch Conditions

The total OR requirement was 1,860 MW on the day until mid-HE 14. This was higher than the normal OR requirement of 1,453 MW because of the planned outage at the Nanticoke RSS4 (one of the reserve station service transformers at the Nanticoke station). The OR requirement reflected the largest contingency, namely the potential loss of three Nanticoke units (if a second RSS was lost), which was about 400 MW higher than normal.

Table 2-5 illustrates the successive changes in forecast demand, the projected price and scheduled imports/exports for HE 12. Forecast demand increased gradually from 19,444 MW day-ahead to 20,297 MW one-hour ahead. As net exports increased from 0 MW day-ahead to 1,657 MW one-hour ahead, the PD price also increased from $13.72/MWh to $53.01/MWh.[70]

No large forced outages occurred during the period. However, at the request of the owner, a fossil-fired unit with a 500 MW capacity was exempted from its DACP commitment 5 hours ahead as there appeared to be no reliability concerns.

Table 2-5: Prices, Ontario Demand and Exports/Imports
December 19, 2008, HE 12

Hours Ahead	Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
DACP (21)	13.72	19,444	0	0	0
10	35.99	19,735	191	961	770
5*	34.99	19,784	169	1,061	892
4	34.99	19,756	169	1,090	921
3	36.49	19,764	194	1,195	1,001
2	49.01	19,847	119	2,127	2,008
1	53.01	20,297	219	1,876	1,657
Real-Time Average	211.01	20,953	119	1,831	1,712
Notable Events	*A 500MW fossil-fired unit was removed from its DACP commitment 5 hours ahead				

[70] Because exports are not included when the DACP price is calculated, the DACP price is not a reliable predictor of future real-time price.

The one-hour ahead supply cushion was 7.4 percent.

Real-time Conditions

Before real-time, 100 MW of imports failed on the MISO interface due to ramp limitations in MISO and 45 MW of exports were failed because they were not scheduled in NYISO. The combined effect was a net import failure of 55 MW.

A fossil-fired unit was de-rated by 90 MW for the loss of one fuel delivery mill from HE 11 interval 4 to HE 14 interval 3.

A hydroelectric unit was forced out of service from HE 12 interval 2 onwards for water diversion purposes, representing a loss of 70 MW baseload generation.

From HE 12 interval 3 to the end of HE 16, a fossil fired unit was de-rated by 80 MW. The de-rating was a consequence of a fuel delivery problem.

Self-scheduling and intermittent generators produced about 90 MW (5.6 percent) more than they projected, partially mitigating the price impact of demand under-forecasting, forced outages and de-ratings of generation units.

Average real-time Ontario Demand in the hour was 20,953 MW, with a peak of 21,030 MW which was 733 MW (or 3.6 percent) greater than the forecast in pre-dispatch. The real-time supply cushion was 0.9 percent at the beginning of the hour, indicating a very tight demand/supply situation.

Assessment

The spike in HOEP in the hour was largely a consequence of demand under-forecast (733 MW) and the outages and de-ratings at a few generators (up to 240 MW). Failed net imports (55 MW) also contributed to the high price.

The MCP was set by the same hydroelectric unit that set the high MCP on December 9, 2008 in HE 12. The offer strategy of this unit is normally structured so as to be out of the money in the morning thereby preserving its limited water for the afternoon peak hours.

2.1.3 January 16, 2009 HE 8 to 10

Prices and Demand

Table 2-6 lists the real-time and pre-dispatch information for HE 8 to 10. The HOEP was above $200/MWh in all three hours. It was greater than $400/MWh in HE 8 and 9 and slightly above $200/MWh in HE 10.

The MCP in HE 8 increased dramatically from $76.79/MWh in interval 1 to $600.00/MWh in interval 6, then stayed around $300/MWh until interval 12 when it rose to $1,998.00/MWh. In HE 9, the MCP stayed at $1,998.00/MWh in interval 1 and 2, and then dropped below $200/MWh in intervals 3 through 12. The MCP in HE 10 was around $220/MWh in six intervals in the middle of the hour and between $190/MWh and $213/MWh in the other intervals.

Table 2-6: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch January 16, 2009 HE 8 to 10

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
8	**1**	76.79	73.00	3.79	20,615	21,272	2,038	2,038
8	**2**	99.84	73.00	26.84	20,901	21,272	2,038	2,038
8	**3**	105.12	73.00	32.12	21,070	21,272	2,038	2,038
8	**4**	245.55	73.00	172.55	21,367	21,272	2,038	2,038
8	**5**	350.12	73.00	277.12	21,450	21,272	2,038	2,038
8	**6**	600.00	73.00	527.00	21,523	21,272	2,038	2,038
8	**7**	245.54	73.00	172.54	21,873	21,272	1,455	2,038
8	**8**	329.44	73.00	256.44	21,719	21,272	1,255	2,038
8	**9**	250.12	73.00	177.12	21,578	21,272	1,255	2,038
8	**10**	270.54	73.00	197.54	21,600	21,272	1,255	2,038
8	**11**	270.54	73.00	197.54	21,642	21,272	1,255	2,038
8	**12**	1998.00	73.00	1925.00	22,093	21,272	1,255	2,038
Average		**403.47**	**73.00**	**330.47**	**21,453**	**21,272**	**1,663**	**2,038**
9	**1**	1998.00	95.00	1903.00	21,642	21,441	1,460	2,006
9	**2**	1998.00	95.00	1903.00	21,675	21,441	1,460	2,006
9	**3**	190.12	95.00	95.12	21,429	21,441	1,460	2,006
9	**4**	150.13	95.00	55.13	21,746	21,441	1,008	2,006
9	**5**	180.00	95.00	85.00	21,773	21,441	1,008	2,006
9	**6**	175.12	95.00	80.12	21,810	21,441	1,008	2,006
9	**7**	190.12	95.00	95.12	21,825	21,441	1,008	2,006
9	**8**	190.12	95.00	95.12	21,810	21,441	1,008	2,006
9	**9**	150.13	95.00	55.13	21,806	21,441	1,008	2,006
9	**10**	150.12	95.00	55.12	21,784	21,441	1,008	2,006
9	**11**	150.12	95.00	55.12	21,808	21,441	1,008	2,006
9	**12**	175.12	95.00	80.12	21,784	21,441	1,008	2,006
Average		**474.76**	**95.00**	**379.76**	**21,741**	**21,441**	**1,121**	**2,006**
10	**1**	190.12	135.00	55.12	21,767	21,616	1,075	975
10	**2**	190.12	135.00	55.12	21,785	21,616	1,075	975
10	**3**	209.66	135.00	74.66	21,805	21,616	1,075	975
10	**4**	212.72	135.00	77.72	21,816	21,616	1,075	975
10	**5**	220.73	135.00	85.73	21,840	21,616	1,075	975
10	**6**	220.73	135.00	85.73	21,840	21,616	1,075	975
10	**7**	220.73	135.00	85.73	21,840	21,616	1,075	975
10	**8**	220.73	135.00	85.73	21,840	21,616	1,075	975
10	**9**	220.73	135.00	85.73	21,840	21,616	1,075	975
10	**10**	220.74	135.00	85.74	21,932	21,616	1,075	975
10	**11**	190.12	135.00	55.12	21,764	21,616	1,075	975
10	**12**	190.12	135.00	55.12	21,787	21,616	1,075	975
Average		**208.94**	**135.00**	**73.94**	**21,821**	**21,616**	**1,075**	**975**

Real-time demand was generally greater (and much greater in some intervals) than the PD forecast. For example, the average demand in each hour was about 200 - 300 MW greater than the PD demand and peak demand was even greater. We document the details in the sections which follow.

Except in HE 10, a significant amount of exports were failed in each hour as a consequence of the IESO's control actions to deal with the tight supply and demand conditions.

Day-Ahead Conditions

Total energy scheduled day-ahead during the DACP run was 21,269 MW for HE 8, 21,659 MW for HE 9 and 21,844 MW for HE 10. Fossil-fired generators were sequentially scheduled online, with 18 units online for HE 8, 20 for HE 9, and 23 for HE 10, out of 31 fossil-fired units that were expected to be available for the day. A total of 3,700 MW was scheduled each hour from these fossil-fired generators. With no imports/exports scheduled in DACP, the day-ahead supply cushion was 28 percent for HE 8 and 27 percent for both HE 9 and 10.

Although OPG's CO_2 strategy for meeting its CO_2 emissions target for coal-fired generation units took effect at the beginning of 2009, there were no "CO_2 outages" or 'NOBA' units for the day.[71]

Pre-dispatch Conditions

The total OR requirement was 1,520 MW on the day, reflecting the largest contingency which was the loss of all units at a large fossil-fired generating station. These units share a common fuel supply, the loss of which would lead to all units being forced out of service.

[71] For detailed discussion on OPG's strategy, refer to the Panel's January 2009 Monitoring Report, pp. 235-246.

Table 2-7 illustrates the successive changes in forecast demand, the projected price and scheduled imports/exports for HE 8 to 10. The demand forecasts were very stable from day-ahead to one-hour ahead for all three hours, but the PD price rose markedly as net exports increased.

A fossil unit with a capacity of 185 MW was forced out of service in HE 6. Three other fossil-fired generators and a hydroelectric generator were forced out of service one hour later. We will discuss these outages in more detail in the following section.

Table 2-7: Prices, Ontario Demand and Exports/imports January 16, 2009, HE 8 to 10

Hours Ahead	HE 8			HE 9			HE 10		
	Price ($/MWh)	Ontario Demand (MW)	Net Exports (MW)	Price ($/MWh)	Ontario Demand (MW)	Net Exports (MW)	Price ($/MWh)	Ontario Demand (MW)	Net Exports (MW)
DACP (17)	46.32	21,269	0	45.81	21,659	0	42.12	21,844	0
10	46.79	21,170	1,147	48.13	21,427	1,277	50.07	21,667	1,348
5	52.85	21,353	1,522	52.69	21,491	1,707	63.49	21,678	1,898
4	54.34	21,316	1,602	63.49	21,493	1,907	63.49	21,692	1,848
3	54.34	21,318	1,702	63.49	21,507	1,857	67.00	21,633	1,848
2*	68.18	21,332	2,243	95.00	21,448	2,072	115.00	21,627	2,019
1**	73.00	21,272	2,038	95.00	21,441	2,006	135.00	21,616	975
Real-Time Average	403.47	21,453	1,663	474.76	21,741	1,121	208.94	21,821	1,075
Notable Events	*In HE 6 a 185 MW fossil-fired unit was forced out of service. **In HE 7 three fossil-fired units and one hydro unit experienced technical problems.								

The one-hour ahead supply cushion was 5.4 percent for HE 8, 5.6 percent for HE 9 and 7.8 percent for HE 10.

Real-time Conditions for HE 8

Figure 2-1 below illustrates the sequence of the real-time outages/deratings.[72] A few minutes after the PD run for HE 8, a gas-fired unit (Unit A) had technical problems and subsequently was shutdown in HE 7 interval 4. Fifteen minutes later another gas-fired

[72] A unit in the graph is a registered facility. A station can have multiple registered facilities.

unit at the same station (Unit B) also experienced technical problems and was shutdown in interval 7. The total loss at the two units was 400 MW.

The loss of these two units also led to a further reduction of about 410 MW in generating capacity at an associated steam unit (Unit F) that uses the residual heat from the two gas-fired units. Although the market participant promptly called the IESO to advise of the outages and subsequent derating at the steam unit,[73] the IESO did not apply the derating to the steam unit until an hour later, leading to the steam unit being scheduled for 410 MW more than it actually could produce until HE 8 interval 8. The outages and de-ratings for the above three units ended in the middle of HE 11.

About 20 minutes before HE 8, a fossil-fired baseload generator with a capacity of about 500 MW (Unit C) was de-rated to 320 MW because of a fuel supply problem. The problem lasted for several days and led to various de-ratings on those days.

Just a few minutes before the start of HE 8, another generating unit (Unit D) was forced out of service due to lack of steam, representing a loss of 110 MW of supply. This outage lasted until HE 24.

Also, just before HE 8, a hydroelectric unit (Unit E) was lost due to station service bus problems. About 150 MW of generation capacity was removed from service. The unit was back in service four days later.

[73] Market participants can either call in or send outage/derating slips to the IESO when a forced outage occurs.

Figure 2-1: Outage/Derating Sequence
January 16, 2009, HE 8 to 10

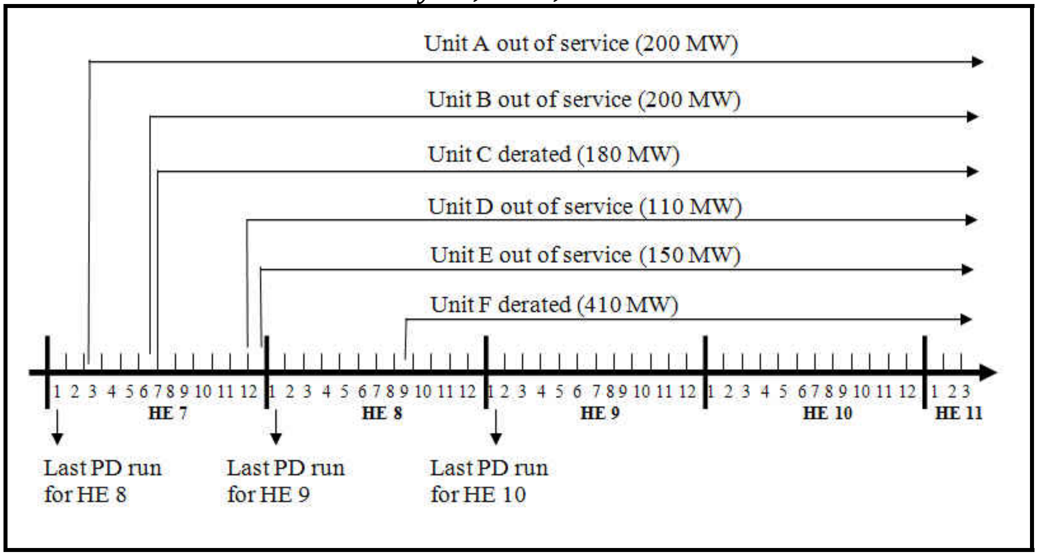
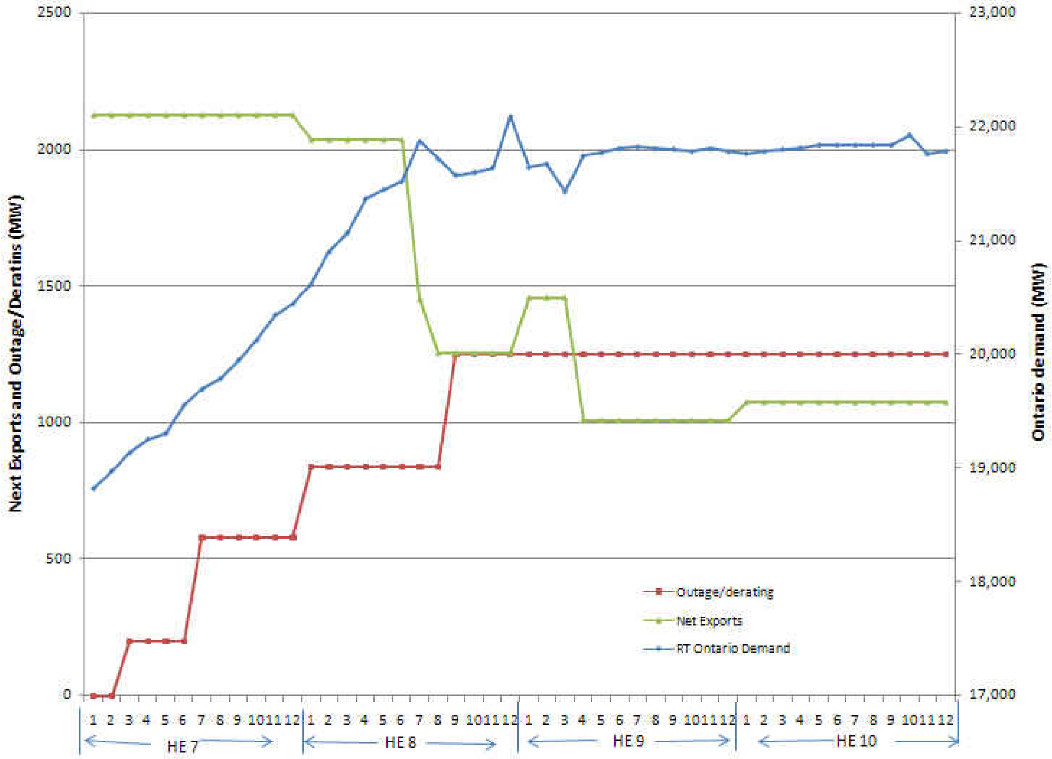


Figure 2-2 below illustrates real-time Ontario Demand, cumulative outage/deratings and net exports in hours HE 7 to HE 10. Ontario Demand was steadily increasing in HE 7 and the first half of HE 8, and then remained roughly constant in HE 9 and 10. The outage and derating quantities increased from 200 MW at the beginning of HE 7 to about 1,200 MW by mid HE 8. As both demand and outages/deratings increased, net exports dropped significantly, part of which was a result of market response and part of which was a result of exports being cut by the IESO for internal adequacy. More details of the IESO control actions are discussed later.

Figure 2-2: Real-Time Ontario Demand, Cumulative Outage/Deratings and Net Exports January 16, 2009 HE 7 to 10



The supply cushion at the beginning of HE 8 was 5.4 percent. Real-time demand ramped up quickly and exceeded the forecast peak demand by interval 4 of the hour. Demand kept increasing and reached 22,093 MW in interval 12, which was 820 MW or 3.8 percent higher than forecast one-hour ahead.

In interval 3 of HE 8, the IESO activated 400 MW of OR for ACE control. The IESO also reduced the system OR requirement by 400 MW at the same time. [74] All OR was de-activated in interval 8 at which time the OR requirement was restored to its original level.

[74] The Panel has recommended that the IESO not reduce the operating reserve requirement when operating reserve is activated for ACE control. For more details, see the Panel's July 2008 Monitoring Report, pp. 192-203. This practice has also been found in breach of the Market Rules.
"In April 2009, the Independent Electricity System Operator was found in breach for systematically failing to maintain total operating reserve as a result of its practice of reducing the minimum operating reserve requirement at the start of operating reserve activations for matters not defined as 'contingency events' within the Market Rules. No voluntary payment amount was assessed for the breach; however, the IESO is ordered to come into compliance with the Market Rules by October 31, 2009."
http://www.ieso.ca/imoweb/marketComp/sanctions.asp

Shortly after activating the OR, in HE 8 interval 7, the IESO cut 583 MW of exports for internal adequacy as a result of a shortfall in the 30 minute OR.[75], The IESO subsequently cut an additional 200 MW of exports starting in interval 8.

Self-scheduling and intermittent generators produced about 129 MW (9.1 percent) less than they had projected, putting additional upward pressure on the HOEP. Most of the deviation was from wind generation.[76]

Real-time Conditions HE 9

Before real-time, an 80 MW import and a 23 MW export were failed on the New York interface because the two transactions were not scheduled in NYISO. In addition, Quebec cut 13 MW of exports to Ontario for reliability concerns in Quebec. The net result was 44 MW of reduced supply.

The supply cushion at the beginning of the hour was -2.0 percent. In response to this tight supply situation, the IESO curtailed 590 MW of exports before real-time and then a further 352 MW from interval 4 to interval 12 of HE 9 for internal resource adequacy.

Real-time peak demand came in interval 7 at 21,825 MW. This was 384 MW (1.8 percent) greater than forecast.

Self-scheduling and intermittent generators produced about 157 MW (10.5 percent) less than they projected, putting additional upward pressure on the HOEP. Most of the deviation was from wind generation.

[75] The IESO real-time dispatch tool Multi-Interval Optimizer (MIO) still showed an operating reserve shortfall even though 800 MW of CAOR was scheduled.
[76] Forecast error by wind-power generation stations contributed to the high prices in HE8 – HE10. In earlier reports the Panel has recommended that the IESO review the forecasting process with wind generators (See the Panel's December 2007 report, pp. 24-28) and that it consider centralized wind forecasting (See the Panel's January report, pp. 253-256). We understand that the IESO is considering this possibility under its Stakeholder Engagement Plan (SE-57).

Real-time Conditions for HE 10

Before real-time, a 100 MW import failed on the MISO interface because of a ramp limitation in MISO.

The fossil-fired generator which had fuel supply problems in HE 7 was further de-rated to 260 MW for HE 10 (from 320 MW in HE 8 and 9). However, the IESO did not undertake any additional control actions.

The supply cushion at the beginning of the hour was -1.7 percent. Average real-time Ontario Demand came in at 21,821 MW, with a peak demand of 21,932 MW, or 316 MW (1.4 percent) greater than forecast.

Self-scheduling and intermittent generators produced about 207 MW (12.9 percent) less than they projected, putting additional upward pressure on the HOEP. Most of the deviation was from wind generation.

Assessment

The tight supply and demand conditions and consequential high HOEP in these hours were primarily a result of higher than expected demand and forced generator outages. Forecast error by self-scheduling and intermittent generators also contributed to the high prices.

In contrast, the IESO's control actions and coding practices relaxed the tight supply and demand conditions causing the HOEP to be lower than what it would have been otherwise. The simulations shown in Table 2-8 below demonstrate that the curtailment of exports for adequacy, associated with a code of "*ADQh*", led to a reduction in exports in the unconstrained sequence and thus a significant reduction in HOEP and that the reduction in the OR requirement in parallel with OR activation further suppressed the HOEP.

- Had the exports curtailed for adequacy not been treated as reducing demand in the unconstrained sequence, the estimated HOEP would have been $1,123.07/MWh (or $719.45/MWh higher, a 178 percent difference) in HE 8 and $1,995.95/MWh (or $1,520.95/MWh higher, a 320 percent difference) in HE 9.

- Had the OR requirement not been reduced in parts of HE 8 and the *ADQh* code not been used when exports were curtailed for adequacy, the estimated HOEP would have been $1,272.36/MWh, or $868.74/MWh (215 percent) higher than the actual HOEP.

Table 2-8: Comparison of 'Actual' and Simulated Price Without the Use of 'ADQh' and Reduction of the Operating Reserve Requirement, January 16, 2009, HE 8 to 10[77]

Delivery Hour	Interval	'Actual' MCP ($/MWh)	Exports Curtailed For *ADQh* (MW)	Simulated MCP Without Using *ADQh* ($/MWh)	Reduction in OR Requirement (MW)	Simulated MCP Without Using *ADQh* and Reducing OR Requirement ($/MWh)
8	**1**	76.79	0	76.79	0	76.79
8	**2**	99.84	0	99.84	0	99.84
8	**3**	105.12	0	105.12	400	113.16
8	**4**	245.54	0	245.54	150	270.54
8	**5**	350.12	0	350.12	150	709.44
8	**6**	599.90	0	599.9	150	1,999.00
8	**7**	245.54	583	1,999.55	150	1,999.57
8	**8**	329.43	783	2,000.00	0	2,000.00
8	**9**	250.12	783	2,000.00	0	2,000.00
8	**10**	270.54	783	2,000.00	0	2,000.00
8	**11**	270.54	783	2,000.00	0	2,000.00
8	**12**	1999.99	783	2,000.00	0	2,000.00
Average		**403.62**	**375**	**1,123.07**	**83**	**1,272.36**
9	**1**	1999.89	590	2,000.00	0	2,000.00
9	**2**	1999.03	590	2,000.00	0	2,000.00
9	**3**	190.12	590	1,999.43	0	1,999.43
9	**4**	150.12	942	2,000.00	0	2,000.00
9	**5**	180.00	942	2,000.00	0	2,000.00
9	**6**	175.12	942	2,000.00	0	2,000.00
9	**7**	190.12	942	2,000.00	0	2,000.00
9	**8**	190.12	942	2,000.00	0	2,000.00
9	**9**	150.12	942	2,000.00	0	2,000.00
9	**10**	150.12	942	2,000.00	0	2,000.00
9	**11**	150.12	942	2,000.00	0	2,000.00
9	**12**	175.12	942	2,000.00	0	2,000.00
Average		**475.00**	**854**	**1,999.95**	**0**	**1,999.95**
10	**1**	190.12	0	190.12	0	190.12
10	**2**	190.12	0	190.12	0	190.12
10	**3**	209.66	0	209.66	0	209.66
10	**4**	212.72	0	212.72	0	212.72
10	**5**	220.73	0	220.73	0	220.73
10	**6**	220.73	0	220.73	0	220.73
10	**7**	220.73	0	220.73	0	220.73
10	**8**	220.73	0	220.73	0	220.73
10	**9**	220.73	0	220.73	0	220.73
10	**10**	220.73	0	220.73	0	220.73
10	**11**	190.12	0	190.12	0	190.12
10	**12**	190.12	0	190.12	0	190.12
Average		**208.94**	**0**	**208.94**	**0**	**208.94**

[77] 'Actual' is the simulated base case without changing any input or model parameters. Because the MAU's simulation tool may have slightly different input data from the actual DSO, the simulation result may be slightly different in some cases. Comparing the simulated base case and the simulation case will mitigate the impact of the different input data.

The Panel has previously recommended to the IESO that exports (or imports) curtailed for internal adequacy ("*ADQh*") should not be removed from the unconstrained schedule in order to ensure that it reflects actual market conditions.[78] Although the IESO believes that "the resultant price impacts of curtailed exports do not represent a distortion", the Panel does not agree with this view. [79] In the Panel's opinion, it is precisely the possibility of this type of high price event that induces market participants to take measures that increase their own price responsiveness rather than having to be subsidized to do so by various efficiency-reducing demand-responsiveness programs.

It is worth noting that, although the demand and supply response in real-time may be limited (except for what is already reflected in generator and dispatchable load offers and bids), there are examples in which consumers have responded to short-term price spikes. The Panel's December 2006 Monitoring Report described how some non-dispatchable loads successfully reduced their consumption during high priced hours.[80]

The MCPs in HE 8-10 were set by various peaking hydroelectric units whose offers in the hour were consistent with their historical offer patterns. Given the very high price of $1998/MWh in three intervals, the MAU began an assessment of whether this may have constituted withholding, but observed that the high offer price by the marginal participant would have induced only a relatively small change in HOEP.

2.1.4 February 18, 2009 HE 11 and 12

Prices and Demand

Table 2-9 provides the relevant real-time and final pre-dispatch data for HE 11 to 13.

- In HE 11, HOEP was slightly above $1,000/MWh with MCP increasing sharply from $80.18/MWh in interval 5 to $183/MWh in interval 6 and then

[78] See the Panel's December 2007 Monitoring Report, pp. 96-103, and the Panel's July 2008 Monitoring Report, pp. 171-180.
[79] See 'IESO Responses to the MSP Recommendations", dated August 19, 2008, http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20080820-Item4_MSP.pdf. The issue is currently reviewed under the IESO's Stakeholdering Engagement Plan (SE-67).
[80] The Panel's December 2006 Monitoring Report, pp. 85-90.

to $1,999.99/MWh in intervals 7 to 12. The HOEP of $1,039.27/MWh was about $1,000/MWh greater than the final PD price.

- In HE 12, HOEP rose to $1,891.14/MWh (substantially higher than the $44.27/MWh final PD price), and the MCP was $1,999.99/MWh in the first 11 intervals. The HOEP in HE 12 was the highest price since the market opening.
- In HE 13, HOEP dropped to $160.96/MWh, but was still about $100/MWh (163 percent) greater than the final PD price.

Table 2-9: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch February 18, 2009 HE 11 to 13

Delivery Hour	Interval	RT MCP	PD MCP	Diff (RT-PD)	RT Ontario Demand	PD Ontario Demand	RT Net Exports	PD Net Exports
11	**1**	44.24	37.80	6.44	18,685	19,017	1,313	1,313
11	**2**	44.30	37.80	6.50	18,752	19,017	1,313	1,313
11	**3**	44.51	37.80	6.71	18,784	19,017	1,313	1,313
11	**4**	74.12	37.80	36.32	18,828	19,017	1,313	1,313
11	**5**	80.18	37.80	42.38	19,092	19,017	1,313	1,313
11	**6**	183.91	37.80	146.11	19,377	19,017	1,313	1,313
11	**7**	1,999.99	37.80	1,962.19	19,310	19,017	1,313	1,313
11	**8**	1,999.99	37.80	1,962.19	19,335	19,017	1,313	1,313
11	**9**	1,999.99	37.80	1,962.19	19,357	19,017	1,313	1,313
11	**10**	1,999.99	37.80	1,962.19	19,358	19,017	1,313	1,313
11	**11**	1,999.99	37.80	1,962.19	19,356	19,017	1,313	1,313
11	**12**	1,999.99	37.80	1,962.19	19,359	19,017	1,313	1,313
Average		**1,039.27**	**37.80**	**1,001.47**	**19,133**	**19,017**	**1,313**	**1,313**
12	**1**	1,999.99	44.27	1,955.72	19,300	19,119	1,460	1,510
12	**2**	1,999.99	44.27	1,955.72	19,312	19,119	1,460	1,510
12	**3**	1,999.99	44.27	1,955.72	19,229	19,119	1,460	1,510
12	**4**	1,999.99	44.27	1,955.72	19,271	19,119	1,460	1,510
12	**5**	1,999.99	44.27	1,955.72	19,266	19,119	1,460	1,510
12	**6**	1,999.99	44.27	1,955.72	19,287	19,119	1,460	1,510
12	**7**	1,999.99	44.27	1,955.72	19,264	19,119	1,460	1,510
12	**8**	1,999.99	44.27	1,955.72	19,236	19,119	1,460	1,510
12	**9**	1,999.99	44.27	1,955.72	19,283	19,119	1,460	1,510
12	**10**	1,999.99	44.27	1,955.72	19,250	19,119	1,460	1,510
12	**11**	1,999.99	44.27	1,955.72	19,259	19,119	1,460	1,510
12	**12**	693.78	44.27	649.51	19,186	19,119	1,460	1,510
Average		**1,891.14**	**44.27**	**1,846.87**	**19,262**	**19,119**	**1,460**	**1,510**
13	**1**	98.50	61.10	37.40	19,265	19,143	692	760
13	**2**	109.74	61.10	48.64	19,247	19,143	692	760
13	**3**	109.74	61.10	48.64	19,248	19,143	692	760
13	**4**	110.08	61.10	48.98	19,157	19,143	692	760
13	**5**	124.74	61.10	63.64	19,176	19,143	692	760
13	**6**	133.37	61.10	72.27	19,187	19,143	692	760
13	**7**	150.00	61.10	88.90	19,214	19,143	692	760
13	**8**	221.68	61.10	160.58	19,258	19,143	692	760
13	**9**	221.68	61.10	160.58	19,221	19,143	692	760
13	**10**	220.41	61.10	159.31	19,223	19,143	692	760
13	**11**	220.78	61.10	159.68	19,229	19,143	692	760
13	**12**	210.75	61.10	149.65	19,226	19,143	692	760
Average		**160.96**	**61.10**	**99.86**	**19,221**	**19,143**	**692**	**760**

Day-Ahead Conditions

The DACP run scheduled 18,998 MW for HE 11 and 18,875 MW for HE 12. Out of 25 fossil-fired units that were expected to be available for the day, sixteen were scheduled for 2,000 MW in each hour. With no imports/exports scheduled in DACP, the day-ahead supply cushion was 36 percent for HE 11 and 37 percent for HE 12.

As a consequence of OPG's CO_2 strategy, one coal-fired unit (about 500 MW of generation capacity) was on CO_2 outage and another unit (about 440 MW) was not offered but available (NOBA) for reliability if needed.[81]

Pre-dispatch Conditions

Table 2-10 illustrates the successive changes in forecast demand, the projected price and scheduled imports/exports for HE 11 and 12. Forecast demand fluctuated slightly between 18,600 MW and 19,000 MW and net exports hovered in the range of 1,500 - 1,650 MW from 10 hours-ahead to 1 hour-ahead. The PD prices from 10 hours-ahead to 1 hour-ahead were in the range of \$33/MWh to \$44/MWh.

[81] The Province of Ontario has directed OPG to reduce its CO_2 emissions from coal-fired generation to 19.6 million tonnes in 2009. In response, the OPG has established a strategy to meet the target, including CO_2 outages, NOBA's, and CO_2 adders. For a detailed discussion, see the Panel's January 2009 Monitoring Report, pp. 235-246.

Table 2-10: Prices, Ontario Demand and Exports/Imports
February 18, 2009, HE 11 and 12

Hours Ahead	HE 11 Price ($/MWh)	HE 11 Ontario Demand (MW)	HE 11 Net Exports (MW)	HE 12 PD Price ($/MWh)	HE 12 Ontario Demand (MW)	HE 12 Net Exports (MW)
DACP (19)	13.72	18,998	0	13.72	18,875	0
10*	36.12	18,787	1,432	37.80	18,663	1,485
5	35.82	18,764	1,657	37.80	18,614	1,642
4	35.52	18,736	1,607	37.62	18,582	1,657
3	33.44	18,704	1,342	37.80	18,759	1,511
2	34.31	18,830	1,417	42.27	18,863	1,555
1	37.80	19,017	1,313	44.27	19,119	1,510
Real-Time Average	1,039.27	19,133	1,313	1,891.14	19,262	1,460
Notable Events	*About 10 hours ahead, two fossil-fired baseload generators released from their DACP commitment					

About 10 hours-ahead of HE 11 (i.e. in HE 2), two fossil-fired baseload generators were removed by the IESO from the DACP commitment at the owner's request as there appeared to be no reliability concerns. The removal led to a reduction of about 700 MW in scheduled baseload generation for HE 11 and 12.

The one-hour ahead supply cushion was 6.7 percent for HE 11 and 5.7 percent for HE 12.

Real-time Conditions for HE 11

A few minutes before the real-time run for HE 11, a nuclear unit with a capacity of 825 MW became unavailable because of the outage of a major transmission line. Often, when a transmission line is forced out of service, if the associated generation is a quick-start unit such as hydroelectric, it is not removed from the unconstrained sequence. However, for fossil-fired or nuclear units, a transmission line outage results in the shut-down of the generating unit and its removal from both the constrained and unconstrained sequences, as was the situation for this event.

The real-time supply cushion was 2.6 percent at the beginning of the hour as a result of the loss of the nuclear unit, indicating very tight demand/supply conditions.

As a result of the transmission outage, the Area Control Error (ACE) reached -914 MW in HE 11 interval 1. In response, the IESO imported 450 MW of Shared Activation of Reserve (SAR), activated 450 MW of OR from within Ontario, and reduced the OR requirement by 450 MW. Two hundred MW of this OR was deactivated in interval 2 and the remaining 250 MW in interval 3. The SAR was terminated in interval 6.

Because of the transmission outage, the operating security limit of the remaining transmission lines that link the nuclear complex to the Toronto area was violated even with the removal of one unit. The IESO manually constrained down another nuclear unit at the same station by 500 MW from interval 9 onwards. The manually constrained-down energy had no impact on the unit's unconstrained schedules and hence this action did not impact the HOEP. The constrained-down unit was back to its normal production level in HE 19.

At almost the same time (HE 11 interval 2), another market participant informed the IESO that one of its fossil-fired generators would be forced out-of-service because of boiler chemistry problems. The unit was de-rated by 260 MW from HE 11 intervals 4 to 12 and then fully shut down in HE 12 interval 1, representing a loss of 460 MW of baseload generation.

In anticipation of the ramping-down of the constrained-down nuclear unit and the shutdown of the fossil-fired unit mentioned above, the IESO activated 500 MW of OR in intervals 5 and 6 and correspondingly reduced the OR requirement by an equivalent amount. This OR was all deactivated in interval 7.

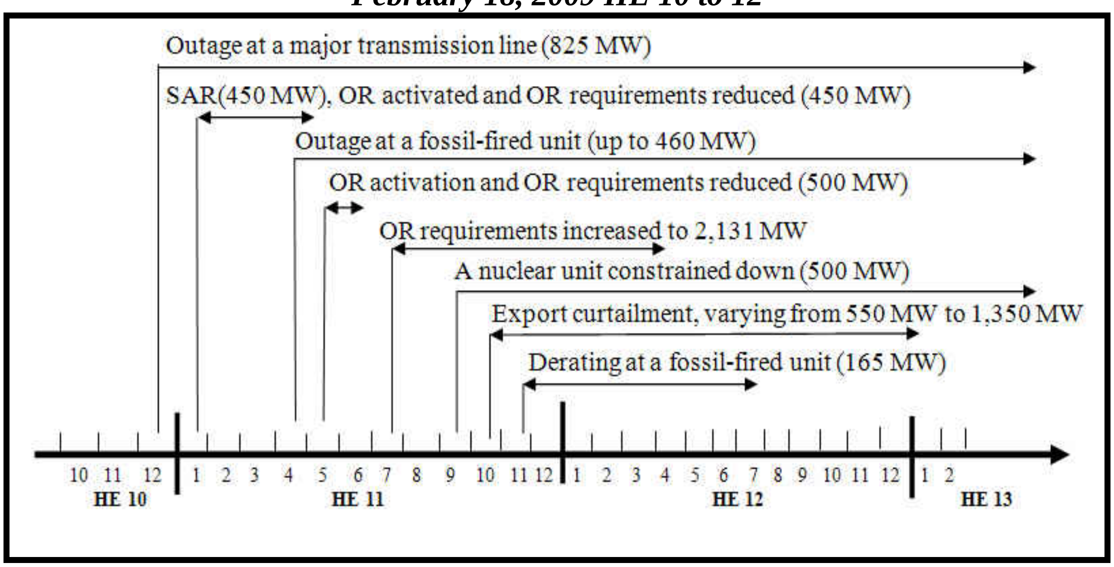
When the OR was deactivated in interval 7, the IESO increased the total OR requirement to 2,131 MW, reflecting the largest contingency at the time which was the potential loss of two nuclear units at the same station. This increase immediately led to a shortage of OR in

Ontario. In response, the IESO curtailed 550 MW of exports on the MISO interface for adequacy for the rest of the intervals of HE 11 and throughout HE 12. However, because these curtailments were considered to alleviate the adequacy concerns that were created by internal security concerns, *TLRi* was used for those curtailed exports and thus there was no impact on the unconstrained schedule (see the discussion '*Assessment*').

In Interval 8, another fossil-fired generator reported having condensate extraction pump problems and was therefore unable to follow its OR dispatch. The unit was subsequently de-rated by 165 MW from HE 11 interval 11 to HE 12 interval 7.

These outages and de-ratings and the IESO's major control actions are summarized in Figure 2-3 below.

Figure 2-3: Major Outages/Deratings and the IESO's Control Actions February 18, 2009 HE 10 to 12



Average real-time Ontario Demand in HE 11 was 19,133 MW, with a peak of 19,377 MW in interval 6, which was 360 MW (or 1.8 percent) greater than the forecast in pre-dispatch. This was the net result of 400 MW higher non-dispatchable demand offset by

40 MW less dispatchable load which was dispatched down in real-time in response to the high MCPs later in the hour.

Self-scheduling and intermittent generators produced almost exactly the amount they had projected one-hour ahead.

Real-time Conditions for HE 12

There were several contingencies in HE 12 including the outage of a major transmission line that led to the removal of one nuclear unit and the constraining-down of a portion of another nuclear unit, an outage at one fossil-fired unit and the de-rating at the other fossil-fired unit (all of which commenced in HE 11 and continued through HE 12). Largely as a result of these outages and an increase in the OR requirement, the real-time supply cushion was -3.6 percent at the beginning of HE12.

Before the real-time run, a 50 MW export failed on the NYISO interface because it did not get scheduled in NYISO.

As mentioned above, in HE 11 interval 7, the IESO curtailed 550 MW of exports on the MISO interface for HE 12. In HE 11 interval 10, the IESO cut a further 400 MW of exports on the NYISO interface for HE 12 and additional 400 MW of exports on the MISO interface in HE 12 interval 4 because of the OR shortfall. The total curtailment of exports from intervals 4 to 12 of HE 12 amounted to 1,350 MW. None of these curtailed exports were removed from the unconstrained sequence as they were deemed to have been cut for internal security concerns (coded with *TLRi*). We will discuss this issue further in the *Assessment* section.

Self-scheduling and intermittent generators produced 28 MW (2.0 percent) less than projected, which made the supply and demand situation slightly worse.

Real-time demand in the hour was very stable with an average of 19,262 MW and a peak of 19,300 MW, which was143 MW (or 0.7 percent) greater than the forecast in pre-dispatch. Again, real-time demand was lower than it would have been had dispatchable loads not reduced their consumption by up to 40 MW in response to the high real-time MCPs.

Assessment

The primary cause of the high prices in HE 11 and 12 was the loss of a major transmission line (resulting in a loss of 825 MW nuclear generation) and the forced outage/derating of two fossil-fired units (up to 625 MW), leading to a total loss of 1,450 MW of baseload or inframarginal generation. The loss of the transmission line also led to another nuclear unit being constrained down and higher than usual OR requirements. The slightly higher than expected real-time demand and self-scheduling and intermittent shortfall each put modest additional upward pressure on the HOEP.

The $1999.99/MWh MCPs seen in many intervals were set by a dispatchable load that bids $1999.99 for the portion of its consumption it wants treated as non-dispatchable. As mentioned before, a few dispatchable loads were dispatched down by up to 40 MW due to the high RT MCP. However, other dispatchable loads that were providing operating reserve were not dispatched down even though their bid prices were lower than MCP. This occurred because there was an OR shortage during this event and in order to provide OR the loads had to be consuming energy.[82] To minimize the penalty costs ascribed to the OR shortage, the IESO dispatch tool determined that it was economic to allow these loads to consume energy even though MCP exceeded their bid price so that they could provide OR.[83] This prevented the reduction in the demand for energy from dispatchable loads and eventually all resources were exhausted.

[82] When operating reserve is activated at a dispatchable load, the load will reduce its consumption, which is in contrast to a generator which increases its output when operating reserve is activated.
[83] For example, a dispatchable load bids $1,990/MWh to consume 1 MW of energy and offers $1/MWh to provide 1 MW of operating reserve. Because of operating reserve shortage, the 1 MW of operating reserve is now valued at $2,000 (the cap of the MCP). In other words, the 1 MW of operating reserve can generate a net value of $1,999 to the market. Even though the market price for energy is $2,000/MWh or $10/MWh above the bid price, the net loss of $10 for 1 MW of energy consumption is far smaller than the net value of the 1 MW operating reserve. As a result, the IESO tool will dispatch the dispatchable load to consume energy so that it is able to provide operating reserve.

The HOEP in HE 13 was below $200/MWh but far above the final PD price. The reason for this was that the capacity of the nuclear unit that was removed from service still showed up in the PD unconstrained sequence even though the unit was forced out of service one hour before the final PD run for HE 13. We understand the IESO is investigating whether this was a tool problem.

SAR and OR Supply

Table 2-11 below summarizes the outages and control actions that took place in HE 11 and HE 12 together with simulations showing their effects on the MCP. The simulations indicate that the immediate impact of the forced outages and deratings (alone) was relatively small. For example, the MCP was about $44/MWh in the first three intervals of HE 11 although the forced outage was 825 MW. As the total outage increased to 1,085 MW with the loss of one fossil-fired unit, the MCP gradually increased to $189/MWh in interval 6.

However, when the OR requirement was increased to 2,131 MW (an increase of about 1,200 MW above the OR requirements in intervals 5 and 6) to reflect the change to the largest contingency, the MCP immediately increased to $2,000/MWh from interval 7 onwards. In these intervals, the OR price was also $2,000/MWh, indicating an OR shortage (the OR shortage price is reported in Table 2-36). This can be seen by examining the scheduled OR in these intervals, which were less than the OR requirement (see the 5th and 6th column in Table 2-11 below).

The OR requirement was reduced to 1,437 MW from HE 12 interval 4 onwards, reflecting the changed system configuration. However, the MCP remained at the $2,000/MWh level in most intervals in HE 12. Again, there was an OR shortage in these intervals and the OR price was also $2,000/MWh.

The shortage of OR also had an effect on energy prices through the joint-optimization process in the scheduling tool: the use of all available OR tightened the energy supply. The OR shortage also led to dispatchable loads that had offered OR not being dispatched down even though their bid prices were lower than the RT MCP. The OR shortage thus reduced the responsiveness of these dispatchable loads to the energy price and prevented energy demand from dropping further.

In summary, during these two hours the first 1,085 MW of outage / derating had only a moderate effect on prices (pushing MCP to about $180/MWh), while the impact of the additional 1,200 MW OR requirements caused the MCP to soar to the $2,000/MWh cap.

Table 2-11: Control Actions and "Actual" and Simulated MCP February 18, 2009 HE 11 and 12

HE	Interval	Outage/ Deratings (MW)	SAR (MW)	OR Required (MW)	OR Scheduled (MW)	"Actual" MCP ($/MWh)	Simulated MCP ($/MWh) (Scenario 1)	Simulated MCP ($/MWh) (Scenario 2)
11	**1**	825	450	987	987	44.24	48.57	74.12
11	**2**	825	450	1,187	1,187	44.30	69.66	74.12
11	**3**	825	450	1,437	1,437	44.51	74.33	74.12
11	**4**	1,085	450	1,437	1,437	74.12	110.83	110.83
11	**5**	1,085	225	937	937	80.18	125.46	178.59
11	**6**	1,085	0	937	937	189.74	141.87	194.90
11	**7**	1,085	0	2,006	1,830	1,999.99	1,999.99	1,999.99
11	**8**	1,085	0	2,131	1,803	1,999.99	1,999.99	1,999.99
11	**9**	1,085	0	2,131	1,781	1,999.99	1,999.99	1,999.99
11	**10**	1,085	0	2,131	1,789	1,999.99	1,999.99	1,999.99
11	**11**	1,285	0	2,131	1,576	1,999.99	1,999.99	1,999.99
11	**12**	1,285	0	2,131	1,590	1,999.99	1,999.99	1,999.99
Average		***1,020***	***169***	***1,642***	***1,441***	***1,039.75***	***1,047.56***	***1,058.88***
12	**1**	1,450	0	2,131	1,199	2,000.00	2,000.00	2,000.00
12	**2**	1,450	0	2,131	1,194	2,000.00	2,000.00	2,000.00
12	**3**	1,450	0	2,131	1,261	2,000.00	2,000.00	2,000.00
12	**4**	1,450	0	1,437	1,247	1,999.99	1,999.99	1,999.99
12	**5**	1,450	0	1,437	1,251	1,999.99	1,999.99	1,999.99
12	**6**	1,450	0	1,437	1,242	1,999.99	1,999.99	1,999.99
12	**7**	1,285	0	1,437	1,221	1,999.99	1,999.99	1,999.99
12	**8**	1,285	0	1,437	1,412	730.96	730.96	730.96
12	**9**	1,285	0	1,437	1,353	1,999.99	1,999.99	1,999.99
12	**10**	1,285	0	1,437	1,392	1,950.00	1,950.00	1,950.00
12	**11**	1,285	0	1,437	1,372	1,999.99	1,999.99	1,999.99
12	**12**	1,285	0	1,437	1,437	679.65	679.65	679.65
Average		***1,185***	***0***	***1,611***	***1,298***	***1,780.05***	***1,780.05***	***1,780.05***

The Panel has recommended in past reports that the IESO should eliminate the price impact of SAR[84] and also replenish the OR requirements promptly.[85]

Table 2-11 reports the simulated MCP under two alternative approaches to the treatment of control actions in the unconstrained sequence. Scenario 1 assumes that the import of SAR was not treated as a reduction in demand in the unconstrained sequence in accordance with the Panel's 2006 recommendation that the import of SAR should not

[84]The Panel's December 2006 Monitoring Report, page 75.
[85] The Panel's July 2007 Monitoring Report, pp. 86-90.

affect demand in the unconstrained sequence. Scenario 2 assumes in addition that the OR requirement was not reduced as a result of the OR activation, as recommended by the Panel in 2007. The HOEP in HE 11 would have been $1,047.56/MWh, or $8/MWh (0.8 percent) higher had SAR not been subtracted from demand in the unconstrained schedule and $1,058.88/MWh, or $19/MWh (1.8 percent) higher had the OR requirement not been reduced and the SAR not been subtracted from demand in the unconstrained schedule. The price increase was relatively small because the “actual” MCP was already at the cap ($1999.99/MWh) in many of the intervals in the two hours and the additional demand in scenarios 1 and 2 cannot increase these MCPs.

Use of TLRi vs. ADQh for export curtailment due to internal adequacy

It is interesting to note that in the current case the IESO used the code of *TLRi* rather than *ADQh* for export curtailment for internal resource adequacy. As the Panel has explained before, [86] the use of *ADQh* tends to lead to counter-intuitive market prices that do not reflect the shortage conditions prevailing in the market. By using the *TLRi* code, the IESO maintained price fidelity.

According to IESO operating procedures, when there is a supply shortage, the use of code depends on the cause of the shortage.[87] The IESO has identified two causes for a shortage: internal transmission security concerns and others.

- If a shortage is caused by internal transmission problems and an export has to be cut, *TLRi* is used. The IESO also recognizes the possibility of using both *TLRi* and *ADQh* for the same hour. For example, if a transmission outage has removed 500 MW of supply from the market but the resource inadequacy is 700 MW, IESO applies *TLRi* to the first 500 MW of export curtailment and then *ADQh* for the remaining 200 MW of exports, from the lowest bid price to the highest bid price.

[86] The Panel’s December 2007 Monitoring Report, pp. 96-103, and the July 2008 Monitoring Report, pp. 171-180.
[87] The IESO’s Procedure 2.4-7: Interchange Operations, section 2.2, Adequacy, dated December 10, 2008.

- If a shortage has other causes, *ADQh* is used. Usually, this type of resource shortage is called a global adequacy concern. When curtailing exports beyond the next hour, *TLRi* is used.

In the current case, the supply shortage was directly induced by the loss of a major transmission line (leading to a loss of 825 MW at one nuclear unit and 500 MW being constrained down at another nuclear unit) and thus the operator applied *TLRi* for those curtailed exports (up to 1,350 MW).

To the Panel, the distinction between the two types of causes is difficult to make in many cases. For example, if it were not for energy in the Northwest bottled by transmission, there might not be an 'adequacy problem' in the rest of the province. Similarly, identifying how much generation is affected by a major transmission outage and then deciding how much export to cut beyond the next hour, although defined by procedures, still calls for some judgment by the IESO. When shortage conditions persist, the PD sequence is supposed to recognize them and schedule fewer exports. As a result, there may be no need for the IESO to manually and arbitrarily constrain off or cut exports in advance.

However, the use of *TLRi* does negatively impact those exporters with exports being constrained off. The issue is discussed below.

Large Negative Constrained off CMSC to Exports

In HE 11 and 12, between 550 MW to 1,350 MW of exports were constrained off. Because the HOEP reached $1,039.27/MWh in HE 11 and $1,891.14/MWh in HE 12, these constrained off exports, mostly bid at low prices, were exposed to significant constrained off payments, which amounted to $3 million, of which $2.7 million was paid in HE 12.

The CMSC formula for exports can be simplified as:

$$(Bidprice - HOEP) * (MW_U - MW_C)$$

Thus, when an export is constrained off (i.e. $MW_U - MW_C > 0$) and the bid price is greater than HOEP, the exporter receives a positive CMSC payment. However, if the HOEP is greater than the bid price, the calculated amount is negative and the export is charged the negative CMSC. For example, an exporter bids to export 100 MWh at $100/MWh. The PD price is $90/MWh but the real-time HOEP turns out to be $2,000/MWh. Assume the DSO has scheduled 100 MWh in both the constrained and unconstrained sequences in PD. Unless the transaction is failed, the exporter receives the energy and pays the $2,000/MWh HOEP. If the IESO were to constrain off the export with a *TLRi* code due to an internal supply shortage, however, the exporter does not get the energy and avoids paying the $2,000 price, but still has to pay $1,900/MWh (i.e. $2,000/MWh - $100/MWh) for being constrained off.[88]

In contrast, if *ADQh* is applied in this case, the exports scheduled in the unconstrained sequence would be the same as the schedule in the constrained sequence (both are 0 MW) and the exporter would not be charged through the (negative) CMSC.

The practice of using both *ADQh* and *TLRi* for adequacy thus has an inconsistent and sometimes significant effect on exporters. To the exporter, the transaction is cut, but depending on the resulting HOEP and which code is applied, it may lead to a large positive CMSC payment, an even larger negative CMSC payment, or no CMSC payment whatsoever.

The design of constrained on payments leads to exporters paying as-bid (and importers paid as-offered) while constrained off payments allow the constrained off resources to make the same operational profit as if they were not constrained off. The Panel has had

[88] This follows from the underlying principle for CMSC, that the payment should return the market participant to the same profit level it would have achieved in the market schedule.

reservations regarding constrained off payments to generators and importers for a long time, since these may provide a gaming opportunity to market participants, in that there is a payment for energy that does not physically flow.[89]

The negative constrained off payment in this case appears just as questionable. This event provides another example how (negative) constrained off payments can lead to perverse results. We reiterate our position that the IESO should review the benefits of constrained off payments with a view to their discontinuation.[90]

Offer Window and 15 Minute Pre-dispatch

When the HOEP spiked above $1,000/MWh in HE 11 on February 18, many market participants called the IESO and asked it to open the mandatory offer window so that they could offer additional resources into the market or reduce or even eliminate their export bids. However, the Market Rules do not allow the IESO to reopen the offer window simply for pricing reasons.

In all electricity markets, 'generators/importers' 'offers and loads/exporters' bids must be submitted ahead of real-time. In other words, there is a required lead time for offers and bids to be received by the system operator.[91] As the Panel found in its January 2009 report, the IESO requires a longer lead time (2 hours) than its major trading partners (75 minutes in NYISO and 30 minutes in MISO).[92] The longer lead time provides some stability for slow moving generators but limits traders' flexibility to respond to changes in the market price.

An alternative way to increase the responsiveness at interties would be a 15 minute dispatch as discussed in the Panel's December 2007 report.[93] Given that the IESO's

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[89] The Panel's special report, "Congestion Management Settlement Credits (SMSC) in the IMO-Administered Electricity Market: Issues related to constrained off payments to generators and imports", February 2003, and more recently our June 2006 (pp. 121-128) and July 2008 Monitoring report (pp. 203-206).
[90] The Panel's July 2008 Monitoring Report, pp. 203-205.
[91] Within the lead time, modifications are possible if requested and allowed by the system operator.
[92] The Panel's January 2009 report, pp. 186-191.
[93] The Panel's December 2007 report, pp. 151-158.

major trading partners (NYISO, MISO, and PJM) all have a 15 minute dispatch of intertie transactions with each other (and occasionally between IESO and MISO when necessary),[94] it would be possible for the IESO to apply 15 minute dispatch on a regular basis if the necessary tools were developed. We previously estimated that the potential efficiency gains of rescheduling imports alone could amount to $8 million per year (based on data from November 2006 to October 2007).

In the current case, if a 15 minute dispatch had been in effect, the efficiency gain to the market would have amounted to $251,000 in the two hours ($4,000 in HE 11 and $247,000 in HE 12), as Table 2-12 below shows. The efficiency gain would have resulted from a reduction in net exports by incorporating the outages into the 15 minute dispatch. As the table shows, the current one-hour ahead dispatch algorithm failed to recognize any forced outages during hours HE 11 – HE 12, while a 15 minute pre-dispatch would have captured the sequence of outages beginning in HE 11 interval 7. This would have led to a reduction in net exports of 63 MW in HE 11 and 668 MW in HE 12 on average. As a result of the reduction in net exports, the HOEP would have been $609.57/MWh in HE 12, or $1,170.48/MWh lower than the actual HOEP. There would have been no impact on the HOEP in HE 11 with a 15 minute dispatch.

[94] In many cases, if MISO needs to adjust transactions with the IESO for either internal or external problems, it will modify these on a 15 minute basis. For details, see the Panel’s January 2009 report.

Table 2-12: Comparison of One Hour Ahead and 15 Minute Ahead Pre-dispatch of Intertie Trades, February 18, 2009 HE 11 and 12

		'Actual'		Simulated			
HE	Interval	Lost Generation in 1 hr ahead PD (MW)	MCP ($/MWh)	Lost Generation in 15 Minute Ahead PD (MW)	Decrease in Net Exports (MW)	MCP ($/MWh)	Efficiency Loss ($1,000)
11	1	0	44.24	0	0	44.24	0
11	2	0	44.30	0	0	44.30	0
11	3	0	44.51	0	0	44.51	0
11	4	0	74.12	0	0	74.12	0
11	5	0	80.18	0	0	80.18	0
11	6	0	189.74	0	0	189.74	0
11	7	0	1999.99	825	50	1999.99	0
11	8	0	1999.99	825	50	1999.99	0
11	9	0	1999.99	825	50	1999.99	0
11	10	0	1999.99	1,085	200	1999.99	1
11	11	0	1999.99	1,085	200	1999.99	2
11	12	0	1999.99	1,085	200	1999.99	1
Average		**0**	**1,039.75**	**478**	**63**	**1,039.75**	**4**
12	1	0	2000.00	1,085	585	1999.99	23
12	2	0	2000.00	1,085	585	1999.99	21
12	3	0	2000.00	1,085	585	1999.99	17
12	4	0	1999.99	1,285	585	221.68	23
12	5	0	1999.99	1,285	585	279.56	24
12	6	0	1999.99	1,285	585	305.12	24
12	7	0	1999.99	1,450	750	109.74	24
12	8	0	730.96	1,450	750	82.12	21
12	9	0	1999.99	1,450	750	82.12	20
12	10	0	1950.00	1,450	750	80.18	19
12	11	0	1999.99	1,450	750	80.18	18
12	12	0	679.65	1,450	750	74.12	13
Average		**0**	**1,780.05**	**1,318**	**668**	**609.57**	**247**

2.1.5 March 3, 2009 HE 9

Prices and Demand

Table 2-13 lists the real-time and pre-dispatch information for HE 8 and 9. The HOEP was $140.53/MWh in HE 8, with the MCP gradually increasing from $79.78/MWh in interval 1 to about $200/MWh in the last two intervals. The average demand was 20,082 MW, with a peak of 20,337 MW or 262 MW (1.3 percent) greater than the forecast peak demand. There were no import or export failures in the hour.

The MCP in HE 9 increased dramatically to $679.65/MWh in interval 1, then dropped to about $118/MWh in interval 6, staying at that level for the rest of the hour. The average demand in the hour was 20,256 MW, with a peak of 20,359 MW or 155 MW (0.8 percent) greater than the forecast peak demand. A 25 MW import failed in this hour.

Table 2-13: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch March 3, 2009 HE 8 and 9

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
8	1	79.78	100.64	-20.86	19,594	20,075	1,678	1,678
8	2	100.64	100.64	0.00	19,794	20,075	1,678	1,678
8	3	104.57	100.64	3.93	19,903	20,075	1,678	1,678
8	4	106.86	100.64	6.22	19,999	20,075	1,678	1,678
8	5	110.35	100.64	9.71	20,028	20,075	1,678	1,678
8	6	155.68	100.64	55.04	20,112	20,075	1,678	1,678
8	7	131.53	100.64	30.89	20,145	20,075	1,678	1,678
8	8	155.78	100.64	55.14	20,228	20,075	1,678	1,678
8	9	155.78	100.64	55.14	20,256	20,075	1,678	1,678
8	10	184.98	100.64	84.34	20,286	20,075	1,678	1,678
8	11	207.18	100.64	106.54	20,337	20,075	1,678	1,678
8	12	193.27	100.64	92.63	20,299	20,075	1,678	1,678
Average		**140.53**	**100.64**	**39.89**	**20,082**	**20,075**	**1,678**	**1,678**
9	1	679.65	99.47	580.18	20,344	20,204	2,281	2,256
9	2	574.90	99.47	475.43	20,324	20,204	2,281	2,256
9	3	248.38	99.47	148.91	20,306	20,204	2,281	2,256
9	4	202.11	99.47	102.64	20,337	20,204	2,281	2,256
9	5	171.62	99.47	72.15	20,359	20,204	2,281	2,256
9	6	118.97	99.47	19.50	20,240	20,204	2,281	2,256
9	7	118.97	99.47	19.50	20,237	20,204	2,281	2,256
9	8	117.83	99.47	18.36	20,195	20,204	2,281	2,256
9	9	117.83	99.47	18.36	20,190	20,204	2,281	2,256
9	10	118.87	99.47	19.40	20,231	20,204	2,281	2,256
9	11	118.87	99.47	19.40	20,220	20,204	2,281	2,256
9	12	115.53	99.47	16.06	20,093	20,204	2,281	2,256
Average		**225.29**	**99.47**	**125.82**	**20,256**	**20,204**	**2,281**	**2,256**

Day-Ahead Conditions

The total energy scheduled day-ahead during the DACP run was 20,037 MW for HE 9. Fifteen, out of 27 fossil-fired units that were expected to be available for the day, were scheduled for a total of 3,046 MW. With no imports/exports scheduled in DACP, the day-ahead supply cushion was 31 percent for HE 9.

Pre-dispatch Conditions

Table 2-14 shows the successive changes in forecast demand, the projected price and scheduled imports/exports for HE 9. The PD price increased sequentially from $37.00/MWh day-ahead to $99.47/MWh one-hour ahead, as forecast demand and scheduled net exports gradually increased.

Table 2-14: Prices, Ontario Demand and Exports/imports March 3, 2009, HE 9

Hours Ahead	HE 9		
	Price ($/MWh)	Ontario Demand (MW)	Net Exports (MW)
DACP (18)	37.00	20,037	0
10	51.00	20,073	1,299
5	75.13	20,097	1,876
4*	83.11	20,246	1,927
3	83.11	20,238	1,688
2	98.88	20,208	2,340
1	99.47	20,204	2,256
Real-Time Average	225.29	20,256	2,281
Notable Events	*235 MW of baseload generation derated due to fuel supply problems 4 hour ahead of RT		

A fossil-fired generator was de-rated by 235 MW in HE 5 due to fuel supply problems. The one-hour ahead supply cushion was 3.3 percent for HE 9.

Real-time Conditions for HE 9

Before the real-time run, 25 MW of imports failed on the MISO interface due to ramp limitation in MISO,[95] putting upward pressure on the HOEP.

[95] In the constrained sequence, another 100 MW of imports was curtailed by MISO because the transaction failed to obtain firm transmission service. However, because the import was constrained on with 0 MW in the unconstrained sequence in the first place, the curtailment had no impact on the HOEP.

In HE 8 interval 5, the fossil-fired generator that had already been de-rated by 235 MW due to fuel supply problems was further de-rated by 25 MW.

One interval later, another fossil-fired generator was de-rated by 100 MW, also because of fuel supply problems.

Self-scheduling and intermittent generators produced about 233 MW (17.8 percent) less than they projected, of which 150 MW was from a new gas-fired generator being commissioned that day. The underperformance of these self-scheduling and intermittent generators put additional upward pressure on the HEOP.

The supply cushion at the beginning of the hour was -1.9 percent. The average demand in the hour was 22,305 MW, with a peak of 22,408 MW or 180 MW (0.8 percent) greater than the one-hour ahead forecast peak demand.

Assessment

The significant drop in the supply cushion from 3.3 percent one-hour ahead to -1.9 percent at the beginning of the hour was a combined result of the supply reductions explained above and the limited collective ramp capability of Ontario generation to adjust to changing intertie flows. From HE 8 to 9, a 605 MW increase in net exports had to be accommodated in interval 1 of HE 9 in the unconstrained sequence.[96]

The increase of net exports was the primary cause of the MCP rising up to $679.65/MWh in HE 9 interval 1. It took six intervals for the MCP to decline to $118/MWh and it remained at that level for the rest of the hour.

[96] In the constrained sequence, the change in the intertie ramping is split into two intervals: interval 12 in the past hour and interval 1 in the current hour. For details, see the Panel's January 2009 Monitoring Report, pp. 92-101.

Overall Assessment of High-Price Hours

There were 8 hours with a HOEP greater than $200/MWh in the study period. In examining individual high price hours and specifically the offer prices of the price-setting generators, the Panel did not identify evidence of abuse of market power by market participants in these events. One instance of possible high-pricing by one participant was reviewed, but did not appear to affect HOEP substantially, in which event the Panel did not conclude there was economic withholding. The price movements in these hours were generally consistent with supply/demand conditions prevailing at the time which we have historically identified as inducing high prices.

2.2 Analysis of Low Price hours

Table 2-15 shows that the total number of hours with a low HOEP has been increasing period over period since 2004, with 2008/09 experiencing a much higher number of events. The increase in the number of low priced hours is consistent with the increased supply and sometimes decreased demand over the last several years. More specifically, the significantly higher number of low priced hours in the current six month review period was largely a consequence of a sizable increase in baseload nuclear production, decreased Ontario Demand and a significant reduction in export capability and flows due to the transmission outages on the New York interface in March and April 2009, as discussed in Chapter 1 and later in this Chapter.

Table 2-15: Number of Hours with a Low HOEP
November - April, 2004 – 2009

	Number of Hours with HOEP < $20/MWh				
	2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
November	0	4	25	10	31
December	0	2	103	78	62
January	4	3	18	59	25
February	0	6	0	30	25
March	0	1	0	0	192
April	0	95	43	84	354
Total	4	111	189	261	689

The primary factors leading to a low HOEP are:

- Low market demand: This typically occurs in overnight hours, on holidays and during the spring and fall seasons. The low market demand may be due to a combination of low Ontario Demand and/or low net export volume. The latter might be due to either low external demand or reduced export capability because of high loop-flows or transmission outages;
- Abundant baseload supply from hydroelectric and nuclear generators: High hydroelectric supply occurs most frequently during the spring-time months of April and May when even peaking hydroelectric plants have abundant water from spring snow melt and increased rainfall, but it can occur at other times.

While these are the primary factors that contribute to a HOEP less than $20/MWh, other factors may also be at play:

- Demand deviation: the forecast peak demand that is used in PD is typically greater than the average RT demand that determines the HOEP. There are two factors that could cause the deviation:
  - Demand over-forecast: This can lead to over-scheduling imports in pre-dispatch, putting a downward pressure on the HOEP because in RT these imports are placed at the bottom of the offer stack.
  - Peak vs. average demand: Even when the peak demand is accurately forecast, a low HOEP can result because of lower RT demand in other intervals. This occurs because some imports that are scheduled based on-peak demand may not be economic in other intervals.
- Failed export transactions: These can place downward pressure on the HOEP.
- Wind generation and/or self-scheduling generators: The volume of wind generation has been increasing in the past two years, as demonstrated in Chapter 1. Because these wind generators are price-takers and typically produce more in off-peak hours, a low off-peak price is more likely to result, everything else being equal. Increased self-scheduling output at new gas-fired generators as a result of commissioning also contributes to low prices.

In late March to mid April 2009 two major transmission lines on the New York interface were taken out of service. The outages led to a significant reduction in export capability to NYISO and also to MISO due to the parallel flow effect.[97] In that period, the IESO had to take actions to deal with the overnight Surplus Baseload Generation (SBG) on a regular basis. We will comment on the SBG issue and the IESO's actions in Chapter 3 section 3.4

For hours with low prices, Table 2-16 and 2-17 below list RT output by generation type, hydro resources that were offered below $20/MWh but were not scheduled, Ontario Demand and net exports. Nuclear, baseload hydroelectric, self-scheduling and intermittent, and coal-fired generators at minimum loading point are generally not price responsive. Other hydroelectric generators during these low-priced hours were typically run-of-the-river generators and had a zero opportunity cost of producing power.[98] As a result, they offered at a low price to generate power. Hydro resources offered below $20/MWh but not scheduled may also have a low or even zero opportunity cost but they have a positive incremental (out-of-pocket) cost of generating rather than spilling.[99]

The total 'low-priced supply' during the low-priced hours in the review period was more than sufficient, on average, to meet total demand (Ontario Demand plus net exports). On average the low-priced supply was 543 MW greater than demand during the hours in which the HOEP was less than $20/MWh.

[97] Because of the parallel flows, a portion of exports that are scheduled to go out through the MISO interface will physically go through the NYISO interface. When the export capability on the NYISO interface is reduced, exports on the MISO interface also have to be reduced to avoid congestion due to the induced parallel path flows on the NYISO interface. For more discussion on parallel path flows, see Chapter 3 section 2.1 in the current report.
[98] OPG's non-prescribed hydroelectric generation was subject to a rebate regulation up to April 30, 2009, which reduced their incentive to lower output at these generators during the low-price hours. OPG was essentially guaranteed a revenue of $48/MWh plus 15 percent of the difference between $48 and MCP, so was largely immune to the low prices. For a detailed discussion, see Chapter 3 of the current report.
[99] This is not a direct measure of spill since the threshold cost at each station is different, and there is no guarantee that even if price appears to approximate that cost, there will be spill if the unit does not generate.

Table 2-16: Supply, Low-priced Hours November 2008 – April 2009, MW

Month	Supply						
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Scheduled Coal at MLP	Other Scheduled Hydro	Other Unscheduled Hydro (offered <$20)	Total
Nov-08	9,537	1,511	1,154	918	1,493	25	14,638
Dec-08	10,946	1,642	1,438	470	1,617	538	16,651
Jan-09	11,256	1,719	1,300	691	1,712	139	16,816
Feb-09	10,228	1,796	1,366	786	1,773	231	16,180
Mar-09	10,152	1,874	1,499	464	1,836	421	16,246
Apr-09	9,576	1,692	1,468	296	1,661	1,092	15,785
Average	9,943	1,735	1,450	418	1,704	719	15,969

*includes generation at the Beck, Saunders, and DeCew generation stations.

Table 2-17: Demand, Low-priced Hours November 2008 – April 2009, MW

Month	Demand			Diff (Supply - Demand)
	Ontario Demand	Net Exports	Total	
Nov-08	13,492	893	14,385	**253**
Dec-08	14,548	1,511	16,059	**592**
Jan-09	14,967	1,693	16,660	**156**
Feb-09	14,984	1,231	16,215	**-35**
Mar-09	14,657	1,147	15,804	**442**
Apr-09	14,180	878	15,058	**727**
Average	14,373	1,053	15,426	**543**

Table 2-18 below summarises the average monthly data on low-priced hours (<$20/MWh) by month for the period November 2008 through April 2009. 'Demand Deviation' is the difference between the pre-dispatch demand (which is the forecast peak demand) and the real-time average demand. As discussed above, this can be a result of forecast errors or simply the difference between peak and average demand within the hour. It appears that the low HOEP in the study period was generally not induced by net export failure, implying that low demand (Ontario Demand plus net exports) and the demand deviation were the main reasons. HOEP is low because the low level of demand can be easily met with low-priced baseload supply.

Table 2-18: Average Monthly Summary Data for Low-priced Hours November 2008 –April 2009

	Number of Low-Priced Hours	Failed Net Exports (MW)	RT Average Demand (MW)	Pre-Dispatch Demand (MW)	Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT - PD) ($/MWh)
November	31	41	13,492	13,921	429	11.69	30.19	-18.50
December	62	165	14,548	14,900	352	6.48	25.64	-19.16
January	25	28	14,967	15,355	388	7.86	35.56	-27.70
February	25	94	14,984	15,329	345	10.09	34.11	-23.22
March	192	44	14,657	14,877	221	1.10	12.17	-11.07
April	354	23	14,180	14,410	231	0.33	8.36	-8.02
Total / Average	689	45	14,373	14,630	258	2.27	13.88	-11.61

2.2.1 Negative Prices

As demonstrated in Chapter 1, the average HOEP in March and April 2009 was much lower than a year ago. The low average monthly HOEP in these two months resulted mainly from a large number of hours with a negative HOEP. Table 2-19 below lists the monthly total number of hours with a negative HOEP for the winter periods from 2004 to 2009. There were 227 hours with a negative HOEP in the past five winters, of which 219 hours occurred in the 2008/09 winter alone. The lowest HOEP since the beginning of the market was -$51.00/MWh, which occurred on March 29, 2009 HE 2-4. We discuss the low-priced hours on that day in subsection 2.2.3. On December 28, 2008, there were several consecutive hours with a HOEP less that -$30/MWh. We discuss these hours in subsection 2.2.2.

Table 2-19: Number of Hours with a Negative HOEP November - April, 2004 – 2009

	Number of Hours with HOEP < $0/MWh				
	2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
November	0	0	0	0	0
December	0	0	3	0	5
January	0	0	0	0	0
February	0	0	0	4	0
March	0	0	0	0	58
April	0	0	0	1	156
Total	0	0	3	5	219

Tables 2-20 and 2-21 below list RT output by generation type as well as hydro resources offered below $0/MWh but not scheduled, Ontario Demand and net exports for the 219 negative-priced hours in the study period. Generally, most negative-price hours in the study period were hours with Surplus Baseload Generation conditions. In many hours, nuclear units that offered at a negative price set the price. For purposes of this analysis, we report the available energy at these nuclear units instead of their actual schedules. Again, baseload hydroelectric, self-scheduling and intermittent, and coal-fired generators at their MLP were offered at a negative and most likely a large negative price, indicating that they wanted to run regardless of the market price. Other hydroelectric resources also provided about 1,300 MW of energy in these hours, implying that there were other factors such as OPG’s rebate mechanism or environmental requirements that induced them to offer at a negative price. On average, the negative priced supply was 1,735 MW greater than demand, and thus a negative price resulted.

Table 2-20: Supply, Negative-priced Hours
November 2008 – April 2009, MW

Month	Supply						
	Available Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Scheduled Coal at MLP	Other Scheduled Hydro	Other Unscheduled Hydro (offered <$0)	Total
Dec-08	11,470	718	1,258	320	763	855	15,384
Mar-09	10,412	1,543	1,439	254	1,529	1,055	16,232
Apr-09	10,579	1,286	1,531	213	1,295	1,514	16,418
Average	10,555	1,341	1,501	226	1,345	1,377	16,345

*include generation at the Beck, Saunders, and DeCew generation stations.

Table 2-21: Demand, Negative-priced Hours
November 2008 – April 2009, MW

Month	Demand			Supply-Demand
	Ontario Demand	Net Exports	Total	
Dec-08	12,222	1,324	13,546	**1,838**
Mar-09	13,905	762	14,667	**1,565**
Apr-09	13,784	839	14,623	**1,795**
Average	13,780	830	14,610	**1,735**

Table 2-22 below lists the summary information for the 219 hours with a negative HOEP in the period November 2008 to April 2009. The large negative HOEPs in five hours of December 2008 were not projected by the final one-hour ahead pre-dispatch and were mainly driven by large amounts of failed exports. In March and April 2009, however, the negative HOEPs were largely projected by the final one-hour ahead pre-dispatch (although failed (net) exports and demand deviations pushed the HOEP down further). The negative PD prices imply that either there was little profit opportunity for exporters to arbitrage the price difference between Ontario and external markets or export capability was actually limited by the physical conditions at the interties. Chapter 1 section 5.2.2 does in fact identify the considerable export congestion on the MISO interties in March and April. We will discuss the intertie issue in later sections.

Table 2-22: Average Monthly Summary Data for Negative-priced Hours November 2008 - April 2009*

	Number of Negative-Priced Hours	Failed Net Exports (MW)	RT Average Demand (MW)	Pre-dispatch Demand (MW)	Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT-Pre-dispatch) ($/MWh)
Dec-08	5	588	12,222	12,505	283	-29.73	6.94	-36.66
Mar-09	58	9	13,905	14,053	148	-14.46	-10.35	-4.11
Apr-09	156	15	13,783	14,009	226	-7.42	-3.08	-4.34
Total / Average	219	27	13,780	13,986	206	-9.80	-4.78	-5.02

*There was no negative HOEP in November, January and February.

All negative HOEP's in March and April 2009 (214 hours in total) occurred in the 27-day period from March 24 to April 19. In this period, the Ontario market frequently experienced a Surplus Baseload Generation (SBG) condition, in which there was too much baseload generation compared to demand.[100] Because baseload generators typically offer at negative prices in order to ensure they are scheduled, a negative price may result when there is more than sufficient supply to meet the total demand.

It is worth pointing out that all self-scheduling and intermittent generators are implicitly considered as baseload generation because they are not dispatchable and generally do not respond to the market price because of their fixed-price contracts.[101] Although for reliability reasons the IESO is authorized to dispatch down these generators if needed, the IESO usually does not instruct them to do so because the IESO re-dispatches dispatchable resources ahead of non-dispatchable resources.[102] We will further discuss the issue of SBG and the consequential negative prices as well as the implications of contracts and regulated prices on generators in Chapter 3 section 3.4 and Chapter 4 section 2.

[100] The IESO defines an SBG condition as *"when the amount of baseload generation (which may largely consist of a supply mix of high minimum load fossil, nuclear and run-of-the-river hydroelectric resources) exceeds the market demand" (*the IESO Procedure 2.4-2, section 7*).*

[101] Although self-scheduling and intermittent generators do have an offer price associated with the quantity that they are going to produce, the IESO DSO doesn't take into account the offer price in the real-time scheduling process.

[102] A further issue that complicates the IESO's decision is that most of these self-scheduling and intermittent generators have a fixed-price contract either with OPA or OEFC, which bases the payment on the actual output at these plants. Dispatching down these generators will reduce their revenue and the IESO does not yet have a compensation scheme in place for such control actions.

2.2.2 December 28, 2008 HE 3 - 7

Prices and Demand

Table 2-23 presents pre-dispatch and real-time summary statistics for HE 3 to 7 on December 28, 2008. Although pre-dispatch prices were positive, the HOEP fell below $0/MWh in all hours and reached -$34.00/MWh in HE 6, the lowest value, recorded since market opening in 2002. During these hours, Ontario Demand was low while net export failures were large (relative to the magnitude of average failure of 31 MW in the study period).

Table 2-23: MCP, Ontario Demand and Net Exports
December 28, 2008, HE 3 to 7
(MW and $/MWh)

Delivery Hour	RT MCP ($/MWh)	Final PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	Average Ontario Demand (MW)	Final PD Ontario Demand (MW)	RT Net Exports (MW)	Final PD Net Exports (MW)	Net Export Failure (MW)
3	(20.14)	7.00	(27.14)	12,319	12,582	1,172	1,687	515
4	(28.83)	3.23	(32.06)	12,068	12,246	1,421	1,707	286
5	(33.00)	3.22	(36.22)	12,011	12,176	1,539	2,072	533
6	(34.00)	3.70	(37.70)	12,177	12,452	1,321	2,231	910
7	(32.67)	17.53	(50.20)	12,533	13,068	1,164	1,860	696

The largest price difference between PD and RT occurred in HE 7. The PD price was $17.53/MWh while the HOEP was -$32.67/MWh, a difference of $50.20/MWh.

Day-Ahead Conditions

Table 2-24 below lists the day-ahead MCP, demand and supply cushion for HE 3 to 7. The forecast day-ahead Ontario Demand at the time of the final DACP run ranged between a low of 12,375 MW in HE 5 to a high of 13,270 MW in HE 7. Only two coal-fired units and three small gas-fired dispatchable units were scheduled at their minimums, representing a total of 320 MW of energy. The day-ahead supply cushion was around 100 percent in all hours.

Table 2-24: Day-Ahead MCP, Demand, and Supply Cushion Statistics December 28, 2008, HE 3 to 7

Hour	MCP ($/MWh)	Ontario Demand (MW)	Supply Cushion (percent)
3	(35.00)	12,781	102
4	(37.00)	12,519	106
5	(51.00)	12,375	108
6	(51.00)	12,648	104
7	(35.00)	13,270	96

Pre-dispatch Conditions

Table 2-25 depicts the PD price evolution from 5 hours ahead to RT as well as the DACP prices. Because exports are excluded from the DACP run, the DACP price was below -$35/MWh for all hours. From 5 hours to 1 hour ahead, the pre-dispatch price was positive for all hours and changed very little, indicating stable pre-dispatch supply and demand conditions. However, the HOEP was below -$20/MWh in all hours, which implies either that there was a significant change in supply and demand conditions from 1 hour ahead to RT or that the difference between the PD and RT pricing algorithms played a significant role.

Table 2-25: PD Prices and HOEP
December 28, 2008, HE 3 to 7
($/MWh)

Hour	3	4	5	6	7
Final DACP run	(35.00)	(37.00)	(51.00)	(51.00)	(35.00)
5 hr PD	6.70	3.22	1.00	3.20	19.40
4-hr PD	3.80	3.22	0.70	3.23	19.40
3 hr PD	5.70	3.20	0.70	3.23	19.40
2 hr PD	7.00	3.20	3.22	7.00	17.51
1 hr PD	7.00	3.23	3.22	3.70	17.53
HOEP	(20.14)	(28.83)	(33.00)	(34.00)	(32.67)
1 hr PD Supply Cushion percent	36.6	39.8	37.7	33.7	30.4

The one-hour ahead supply cushion was above 30 percent in all hours indicating a condition of excess supply.

Real-time Conditions

Significant export failures occurred before real-time at the New York interfaces. On the New York interface, 400 to 634 MW of exports failed as these transactions were not economic in New York. In fact, from HE 3 to 7, the New York interface was congested with a PD price of about $20/MWh in the New York zone (within Ontario). However, the one-hour ahead price (and RT price) in the New York OH zone was below $7/MWh in most of these hours. Thus, if the one-hour ahead prices were realized in real-time in both markets, exporters would have incurred losses and failing these transactions would have been rational if the potential failure charge in Ontario and NYISO were expected smaller than the loss.

Meanwhile, PJM and MISO were experiencing SBG conditions at the time. A large amount of exports destined for these two markets through the MISO interface were curtailed by their system operators in order to deal with their SBG conditions. As a result of these export failures, Ontario also found itself having SBG conditions (Ontario would not have had SBG conditions had these export not failed). In response, the IESO constrained down a few nuclear units by up to 300 MW and cut some imports from MISO and Manitoba using the adequacy (‘*ADQh*’) code.[103] Table 2-26 below presents hourly import and export failures at the Michigan and New York interties. Net export failures varied from 286 MW in HE 4 to 910 MW in HE6.

Table 2-26: Import and Export Failures
December 28, 2008 HE 3 to 7
(MW)

Hour	Failed Ontario Exports		Failed Imports	Net Export Failures
	Not Scheduled in NYISO	Cut by PJM and MISO for SBG	Cut by IESO for SBG	
3	634	242	361	515
4	534	100	348	286
5	462	142	71	533
6	450	821	361	910
7	400	651	355	696

Table 2-27 below lists the PD Ontario Demand, RT average and peak demand, and PD to RT self-scheduling and intermittent generator deviations. The table shows that hourly peak demand was only slightly over-forecast with the exception of HE 3 and HE 7. In HE 3, peak demand was marginally under-forecast by 0.2 percent while in HE 7 peak demand was over-forecast by 2.8 percent. The difference between average and peak demand in real-time was generally larger than the peak forecast error, averaging 189 MW (1.5 percent) over the 5 hours. Self-scheduling and intermittent generators produced 82 to 166 MW (6.0 percent to 11.9 percent) less than expected, slightly offsetting the downward pressure of the export failures on the HOEP.

[103] According to the IESO’s Procedure 2.4-7 (Interchange Operations) dated December 10, 2008, all curtailed imports for a Surplus Baseload Generation event are associated with a code of *ADQh*.

Table 2-27: PD and RT Demand Statistics,
December 28, 2008, HE 3 to 7
(MW and Percent)

Delivery Hour	PD Demand (MW)	RT Average Demand (MW)	RT Peak Demand (MW)	Peak Demand Over-Forecast		RT Peak – RT Average Demand		Over-forecast of Self-scheduling & intermittent generators	
				MW	Percent	MW	Percent	MW	Percent
3	12,582	12,319	12,608	(26)	(0.2)	289	2.3	166	11.9
4	12,246	12,068	12,152	94	0.8	84	0.7	146	10.5
5	12,176	12,011	12,137	39	0.3	126	1.0	106	7.7
6	12,452	12,177	12,458	(6)	0.0	281	2.3	82	6.0
7	13,068	12,533	12,697	371	2.8	164	1.3	94	6.9

Assessment

It is clear that the low real-time prices during HE 3-7 were mainly a result of abundant baseload supply and large export failures (almost 590 MW on average) at the New York and MISO interfaces. The use of peak instead of average forecast demand (which differed by an average of almost 200 MW in these hours) also contributed to excess supply by raising pre-dispatch prices, attracting additional imports and/or reducing exports (e.g. by up to 170 MW in HE 17). Although the vast majority of imports were subsequently curtailed by the IESO, the curtailment action had the effect of distorting the market price as will be discussed below. Precluded potential exports on the New York interface (no further exports could flow on the MISO interface because of SBG in MISO and PJM) further exacerbated the SBG condition as some of these exports might have flowed successfully.

The IESO's action of curtailing imports for adequacy had the effect of mitigating the downward pressure on the HOEP as the curtailed imports were removed from the unconstrained sequence.[104] In its July 2008 Monitoring Report, the Panel observed that the '*ADQh*' code overrides the value of the curtailed transactions in the market schedule

[104] The use of *ADQh* will equalize the constrained schedule to the unconstrained schedule.

and distorts the HOEP.[105] When imports are cut for adequacy, the HOEP is effectively increased, while when exports are cut for adequacy the HOEP is decreased. Simulations results reported in Table 2-28 show that if the failed imports were not removed from the unconstrained sequence, the HOEP would have been \$0.67/MWh (2 percent) to \$12.36/MWh (61 percent) lower.

Table 2-28: 'Actual' and Simulated HOEP
December 28, 2008 HE 3 to 7
(\$/MWh)

Delivery Hour	'Actual' HOEP	Simulated HOEP	Difference	percent Difference
3	(20.14)	(32.50)	(12.36)	(61.4)
4	(31.67)	(33.67)	(2.00)	(6.3)
5	(33.00)	(33.67)	(0.67)	(2.0)
6	(34.00)	(36.50)	(2.50)	(7.4)
7	(32.67)	(35.00)	(2.33)	(7.1)

Limiting manual intervention to the market by the IESO is consistent with the general principles of market operation. According to the Market Rules:

> "*to the fullest extent possible consistent with maintaining the reliability of the IESO-controlled grid, the IESO shall apply the Market Rules relating to reliability so as to minimize the IESO's intervention into the operation of the IESO-administered markets. However, the maintenance of a reliable IESO-controlled grid shall be considered of paramount importance under these Market Rules, and the IESO shall have authority to intervene in the IESO-administered markets to the extent necessary to maintain the reliability of the IESO-controlled grid.*"[106]

[105] See the Panel's July 2008 Monitoring Report, pp. 171-180 for more details on the impact of the *ADQh* code on the unconstrained schedule.
[106] Market Rules, Chapter 5: Power System Reliability, section 1: Purposes, Interpretation and General Principles, section 1.2: General Principles

The Panel accepts that the IESO must take whatever actions it deems necessary to deal with the SBG conditions that threaten system reliability. But these actions should be structured so as to minimize any distortion of market signals.

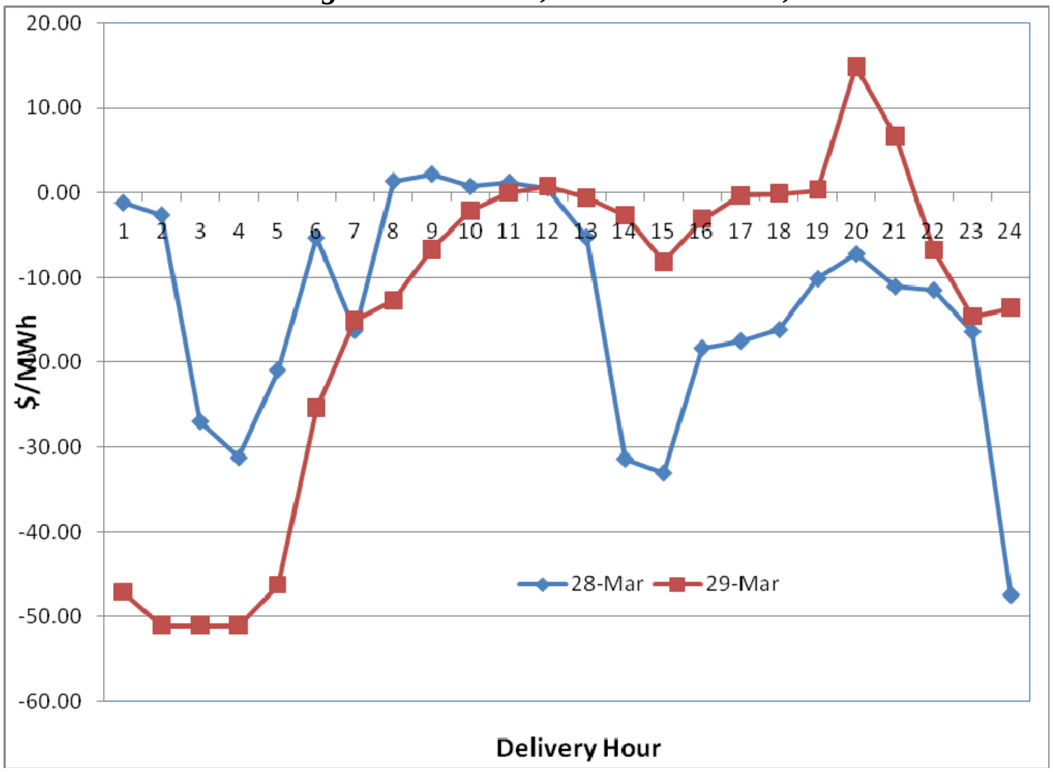
2.2.3 March 28 and 29, 2009

The HOEP reached a historic low of -$51.00/MWh in March 29, 2009 HE 2-4.

March 28 and 29 were two weekend days after one of two major transmission lines (PA302) on the New York interface went out of service. Another transmission line (BP76) had also been out of service since January 30, 2008. The historic low of HOEP of -$51/MWh occurred on March 28 in HE 2-4. The daily average HOEP reached -$13.42/MWh on March 28 and -$13.96/MWh on March 29, the lowest since market opening.

Figure 2-4 below plots the hourly HOEP on the two days. One can see that in most hours on both days, the HOEP was negative. The highest HOEP was only about $15/MWh on March 29 HE 20, while the lowest HOEP reached -$51/MWh on March 29 HE 2 to 4.

Figure 2-4: HOEP, March 28 and 29, 2009



This section will focus on the market situation around the hours with the lowest HOEP.

Prices and Demand

Table 2-29 lists the real-time and pre-dispatch information from March 28 HE 23 to March 29 HE 6. The HOEP varied from -$16.33/MWh to -$51.00/MWh. In these hours, Ontario Demand was low (slightly above 12,000 MW in most hours) and there was little or no export failure.

Table 2-29: MCP, Ontario Demand and Net Exports, Real-Time and Final Pre-dispatch
March 28, 2008 HE 23 to March 29, 2009 HE 6

Delivery Hour	Delivery Date	HOEP ($/MWh)	PD MCP ($/MWh)	Diff (HOEP-PD MCP) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
28-Mar	23	-16.33	-10.48	-5.85	13,498	13,969	682	759
	24	-47.37	-14	-33.37	12,750	12,926	708	759
29-Mar	1	-47.03	-30.6	-16.43	12,403	12,489	729	759
	2	-51.00	-51.00	0.00	12,162	12,279	759	759
	3	-51.00	-51.00	0.00	12,030	12,024	759	759
	4	-51.00	-51.00	0.00	12,013	11,912	759	759
	5	-46.21	-42.6	-3.61	12,162	12,268	817	758
	6	-25.38	-14	-11.38	12,492	12,647	829	758

Analysis

Day-Ahead Conditions

Table 2-30 lists the day-ahead information for the 8 hours. The Ontario Demand forecast at the time of the final DACP run was from 12,075 MW for March 29 HE 4 to 14,667 MW for March 28 HE 23. Only one coal-fired unit and three small gas-fired dispatchable units were scheduled at their minimums, providing a total of 230 MW of energy. The day-ahead supply cushion varied from 60 percent to 92 percent.

Table 2-30: Day-Ahead MCP, Demand and Supply Cushion
March 28, 2008 HE 23 to March 29, 2009 HE 6

Date	Hour	MCP ($/MWh)	Ontario Demand (MW)	Supply Cushion (percent)
28-Mar	23	0.00	14,667	60
	24	-10.00	14,007	67
29-Mar	1	-51.00	12,628	85
	2	-52.00	12,337	89
	3	-52.00	12,115	92
	4	-52.00	12,075	92
	5	-52.00	12,407	88
	6	-51.00	12,879	82

Pre-dispatch Conditions

Table 2-31 depicts the evolution of the PD price from 5 hours ahead to RT as well as the DACP prices. The DACP price was negative in most hours, with -$51/MWh or -$52/MWh on March 29 HE 1-6. From 5 to 1 hour ahead, the pre-dispatch MCP changed little for all hours except March 29 HE 6, indicating generally stable and predictable pre-dispatch supply and demand conditions over time.

Table 2-31: PD Price, HOEP and One Hour Ahead Supply Cushion March 28, 2008 HE 23 to March 29, 2009 HE 6, $/MWh

Hours Ahead	Delivery Hour							
	28-Mar		29-Mar					
	23	24	1	2	3	4	5	6
DACP	0.00	-10.00	-51.00	-52.00	-52.00	-52.00	-52.00	-51.00
5	-10.00	-13.00	-12.94	-51.00	-51.00	-51.00	-42.60	-14.00
4	-10.00	-13.00	-30.60	-50.60	-51.00	-51.00	-50.00	-25.00
3	-10.28	-13.00	-25.00	-51.00	-51.00	-51.00	-50.60	-14.00
2	-10.28	-14.00	-50.50	-51.00	-51.00	-51.00	-50.00	-14.00
1	-10.48	-14.00	-30.60	-51.00	-51.00	-51.00	-42.60	-14.00
HOEP	-16.33	-47.37	-47.03	-51.00	-51.00	-51.00	-46.21	-25.38
1 hour ahead Supply Cushion	20	28	32	35	39	41	38	33

The one-hour ahead supply cushion ranged from 20 percent to 41 percent.

When the transmission lines (PA301 and PA302) on the NYISO interface sequentially went out of service, the IESO forecast frequent SBG conditions for several days until the lines came back in service. [107] The outage on the two lines reduced the total export capability from about 4,200 MW to 655 MW on both the NYISO and MISO interface. In response, the IESO regularly contacted major market participants, informing them of the possibility of constraining down their generators based on their offers and preferences.

On March 28, three nuclear units at one station were dispatched down a total of 900 MW for most of the day because of the expected SBG situation.[108] In HE 24, the IESO's dispatch tool showed a further reduction on the fourth nuclear unit at the same station, leading to a total reduction of 1,200 MW at this nuclear station until March 29 HE 8.

[107] PA302 had a planned outage from March 24 to April 5, and then PA301 from April 5 to April 17.
[108] This was a manual limitation although much of the output may have been dispatched down automatically by the DSO. For operational reasons – not to cause the units to be frequently ramped up and down – the manual dispatch was applied.

Real-time Conditions

About 30 minutes before the real-time run for each hour from March 28 HE 23 to March 29 HE 2, 100 to 250 MW of exports failed on the MISO interface due to internal congestion in MISO. These export failures further aggravated the SBG condition, requiring further cuts of internal generation. To prevent such deep cuts, the IESO curtailed imports on the MISO interface by 70 to 199 MW, partially offsetting the export failures. These import curtailments were associated with an *ADQh* code.

On March 29 HE 5, 59 MW of imports failed on the MISO interface due to an incorrect NERC tag in Ontario. On March 29 HE 6, 100 MW of imports failed on the MISO interface due to ramp limitations in MISO and 29 MW of exports failed on the Quebec interface because of reliability problems in Quebec, leading to a net import failure of 71 MW. All intertie failures are listed in Table 2-32 below.

Table 2-32: Failed Imports/exports by IESO or MP Selected Hours, March 28 & 29, 2009 (MW)

		Failed Exports		Failed Imports		
Date	**Hour**	**Curtailed by IESO**	**Failed by MP or external ISO**	**Curtailed by IESO**	**Failed by MP or external ISO**	**Net Export Failure**
28-Mar	**23**	0	152	75	0	77
	24	0	250	199	0	51
29-Mar	**1**	0	100	70	0	30
	2	0	100	100	0	0
	3	0	0	0	0	0
	4	0	0	0	0	0
	5	0	0	0	59	-59
	6	29	0	0	100	-71

Table 2-33 below lists the real-time demand and supply in the hours under examination. Because export capability was limited, total demand (Ontario Demand plus net exports) was only around 13,000 MW in most hours. However, the total supply (capacity available from nuclear units and actual production from other generators) in those hours was all above 14,000 MW, which on average exceeded demand by more than 1,000 MW. Because all these generators offered at a negative price, a negative HOEP resulted.

Table 2-33: RT Demand and Supply
March 28, 2008 HE 23 to March 29, 2009 HE 6

Date	Hour	Demand			Supply					Difference (Supply-Demand) (MW)	RT Supply Cushion (percent)
		RT Peak Ontario Demand (MW)	Net Exports (MW)	Total Demand (MW)	Available Nuclear (MW)	Self-scheduling and Intermittent Generators (MW)	Baseload Hydro (MW)*	Others (MW)	Total Supply (MW)		
28-Mar	23	13,857	682	14,539	10,410	1,413	1,519	1,728	15,070	531	16
	24	13,063	708	13,771	10,410	1,418	1,639	1,267	14,734	963	15
29-Mar	1	12,509	729	13,238	10,410	1,451	1,641	955	14,457	1,219	19
	2	12,280	759	13,039	10,410	1,460	1,597	901	14,368	1,329	23
	3	12,074	759	12,833	10,410	1,430	1,599	916	14,355	1,522	24
	4	12,042	759	12,801	10,410	1,392	1,599	918	14,319	1,518	26
	5	12,242	817	13,059	10,410	1,326	1,648	891	14,275	1,216	26
	6	12,764	829	13,593	10,410	1,330	1,776	1,013	14,529	936	23

*Includes the Beck, DeCew, and Saunders stations.

As demonstrated in earlier sections, most generators in Ontario either have a contract with OPA or OEFC, or are subject to government regulation. As a result, some generators have various degrees of incentive to respond to market prices, and some have no incentive to do so. In these hours, those who were shielded from low market prices offered their energy deep into the money although they may have had a higher incremental production cost (such as gas-fired self-scheduling generators) than generators exposed to the market price. Conversely, those exposed to the market price offered at higher prices even though their incremental production cost may have been much less. While the true cost saving (avoided cost) of dispatching down these lower marginal cost generators may have been much lower, the IESO had no choice but to dispatch them down because their offer prices were higher.

Unfortunately during SBG situations, those who offered at relatively higher prices were nuclear generators, and as a result they were chosen to be dispatched down. Table 2-34 below lists the available nuclear capacity and their actual output showing that, in these hours, the output of nuclear units was reduced by about 1,000 MW to nearly 1,600 MW.

Because these units were manually dispatched down, the unconstrained sequence was not affected and the HOEP did reflect actual supply and demand conditions at the time.

Table 2-34: Constrained-down Nuclear Generation, MW Selected Hours, March 28 & 29, 2009 (MW)

Date	Hour	Available Nuclear	Output	Difference
28-Mar	23	10,410	9,384	1,026
	24	10,410	9,029	1,381
29-Mar	1	10,410	9,096	1,314
	2	10,410	8,989	1,421
	3	10,410	8,873	1,537
	4	10,410	8,830	1,580
	5	10,410	8,838	1,572
	6	10,410	8,984	1,426

Assessment

It is clear that the low price in these hours was mainly a result of abundant baseload supply relative to a low market demand (a lower Ontario Demand and a lower export due to the outage on the NYISO interface). The implications of the IESO actions and of the contracts of some of generators will be discussed in Chapter 3 section 3.4.

3. Anomalous uplifts

In the study period, there were five hours that trigger our bright line test for anomalous uplift.

- The hourly OR payment was greater than $100,000 on January 16, 2009, HE 8 and 9, and on February 18, 2009, HE 11 and 12.
- The hourly CMSC payment was greater than $500,000 on December 18, 2008, HE 9

On February 18, 2009, the CMSC was -$1 million on the NYISO interface, and -$1.6 million on the MISO interface, both resulted from a high HOEP in HE 11 and 12 and the control actions taken by the IESO to curtail exports. We discussed this event in section 2.1.4.

3.1 Anomalous OR

The higher hourly OR payment on January 16 (HE 8 and 9) and February 18 (HE 11 and 12) was a consequence of tight supply and demand conditions. As we discussed in section 2.1.3 and 2.1.4, the HOEP was above $200/MWh in these hours.

3.1.1 January 16, 2009 HE 8 and 9

Before HE 8, there was a loss of 840 MW of generation and an additional 400 MW of generation was lost within the hour. The RT peak demand was also 820 MW greater than forecast one-hour ahead.

Table 2-35 below lists the interval energy and OR MCP in HE 8 and 9. From HE 8 interval 12 to HE 9 interval 2, there was a shortage of OR and OR prices were $1,998.00/MWh in each interval. In each of these three intervals, the OR payment was above $100,000, which brought the total OR payment to $151,628 in HE 8 and $298,747 in HE 9.

Table 2-35: Energy and OR MCP, January 16, 2009 HE 8 and 9

Hour	Interval	Energy ($/MWh)	10N ($/MWh)	10S ($/MWh)	30R ($/MWh)	Total OR Payment ($)
8	1	76.79	30.00	30.00	30.00	3,260
8	2	99.84	30.00	30.00	30.00	2,734
8	3	105.12	30.00	30.00	30.00	2,427
8	4	245.55	75.00	75.00	75.00	5,569
8	5	350.12	100.00	100.00	100.00	5,839
8	6	600.00	100.00	100.00	100.00	3,902
8	7	245.54	75.00	75.00	75.00	2,229
8	8	329.44	100.00	100.00	100.00	2,356
8	9	250.12	100.00	100.00	100.00	6,481
8	10	270.54	100.00	100.00	100.00	6,126
8	11	270.54	100.00	100.00	100.00	5,808
8	12	1,998.00	1,998.00	1,998.00	1,998.00	104,897
Average/Total		**403.47**	**236.50**	**236.50**	**236.50**	**151,628**
9	1	1,998.00	1,998.00	1,998.00	1,998.00	110,907
9	2	1,998.00	1,998.00	1,998.00	1,998.00	114,038
9	3	190.12	100.00	100.00	100.00	6,000
9	4	150.13	75.00	75.00	75.00	6,825
9	5	180.00	100.00	100.00	100.00	8,612
9	6	175.12	100.00	100.00	100.00	8,417
9	7	190.12	100.00	100.00	100.00	8,493
9	8	190.12	100.00	100.00	100.00	8,658
9	9	150.13	75.00	75.00	75.00	6,082
9	10	150.12	75.00	75.00	75.00	5,907
9	11	150.12	75.00	75.00	75.00	6,340
9	12	175.12	100.00	100.00	100.00	8,468
Average/Total		**474.76**	**408.00**	**408.00**	**408.00**	**298,747**

3.1.2 February 18, 2009 HE 11 and 12

As discussed in section 2.1.4, HOEP was very high in these hours because of the outage of a transmission line and subsequent outage or de-rating at two fossil-fired generators. Higher-than-forecast real-time demand also contributed to the high HOEPs.

In most intervals of the two hours, there were shortages in OR supply, leading to an OR price of $1,999.00/MWh, as shown in Table 2-36 below. In 11 out of the 17 shortage intervals, the OR payment was considerably greater than $100,000.

Table 2-36: Energy and OR MCP, February 18, 2009 HE 11 and 12

Hour	Interval	Energy ($/MWh)	10N ($/MWh)	10S ($/MWh)	30R ($/MWh)	Total OR Payment ($)
11	1	44.24	0.20	0.20	0.20	22
11	2	44.30	5.72	5.72	5.72	630
11	3	44.51	8.76	8.76	8.76	721
11	4	74.12	30.00	30.00	30.00	2,967
11	5	80.18	5.72	5.72	5.72	673
11	6	183.91	21.87	33.91	21.87	1,764
11	7	1,999.99	1,999.99	1,999.99	1,999.99	143,217
11	8	1,999.99	1,999.99	1,999.99	1,999.99	104,443
11	9	1,999.99	1,999.99	1,999.99	1,999.99	28,602
11	10	1,999.99	1,999.99	1,999.99	1,999.99	87,534
11	11	1,999.99	1,999.99	1,999.99	1,999.99	77,660
11	12	1,999.99	1,999.99	1,999.99	1,999.99	101,662
Average/Total		**1,039.27**	**1,006.02**	**1,007.02**	**1,006.02**	**549,895**
12	1	1,999.99	1,999.99	1,999.99	1,999.99	81,364
12	2	1,999.99	1,999.99	1,999.99	1,999.99	80,416
12	3	1,999.99	1,999.99	1,999.99	1,999.99	93,466
12	4	1,999.99	1,999.99	1,999.99	1,999.99	114,833
12	5	1,999.99	1,999.99	1,999.99	1,999.99	146,601
12	6	1,999.99	1,999.99	1,999.99	1,999.99	153,229
12	7	1,999.99	1,999.99	1,999.99	1,999.99	165,247
12	8	1,999.99	1,999.99	1,999.99	1,999.99	167,581
12	9	1,999.99	1,999.99	1,999.99	1,999.99	158,581
12	10	1,999.99	1,999.99	1,999.99	1,999.99	144,463
12	11	1,999.99	1,999.99	1,999.99	1,999.99	143,063
12	12	693.78	100.00	111.48	100.00	8,578
Average/Total		**1,891.14**	**1,841.66**	**1,842.61**	**1,841.66**	**1,457,422**

3.2 Anomalous CMSC

The hourly CMSC payment was $516,000 or $26.49/MWh on December 18, 2008, HE 9. The HOEP was only $56.66/MWh.

The high CMSC payment was induced by a forced outage on a major transmission line that links the Ontario and MISO. On that day, line L4D was on a planned outage. In the middle of HE 8, another major line L51D was also forced out of service due to problems on the MISO side. The outage immediately led to thermal overload violations on the remaining two transmission lines (B3N and J5D).

In response, the IESO curtailed all 1,050 MW of exports on the MISO interface and 510 MW of exports on the NYISO interface. The curtailment of exports on the NYISO interface was necessary as a result of the Lake Erie Circulation effect. Some of energy scheduled to NYISO would have physically flowed through the MISO interface to NYISO, and further aggravated the congestion on the MISO interface. To relieve the congestion on the MISO interface, cutting some of exports to NYISO was considered necessary.

Because these curtailed exports were associated with a *TLRi* code, they were eligible for constrained off payment. In the hour, a total of $480,000 was pay to exporters for the 1,560 MW of curtailed exports.

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Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This Chapter summarises changes in the market related to matters discussed in the Panel's last report that impact the efficient operation of the IESO-administered markets. It also identifies and discusses new developments arising in the marketplace.

Section 2 identifies material changes that have occurred since our last report related to matters discussed in that or prior reports. This section includes four issues:

- After NYISO banned the linked wheeling from NYISO to PJM through Ontario, exports from Ontario to PJM increased significantly. In this section we expand our previous analysis and undertake a more detailed study on the implications of these increased exports for the Ontario market.
- OPG has implemented a series of strategies to contain its CO_2 emissions to meet the 2009 target set by the Government of Ontario. This section summarizes the current outcomes and their implications for the market.
- We provide updated information on a market participant's response to environmental issues.
- Finally, we discuss the further activity under OPA's DR 3 program.

In Chapter 3 the Panel comments on new issues arising:

- Allocation of common costs in cost guarantee programs.
- Consequences of an incorrect Daily Energy Limit (DEL) at hydroelectric generators.
- Implications of the changes to payment schedules for OPG's nuclear and regulated hydroelectric assets approved by the Ontario Energy Board (OEB) in November 2008.
- Increased incidents of Surplus Baseload Generation (SBG) in the recent months.

2. Changes to the Marketplace since the Panel's Last Report

2.1 *Increased Exports from Ontario to PJM*

In our July 2008 and January 2009 reports, we observed that linked wheeling transactions through Ontario, especially transactions from New York to PJM, began to increase dramatically in January 2008 but then dropped to zero beginning July 22, 2008 when the NYISO prohibited these transactions (as well as linked wheeling transactions on other 7 paths).[109] About the same time that linked wheeling transactions from New York to PJM (through Ontario) started to increase, exports from Ontario to PJM (through MISO) also significantly increased. Since the NYISO prohibition, exports from Ontario to PJM through MISO have further increased.

Following NYISO's prohibition on July 22, 2008, the U.S. Federal Energy Regulatory Commission (FERC) initiated an investigation of the situation. On July 16, 2009 FERC adopted and released a staff report that found no market manipulation or other wrong doing on the part of market participants related to the linked wheel transactions in the first half of 2008, although it did identify a need to find solutions to the 'loop flow problem', which was exacerbated by such transactions.[110]

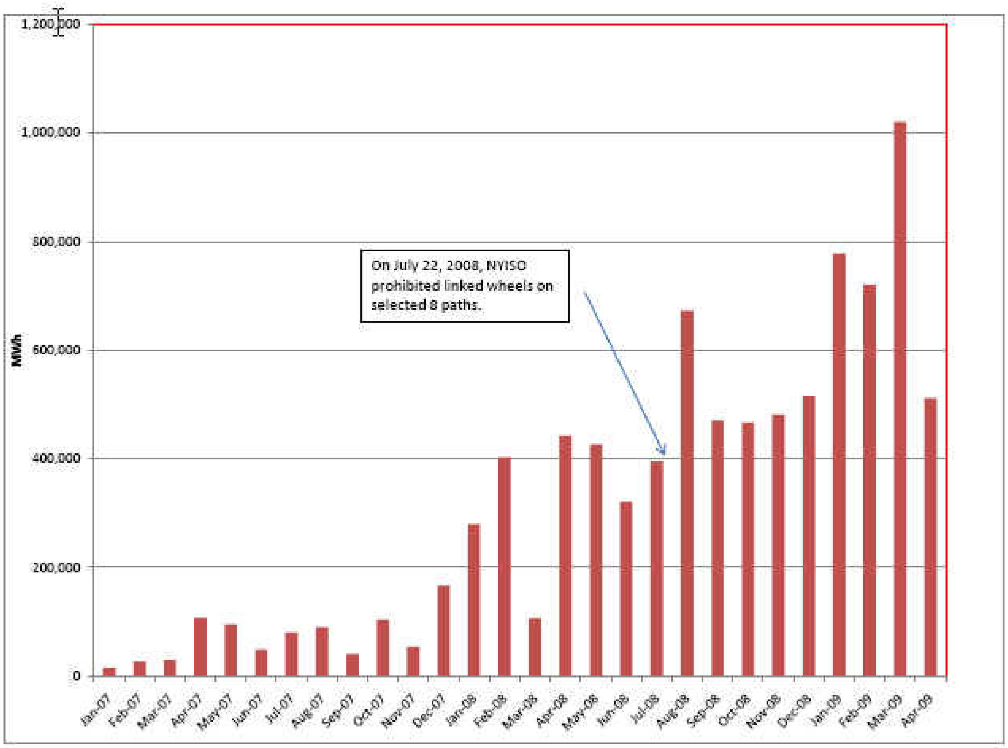
At the Panel's request, the MAU has been monitoring the Ontario/PJM transactions and their impact on the Ontario market. Below we examine the implications of these export transactions and their associated parallel path flows, addressing the following questions, among others:

i) How are these flows being modeled in the IESO's scheduling tools?
ii) Do these flows exacerbate congestion while not being charged for this?

[109] For a detailed discussion on how these linked wheel transactions were induced and why NYISO prohibited transaction on 8 selected paths, see the Panel's July 2008 Monitoring Report (pp. 164-171) as well as our January 2009 Monitoring Report (pp. 193-197) and the NYISO submission to FERC on July 21, 2008, available at http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2008/07/nyiso_exgnt_crcmstnc_extrnl_trnsctns_7_21_09.pdf.
[110] See "Order Authorizing Public Disclosure of Enforcement Staff Report and Directing the Filing of an Additional Report", 128 FERC ¶ 61,049, July 16, 2009. The staff report includes a discussion of the causes and consequences of Lake Erie loop flow.

As shown in Figure 3-1 below, on a year-over-year basis, exports to PJM this winter period reached about 4.03 TWh, 178 percent higher than the 1.45 TWh last winter. In March 2009, exports from Ontario to PJM reached a record monthly high of 1.02 TWh, and then dropped to 0.5 TWh in April 2009 when export capability on the MISO/Ontario interface was significantly reduced as a result of planned outages at two major transmission lines on the NYISO/Ontario interface. Diminished transmission capability with New York simultaneously reduces export capability on the MISO/Ontario interface because a percentage of an export to MISO (including those destined for PJM) physically flows across the NYISO/Ontario interface, as will be illustrated below. If exports through the MISO/Ontario interface were not restricted, the NYISO/Ontario interface would have become congested requiring IESO to re-dispatch generation (likely sub-optimally) to avoid this.

Figure 3-1: Exports from Ontario to PJM through MISO



Parallel Path Flows and Lake Erie Circulation

Electricity flows in a network along all available paths (also called parallel paths) between the points of injection (generation) and the points of consumption (loads). Transactions arranged between entities such as IESO, MISO or PJM, would flow from the generation source in an area designated to support the sale, to the point of consumption in another area. That means an export from Ontario to eastern PJM, for example, would partially flow across Ontario's interconnections with Michigan and partially across the interconnections with New York.

The same is true for other transactions in the grid, which means, for example, that some portion of exports from MISO to PJM would also flow across the Michigan intertie with Ontario, through Ontario and out the Ontario intertie with New York, continuing from there along various paths to PJM. All these external transactions induce flows in Ontario, sometimes causing a net flow from Michigan to New York, and sometimes in the opposite direction. The distribution of these physical flows is a function of the 'impedances' of the parallel lines (paths) between all the generators producing the electricity and all the loads consuming it.

When transactions are scheduled between jurisdictions, there is an assigned path, called the 'contract path' which assumes that 100 percent of the transaction is flowing along that path. The difference between the scheduled amount and actual flow is referred to as 'unscheduled flow'. The industry has given a specific name to the unscheduled flows for energy flowing near Lake Erie, i.e. Lake Erie Circulation (LEC). When contracted and actual flows differ in the form of more energy than contracted flowing from Michigan to New York through Ontario, it is referred to as positive LEC or clockwise (CW) LEC. Net energy flows in excess of contracted volume in the opposite direction from New York towards Michigan are negative LEC or counter-clockwise (CCW) LEC. Flows which differ from the contract path are also referred to as 'loop flow'.

Loop flows are also induced by the electricity flow from generation in a given area to the load in the same area. For example, energy from generators in Ontario near Windsor and Sarnia would flow mostly through Ontario to the load centre (near Toronto), but a portion would also flow south of Lake Erie, exiting at the intertie with Michigan and re-entering Ontario at the New York intertie. The flow out of and then back into Ontario is not scheduled. Similar effects occur for generation in other areas. Such flows also contribute to observed loop flows and LEC.

Parallel path flows can be controlled with special transformers called phase shifters. There are a number of phase shifters at IESO interties with New York at Cornwall, with Michigan near Windsor, Minnesota at Fort Frances, and Manitoba at Whiteshell. New phase shifters are anticipated to come in-service at the Michigan intertie near Sarnia by the end of 2009. Once in-service, up to 600 MW of LEC will be controllable.[111] Parallel path flows can also be controlled using back-to-back direct current (DC) technology[112] such as the new interconnection with Quebec at Ottawa, which came in-service July 2, 2009.

The increase in exports to PJM is an important issue for Ontario because these exports flow on both the NYISO/Ontario and Michigan/Ontario interfaces. As is the case in other markets or jurisdictions, the market participant chooses a contract path for transactions between markets or jurisdictions. The contract path assumes that the entire transaction flows into the neighbouring jurisdiction across the interconnection between them, Thus for an IESO export to PJM, the 'Contract Path' is from Ontario through Michigan (MISO) to PJM, even though a large portion flows out at the New York interface. Depending on the jurisdiction, however, scheduling models and pricing of transactions may differ from the contract path assumption.

IESO's scheduling model for the unconstrained sequence begins by assuming that 100 percent of an export or import flows across the intertie scheduled as the contract path,

[111] See the Panel's December 2007 Monitoring Report, pp. 146 – 151, which contained recommendations to the IESO and Hydro One to take actions necessary to allow operation of these phase shifters.
[112] A back-to-back DC connection converts the AC power to DC, then reconverts this back to AC. This process allows the flow to be controlled, but with some energy loss.

while the constrained sequence allows for some parallel flows (as explained later). Recognizing that discrepancies can arise between the actual physical flows and the modeling assumptions, both the unconstrained and constrained sequences apply adjustment factors to account for some of the differences. Below, we explore how exports to PJM flow and the extent to which these flows are taken into account by the IESO's tools.

Power Flows for Exports to PJM

All transactions between southern Ontario and the U.S. as well as those between or within MISO and PJM induce Lake Erie Circulation with some transactions causing clockwise flows and some counter-clockwise. The net effect is what is measured as LEC. In the following discussion we focus on that portion induced by exports from Ontario to PJM. Figure 3-2 below illustrates how the LEC loop-flow is caused by an export to PJM through MISO. In Ontario, for example, an export of 100 MW may be scheduled to flow fully out the MISO/Ontario intertie, according to its contract path (through MISO to PJM), which is represented by the black line with an arrow. However, a portion of the physical flow of power (let's assume 40 MW) flows through NYISO. The difference between the contract quantity and the actual flow (40 MW) is a measure of the LEC associated with this transaction. In this example, the LEC is clockwise.

Figure 3-2: Contract and Physical Path of Exports to PJM through MISO

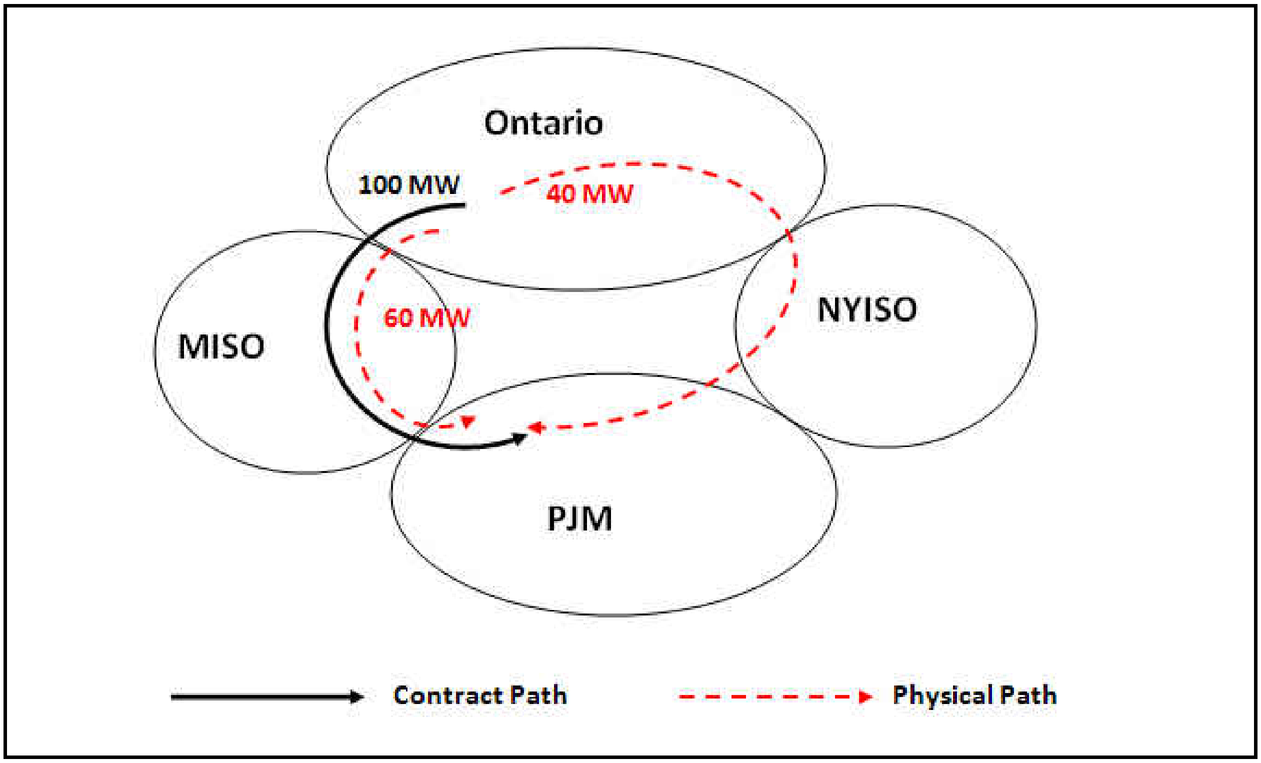
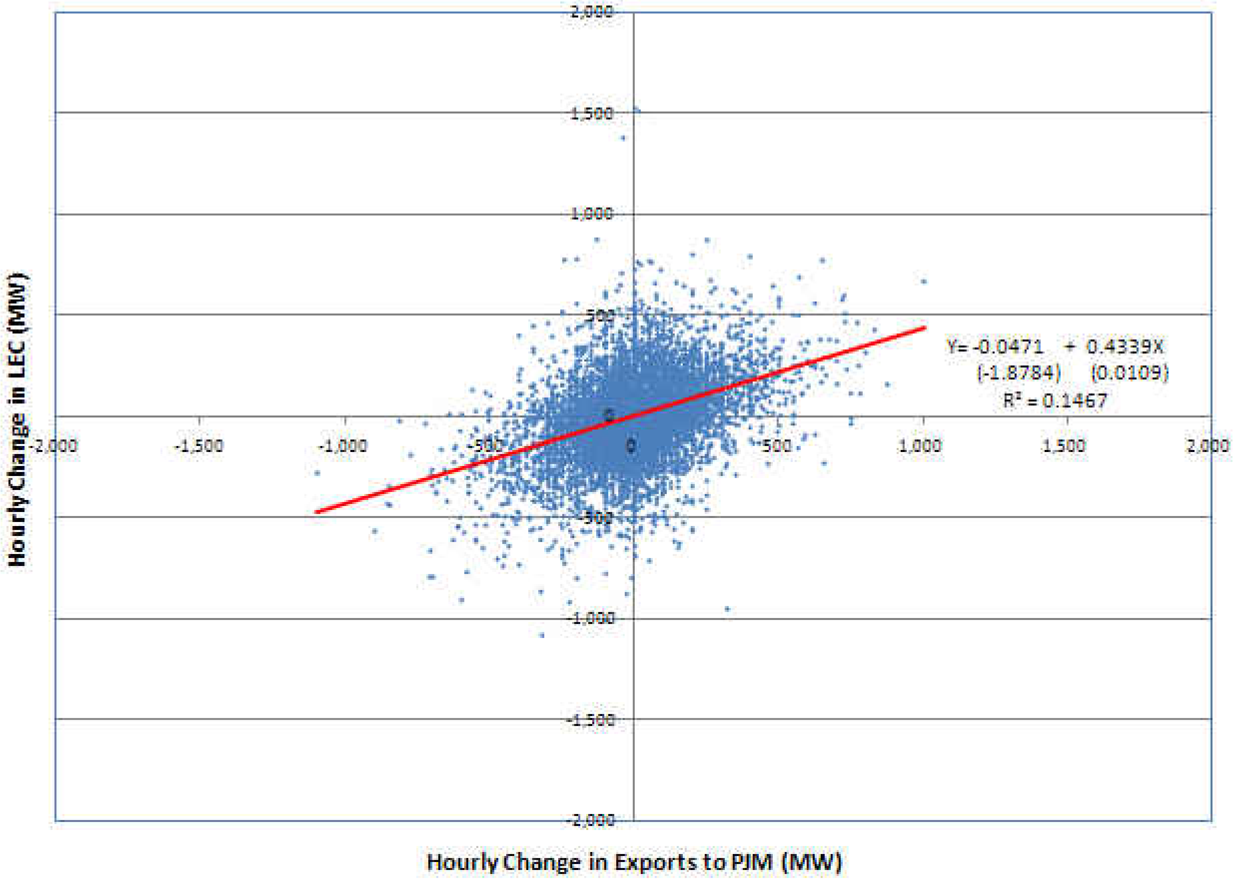


Figure 3-3 below plots the hourly change in the schedules to PJM through MISO against the hourly change in the measured LEC at the NYISO/Ontario interface.[113] The scatter of points on the graph implies a linear relationship between the change in exports to PJM and the change in the LEC. Based on the data from January 1, 2008 to April 2009, roughly 43 percent of exports to PJM through MISO (the contract path) actually go through NYISO and the remaining 57 percent go through MISO. While this simple model does not attempt to specify all other potential factors influencing actual LEC (e.g. loop flow from other transactions external to and within Ontario), the 95 percent confidence interval around the 43 percent estimate implies that the actual split to NYISO probably lies within two percentage points of this estimate. [114]

[113] For this analysis, we are measuring LEC as the difference between actual and scheduled flows across the New York interface.
[114] The actual share of exports to PJM going through NYISO could be as low as 41% and as high as 46% based on a 95% of confidence level. While the percentage of the variation in the LEC explained by the model is relatively low, the unexplained variation may or may not be systematic. Other factors that could affect the relationship include scheduled transactions between all interconnected jurisdictions (especially IESO, MISO, PJM, and NYISO), internal generation within each jurisdictions, use of the phase-shifters, transmission capability between and within jurisdictions, etc.

Figure 3-3: Relationship of LEC and Exports to PJM through MISO
January 1, 2008 to April 30, 2009



The IESO has explained that within the NERC Interchange Distribution Calculator (IDC), which is used for reviewing the impact of external transactions, the distribution is roughly a 50-50 split.[115] The regression above indicates that the modeling assumptions are relatively close to the observed average hour-to-hour changes. While estimates of the percentage of exports to PJM that flows out at the NYISO intertie vary and the actual percentage depends on a variety of factors, the basic point is that this percentage is substantial.

[115] Through direct communications from the IESO, the MAU is informed that the current IDC model shows a 53 percent flow across the New York intertie for Ontario to PJM transactions, but this can change for different assumptions, such as line outages, unit commitment in the underlying grid model. However, the value is also quite sensitive to the assumed source for the energy sold, e.g. whether from Lambton at the Michigan border or Beck at the New York border.

Why loop flow is an issue – the NYISO experience

The Panel's interest in PJM exports and linked wheels through Ontario arises from the experience of NYISO in 2008 when high congestion costs were incurred as a result of large quantities of exports out of New York scheduled through Ontario and MISO with the destination being PJM.[116] A large portion (about 80 percent) of the actual flow was directly from New York to PJM. The difference between actual and contract flows added to the congestion in New York and imposed significant congestion costs on New York consumers. This provided profit opportunities for traders because the export price from New York and transmission costs along this contract path tended to be lower than the PJM import price.

The NYISO (like the IESO and ISO-NE) prices its "external transactions based on the path over which a transaction is scheduled into or out of [the Control Area]. ... NYISO does not consider the originating source of an import or ultimate sink of an export."[117] This means that an export transaction between NYISO and the IESO, even one whose ultimate destination is PJM, is priced as if the most of the actual flow is across the path between NYISO and the IESO. Actual flows for an export to PJM are better reflected in the modeling applied by NYISO when a transaction is scheduled directly between NYISO and PJM, with about 80 percent flowing directly over the interconnections between NYISO and PJM.

"NYISO's real-time software continually re-dispatches internal generation in response to actual power flows and real-time transmission constraints… [NYISO] incurs additional congestion related costs when actual power flows include unscheduled power flows that exacerbate internal [New York] west-to-east transmission constraints."[118] Studies performed by NYISO indicate that on one day analyzed, exporters were charged $80/MWh to take power out of New York when scheduled through Ontario, rather than the $100/MWh price they would have been charged for a direct transaction to PJM. This

[116] See the Panel's January 2009 Monitoring Report, pp. 193-197.
[117] New York ISO "Exigent Circumstances Filing" July 21, 2008, p. 5.
[118] *Ibid*, pp. 7-8.

assessment indicated that "market participants scheduling transactions over the circuitous scheduling path around Lake Erie are not being assessed the full congestion cost … [To] the extent that [these transactions] would not be profitable if the market participant had to pay the true congestion cost …, the scheduling of these transactions is inefficient."[119]

By implication from the New York experience, the IESO may have cause for concern if:

i) exports (or more generally any transactions) take place whose actual flow path differs significantly from the contract path;

ii) those transactions flow across significantly congested paths; and

iii) the pricing of those transactions does not reflect the actual congestion.

As an example, consider a situation where there are high prices in Ontario and an import flows from PJM to Ontario, scheduled through MISO but with a large portion of the import quantity actually flowing through New York. This is an unlikely situation given current congestion and pricing, but it illustrates the issue. In the unconstrained pre-dispatch, the import would be modeled as entering Ontario at the Michigan intertie only, and offsets gas-fired generation, assumed to be at the margin and which happens to be in southwestern Ontario (near Windsor). The import gets a price close to the offset gas price, assuming no significant changes in real-time. However, with a large portion of the import flowing into Ontario at the New York intertie, it will load transmission from the Niagara area to the rest of the province (Queenston Flow West or QFW). Typically there is sufficient transmission to accommodate this unless an outage has reduced the QFW flow limit. Given that the import is fixed going into real-time, assume it flows and uses up, say 100 MW, of the QFW allowed flow (potentially exceeding its limit). (Assume further this was not observed in pre-dispatch which may have caused the import to be constrained off.) Because of the 'unexpected' 100 MW flow, some other generation must be reduced to reduce flow on QFW and ensure the QFW limit is respected. This could mean backing down 100 MW of Beck generation[120] and then increasing 100 MW of gas-fired generation elsewhere to balance the total required supply. In this case, the use of congested internal transmission (QFW) that was not modeled in pre-dispatch leads to a

[119] *Ibid*, p.18.
[120] Actually more than 100 MW since a fraction flows south of Lake Erie.

portion of the import reducing less expensive Beck hydro generation, rather than the expected offset of gas-fired generation. This adds to the congestion cost, but since importers do not pay uplift (which includes congestion management costs) there is no charge to the importer for using the congested transmission.[121]

Above, we have discussed how Ontario to PJM exports flow on paths quite different from the contract path. Below, we review how the IESO models transactions and unscheduled flows, and whether unscheduled flows exacerbate congested transmission paths.

IESO Modeling of Transactions

Imports and exports are scheduled in the pre-dispatch process based on bids and offers, with successful transactions treated as fixed quantities in real-time. Pre-dispatch modeling differs in the unconstrained and constrained sequences. Imports and exports are fixed quantities in both the constrained and unconstrained real-time sequences, based on the pre-dispatch schedules (although these may be manually modified as necessary by the IESO).

For the unconstrained pre-dispatch sequence, a transaction is assumed to be injected or withdrawn from the grid at the intertie point (along the contract path), with the net flow into or out of the intertie point limited by the projected capability of the intertie to support transactions. The intertie is considered to be a radial connection i.e. with a single link to Ontario and no links elsewhere, which means the entire scheduled quantity is treated as flowing across the intertie.

Because loop flows utilize some of the capacity of an intertie, its actual net scheduling capability may be diminished (for unscheduled flows in that direction) or increased (for unscheduled flows in the opposite direction). The resulting net schedule plus unscheduled flow must respect the intertie scheduling capability. Scheduling around

[121] Importers would only pay for congestion at the interties as determined in the unconstrained sequences. In the IESO market, importers and generators do not pay the hourly uplifts which include components for losses, (internal) congestion management (CMSC), operating reserve and the intertie offer guarantee IOG). See Chapter 1 section 2.5. The first two components, for losses and congestion, would be implicitly charged if nodal pricing were used in Ontario as opposed to uniform pricing.

these loop flows implies that the IESO may need to modify its own transactions recognizing that uncontrollable flow (essentially other unscheduled users) are using its intertie capability. The IESO schedules transactions at its interties accounting for these uncontrollable flows, and, if necessary, it invokes NERC Transmission Loading Relief (TLR) procedures to cut other (controllable) transactions in real-time if actual flows exceed limits along any of its critical transmission interfaces.[122]

In summary, the IESO projects uncontrollable loop flow[123] and if this represents a significant impact on intertie limits, it may modify the effective net intertie scheduling limits to apply in pre-dispatch.

This treatment of the scheduling limits means that the IESO's unconstrained sequence recognizes a portion of externally-induced unscheduled flows. Another component of the projected uncontrollable loop flow would be associated with IESO's own imports and exports based on what is observable through the NERC's IDC tool, modified by the IESO for anticipated changes over the coming hours.

The process for dealing with loop flows is different and more complicated for the IESO's constrained pre-dispatch sequence. The underlying differences are due to two assumptions: i) the source or sink for the transaction is outside Ontario and; ii) the transactions flow along multiple (parallel) paths. The source or sink is a pre-determined location within the control area of the directly-connected neighbour, i.e. in Michigan or New York. In other words, the destination for an export scheduled to PJM through MISO, is assumed to be in MISO.

The constrained pre-dispatch sequence also models actual flows, but does this through a two-part process. One portion of actual flow is modeled dynamically while a second

[122] Typically the IESO invokes NERC's TLR3a procedure, which cuts external non-firm transactions with unscheduled flows across IESO's critical interfaces (referred to as 'Flowgates'). This leaves unaffected flows associated with Firm transactions elsewhere (i.e. which have Firm transmission rights, which some other jurisdiction may be relying on to meet its requirements). On occasion, if necessary, the IESO would invoke TLR procedures that could cut Firm transactions a s well. See NERC Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief. http://www.nerc.com/files/IRO-006-4.pdf

[123] The IESO uses the NERC Interchanges Distribution Calculator (IDC) to identify what transactions may be controllable or uncontrollable, and based on anticipated changes for the scheduling hour, projects uncontrollable flows through Ontario in a given hour.

portion is based on a projection of the flow. This means that an additional MW of exports (e.g. to MISO) would induce incremental flows on multiple paths between the marginal generating sources in Ontario and the assumed sink in MISO, thereby dynamically affecting internal transmission flows as well as flows across both the New York and Michigan interconnections. However, since these features of the scheduling tools do not capture the impact of external flows, the IESO still projects uncontrollable flows associated with external transactions. This projection is entered into the constrained sequence as a parameter called 'Loop Flow' which is added to the above-mentioned dynamically determined flows on transmission throughout southern Ontario, not just at the interties.

One limitation of the above modeling procedure is the assumption of the same sink in MISO for exports whether their actual sink is in MISO or PJM. That means that the dynamically determined flows for an export to PJM may be a poor approximation of actual flows. Since loop flows across the New York intertie for a MISO export are less than for a PJM export, the dynamic impact of PJM exports flowing out at the New York interconnections is understated. The IESO may anticipate this difference and could also include it in its Loop Flow parameter.

Thus, in both its unconstrained and constrained sequences the IESO treats transactions as originating or terminating in the immediate neighbouring jurisdictions, whether at the interconnection itself (as in the unconstrained sequence) or within the neighbouring area (in the constrained sequence). Both sequences also account for uncontrollable loop flows including loop flows from IESO imports and exports, although to a different degree and with the constrained sequence modeling the impacts of imports and exports dynamically. The latter difference is important. With dynamic modeling in the constrained sequence, an export to PJM (assumed to be MISO) may be constrained off if its clockwise flow contributes to congestion within Ontario or at the New York interface. On the other hand, the pricing for transactions is based on the unconstrained sequence which does not dynamically capture the loop flow associated with the transaction. This means that even though an export to PJM may partially flow across the New York intertie and contribute to intertie congestion there, this incremental congestion is not observed in the pricing applied to the export at the Michigan intertie.

The implications of these modeling features with respect to exports to PJM are addressed below. We look specifically at how these exports contribute to real-time congestion (in the constrained sequence) and the need to re-dispatch generation for internal congestion.

Internal Congestion and PJM Exports

Although there may be other factors contributing to loop flow, the Panel would be concerned if the significant loop flow for exports to PJM implied use of internally congested transmission, particularly if this induced an increase in congestion payments (CMSC) that were only partly charged to the export.

As noted earlier (see the regression analysis discussed above) about 43 percent of an export to PJM flows out at the Niagara intertie even though it is treated as flowing out entirely at Michigan (in the unconstrained schedule). In the constrained pre-dispatch with an assumed Michigan destination, some loop flow would be recognized dynamically, with an additional component of the clockwise flow potentially captured through the IESO projection of the Loop Flow parameter. With the loop flow from west to east through southern Ontario, one question that can be asked is whether there is internal congestion in real-time that is being exacerbated by the loop flow. This can be assessed by determining if there is significant congestion on flows between Ontario's borders with Michigan and New York.

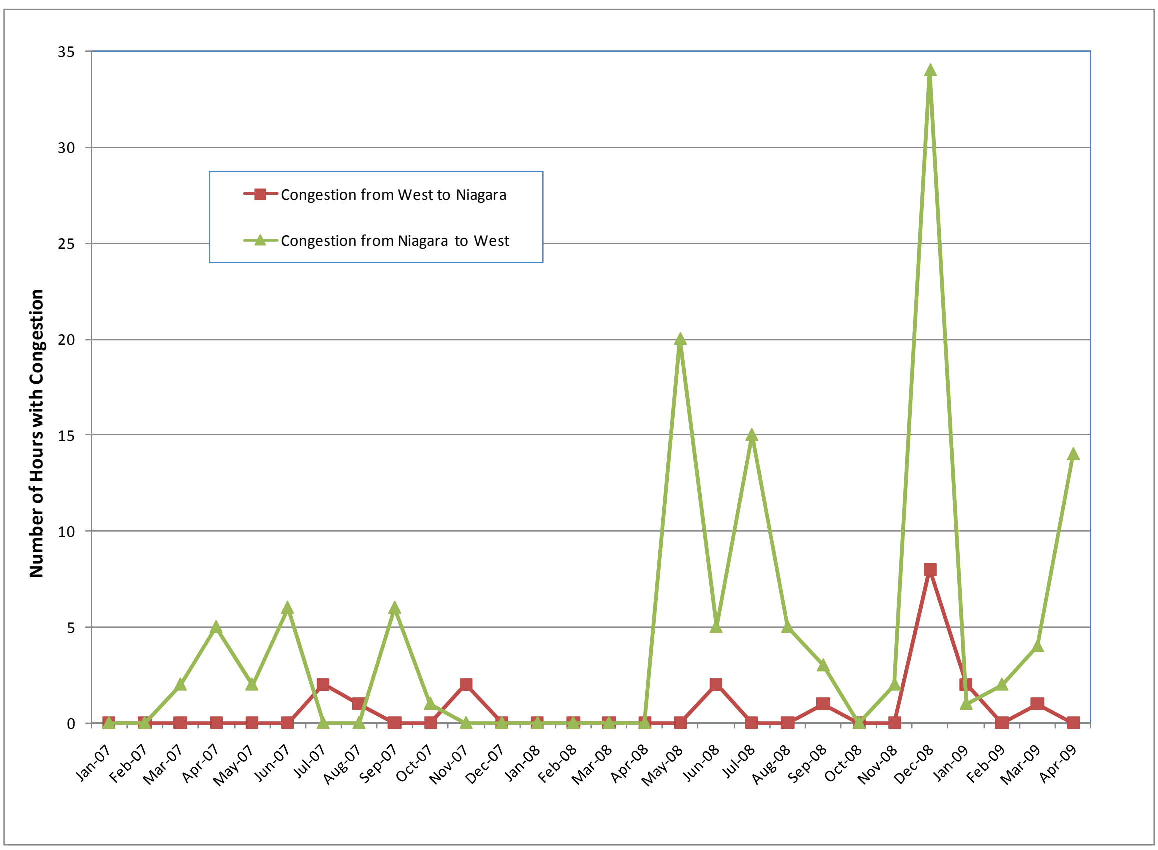
There are two major internal interfaces in southern Ontario that could become congested – the Buchanan-Longwood input (BLIP is flow near London) and QFW (mentioned earlier, as a limit on flow in the Niagara area).[124] There may be some other local limits as well. One simple way to identify if there is congestion in southern Ontario is to look for differences between the nodal prices in the Windsor / Lambton area and the Niagara /

[124] BLIP is a limit on flows west, while negative BLIP is a limit on flows east. QFW is a limit on flow west out of the Niagara area.

Beck areas respectively. Any significant congestion at any interface between these two locations would be observable as a material difference in the nodal prices.

Figure 3-4 below shows the number of hours of congestion monthly between the West zone (near the Michigan border) and the Niagara zone (near the New York border) in both directions.[125] Table 3-4 shows the monthly total number of hours with congestion in both directions. For this assessment, the transmission is considered congested from the Western zone to the Niagara zone if the median shadow price in the Niagara zone is at least 5 percent greater than the median shadow price in the Western zone. Similarly congestion from the Niagara zone to the Western zone would exist if the median shadow price in the Western zone is at least 5 percent greater than in the Niagara zone. [126]

Figure 3-4: Congestion between the West Zone and Niagara Zone
January 2007 to April 2009
Number of Hours per Month



[125] These are the same zones as included in the Chapter 1 discussion of nodal prices (Figure 1-13).
[126] We assume 5% as a basis for identifying significant nodal price differences, recognizing that losses can induce small differences, typically on the order of 1to 2 percent.

Between January 2008 and April 2009, congestion in either direction was higher than in 2007 but still only occurred on average about 1 percent of total hours. It appears that there was generally more counter clockwise congestion (for flows from Niagara to the West zone) than clockwise congestion (from the West to Niagara) although the number of hours for each is fairly small. In only one month, December 2008, did clockwise congestion occur for more than 2 hours, when it reached 8 hours that month (about 1 percent of total hours in the month. (These results are consistent with the average zonal prices shown in Table 1-21 being quite close, with Niagara prices tending to be marginally lower.)

The finding of only a few hours of internal congestion, in either direction, suggests that PJM exports, and more generally other imports and exports from Ontario, are typically not exacerbating internal congestion.

Congestion of Interties

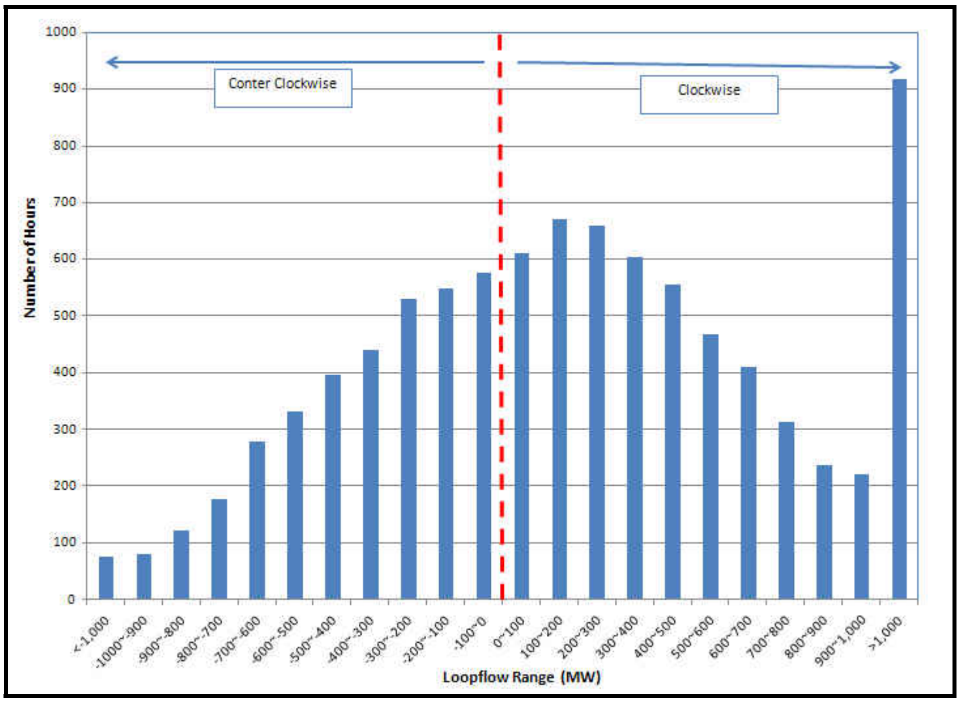
One limitation of the above assessment is that some actions, such as re-dispatching generation or constraining off exports or imports because of loop flows, can lead to an appearance of 'no problem' after the control action is taken.

The conclusion that there has been little internal congestion is also somewhat at odds with the fact that since January 2008 clockwise (positive) Lake Erie circulation has been large and fairly common, and that in recent months the IESO has frequently been invoking the NERC TLR procedure, mostly in the early morning or at the end of the day, because high clockwise Lake Erie Circulation was causing intertie flows to be near their limits.[127]

[127] In addition, since May 2009, the NYISO has invoked TLRs because of loop flows on their system near the Ontario border, which has led to cutting substantial portions of IESO to PJM exports.

Figure 3-5 shows the frequency distribution for LEC[128] in aggregate from January 2008 to April 2009 (excluding about 3 months July to Sept 2008 due to missing data). Positive values represent clockwise LEC. The figure shows that LEC exceeded 1000 MW for more than 900 hours (or about 10 percent of the time). Loop flow was clockwise 62 percent of the time and counter clockwise 38 percent of the time.

Figure 3-5: Frequency Distribution of Lake Erie Circulation January 2008 to April 2009 (excluding July – September 2008) Number of Hours



Frequent use of the TLR procedure by the IESO implies that it was common for flows to be near Ontario flowgate limits and that the IESO required external transactions to be cut to reduce the impact of their induced loop flows. Many of the TLRs invoked were because of concerns for the flows at the Ontario – New York intertie itself, rather than internal interfaces in Ontario. The MAU is undertaking some further analyses which will assess whether the PJM exports may be contributing to congestion at the New York intertie itself, rather than congestion internal to Ontario.

[128] LEC is calculated here as actual flows minus net scheduled exports at the New York Intertie.

Assessment

The Panel has identified some shortcomings, which may be largely unavoidable, in the way export and import transactions are accounted for by the IESO's scheduling tools for both the constrained and unconstrained sequences. These shortcomings are the result of discrepancies between modeled, actual and contracted flows, and the need to project and fix rather than dynamically determine some loop flow quantities. In spite of these shortcomings, the large volume of exports from Ontario to PJM, and the differences between the actual flows they induce and the contractual path have generally not been a problem for Ontario in terms of congestion on transmission within Ontario. The MAU is continuing to analyze the situation to identify what the effect the PJM exports may have on congestion of the intertie at New York.

Based on the analysis to date, last year's wheeling sales from New York to PJM through Ontario and MISO had a much different impact on NYISO than the current exports from Ontario through Michigan to PJM have had on Ontario. This is the result of different levels of internal congestion in New York and Ontario. NYISO had considerable congestion limiting its flows from the west to east within New York, only a portion of which was captured in the pricing for exports to Ontario and onward to PJM, resulting in other participants in New York bearing these costs. Ontario does not directly charge for real-time congestion associated with a transaction except through uplift which averages such costs across all transactions. However, as seen by comparing nodal prices near Michigan and Niagara the effect of exports to PJM on internal congestion in Ontario has been minimal.

Nevertheless, the MAU will continue to monitor and analyze exports to PJM, loop flows and congestion at the New York intertie to improve its understanding of the potential issues from a market efficiency perspective. The Panel notes FERC's directive to NYISO (issued on July 16, 2009) to develop long-term comprehensive solutions to the "loop flow problem" through a collaborative process with interested parties, including neighbouring markets.[129] The Panel encourages the IESO to continue to participate actively in this process.

The Panel understands that there has been significant progress in bringing the phase-shifters at the Michigan interface into service. We encourage such efforts among various parties to bring these facilities into service as soon as possible.

2.2 OPG's CO_2 Emissions Target

In May 2008, the Minister of Energy issued a declaration regarding the reduction of CO_2 emissions from OPG's coal-fired generating stations. The declaration and the subsequent shareholder resolution require OPG to meet annual limits on CO_2 emissions for the 2009 and 2010 calendar years of 19.6 million and 15.6 million metric tonnes (MMt) respectively (approximately equivalent to 19.6 TWh and 15.6 TWh of production).[130] Between 2011 and 2014, OPG must meet a 'hard cap' of 11.5 Mt on CO_2 emissions as specified in Ontario Regulation 496/07 with the intention of shutting coal generators down after 2014.

On November 28, 2008, OPG submitted its *Implementation Strategy for 2009* to the Minister, describing OPG's strategy for meeting its emission target in 2009.[131] In its January 2009 Monitoring Report, the Panel reviewed OPG's strategy for meeting its CO_2 emissions target and expressed some concerns regarding the use of designating units as NOBA ('Not Offered but Available') and planned 'CO_2 outages'.[132] In this report, we review the market impact of the first four months of OPG's Implementation Strategy.

Coal-fired Generation

[129] *Op. Cit*. FERC Order, 128 FERC ¶ 61,049, paragraph 1.
[130] OPG, "Addressing Carbon Dioxide Emissions Arising from the Use of Coal at its Coal-fired Generating Stations, May 15, 2008." http://www.opg.com/pdf/directive_co2.pdf
[131] See "*OPG's Strategy to Meet the 2009 CO2 Emission Target*" at http://www.opg.com/safety/sustainable/emissions/carbon.asp
[132] See the Panel's January 2009 Monitoring Report, pp. 235-242.

OPG's production from coal-fired generators fell significantly in the first four months of 2009 relative to last year. In 2008, OPG's coal-fired generators produced 23.2 TWh, with 8.8 TWh being produced between January and April 2008. OPG coal-fired generation has fallen to 4.9 TWh between January and April 2009, which represents only 55 percent of the coal production over the same months last year. The main reasons for the decline in coal generation include improved baseload supply performance, lower Ontario Demand, and transmission outages that significantly limited Ontario's export capability in March and April 2009. The 2009 CO_2 target represents a production decrease of about 3.6 TWh (or 16 percent relative to 2008 production from OPG's coal units). Thus the production decrease of 3.9 TWh in the first four months has surpassed the required reduction for the whole year.

<u>Emissions Cost Adder</u>

As part of its Implementation Strategy, OPG specified that it would apply a uniform emissions cost adder to all offers from coal-fired generators. Initially, OPG estimated that an adder of approximately $7.50/MWh would, in conjunction with the other elements of the Implementation Strategy, allow OPG to meet its 2009 emissions target of 19.6 Mt of CO_2 emissions. On February 17, 2009, OPG noted that as a result of significantly reduced production from its coal-fired generation, it was reducing the adder to approximately $1.00/MWh. Further reductions in projected production of coal-fired energy led OPG to eliminate the adder entirely on March 17, 2009.[133]

<u>NOBA Units</u>

Between January and April 2009, OPG has designated at least one coal unit as NOBA in 39 days, for a total of 53 unit-days, of which all but two were taken in March and April 2009. Of these 39 days, there were 14 days when two coal units were on NOBA. The capacities of the NOBA units ranged from 440 to 485 MW, roughly the size of the other major coal-fired units. Measured as MW-days (MW capacity times days), 96 percent of

[133] http://www.opg.com/safety/sustainable/emissions/carbon.asp

the NOBA MW-days were taken in March and April. A larger number of NOBAs were originally scheduled, but OPG planned to and did occasionally remove the NOBA designation from a unit if one of the other coal-units was forced out-of-service.

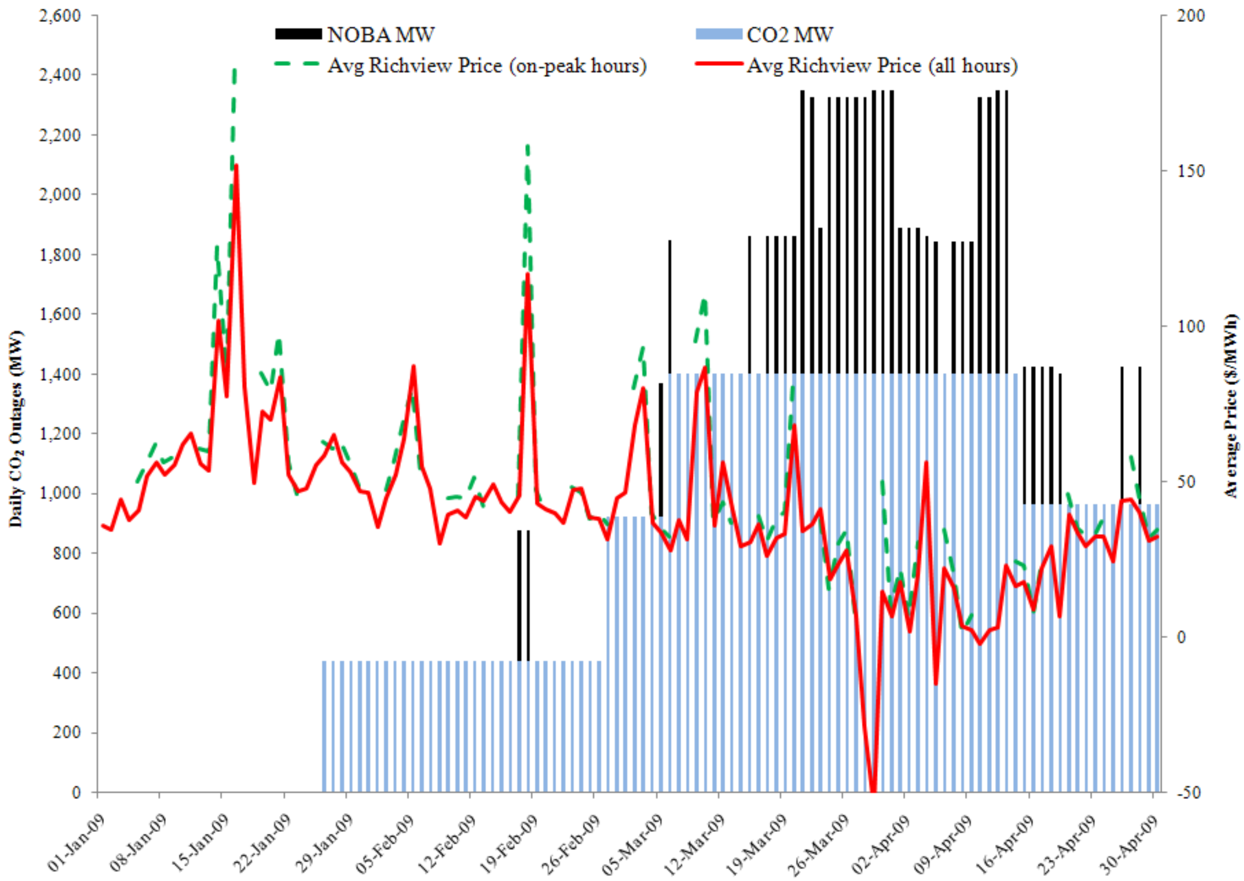
In its last report, the Panel observed that an adder strategy would be consistent with the concept of opportunity cost pricing and would generally be the efficiency maximizing way of managing the supply of a scarce resource (unless there were specific operating cost savings available from NOBA units that could not be achieved without the use of the NOBA process). The use of the NOBA strategy could also be roughly consistent with market efficiency if units are designated as NOBA during the lowest-priced days in the year and are available on higher-priced days when they would be economic.

To the end of April, it appears that OPG has designated NOBA units during some of the lower priced days in 2009. For example, the average HOEP on days with at least one NOBA was $21.06/MWh compared to an average of $44.43/MWh on days with no NOBA On-peak prices tell the same story. The average on-peak HOEP was $34.67/MWh on days with NOBA and $51.20/MWh on all other days in 2009.

The Richview nodal price is an alternative measure and better indicator of marginal costs or opportunity costs each day. Figure 3-6 plots the daily average Richview price (all hours and on-peak hours only[134]) against the amount of MW designated as NOBA -- and also the CO_2 outage by OPG (see below) -- for each day over the first four months of 2009.[135] Based on the Figure, OPG designated the greatest amount of NOBA's between the middle of March and the middle of April, which also contained some of the lowest daily average Richview prices so far in 2009.

[134] Average Richview off-peak prices are not plotted separately since coal-fired units generally find that most economic opportunities occur during the on-peak hours. Potential economic opportunities during the off-peak hours would also be reflected in the average Richview price over all hours of the day.
[135] The green line in Figure 3-6 plots the daily average Richview price during the on-peak hours only. Since all hours during the weekend are classified as off-peak, there are gaps in the price series.

Figure 3-6: Daily NOBA and CO_2 Outage MW and Average Richview Shadow Price January 1 – April 30, 2009 (MW and $/MWh)



Of the 39 NOBA days so far in 2009, 28 (76 percent) were taken on days where the daily average Richview price (over all hours) fell within the lowest 33 percent ranked highest to lowest, whereas only 3 days (8 percent) fell in the top 33 percent of the daily average Richview prices. When looking at on-peak prices only, 18 of the 25 NOBA's (72percent) taken during weekdays fell within the lowest 33 percent of average on-peak prices ranked highest to lowest, while only 2 days (8 percent) fell within the top 33 percent.[136]

It is worth noting, however, there were several days on which NOBA units would have been economic had they been in operation (i.e. days such as Feb 17-18, March 20 and

[136] All weekends hours are considered off-peak.

April 4, corresponding to price spikes on the graph above). The Panel's continuing reservation about the use of NOBA's is that if OPG had simply employed an adder strategy alone, these units might have been called to market on these higher priced days.[137]

CO_2 Outages

In its November 2008 submission to the Minister, OPG pointed out that an important component of its Implementation Strategy was the use of planned CO_2 outages, although none would be scheduled in January, July or August. Over the first four months of 2009 (as shown in Figure 3-6 above) there have been three planned outages designated as CO_2 outages. The first CO_2 outage began on January 26, the second on February 27, and the third on March 6. 2009. Between March 6 and April 14, all three CO_2 outages were in effect. As of April 30, 2009, two of OPG's coal units were on CO_2 outage and were expected to be made available at the end of June.

In its last report, the Panel expressed the concern that if coal units on CO_2 outages were extended (i.e. beyond the normal period to perform planned outages) the generation might not be available to the market on days when their production would have been economic. Again, given the lower prices prevailing thus far in 2009, there may have been fewer instances when these units would have been economic than in previous years. However, there were days in February and early March 2009 (on days with no units on NOBA) where daily average prices were higher than average prices between mid-March and the end of April 2009. Although there were no NOBA units taken when daily average prices were high in February and early March, there were two or three CO_2 outages covering several of these days. If some portion of these outages could have been avoided, there may have been opportunities for additional coal units to run economically. Based on its communications with OPG, the Panel is somewhat unsure whether some of the current planned CO_2 outages are longer than they would have been in the absence of

[137] That would have depended on what pre-dispatch conditions were projecting a few hours ahead, how OPG would have responded to that information, and possibly other factors related to how cold the coal units may have been, or other interactions considered by OPG related to coal unit starts and stops.

the CO_2 Implementation Strategy. The Panel will seek additional information from OPG regarding the length of its CO_2 outages.

OPGs View of the Benefits of NOBAs and CO_2 Outages

In April 2009, the MAU, acting on behalf of the Panel, requested additional information from OPG concerning the potential cost savings from using NOBA and CO_2 designations instead of managing coal output (and CO_2 emissions) solely through an offer strategy. OPG responded with mainly qualitative information on the benefits of its strategy and acknowledged that little data on realized cost savings has been accumulated in part due to low coal generation levels over the first four months of 2009.

In its response, OPG claimed that designating units as NOBA would reduce total starts, allow units to cool naturally prior to planned outages, and allow these units to "…run at a higher output level and receive less erratic dispatch signals." OPG believes that these benefits will result in improved equipment reliability and lower maintenance costs until its coal-fired units are shut down in 2014. OPG expressed the view that it would be difficult to obtain the same savings using only an offer strategy since there would still be uncertainty regarding events in real-time and this could result in units being scheduled at high offer prices. NOBA designations and CO_2 outages assure that the units will not be scheduled.

OPG added that its Fossil Business Plan maintenance budget has been reduced over the next five years (relative to 2008 projections), partly due to its CO_2 emission strategy. However, OPG did not identify what portion of the savings would be obtained through NOBA and CO_2 outages, what portion results from the generally lower production levels needed to meet the overall emissions targets, and what portion could not be obtained using an adder strategy.

Assessment

When assessing the implications of various program designs and market participant behaviour, the Panel generally focuses on market efficiency impacts.[138] While the Panel recognizes that efficiency may only be one of a number of factors that bear on OPG's decision-making, we find OPG's arguments regarding the advantages of NOBA's and CO_2 outages over the use of a simple adder have not addressed the efficiency concerns set out in the Panel's January 2009 Monitoring Report.

While OPG has not provided the Panel with information supporting the expected decline in its operation and maintenance (O&M) expenditures on its coal fleet, the Panel assumes for present purposes that there may be such a decline. What remains unclear, however, is the portion, if any, of this saving that could not be realized in the absence of NOBA's and CO_2 outages. OPG has also reported an improvement in a measure it developed to report on reliability for its coal-fleet.[139] However, the Panel has not been provided with information regarding the extent to which such reliability improvements could be realized without NOBA's and CO_2 outages, and how the system benefits from these improvements. For these reasons, the Panel remains concerned that the overall efficiency implications of OPG's coal generation reduction strategy for Ontario market are negative.

In light of extremely low coal production levels so far in 2009, the Panel also questions the need for the continuing use of NOBA's and further CO_2 outages, at least for the remainder of 2009. As of June 30, 2009, OPG coal production totalled 6.1 TWh, about half of OPG's coal production of 12.4 TWh over the same six months last year. OPG is only required to reduce coal production by approximately 3.6 TWh this year compared to 2008 production in order to meet its CO_2 emission target. Given OPG has thus far this year generated about 50 percent less from its coal-fired units than in the first six months of last year, it would only approach the emissions target by the end of 2009 if the coal units produced 25 percent more than during the last six months of last year. It appears

[138] See the Panel's mandate to assess market efficiency in Ontario Energy Board bylaw #3, Article 7.
[139] OPG quoted an improvement in an index which measures fossil fleet reliability when it is required to operate.

that OPG is unlikely to exceed the emissions target this year even if it took no further actions to limit coal production. This means OPG does not need to use NOBA's and CO_2 outages for the rest of 2009, and normal offers should be sufficient to comply with the 2009 CO_2 emissions target. If OPG continues to use NOBA and/or CO_2 outages to further reduce coal-fired generation, the Panel would need to assess whether this constitutes withholding and contributes to market inefficiencies.[140]

In an initial review of OPG's Implementation Strategy in the January 2009 Report, the Panel commended the inclusion of an emissions adder as it would be expected to lead to efficient and transparent production and consumption responses in the market.[141] When OPG began to recognize in February and March that its full Implementation Strategy would not be required to comply with the 2009 CO_2 target, it eliminated the adder rather than NOBAs or CO_2 outages. Based on the information received to date from OPG, the Panel continues to hold the view that NOBA's and CO_2 outages are not the most efficient means of achieving OPG's emission targets and that these targets are likely to be met more economically if OPG were to rely solely on an appropriate emissions adder.

Recommendation 3-1

(i) Ontario Power Generation (OPG) should discontinue the use of Not Offered but Available (NOBA) designations and CO_2 outages in excess of regular planned outages for the remainder of 2009 since they do not appear to be necessary to meet its 2009 CO_2 emission target, and

(ii) To the extent that OPG forecasts a need to reduce coal-fired generation in order to comply with its CO_2 emissions limit, the Panel recommends OPG should employ a strategy that utilizes an emissions adder alone as the most efficient way to offer an energy-limited resource into the market at the times when it has the most economic value.

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[140] The Ministerial Directive of May 2008 directs the OEB to change the licence for OPG (Appendix A Part 5 section a.1) which removes the requirement for OPG to offer coal-fired capacity for operating reserves to the extent necessary to comply with the CO_2 emission target. Ontario Order –In-Council OIC 694-2008 "Directive for Licence Amendments Regarding Co_2 Emissions Reduction Policy", May 14, 2008.

[141] See the Panel's January 2009 Monitoring Report, pp. 238.

2.3 A Market Participant's Use of a Negative Adder for Environmental Reasons

In its last report, based on its mandate to make recommendations related to market efficiency, the Panel discussed the efficiency implications of a market participant's strategy of reducing emissions by applying a negative adder to offers for two fossil-fired generating units at its 'Facility A'. The Panel recommended that market participants' offers should reflect the environmental costs implied by environmental standards established by appropriate regulatory authorities.[142] The Panel holds the view that the environmental standards established by the proper regulatory authorities implicitly reflect a judgement about the relative overall benefits and costs of the chosen level of pollution and that a further reduction in the emission levels below the established levels is likely to lead to greater inefficiencies in the market.

A negative adder means that the market participant offers this capacity into the market at a price below its incremental cost. The participant explained that the negative adder was implemented to ensure that Facility A capacity would be dispatched before other, higher-emitting, but lower cost, generation at the participant's 'Facility B'.[143] Occasionally, the negative adder also resulted in Facility A generation displacing other lower-cost generation as well. This section provides an update on the participant's use of the negative adder and its magnitude over the current review period.

The participant began applying the negative adder to its two lower-emitting Facility A units in March 2007. Figure 3-7 plots the weekly negative adder since it was introduced. The participant's fossil-fired units at Facility A and Facility B use different fuels and the adder is adjusted as the relative prices of the fuels change in order to ensure that the lower-emitting Facility A units are dispatched first. As pointed out in the Panel's last report, the participant increased the adder rapidly beginning in March 2008 and this

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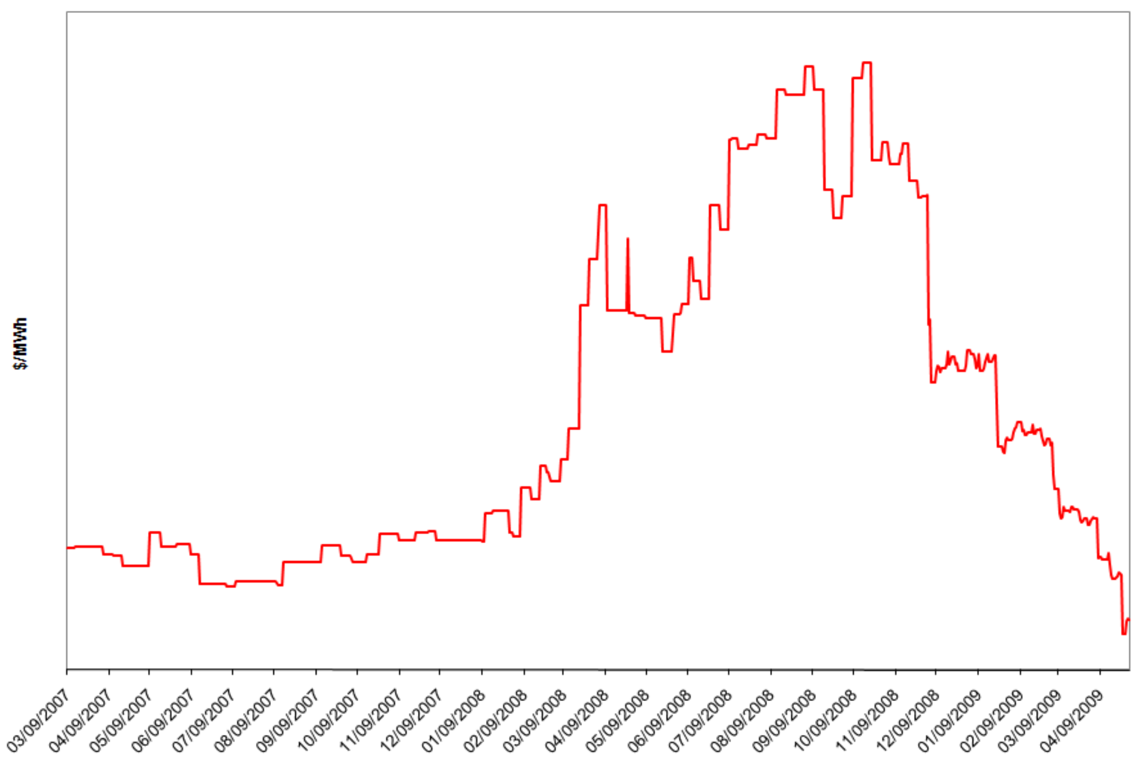
[142] See the Panel's January 2009 Monitoring Report, pp. 226-235.

[143] The Panel recognized that the negative adder may have led to some reduction in emissions of NO_x and SO_2, although the benefit was partially offset by increased inefficient exports leading to increased production from fossil-fired generation. The Panel also estimated that the negative adder induced an $18.7 million efficiency loss during the period due to higher cost generation being dispatched ahead of lower cost generation.

continued into the autumn months. Since the end of October 2008, however, the price of the fuel used at Facility A has fallen significantly relative to the price of the fuel used at Facility B.[144] As a result, the participant gradually decreased the magnitude of the adder so that, as of April 2009, the negative adder was at its lowest level since being implemented. The smaller is the adder, the less likely it is that the market participant's strategy will result in the replacement of lower cost generation by higher cost generation in the merit order. Put another way, the efficiency loss resulting from the market participant's strategy is smaller when there is only a small fuel price difference between facilities A and B. As a consequence, the estimated inefficiency resulting from the market participant's strategy over the most recent six month period was less than one-third of the $16.5 million estimated for the May to October 2008 summer period.[145]

Figure 3-7: Negative Adder Applied to Offers for a Facility A Unit, (March 9, 2007 – April 30, 2009)



[144] For a complete review of fuel price trends, please refer to section 4.5 in Chapter 1.

[145] Although the Panel's estimate of efficiency loss totalled $18.7 million between November 2007 and October 2008, only $2.2 million was attributable to the period between November 2007 and April 2008 when the negative adder was at relatively low levels.

In February, the participant notified the MAU that it would be adjusting the negative adder strategy associated with the low-emitting Facility A units beginning February 20, 2009. The new strategy reduces the possibility of displacing other low-emitting fossil-fired units run by other market participants (not Facility B) by eliminating the negative adder on a portion of the generating units' output in selected hours. Since then, the negative adder has been removed by the participant for some portion of Facility A's production in roughly 75 percent of all hours.

In its last report, the Panel found that by putting downward pressure on the HOEP, the negative adder likely also increased exports, which partially offset the effort to reduce emissions.[146] The use of smaller negative adders and the recent removal of the adder entirely for a portion of the production capability of the generating units concerned should have the effect of reducing both the incidence of inefficient export activity and overall market inefficiency.

2.4 OPA's DR 3 Program

OPA's Demand Response Phase 3 (or DR3) program was initiated in August 2008. The operation of the program in its first 3 months was reviewed in the Panel's last monitoring report.[147] Below, we review the activity of the program in the period November 2008 to April 2009.

The Panel concluded in its last report that during its initial period of operation, the DR3 program was inefficient from a short-term perspective. This followed from an assessment of the possible efficiency gains from reducing load which is willing to pay the HOEP but is not willing to pay the higher Richview price (which reflects the marginal cost of electric power more accurately than the HOEP). The Panel found that the estimated value attached by loads to consumption foregone under the DR3 program vastly exceeded the avoided cost of generation.

[146] See the Panel's January 2009 Monitoring Report, pp. 226-235.
[147] See the Panel's January 2009 Monitoring Report, pp. 197-212.

The Panel also noted that the program had the potential to be efficient from a long-term perspective if it avoided the cost of a corresponding amount of new peaking generation. For that assessment we compared the portion of the cost of a new peaking generator that would not be recovered from the market (i.e. that OPA would likely have to compensate through procurement contracts) with the consumer surplus on foregone consumption.[148] This analysis showed that, while a perfectly targeted DR3-type program might theoretically be efficiency-increasing in the long-run, it would be more efficient if the payment to forego consumption were lower than it is at present so that it did not attract participants whose value of foregone consumption is greater than the avoided cost of building a new peaking generator. Moreover, as a practical matter, the poor targeting of high-demand or high-priced hours by the existing DR3 program rendered it unlikely to reduce the need for new peaking capacity. Accordingly, the Panel recommended that OPA review the effectiveness and efficiency of the program[149] and OPA and IESO work towards improving both the targeting of program activations and the supply cushion calculation upon which activations are based.

In this report, we extend our analysis to cover the first nine months of operation of the DR3 program.

2.4.1 OPA's View on the DR3 Program

OPA has commented on our previous and current analysis. With respect to long-term efficiency, OPA notes that average potential payments under DR3 are competitive with all in costs of simple cycle gas turbine generation. It also notes because DR3 contracts are between 1 and 5 years, they offer more flexibility than an alternative generation contract of normally 20 years. This allows prices and even the procurement mechanism to be modified over time.

[148] Essentially the comparison is between the avoided cost of a peaking generator (which is equal to the revenue from the market plus the cost unrecovered from the market) and the consumer valuation of the offsetting consumption (which is equal to the consumer surplus plus the payment to generators through the market). Because the revenue from the market and the payment to generators through the market cancel each other, only the cost unrecovered from the market and the consumer surplus need to be compared.
[149] One way to improve the efficiency of the program would be to reduce the payments to loads to forego consumption.

OPA has indicated to the Panel that its approach to targeting and setting triggers for DR3 led to DR3 being available for the peak demands for the months of September, October and November had it been needed for activation. However, DR3 was not available for the peak demand in December given the energy limitations of the DR3 resource due to earlier activations. Insofar as the triggers themselves, OPA has modified day-ahead triggers to account for differences in import offers days-ahead and day-at-hand, and is willing to look for further improvements in triggers for activation.

2.4.2 Activations Under DR3

Table 3-1 shows the IESO supply cushion targets, which are triggers for activations, since the program's inception. The lower the supply cushion trigger, the less likely it is that there will be an activation. The 100 Hour column is the trigger which has been used for loads contracted for 100 hours of activation annually, while the 200 Hour column contains the trigger applied for activations of loads contracted for 200 hours annually.

Table 3-1: IESO Supply Cushion Trigger for Activation of DR3
August 2008 – April 2009

	IESO Supply Cushion Triggers	
Effective Period	**100 Hour (%)**	**200 Hour (%)**
August 1 - August 26, 2008	24	25
August 27 - September 17, 2008	29	30
September 18 - December 1, 2008	18	23
December 2, 2008 – January 4, 2009	0	0
January 5, 2009 – April 30, 2009	11	12

The supply cushion triggers were reduced to 0 percent through most of December 2008 and into the first week of January 2009. The lower triggers were selected following discussions between OPA and IESO. Given both the limit on annual activations and the period the program had already run in 2008, it was concluded that no further activations should be planned for December; hence the very low triggers were established. On January 5, 2009 the triggers were increased to the 11 percent and 12 percent for 100 hour and 200 hour contracts respectively. The triggers set for early 2009 were based on the anticipation of significant outages planned for the spring, and the possible benefit of reserving activations for this period.

Table 3-2 shows the activations that occurred in the 6-month winter period for participants with 200 hour and 100 hour DR3 contracts. Between November 2008 and April 2009, there have been seven activations under the DR3 program: six in November and one on December 1st. With the lower triggers in place since December 2, 2008 there have been no activations. The table shows market demand and prices (both the average HOEP and Richview nodal prices) in the activation hours. HOEP represents the market price for energy (paid by loads), while the Richview price is an approximation of the marginal cost of the generation required to meet demand. The excess of the Richview price over the HOEP represents the potential short-term efficiency gain from demand reduction since non-dispatchable loads may be consuming energy they value above the HOEP but below the Richview price.

Table 3-2: DR3 Activations, Market Prices, and Payment per Activation November 1, 2008 – April 30, 2009

Date	Activation Hour	200 Hour Contract Activated (MW)	100 Hour Contract Activated (MW)	Average HOEP ($/MWh)	Average Richview Price ($/MWh)	Difference (Richview - HOEP) ($/MWh)
11/10/2008	18 - 21	48.4	0.0	72.26	71.94	(0.32)
11/17/2008	18 – 21	48.4	0.0	75.47	83.14	7.67
11/18/2008	17 – 20	48.4	35.0	82.03	83.15	1.12
11/19/2008	17 – 20	48.4	35.0	101.04	101.89	0.85
11/24/2008	17 – 20	48.4	35.0	97.39	121.07	23.68
11/26/2008	18 – 21	48.4	0.0	71.66	75.87	4.21
12/01/2008	17 - 20	48.4	0.0	75.70	77.64	1.94
Average		48.4	15.0	84.89	91.18	5.59

For the 200 hour contract participants, each activation lasted 4 hours and involved 48.4 MW when the supply cushion fell below the 23 percent trigger. For the 100 hour contract participants, there were three activations involving 35 MW when the supply cushion fell below the 18 percent trigger.

Average HOEP during the 4-hour activations ranged from about $72/MWh to $101/MWh. Richview prices for one 4-hour activation averaged as high as $121/MWh, which was almost $24/MWh higher than the corresponding average HOEP. The average price across all activation hours was $84.89/MWh for HOEP and $91.18/MWh for Richview. Each of these is higher than the corresponding average activation prices between August and October 2008 which were $76.33/MWh for the HOEP and $79.75/MWh for the Richview price.

The average excess of the Richview price over the HOEP was $5.59/MWh. This is the maximum short term efficiency gain that would be realized if all consumption foregone under the program was valued at the HOEP. In contrast, if all foregone consumption was valued at the Richview price, there would be no short term efficiency gain. To the extent that foregone consumption was valued above the Richview price, there would be efficiency losses. Given that participants are paid $200/MWh to forego consumption, it is almost certainly the case that the value of most of the consumption foregone by program participants was well in excess of the Richview price and that, as a consequence, the DR3 program was efficiency-reducing.

2.4.3 Targeting of Activations

As noted in the last Panel report, OPA's objective for the DR3 program has been:

> "*To assist in reducing the system peak demand during pre-determined scheduled periods noted for high-demand, high prices and tight supply by contracting with a broad range of consumers to participate in managing the electricity needs of Ontario*." [150]

If DR3 is to achieve its stated goal, the program should lead to activations in high-demand, high-price or tight supply periods. The higher average prices during activation hours shown in Table 3-2 above might suggest somewhat better targeting of the activations in November and December, compared with the August – October period.

[150] OPA: "A Progress Report on Electricity Conservation – 2008 Quarter 2", p. 29, http://www.powerauthority.on.ca/Storage/82/7717_Q2_2008_Conservation_progress_report_updated_Aug._29.pdf

This conclusion is not borne out, however, by the ranking of high-demands and high prices.

Table 3-3 shows the highest hourly market demand and HOEP within each 4-hour activation event, and the ranking of these across all hours. Since the 100 or 200 hours of activations are counted within a calendar year, the Panel examined rankings within the August to December 2008 period during which DR3 operated, as well as the ranking across the full calendar year 2008, as a proxy for what a full year of operation might look like.

Table 3-3: Ranks of the Peak Demand and HOEP During Hours with DR3 Activations
November – December 2008

Date	Contract Type (Hours)	Activation Hours	Highest Demand in Activation Hours (MW)	Rank of the Highest Demand in Each Activation		Highest HOEP in Activation Hours ($/MWh)	Rank of the Highest HOEP in Each Activation	
				Aug – Dec 2008	All 2008		Aug – Dec 2008	All 2008
11/10/2008	200	18 - 21	19,669	326	1202	84.69	244	839
11/17/2008	200	18 – 21	20,267	203	777	77.60	339	1,119
11/18/2008	100/200	17 – 20	20,693	137	523	86.92	209	759
11/19/2008	100/200	17 – 20	21,054	96	349	114.93	48	262
11/24/2008	100/200	17 – 20	21,028	97	361	104.24	86	396
11/26/2008	200	18 – 21	20,674	143	533	87.91	198	730
12/01/2008	200	17 - 20	21,064	94	345	82.89	266	907

With activations lasting 4 hours, there would be at most 25 activations across the year for the 100 hour participants and 50 activations across the year for the 200 hour participants. Thus, for a perfectly-targeted program, the ranking of all the highest demands or prices in the activation window would be expected to lie within the top 25 or 50 across the year, and within a proportionally smaller range for the 5-month period the program actually operated given a smaller number of hours in the 5-month period. This turns out not to be the case. Only the November 19th activation falls within the top 50 high priced hours for August to December, and no activation falls within the top 50 hours for the year, for either the demand or price measure. Thus the targeting of the seven activations in

November and December was less successful than the four best activation hours covered in the Panel's last report (i.e. the activations which occurred between August 18 and September 4, 2008[151]).

In summary, the DR3 program is very likely to induce short-term inefficiency because payments to participants far exceed the small potential short-term efficiency gains available from foregoing consumption. In addition, given its present poor targeting, the program appears unlikely to achieve the potential long term efficiency benefits because it is does not appear to reduce the need for peaking generation in high price/demand hours. As a result, the Panel reiterates the recommendations in its prior report which encouraged OPA to improve the program design and OPA to work with IESO to improve the supply cushion targets.[152]

3. New Matters

3.1 Cost Allocation in the Generator Commitment Programs

The Panel has commented in past reports about design flaws in the IESO's Spare Generation Online (SGOL) and Day-Ahead Commitment (DACP) programs.[153] Market Rule amendment proposals are before the IESO's Technical Panel to address many of these matters.[154] An additional area that warrants attention is the allocation of costs among the gas and steam turbine units of combined cycle gas-fired generators. Both SGOL and DACP provide generators a cost guarantee that is unit-based. While older technologies generally involved units operating independently of each other at a particular station, many of the new gas-fired generators in Ontario are combined cycle gas turbine (CCGT) generators with waste heat from one or more gas turbines (GT) providing the energy to drive a steam turbine (ST).

[151] For the 2008 demand ranking, the 4 events ranged from the 23rd highest demand hour to the 184th highest.
[152] See the Panel's January 2009 Monitoring Report, Recommendation 3-1, pp. 197-213.
[153] See the Panel's January 2009 Monitoring Report (pages 213-220) and the July 2007 Monitoring Report (pp.114-123).
[154] See MR-00356 and MR-00252 at http://www.ieso.ca/imoweb/amendments/tp_meetings.asp

The costs allowed for purposes of the SGOL submitted cost are limited to fuel costs incurred. But neither Market Rules nor IESO procedures indicate how these costs should be distributed across the gas and steam turbines in a combined-cycle station. This can lead to situations in which some units in a station incur large revenue shortfalls and are thus eligible for large SGOL payments while other units in the same station are earning revenues well in excess of their allocated costs and the station as a whole is covering its costs. In this situation, there is an over-recovery of costs, since revenue shortfalls on some units are used as the basis for recovery of program payments without adjustment for excess revenues on other units in the same station.

The tendency for over-recovery of costs makes it profitable for combined cycle generators to start-up more often than would otherwise be the case, even though they may displace lower cost generation and therefore reduce market efficiency. This design flaw, which is common to both the SGOL and DACP programs, can be rectified with a relatively simple change in the cost-recovery criteria.

<u>Illustrative Alternative Allocations</u>

For purposes of illustration, assume a combined-cycle station with two gas turbines with a minimum loading point of 100 MW each and one steam turbine with an minimum loading point of 100 MW, corresponding to the MLPs of the two gas turbines. The station has a minimum run time of 10 hours, a start-up cost of $10,000, speed-no-load cost of $2,000, and an incremental energy cost of $60/MWh on each gas turbine.[155] To run at 100 MW for 10 hours, each gas turbine incurs a cost equal to $10,000 + 10 * $2,000 + 10 * 100 * $60 = $10,000 + $20,000 + $60,000 = $90,000. For the 10 * 100 MW produced, this represents an average cost of $90/MWh. Including the steam turbine production, overall station operation costs are $180,000 / (3*10* 100) = $60/MWh.

Assume the generator offers the gas turbines at a price of $65/MWh, and the steam turbine at $30/MWh. In the initial hour of operation, the nodal price is assumed to be

[155] Costs to run the steam turbine are assumed for ease of illustration to be negligible.

$70/MWh, but is lower in all other hours and averages $55/MWh. The station operates over a 10 hour period with market prices (HOEP's) that range from $40 to $60/MWh, and average $50/MWh. During this time, the gas turbines each receive energy plus CMSC payments which total 10*100* $65 = $65,000 (since MCP energy prices are always below the $65/MWh offer price). The steam turbine receives only energy revenue amounting to 10*100*$50 = $50,000 (since the MCP always exceed the $30/MWh offer price).

Consider the following possible cost allocations:

- Allocation 1 – All costs allocated to unit that directly incurs cost
- Allocation 2 - The cost of one gas turbine is split equally with the steam turbine
- Allocation 3 – The total costs are pro-rated by MWh production
- Allocation 4 – All costs are allocated to the steam turbine[156]
- Allocation 5 – Costs pro-rated according to associated total revenue
- Allocation 6 – Costs and revenue are aggregated for the entire station

[156] This is an extreme allocation, not observed in practice but included to show the range of possibilities.

Table 3-4: Alternative Allocation Methods for SGOL and DACP Cost Guarantees at Multi-unit Combined Cycle Stations

	Allocation 1	Allocation 2	Allocation 3	Allocation 4	Allocation 5	Allocation 6 (Station-wide)
GT 1:						
Allocated Cost	$90,000	$90,000	$60,000	$0	$65,000	
Revenue (Energy plus CMSC)	$65,000	$65,000	$65,000	$65,000	$65,000	
SGOL	$25,000	$25,000	$0	$0	$0	
Total Revenue	$90,000	$90,000	$65,000	$65,000	$65,000	
GT 2:						
Allocated Cost	$90,000	$45,000	$60,000	$0	$65,000	
Revenue (Energy plus CMSC)	$65,000	$65,000	$65,000	$65,000	$65,000	
SGOL	$25,000	$0	$0	$0	$0	
Total Revenue	$90,000	$65,000	$65,000	$65,000	$65,000	
ST:						
Allocated Cost	$0	$45,000	$60,000	$180,000	$50,000	
Revenue (Energy plus CMSC)	$50,000	$50,000	$50,000	$50,000	$50,000	
SGOL	$0	$0	$10,000	$130,000	$0	
Total Revenue	$50,000	$50,000	$60,000	$180,000	$50,000	
Station Total:						
Revenue (Energy plus CMSC)	$180,000	$180,000	$180,000	$180,000	$180,000	$180,000
SGOL	$50,000	$25,000	$10,000	$130,000	$0	$0
Total Sub-total	$230,000	$205,000	$190,000	$310,000	$180,000	$180,000
Total Cost	$180,000	$180,000	$180,000	$180,000	$180,000	$180,000

As Table 3-4 shows, the allocations lead to total revenues plus SGOL payments ranging from $180,000 to $310,000. This is compared with total production costs for the station of only $180,000, which means all but two allocations yield revenue in excess of cost. Given that the SGOL program is intended to guarantee generation costs when real time market prices are low, one would have expected that revenues would only be guaranteed up to the levels of costs. However, each of the above allocations except 5 and 6, lead to total payments exceeding costs. The reason for this is that, under allocations 1-4, some of the costs that support the generation are separated from the corresponding revenues because of the allocation. Allocation 5 allocates costs based on revenue and Allocation 6, which is calculated plant-wide, avoids the segregation of revenues from the costs which support the production. For the other cost allocations, however, total payments exceed costs so that the station has an incentive to operate simply to collect these excess payments. To the extent that this displaces less costly generation in the merit order, this is inefficient and the SGOL payments do not achieve the program objectives of guaranteeing the generation costs if the real-time market situations turn out to be unfavourable.

A better design for the cost guarantee program in this situation would be to set payments equal to the combined excess of costs over revenue for the three units in the station (Allocation 6). A station-based SGOL calculation would compare total revenues across all units, with total costs across all units. In the example above, total revenues are $65,000 + $65,000 + $50,000 = $180,000. Since total costs also equal to $180,000 there would be no additional SGOL payment needed. Allocation 5 would achieve the same result, because it prorates costs on the basis of the revenues derived from each generating unit in the station.

The MAU compared cost guarantee payments using the current unit-based approach with one using a station-based approach. The comparison was performed for two combined cycle gas generators, one typically relying on the SGOL program and the other which typically uses DACP rather than SGOL to get constrained on. Based on operations in 2007 and 2008, the SGOL payment would have been lower by more than 50 percent, and the DACP guarantee payment would have been about 20 percent lower if these payments had been calculated on a station basis rather than a unit basis. In total for these two stations alone, guarantee payments could have been almost $8 million lower while keeping them whole and maintaining their incentive to come to market when needed under the DACP or SGOL programs.[157]

[157] With changes being contemplated by the IESO for SGOL and DACP, the benefits of station-wide aggregation could be lower. With those changes there would typically be a smaller component of cost at risk, since the modified programs allow the submission of only the start-up and ramping costs.

The Panel believes that it is both more efficient and more consistent with the objectives of the SGOL and DACP programs to compare costs and revenues across units whose operation is tied to one another. The simplest way to achieve this is through a station-wide aggregation. If a market participant chooses to operate generating units as a group, the cost guarantee should be applied to the group.[158] As noted above, the same outcome can be achieved by requiring the cost allocation submitted by a generating station operator to be pro-rated according to revenue. Accordingly, we have the following recommendation:

Recommendation 3-2

The IESO should improve the mechanisms for aligning submitted costs and associated revenue streams at combined cycle stations for its Spare Generation On-line and Day-Ahead Commitment Process generation cost guarantee programs, in the context of the other changes taking place to these programs. The preferred mechanism is to determine guarantee payments on an aggregate basis for all units at a station. Alternatively, the IESO should eliminate allocations that result in over-compensation (for example, by requiring allocation of submitted costs among units in proportion to the revenue they generate during the period associated with those costs).

3.2 Application of the Daily Energy Limit at Hydroelectric Stations

The Daily Energy Limit (DEL) is the maximum amount of energy that can be scheduled at a specified hydroelectric generation facility for a given day.[159] Generally, a hydroelectric station operator estimates how much power it can generate for the coming day and updates this estimate day-at-hand if necessary based on its projections of water inflow, storage capability, generation capacity and possibly environmental limitations. The Panel's expectation is that hydro generators normally attempt to operate so that this

[158] A case can be made for a smaller aggregates if two sets of generators in a station are operated independently, such as 2 independent groups each with 2 GTs feeding only the ST in that group. However, this is not common at the moment.
[159] The DSO scheduling tool allows the specification of a daily limit for a given delivery day for a "facility" designated as energy-limited. A facility may be a hydroelectric unit or an aggregate of several units at a single plant.

limited daily energy is used in the highest priced hours during the day. In doing so, the generator maximizes its profit in a manner that is generally most efficient for the market.

When the IESO's scheduling tool determines the pre-dispatch schedules (both energy and OR) for a hydro unit for the coming dispatch hours, it first estimates how much energy remains available for the day (i.e. based on the difference between the submitted DEL and the cumulated schedules in previous hours on the day).[160] If the calculation shows that no energy remains, the pre-dispatch tool will not schedule the unit for either energy or OR, even if its offer is economic. If there is sufficient remaining energy, however, economic offers will be scheduled.

The IESO's real-time dispatch algorithm does not take the DEL into account. In other words, the real-time DSO schedules hydro generators based on their offers in each hour and the total scheduled generation can be greater than or less than the DEL. As a consequence, there can be a mismatch between what the pre-dispatch projects as being available and what the real-time dispatch assumes. If a unit has submitted a low DEL, the DEL may be depleted in the early hours of the day. The IESO will then not schedule the unit in pre-dispatch sequences in subsequent hours on the day, but will keep scheduling it in the real-time sequence if its offers are economic. An understated DEL can thus generate a persistent discrepancy between the pre-dispatch and real-time schedules for many hours of a day, unless the market participant modifies its submitted DEL or its offers. If the DEL does not accurately reflect the available energy, it will likely reduce market efficiency. This will occur because the pre-dispatch schedules imports, exports and possibly generators with a slow ramping capability (such as fossil-fired generators) on the assumption that the DEL is the maximum supply available from the (typically inexpensive) hydroelectric generator, whose additional energy will often be selected in real-time.

The IESO's Market Rules do not require a market participant to submit its DEL to the IESO (i.e. it is optional to do so). If a DEL is not submitted, DEL is treated as unlimited

[160] Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve market, section 1.3.4. The Structure of Dispatch Data.

(some large number will be assumed) and thus the energy may be scheduled by the IESO, possibly in every hour of the day as long as the offers are economic. The Market Rules require participants to submit to the IESO revised dispatch data “as soon as practical” if the quantity scheduled is not what the participant “reasonably expects to be delivered. [161] However, a compliance investigation is more likely to be triggered if a participant has submitted a DEL which is lower than its actual available water and this leads to a discrepancy between the pre-dispatch and real-time schedules, the participant may be subject to a compliance review and could be penalized.[162]

The event of March 18, 2009 as described below highlights how an inaccurate DEL can affect the market.

3.2.1 March 18, 2009 HE 11-20

On March 18, 2009, a market participant mistakenly submitted incorrect DELs for three of its hydro generators, leading to a schedule of 0 MW in pre-dispatch but 850 MW in real-time, from HE 11 to 20, for a total of 8,500 MWh. The DELs were later increased from HE 21 onwards when the participant noticed the problem.

Table 3-5 below lists the actual PD and RT prices as well as the simulated PD and RT prices that would have prevailed if the market participant had submitted correct DELs. Had the DELs been correct, there would have been on average 328 MW (or a total of 3,280 MWh) more in net exports and the HOEP would have been an average of \$8.40/MWh (or 39 percent) higher during the ten hours.

[161] Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Market, section 1.3.4 The Structure of Dispatch Data.
[162] Market Rules, Chapter 7, section 3.3.8.

Table 3-5: Actual and Simulated Pre-Dispatch and Real-Time Prices March 18, 2009 HE 11 to 20

HE	Pre-Dispatch			Real-Time			
	Actual PD MCP ($/MWh)	Simulated PD MCP ($/MWh)	Increase in Net Exports (MW)	"Actual" HOEP* ($/MWh)	Simulated HOEP ($/MWh)	Increase (Simulated – Actual) /Actual (%)	Efficiency loss ($1,000)
11	38.12	32.50	438	33.32	38.34	15	1
12	39.20	34.04	325	31.48	34.90	11	1
13	36.70	30.08	90	31.53	32.83	4	0
14	34.02	25.44	159	2.05	10.76	425	5
15	34.82	28.47	155	17.76	28.35	60	2
16	34.08	25.44	151	2.20	11.55	425	4
17	35.12	27.36	50	28.61	29.10	2	0
18	40.00	34.73	386	32.11	35.86	12	-3
19	58.44	49.00	767	26.07	45.35	74	-1
20	60.16	50.00	759	12.63	34.77	175	11
Average	**41.07**	**33.71**	**328**	**21.78**	**30.18**	**39**	**2**

The HOEP is the simulated base-case HOEP, which can be slightly different from the actual HOEP because of the small differences between our simulation tool and the IESO DSO.

The market participant's mistake also led to an efficiency loss to the market because more expensive imports were scheduled and economic exports were not scheduled. The estimated efficiency loss has two components, one for exports which should have been scheduled and one for imports which should not have been scheduled. For exports, the efficiency loss is estimated as the difference between the replacement costs of the unscheduled exports in external markets (i.e. the unscheduled exports times the price in external markets) and the avoided generation cost for those exports in Ontario. For imports the efficiency loss is estimated as the difference between the costs of additional imports (i.e. increased imports times the price in external markets) and the avoided generation cost in Ontario.[163] In the ten hours, the average efficiency loss was $2,000/hour, or a total of $20,000.[164]

3.2.2 Assessment

DEL errors frequently impact the IESO dispatch schedules. Table 3-6 below lists the monthly total number of hours when a DEL is binding, the mismatched RT and PD schedules arising when there is a binding DEL,[165] and the average MWh per event in the month. DEL could be low or high; the issue is whether it is binding below the real-time capability. In the period January 2008 to April 2009, hydro units had 233,572 MWh scheduled in RT even though they were not scheduled in PD due to a binding DEL. The total number of affected hours is 2,622 hours, or 22 percent of total hours (in total there were 11,664 hours). On average, there was 89 MW more supply in RT in these hours.

[163]Because there is no market in Manitoba and Quebec, we used the zonal price in the neighbouring markets as the opportunity cost of the imports from these two areas: the price in the Minnesota hub for imports from Manitoba and the price at the NYISO HQ zone for imports from Quebec. The estimated generation cost in Ontario is based on the simulation for the unconstrained sequence as we only have an unconstrained simulator. However, given the abundant supply/demand condition at the time, the actual generation cost (in the constrained sequence) at the time should be very similar to the estimated generation cost in the unconstrained sequence.

[164] The efficiency loss in a specific hour could be negative (i.e. a wrong DEL may have led to efficiency gain) because the hourly efficiency loss is estimated *ex post* and a wrong DEL may have led to more imports or fewer exports which turned out to be *ex post* efficient.

[165] A hydro resource may be scheduled in RT but not in PD due to a tighter supply in RT, for example, as a result of generation or transmission outage and/or heavier than forecast demand. Because of complexity of distinguishing schedule differences due to system conditions from those due to the DEL limitations, we assume all schedule differences when the DEL is binding are due to the DEL. Given that the PD price is generally greater than the RT price (both HOEP and the Richview shadow price) and the DEL is binding generally in the last few hours of the day, we expect that the difference due to RT system configuration is relatively small.

***Table 3-6: Summary Statistics of Daily Energy Limit (DEL) Impact
January 2008 – April 2009***

Month	Schedule Difference (RT-PD) due to DEL (MWh)	Events (Number of Hours)	Average Difference (MWh/event)
Jan-08	22,203	278	80
Feb-08	45,913	419	110
Mar-08	31,809	287	111
Apr-08	19,991	190	105
May-08	4,100	57	72
Jun-08	7,535	86	88
Jul-08	10,109	145	70
Aug-08	7,610	122	62
Sep-08	4,667	77	61
Oct-08	4,673	66	71
Nov-08	8,110	91	89
Dec-08	5,341	86	62
Jan-09	9,733	146	67
Feb-09	11,737	219	54
Mar-09	21,618	163	133
Apr-09	18,423	190	97
Total/ Average	233,572	2,622	89

DEL errors occurred most frequently during the months of January to April, and the average impact (MWh/event) in these months was also somewhat higher. In the these months, DEL caused schedule differences for at least 146 hours in each month and for as much as 419 hours in February 2008. The energy missing in PD averaged about 100 MW per event during the winter months of 2008. This was exceeded only by the March 2009 average of 133 MWh, which was affected by the significant error occurring on March 18, 2009 as reported above. In the months of May-December, the total number of hours with a DEL error was somewhat smaller and the average impact was also smaller.

Because there are numerous DELs relating to individual hydroelectric units and assessing their full impact requires the simulation of the PD sequence, a detailed study on the impact of DEL on market prices and efficiency has not yet been undertaken. However, the Panel would expect a material impact from incorrect DELs on the market price as well as market efficiency, given both the frequency and relative size of the deviations reported in Table 3-6 above as well as the impact observed in the single simulation for March 18, 2009.

While a correct understanding of energy limitations could be useful to the IESO for its system adequacy and reliability assessments during the days when the system is tight or reliability may be threatened, the above data implies an understated error in the submitted DEL 22 percent of the time, with errors averaging about 89 MW. Relying on compliance enforcement in its current form may not provide a sufficient inducement for participants to provide accurate data. First, there is no requirement to submit a DEL. If a market participant does not provide the IESO with its DEL, the IESO will use a default and sufficiently large value. As a result, the DEL is never binding and the participant is free of any potential consequences that might have otherwise been caused by a low DEL. However, if the participant provides a DEL which is too low, it may be penalized. The potential penalty would tend to induce a market participant to provide an exaggerated DEL or not to provide one at all.[166]

Given that the DEL is a rough number for a day and a market participant has better information on the water availability in RT, it is possible that a market participant can better manage the scheduling of its energy through its RT offer strategy, based on the information it has a few hours in advance. In any event, it must adjust its offers to avoid being scheduled in RT because the DEL does not do so.

In summary, at this time, it does not appear that either the IESO or market participants need the DEL feature in the current pre-dispatch scheduling tool. Given its absence in the real-time scheduling tool, the Panel assumes that introducing a DEL into the current real-time tool would be a time-consuming, costly and unattractive alternative, especially given the pending development of the IESO's Enhanced Day-Ahead Commitment (EDAC) process. Because EDAC is being designed to optimize generator and intertie

[166] The Panel has not yet undertaken an assessment of the extent to which DELs were overstated or not submitted at all.

trade schedules over 24 hours, available energy would be scheduled in the hours with the highest value to the market. This implies that a more accurate DEL based on mandatory submissions and compliance consequences for significant errors, would likely be important to incorporate into the EDAC. In any event, it must adjust its offers to avoid being scheduled in RT because the DEL does not do so.

Recommendation 3-3

Given the frequency and impact on the market of incorrect Daily Energy Limit (DEL) submissions for hydroelectric generators, the Panel recommends that the IESO should discontinue the use of the DEL feature in the pre-dispatch schedules (including the Day-Ahead Commitment Process pre-dispatches) until an Enhanced Day-Ahead Commitment process is introduced which is specifically designed to optimize resources over 24 hours using accurate estimates of energy limits for hydroelectric resources. Alternatively, if the IESO considers that the DEL is currently useful for reliability reasons, the IESO should require submission of DELs from all hydroelectric generators, and strengthen the compliance provisions in the Market Rules to incent participants to submit more accurate forecasts of DEL.

3.3 New Regulation Governing OPG's Prescribed Assets

OPG is a public-owned generator in the province whose production represented a market share of about 70 percent in 2008. Since market opening in 2002, OPG has been subject to a variety of measures that were designed to constrain or ameliorate the consequences of the potential for it to exercise market power. OPG was initially obligated to make rebates to Ontario consumers pursuant to the Market Power Mitigation Agreement (MPMA).[167] The Agreement required OPG to rebate its revenue above $38/MWh on 90

[167] For a detailed description of MPMA and its evolution into Business Protection Plan Rebate, see the Panel's October 2002 Monitoring Report, pp. 30-32.

percent of its forecast domestic energy supply, as well as to set up incentives and a schedule for OPG to divest some of its generation capacity.

Beginning April 1, 2005, the MPMA was replaced with new regulations and the Ontario Energy Board (OEB) was granted the authority to review the price set for the output from the so-called prescribed facilities.[168] Prescribed assets included some hydroelectric generation and all nuclear generation operated by OPG.[169]

- The hydroelectric generation classified as prescribed assets are the Beck complex, the DeCew Falls station and the Saunders station. In 2008, these units provided 18.29 TWh to the Ontario market, accounting for 12 percent of total Ontario Demand. Under the 2005 regulations, the output from prescribed hydroelectric assets was guaranteed a fixed price of $33.00/MWh for up to 1,900 MW per hour, and the market price for any output above 1,900 MW in any hour.
- The nuclear capacity consists of the Pickering and Darlington stations. In 2008, these units provided 48.64 TWh to the Ontario market, accounting for 33 percent of total Ontario Demand. All output from nuclear units was paid a fixed price of $49.50/MWh.

Table 3-7 below lists the maximum capacity at each of these stations.

Table 3-7: Generation Capacity of Prescribed Assets

Hydroelectric		Nuclear	
Station	**Capacity (MW)**	**Station**	**Capacity (MW)**
Sir Adam Beck I	447	**Pickering**	3,094
Sir Adam Beck II	1,499	**Darlington**	3,512
Sir Adam Beck Pump Storage Station	174		
DeCew Falls	167		
R. H. Saunders	1,045		
Total	**3,332**	**Total**	**6,606**
Percentage of Total Generation Capacity in Ontario (about 33,000 MW in 2008)	**10**		**20**

[168] O. Reg. 53/05
[169] For details, see the IESO website: http://www.ieso.ca/imoweb/b100/b100_marketRebates.asp.

OPG's other generation assets are non-prescribed assets, which include all generation facilities except the above prescribed facilities and the Lennox generation station (which is subject to the Reliability Must Run (RMR) contract with the IESO[170]). A revenue cap of $47/MWh was imposed on 85 percent of the output from these generation facilities over each hour (subject to certain adjustments).[171] This payment structure expired on April 30, 2009 with the result that starting May 1, 2009, these generating units are subject to the market price. However, as of January 1, 2009, OPG has had an additional contingency support agreement in place with the Ontario Energy Financial Corporation (OEFC) to ensure cost recovery at its Nanticoke and Lambton coal-fired stations as a result of the CO_2 emission targets.[172] The establishment of an appropriate cost recovery mechanism was identified in the May 2008 Resolution of the Shareholder to decrease OPG's coal-fired CO_2 emissions.[173]

3.3.1 New Payment Structure for Prescribed Assets

In November 2007, OPG filed an application to the OEB for setting new payment amounts for its prescribed assets based on a 21-month test period from April 1, 2008 to December 31, 2009. The OEB issued its decision on this application on November 3, 2008.[174] The key aspects of the decision concerning the payment to OPG for generation from its prescribed assets include:

- Hydroelectric assets:
  - Effective December 1, 2008, a new hydro incentive mechanism applies. The new formula for payment is as follows:

[170] The RMR contract is reviewed and renewed yearly, subject to the approval of the Ontario Energy Board under section 5 of OPG's licence, which requires that any reliability must-run contract be approved by the OEB before its implementation.
[171] The $47/MWh price cap was set for the first year and has been adjusted over time between $46/MWh and $48/MWh. For details, see the IESO's website: http://www.ieso.ca/imoweb/siteShared/electricity_bill.asp?sid=bi. .
[172] For cost recovery details, see OPG's 2009 first quarter financial report at http://www.opg.com/investor/pdf/2009_Q1_FullRpt.pdf
[173] "Addressing Carbon Dioxide Emissions Arising from the Use of Coal at its Coal-fired Generating Stations, May 15, 2008." http://www.opg.com/pdf/directive_co2.pdf
[174] Ontario Energy Board, *EB-2007-0905: In the Matter of an Application by OPG Inc. Payment Amounts for Prescribed Facilities, Decision with Reasons*, November 3, 2008.

$$\sum_{t} MWavg * RegRate + (MW(t) - MWavg) * MCP(t)$$

Where:

MWavg = the actual average hourly net energy production over the month

RegRate = $38.84/MWh which is the base rate of $36.66/MWh plus an adder to recover the lost revenue had the new base rate been applied for the period April to November 2008.

MW(t) = net energy production supplied into the IESO market for each hour of the month

MCP(t) = the market clearing price for each hour of the month

- Generation and revenue under Segregated Mode of Operation (SMO) and revenue from water sold to New York at the Niagara Falls (Water Transfer) are excluded from the payment calculation. [175]

- Nuclear assets: during the period December 2008 to December 2009 OPG is to receive $58.20/MWh for every MWh that is produced at its nuclear units.[176]

These changes in the payment structure were expected to provide increased incentives for OPG to respond to market signals on its prescribed hydro assets and thus improve market efficiency. The following section summarizes the efficiency implications of these changes.

[175] A corresponding amount, $23.98 million, based on historical revenues is deducted from the OPG's total revenue requirement for the test period April 2008 to December 2009.
[176] This includes the retroactive cost recovery for the period April 1, 2008 to November 30, 2008 and amounts for other account balance.

3.3.2 Implications of the New Payment Structure

Appendix A to this Chapter provides a comparison of OPG's optimal strategies under the old and new payment regimes with the strategy of a competitive company that is not regulated. It suggests that the new payment regime will induce OPG to make more efficient production and pump-storage decisions. While the new payment structure is improved relative to the previous arrangement, it does not always lead to an efficient production decision.[177] In addition, the effects of the new payment regime on the use of Segregated Mode of Operation (SMO) and the water transfer decision are somewhat ambiguous because of the unknown sale price relative to the on-peak and off-peak Ontario market price.[178] In general, the new regime enhances incentives that will contribute to market efficiency.

One way to compare the impact of the new payment regime to the old one is to compare the actual output under each regime to the 'optimal' output in each period (assuming no production restrictions at a station except for unit capacities). The Panel has defined optimal output as the calibrated hourly output level of a competitive firm in an ideal world in which water can be reallocated to any hour in the day without incurring costs and the competitive firm has perfect information on the HOEP.[179] To minimize the impact of different water and capacity availability in each period on the comparison, we normalize the output difference (i.e. the calibrated optimal output minus the actual

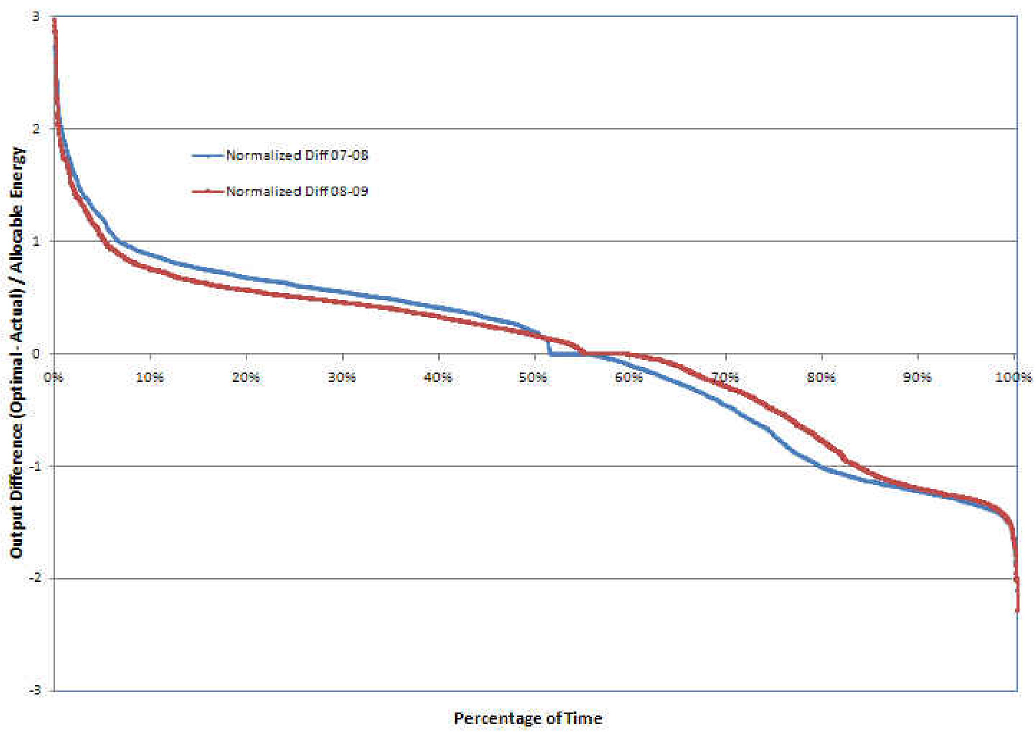
[177] For example, in months with a low average HOEP, OPG may still have little incentive to spill water at hydroelectric stations when it is efficient to do so. When HOEP is negative in an hour, this may be a signal to spill. However if HOEP in some hours is only moderately negative, in a month with low average HOEP, the payment structure may not induce the efficient outcome. The intuition is that by not spilling OPG will receive a regulated rate of $38.84/MWh (the first term in the payment formula) but the revenue will be adjusted down by the amount of the second term. If the HOEP in the negative priced hour is within $38.84/MWh of the monthly average HOEP, the incentive is to produce (assuming minimal water rental charges for production). See Table 3-10 which shows production during SBG conditions.

[178] OPG can operate the Saunders station under SMO, i.e. directly switch to the Quebec grid by disconnecting with the IESO-administered grid. OPG can also transfer water at the Beck station to New York under the Water Treaty with New York, rather than produce power. These activities are significantly limited by internal and external system configuration and subject to IESO's scrutiny. In the past years, the revenue from these two sources was relatively small (about a few million dollars) compared to the total revenue from these stations in the Ontario market.

[179] We assume the total actual daily output as the true daily energy limit (DEL) which in turn can be reallocated among hours. We assume the hourly minimum output in a day as the run-of-the-river output, and the maximum offered quantity in the day as the maximum capacity. Then the re-allocable energy in the day is the difference between the total DEL and the total run-of-the-river output. We then allocate this energy to each hour, beginning with the highest-priced hour with the restrictions of minimum and maximum output level in each hour.

output) against the daily total re-allocatable energy, which is the total daily output minus the total run-of-the river output. Figure 3-8 below plots the duration curve of the normalized differences between ideal and actual output at the Beck and DeCew Falls stations in the periods December to April 2007/08 and December to April 2008/09 respectively.[180] It can be seen that the curve for 2008/09 is closer to the horizontal axis, indicating the actual output in 2008/09 was closer to the optimal competitive output. This supports the conclusion of the theoretical analysis in Appendix A that the new payment regime will be efficiency-improving.[181]

Figure 3-8: Output Deviation Duration Curve at Prescribed Hydro Stations December to April, 2007/08 and 2008/09



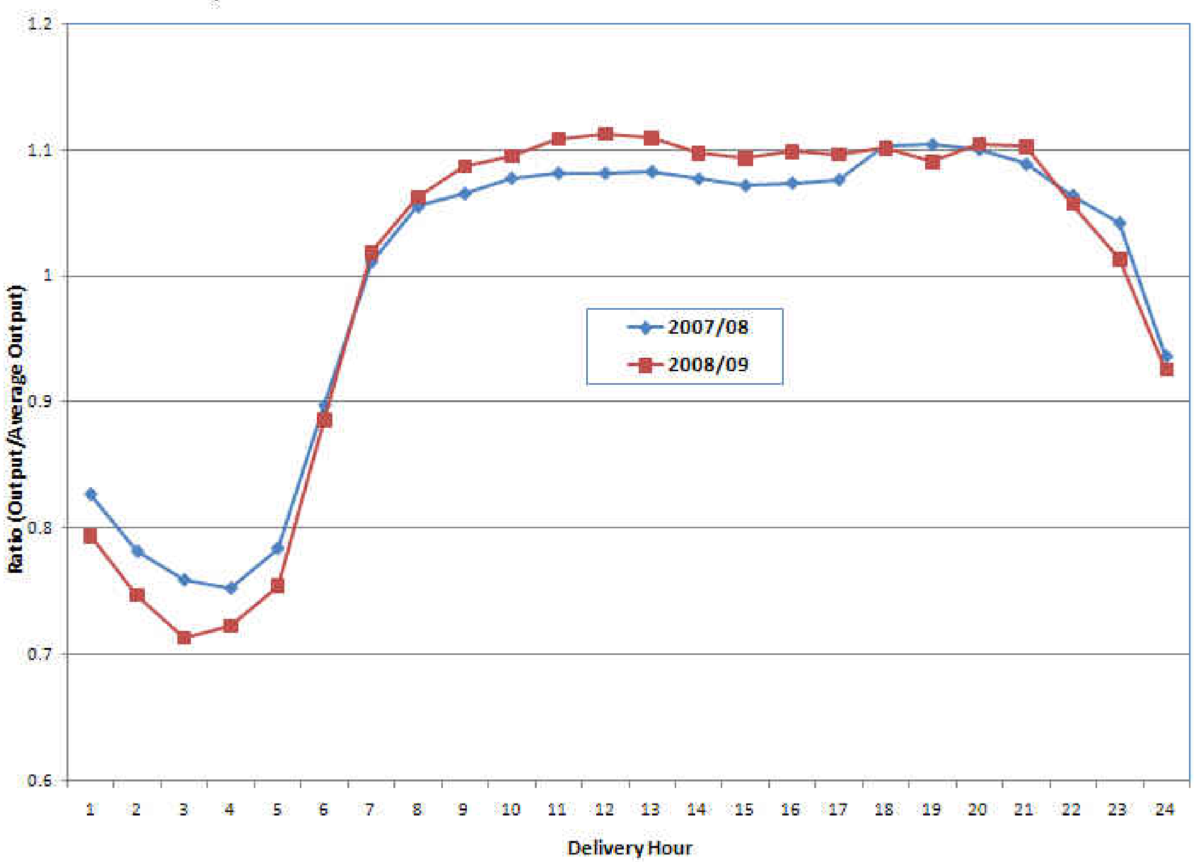
Another way to show how the new payment regime has affected offers is to see whether or not OPG has shifted more water from off-peak to on-peak since the inception of the

[180] The Saunders station is not included because its water shifting capability is very limited and the SMO there complicates the calculation of the optimal output.

[181] To test whether the difference is statistically significant, we separated the duration curve into 10 blocks based on the percentage of time: 0-10%, 10-20%, 20-30%, and so on. The test shows that the mean of 2008/09 is significantly different from the mean of 2007/08 in each block at the 1% confidence level. We also tested the hypothesis of an equal mean for the difference (without normalization) and found that the mean of 2008/09 is still significantly different from the mean of 2007/08 at the 1% confidence level in seven blocks (from 10% to 80%) but insignificantly different at the 1% confidence level in the 0-10%, 80-90% and 90-100% block.

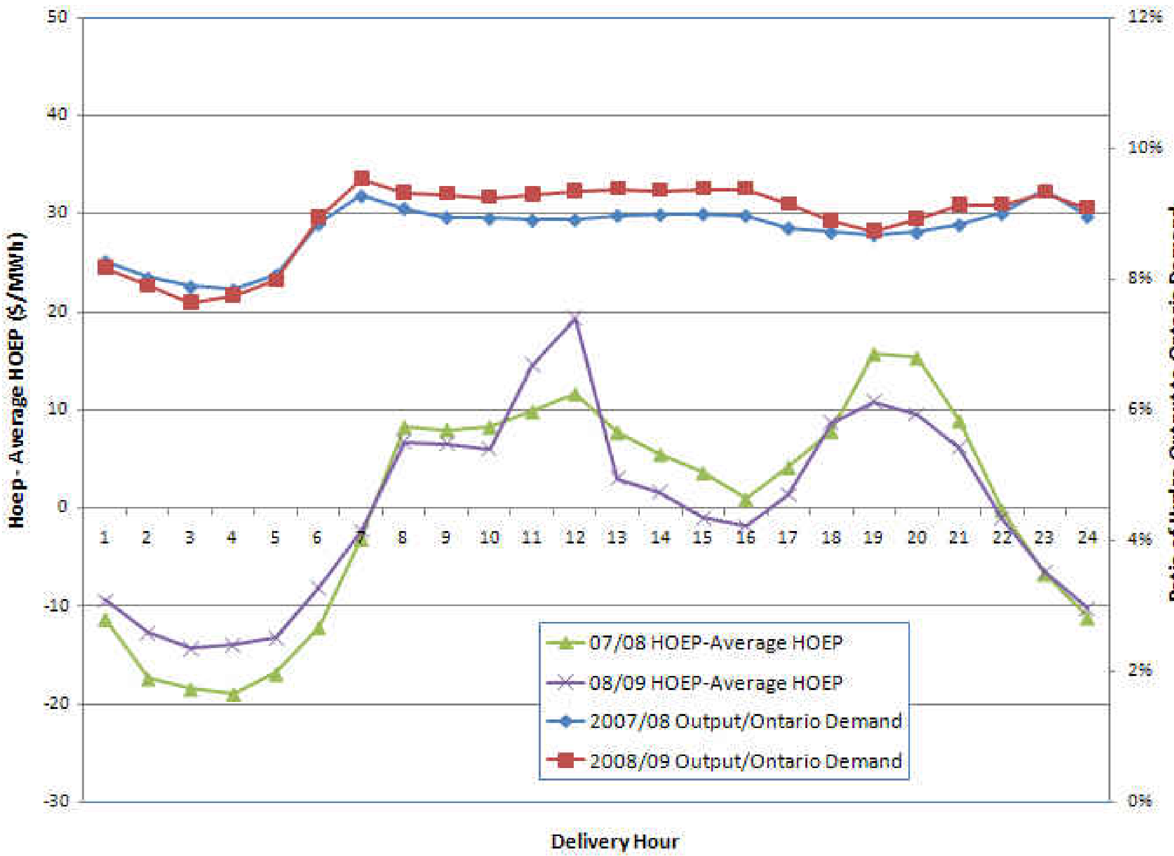
new payment regime. Figure 3-9 below plots the ratio of hourly output to average output at the Beck and DeCew Falls stations by delivery hour for the period December to April, 2007/08 and 2008/09. This ratio shows how actual hourly output has deviated from average output: the higher is the index, the more water is shifted to the hour. One can see that OPG had shifted more hydro production from off-peak to on-peak in the new payment period.

Figure 3-9: Ratio of Hourly Output to Average Output
December to April, 2007/08 and 2008/09



However, the shifting of hydro production could be a consequence of a change in the pattern of market price and demand. Figure 3-10 below plots the difference between the hourly average HOEP and the overall average HOEP in each period as well as the ratio of the hydro output at Beck and DeCew Falls to the Ontario Demand. One can see that based on the output ratio, OPG did shift more water from off-peak to on-peak in the new payment period. The price difference provides additional evidence that the shifting in water was more likely a consequence of the change in the payment regime: although the on-peak to off-peak price difference in 2008/09, $16.49/MWh on average, was smaller than the 2007/08 average of $21.42/MWh, OPG had shifted more water from off-peak to on-peak.[182] Both indices provide evidence that the new payment regime does provide stronger incentives for OPG to more efficiently respond to the market signal.

Figure 3-10: Average HOEP Difference and Ratio of Hydro Output to Ontario Demand (December to April, 2007/08 and 2008/09)



The estimation of the efficiency gains to the market resulting from water shifting is difficult because the shifting decision depends not only on factors such as on-peak vs. off-peak prices, water availability and the cost of pumping water; but also on the physical operation of the Beck complex and operational decisions made by the IESO. One simple

[182] The hourly average prices in HE 11 and 12 in 2008/09 are higher, because the HOEP was distorted by two price spikes on February 18, 2009 when the HOEP reached above $1,000/MWh.

way to assess the efficiency gain is to assume that without the new payment regime OPG would, on average, have generated power in the same pattern as it did in the same period a year earlier (i.e. the hourly ratio in 2008/09 would have been the same as the hourly ratio in 2007/08). Then for each hour we multiply the average difference in energy production by the average Richview nodal price in 2008/09 (this assumes the shifting has no effect on the Richview price[183]) and then multiply by the total number of days in the study period. The average hourly Richview price is assumed to be the value of the power produced in each hour of the study period. Mathematically, the efficiency gain is estimated based on the following formula:

$$Efficiency\_Gain = \sum_{t=1}^{24} (Output_t - Output_{t,ref}) * Richview\_Price_t * Days$$

Where $Output_t$ – average hourly output in hour t

$Output_{t,ref}$ – estimated average hourly output in hour t had the 2007/08 production pattern been followed

$Richview\_Price_t$ – the average Richview nodal price in hour t

$Days$ – the total number of days in the study period

Based on this calculation, the Panel's estimate of the efficiency gain to the market from water shifting at the Beck and DeCew Falls stations amounts to approximately $1.5 million dollars for the five month period December 2008 to April 2009. The Panel recognizes the approximate nature of this estimate, and notes that OPG does not accept this analysis as accurate. However, the Panel is satisfied that the new regulated pricing

[183] Based on the production pattern last year, the on-peak Richview price would have been higher and the off-peak Richview price would have been lower since there was relatively more off-peak and less on-peak. Thus the estimation based on an unchanged Richview price may provide a conservative estimate of the true efficiency gains.

regime does lead to increased efficiencies due to greater shifting of production from off-peak to on-peak.

3.4 Increased Incidents with Surplus Baseload Generation (SBG)

SBG has become a significant reliability issue in Ontario and the corresponding low prices or even negative prices has also become an important issue among market participants in the past months. In this section, we discuss the main causes of the SBG conditions in the review period and the manner in which various market participants are incented to respond to low or negative prices during such conditions.

3.4.1 Introduction

An SBG condition is defined by the IESO as

> *"when the amount of baseload generation (which may largely consist of a supply mix of high minimum load fossil, nuclear and run-of-the-river hydroelectric resources) exceeds the market demand"*[184]

When an SBG occurs, the market is oversupplied and either market participants or the IESO have to take manual actions to reduce supply. Table 3-8 below lists the number of hours with SBG conditions. In each winter period from 2005 to 2008, there were about 20 hours with an SBG condition, most of which occurred during either the Christmas holiday period or the spring freshet period when water for hydro generation is plentiful. In the current review period, however, the number of hours with an SBG condition increased sharply to 200 hours, most of which were in March and April. It is also noted that SBG occurred in all months in the review period.

[184] IESO Procedure 2.4-2, section 7, December 10, 2008. The IESO also publishes a daily report "Forecast Surplus Baseload Generation Report" which, at the request of market participants, relies on an alternative definition of SBG, using Ontario Demand which may represent a more extreme projection. For details, see https://www.ieso.ca/imoweb/marketdata/sbg.asp

Table 3-8: Number of Hours with Surplus Baseload Generation November to April, 2002 to 2009

Month	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
November	0	0	0	0	0	0	3
December	0	0	0	1	11	0	13
January	0	0	0	4	0	0	4
February	0	0	0	0	0	0	8
March	0	0	0	0	0	0	48
April	0	0	0	19	6	20	124
Total	0	0	0	24	17	20	200

It is worth noting that an SBG condition refers to the supply and demand situation in the constrained sequence. In an SBG hour, the market price (which is determined in the unconstrained sequence) could be greater than $0/MWh. Similarly, there may be no SBG condition when the market price is below $0/MWh. The HOEP, however, was below $0/MWh in the vast majority of SBG hours.

The increase in SBG in the current review period was caused by several factors:

- *reduced Ontario Demand* : as shown in Chapter 1, the Ontario Demand was about 4.6 percent lower this winter than the year before.
- *reduced outages of nuclear units:* planned and forced outage of nuclear units were much lower in this review period, as shown in Chapter 1.
- *outages on the New York/Ontario interface*: in addition to a prolonged planned outage at BP76 (a relatively small transmission line on the New York/Ontario interface), successive planned outages of two major transmission lines (PA301 and PA302) on the NYISO side of the New York/Ontario interface were conducted between March 24 and April 17. This led to the net export capability on the New York/Ontario interface being reduced to 0 MW (compared to about 2,200 MW normally) and the net export capability on the Michigan/Ontario interface being reduced to 655 MW (compared to about 2,000 MW normally) during the period. The reduction in

the net export schedule capability on the MISO interface was intended to reduce the clockwise Lake Erie Circulation (LEC), since only a small LEC flow could be accommodated at the New York/Ontario interface.[185]

- *increased wind generation*: wind generation has increased significantly as installed capacity has expanded over the past two years (see Chapter 1); and
- *commissioning gas generation:* there has been a large increase in gas generation capacity (as documented in Chapter 1) some of which was being commissioned during the review period to honour in-service obligations in OPA contracts.

In its submission for the Integrated Power System Plan (IPSP) review,[186] the IESO forecast increasing SBG events in the future (Figure 3-11). With the *Green Energy and Green Economy Act, 2009* (GEA) and more renewable energy generation capacity being planned, the number of hours with SBG may increase faster than forecast by the IESO for two reasons. First, the vast majority of green energy generators are expected to be wind-power generators, which are treated as non-dispatchable. Second, wind-power generators typically have their highest output overnight when SBG events are more likely to occur.[187]

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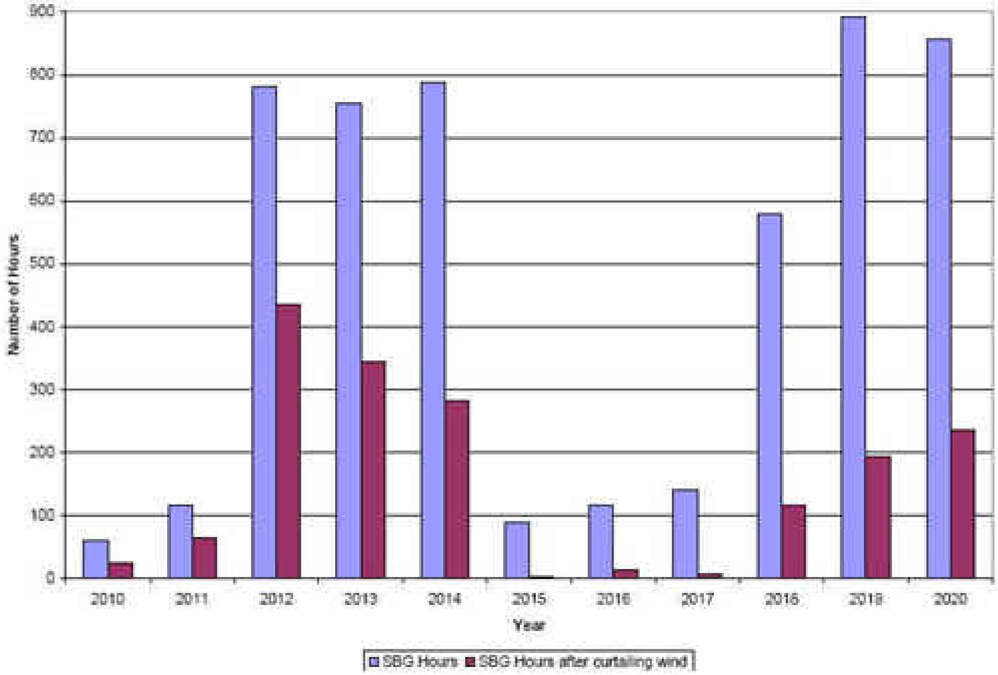
[185] There was still limited transmission capability on the other two transmission lines on the NYISO interface. Because of the Lake Erie Circulation, these lines could be easily congested. As a result, the IESO put zero limits for net export (and imports) scheduling between Ontario and NYISO.
[186] IESO, "*Operability Review of OPA's Integrated Power System Plan*", April 21, 2008.
[187] Starting in 2008, the IESO includes a forecast of SBG by comparing minimum Demand and Baseload Generation (Figure 6.1) as part of its 18 Month Outlook Update. See https://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

Figure 3-11: IESO Projected Number of Hours with SBG Projections Prepared for the Integrated Power System Plan 2010 to 2020



The main purpose of this section is to examine control actions by the IESO or market participants and the causes of the SBG conditions, with a secondary focus on the market situation when HOEP was negative.

3.4.2 <u>IESO and Market Participants' Actions during SBG conditions</u>

In anticipation of or during an SBG event, the IESO is authorized to take several control actions. These actions and their market impacts include:

- *Cut imports for adequacy*: The IESO cuts imports with an *ADQh* code, which has the effect of reducing supply and thus increasing the market price during surplus conditions. The Panel has previously recommended that the IESO should eliminate the counter-intuitive market impact of the code.[188]

[188] The Panel's July 2008 Monitoring Report, pp. 171-180. Because curtailed imports for *ADQh* are also removed from the unconstrained sequence, the HOEP is increased which is inconsistent with the oversupply situation at the time.

- *Derate of coal-fired generators to their "gas support" level*:[189] This action could be initiated by either IESO or OPG. It is accomplished by derating coal units to a level lower than their registered MLPs, thereby increasing the market price by removing this supply from the market. The Panel expressed its concerns regarding the market impact of this type of intervention in its July 2008 Monitoring Report, observing that with a minor change in the definition of the MLP by the IESO the market participant concerned could withdraw this generation from the market by adjusting its offers.[190]
- *Shutdown or reject the start-up of fossil-fired units:* Some fossil-fired generators may request synchronization even under SBG conditions because of commissioning or cost-guarantee programs such as SGOL. The IESO can reject their synchronization for reliability concerns and may also order some operating fossil-fired generators to fully shut down. This action has the effect of increasing the HOEP because offline fossil-fired generators are not considered as available by the unconstrained sequence.
- *Dispatch down baseload hydro generators:* This may be ordered by the IESO even though it means spilling of water. This action does not impact the market price.
- *Constrain or shut down nuclear units*: Nuclear units are typically designed to produce at their maximum capacity, but do have some small flexibility to ramp down output.[191] Nuclear units may be dispatched or shut down ahead of or during the real-time dispatch. As discussed below, dispatching down in pre-dispatch may dampen market efficiency. At times, a nuclear generator, in consultation with the IESO, may choose to shut down fully even though the generator has to be offline for at least 48 hours. When a nuclear unit is constrained down, the HOEP is not affected, while the HOEP is increased if it is shutdown.

[189] Some coal-fired generators can also use natural gas as fuel, which allows the generator to sustain production at a lower minimum output level, their 'gas support' level.
[190] See the Panel's July 2008 Monitoring Report, pp. 110-112. The IESO Compliance group investigated this derating practice and concluded that it was not a violation of the Market Rules.
[191] For example, when performing an SBG manoeuvre Bruce Power does not change the power output of the reactor, rather it relies on the Condenser Steam Discharge Valve (CSDV), which instead of producing power directs steam to the condenser for cooling. For a description of Bruce unit operational flexibility and limitations, see http://ieso.ca/imoweb/pubs/consult/se57/se57-20090703-BrucePower.pdf.

- *Increase NISL to allow increased net exports*: The Panel has recommended that the IESO review the Net Intertie Scheduling Limit (NISL) so as to facilitate more exports (and/or reductions in imports), particularly during low-demand periods.[192] The IESO put a procedure in place effective December 23, 2008 to increase the NISL to 1,000 MW, where feasible, when there is an SBG event.[193]

3.4.3 Assessment

In most spot markets, supply and demand can be cleared at the market price because of production and demand flexibility as well as the buffering effect of inventories, queuing and order backlogs. In other words, the time when the market is cleared can be different from the time when the goods or services are physically delivered.

In the electricity market, however, the power offered to sell or bid to purchase must be delivered and be balanced at the time the market is cleared. Because real-time demand fluctuates quickly, supply must move rapidly to accommodate it. When nuclear or fossil units at MLP are at the margin, either they cannot ramp down or up or they cannot ramp as fast as required (nuclear units can produce at a lower but stable output level but cannot ramp frequently). As a result, the system operator may have to anticipate these limitations and intervene in the market to dispatch down these less flexible marginal resources in advance or cut imports ahead of real-time. In doing so, more flexible generation resources can be moved to the margin and the market will be balanced and cleared.

Currently the most frequently applied control actions are to cut imports with the *ADQh* code and to dispatch down nuclear units:

[192] See the Panel's July 2008 Monitoring Report, pp. 103-110. More generally, in its July 2007 Monitoring Report (pp. 97-100), the Panel recommended that IESO review whether the default 700 MW limit could be increased.
[193] IESO Internal Manual 2.4 Procedure 2.4-2, Chapter 7, 'Respond to Surplus Baseload Generation Events'.

- As the Panel stated before, while it may be necessary for the IESO to cut imports for reliability, the use of *ADQh* for this purpose has the counter-productive effect of increasing the HOEP.
- The manual dispatching down of nuclear units in pre-dispatch has the potential to reduce market efficiency and further aggravate the SBG condition. If the action is taken in final pre-dispatch, as noted in the Panel's last report, the reduction in nuclear supply in pre-dispatch may lead to more imports or fewer exports.[194]

In the prior report, the Panel stated that the IESO had revised its procedure so that the manual constraining down of the nuclear units would not affect the pre-dispatch schedules.[195] However, this has turned out not to be the case currently: the manual dispatching down of nuclear units can still affect the pre-dispatch constrained sequence. Generally, constraining down nuclear units in pre-dispatch may cause market inefficiency because it reduces the nuclear supply in pre-dispatch, leading to a higher pre-dispatch shadow price and thus more imports and fewer exports in the constrained schedule. In its last report, the Panel identified an event in which the action of constraining down nuclear units in pre-dispatch reduced net exports by 946 MWh in a four hour period and resulted in an efficiency loss of $32,000.[196] The Panel has asked the MAU to continue monitoring this situation.

Typically, when there is an SBG event, the market price is low or even negative. A low market price should be signaling generators/importers to reduce their supply and consumers/exporters to increase demand. In a hybrid market such as Ontario's, however, some market participants may ignore market price signals either part of the time or all the time. For example, some generators (such as renewable generators and NUG's) have an incentive to produce as much as they can because of fixed price contracts or regulation,

[194] See the Panel's January 2009 Monitoring Report, pp. 169-171.
[195] The IESO could do so by manually putting a constraint on the designated nuclear unit or units after the pre-dispatch run for the delivery hour. The process is extremely time-consuming. The IESO applied the procedure in a few cases before March 2009 when the SBG started to occur on a daily basis.
[196] See the Panel's January 2009 Monitoring Report, pp. 170-171.

while others may be online because of the cost guarantee programs (such as SGOL or DACP programs).

In the following sections, we will discuss the manner in which various categories of market participants are incented to respond to low or negative prices during SBG conditions.

Prices to Intertie Traders

Importers and exporters arbitrage the price difference between Ontario and external markets and thus are very sensitive to the price in Ontario. In Ontario, intertie transactions are settled at the price at the respective intertie zone: exporters pay and importers receive the intertie zonal price rather than the HOEP. When there is import congestion, the intertie zonal price is lower than the HOEP. When there is export congestion, the intertie zonal price is higher than the HOEP. As a result, the HOEP can be persistently lower than the price in external markets if the intertie is export congested.

Even though there were many negative HOEP hours in the review period, the major intertie zones had fewer negative prices because of export congestion. Table 3-9 below lists the monthly total number of hours with a negative real-time price in the review period. It appears that although there were a significant number of hours with a negative HOEP, the number of hours with a negative price in the Michigan zone (within Ontario) was much lower (and in line with the number of hours with a negative price in the MISO Michigan hub), indicating that the Michigan/Ontario interface was frequently congested (in the unconstrained schedule) during these negative-priced hours. The number of hours with a negative price in the New York zone (within Ontario) was similar to the number of hours with negative HOEP in Ontario because the interface was rarely congested in those hours. The PA301 and PA302 outages at the New York interface in March and April 2009, led to the increased congestion at the Michigan intertie as well as the limited congestion at the New York intertie. The former was congested because of the reduced limit at Michigan, while there was little congestion for the latter since there were almost no imports or exports being offered on the New York interface during the outage period.

Table 3-9: Number of Hours with Negative Prices in Ontario, NYISO and MISO November 2008 to April 2009

Month	Michigan Hub	NY OH Zone	Ontario		
			HOEP	New York Zone	Michigan Zone
Nov-08	1	0	0	0	0
Dec-08	0	8	5	5	5
Jan-09	1	0	0	0	0
Feb-09	5	2	0	0	0
Mar-09	13	6	58	54	5
Apr-09	16	7	156	154	28
Total	**36**	**22**	**219**	**191**	**38**

<u>Prices to Ontario Customers</u>

A negative HOEP benefits customers who can shift their consumption from high-priced hours to negative-priced hours (such as some wholesale customers). The benefit may be partially mitigated by transformation and connection charges since these charges are calculated based on maximum hourly consumption in the month.[197] If off-peak consumption is already larger than on-peak, the shifting of additional load off-peak could increase maximum hourly consumption thereby increasing transformation and connection charges and offsetting some of the saving from shifting consumption from higher-priced hours to the negative-priced hours. Although these customers pay Global Adjustment (GA), it has no impact on the consumption shifting because the GA charge is based on total consumption in a month.

For other customers who pay the HOEP[198] but cannot respond to changes in it, a negative HOEP does not necessarily lead to a lower bill because of a higher Global Adjustment

[197]Consumers who own their transformation and connection equipment are exempt from these charges.
[198] The majority of residential customers are not directly affected by HOEP since they are on the Regulated Pricing Plan (RPP) which charges a constant rate. However, this rate is based on forecasts of HOEP and Global Adjustment, and is periodically updated, so changes in the HOEP and GA do have indirect effects.

paid to generators who have a contract with OPA or Ontario Electricity Financial Corporation (OEFC), or the revenue requirement for OPG, as a result of the lower HOEP. As demonstrated in Chapter 1 section 2.1.2, the effective price that Ontario consumers pay generally has been relatively stable compared to the HOEP, fluctuating between $50/MWh and $60/MWh in the past four years as illustrated in Figure 1-2 in Chapter 1. For example, the effective price was $56.67/MWh in March 2009 and $56.36/MWh in April 2009, although the average HOEP was only $28.88/MWh in March and $18.40/MWh in April.

Price to Generators

Ontario is a hybrid market: most generators have contracts with OPA, OEFC or IESO, or are subject to government regulation. As a result, a negative HOEP has different implications for different generators.

Existing contracts include OPA contracts with major power suppliers and various renewable generators;[199] and, OEFC contracts with numerous non-utility generators (NUGs):

- *OPA's contract with Bruce Power*: Bruce A units are paid a fixed rate for each MWh of production, while Bruce B units have an annual floor price ($45/MWh as of 2005 with annual inflation adjustments).[200]
- *OPA's Clean Energy Supply (CES) and Early Mover contracts*: All large gas-fired generators that came, or will come, online after market opening have contracts of this nature. When the HOEP is higher than the calculated contract strike price, the unit is deemed to produce energy, and any estimated profit based on the deemed output is ultimately removed from the monthly payment to it, whether or not they actually produce.
- *OPA's Renewable Energy contracts*: these generators are paid a fixed price for every MWh they produce.

[199] For a detailed discussion on these contracts, see the Panel's December 2007 Monitoring Report, pp. 169-185.
[200] This was the 2005 price. It is adjusted yearly to account for inflation. In each calendar year, if the average market revenue earned by Bruce on its output is lower than the floor price, Bruce B will be topped up to the price. Otherwise there is no top-up payment.

- *OEFC's NUG contracts*: generators are paid a fixed price based on their actual output. These generators are typically very small and not dispatchable. Some of these contracts have expired and were renewed with slightly different contract terms, while others will expire in coming years.

The prices that OPG receives are determined by a series of regulatory payment regimes or contracts.

- *Prescribed nuclear assets*: OPG nuclear units are paid a fixed price per MWh produced so that their generation decisions are not sensitive to market prices. Starting in December 2008, the payment is $58.20/MWh.
- *Prescribed hydro assets (the Beck, DeCew Falls, and Saunders stations)*: starting in December 2008, the total output of these stations is paid a fixed-price that is adjusted for the HOEP and actual hourly output as described in section 3.3 of the current Chapter.
- *OPG's non-prescribed assets (OPG's other facilities except Lennox):* these units have been subject to a revenue rebate mechanism (which expired on April 30, 2009). This regulation left these units only partially subject to market prices as is described below.
- *IESO's Reliability Must Run (RMR) contract with OPG for the Lennox station*: the contract allows OPG to recover most of its costs, with a financial incentive to maintain reliability and a further driver to respond to market prices based on OPG retaining about five percent of its market revenues.[201]

The IESO also has various reliability programs that have the effect of attenuating the link between the revenues of participating generators and the market price. In particular, the IESO's DACP and SGOL programs guarantee an eligible generator its fuel cost (plus the O&M cost in the DACP) if the market price turns out to be unfavourable. Because of design flaws in these programs, a generator may actually make a profit from the

[201] The RMR contract is subject to review and approval by the OEB. For a copy of the latest Lennox contract, see: http://www.opg.com/about/reg/filings/Lennox/files/Lennox%20RMR%20(EB-2008-0298)/OPG%20Lennox%20RMR%20application%20(EB-2008-0298).pdf. For the OEB's December 15, 2008 decision see http://www.oeb.gov.on.ca/OEB/Hearingsanddecisions

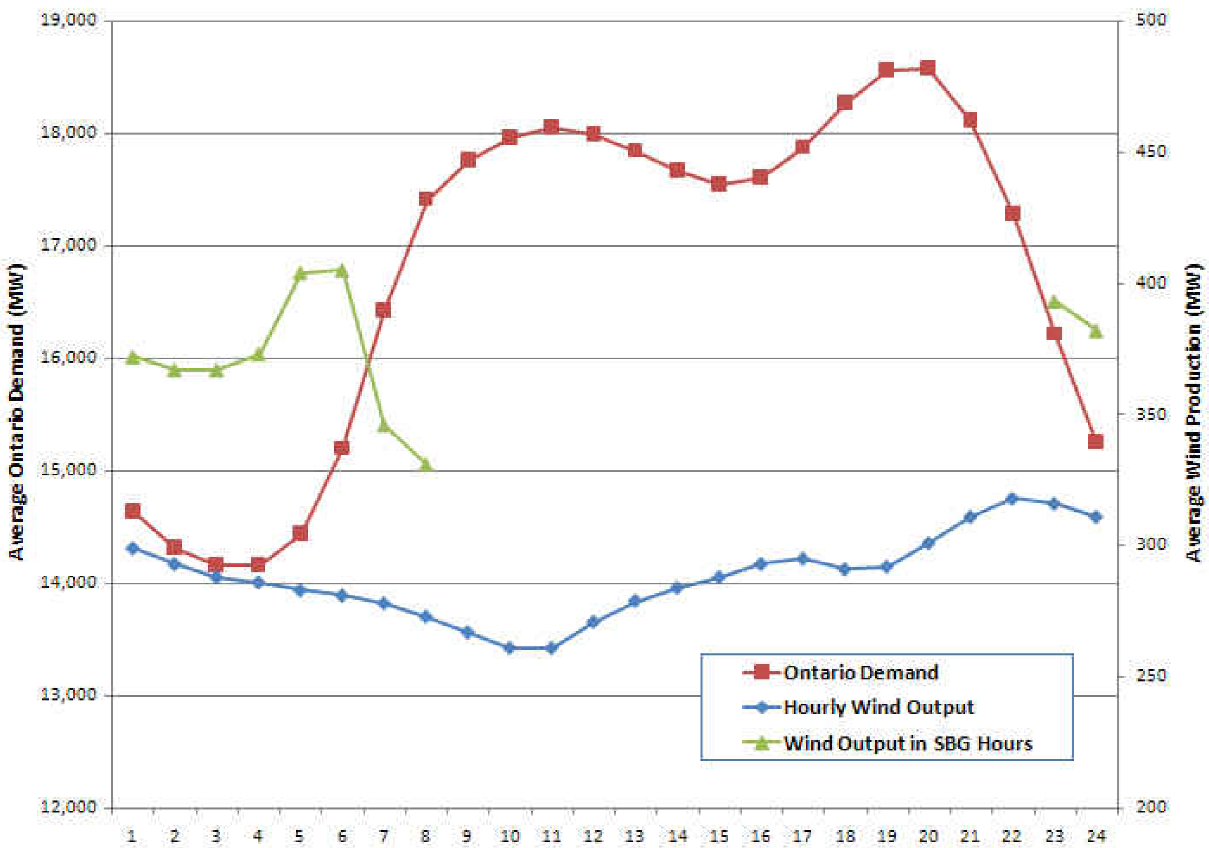
programs. These programs reduce the responsiveness of generators to market signals as the Panel has documented in its July 2007 Monitoring Report[202] and in section 3.1 of this report.

Negative HOEP has different impacts on generators, depending on the type of contracts/regulations governing them and on their involvement in the IESO programs:[203]

- *Bruce A and B*: Bruce A has no financial incentive to reduce output in response to a lower HOEP as it is guaranteed a fixed-price for its production. In contrast, Bruce B does have a financial incentive to reduce output (and has done so when HOEP has been negative) if the average price for the year is expected to be greater than the floor price in its contract (because when the annual average price is greater than the floor price, Bruce B is fully exposed to the market price).
- *Generators with CES/Early Mover contracts*: these generators are motivated by their contracts to offer at marginal cost and are generally highly responsive to the market price. As a result, they are generally offline overnight when the HOEP is low or negative. However, their incentive to operate is further complicated by participation in IESO's DACP or SGOL programs as described below.
- *Renewable energy generators with an OPA contract*: such generators have no financial incentive to reduce output when the HOEP is negative. In fact, because a negative HOEP usually occurs in off-peak hours (HE 23-HE 6), and the wind is frequently stronger in off-peak hours, these generators generally produce more during negative-priced hours. Figure 3-12 below shows average wind output and Ontario Demand by hour in the period January to April 2009 and the average wind output during the SBG hours.[204] During these hours, wind generators on average produced roughly 70 MW more than they did in the same hours when there was no SBG.

[202] See the Panel's July 2007 Monitoring Report, pp. 114-127.
[203] Generators may temporarily be negatively impacted by a negative HOEP because they are required to pay the negative price in the current month settlement, but will be paid back their contractual or regulatory entitlement in the same or a later month through an additional payment corresponding to the Global Adjustment.
[204] We limited the time period to January to April 2009 to reflect the impact of the full current portfolio of wind generation capacity. Because some SBG events occurred in November and December 2008 when two large wind generators were not operating, an average wind output for the review period November 2008 to April 2009 would be lower.

Figure 3-12: Average Ontario Demand and Wind Production by Hour January – April 2009, MW



- *Generators with an NUG contract*: these generators have no financial incentive to reduce output when the HOEP is negative.
- *OPG's prescribed assets*: The OPG nuclear units have no financial incentive to respond to the HOEP. As discussed in section 3.3 above, OPG's hydroelectric units now generally have strong incentives to shift water from off-peak to on-peak where it is feasible to do so. However, at times they may have an incentive not to spill water even though the HOEP is negative, since they could lose regulated payments as a result of reduced production. During negative-priced hours OPG has been generating from its prescribed hydroelectric stations and has not reported any spill from these units.
- *OPG's non-prescribed assets*: for coal and hydroelectric generation (other than prescribed baseload hydro) OPG had limited incentive to respond to negative

prices until recent conditions led to much lower monthly average HOEPs, because of the pricing structure for these assets . Prior to about February 2009, when market payments to these assets exceeded $48/MWh, OPG would rebate a large portion of the payment (since it would retain $48/MWh plus 15 percent of the difference between market price and $48/MWh). Thus even if the HOEP were negative in several hours, if overall average prices were above $48/MWh when these assets generated, OPG might still have a financial incentive to generate[205] However, because prices in the February to April quarter of 2009 were so low, and the rebate mechanism had a roll-over provision to the next quarter, but no top-up provision, OPG's non-prescribed assets in that quarter were paid the market price. As such, to the extent this situation was anticipated by OPG, these assets would have had a strong market price signal during this period. The incentive to respond to market price at OPG's coal-fired units may have been further complicated by the cost recovery agreement between OPG and OEFC, which took effect on January 1, 2009. The Panel has not yet assessed the impact of that agreement but will review it in a future Panel report. In addition with the expiration of the non-prescribed asset payment regime on May 1, 2009, it is expected that these facilities (peaking hydro and coal-fired units) will generally be more responsive to the market price. Again, this will be reviewed in a future report.

- *Lennox*: OPG has a limited incentive to respond to the market price with its Lennox units. In the current review period, however, it was never online during an SBG event.
- *Generators under the IESO's SGOL/DACP programs*: most large gas-fired generators and all coal-fired generators are eligible for these programs. Because the fuel costs (and the O&M cost in the DACP case) for which they are reimbursed under these programs need not be related to their offers, they can be online and make a profit even when the HOEP is negative. There were occasions

[205] For example, assume OPG produced when the HOEP was -$10/MWh. The total revenue in the hour would be $39.30/MWh (i.e. $48/MWh + 15% *[-10 -48]/MWh). It would be profitable for OPG to produce as long as this revenue was greater than the production cost.

during the review period when one generator was online for SGOL even though Ontario had an SBG situation and the HOEP was negative overnight.

Table 3-10 below lists the average output from various categories of generators during the negative priced hours in the review period. One can see that out of the total 14,518 MW supply: 8,217 MW was not exposed to the market price at all; 1,541 MW from OPG's prescribed hydro was largely exposed to the market price but did not spill;[206] 1,465 MW from OPG's non-prescribed (hydroelectric) assets may have had incentives to respond to negative prices but was not spilled[207]; and 3,295 MW was largely exposed to the market price (excluding other payments for cost or revenue guarantees).

Of the 3,295 MW of supply that was fully exposed to the market price during the review period:

- 365 MW was from commissioning gas-fired generators. These generators were fully exposed to the market price and were willing to accept the financial risk so as to honour their in-service obligations in the contracts with the OPA. They were unwilling to be dispatched or shut down for SBG unless it was necessary.
- A small gas-fired generator with an early mover contract also generated 142 MW on average. This generator typically runs around the clock because of its minimum generation requirement.
- Bruce B provided 2,704 MW on average. The units at this station are guaranteed an annual floor price floor by OPA. ($45/MWh as of 2005 plus inflation adjustments). In other words, when the yearly average HOEP is less than the floor price, OPA will top up the payment. In such a situation, a negative HOEP does not affect Bruce Power's revenue. In contrast, if the yearly average HOEP is greater than the price floor, Bruce Power does not receive any payment from OPA, is fully exposed to the market, and will end up paying for production in the hours when the HOEP is negative. When it expects a yearly average HOEP greater than the price floor, Bruce Power may therefore be willing to be

[206] The reason that OPG did not spill may have been because of the payment scheme, or possibly because of the inability to spill due to environmental or safety regulations.
[207] Some spill occurred at these stations, but OPG may not have been able to reduce production below the identified 1465 MW.

dispatched down depending on whether the avoided cost of a negative HOEP exceeds the potential costs associated with manoeuvring nuclear units.[208]

- There were a few small self-scheduling generators without a NUG contract that were online in these hours and produced 85 MW on average. These generators may either have other contractual or commercial considerations, or have technical difficulties in shutting down during these hours.

Table 3-10: Average Hourly Production by Contract/Regulation Type during Negative HOEP Hours, November 2008 to April 2009

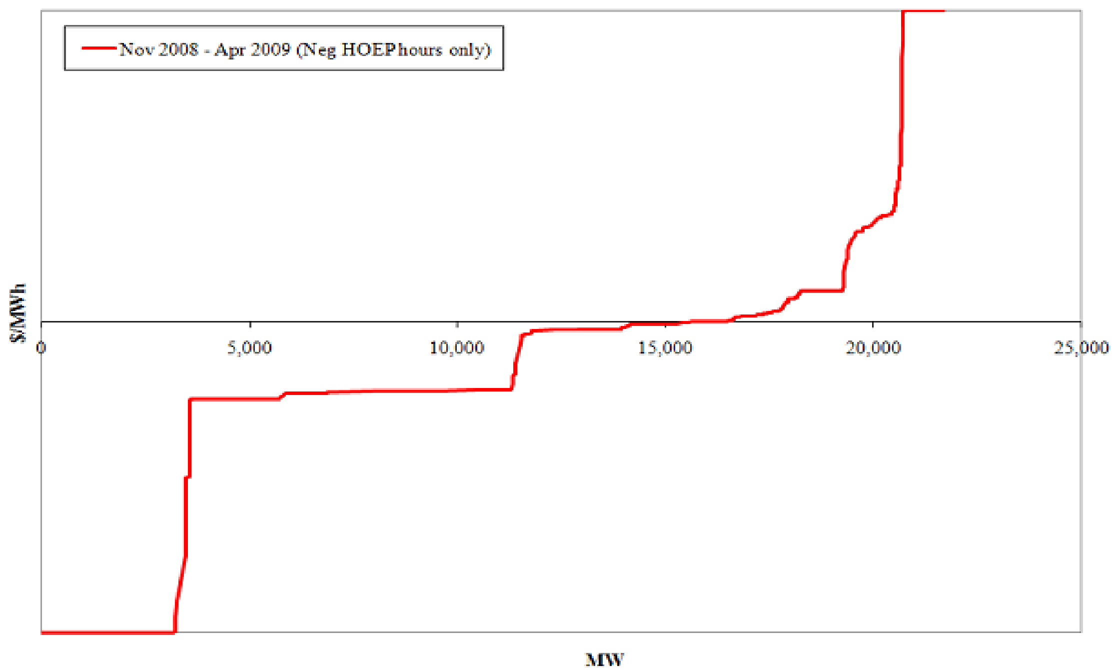
Payment Type	Resources	Output (MW)
Fixed Price Contract	Generators with a NUG contract	952
	Bruce A	1,479
	OPG Nuclear	5,485
	Wind	300
	sub total	**8,217**
Other OPG Regulated Generation	Prescribed Hydro	1,541
	Non-prescribed	1,465
	sub total	**3,006**
Market	Commissioning gas-fired units	365
	Early movers	142
	Bruce B*	2,704
	Fringe	85
	sub total	**3,295**
Total		**14,518**

*Bruce B has an annual floor price.

[208] Bruce Power in its presentation to the IESO's Market Pricing Working Group on December 2, 2008 indicated that there are generally four types of risks: (1) environmental risks, (2) equipment reliability concerns, (3) increased probability of turbine trips, and (4) human performance risks. For detail, see http://www.theimo.com/imoweb/pubs/consult/mep2/MP_WG-20081202-Presentation-SBG-Bruce_Power.pdf and http://ieso.ca/imoweb/pubs/consult/se57/se57-20090703-BrucePower.pdf.

Figure 3-13 below plots the average offer curve during the negative priced hours. It appears that of the roughly 15,000 MW of capacity that offered below $0/MWh, about 12,000 MW was offered at very low prices, which may indicate that some of these generators are insulated from the market price or they are willing to accept negative prices when generating.

Figure 3-13: Average Offer Curve during Negative-Priced Hours November 2008 to April 2009



Based on the submitted offer prices, the IESO manually selected up to 300 MW per unit of Bruce B to deal with the SBG situations, after it curtailed all possible imports. In the 200 hours with an SBG condition, Bruce B was maneuvered in 167 hours. Bruce Power has noted that maneuvering Bruce B entails costs and risks. It is costly because it requires condensing steam that has already incurred a production cost or incurring additional cost to reduce output by adjusting its production process. It is risky because maneuvering these units significantly increases the possibility of being forced out of service.[209] For these reasons, it would likely have been more efficient to dispatch down some gas-fired

[209] Although the IESO and Bruce Power coordinate manoeuvring to reduce these concerns, Bruce Power continues to views these as costly and risky. "Surplus Baseload Generation: A Nuclear Operators Perspective" presentation to Market Pricing Working Group, December 2, 2008. http://www.theimo.com/imoweb/pubs/consult/mep2/MP_WG-20081202-Presentation-SBG-Bruce_Power.pdf.

generators who have NUG contracts and/or wind-power generators even though they were offered deep into the money or self-dispatched regardless of the market price.[210]

Our understanding is that all OPA contracts with wind generators and almost all NUG contracts are based on actual production. This provides no financial incentive for these generators to respond to the market price and aggravates SBG situations. We anticipate more SBG events in the future due to more wind generation coming online as a result of the passage of the *Green Energy and Green Economy Act, 2009* and in the longer term more nuclear generation coming online (either through refurbishment or new construction).

Recommendation 3-4

In order to improve the price responsiveness of generation to low market price and Surplus Baseload Generation conditions, the Panel recommends that when Non-Utility Generation contracts are renewed and renewable energy (primarily wind-power) contracts are designed, the Ontario Power Authority and Ontario Electricity Financial Corporation should design the contracts in a way to motivate these generators to respond to the market price, at least when it is negative.

[210] Contrary to the information available from Bruce Power, there is little compiled information for the Panel to draw on to establish the costs to those other generators to reduce production. However, wind generators have acknowledged to the IESO, their ability to quickly respond to directions to reduce production. For gas-fired NUGS, costs to reduce production should be comparable to other gas-fired generation, except where it is part of a co-generation facility.

Appendix A: Comparison of the Old and New Payment Regime for OPG's Prescribed Hydroelectric Generation

The purpose of this comparison is to assess which payment approach provides a greater incentive for OPG to allocate its water resources efficiently. In this assessment, we assume that OPG is purely a profit maximizer and owns only the prescribed hydro generation. In reality, OPG is a publicly-owned generator and may serve other public interests under the direction of the Government of Ontario. The assessment embodies a number of simplifying assumptions which allow the incentives of the different payment regimes to be illustrated.

We first establish a competitive benchmark and then compare how the two payment regimes differ from the benchmark. To simplify the analysis, we use a two period (on and off-peak, or more generally high and low-price period) model. We assume the on-peak energy price is greater than the off-peak price and that hydro generating assets are considered separately from any other generation or load portfolio (i.e. the generator attempts to maximize its profit from these generation assets and is small enough not to affect market prices).

We also assume that there exists a certain amount of run-of-the-river water that must flow in each period. The generator can either generate power with the water or simply spill it, whichever is more profitable.

The payment regime for prescribed hydroelectric assets is intended to allow OPG to recover its reasonable costs (including a reasonable rate of return, as assessed by the OEB), and also to provide operational drivers for OPG to respond to the market price. Market efficiency can be improved if OPG is incented to better respond to the market price through shifting production from off-peak to on-peak, given that:

- OPG has some storage capability at these prescribed hydroelectric stations with relatively little cost to shift production, and
- OPG has a pump storage which allows it to pump water for use at a later time when it is more profitable. Because of production efficiency losses however,

roughly 1 MW of power consumed for pumping water (including lost power production at downstream units and power consumed for pumping water) can only reproduce 0.8 MW (at the pump storage generation stations and downstream units) at a later time.[211] For simplicity, we assume the cost of pumping water is $10/MWh (which includes the production efficiency loss and other operational costs) as OPG did in its OEB submissions.[212]

Decisions regarding pumping, storage and generating power are complicated because of the limitations on storage, the complexity of production at the Beck site and transmission constraints. The Beck complex also provides Automatic Generation Control (AGC) to the Ontario market as well as operating reserve, which further complicates its energy production decisions. In addition, OPG sometimes has opportunities to connect to the Quebec grid in Segregated Mode of Operation (SMO) or to enter into water transfer (WT) transactions with New York. Such decisions are affected by the system conditions in Ontario and Quebec (SMO) or NYISO (WT). The IESO may not allow SMO or recall SMO because of reliability problems in Ontario, and Quebec and/or NYISO may decide not to receive the energy from SMO or WT.

1. The competitive benchmark

For a competitive market participant that is fully exposed to the marketplace, its revenue is what it receives from the market. The simplified profit function can be written as:[213]

$$\pi_c = MW(on) * HOEP(on) + MW(off) * HOEP(off)$$

Subject to: $MW(off) + MW(on) \leq Daily\ Limit$

Where

[211] See OPG's "Undertaking J15.6" filed on July 3, 2008, p. 2.
[212] The true cost of pumping is variable, including charges in the market (such as uplift charges and transmission charges) and depending on the production efficiency loss and the price differential between the fixed payment and the market price when water is pumped.
[213] This is the gross revenue function, but can be considered as a simplified profit function. The complete revenue function is necessarily very complicated, and would include the storage shift of water from off-peak to on-peak, pumping water from off-peak to on-peak, selling water or power under SMO/WT at on- and/or off-peak, and various prices including the on- and off-peak price, sale price of SMO/WT, and the variable water pumping costs. The profit function depends on the revenue and the costs of operation and water rental. For comparison simplicity, we assume the costs of operating the stations and water rental are the same for a competitive firm and OPG. Thus comparing the revenue is equivalent to comparing the profit.

MW(on) -- the output at on-peak
MW(off) -- the output at off-peak
HOEP(on) -- the energy price at on-peak
HOEP(off) -- the energy price at off-peak
Daily Limit -- the daily energy limit

Recognizing the additional profit opportunities from pumping and SMO/WT, the optimal strategy of the competitive firm is:

- To maximize output at on-peak, given a higher *HOEP(on)* than the *HOEP(off),* and produce at off-peak even though *HOEP(off)< HOEP(on)* if not producing will lead to spill water.
- Not to produce when the HOEP, either on-peak or off-peak, is negative, even though this means spilling water.
- To pump water off-peak as long as {*HOEP(on)-HOEP(off)*} > \$10, because every MW shifted from off-peak to on-peak will make a profit of {*HOEP(on)*-*HOEP(off)*-10}.
- To operate under SMO or WT off-peak if the sale price is greater than the *HOEP(off)* or on-peak if the sale price is greater than the *HOEP(on)*.

Illustrative examples:

We focus on the generation, water-shifting and pumping decisions in the following numerical examples. Assume the on-peak price is \$40/MWh. The production decision of a competitive firm then depends on the off-peak price. Given the assumptions of a \$10/MWh pumping cost, the competitive firm's production decisions are listed in Appendix A Table 1 below.

Appendix A Table 1: Illustrative Examples of the Generation Decisions of A Competitive Firm

HOEP(on) ($/MWh)	HOEP(off) ($/MWh)	Generation Decision		Shift Decision	Pumping Decision
		On-peak	Off-peak		
40	30.01	Yes	Yes	Yes	No
40	20.01	Yes	Yes	Yes	Yes
40	10.01	Yes	Yes	Yes	Yes
40	0.01	Yes	Yes	Yes	Yes
40	-10.01	Yes	No	Yes	Yes
40	-20.01	Yes	No	Yes	Yes
40	-40.01	Yes	No	Yes	Yes

Each column in the Table should be treated independently, since for example generation off-peak would preclude shifting water on-peak, and by implication the table does not identify which alternative to pursue between columns. The firm has incentive to shift water from off-peak to on-peak in all cases, but will not pump water when the price difference between on-peak and off-peak is smaller than the cost of pumping ($10/MWh). The generator will stop generating power when the price is negative (i.e. off-peak).

2. The old payment structure

Under the old payment structure, OPG was paid $33.00/MWh for output up to 1,900 MW in each hour, and then the market price (HOEP) for energy above 1,900 MW. In a two period model, the profit function for OPG can be expressed as:

$$\pi_0 = \{Min[1900, MW(off)] + Min[1900, MW(on)]\} * 33$$
$$+ Max[0, MW(off) - 1900] * HOEP(off)$$
$$+ Max[0, MW(on) - 1900] * HOEP(on)$$

Subject to: $MW(off) + MW(on) \leq Daily\ Limit$

Assume the minimum production without spill is lower than 1,900 MW and the on-peak output can go above 1,900 MW. Again, accounting for pumping and SMO/WT, the optimal strategy is illustrated in Appendix A Table 2 below.

Appendix A Table 2: Generation Decisions under Different Scenarios Under the Old Payment Regime

Scenario	Scenario 1 [HOEP(on)<$33 but >0 and HOEP(off)<$33]	Scenario 2 [HOEP(on)>$33 and HOEP(off) <$33]	Scenario 3 [HOEP(on)>$33 and HOEP(off)>$33]
Generation Decision	• Maximize output up to 1,900 MW in both on- and off-peak and use the rest water in on-peak • Produce and won't spill water when HOEP(off) <0	• Maximize on-peak output • Produce and won't spill water when HOEP(off) <0	• Maximize on-peak output
Shift Decision	No shifting	Shift from off-peak to on-peak	Shift from off-peak to on-peak
Pumping Decision	No pumping	Pumping When *HOEP(on)*- $33 >$10	Pumping When *HOEP(on)*- $33 >$10
SMO or WT	• To use SMO or WT whenever the sale price is greater than $33/MWh, or • at on-peak if the sale price is greater than *HOEP(on)* and the *MW(on)* must be greater than 1,900 MW	• To use SMO or WT at off-peak if the sale price is greater than $33/MWh, or • at on-peak if the sale price is greater than *HOEP(on)*.	• To operate under SMO or WT at off-peak if the sale price is greater than $33/MWh , or • at on-peak if the sale price is greater than *HOEP(on)*.

In the following example, we focus on the second scenario in which the on-peak price is greater than $33/MWh while the off-peak price less than $33/MWh as has been common in the past few months.

Appendix A Table 3: Illustrative Examples of Generation Decisions Under the Old Payment Regime

HOEP(on) ($/MWh)	HOEP(off) ($/MWh)	Generation Decision		Shift Decision	Pumping Decision
		On-peak	Off-peak		
40	30.01	Yes	Yes	Yes	No
40	20.01	Yes	Yes	Yes	No
40	10.01	Yes	Yes	Yes	No
40	0.01	Yes	Yes	Yes	No
40	-10.01	Yes	Yes	Yes	No
40	-20.01	Yes	Yes	Yes	No
40	-40.01	Yes	Yes	Yes	No

Under the old payment regime and the assumption that the on-peak price is greater than $33/MWh while the off-peak price is less than $33/MWh, OPG would have incentives to shift water from off-peak to on-peak. It would also have the incentive to generate power all the time, even when the HOEP is negative. It would have no incentive to pump water, in this example where the on-peak price is only $40/MWh.

3. The new payment structure

Under the new payment structure, the simplified profit equation is:

$$\sum_t \text{MWavg} * \text{RegRate} + (\text{MW}(t) - \text{MWavg}) * \text{MCP}(t)$$

Subject to $\sum_t \text{MWavg} \leq \text{Daily Limit}$

In a two-period model, the equation can be written as:

$$\pi_N = [MW(on) + MW(off)] * RegRate$$
$$+[MW(on) - MWavg] * HOEP(on)$$
$$+[MW(off) - MWavg] * HOEP(off)$$

Subject to: $MW(off) + MW(on) \leq Daily\ Limit$

Where: $MWavg = [MW(off) + MW(on)]/2$

The profit function can be further rewritten as:

$$\pi_N = [MW(on) + MW(off)] * 38.84$$

$$+[MW(on) - MW(off)] * [HOEP(on) - HOEP(off)]/2$$

Subject to: $MW(off) + MW(on) \leq Daily\ Limit$

Under the new regime, the optimal strategy is:

- To maximize on-peak output, as total revenue is positively related to on-peak output *MW(on)* and the incremental revenue at on-peak is greater than the incremental revenue at off-peak,[214]
- Not to produce at off-peak when the [*HOEP(on)-HOEP(off)*]/2 is greater than 38.84, but produce off-peak if [*HOEP(on)-HOEP(off)*]/2 is less than 38.84,[215] which could include situations where the *HOEP(off)* is negative,
- To pump water at off-peak if {*HOEP(on)-HOEP(off)*} > $10 because every MW shifted from off-peak to on-peak would generate a revenue of {*HOEP(on)-HOEP(off)*} which is greater than the $10 cost of pumping,[216] and
- To operate under SMO or WT at off-peak if the sale price is greater than $38.84-{*HOEP(on)-HOEP(off)*}/2, or at on-peak if the sale price is greater than $38.84+{*HOEP(on)-HOEP(off)*}/2.[217]

[214] The marginal revenue of on-peak output is 38.84+ [*HOEP(on)-HOEP(off)*]/2 which is positive and greater than the marginal revenue of off-peak output 38.84- [*HOEP(on)-HOEP(off)*]/2 as long as *HOEP(on)* is greater than *HOEP(off).*

[215] If a further shifting of water from off-peak to on-peak is impossible and the marginal revenue of off-peak output 38.84-[*HOEP(on)-HOEP(off)*]/2 is greater than 0, OPG has incentives to generate power at off-peak. In other words, OPG would be motivated to run rather than spill water when the HOEP is negative, while a competitive firm would spill water to avoid a negative HOEP.

[216] The revenue results from an 1 MW decrease in *MW(off)* and consequentially an 1 MW increase in *MW(on)*. The net result is {1-(-1)}*{*HOEP(on)-HOEP(off)*}/2, which is {HOEP(on)-HOEP(off)}.

[217] A MW removed at off-peak will result in a loss of $38.84-{*HOEP(on)-HOEP(off)*}/2 in revenue, and a MW removed at on-peak leads to a loss of $38.84+{*HOEP(on)-HOEP(off)*}/2 in revenue.

The incentives under the new regime are summarized in the following table.

Appendix A Table 4: Illustrative Examples of Generation Decisions Under the New Payment Regime

HOEP(on) ($/MWh)	HOEP(off) ($/MWh)	Generation Decision		Shift Decision	Pumping Decision
		On-peak	Off-peak		
40	30.01	Yes	Yes	Yes	No
40	20.01	Yes	Yes	Yes	Yes
40	10.01	Yes	Yes	Yes	Yes
40	0.01	Yes	Yes	Yes	Yes
40	-10.01	Yes	Yes	Yes	Yes
40	-20.01	Yes	Yes	Yes	Yes
40	-40.01	Yes	No	Yes	Yes

Under the new payment regime, OPG would have incentives to shift water from off-peak to on-peak and to generate power all the time except when the HOEP has a large negative value. When the HOEP has a large negative value, the loss in revenue due to the adjustment (the second term in the profit function) would be greater than the increase in revenue from the regulated price (the first term in the profit function). It has incentives to pump water whenever the on and off-peak HOEP difference is greater than $10/MWh.

4. Assessment

The old payment regime had complicated implications for OPG's shifting and pumping storage decisions. The new payment regime is closer to the competitive case in most situations. Appendix A Table 5 below summarizes the major implications under the three different scenarios.

Appendix A Table 5: Summary of the Comparison of the Three Scenarios

Strategy	Competitive Benchmark	Old Payment Regime	New Payment Regime
Production	On-peak preferred, and will not produce when HOEP is negative	On-peak is preferred, but will produce and won't spill water at off-peak even when the HOEP is negative.	On-peak preferred, but may produce when the HOEP is negative.
Water Shifting	Yes	Yes	Yes
Pumping	When *HOEP(on)-HOEP(off)* > $10	When *HOEP(on)* - $33 >$10	When *HOEP(on)-HOEP(off)* > $10
SMO or WT	(1) off-peak if the sale price > *HOEP(off)* (2) on-peak if the sale price is greater than *HOEP(on)*	(1) off-peak if the sale price >$33/MWh (2) on-peak if the sale price > *HOEP(on)*	(1) off-peak if the sale price > $38.84-{*HOEP(on)-HOEP(off)*}/2 (2) on-peak if the sale price > $38.84+{*HOEP(on)-HOEP(off)*}/2

It can be seen that new payment regime should improve market efficiency because the pumping decision incentives under the new regime are the same as under the competitive benchmark. In a negative HOEP environment, there remains some incentive to produce under the new payment regime (given the various assumptions above). This is inconsistent with the competitive case and may lead to market inefficiency.

Both the new and old regimes lead to a different SMO/WT decision from the competitive case, indicating an efficiency loss under either regime. Because of unavailability of the sale prices for SMO/WT, it is difficult to assess which approach would result in a smaller efficiency loss. Given that the amount of exports under SMO/WT is traditionally small, the efficiency differential between the two regimes may be relatively modest.

Appendix A Table 6 below summarizes the difference between the three payment regimes using the HOEPs from the previous examples. The decision to shift water is not listed as it is the same under the three regimes. It can be seen that the pumping decision is exactly the same for a competitive firm and OPG under the new payment regime regardless of HOEP levels. Although the response to small to moderate negative prices is similar under the old and new payment regimes, the new regime does provide incentives for OPG to stop producing when a large negative HOEP is expected. This is an efficiency improvement relative to the old regime.

Appendix A Table 6: Comparison of Three Scenarios

HOEP(on) ($/MWh)	HOEP(off) ($/MWh)	Generation Decision (Off-peak)			Pumping Decision		
		Competitive	Old Regime	New Regime	Competitive	Old Regime	New Regime
40	30.01	Yes	Yes	Yes	No	No	No
40	20.01	Yes	Yes	Yes	Yes	No	Yes
40	10.01	Yes	Yes	Yes	Yes	No	Yes
40	0.01	Yes	Yes	Yes	Yes	No	Yes
40	-10.01	No	Yes	Yes	Yes	No	Yes
40	-20.01	No	Yes	Yes	Yes	No	Yes
40	-40.01	No	Yes	No	Yes	No	Yes

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Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is our 14th semi-annual Monitoring Report of the IESO-administered markets. It covers the winter period, November 2008 to April 2009. As in our previous reports, we conclude that the market has operated reasonably well according to the parameters set for it, although there were occasions where actions by market participants or the IESO led to inefficient outcomes.[218] As is customary, the MAU communicated with market participants from time to time to review and understand market behaviour. One such situation involved behaviour and pricing by a generator in the SGOL program, for which an assessment is still ongoing.

We again observed some areas of concern that affect market efficiency and have made recommendations for improvement. These recommendations are summarized at the end of this Chapter.

The average monthly HOEP of $40.98/MWh was $8.18/MWh (16.6 percent) lower than the HOEP corresponding to the same period a year ago. The on-peak HOEP was 18.1 percent lower and off-peak HOEP was 14.5 percent lower. The effective HOEP, which is a load weighted measure of price that takes into account the OPG Rebate and Global Adjustment, increased period-over-period by $3.69/MWh (6.8 percent) to $58.08/MWh this year, even though load-weighted HOEP by itself fell $7.78/MWh (or 15.2 percent).

A major cause for the decrease in HOEP was the lower Ontario Demand experienced this period due in large part to the downturn in the economy. The HOEP dropped dramatically in March and April 2009 compared to the same months in 2008, by 55 percent and 71 percent respectively, due to a further reduction in market demand which

[218] In spite of the Panel's general conclusion that the market operated reasonably well according to the parameters set for it, the Panel observes that as usual there have been many instances of CMSC adjustment through the administrative activity performed by the MAU under the Local Market Power mitigation rules.

was the result of intertie outages at New York in late March to mid April severely limiting exports. As the Panel has previously observed, a lower HOEP generally leads to an offset in Global Adjustment of somewhat similar magnitude.[219] HOEP was so low in these last two months of the period that the Global Adjustment was almost as large as the average HOEP in March, and more than twice as large (106 percent higher) in April.

Ontario Demand fell this winter to 73.3 TWh, which is 3.6 TWh or 4.6 percent lower than last year. The decrease was partly due to lower consumption by local distribution companies (which deliver power to residential and small business consumers), which moved from a four year peak for monthly consumption in January to the lowest levels recorded since market opening in April. However, the majority of the Ontario Demand decrease was due to consumption by wholesale load which was persistently low for the entire period, with demand in every month being lower than any previous month recorded since market opening. This culminated in the lowest monthly level in April at 1,700 GWh, which is about 20 percent below October 2008, representing the lowest monthly level seen in any earlier period, and about 1/3 below typical consumption (in 2004) prior to the onset of the downward trend.

In this period, there were 8 hours when HOEP exceeded $200/MWh, compared with only 2 hours last year. There were 689 hours (approximately 16 percent of all the hours over the period) with prices below $20/MWh, compared to 261 hours in the same period last year, continuing a trend toward more low-priced hours in the past four years, as shown in Table 2-15 in Chapter 2. These included 219 hours with a negative HOEP, almost all of which occurred in March and April. Our review of these and other apparently anomalous hours led us to conclude that the price movements in these hours were, for the most part, consistent with the supply/demand conditions prevailing at the time. The emergence of a large number of hours with negative prices is, however, of some interest and is discussed further in the next section.

[219] For a review of the impact of the Global Adjustment and the OPG Rebate on the effective price, see Chapter 1,section 2.1.2.

The six-month average coal price was higher this winter compared to the previous year, by 38 percent for Central Appalachian coal and 17 percent for Power River Basin coal, while the six-month average gas price was lower by 24 percent. From November 2008 to April 2009 both coal and gas price fell, by 36 percent and 43 percent, respectively. However, both coal and natural gas fuel prices started the current winter period at prices higher than the same month a year earlier and ended at prices below the previous year.

As demand fell this winter, there was a shift in the price setting fuel at the margin. Coal was the marginal on-peak price setter 50 percent of all intervals, compared to 44 percent in the same period last year. In the off-peak, coal set prices 70 percent of the time compared to 76 percent in the prior year period. The shifts were most pronounced in off-peak periods in April. Coal fell from being the price setter 65 percent of the off-peak intervals in April last year to 28 percent this April, while hydroelectric grew from 31 percent to 48 percent. Nuclear generation, which rarely set prices before this winter, was the price setter 19 percent of the off-peak intervals this April.

Market-related hourly uplift payments for congestion, import guarantees, and other matters were about 14 percent lower than the corresponding period a year ago. There was a large reduction in IOG payments and costs for transmission losses, totalling $38 million, almost half of which was offset by an increase in Operating Reserve (OR) payments.

- Lower IOG payments were due to a combination of lower demands and lower prices, which led to fewer imports and a lower spread between pre-dispatch prices and HOEP.
- The cost of transmission losses was lower because these are essentially priced at HOEP, which was lower.
- Higher OR requirements and less OR supply led to higher prices and increased purchases of OR, and therefore higher payments.

- There were only small changes to CMSC payments across the province (except for some reduction in payments for Dispatchable Loads),

Nodal prices in most parts of the province (except the north) fell 22 to 24 percent compared to last year, similar to the change in the Richview nodal price. This winter the zonal price in the Northwest fell dramatically, to an average six-month record low of minus $272/MWh, compared with the average six-month zonal price of minus $44/MWh last winter. Further reductions in demand in the Northwest, coupled with abundant low-priced domestic and import supply, continue to cause congestion on the East-West tie lines to the rest of the province and bottling of supply. Therefore, conditions have driven hydroelectric generation to lower offer prices in an attempt to avoid spill.

The remainder of this Chapter is organized as follows: section 2 discusses the emergence of a large number of hours with negative HOEP and the increasing tendency toward more periods with Surplus Baseload Generation. Section 3 reports on the IESO's and others actions in response to previous Panel recommendations. Finally, section 4 excerpts and lists the recommendations made in the body of this report.

2. Negative Priced Periods and Surplus Baseload Conditions

In the above summary for the period, we noted two conditions that have been relatively unusual in the past but were fairly common in March and April this winter – negative HOEP and nuclear generation setting price. Low (especially negative) prices and nuclear generation being at the margin frequently occur during what the IESO refers to as a Surplus Baseload Generation (SBG) condition. This condition means that there is more "baseload" generation available than is needed to meet the total Ontario Demand and net exports. [220] Negative prices and SBG represent significant issues from the perspective of

[220] As discussed in Chapter 3, the IESO defines SBG as the condition "when the amount of baseload generation (which may largely consist of a supply mix of high minimum load fossil, nuclear and run-of-the-river hydroelectric resources) exceeds the market demand" (IESO Internal Procedures).

market efficiency (the inability to use very low cost generation); and reliability (since demand and generation must always be balanced).

The main contributor to the negative prices and nuclear at the margin was the low market demand experienced this winter, induced by the weaker economy and intertie outages which severely limited exports for several weeks. Although the outages were short-lived, and demand may recover over time, the Panel anticipates that SBG outcomes will continue to occur in the Ontario market with some frequency for an extended period of time. This is partly because of the large quantity of baseload generation currently in-service, the expected increase in renewable energy capacity in Ontario (and neighbouring jurisdictions which may limit export opportunities in the future), and the expected restart of 1,500 MW of nuclear generatio. The Panel believes that market mechanisms or at least market-friendly mechanisms are the best way to deal with SBG conditions.

Conditions observed this winter

As reported in Chapters 1and 2, and discussed in more detail in Chapter 3, section 3.4, this winter Ontario experienced very low HOEP prices and extended periods of SBG. HOEP was negative in 219 hours, nuclear generation set prices 3 percent of the time (equivalent to about 112 hours), and IESO identified SBG conditions in 200 hours.

Most of the SBG and low prices were experienced off-peak. At times the situation was worsened by the coincidental interface limitations at New York, which severely reduced export demand to New York and MISO, or by large amounts of failed exports to external markets cut because of SBG situations in those markets. At other times SBG was avoided because of the large quantities of nuclear generation that was on planned outage for an extended period of time.

While gas-fired generation would not normally be economic off-peak, we saw a surprising amount of it online even during low demand periods. Some of this was due to new units going through their commissioning process. Some of the generation was online because of the poor design of the SGOL program which occasionally encouraged gas units to start-up at the end of the day, and run for several hours overnight to satisfy their lengthy minimum run-time requirements. Coal-fired generation might also run occasionally overnight at minimum levels to avoid the cost of a start-up or the higher likelihood of a run-back or forced outage when starting. Other generators, such as self-scheduled NUGs (which is in large part are gas-fired) and intermittent generation (wind etc.) were also running in overnight hours, including periods with low prices and SBG.

Additional new generation is planned

With the shut-down of coal-fired generation expected by 2014, the OPA has added and is planning to bring more new generation on-line. Some of this is new gas-fired generation. The *Green Energy and Green Economy Act, 2009* is representative of an accelerated interest in renewable energy, which over the next years is anticipated to encourage (through Feed-in Tariffs or FIT[221]) substantial new intermittent renewable generation. Some 2,500 MW of new-gas-fired generation is also planned to come in service from May 2009 to 2013 along with 1,500 MW of re-furbished nuclear generation.[222]

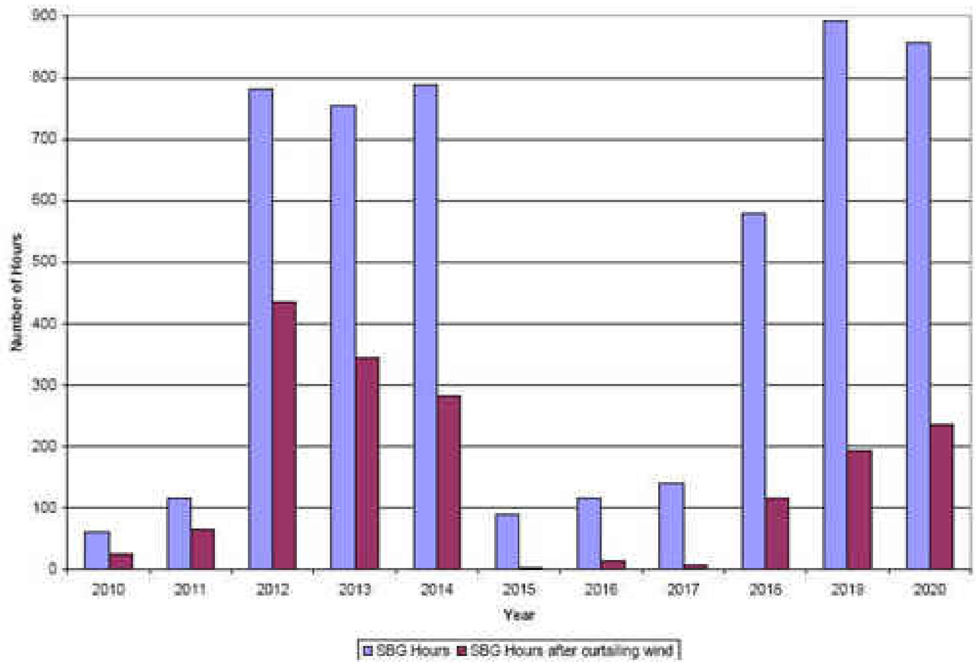
As noted in Chapter 3, during the Integrated Power System Plan (IPSP) proceedings the IESO had forecast increasing SBG events in the future (as shown in Figure 4-1 produced below).[223] This projection showed well-under 100 hours of SBG in 2010 growing to over 800 in 2020.

[221] See OPA's website: http://www.powerauthority.on.ca/FIT/

[222] For details, see OPA's website: http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=123. Above we refer to the restart of 1,500 MW of nuclear capacity, although the original OPA contract for Bruce A included 3,000MW, 1,500 MW of which is already in operation.

[223] IESO, "Operability Review of OPA's Integrated Power System Plan", April 21, 2008.

Figure 4-1: Projected Number of Hours with SBG, 2010 to 2020 (IESO Projection for IPSP)



Actual SBG conditions could well be higher than this projection from early 2008. Lower market demand has induced 200 hours of SBG in the six months ending April 2009 alone. For later years, with more renewable energy now being targeted through the *Green Energy and Green Economy Act, 2009* the number of hours with SBG may become larger for two reasons. First, the vast majority of green energy generators are expected to be wind-power generators, which are traditionally non-dispatchable. Second, wind-power generators typically have their highest output overnight when the SBG condition is more likely to occur.

Market-friendly Steps for Reducing SBG

Well-structured contracts or other pricing-arrangements and improvements in the functioning of the market can help alleviate some of these anticipated problems. The Panel reported in Chapter 3 how recent changes to regulated pricing for OPG's baseload hydroelectric generation shift production incentives from off-peak to on-peak hours. With a variety of new generation programs and contracts being developed, there are opportunities to design these to be at least partially responsive to market prices. Finally, the IESO has been modifying some of its procedures and programs to respond better to SBG and low prices, although there may be opportunities for further improvement.

Because many Ontario generators have contractual or regulated pricing arrangements,[224] which may undermine the link between market prices and the compensation received by the generator, low or even negative market prices alone do not necessarily provide incentives to reduce production. Consequently, efficiency may be reduced if a contract price encourages a more expensive generator to run while a less expensive unit, or a unit with a high cost of reducing production, is constrained down or shut down during SBG conditions. Chapter 3, section 3.4 provides an assessment of how different market participants and groups of generators might respond to low prices.

For example, a wind generating unit or NUG would have an incentive to continue to generate even with negative prices, because of the relatively large payments guaranteed in their contracts. If such units continue to generate during SBG events, a nuclear unit may have to manoeuvre (reduce output) or water at hydroelectric plants might be spilled. Significant costs or risks to equipment or risks of being forced out-of-service may be incurred to manoeuvre nuclear output, while incremental costs to reduce wind or hydro production may well be close to zero. Consequently, the efficient solution would generally be to run the nuclear plant while reducing output at the others.[225]

In 2008 OPG's regulated baseload hydroelectric generation moved to a pricing arrangement which relies on the market price as the marginal driver for production (see chapter 3 section 3.3). This has led to an observable reduction in off-peak production. At the end of April 2009, regulated pricing ended for OPG's non-prescribed assets, including its peaking hydroelectric[226] and coal generation, although market prices may

[224] This includes Pickering, Darlington, Bruce A, wind and other renewable generation, and NUGs OPG's baseload hydroelectric plant has regulated pricing for its average production but marginal pricing drivers for marginal production. Until April 2009 OPG's peaking hydroelectric and coal generation also had regulated prices, although market prices may have been a driver for these as of February 2009, as discussed in more detail in Chapter 3.
[225] Wind-powered generation or gas-fired NUGS may be good candidates for reduction, assuming the latter are, not part of a cogeneration operation.
[226] OPG's peaking generation includes stations that have abundant water during extended periods of the year, primarily during spring runoffs.

have been a driver for these as of February 2009 as we discussed in detail in Chapter 3, With the expiring of regulated pricing, these units will be paid market prices, which now becomes more of a driver for production. This should enhance market efficiency by encouraging generation to minimize production in low and negative-priced hours, either by moving energy-limited production to higher priced hours or by spilling water rather than producing.

The Panel understands that the OPA is contemplating contracts for other hydroelectric generation.[227] Like OPG's restructured regulated rates for its baseload hydroelectric payments and as previously recommended by the Panel,[228] we encourage the OPA to seek pricing arrangements in any new contracts that maintain the market energy price as a driver for production.

The Panel also understands that some NUG contracts are terminating or coming up for renewal, with significant contracts beginning to expire in 2012.[229] Ideally these renewed contracts would also use HOEP as a price driver, like OPA's CES contracts. With respect to FIT payments for new renewable generation, OPA's draft FIT contract includes payment mechanisms that would provide incentives to wind generation to shut down during low-priced or negative priced hours.[230] Accordingly, the Panel is recommending that contracts be designed to motivate these generators to respond to market price, at least when it is negative. (See section 4).

The Panel encourages the IESO to continue its efforts to improve its programs and procedures to allow the market to respond efficiently to low-price conditions. The Panel has discussed and made recommendations with respect to the following four items:

[227] Pursuant to the December 20, 2007 and May 7, 2009 Directives from the Minister: http://www.powerauthority.on.ca/Storage/61/5625_December_20%2C_2007_Hydro_Electric_Agreements_with_OPG.pdf and http://www.powerauthority.on.ca/Storage/100/9573_May_7_2009_Negotiating_New_Contracts_Hydro-Electric.pdf
[228] See the Panel's December 2007 Monitoring Report, review of contracts pp. 169-185, and ***Recommendation 3-8*** p.183
[229] For details, see: http://www.powerauthority.on.ca/Storage/32/2744_APPrO_Presentation_Nov15_PJB-JCA.pdf.
[230] FIT Contract Exhibits - Draft June 8, 2009, Exhibit B, sections 1.4 and 1.5, http://www.powerauthority.on.ca/FIT/Storage/10/10250_FIT_Contract_Exhibits_-_Draft_June_8_2009.pdf

i) removing incentives in the existing SGOL and DACP guarantee programs for generation to be committed when not efficient, including running in overnight hours, as being contemplated in current design modifications.

ii) expanding NISL during SBG situations to allow greater levels of exports, as was initiated in June 2009;

iii) excluding expected nuclear reductions in the pre-dispatch since reducing the units in pre-dispatch simply leads to scheduling more imports or reducing exports;[231] and

iv) introducing 15-minute dispatch which would allow rescheduling imports and exports every 15 minutes in response to changing SBG conditions.[232]

The IESO has taken some action on NISL[233] and is working on revisions to the SGOL and DACP programs.[234]

3. *Implementation of Previous Panel Recommendations*

The Panel's January 2009 report contained eight recommendations, of which seven were directed at the IESO, at least in part.

3.1 Recommendations to IESO

The IESO formally reports on the status of actions it has taken in response to these recommendations. Following each of the Panel's Monitoring Reports the IESO posts this information on its web site and discusses the recommendations and its actions with the Stakeholder Advisory Committee (SAC).[235]

[231] See the Panel's January 2009 Market Report, pp. 169-171. Note, in that report the Panel reported that the IESO had modified its procedure, however, shortly thereafter it continued to apply nuclear reductions in the pre-dispatch.
[232] See the discussion in the Panel's January 2009 Monitoring Report, pp. 253-256 and Chapter 2 section 2.1.4 of the current report.
[233] See discussion in the Panel's July 2008 Monitoring Report, pp. 107-110. The Panel in its January 2009 Monitoring Report p. 258, reported that the IESO had changed its procedure, but this was for test purposes. The IESO formally adopted the modified procedure, allowing increased NISL during SBG, as of December 23, 2008. (The Panel had also encouraged the IESO to increase NISL in other situations as well, such as high-priced hours, but this has not occurred).
[234] See proposed amendments for MR-00356, http://www.ieso.ca/imoweb/pubs/mr2009/MR-00356-R00-R02.pdf
[235] See latest presentation to SAC, "IESO Response to MSP Recommendations" dated June 2, 2009 at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20090602.pdf

In this section we review the status of the recommendations from our last Monitoring Report, released in January 2009. The IESO responses to these are summarized in Table 4-1 below.

Table 4-1: Summary of IESO Responses to Recommendations

Recommendation Number & Status	Subject	Summary of Action
2-1 **Open** **Low Priority**	Ramping of Intertie Schedules	"Industry processes typically have successful transactions ramping in and out a little before and a little after the start and end of the hour… however settlement for these transactions remain within the bounds of the scheduling hour. … In order to be consistent with the industry standard the unconstrained (or market) sequence is reflective of participant offers/bids… That being said, the IESO does acknowledge that the current method does create two interval prices." "This change would require system changes and as settlements are working appropriately and there are no operational concerns, the IESO assigns this recommendation a low priority."
2-2 **Open** **Low Priority**	Applying Failure Code to Specific Intervals	"The IESO has been aware of this issue and is currently looking at possible solutions and these changes are currently given a low priority."
3-1 (2-1) **Open** **Low Priority**	IESO's Supply Cushion Calculation (used for DR3)	"The IESO acknowledges the differences in the MSP and IESO supply cushion calculations and will consider the appropriate changes. At this time, the IESO supply cushion calculation is … consistent with the capacity calculation that is published in the System Status Report and the IESO believes that being consistent with this application is important."
3-2 **In Progress** **Q1, 2010**	Limiting Self-induced CMSC for Generator Ramp-down	"The IESO agrees with this recommendation [and]… require[s] market rule amendments. This … currently sits with the Technical Panel (MR-00252)." This market rule is expected to be completed by the end of Q1 2010."

Recommendation Number & Status	Subject	Summary of Action
3-3 **In Progress Q3, 2009**	DACP Generator Cost Guarantee Based on Submitted Offers	"The IESO agrees with this recommendation and initiated market rule amendment MR-00356: Interim Changes to Real-Time and Day-Ahead Generation Cost Guarantee Programs"
3-4 **In Progress Q3, 2009**	Operating Reserve from Gas-Fired Generation	"A solution to this issue is being proposed under market rule amendment MR-00356"
4-1(i) **In Progress Q3, 2009**	Centralized Wind Forecasting	"The IESO agrees with this MSP recommendation and is working on the assessment of benefits for centralized renewable forecasting into the IESO controlled grid. [As part of] … IESO SE-57 (Embedded and Renewable Generation) … the IESO is considering all of the recommendations identified … in the NERC special report on 'Accommodating High Levels of Variable Generation' "
4-1(ii) **In Progress Q4, 2010**	15-Minute Dispatch	"[As part of] … IESO SE-57 (Embedded and Renewable Generation) … the IESO is considering all of the recommendations identified … in the NERC special report on 'Accommodating High Levels of Variable Generation' " "Investigation of a 15-minute dispatch algorithm will be explored under SE-61 … (Exploration of Enhancements to Dispatch Methodology and Processes)."

The Panel notes that the IESO generally agrees with the relative priorities the Panel assigned to recommendations in the January 2009 Monitoring Report. The IESO is in the process of reviewing or modifying its rules or procedures for each recommendation identified by the Panel as being ranked number 1 in the categories of price fidelity, dispatch and hourly uplift payments. The IESO has assigned a 'Low Priority' to three of the Panel recommendations, but each of these are at the low end of the rankings applied by the Panel.

As an extension to its prioritization efforts, in February 2009 the Panel reviewed all of the recommendations made to the IESO during its four reports covering the period November

2006 through October 2008. A complete list of the recommendations to the IESO during this period, the Panel's identification of the highest priorities, and the implementation status is included in Appendix 4-A of this chapter.

3.2 Other Recommendations

The winter 2008 Monitoring Report made two recommendations to the OPA: i) that it review the effectiveness and efficiency of the DR3 program with a view to improving its targeting of high-demand and/or high-priced hours, and ii) until that review is completed, that it improve its targeting by working with the IESO to improve the supply cushion metric used to trigger activations, and develop other more effective triggers. As noted above, the IESO has not made changes to its supply cushion. OPA viewed the Panel's assessment of the first three months of DR3 as covering an unrepresentatively brief a period and, so far as the Panel is aware, has not implemented any changes to address the Panel recommendations. [236] The Panel understands however, that with respect to improvements in activation of DR3, OPA is considering several opportunities including the suggestion that the IESO undertake to improve Supply Cushion calculations with respect to import offers As indicated in Section 2.4 of Chapter 3 of this report, the Panel's assessment of the further six months of DR3 operation during the past winter period reconfirmed the prior findings and the Panel therefore reiterates in this report its prior recommendations.

The Panel's January 2009 Report studied two situations where market participants were required to consider environmental compliance issues, and recommended that energy offers should reflect such costs. As summarized in Chapter 3, section 2.3, the market participant that was under-pricing its energy offers through the use of a negative adder has reduced, but not eliminated, the frequency and magnitude of its negative adder.

[236] OPA has indicated to the Panel that it has modified its day-ahead supply cushion targets, to more closely align triggers used for day ahead Standby Notice with an event day Standby Notice and Activation Notice. This adjusts for different information regarding imports available during the day-ahead selection.

The second environmental issue involved OPG's strategy for compliance with its coal emission targets. As reported in Chapter 3 section 2.2, OPG has chosen to reduce its reliance on a flat adder, which the Panel believes is the offer strategy most likely to efficiently target an energy-limited resource into the periods where it has the greatest value to the market. Moreover, OPG is continuing to use strategies which may result in withholding capacity from the market beyond the level needed to meet its 2009 CO_2 emissions target. As a result, the Panel will continue discussions with OPG and conduct a more detailed assessment of OPG's coal-fired generation offers during the remainder of 2009.

4. Summary of Recommendations

The IESO's Stakeholder Advisory Committee has encouraged the Panel to provide information about the relative priorities of the recommendations in its reports.[237] In doing so, the Panel notes that it has in the past and will continue to provide efficiency, frequency or other measures of quantitative impact where this is feasible, but that some issues are not readily quantifiable. In addition, the Panel has always recognized that recommendations may have implications which extend beyond its focus on market power, gaming and efficiency and that the mandate and resources of the Panel do not extend to stakeholdering of potential changes or detailed assessments of implementation issues. Accordingly, many of the Panel's recommendations are framed as encouraging responsible institutions such as the IESO to consider whether, when and how a particular recommendation should be implemented, including process issues such as whether stakeholdering is useful and the use of detailed cost-benefit analysis or other forms of evaluation.

As in the previous report, the Panel considered that it would be useful to group the recommendations thematically by category: price fidelity, dispatch and uplift

[237] See Agenda Item 4 in the minutes of the February 6, 2008 meeting of the Stakeholder Advisory Committee at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20080206-Minutes.pdf

payments.[238] Some recommendations could have impacts in more than one category (e.g. a scheduling change could affect prices as well as uplift) and we have included the recommendation in the category of its primary effect. Since there is only one recommendation to the IESO in each of these three groups, the Panel has not needed to prioritize the recommendations in this report.

4.1 Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market.

Recommendation 3-3 (Chapter 3, section 3.2)

Given the frequency and impact on the market of incorrect Daily Energy Limit (DEL) submissions for hydroelectric generators, the Panel recommends that the IESO should discontinue the use of the DEL feature in the pre-dispatch schedules (including the Day-Ahead Commitment Process pre-dispatches) until an Enhanced Day-Ahead Commitment process is introduced which is specifically designed to optimize resources over 24 hours using accurate estimates of energy limits for hydroelectric resources. Alternatively, if the IESO considers that the DEL is currently useful for reliability reasons, the IESO should require submission of DELs from all hydroelectric generators, and strengthen the compliance provisions in the Market Rules to incent participants to submit more accurate forecasts of DEL.

4.2 Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market.

[238]There are no recommendations in the transparency category in the current report. Although the uplift category previously applied to hourly uplifts, the current recommendation relates to non-hourly uplift payments.

Recommendation 3-1 (Chapter 3, section 2.2)

(i) Ontario Power Generation(OPG) should discontinue the use of Not Offered but Available (NOBA) designations and CO_2 outages in excess of regular planned outages for the remainder of 2009 since they do not appear to be necessary to meet its 2009 CO_2 emission target, and

(ii) To the extent that OPG forecasts a need to reduce coal-fired generation in order to comply with its CO_2 emissions limit, the Panel recommends OPG should employ a strategy that utilizes an emissions adder alone as the most efficient way to offer an energy-limited resource into the market at the times when it has the most economic value.

Recommendation 3-4 (Chapter 3, section 3.4)

In order to improve the price responsiveness of generation to low market price and Surplus Baseload Generation conditions, the Panel recommends that when Non-Utility Generation contracts are renewed and renewable energy (primarily wind-power) contracts are designed, the Ontario Power Authority and Ontario Electricity Financial Corporation should design the contracts in a way to motivate these generators to respond to the market price, at least when it is negative

4.3 Uplift Payments

The Panel examines hourly uplift payments[239] both in respect of their contribution to the effective HOEP and also their impact on the efficient operation of the market.[240]

[239] Hourly uplift is the term used to describe wholesale market related uplifts as opposed to other forms of uplift payments.
[240] The Panel is aware that the IESO has already begun stakeholdering of the issues referred to in this recommendation.

<u>Recommendation 3-2 (Chapter 3, section 3.1)</u>

The IESO should improve the mechanisms for aligning submitted costs and associated revenue streams at combined cycle stations for its Spare Generation On-line and Day-Ahead Commitment Process generation cost guarantee programs, in the context of the other changes taking place to these programs. The preferred mechanism is to determine guarantee payments on an aggregate basis for all units at a station. Alternatively, the IESO should eliminate allocations that result in over-compensation (for example, by requiring allocation of submitted costs among units in proportion to the revenue they generate during the period associated with those costs).

Appendix 4-A: Status of Outstanding MSP Recommendations July 2007 – January 2009 Monitoring Report (#10 - #13)

Recommendations Related to Price Fidelity

Label	Report Date	Reference	Recommendation	IESO Response: Status
A **(1)**	Dec-07	MSP Report #11, 1-1 (Chapter 1 Section 2.4.3)	The Panel encourages the IESO to continue to review the forecasting process with wind generators and determine methods to reduce forecast errors. Such generators should have incentives (positive or negative) to encourage accurate forecasting.	In Progress, the issue is being addressed through SE-57 (Q3 2009)
	Dec-07	MSP Report #11, 3-7 (Chapter 3 Section 4.4.3)	To the extent possible in its stakeholder consultation on embedded generation, the IESO should consider opportunities to reduce inefficiency through the development of the capability for accurate forecasting of embedded generation production, which may require the provision of real-time production and related information (e.g. outages).	In Progress, part of SE-57 (Consultation on Embedded & Renewable Generation) (Q3 2009)
	Jan-09	MSP Report #13, 4-1 (Chapter 4, section 2)	In an effort to efficiently accommodate greater levels of renewable resources in the Ontario Market: i) The Panel recommends the IESO consider centralised wind forecasting to reduce the forecast errors associated with directly connected and embedded wind generation in the pre-dispatch schedules; ii) The Panel also reiterates its December 2007 recommendation that the IESO investigate a 15-minute dispatch algorithm which should further reduce forecast errors and allow for more frequent rescheduling of imports and exports in response to the different output characteristics of renewable resources.	In Progress, part of SE-57 (Consultation on Embedded & Renewable Generation) i. Q3 2009 ii. Q4 2010
B **(2)**	Dec-07	MSP Report #11, 2-1 (Chapter 2 Section 2.1.2.3)	Export curtailment due to 'adequacy' has an effect of suppressing the market price during times of serious scarcity since the curtailed amount is removed from the market schedule, thus distorting the market price signal. The Panel recommends that the IESO not remove the curtailed amount due to 'adequacy' from the market schedule.	In Progress, part of SE-67 IESO has since added a new Procedure cutting imports during SBG and using the ADQH

Label	Report Date	Reference	Recommendation	IESO Response: Status
	Jul-08	MSP Report #12, 3-6 (part 2) (Chapter 3, section 3.3)	The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy (‘ADQh’) should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted.	code and indicates it will stakeholder this as well.
C **(3)**	Jul-08	MSP Report #12, 3-7 (Chapter 3, section 4.1)	The MSP recommends that the IESO explore a solution to the emerging problem posed by recallable exports that are designated for Control Action Operating Reserve (CAOR), which induce counter-intuitive prices when rejected by the New York Independent System Operator and the Midwest Independent Transmission System Operator.	The IESO removed CAOR from PD as an interim procedure. MPWG exploring other alternatives. SE-72 on hold.
D **(4)**	Jul-07	MSP Report #10, 3-6 (pp. 129-153)	The Panel recognizes that adopting locational pricing would be a fundamental design change; however, we encourage the IESO to assess the efficiency benefits and costs of such an approach to provide a sound analytic basis for the consideration of future policy decisions.	On hold, SE-25 set up to look at Locational Pricing
E	Jul-08	MSP Report #12, 3-6 (part 1) (Chapter 3, section 3.3)	For inter-jurisdictional transactions that fail because of market participants’ (‘OTH’) or external system operators’ actions (‘TLRe’ and ‘MrNh’), the MSP recommends the IESO revise its procedures to avoid distorting the unconstrained schedule. This would prevent counter-intuitive pricing results (and would allow traders in those instances to receive the Congestion Management Settlement Credit payment consistent with other situations where such payments are currently available).	In Progress, being internally assessed. Low priority.
F	Jul-08	MSP Report #12, 2-2 (Chapter 2, section 2.2.4)	The MSP reiterates the recommendations in its December 2006 and June 2007 reports, respectively, regarding Shared Activation of Reserve (SAR), and prompt replenishment of the Operating Reserve requirement levels. In addition, the MSP recommends the IESO review the application of Regional Reserve Sharing (RRS) because the current treatment of RRS in the unconstrained sequence also induces counter-intuitive prices.	SAR: In Progress under SE-67. OR replenishment issue: Closed. RRS: Low priority

Label	Report Date	Reference	Recommendation	IESO Response: Status
G	Jul-08	MSP Report #12, 3-8 (part 1) (Chapter 3, section 4.2)	To avoid distorting market prices, the MSP recommends that the IESO maintain the Operating Reserve requirement when Operating Reserve is activated in response to Area Control Error (ACE).	High priority. The IESO is currently looking into options to become compliant with the Market Rules for ACE deviations due to load following. All other ACE deviations are part of SE-67.
H	Jan-09	MSP Report #13, 2-1 (Chapter 2, section 2.1.1)	The Panel recommends that the IESO's ramping of intertie schedules in the unconstrained process (the pricing algorithm) be consistent with actual intertie procedures and the treatment in the constrained scheduling process.	Open, Low Priority
I	Jan-09	MSP Report #13, 2-2 (Chapter 2, section 2.1.11)	The Panel recommends that when an intertie trade fails in some intervals while not in others within the hour, the IESO should apply a failure code only for those intervals with the failure.	Open, Low Priority

Recommendations Related to Dispatch

Label	Report Date	Reference	Recommendation	IESO Response: Status
A **(1)**	Jul-07	MSP Report #10, 2-3 (pp. 100-106)	The Panel recommends the IESO should explore improvements to the load predictor tool in order to reduce forecast errors associated with sudden changes in dispatchable load consumption, and the resulting dispatch inefficiencies.	In Progress, part of SE-61 (Q4 2010).
	Dec-07	MSP Report #11, 3-1 (Chapter 3 Section 2.3)	Consistent with prior recommendations directed at improving the IESO load predictor, whose algorithm imputes changes in non-dispatchable load that can induce consumption inefficiency and	

Label	Report Date	Reference	Recommendation	IESO Response: Status
			forecast errors, the Panel recommends that the IESO review its load predictor methodology to determine if it is a source of persistent under-forecasting of demand	
B **(2)**	Dec-07	MSP Report #11, 3-3 (Chapter 3 Section 3.1)	The MSP recommends the IESO begin investigation of a 15 minute dispatch algorithm to enhance the efficiency of the market. ** The recommendation was also made in part ii) of MSP Report #13, Rec 4-1 (Chapter 4, section 2) as part of the wind recommendation.*	In Progress, part of SE-61 (Q4 2010).
C **(3)**	Jan-09	MSP Report #13, 3-3 (Chapter 3, section 3.3)	In consideration of the length of time until the Panel's prior recommendation of an optimized Day Ahead Commitment Process (DACP) can be put in place (estimated to be 2011), the Panel recommends that the IESO consider basing the Generator Cost Guarantee on the offer submitted by the generator or other interim solutions that allow actual generation costs to be taken into account in DACP scheduling decisions.	In Progress, Part of SE-73 (design of EDAC completion expected to be Q4 2009) or Part of MR-00356 (SGOL/DACP) (Q3 2009).
	Jul-07	MSP Report #10, 3-2 (pp. 114-121)	The Panel recommends the IESO review the DACP in order to reduce the costs and improve the effectiveness of the Generator Cost Guarantee. Three-part bidding with 24 hour optimization, similar to the NYISO methodology, may be one such approach. We further recommend as an interim alternative that the IESO consider mechanisms which allow the full magnitude of domestic generator costs to be taken into account in DACP scheduling decisions.	

Label	Report Date	Reference	Recommendation	IESO Response: Status
	Jul-07	MSP Report #10, 3-3 (pp. 121-123)	In parallel with the recommended review of the DA-GCG, the Panel believes that it would be useful for the IESO to review the interface between the SGOL and DA-GCG as well as mechanisms for considering the full amounts of SGOL cost reimbursements in scheduling decisions.	
D (4)	Jan-09	MSP Report #13, 3-4 (Chapter 3, section 3.4)	As coal-fired generators are eventually phased out, the market will require replacement for this source of Operating Reserve (OR). New gas-fired generators are generally not offering OR. The Panel recommends that the IESO and OPA explore alternatives for obtaining appropriate OR offers from recent and future gas-fired generation entrants.	In Progress, Part of MR-00356 (SGOL-DACP) (Q3 2009).
E	Dec-07	MSP Report #11, 3-2 (Chapter 3 Section 2.5)	(1) The IESO should expedite completion of the necessary agreements with Hydro One, the Midwest ISO and ITC Transmission for operation of the Phase Angle Regulators on the Michigan intertie. The IESO (and Hydro One) should also complete necessary staff training as soon as possible. Any improvement on the spring 2008 implementation target would have positive efficiency (as well as reliability) effects on the Ontario (and Midwest ISO) system and any slippage would have the opposite effects. (2) Hydro One should work towards developing ratings that will safeguard the Phase Angle Regulators and provide operationally useful Limited Time Ratings as soon as possible.	In Progress. Negotiating operating agreement.
F	Jul-07	MSP Report #10, 2-2 (pp 97-100)	The Net Interchange Scheduling Limit of 700 MW has been in effect since the market opened. In the light of 5 years' experience with market-based trading, the NISL's potential to limit efficient	The IESO implemented a procedure to change the NISL to 1,000 MW in cases when Surplus Baseload Generation conditions are expected and more imports

Label	Report Date	Reference	Recommendation	IESO Response: Status
			trade and changes in both the number of generators and their combined ramp capability, the Panel encourages the IESO to review whether the 700 MW limit could be increased.	are needed. The IESO is currently no changing the NISL but there is on-going monitoring.
	Jul-08	MSP Report #12, 2-1 (Chapter 2, section 2.2.1)	The MSP reiterates the recommendation in its June 2007 report that the IESO should review the 700 MW Net Interchange Scheduling Limit (NISL). This review should take into account the effects on potential efficient exports from Ontario in addition to the import issues raised in the MSP's prior report.	
G	Jul-08	MSP Report #12, 3-8 (part 2) (Chapter 3, section 4.2)	If the IESO believes that it must maintain a higher standard than the NERC Control Performance Standard, the MSP recommends that the IESO conduct a cost-benefit analysis comparing alternatives for responding to Area Control Error (ACE) deviations, that is: providing more Automatic Generation Control (AGC); using One-Time Dispatch (OTD); using Operating Reserve Activation (ORA); and establishing a capability to re-run the dispatch algorithm on demand.	High priority. The IESO is currently looking into options to become compliant with the Market Rules for ACE deviations due to load following. All other ACE deviations are part of SE-67.
H	Jul-08	MSP Report #12, 3-8 (part 3) (Chapter 3, section 4.2)	In the interim, until a cost-benefit study of the alternatives for handling ACE deviations is completed, in accordance with Recommendation 3-8(2), and assuming the IESO adopts Recommendation 3-8(1) regarding the maintenance of the Operating Reserve requirement level when Operating Reserve is activated for ACE, the MSP recommends that the IESO should use ORA instead of One-Time Dispatch to deal with negative ACE whenever possible.	See G above.

Recommendations Related to Transparency

Label	Report Date	Reference	Recommendation	IESO Response: Status
A **(1)**	Jul-08	MSP Report #12, 3-5 (Chapter 3, section 3.1)	The IESO is planning to publish the supply cushion on a hourly basis. Its current calculation, however, does not represent actual supply capability. The MSP recommends that the IESO refine its formula to take into account forced outages, deratings, and import capabilities at the interties.	In Progress, being internally assessed. Low priority.
	Jan-09	MSP Report #13, 3-1 (Chapter 3, section 3.1)	1) In light of the Panel's findings on the inefficiency of the Demand Response Phase 3 (DR3) program, the Ontario Power Authority (OPA) should review the effectiveness and efficiency of the program. 2) Until that review is completed, to improve short term dispatch efficiency: (a) the IESO, with input from the OPA, should improve the supply cushion calculation; and/or (b) the OPA should develop other triggers such as a pre-dispatch price threshold that could be better indicators of tight supply/demand conditions.	
B **(2)**	Jul-08	MSP Report #12, 3-2 (Chapter 3, section 3.1)	The MSP recommends that the IESO publish masked bid and offer data on a four month time lag.	In Progress, being internally assessed. Low priority.
C	Jul-08	MSP Report #12, 3-4 (Chapter 3, section 3.1)	The MSP recommends that when the System Status Reports indicate that a generating unit of greater than 250 MW has been forced from service, the IESO should also disclose the fuel type of the unit in order to increase the information available to all market participants regarding future market conditions.	In Progress, being internally assessed. Low priority.
D	Jul-08	MSP Report #12, 3-3 (Chapter 3, section 3.1)	The MSP recommends that the IESO publish generating unit output using a one-hour lag rather than the current two-hour lag.	In Progress, being internally assessed. Low priority.

Recommendations Related to Uplift

Label	Report Date	Reference	Recommendation	IESO Response: Status
A **(1)**	Jan-09	MSP Report #13, 3-2 (Chapter 3, section 3.2)	In an earlier report, the Panel encouraged the IESO to limit self-induced congestion management settlement credit (CMSC) payments to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons. The Panel further recommends that the IESO take similar action to limit CMSC payments where these are induced by the generator strategically raising its offer price to signal the ramping down of its generation.	In Progress, part of MR-00252 (Q1 2010).
	Dec-07	MSP Report #11, 3-4 (Chapter 3 Section 4.1)	The IESO should initiate a rule change to allow the recovery of self-induced congestion management settlement credit payments which are made to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons.	In Progress, IESO agrees but is considered low priority.
B **(2)**	Jul-07	MSP Report #10, 3-4 (pp. 124-127)	The Panel recommends the IESO review off-peak conditions to determine if the RT-IOG and DA-IOG programs are providing an improvement in reliability commensurate with the payments being made. The IESO should consider discontinuing off-peak IOG payments where these no longer appear to provide corresponding reliability benefits.	In Progress, under IESO internal assessment. Low priority.
	Jul-08	MSP Report #12, 3-1 (Chapter 3, section 2.2.4)	As market supply conditions have improved, an increasing fraction of Intertie Offer Guarantee (IOG) payments is being paid in hours when there appear to be negligible reliability concerns. The MSP recommends the IESO review the real-time IOG program and determine if it is providing commensurate improvements in reliability.	
C **(3)**	Jul-08	MSP Report #12, 3-9 (Chapter 3, section 5)	The MSP recommends that the IESO review the benefits of constrained off payments with a view to their discontinuation.	In Progress, being internally assessed. Low priority.
D	Jul-07	MSP Report #10, 3-5 (pp. 127-129)	The Panel recommends the IESO review the treatment of energy exported through Segregated Mode of Operation with a view to including this energy in the determination of RT-IOG offsets for implied wheeling.	In Progress, IESO agrees but is considered low priority.

Label	Report Date	Reference	Recommendation	IESO Response: Status
E	Dec-07	MSP Report #11, 3-5 (Chapter 3 Section 4.2)	The IESO should initiate a rule change to make Intertie Offer Guarantee payments subject to offsets where affiliated market participants are simultaneously importing and exporting	In Progress, IESO agrees but is considered low priority.

Ontario Energy Board Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2008 – April 2009

PUBLIC

2009

In some instances, the data reported in this Report has been updated or recalculated and therefore may differ from values previously quoted in our earlier reports.

List of Tables

Table A-1: Monthly Energy Demand, May 2007 – April 2009 (TWh)

	Ontario Demand*		Exports		Total Market Demand	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	11.83	11.41	1.08	2.65	12.91	14.06
Jun	12.69	12.20	1.04	2.52	13.74	14.72
Jul	12.85	13.15	1.30	2.43	14.15	15.59
Aug	13.47	12.57	1.12	1.69	14.60	14.26
Sep	11.95	11.82	0.92	1.26	12.88	13.08
Oct	11.92	11.67	0.93	1.46	12.85	13.13
Nov	12.39	11.85	0.97	1.36	13.35	13.21
Dec	13.45	13.09	1.31	1.41	14.76	14.50
Jan	13.63	13.75	2.06	1.82	15.70	15.58
Feb	12.90	11.71	1.65	1.35	14.54	13.05
Mar	13.01	12.18	1.89	1.45	14.89	13.62
Apr	11.52	10.77	2.42	0.80	13.94	11.57
May – Oct	74.71	72.82	6.39	12.01	81.13	84.84
Nov - Apr	76.90	73.35	10.30	8.19	87.18	81.53
May - Apr	151.61	146.17	16.69	20.20	168.31	166.37

* Data includes dispatchable loads

Table A-2: Average Monthly Temperature, May 2003 – April 2009 (°Celsius)*

	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009
May	12.23	13.31	12.14	14.59	14.77	11.98
Jun	18.53	17.78	22.54	19.76	20.84	19.39
Jul	21.71	20.65	24.09	23.50	21.42	21.73
Aug	21.85	19.57	22.53	21.22	22.27	19.66
Sep	17.12	18.4	18.33	15.79	18.34	17.08
Oct	9.04	10.85	11.01	9.07	14.11	9.13
Nov	4.91	5.29	5.06	5.25	2.91	3.17
Dec	(0.03)	(2.54)	(3.13)	1.94	(2.12)	(2.86)
Jan	(9.13)	(6.78)	0.30	(2.65)	(2.07)	(8.20)
Feb	(3.29)	(3.60)	(3.56)	(7.99)	(4.99)	(3.20)
Mar	2.26	(1.29)	1.21	0.59	(1.46)	1.02
Apr	6.88	8.18	8.36	6.29	9.48	7.68
May - Oct	16.75	16.76	18.44	17.32	18.63	16.50
Nov - Apr	0.27	(0.12)	1.37	0.57	0.29	(0.40)
May - Apr	8.51	8.32	9.91	8.95	9.46	8.05

* Temperature is calculated at Toronto Pearson International Airport

Table A-3: Number of Days Temperature Exceeded 30°C, May 2003 – April 2009 (Number of days)*

	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009
May	0	0	0	2	1	0
Jun	4	2	9	3	6	4
Jul	4	1	11	9	4	3
Aug	4	0	7	3	8	0
Sep	0	0	2	0	4	1
Oct	0	0	0	0	1	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May - Oct	12	3	29	17	24	8
Nov - Apr	0	0	0	0	0	0
May - Apr	12	3	29	17	24	8

* Temperature is calculated at Toronto Pearson International Airport

Table A-4: Outages, May 2007 - April 2009 (TWh)*

	Total Outage		Planned Outage**		Forced Outage	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	5.38	5.43	3.63	1.69	1.75	3.74
Jun	3.58	4.15	1.36	1.21	2.22	2.94
Jul	3.34	2.99	0.95	0.90	2.39	2.09
Aug	3.59	3.24	0.45	1.00	3.14	2.24
Sep	5.43	5.09	2.41	2.32	3.02	2.77
Oct	6.47	5.38	3.77	2.68	2.70	2.70
Nov	5.47	5.50	2.96	2.63	2.51	2.87
Dec	3.69	3.74	1.58	1.23	2.11	2.51
Jan	2.88	3.56	0.96	1.03	1.92	2.53
Feb	3.10	3.87	0.79	1.94	2.31	1.93
Mar	4.97	4.74	2.39	2.78	2.58	1.96
Apr	5.30	5.99	2.44	3.09	2.86	2.90
May – Oct	27.79	26.28	12.57	9.80	15.22	16.48
Nov - Apr	25.41	27.40	11.12	12.70	14.29	14.70
May - Apr	53.20	53.68	23.69	22.50	29.51	31.18

* There are two sets of data that reflect outages information. Past reports have relied on information from the IESO's outage database. This table reflects the outage information that is actually input to the DSO to determine price. The MAU has reconciled the difference between the two sets of data by applying outage types from the IESO's outage database to the DSO outage information.
** As described in Section 4.4 of Chapter 1, although CO2 Outages are recorded as forced outages by the IESO, they are classified as planned outages for purposes of our statistics.

Table A-5: Average HOEP, On and Off-Peak, May 2007 – April 2009 ($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009
May	38.50	34.56	53.78	47.12	24.77	24.21
Jun	44.38	57.44	57.32	76.57	33.06	42.13
Jul	43.90	56.58	57.70	82.78	32.54	35.00
Aug	53.62	46.57	69.80	60.63	39.10	35.96
Sep	44.63	49.09	58.27	58.58	34.66	40.78
Oct	48.91	45.27	60.19	55.87	38.77	35.75
Nov	46.95	51.78	56.35	59.98	37.96	45.22
Dec	49.08	46.34	62.96	57.67	39.48	37.02
Jan	40.74	53.22	50.89	62.32	31.62	45.73
Feb	52.38	47.24	67.48	57.78	39.52	38.53
Mar	56.84	28.88	68.60	36.65	48.72	21.90
Apr	48.98	18.40	63.61	28.62	34.99	10.22
May – Oct	45.66	48.25	59.51	63.59	33.82	35.64
Nov - Apr	49.16	40.98	61.65	50.50	38.72	33.10
May - Apr	47.41	44.61	60.58	57.05	36.27	34.37

Table A-6: Average Monthly Richview Slack Bus Price, All hours, On and Off-Peak, May 2007 – April 2009 ($/MWh)

	All Hours		On-peak		Off-Peak	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	41.69	50.81	57.84	68.89	27.18	35.92
Jun	71.03	79.49	103.80	110.58	42.38	54.61
Jul	49.16	68.20	66.92	99.70	34.54	42.26
Aug	61.53	62.59	82.04	81.67	43.10	48.19
Sep	51.71	65.84	71.36	69.01	37.35	63.06
Oct	55.73	51.94	68.24	65.14	44.49	40.09
Nov	54.33	56.80	64.14	64.46	44.94	50.67
Dec	55.46	50.91	71.37	61.84	44.47	41.91
Jan	49.67	60.17	64.99	71.65	35.92	50.73
Feb	60.84	47.52	78.58	54.64	45.73	41.64
Mar	65.23	33.72	79.77	46.34	55.19	22.39
Apr	62.24	21.28	80.80	28.12	44.49	15.81
May – Oct	55.14	63.15	75.03	82.50	38.17	47.36
Nov - Apr	57.96	45.07	73.28	54.51	45.12	37.19
May - Apr	56.55	54.11	74.15	68.50	41.65	42.27

Table A-7: Ontario Consumption by Type of Usage*,
May 2007 – April 2009
(TWh)

	LDC's**		Wholesale Loads		Generators		Metered Energy Consumption***		Transmission Losses		Total Energy Consumption****	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	9.16	8.79	2.30	2.18	0.13	0.07	11.59	11.04	0.23	0.37	11.82	11.41
Jun	10.05	9.53	2.26	2.27	0.11	0.09	12.42	11.89	0.27	0.30	12.69	12.19
Jul	10.17	10.39	2.26	2.33	0.11	0.09	12.54	12.81	0.30	0.35	12.84	13.16
Aug	10.65	9.77	2.36	2.31	0.13	0.08	13.14	12.16	0.31	0.39	13.45	12.55
Sep	9.38	9.14	2.18	2.24	0.12	0.09	11.68	11.47	0.24	0.32	11.92	11.79
Oct	9.36	9.17	2.23	2.12	0.08	0.09	11.67	11.37	0.24	0.26	11.91	11.63
Nov	9.79	9.54	2.18	1.92	0.09	0.08	12.06	11.54	0.29	0.29	12.35	11.83
Dec	10.77	10.70	2.20	1.95	0.08	0.08	13.05	12.73	0.36	0.36	13.41	13.09
Jan	10.92	11.31	2.26	2.06	0.07	0.08	13.25	13.45	0.36	0.28	13.61	13.73
Feb	10.35	9.60	2.13	1.74	0.06	0.07	12.54	11.40	0.36	0.30	12.90	11.70
Mar	10.37	9.88	2.22	1.87	0.09	0.06	12.68	11.81	0.32	0.36	13.00	12.17
Apr	8.94	8.65	2.15	1.69	0.08	0.08	11.17	10.43	0.35	0.32	11.52	10.75
May –Oct	58.77	56.79	13.59	13.46	0.68	0.51	73.04	70.72	1.59	2.01	74.63	72.73
Nov - Apr	61.14	59.68	13.14	11.23	0.47	0.45	74.75	71.36	2.04	1.91	76.79	73.27
May -Apr	119.91	116.47	26.73	24.69	1.15	0.96	147.79	142.08	3.63	3.92	151.42	146.00

* The data in this table has been revised back to May 2007 using updated participant data.
** LDC's is net of any local generation within the LDC
*** Metered Energy Consumption = LDC's + Wholesale Loads + Generators
**** Total Energy Consumption = Metered Energy Consumption – Transmission Losses

Table A-8: Frequency Distribution of HOEP, May 2007 – April 2009
(Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	< 10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	6.59	20.03	9.01	5.91	26.61	5.11	**27.55**	**34.81**	6.72	17.20	5.65	7.53	5.11	4.03	10.75	4.57	2.02	0.81	0.00	0.00
Jun	3.19	8.61	6.11	3.47	26.11	4.31	**27.36**	**22.50**	7.08	18.75	6.39	6.53	9.17	6.81	10.00	14.17	4.31	14.31	0.28	0.56
Jul	2.82	11.96	4.84	7.39	24.19	4.84	**27.96**	13.71	9.01	**20.03**	8.74	3.63	6.59	5.78	13.98	16.13	1.75	16.13	0.13	0.40
Aug	0.81	12.63	0.67	4.30	14.52	5.78	27.55	13.04	10.35	**36.02**	7.93	6.45	6.99	4.30	**28.09**	13.04	3.09	4.17	0.00	0.27
Sep	3.06	9.44	3.19	3.06	20.42	5.83	**26.94**	18.47	13.61	**25.83**	11.25	10.69	6.53	11.25	13.33	10.56	1.67	4.17	0.00	0.69
Oct	2.69	5.78	2.15	5.51	17.61	4.84	**22.98**	15.46	12.37	**37.77**	10.62	15.73	11.69	7.39	18.82	5.91	0.94	1.21	0.13	0.40
Nov	0.97	1.53	0.42	2.78	10.14	3.19	**35.14**	21.11	17.78	**26.39**	15.28	13.06	7.64	15.28	11.81	14.44	0.83	2.22	0.00	0.00
Dec	5.38	5.11	5.11	3.23	15.32	5.11	**21.24**	**31.45**	11.29	21.24	9.27	12.37	9.14	10.48	19.49	9.14	3.76	1.61	0.00	0.27
Jan	4.84	2.42	3.09	0.94	19.09	0.81	**37.77**	6.99	13.31	**44.49**	6.72	21.64	4.30	11.16	8.60	9.54	2.28	1.61	0.00	0.40
Feb	3.16	1.79	1.15	1.93	5.60	3.13	**30.03**	**39.14**	16.95	35.57	13.07	9.52	10.78	3.72	13.22	3.87	5.89	1.04	0.14	0.30
Mar	0.00	19.76	0.00	6.05	0.13	13.04	24.46	**43.01**	**26.34**	10.62	15.73	2.55	10.35	1.61	17.74	2.96	5.24	0.27	0.00	0.13
Apr	8.61	**41.39**	3.06	7.78	3.47	12.78	**32.78**	26.53	13.75	8.47	12.64	1.39	5.83	0.83	14.86	0.69	4.86	0.14	0.14	0.00
May –Oct	3.19	11.41	4.33	4.94	21.58	5.12	**26.72**	19.67	9.86	**25.93**	8.43	8.43	7.68	6.59	15.83	10.73	2.30	6.80	0.09	0.39
Nov - Apr	3.83	12.00	2.14	3.79	8.96	6.34	**30.24**	**28.04**	16.57	24.46	12.12	10.09	8.01	7.18	14.29	6.77	3.81	1.15	0.05	0.18
May -Apr	3.51	11.70	3.23	4.36	15.27	5.73	**28.48**	23.85	13.21	**25.20**	10.27	9.26	7.84	6.89	15.06	8.75	3.05	3.97	0.07	0.29

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2007 – April 2009
(Percentage of Hours within Defined Range)

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<10.00		**10.01 - 20.00**		**20.01 - 30.00**		**30.01 - 40.00**		**40.01 - 50.00**		**50.01 - 60.00**		**60.01 - 70.00**		**70.01 - 100.00**		**100.01 - 200.00**		**> 200.01**	
	2007/2008	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**
May	6.59	18.68	8.06	6.45	22.04	5.38	**30.65**	**25.67**	7.93	24.06	4.30	8.20	6.18	5.11	11.42	5.24	2.82	1.21	0.00	0.00
Jun	3.06	7.64	4.86	3.89	20.14	3.75	**31.11**	15.83	8.75	**22.92**	6.39	7.64	6.81	7.22	12.64	13.89	5.83	16.53	0.42	0.69
Jul	2.96	11.83	4.03	6.18	18.82	5.11	**30.38**	9.68	11.83	**23.39**	6.59	4.70	7.93	4.57	15.32	15.32	2.02	18.68	0.13	0.54
Aug	0.94	11.29	0.67	4.70	9.68	5.11	29.03	11.96	11.69	**32.80**	6.99	10.75	7.80	4.84	**29.57**	13.04	3.63	5.11	0.00	0.40
Sep	2.92	8.61	3.33	3.75	16.11	5.28	**28.19**	14.17	13.89	**28.33**	11.25	10.28	7.22	9.72	14.03	14.44	3.06	4.72	0.00	0.69
Oct	2.55	4.97	2.28	5.91	12.90	4.97	**23.92**	11.42	13.44	**36.02**	9.54	18.15	11.96	9.27	20.83	7.39	2.42	1.48	0.13	0.40
Nov	0.97	1.67	0.42	2.36	6.39	3.06	**32.64**	14.86	18.89	**29.58**	15.42	11.39	10.97	16.25	12.64	17.78	1.67	3.06	0.00	0.00
Dec	4.84	4.84	4.84	2.96	13.58	4.70	**21.37**	25.40	10.89	**25.54**	9.95	12.77	9.41	10.35	18.82	10.89	6.32	2.28	0.00	0.27
Jan	4.70	2.28	2.69	1.08	15.99	0.67	**36.56**	4.84	15.32	**39.11**	7.53	24.73	5.11	12.37	9.01	12.37	3.09	2.15	0.00	0.40
Feb	3.16	1.19	1.01	2.23	5.03	2.98	**25.86**	31.25	17.24	**38.69**	13.36	11.90	12.79	5.65	14.66	4.76	6.75	1.04	0.14	0.30
Mar	0.00	19.22	0.00	5.91	0.00	8.74	17.61	**42.20**	**29.97**	16.13	15.86	2.69	10.89	1.48	19.22	3.23	6.45	0.27	0.00	0.13
Apr	8.06	**40.42**	3.33	6.81	3.61	10.00	**25.83**	24.44	16.53	12.08	13.75	4.03	6.67	1.11	16.81	0.83	5.28	0.28	0.14	0.00
May- Oct	3.17	10.50	3.87	5.15	16.62	4.93	**28.88**	14.79	11.26	**27.92**	7.51	9.95	7.98	6.79	17.3	11.55	3.3	7.96	0.11	0.45
Nov - Apr	2.73	11.60	2.05	3.56	7.43	5.03	**26.65**	23.83	18.14	**26.86**	12.65	11.25	9.31	7.87	15.19	8.31	4.93	1.51	0.05	0.18
May -Apr	2.97	11.05	2.96	4.35	12.02	4.98	**27.76**	19.31	14.7	**27.39**	10.08	10.60	8.65	7.33	16.25	9.93	4.11	4.73	0.08	0.32

* Bolded values show highest percentage within month.

Table A-10: Total Hourly Uplift Charge as a Percentage of HOEP, On and Off-Peak, May 2007 – April 2009 (%)

	All Hours		On-Peak		Off-Peak	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	4.68	7.06	6.13	6.24	3.38	7.73
Jun	5.69	8.23	6.77	6.18	4.74	9.87
Jul	4.47	6.70	4.87	5.13	4.13	7.99
Aug	4.26	7.97	4.97	4.91	3.62	10.29
Sep	4.65	6.40	5.60	5.43	3.94	7.24
Oct	4.27	6.42	5.17	5.08	3.45	7.62
Nov	5.08	5.40	5.58	5.76	4.61	5.10
Dec	4.57	4.31	4.46	4.29	4.65	4.32
Jan	4.40	3.92	5.09	4.25	3.79	3.65
Feb	3.80	4.73	5.20	5.23	2.61	4.31
Mar	4.24	6.75	4.53	7.00	4.04	6.52
Apr	7.72	20.81	5.93	14.64*	9.43	25.73
May- Oct	4.67	7.13	5.59	5.50	3.88	8.46
Nov - Apr	4.97	7.65	5.13	6.86	4.86	8.27
May -Apr	4.82	7.39	5.36	6.18	4.37	8.36

* The HOEP in hour 20 on April 8, 2009 was $0/MWh, therefore it was removed from the April 2009 monthly calculation as it led to an undefined observation.

Table A-11: Total Hourly Uplift Charge by Component,
May 2007 – April 2009
($ Millions)

	Total Hourly Uplift*		RT IOG**		DA IOG*		CMSC***		Operating Reserve		Losses	
	2007/2008	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**
May	24.03	28.44	2.48	1.56	0.33	0.05	9.70	11.33	1.00	5.06	10.54	10.44
Jun	39.12	60.39	2.26	3.38	1.08	0.1	20.58	34.69	1.24	4.70	13.97	17.51
Jul	26.25	46.34	1.51	1.89	0.65	0.06	8.75	18.79	1.10	6.08	14.24	19.52
Aug	35.96	35.13	2.31	1.01	0.64	0.03	14.58	16.31	0.60	2.66	17.83	15.13
Sep	29.76	32.54	1.72	1.52	2.79	0.22	12.30	16.05	0.77	0.89	12.18	13.87
Oct	27.81	30.11	2.47	1.44	1.35	0.02	10.21	14.54	0.84	4.21	12.94	9.90
Nov	30.72	33.80	2.98	1.94	1.20	0.37	11.70	15.46	1.49	4.11	13.35	11.93
Dec	32.94	26.23	3.98	1.19	0.25	0.23	11.38	6.33	1.10	2.54	16.22	15.95
Jan	30.04	32.47	4.05	1.21	0.10	0.04	9.42	9.79	2.25	6.23	14.22	15.20
Feb	34.10	29.08	5.68	0.97	0.27	0.06	11.31	7.94	2.27	6.82	14.57	13.29
Mar	35.62	23.85	3.99	0.79	0.22	0.03	12.82	10.44	1.40	4.24	17.19	8.35
Apr	37.39	27.11	4.22	0.31	0.11	0.01	14.31	13.12	4.77	7.64	13.99	6.02
May- Oct	182.93	232.95	12.75	10.80	6.84	0.48	76.12	111.71	5.55	23.60	81.70	86.37
Nov - Apr	200.81	172.54	24.90	6.41	2.15	0.74	70.94	63.08	13.28	31.58	89.54	70.74
May -Apr	383.74	405.49	37.65	17.21	8.99	1.22	147.06	174.79	18.83	55.18	171.24	157.11

* Total Hourly Uplift = RT IOG + DA IOG + CMSC + Operating Reserve + Losses
** The IOG numbers are not adjusted for IOG offsets, which was implemented in July 2002. IOG offsets are reported in Table A-16. All IOG Reversals have been applied to RT IOG.
*** Numbers are adjusted for Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments.

Table A-12: Operating Reserve Prices,
May 2007 – April 2009
($/MWh)

	10N		10S		30R	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.78	5.92	2.17	6.36	0.78	4.47
Jun	1.21	6.07	2.98	6.11	1.21	5.66
Jul	1.00	7.20	1.97	7.36	1.00	7.00
Aug	0.41	3.11	1.78	3.14	0.41	2.97
Sep	0.63	1.06	1.95	1.19	0.63	1.03
Oct	0.62	3.84	1.90	4.33	0.62	3.04
Nov	1.20	3.95	1.99	4.86	1.09	3.74
Dec	0.96	2.47	1.71	2.73	0.96	2.39
Jan	2.53	6.73	2.77	6.73	2.45	6.27
Feb	2.67	10.17	3.20	10.18	2.55	9.15
Mar	1.56	4.64	2.13	4.93	1.49	3.93
Apr	6.22	8.26	6.38	9.82	5.55	4.86
May- Oct	0.78	4.53	2.13	4.75	0.78	4.03
Nov - Apr	2.52	6.04	3.03	6.54	2.35	5.06
May -Apr	1.65	5.29	2.58	5.65	1.56	4.54

Table A-13: Baseload Supply Relative to Demand and HOEP, Off-Peak, May 2007 – April 2009 (Average Hourly MW)*

	Nuclear		Baseload Hydroelectric		Self-Scheduling Supply		Total Baseload Generation		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	9,360	8,180	1,999	2,037	809	779	12,168	10,996	13,543	13,352	24.77	24.21
Jun	9,380	9,027	1,806	1,886	719	617	11,905	11,530	15,005	14,934	33.06	42.13
Jul	9,695	10,098	1,720	1,963	699	597	12,114	12,658	14,703	15,243	32.54	35.00
Aug	9,490	10,143	1,610	1,888	748	628	11,848	12,659	15,493	14,751	39.10	35.96
Sep	8,797	9,798	1,662	1,797	772	703	11,231	12,298	14,400	14,255	34.66	40.78
Oct	8,162	9,645	1,861	1,780	993	1,073	11,016	12,498	13,983	13,771	38.77	35.75
Nov	8,369	9,353	1,840	1,843	1,002	1,087	11,211	12,283	14,941	14,645	37.96	45.22
Dec	10,355	10,630	1,783	1,979	1,042	1,323	13,180	13,932	16,230	15,756	39.48	37.02
Jan	10,978	10,675	1,788	1,934	1,077	1,179	13,843	13,788	16,127	16,744	31.62	45.73
Feb	9,987	10,161	1,974	1,996	1,017	1,264	12,978	13,421	16,416	15,666	39.52	38.53
Mar	8,708	10,229	2,232	2,079	960	1,374	11,900	13,682	15,803	14,618	48.72	21.90
Apr	8,640	8,827	2,104	1,868	823	1,365	11,567	12,060	13,931	13,332	34.99	10.22
May- Oct	9,147	9,482	1,776	1,892	790	733	11,714	12,107	14,521	14,384	33.82	35.64
Nov - Apr	9,506	9,979	1,954	1,950	987	1,265	12,447	13,194	15,575	15,127	38.72	33.10
May -Apr	9,327	9,731	1,865	1,921	888	999	12,080	12,650	15,048	14,756	36.27	34.37

Table A-14: Baseload Supply Relative to Demand and HOEP, On-Peak, May 2007 – April 2009 (Average Hourly MW)*

	Nuclear		Baseload Hydroelectric		Self-Scheduling Supply		Total Baseload Generation		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	9,399	8,193	2,464	2,368	1,201	1,287	13,064	11,848	17,417	16,558	53.78	47.12
Jun	9,344	9,091	2,266	2,225	1,166	937	12,776	12,253	19,597	18,204	57.32	76.57
Jul	9,719	9,983	2,129	2,296	1,044	890	12,892	13,169	19,250	19,442	57.70	82.78
Aug	9,477	10,114	2,061	2,259	1,013	899	12,551	13,272	19,978	18,484	69.80	60.63
Sep	8,647	9,787	1,969	2,146	1,058	1,017	11,674	12,950	18,415	17,776	58.27	58.58
Oct	8,231	9,662	2,062	2,100	1,176	1,216	11,469	12,978	17,229	17,023	60.19	55.87
Nov	8,611	9,391	2,304	2,267	1,235	1,208	12,150	12,866	18,520	18,027	56.35	59.98
Dec	10,287	10,592	2,140	2,303	1,265	1,429	13,692	14,324	19,463	19,158	62.96	57.67
Jan	10,959	10,529	2,063	2,187	1,310	1,296	14,332	14,012	19,624	19,855	50.89	62.32
Feb	9,921	10,177	2,216	2,258	1,222	1,442	13,359	13,877	19,812	18,828	67.48	57.78
Mar	8,798	10,274	2,432	2,390	1,239	1,630	12,469	14,294	18,606	17,558	68.60	36.65
Apr	8,567	8,301	2,425	2,317	1,180	1,621	12,172	12,239	17,025	16,199	63.61	28.62
May- Oct	9,136	9,472	2,159	2,232	1,110	1,041	12,404	12,745	18,648	17,915	59.51	63.59
Nov - Apr	9,524	9,877	2,263	2,287	1,242	1,438	13,029	13,602	18,842	18,271	61.65	50.50
May -Apr	9,330	9,675	2,211	2,260	1,176	1,239	12,717	13,174	18,745	18,093	60.58	57.05

Table A-15: RT IOG Payments, Top 10 Days,
November 2008 – April 2009

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)*	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
11/25/2008	16,310	0.23	14.02	22,007
11/12/2008	19,689	0.20	10.32	21,817
11/21/2008	9,659	0.15	15.58	22,187
11/23/2008	10,427	0.14	13.42	20,780
01/26/2009	9,070	0.13	14.59	25,342
03/03/2009	5,960	0.13	21.82	23,418
01/27/2009	9,619	0.12	12.95	24,594
11/20/2008	10,254	0.12	12.01	22,060
12/08/2008	11,741	0.12	10.33	24,352
01/04/2009	7,379	0.11	15.36	21,789
	Total Top 10 days	**1.47**	**14.04**	
	Total for Period	**6.54**	**9.87**	
	% of Total Payments	**22.48**		

* Numbers are not netted against IOG offset for the 'implied wheel'.

Table A-16: IOG Offsets due to Implied Wheeling, May 2007 – April 2009 ($ '000 and %)

	Real-time IOG Payments ($'000)		IOG Offset ($'000)		IOG Offset (%)	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	2,493	1,610	225	187	9.03	11.61
Jun	2,345	3,472	72	415	3.06	11.95
Jul	1,579	1,950	160	333	10.13	17.06
Aug	2,424	1,035	132	136	5.44	13.17
Sep	1,845	1,563	138	122	7.47	7.83
Oct	2,708	1,459	156	161	5.77	11.06
Nov	3,221	1,994	234	178	7.27	8.91
Dec	4,069	1,200	379	95	9.33	7.91
Jan	4,145	1,237	216	89	5.21	7.19
Feb	5,822	980	400	58	6.86	5.92
Mar	4,091	808	301	46	7.36	5.74
Apr	4,330	318	347	16	8.02	5.09
May- Oct	13,394	11,011	883	1,354	6.59	12.21
Nov - Apr	25,678	6,537	1,877	482	7.31	6.79
May -Apr	39,072	17,626	2,760	1,836	7.06	9.45

Table A-17: CMSC Payments, Energy and Operating Reserve, May 2007 – April 2009 ($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	9.57	5.57	1.77	3.42	11.76	9.87	0.59	2.06	12.35	11.93
Jun	11.93	23.06	5.75	9.47	19.91	34.43	1.46	1.7	21.37	36.13
Jul	7.50	12.52	2.27	5.37	9.52	19.48	0.92	1.43	10.45	20.92
Aug	9.76	11.14	4.26	3.92	14.59	16.49	0.49	0.69	15.08	17.18
Sep	8.33	11.86	4.04	4.69	12.72	17.56	0.49	0.63	13.21	18.19
Oct	10.13	9.13	2.13	3.89	12.72	13.81	0.53	1.26	13.26	15.07
Nov	8.37	11.54	3.45	5.12	12.29	17.33	0.52	1.50	12.81	18.83
Dec	7.40	3.98	4.02	1.83	11.93	6.42	0.45	0.82	12.38	7.24
Jan	6.21	5.66	3.37	2.23	9.92	9.31	0.77	1.30	10.69	10.61
Feb	6.51	5.10	3.77	1.96	11.04	7.70	0.98	1.13	12.02	8.83
Mar	7.00	3.84	4.03	4.37	11.89	9.53	1.40	1.29	13.29	10.82
Apr	8.02	5.45	4.39	5.72	13.44	11.59	1.77	2.01	15.21	13.60
May- Oct	57.22	73.28	20.22	30.76	81.22	111.64	4.48	7.77	85.72	119.42
Nov - Apr	43.51	35.57	23.03	21.23	70.51	61.88	5.89	8.05	76.40	69.93
May -Apr	100.73	108.85	43.25	51.99	151.73	173.52	10.37	15.82	162.12	189.35

* The sum for energy being constrained on and off does not equal the total CMSC for energy in some months. This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC amounts.** The totals for CMSC payments do not equal the totals for CMSC payments in Table A-11: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months. Neither table includes Local Market Power adjustments.

Table A-18: Share of Constrained On Payments for Energy by Type of Supplier, May 2007 – April 2009 (%)

	Domestic Generators		Imports	
	2007/2008	2008/2009	2007/2008	2008/2009
May	60	58	40	42
Jun	67	64	33	36
Jul	74	56	26	44
Aug	68	87	32	13
Sep	67	76	33	24
Oct	71	77	29	23
Nov	69	72	31	28
Dec	61	87	39	13
Jan	61	84	39	16
Feb	64	71	36	29
Mar	56	85	44	15
Apr	46	96	54	4
May- Oct	68	70	32	30
Nov - Apr	60	83	41	18
May -Apr	64	76	36	24

Table A-19: Share of CMSC Payments Received by Top Facilities, May 2007 – April 2009 (%)

	Share of Total Payments Received by Top 10 Facilities				Share of Total Payments Received by Top 5 Facilities			
	Constrained Off		Constrained On		Constrained Off		Constrained On	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	58.89	49.47	41.69	48.14	45.46	36.17	27.10	30.78
Jun	57.61	68.08	46.56	57.38	34.93	46.00	30.40	44.37
Jul	59.77	61.59	53.11	57.37	47.84	53.32	38.24	46.66
Aug	67.12	67.07	51.85	57.06	54.33	58.32	34.86	46.03
Sep	67.24	70.98	53.98	46.13	53.91	57.84	38.09	32.57
Oct	75.42	67.55	50.83	49.92	68.27	56.22	34.78	37.62
Nov	64.73	74.47	59.43	58.24	53.27	66.08	38.67	39.68
Dec	55.99	53.43	53.48	51.82	45.72	41.76	38.16	35.30
Jan	55.64	51.26	55.45	52.89	47.39	37.51	38.54	39.81
Feb	44.57	63.71	59.55	51.05	33.94	53.85	42.48	36.08
Mar	57.87	45.88	53.29	53.92	45.63	37.58	37.34	35.24
Apr	46.04	67.38	44.50	70.85	34.32	57.80	27.51	56.57
May – Oct	64.34	64.12	49.67	52.67	50.79	51.31	33.91	39.67
Nov - Apr	54.14	59.36	54.28	56.46	43.38	49.10	37.12	40.45
May - Apr	59.24	61.74	51.98	54.56	47.08	50.20	35.51	40.06

Table A-20: Supply Cushion Statistics, All Hours,
May 2007 – April 2009
(% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	19.0	15.7	0	1	145	255	19.9	20.5	4	0	159	62
Jun	17.8	19.2	0	0	205	167	20.0	22.1	15	0	192	93
Jul	19.1	19.6	0	0	198	153	22.3	24.5	0	0	134	47
Aug	23.7	21.6	0	0	52	120	21.8	24.8	8	0	126	76
Sep	24.3	22.9	0	0	17	62	17.6	21.1	28	0	256	132
Oct	18.1	19.7	0	0	154	150	16.6	22.0	3	0	270	60
Nov	17.6	18.6	0	0	164	127	13.2	18.5	20	5	362	162
Dec	19.6	17.2	0	0	93	170	17.6	20.4	7	0	193	81
Jan	16.0	14.4	0	0	271	262	18.0	19.2	23	0	223	54
Feb	15.7	13.5	0	0	208	261	13.1	17.8	33	0	312	95
Mar	17.2	13.8	0	0	143	279	15.6	20.6	2	0	240	71
Apr	12.7	16.7	6	0	383	150	19.3	16.6	0	0	110	154
May- Oct	20.3	19.8	0	1	771	907	19.7	22.5	58	0	1,137	470
Nov - Apr	16.4	15.7	6	0	1,262	1,249	16.1	18.9	85	5	1,440	617
May -Apr	18.4	17.7	6	1	2,033	2,156	17.9	20.7	143	5	2,577	1,087

* This category includes hours with a negative supply cushion

Table A-21: Supply Cushion Statistics, On-Peak, May 2007 – April 2009 (% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	11.3	9.6	0	1	133	193	11.1	14.4	4	0	156	58
Jun	10.5	11.4	0	0	162	129	10.3	14.6	15	0	168	69
Jul	10.8	12.5	0	0	168	118	12.5	16.4	0	0	129	38
Aug	15.5	13.5	0	0	52	94	12.4	16.0	8	0	115	59
Sep	16.1	14.4	0	0	16	59	8.3	12.8	28	0	213	108
Oct	12.2	12.9	0	0	144	129	8.7	15.2	3	0	234	53
Nov	11.9	12.4	0	0	131	97	6.8	12.1	16	5	292	135
Dec	14.0	11.5	0	0	68	137	10.9	14.4	5	0	140	73
Jan	9.6	15.2	0	0	221	85	10.1	20.2	23	0	186	16
Feb	10.2	14.3	0	0	172	102	6.7	18.0	30	0	239	35
Mar	12.2	11.3	0	0	108	152	9.3	17.4	0	0	184	52
Apr	6.9	15.8	4	0	289	94	13.2	16.7	0	0	100	83
May- Oct	12.7	12.4	0	1	675	722	10.6	14.9	58	0	1,015	385
Nov - Apr	10.8	13.4	4	0	989	667	9.5	16.5	74	5	1,141	394
May -Apr	11.8	12.9	4	1	1,664	1,389	10.0	15.7	132	5	2,156	779

* This category includes hours with a negative supply cushion

Table A-22: Supply Cushion Statistics, Off-Peak, May 2007 – April 2009 (% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	25.9	20.7	0	0	12	62	27.7	25.5	0	0	3	4
Jun	24.2	25.5	0	0	43	38	28.4	28.1	0	0	24	24
Jul	25.9	25.5	0	0	30	35	30.4	31.1	0	0	5	9
Aug	31.1	27.7	0	0	0	26	30.3	31.5	0	0	11	17
Sep	30.3	30.3	0	0	1	3	24.4	28.4	0	0	43	24
Oct	23.4	25.9	0	0	10	21	23.7	28.1	0	0	36	7
Nov	23.0	23.5	0	0	33	30	19.3	23.7	4	0	70	27
Dec	23.4	21.9	0	0	25	33	22.2	25.2	2	0	53	8
Jan	21.6	13.7	0	0	50	177	25.1	18.3	0	0	37	38
Feb	20.4	12.8	0	0	36	159	18.5	17.5	3	0	73	60
Mar	20.6	15.8	0	0	35	127	20.0	23.2	2	0	56	19
Apr	18.3	17.6	2	0	94	56	25.3	16.5	0	0	10	71
May- Oct	26.8	25.9	0	0	96	185	27.5	28.8	0	0	122	85
Nov - Apr	21.2	17.6	2	0	273	582	21.7	20.7	11	0	299	223
May -Apr	24.0	21.7	2	0	369	767	24.6	24.8	11	0	421	308

* This category includes hours with a negative supply cushion

Table A-23: Share of Real-time MCP Set by Resource Type, May 2007 – April 2009 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	61	67	0	0	13	3	26	31
Jun	61	60	0	0	18	16	21	24
Jul	58	57	0	0	20	17	22	26
Aug	44	65	0	0	38	9	17	27
Sep	52	59	0	0	25	12	23	28
Oct	46	67	0	0	30	8	24	25
Nov	55	59	0	0	23	24	22	17
Dec	47	60	0	1	27	19	26	20
Jan	70	61	0	0	12	26	18	13
Feb	60	69	0	0	19	19	21	12
Mar	59	63	0	3	15	8	26	26
Apr	62	35	0	11	13	13	25	41
May – Oct	54	63	0	0	24	11	22	27
Nov - Apr	59	58	0	3	18	18	23	22
May - Apr	56	60	0	1	21	15	23	24

Table A-24: Share of Real-time MCP Set by Resource Type, Off-Peak, May 2007 – April 2009 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	72	54	0	0	1	1	27	45
Jun	73	65	0	0	6	7	20	28
Jul	74	61	0	0	5	4	21	35
Aug	70	61	0	0	18	3	12	35
Sep	67	63	0	0	11	4	22	32
Oct	64	67	0	0	13	1	23	32
Nov	76	69	0	0	7	10	17	21
Dec	57	73	0	1	15	5	28	21
Jan	78	75	0	0	2	10	20	15
Feb	75	79	0	0	4	7	21	14
Mar	73	59	0	6	5	3	22	32
Apr	65	28	0	19	4	5	31	48
May – Oct	70	62	0	0	9	3	21	35
Nov - Apr	71	64	0	4	6	7	23	25
May - Apr	70	63	0	2	8	5	22	30

Table A-25: Share of Real-time MCP Set by Resource Type, On-Peak, May 2007 – April 2009 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	49	82	0	0	26	5	25	13
Jun	47	54	0	0	31	27	22	19
Jul	38	52	0	0	39	33	23	16
Aug	15	69	0	0	62	16	23	15
Sep	32	55	0	0	45	21	24	23
Oct	26	68	0	0	49	15	26	16
Nov	33	47	0	0	40	41	27	12
Dec	32	44	0	0	45	37	23	19
Jan	60	44	0	0	23	46	17	10
Feb	42	56	0	0	36	33	22	11
Mar	39	67	0	0	29	14	32	19
Apr	59	44	0	1	22	23	19	32
May – Oct	35	63	0	0	42	20	24	17
Nov - Apr	44	50	0	0	33	32	23	17
May - Apr	39	57	0	0	37	26	24	17

Table A-26: Resources Selected in the Real-time Market Schedule, May 2007 – April 2009 (TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Domestic Generation*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.39	1.58	1.08	2.65	1.59	1.40	0.81	0.69	2.99	4.04	6.98	6.09	12.36	12.22
Jun	0.47	1.57	1.04	2.52	2.45	2.19	0.85	0.83	3.07	3.50	6.74	6.52	13.11	13.03
Jul	0.49	1.27	1.30	2.43	2.58	2.31	0.86	0.80	2.85	3.63	7.22	7.47	13.51	14.21
Aug	0.67	0.55	1.12	1.69	3.17	2.10	1.15	0.72	2.35	3.22	7.06	7.54	13.73	13.58
Sep	0.87	0.66	0.92	1.26	2.38	1.80	0.90	0.77	2.23	2.60	6.29	7.05	11.80	12.23
Oct	0.80	0.65	0.93	1.46	2.07	1.47	1.02	0.82	2.61	2.62	6.10	7.18	11.79	12.09
Nov	1.00	0.79	0.97	1.36	2.30	1.59	0.97	1.04	2.74	2.76	6.11	6.75	12.12	12.14
Dec	1.00	0.41	1.31	1.41	2.02	1.62	1.07	1.17	2.72	3.03	7.68	7.90	13.49	13.71
Jan	0.97	0.64	2.06	1.82	2.17	2.16	0.92	1.28	3.19	3.30	8.16	7.89	14.44	14.64
Feb	0.79	0.41	1.65	1.35	2.48	1.34	0.91	1.12	3.20	3.03	6.93	6.83	13.52	12.33
Mar	1.20	0.65	1.89	1.42	2.65	0.96	0.92	1.18	3.36	3.27	6.51	7.63	13.44	13.04
Apr	1.26	0.79	2.42	1.35	1.87	0.56	0.76	1.06	3.64	3.19	6.19	6.19	12.46	10.99
May – Oct	3.69	6.28	6.39	12.01	14.24	11.27	5.59	4.63	16.10	19.61	40.39	41.85	76.30	77.36
Nov - Apr	6.22	3.69	10.30	8.71	13.49	8.23	5.55	6.85	18.85	18.58	41.58	43.19	79.47	76.85
May - Apr	9.91	9.97	16.69	20.72	27.73	19.50	11.14	11.48	34.95	38.19	81.97	85.04	155.77	154.21

* Domestic generation is the sum of Coal, Oil/Gas, Hydroelectric, and Nuclear.

Table A-27: Share of Resources Selected in Real-time Market Schedule, May 2007 – April 2009 (% of MW Scheduled)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	3	13	9	22	13	11	7	6	24	33	56	50
Jun	4	12	8	19	19	17	6	6	23	27	51	50
Jul	4	9	10	17	19	16	6	6	21	26	53	53
Aug	5	4	8	12	23	15	8	5	17	24	51	56
Sep	7	5	8	10	20	15	8	6	19	21	53	58
Oct	7	5	8	12	18	12	9	7	22	22	52	59
Nov	8	7	8	11	19	13	8	9	23	23	50	56
Dec	7	3	10	10	15	12	8	9	20	22	57	58
Jan	7	4	14	12	15	15	6	9	22	23	57	54
Feb	6	3	12	11	18	11	7	9	24	25	51	55
Mar	9	5	14	11	20	7	7	9	25	25	48	59
Apr	10	7	19	12	15	5	6	10	29	29	50	56
May – Oct	5	8	8	16	19	15	7	6	21	25	53	54
Nov - Apr	8	5	13	11	17	11	7	9	24	24	52	56
May - Apr	6	6	11	13	18	13	7	7	22	25	53	55

*Table A-28: Offtakes by Intertie Zone, On-Peak and Off-Peak, May 2007 – April 2009 (GWh)**

		MB		MI		MN		NY		PQ	
		2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	**Off-peak**	3.1	0.0	170.2	814.3	11.8	10.6	334.2	525.9	57.6	59.0
	On-Peak	3.5	0.0	257.4	781.4	10.9	12.3	197.2	402.9	36.0	42.8
Jun	**Off-peak**	0.5	0.0	65.9	697.8	4.0	3.2	566.6	606.5	39.5	54.9
	On-Peak	0.7	0.0	109.9	630.5	6.9	5.8	228.6	492.6	20.3	33.1
Jul	**Off-peak**	0.0	0.0	76.4	624.4	6.3	6.1	638.4	599.8	42.2	49.8
	On-Peak	0.2	0.0	130.5	528.7	8.9	4.0	376.9	593.3	19.7	28.6
Aug	**Off-peak**	0.0	0.0	61.9	494.0	3.5	5.3	556.0	379.6	52.4	50.4
	On-Peak	0.1	0.0	201.6	398.6	6.0	8.1	215.6	327.0	27.2	29.3
Sep	**Off-peak**	0.0	0.0	21.3	304.5	0.3	0.8	491.4	362.7	65.7	53
	On-Peak	0.0	0.0	52.7	240.1	0.7	2.5	258.0	257.2	31.9	36
Oct	**Off-peak**	0.0	0.0	72.6	314.8	0.4	2.6	453.1	395.0	30.1	54.7
	On-Peak	0.0	0.0	68.6	242.0	0.5	1.5	284.9	413.4	22.9	36.3
Nov	**Off-peak**	0.0	0.0	30.8	327.1	1.6	0.9	496.9	404.2	43.8	53.7
	On-Peak	1.3	0.0	51.3	209.5	7.7	1.1	307.9	321.4	25.5	39.3
Dec	**Off-peak**	4.0	17.3	140.1	313.8	7.3	13.8	523.4	361.1	64.0	49.0
	On-Peak	1.2	32.4	90.3	296.1	6.0	17.4	446.5	271.6	31.6	34.1
Jan	**Off-peak**	4.7	2.0	383.8	445.2	23.8	1.8	553.4	531.3	56.7	33.7
	On-Peak	6.9	15.9	328.2	376.2	19.6	3.1	645.6	389.6	41.0	23.8
Feb	**Off-peak**	0.3	0.0	365.7	430.4	10.7	0.5	448.4	367.8	43.4	13.4
	On-Peak	0.2	0.6	353.4	338.4	10.7	2.3	388.2	187.9	26.0	4.5
Mar	**Off-peak**	0.0	1.1	473.9	597.4	11.2	4.9	614.3	183.9	54.7	17.5
	On-Peak	0.2	0.0	364.5	525.5	15.4	4.4	324.7	105.6	30.0	5.8
Apr	**Off-peak**	4.9	6.9	561.9	351.7	7.1	18.3	601.7	110.5	45.9	9.7
	On-Peak	2.5	0.0	599.8	245.4	8.4	8.3	560.9	44.4	31.1	4.0
May- Oct	**Off-peak**	3.6	0.0	468.3	3,250.1	26.3	28.6	3,039.7	2,869.4	287.5	321.8
	On-Peak	4.5	0.0	820.7	2,821.3	33.9	34.2	1,561.2	2,486.5	158.0	206.0
	Total	8.1	0.0	1,289.0	6,071.4	60.2	62.9	4,600.9	5,355.8	445.5	527.8
Nov– Apr	**Off-peak**	13.9	27.3	1,956.2	2,465.6	61.7	40.2	3,238.1	1,958.8	308.5	177.0
	On-Peak	12.3	48.9	1,787.5	1,991.1	67.8	36.6	2,673.8	1,320.5	185.2	111.5
	Total	26.2	76.2	3,743.7	4,456.7	129.5	76.8	5,911.9	3,279.3	493.7	288.5
May- Apr	**Off-peak**	17.5	27.3	2,424.5	5,715.4	88.0	68.8	6,277.8	4,828.3	596.0	498.8
	On-Peak	16.8	48.9	2,608.2	4,812.4	101.7	70.8	4,235.0	3,806.9	343.2	317.6
	Total	34.3	76.2	5,032.7	10,527.8	189.7	139.6	10,512.8	8,635.2	939.2	816.4

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

Table A-29: Injections by Intertie Zone, On-Peak and Off-Peak, May 2007 – April 2009 (GWh)*

		MB		MI		MN		NY		PQ	
		2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	Off-peak	36.9	53.4	33.5	144.5	7.0	11.3	71.1	599.8	4.1	0.2
	On-Peak	17.4	38.6	43.6	153.2	9.4	9.0	55.8	560.9	109.2	8.1
Jun	Off-peak	68.0	86.3	84.5	254.4	16.1	19.9	10.0	482.4	23.3	12.8
	On-Peak	49.3	57.4	86.0	148.8	13.1	18.9	50.6	452.7	73.5	36.2
Jul	Off-peak	88.5	81.5	121.4	145.4	16.6	18.0	7.1	344.8	5.7	22.0
	On-Peak	40.9	69.6	100.7	158.0	12.2	17.6	53.6	326.1	43.5	89.0
Aug	Off-peak	79.1	90.1	173.9	96.4	23.3	19.6	24.4	48.1	5.8	20.1
	On-Peak	65.3	75.9	100.3	57.0	21.4	14.8	115.1	38.5	60.3	87.2
Sep	Off-peak	79.0	77.0	340.3	245.0	29.1	16.9	10.4	32.1	6.9	6.3
	On-Peak	57.5	59.1	252.1	157.0	25.7	15.5	46.6	20.5	19.1	33.1
Oct	Off-peak	60.2	84.8	275.4	207.3	15.7	21.4	10.3	38.1	14.3	0.5
	On-Peak	45.6	75.2	309.5	137.3	14.8	17.6	37.6	65.1	16.9	1.9
Nov	Off-peak	65.6	91.7	390.6	294.0	14.3	24.1	13.6	7.1	9.3	6.4
	On-Peak	53.1	68.5	315.5	195.8	10.8	15.7	58.2	71.8	70.4	19.9
Dec	Off-peak	52.3	25.7	351.1	153.6	16.5	7.5	76.3	13.2	1.1	2.1
	On-Peak	60.3	17.6	321.4	111.8	14.3	5.4	102.9	57.7	7.1	18.5
Jan	Off-peak	44.4	48.3	32.3	303.2	8.9	17.7	243.8	10.0	20.8	0.7
	On-Peak	46.4	14.6	76.3	218.5	11.3	11.4	405.2	8.8	77.5	9.5
Feb	Off-peak	34.0	57.0	80.0	144.0	8.1	13.6	162.3	5.0	43.0	7.9
	On-Peak	27.5	39.6	120.1	92.3	8.5	10.9	171.9	14.0	131.4	29.3
Mar	Off-peak	53.1	36.1	219.3	61.8	13.7	14.2	367.6	24.5	22.1	11.0
	On-Peak	36.8	33.7	130.4	50.1	10.4	11.4	278.7	4.7	68.8	25.8
Apr	Off-peak	53.1	39.9	188.6	57.0	11.1	6.7	343.6	5.0	10.3	1.4
	On-Peak	41.3	37.4	215.3	35.5	12.0	7.7	323.9	9.8	63.4	16.4
May - Oct	Off-peak	411.7	473.1	1,029.0	1093.0	107.8	107.1	133.3	1545.3	60.1	61.9
	On-Peak	276.0	375.8	892.2	811.3	96.6	93.4	359.3	1463.8	322.5	255.5
	Total	687.7	848.9	1,921.2	1904.3	204.4	200.5	492.6	3009.1	382.6	317.4
Nov– Apr	Off-peak	302.5	298.7	1,261.9	1,013.6	72.6	83.8	1,207.2	64.8	106.6	29.5
	On-Peak	265.4	211.4	1,179.0	704.0	67.3	62.5	1,340.8	166.8	418.6	119.4
	Total	567.9	510.1	2,440.9	1,717.6	139.9	146.3	2,548.0	231.6	525.2	148.9
May - Apr	Off-peak	714.2	771.8	2,290.9	2,106.6	180.4	190.9	1,340.5	1,610.1	166.7	91.4
	On-Peak	541.4	587.2	2,071.2	1,515.3	163.9	155.9	1,700.1	1,630.6	741.1	374.9
	Total	1,255.6	1,359.0	4,362.1	3,621.9	344.3	346.8	3,040.6	3,240.7	907.8	466.3

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

Table A-30: Net Exports, May 2007 – April 2009
(MWh)

	On-peak		Off-peak		Total	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	269,688	469,712	424,277	600,609	693,966	1,070,321
Jun	93,969	448,028	474,515	506,570	568,484	954,598
Jul	285,182	494,270	523,963	668,496	809,145	1,162,766
Aug	88,026	489,663	367,333	655,126	455,359	1,144,789
Sep	(57,635)	250,635	112,928	343,827	55,293	594,461
Oct	(47,499)	396,042	180,297	414,933	132,798	810,975
Nov	(114,506)	199,619	79,738	362,718	(34,769)	562,337
Dec	69,711	440,568	241,428	552,920	311,139	993,488
Jan	424,622	545,858	672,407	634,131	1,097,030	1,179,989
Feb	319,136	347,625	541,020	584,563	860,156	932,188
Mar	209,884	515,577	478,247	657,324	688,131	1,172,901
Apr	546,762	195,299	614,612	387,107	1,161,374	582,406
May- Oct	631,731	2,548,350	2,083,313	3,189,728	2,715,045	5,738,077
Nov - Apr	1,455,609	2,244,546	2,627,452	3,178,763	4,083,061	5,423,309
May -Apr	2,087,340	4,792,896	4,710,765	6,368,324	6,798,106	11,161,219

Table A-31: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP, May 2007 – April 2009 ($/MWh)

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)											
	Average Difference		Absolute Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	7.63	3.13	12.08	9.62	72.88	44.97	(93.58)	(61.87)	16.11	14.12	19.8	9.1
Jun	6.83	5.29	13.29	15.71	99.04	176.97	(305.24)	(214.18)	22.95	25.31	15.4	9.2
Jul	3.58	3.12	9.66	12.67	62.49	72.09	(215.90)	(159.24)	16.64	19.73	8.2	5.5
Aug	7.68	(1.05)	11.10	10.48	79.74	36.67	(61.26)	(306.69)	14.90	22.85	14.3	(2.3)
Sep	3.91	(0.74)	8.65	11.36	60.95	50.45	(69.49)	(336.00)	12.18	25.16	8.8	(1.5)
Oct	6.73	1.23	10.07	9.48	82.25	38.91	(234.52)	(244.94)	15.40	18.64	13.8	2.7
Nov	6.68	2.31	10.16	8.87	50.18	43.57	(54.74)	(78.83)	13.48	12.73	14.2	4.5
Dec	6.62	0.64	11.29	10.01	48.05	52.07	(50.61)	(184.42)	14.24	19.11	13.5	1.4
Jan	8.78	2.13	11.46	9.30	63.38	52.48	(84.51)	(411.27)	14.28	24.17	21.6	4.0
Feb	10.79	(2.13)	14.89	10.94	68.85	42.49	(505.62)	(1,853.34)	25.50	82.19	20.6	(4.5)
Mar	8.55	2.38	15.19	7.66	77.36	68.23	(125.90)	(142.18)	20.29	13.43	15.0	8.2
Apr	7.42	1.86	15.67	7.85	82.12	42.11	(145.17)	(81.83)	22.34	12.68	15.1	10.1
May – Oct	6.06	1.83	10.81	11.55	76.23	70.01	(163.33)	(220.49)	16.36	20.97	13.3	3.8
Nov - Apr	8.14	1.20	13.11	9.11	64.99	50.16	(161.09)	(458.65)	18.36	27.39	16.6	2.9
May - Apr	7.10	1.51	11.96	10.33	70.61	60.08	(162.21)	(339.57)	17.36	24.18	15.0	3.4

*In previous MSP Reports, the average difference as a percentage of HOEP statistics (presented in the final columns of Tables A-31 and A-32) were calculated hourly and then averaged over the month. However, given the high frequency of HOEP around $0/MWh (and sometimes a HOEP equal to $0/MWh), the result was being driven up (or down) by some very large outliers. To minimize this outlier effect, the calculation has been revised as the average price difference as a percentage of the average HOEP in each month (denominator being the monthly average HOEP reported in Table A-5). Results have been adjusted going back to May 2007.

Table A-32: Measures of Difference between 1-Hour Ahead Pre-dispatch Prices and HOEP, May 2007 – April 2009 ($/MWh)

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)											
	Average Difference		Absolute Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	8.23	4.86	11.55	9.33	71.78	63.30	(77.17)	(45.40)	14.49	13.02	21.4	14.1
Jun	6.99	8.60	12.07	14.97	94.35	115.21	(331.10)	(217.42)	21.84	22.60	15.8	15.0
Jul	5.26	5.21	9.74	11.66	62.02	61.08	(211.39)	(155.88)	15.91	17.67	12.0	9.2
Aug	8.16	1.23	10.22	10.54	74.6	36.54	(60.38)	(330.15)	13.56	22.67	15.2	2.6
Sep	5.96	1.88	9.11	11.33	83.01	334.24	(68.97)	(337.64)	12.46	27.03	13.4	3.8
Oct	8.17	2.88	10.66	9.12	66.75	38.77	(236.65)	(234.55)	14.99	18.14	16.7	6.4
Nov	7.50	4.81	10.52	8.99	56.65	42.9	(58.16)	(67.71)	12.91	11.81	16.0	9.3
Dec	7.37	3.08	10.74	9.92	52.08	83.79	(52.54)	(177.65)	13.32	18.12	15.0	6.6
Jan	9.41	7.42	11.25	12.44	64.78	1,925.02	(66.65)	(379.76)	13.52	73.97	23.1	13.9
Feb	11.28	0.18	15.06	11.29	107.12	60.23	(485.46)	(1,846.87)	25.08	81.92	21.5	0.4
Mar	10.87	4.35	15.00	7.87	77.36	66.62	(124.21)	(125.82)	18.68	13.35	19.1	15.1
Apr	8.46	3.66	15.41	7.82	77.91	57.88	(143.82)	(80.80)	21.38	11.89	17.3	19.9
May – Oct	7.13	4.11	10.56	11.16	75.42	108.19	(164.28)	(220.17)	15.54	20.19	15.6	8.5
Nov - Apr	9.15	3.92	13.00	9.72	72.65	372.74	(155.14)	(446.44)	17.48	35.18	18.6	9.6
May - Apr	8.14	4.01	11.78	10.44	74.03	240.47	(159.71)	(333.30)	16.51	27.68	17.2	9.0

Table A-33: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP, May 2007 – April 2009 ($/MWh)

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009
May	1.13	(5.06)	13.6	27.8
Jun	(1.59)	(4.79)	8.4	18.5
Jul	(1.87)	(6.84)	6.3	8.8
Aug	0.99	(9.75)	6.1	12.9
Sep	(2.35)	(10.44)	11.5	12.4
Oct	(3.59)	(8.31)	6.8	7.7
Nov	(6.48)	(7.68)	(1.6)	0.6
Dec	(5.45)	(8.92)	3.3	5.5
Jan	(2.76)	(6.72)	8.9	12.2
Feb	(0.84)	(11.05)	12.8	3.0
Mar	(1.74)	(3.38)	3.3	21.2
Apr	(9.05)	(2.82)	15.1	64.7
May – Oct	(1.21)	(7.53)	8.78	14.68
Nov - Apr	(4.39)	(6.76)	6.97	17.87
May - Apr	(2.80)	(7.15)	7.88	16.28

* This is an average of hourly differences relative to hourly peak MCP

Table A-34: Average Monthly HOEP Compared to Average Monthly Peak Hourly MCP, May 2007 – April 2009 ($/MWh)

	Hourly Peak MCP		HOEP		Peak minus HOEP	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	45.60	44.48	38.50	34.56	7.11	9.93
Jun	52.95	70.68	44.38	57.44	8.57	13.24
Jul	51.04	68.63	43.90	56.58	7.13	12.05
Aug	60.80	57.55	53.62	46.57	7.18	10.98
Sep	52.94	61.41	44.63	49.09	8.31	12.32
Oct	60.66	56.49	48.91	45.27	11.76	11.22
Nov	60.93	64.27	46.95	51.78	13.98	12.49
Dec	61.92	58.34	49.08	46.34	12.85	12.00
Jan	52.94	67.36	40.74	53.22	12.20	14.14
Feb	64.50	58.48	52.38	47.24	12.12	11.24
Mar	69.45	36.81	56.84	29.05	12.61	7.76
Apr	66.50	25.12	48.98	18.66	17.52	6.45
May – Oct	54.00	59.87	45.66	48.25	8.34	11.62
Nov – Apr	62.71	51.73	49.16	41.05	13.55	10.68
May - Apr	58.35	55.80	47.41	44.65	10.95	11.15

Table A-35: Frequency Distribution of Difference between 1-Hour Pre-dispatch and HOEP, May 2007 – April 2009 (%)*

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)															
	< -$50.01		**-$50.00 to -$20.01**		**-$20.00 to -$10.01**		**-$10.00 to -$0.01**		**$0.00 to $9.99**		**$10.00 to $19.99**		**$20.00 to $49.99**		**> $50.00**	
	2007/2008	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**
May	0.7	0.0	2.4	3.6	1.5	3.6	11.0	21.9	48.5	42.6	17.7	14.5	17.5	13.4	0.8	0.3
Jun	1.3	0.8	1.7	3.8	2.5	5.0	13.6	15.0	50.4	37.8	13.6	14.9	14.6	18.8	0.0	**3.9**
Jul	0.8	1.5	2.2	2.8	2.6	4.6	13.0	19.2	53.1	40.2	16.5	15.7	11.3	15.2	0.4	0.8
Aug	0.1	**1.7**	1.1	**5.0**	1.7	4.4	13.0	17.3	51.9	47.8	16.7	14.2	14.0	9.4	3.1	0.0
Sep	0.4	1.4	1.3	3.7	3.7	**5.8**	13.9	22.4	51.8	40.3	19.4	17.1	8.8	9.2	0.0	0.1
Oct	0.3	1.2	0.5	2.0	2.0	3.9	14.9	22.0	45.3	47.0	20.3	15.6	16.5	8.2	0.1	0.0
Nov	0.1	0.1	1.5	2.5	3.7	3.7	14.4	**23.2**	44.9	41.4	20.1	19.9	14.7	9.2	0.4	0.0
Dec	0.1	1.2	2.3	3.2	2.7	4.3	18.0	18.4	42.7	50.2	18.4	12.8	15.6	9.3	1.2	0.5
Jan	0.3	0.7	0.5	1.9	2.3	1.7	11.6	18.7	47.2	51.1	17.9	13.2	19.1	12.5	0.0	0.3
Feb	0.1	0.9	2.0	0.4	2.2	1.8	8.9	19.2	40.4	**57.9**	**21.1**	13.8	22.1	5.8	2.2	0.1
Mar	0.8	0.4	2.2	2.0	1.9	2.2	16.0	21.9	34.8	51.9	18.7	13.3	22.6	7.7	1.1	0.7
Apr	1.7	0.6	3.7	2.4	3.6	3.1	12.5	22.4	34.7	49.7	18.8	13.1	**23.5**	8.8	1.3	0.1
May – Oct	0.6	1.1	1.5	3.5	2.3	4.6	13.2	19.6	50.2	42.6	17.4	15.3	13.8	12.4	0.7	0.9
Nov – Apr	0.5	0.7	2.0	2.1	2.7	2.8	13.6	20.6	40.8	50.4	19.2	14.4	19.6	8.9	1.0	0.3
May - Apr	0.6	0.9	1.8	2.8	2.5	3.7	13.4	20.1	45.5	46.5	18.3	14.8	16.7	10.6	0.9	0.6

* Bold values show highest percentage within price range.

Table A-36: Difference between 1-Hour Pre-dispatch Price and HOEP within Defined Ranges, May 2007 – April 2009

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	84.3	70.8	0.1	0.0	15.6	29.2
Jun	80.7	75.1	0.3	0.3	19.0	24.6
Jul	81.2	71.9	0.3	0.0	18.6	28.1
Aug	83.9	71.1	0.1	0.4	16.0	28.5
Sep	80.7	66.7	0.0	0.0	19.3	33.3
Oct	82.3	70.3	0.0	0.5	17.7	29.2
Nov	80.1	70.1	0.0	0.3	19.9	29.6
Dec	76.9	72.1	0.0	0.7	23.1	27.2
Jan	85.1	76.3	0.3	0.7	14.7	23.0
Feb	86.6	77.4	0.1	0.3	13.2	22.3
Mar	79.0	72.3	0.1	1.2	20.8	26.5
Apr	78.2	70.3	0.3	1.4	21.5	28.3
May – Oct	82.2	71.0	0.1	0.2	17.7	28.8
Nov – Apr	81.0	73.1	0.1	0.8	18.9	26.2
May - Apr	81.6	72.0	0.1	0.5	18.3	27.5

Table A-37: Difference between 1-Hour Pre-dispatch Price and Hourly Peak MCP within Defined Ranges, May 2007 – April 2009

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009
May	62.1	47.8	2.4	1.6	35.5	50.5
Jun	57.1	46.7	2.9	1.8	40.0	51.5
Jul	55.7	41.9	3.6	2.7	40.7	55.4
Aug	58.7	38.8	2.4	3.6	38.8	57.5
Sep	46.8	35.1	3.5	2.4	49.7	62.5
Oct	48.9	38.4	2.8	3.2	48.3	58.3
Nov	41.7	39.4	3.1	3.5	55.3	57.1
Dec	46.0	37.7	2.0	4.2	52.0	58.1
Jan	54.7	50.1	2.2	2.8	43.1	47.0
Feb	61.5	46.7	1.9	2.8	36.6	50.4
Mar	50.9	48.0	3.2	4.4	45.8	47.6
Apr	51.2	42.5	1.5	8.8	47.2	48.8
May – Oct	54.9	41.5	2.9	2.6	42.2	56.0
Nov – Apr	51.0	44.1	2.3	4.4	46.7	51.5
May - Apr	52.9	42.8	2.6	3.5	44.4	53.7

Table A-38: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2007 – April 2009

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	285	269	259	247	173	193	142	156	1.8	1.8	1.7	1.6	1.1	1.3	0.9	1.0
Jun	418	390	350	343	287	269	209	210	2.4	2.3	2.1	2.1	1.6	1.5	1.2	1.2
Jul	399	396	337	336	275	274	201	198	2.3	2.3	2.0	2.0	1.6	1.5	1.1	1.1
Aug	455	333	382	307	307	241	225	197	2.5	2.0	2.2	1.9	1.7	1.4	1.2	1.1
Sep	368	280	318	267	237	208	180	159	2.3	1.7	2.0	1.7	1.4	1.1	1.1	1.0
Oct	336	290	307	272	192	241	160	153	2.1	1.9	2.0	1.8	1.2	1.1	1.0	1.0
Nov	310	318	300	298	178	285	154	159	1.8	2.0	1.8	1.8	1.0	1.1	0.9	1.0
Dec	352	388	316	346	256	312	203	193	1.9	2.2	1.7	2.0	1.4	1.4	1.1	1.1
Jan	367	403	327	355	205	350	163	197	2.0	2.2	1.8	1.9	1.1	1.3	0.9	1.1
Feb	344	333	313	300	212	283	180	165	1.9	1.9	1.7	1.7	1.1	1.2	1.0	0.9
Mar	344	341	302	292	238	211	188	198	2.0	2.1	1.7	1.8	1.3	1.5	1.1	1.2
Apr	284	305	263	262	182	201	154	175	1.8	2.1	1.7	1.8	1.1	1.4	1.0	1.2
May – Oct	377	326	326	295	245	238	186	179	2.2	2.0	2.0	1.9	1.4	1.3	1.1	1.1
Nov – Apr	334	348	304	309	212	274	174	181	1.9	2.1	1.7	1.8	1.2	1.3	1.0	1.1
May - Apr	355	337	315	302	229	256	180	180	2.1	2.0	1.9	1.8	1.3	1.3	1.0	1.1

Table A-39: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2007 – April 2009 (%)*

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	1	1	12	13	15	15	21	18	22	22	16	15	13	16	0	1	49	46	51	54
Jun	4	5	19	21	14	14	17	16	16	14	12	12	15	16	3	2	54	56	46	44
Jul	4	4	21	18	12	12	17	17	17	16	14	15	13	16	1	3	55	50	45	50
Aug	5	3	24	15	16	13	15	18	12	16	11	13	15	20	2	3	60	48	40	52
Sep	3	0	16	13	16	11	20	19	18	23	11	16	15	16	2	1	54	44	46	56
Oct	1	1	18	15	19	17	18	21	21	19	13	16	9	11	1	1	56	53	44	47
Nov	2	2	15	17	15	16	23	23	19	19	15	12	11	10	0	1	55	58	45	42
Dec	3	4	19	20	11	17	14	20	17	15	14	11	20	11	2	2	47	61	53	39
Jan	3	3	18	26	18	17	22	20	19	13	11	10	10	10	0	1	60	66	40	34
Feb	3	2	20	17	15	18	18	19	20	20	11	12	11	11	2	1	56	56	44	44
Mar	2	1	24	19	13	13	18	16	16	17	11	12	15	18	1	3	57	50	43	50
Apr	1	1	14	16	16	14	19	18	22	18	14	14	13	16	1	2	50	50	50	50
May – Oct	3	2	18	16	15	14	18	18	18	18	13	15	13	16	2	2	54	50	46	51
Nov – Apr	2	3	18	20	15	17	19	21	19	17	13	11	13	11	1	1	54	60	46	40
May - Apr	3	3	18	18	15	15	19	19	18	18	13	13	13	14	1	2	55	54	45	46

* Data includes both dispatchable and non-dispatchable load.

*Table A-40: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, May 2007 – April 2009 (MW and %)**

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	741,893	782,035	182.2	466.4	(194.2)	(187.6)	2.6	42.6	0.0	4.4
Jun	691,114	572,393	276.5	257.9	(144.7)	(138.3)	32.0	37.0	3.7	5.0
Jul	665,874	574,125	233.8	259.5	(147.9)	(524.7)	40.6	42.1	4.7	5.3
Aug	669,870	599,291	167.5	666.2	(167.3)	(178.7)	26.7	60.9	2.9	7.5
Sep	655,691	625,327	186.6	874.8	(162.4)	(1014.6)	17.9	19.0	2.1	2.0
Oct	817,009	861,952	177.9	1055.6	(247.5)	(334.1)	18.3	18.1	1.6	0.8
Nov	815,131	840,871	218.8	232.9	(161.6)	(207.1)	15.9	27.1	1.4	2.4
Dec	846,484	1,075,374	199.2	635.3	(214.2)	(179.2)	4.9	76.1	0.6	5.2
Jan	893,372	935,618	285.9	590.1	(163.5)	(279.3)	13.3	25.4	1.2	1.9
Feb	784,525	925,681	195.2	616.4	(171.5)	(261.7)	15.7	33.2	1.4	2.4
Mar	809,244	1,130,834	233.7	535.4	(190.5)	(266.5)	13.7	25.0	1.3	1.3
Apr	727,988	1089,791	314.2	893.0	(243.2)	(529.8)	13.4	34.4	1.6	2.2
May – Oct	706,909	669,187	204.1	596.7	(177.3)	(396.3)	23.0	37.0	2.5	4.2
Nov – Apr	812,791	999,695	241.2	583.9	(190.8)	(287.3)	13.0	36.9	1.3	2.6
May - Apr	759,850	834,441	222.6	590.3	(184.0)	(341.8)	18.0	36.7	1.9	3.4

* Self-scheduled generators comprise list as well as those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.
** Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-41: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2007 – April 2009

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	68,746	107,523	137.8	173.9	(199.9)	(178.0)	4.2	4.5	4.8	2.6
Jun	54,863	59,868	146.7	144.1	(153.0)	(162.9)	9.4	1.7	14.8	0.4
Jul	44,078	61,196	154.0	154.8	(187.8)	(125.6)	5.7	6.3	14.2	(317.9)
Aug	54,869	60,478	159.1	122.0	(148.8)	(209.2)	1.7	8.0	(11.1)	14.3
Sep	74,113	81,062	143.3	182.1	(205.8)	(182.0)	(3.3)	9.8	(2.2)	8.6
Oct	106,536	160,840	150.1	191.9	(227.9)	(234.7)	4.1	7.3	0.8	4.3
Nov	113,859	167,804	178.0	190.5	(166.1)	(191.8)	11.1	15.2	9.3	7.0
Dec	120,139	277,106	183.8	312.3	(203.0)	(226.9)	3.2	30.0	4.2	11.7
Jan	152,155	192,994	205.7	242.0	(155.4)	(252.3)	5.0	17.0	5.6	12.1
Feb	105,099	217,694	148.2	283.6	(166.8)	(251.3)	15.6	27.8	12.0	14.6
Mar	119,586	207,877	136.1	262.5	(169.9)	(357.3)	8.1	13.6	5.3	7.9
Apr	107,994	262,595	180.9	285.0	(240.4)	(317.8)	(3.3)	12.5	(1.7)	4.1
May – Oct	67,201	79,313	148.5	158.2	(187.2)	(182.1)	3.6	2.1	3.6	(53.5)
Nov – Apr	119,805	221,012	172.1	262.7	(183.6)	(266.2)	6.6	19.4	5.8	9.6
May - Apr	93,503	154,753	160.3	212.1	(185.4)	(224.2)	5.1	12.8	4.7	(19.2)

* Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-42: Failed Imports into Ontario, May 2007 – April 2009 (Incidents and Average MW)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	192	364	453	1,085	135	212	6.3	4.7
Jun	148	402	400	1,369	95	234	2.9	5.7
Jul	112	339	700	979	123	182	2.8	4.6
Aug	207	271	546	880	118	142	3.5	6.6
Sep	155	350	525	989	146	218	2.5	10.4
Oct	173	340	607	1,029	116	188	2.4	9.0
Nov	214	285	677	730	137	151	2.8	5.2
Dec	182	223	597	812	125	142	2.2	7.2
Jan	354	296	1,255	600	259	142	8.7	6.1
Feb	342	151	1,500	800	315	153	12.0	5.3
Mar	488	185	1,586	575	340	107	12.1	6.8
Apr	303	150	660	425	157	108	3.6	6.9
May-Oct	987	2,066	539	1,055	122	196	3.4	6.8
Nov-Apr	1,883	1,290	1,046	657	222	134	6.9	6.3
May-Apr	2,870	3,356	792	856	172	165	5.2	6.5

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-43: Failed Imports into Ontario, On-Peak, May 2007 – April 2009 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	107	156	453	680	146	182	6.2	3.6
Jun	83	185	289	1,369	98	225	2.9	5.5
Jul	69	165	700	979	114	172	3.0	4.1
Aug	121	120	546	880	104	144	3.4	5.9
Sep	80	141	421	702	139	175	2.7	8.0
Oct	97	147	607	1,029	123	181	2.7	8.2
Nov	110	104	446	730	120	145	2.5	3.9
Dec	82	114	500	531	115	138	1.8	7.0
Jan	202	125	1,255	575	281	127	8.4	5.7
Feb	165	60	1,500	800	305	152	9.9	4.7
Mar	246	44	1,190	375	349	64	14.0	2.2
Apr	166	31	660	225	165	75	4.0	2.1
May-Oct	557	914	503	940	121	180	3.5	5.9
Nov-Apr	971	478	925	539	223	117	6.8	4.3
May-Apr	1,528	1392	714	740	172	148	5.1	5.1

* Excludes transaction failures of less than 1 MW.

** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-44: Failed Imports into Ontario, Off-Peak, May 2007 – April 2009 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	85	208	450	1,085	120	235	6.3	5.7
Jun	65	217	400	1,225	91	242	2.9	5.8
Jul	43	174	662	818	138	192	2.4	5.2
Aug	86	151	500	600	138	141	3.7	7.2
Sep	75	209	525	989	153	247	2.4	12.0
Oct	76	193	435	950	107	193	2.1	9.6
Nov	104	181	677	725	155	154	3.2	6.2
Dec	100	109	597	812	133	147	2.6	7.4
Jan	152	171	892	600	228	152	9.0	6.4
Feb	177	91	1,300	605	324	155	14.9	5.8
Mar	242	141	1,586	575	330	120	10.6	10.3
Apr	137	119	400	425	146	116	3.2	11.2
May-Oct	430	1,152	495	945	125	208	3.3	7.6
Nov-Apr	912	812	909	624	219	141	7.3	7.9
May-Apr	1,342	1,964	702	784	172	175	5.3	7.7

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-45: Failed Exports from Ontario,
May 2007 – April 2009
(Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	522	671	938	1,100	202	225	8.9	5.4
Jun	382	605	733	1,450	167	235	5.8	5.3
Jul	350	564	1,079	1,858	175	160	4.5	3.6
Aug	373	404	900	709	163	140	5.2	3.2
Sep	397	359	1,071	729	208	152	8.2	4.2
Oct	390	377	898	725	194	140	7.5	3.5
Nov	368	315	876	552	171	131	6.1	2.9
Dec	438	386	932	1,645	185	176	5.8	4.6
Jan	563	435	1,840	965	288	135	7.3	3.1
Feb	533	344	1,675	675	387	134	11.1	3.3
Mar	582	360	1,574	1,815	334	168	9.3	4.0
Apr	564	319	943	900	205	107	4.5	4.1
May-Oct	2,414	2,980	937	1,095	185	175	6.7	4.2
Nov-Apr	3,048	2,159	1,307	1,092	262	142	7.4	3.7
May-Apr	5,462	5,139	1,122	1,094	223	159	7.0	3.9

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-46: Failed Exports from Ontario, On-Peak, May 2007 – April 2009 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	199	306	938	915	224	211	8.1	4.9
Jun	150	261	733	1,100	179	246	6.8	5.3
Jul	164	242	1,079	1,263	201	184	5.8	3.7
Aug	155	170	900	558	154	139	5.0	3.0
Sep	146	167	942	610	204	148	8.0	4.4
Oct	160	178	645	725	171	150	6.8	3.7
Nov	147	130	633	552	149	155	5.3	3.4
Dec	175	183	650	1,645	182	189	5.3	5.1
Jan	283	204	1,840	965	336	158	8.4	3.8
Feb	226	160	1,675	675	355	145	9.3	4.2
Mar	253	159	1,300	1,102	387	159	11.8	3.8
Apr	272	106	820	578	219	193	4.7	3.2
May-Oct	974	1,324	873	862	189	180	6.8	4.2
Nov-Apr	1,356	942	1,153	920	271	167	7.5	3.9
May-Apr	2,330	2,266	1,013	891	230	173	7.1	4.0

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-47: Failed Exports from Ontario, Off-Peak, May 2007 – April 2009 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	323	365	902	1,100	188	237	9.5	5.8
Jun	232	344	570	1,450	159	227	5.2	5.4
Jul	186	322	627	1,858	152	141	3.6	3.4
Aug	218	234	722	709	170	140	5.2	3.4
Sep	251	192	1,071	729	209	154	8.3	4.0
Oct	230	199	898	492	211	131	8.0	3.3
Nov	221	185	876	497	186	114	6.7	2.6
Dec	263	203	932	1,271	187	165	6.2	4.2
Jan	280	231	1,705	639	239	115	6.2	2.6
Feb	307	184	1,517	484	410	124	12.7	2.7
Mar	329	201	1,574	1,815	294	174	7.7	4.2
Apr	292	213	943	900	191	114	4.4	4.7
May-Oct	1,440	1,656	798	1,056	182	172	6.6	4.2
Nov-Apr	1,692	1,217	1,258	934	251	134	7.3	3.5
May-Apr	3,132	2,873	1,028	995	216	153	7.0	3.9

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-48: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2007 – April 2009

	Average Hourly Reserve (MW)		% of Total Requirements												Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	1,346	1,374	18.9	16.1	65.5	22.6	2.7	39.2	6.5	9.3	0.1	9.4	2.1	0.0	4.2	3.4
Jun	1,333	1,316	17.7	18.7	52.8	37.5	11.2	18.0	10.3	13.6	0.3	8.2	4.1	0.0	3.6	3.9
Jul	1,316	1,315	16.3	18.3	64.3	44.1	4.1	13.9	7.0	14.6	0.1	5.8	5.5	0.0	2.7	3.3
Aug	1,324	1,317	14.5	20.4	71.7	51.6	2.5	10.3	6.8	10.8	0.0	3.0	1.2	0.0	3.2	4.0
Sep	1,320	1,324	15.5	19.2	70.2	58.5	3.2	9.1	5.8	7.4	0.1	1.6	2.1	0.0	3.1	4.2
Oct	1,330	1,491	15.2	9.2	71.8	61.0	1.8	15.3	7.1	6.4	0.0	4.3	1.3	0.1	2.7	3.7
Nov	1,382	1,546	14.7	4.8	69.2	64.7	1.9	13.5	6.2	9.4	1.2	4.2	3.0	0.2	3.8	3.3
Dec	1,315	1,516	15.2	5.4	71.1	73.4	1.2	8.1	6.9	8.3	0.8	1.8	1.0	0.0	3.7	2.9
Jan	1,317	1,522	19.1	6.2	57.6	56.3	5.8	21.2	8.0	12.0	2.3	4.2	2.9	0.0	4.3	0.0
Feb	1,319	1,472	19.0	4.3	50.3	56.0	9.3	26.2	10.6	8.1	2.7	5.4	3.8	0.0	4.3	0.0
Mar	1,316	1,456	16.9	7.9	51.4	53.4	8.6	27.2	9.8	7.2	3.6	4.3	6.3	0.0	3.2	0.0
Apr	1,315	1,588	17.8	5.3	37.8	42.7	20.6	29.1	8.6	14.8	8.1	8.2	4.0	0.0	3.2	0.0
May-Oct	1,328	1,356	16.4	17.0	66.1	45.9	4.3	17.6	7.3	10.3	0.1	5.4	2.7	0.0	3.3	3.8
Nov-Apr	1,327	1,517	17.1	5.7	56.2	57.7	7.9	20.9	8.4	10.0	3.1	4.7	3.5	0.0	3.8	1.0
May-Apr	1,328	1,436	16.7	11.3	61.2	51.8	6.1	19.2	7.8	10.2	1.6	5.0	3.1	0.0	3.5	2.4

Table A-49: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2007 – April 2009

	Average Hourly Reserve (MW)		% of Total Requirements												Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	1,340	1,333	19.4	22.3	69.2	42.7	2.0	19.4	4.7	9.7	0.0	1.7	0.0	0.1	4.7	4.1
Jun	1,316	1,358	19.9	20.9	65.5	54.9	4.0	5.4	5.7	12.1	0.0	2.4	0.6	0.0	4.3	4.3
Jul	1,313	1,315	18.1	19.5	72.1	57.2	0.8	7.6	5.9	10.3	0.0	1.7	0.1	0.0	3.1	3.7
Aug	1,316	1,321	15.5	21.3	71.4	61.9	1.7	2.2	6.6	9.6	0.0	0.5	0.0	0.0	4.7	4.5
Sep	1,317	1,329	17.1	20.7	70.7	65.3	1.4	0.4	5.8	8.4	0.0	0.8	0.1	0.0	4.9	4.4
Oct	1,316	1,477	16.8	13.1	72.3	72.5	1.1	4.2	6.0	6.2	0.0	0.4	0.9	0.0	2.9	3.7
Nov	1,415	1,523	15.4	7.0	69.5	79.0	1.8	3.3	6.7	6.4	0.1	0.5	2.3	0.0	4.4	3.7
Dec	1,358	1,507	16.9	5.5	70.9	81.2	0.7	2.5	6.5	7.2	0.2	0.2	0.3	0.0	4.6	3.3
Jan	1,316	1,517	21.4	8.8	63.6	79.4	0.8	4.6	9.0	6.3	0.2	0.9	0.2	0.0	4.8	0.0
Feb	1,317	1,466	21.9	7.0	59.8	79.4	1.3	7.3	11.7	5.2	0.2	1.0	0.4	0.0	4.7	0.0
Mar	1,323	1,454	20.6	10.3	62.6	78.6	2.2	4.5	9.9	6.2	0.2	0.5	0.8	0.0	3.8	0.0
Apr	1,352	1,530	21.6	9.2	50.4	70.4	12.2	9.8	8.3	8.9	3.5	1.7	0.7	0.0	3.3	0.0
May-Oct	1,320	1,356	17.8	19.6	70.2	59.1	1.8	6.5	5.8	9.4	0.0	1.2	0.3	0.0	4.1	4.1
Nov-Apr	1,347	1,500	19.6	7.9	62.8	78.0	3.2	5.3	8.7	6.7	0.7	0.8	0.8	0.0	4.3	1.2
May-Apr	1,333	1,428	18.7	13.8	66.5	68.6	2.5	5.9	7.2	8.0	0.4	1.0	0.5	0.0	4.2	2.6

Table A-50: Day Ahead Forecast Error, May 2007 – April 2009 (as of Hour 18)

	Average Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 3%		Percentage of Hours with Absolute Error ≥ 3%	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	(26)	(101)	1.31	1.58	53	100	7	13
Jun	0	113	2.67	2.45	252	215	35	30
Jul	98	61	2.61	2.77	227	312	31	42
Aug	113	(13)	2.21	1.99	188	177	25	24
Sep	68	(82)	1.79	1.58	139	80	19	11
Oct	(70)	5	1.53	1.36	92	76	12	10
Nov	(93)	45	1.31	1.62	51	105	7	15
Dec	(115)	84	1.81	2.19	147	195	20	26
Jan	65	216	1.74	2.25	128	183	17	25
Feb	(17)	68	1.42	2.26	65	191	9	28
Mar	69	(77)	1.83	2.48	145	228	19	31
Apr	(101)	46	1.69	2.07	130	187	18	26
May-Oct	31	(3)	2.02	1.96	951	960	22	22
Nov-Apr	(32)	64	1.63	2.15	666	182	15	25
May-Apr	(1)	30	1.83	2.05	1,617	171	18	23

Table A-51: Average One Hour Ahead Forecast Error, May 2007 – April 2009

	Peak Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 2%		Percentage of Hours with Absolute Error ≥ 2%	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	(2)	(15)	0.89	1.02	63	87	8	12
Jun	19	39	1.19	1.22	129	136	18	19
Jul	39	14	1.14	1.10	126	115	17	15
Aug	61	(17)	1.22	1.13	125	114	17	15
Sep	22	(22)	1.06	0.96	94	81	13	11
Oct	39	13	0.99	0.97	92	69	12	9
Nov	19	38	0.88	0.96	59	75	8	10
Dec	(2)	52	1.12	1.10	102	112	14	15
Jan	53	77	0.88	1.06	66	103	9	14
Feb	40	38	0.96	0.94	77	58	11	9
Mar	40	(7)	1.06	1.20	90	133	12	18
Apr	2	(7)	0.95	1.15	67	113	9	16
May-Oct	30	(0)	1.08	1.07	629	602	14	14
Nov-Apr	25	32	0.98	1.07	461	99	11	14
May-Apr	28	17	1.03	1.07	1,090	100	12	14

Table A-52: Monthly Payments for Reliability Programs, May 2007 – April 2009 ($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		ELRP		Total	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.33	0.05	2.33	1.42	1.01	5.07	1.15	1.07	0.11	0.13	0.00	0.00	4.93	7.74
Jun	1.08	0.10	2.27	3.06	1.24	4.79	2.04	3.31	0.07	0.03	0.01	0.00	6.71	11.29
Jul	0.65	0.06	1.42	1.62	1.10	6.09	2.29	3.52	0.22	0.15	0.00	0.00	5.68	11.44
Aug	0.64	0.03	2.29	0.90	0.61	2.66	1.58	2.82	0.06	0.01	0.00	0.00	5.18	6.42
Sep	2.79	0.22	1.71	1.44	0.78	0.89	1.67	2.32	0.03	0.03	0.01	0.00	6.99	4.90
Oct	1.35	0.02	2.55	1.30	0.85	4.21	1.99	1.73	0.04	0.12	0.00	0.00	6.78	7.38
Nov	1.20	0.37	2.99	1.82	1.50	4.17	1.06	3.86	0.06	0.03	0.00	0.00	6.81	10.25
Dec	0.25	0.23	3.69	1.10	1.07	2.56	2.01	5.68	0.01	0.18	0.00	0.00	7.03	9.75
Jan	0.10	0.04	3.93	1.15	2.25	6.23	2.06	5.47	0.11	0.59	0.00	0.00	8.45	13.48
Feb	0.27	0.06	5.44	0.92	2.25	6.82	1.42	5.16	0.20	0.64	0.00	0.00	9.58	13.60
Mar	0.22	0.03	3.79	0.76	1.40	4.28	2.22	7.58	0.09	0.87	0.00	0.00	7.72	13.52
Apr	0.11	0.01	3.98	0.30	4.77	7.58	3.59	1.80	0.06	0.44	0.00	0.00	12.51	10.13
May – Oct	6.84	0.48	12.57	9.74	5.59	23.71	10.72	14.77	0.53	0.47	0.02	0.00	36.27	49.17
Nov – Apr	2.15	0.74	23.82	6.05	13.24	31.64	12.36	29.55	0.53	2.75	0.00	0.00	52.10	70.73
May - Apr	8.99	1.22	36.39	15.79	18.83	55.35	23.08	44.32	1.06	3.22	0.02	0.00	88.37	119.9

* In certain situations, payments for the same import are made via the DA IOG and RT IOG programs but subsequently one of the payments is recovered through the IOG reversal. Since June 2006, approximately $2.66 million has been received through the IOG reversal. The data reported in this table does not account for the IOG reversal.

Table A-53: Summary Statistics for Hours when HOEP < $20/MWh, November 2008 – April 2009

Month	Number of Hours*	PD Demand (MW)**	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	% Change in Price	Minimum HOEP
November	31	13,567	13,123	(3.3)	41	30.19	11.69	(61.3)	1.74
December	62	14,630	14,267	(2.5)	165	25.64	6.48	(74.7)	(34.00)
January	25	15,043	14,617	(2.8)	28	35.56	7.86	(77.9)	3.40
February	25	14,940	14,588	(2.4)	94	34.11	10.90	(68.1)	4.23
March	192	14,476	14,246	(1.6)	44	12.17	1.10	(91.0)	(51.00)
April	354	14,031	13,795	(1.7)	23	8.36	0.33	(96.0)	(39.82)
Total	689	14,258	13,991	(1.9)	45	13.88	2.27	(83.7)	(51.00)

* Monthly figures reflect the average of hourly PD and RT Demand, Net Failed Exports, and PD and HOEP prices over all hours when HOEP was less than $20/MWh.

Table A-54: Summary Statistics for Hours when HOEP < $0/MWh, November 2008 – April 2009

Month	Number of Hours*	PD Demand (MW)**	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	% Change in Price	Minimum HOEP
November	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
December	5	12,137	11,847	(2.4)	588	6.94	(29.73)	(528.6)	(34.00)
January	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
February	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
March	58	13,581	13,426	(1.1)	9	(10.35)	(14.46)	(39.7)	(51.00)
April	156	13,584	13,351	(1.7)	16	(3.08)	(7.42)	(141.1)	(39.82)
Total	219	13,550	13,336	(1.6)	27	(4.78)	(9.80)	(105.1)	(51.00)

* Monthly figures reflect the average of hourly PD and RT Demand, Net Failed Exports, and PD and HOEP prices over all hours when HOEP was negative.