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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2010 – April 2011

November 2011

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Ontario

November 14, 2011

Ms. Rosemarie T. Leclair
Chair
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Leclair:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Roger Ware and Bill Rupert, I am pleased to provide you with the Panel's 18th semi-annual Monitoring Report on the IESO-administered wholesale electricity markets.

This report, covering the period November 2010 to April 2011, is submitted pursuant to Article 7.1.1 of Ontario Energy Board By-law #3.

Best Regards,

Neil Campbell
Chair, Market Surveillance Panel

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Executive Summary

Overall Assessment

Over the winter period, November 2010 to April 2011, Ontario's wholesale electricity market operated reasonably well having regard to its hybrid design. Wholesale electricity prices generally reflected the underlying demand and supply conditions. There were occasions where the design of generation contracts, actions by market participants, or actions taken by the IESO led to inefficient outcomes. The Panel continues to identify areas for improvement in the market and in this report makes four recommendations, which are reproduced at the end of this Executive Summary.

The MSP did not find an abuse of market power to have occurred in this period. In August 2011, the Panel concluded its investigation of an alleged abuse of market power by Ontario Power Generation (OPG) related to that company's operation of its coal-fired generating units. The Panel concluded that OPG coal-fired generation offers did not constitute an exercise or abuse of market power. The Panel currently has five investigations underway, all of which relate to possible gaming issues.

Demand and Supply Conditions

Ontario demand was 144 TWh for the period May 2010 to April 2011, up 5.7 TWh (four percent) compared to the previous period. With one exception, demand in all months in the 2010/2011 period was higher than in 2009/2010 (October 2010 was slightly lower than October 2009). The increase in demand came in part from customers served by local distribution companies (LDCs). Electricity consumption by wholesale customers (i.e. large industrial and natural resource customers that are directly connected to the IESO-controlled grid), which hit a record low in mid-2009, also increased marginally.

There were several significant changes to Ontario's supply mix in the 12 months to April 30, 2011. There were 1,626 MW of capacity added into the market (roughly a 5 percent increase), 1,026 MW from two large gas-fired generators, 330 MW from four large wind generators, and 270 MW from new or returning small hydro electric stations.

OPG shut down four coal-fired units (2,000 MW of capacity) in October 2010, in advance of the Ontario Government's requirement that coal-fired generation be phased out by the end of 2014. Shutting down these four units reduced Ontario's supply capacity by approximately five percent, and reduced Ontario's coal-fired generating capacity by 31%.

Market Prices, Uplifts and the Global Adjustment

The average HOEP for the May 2010 to April 2011 period was $35.64/MWh, up from $28.27/MWh (26.1 percent) one year earlier. Both on- and off-peak average HOEP increased this year. One major reason for the sharp increase in HOEP was an increase in electricity demand as Ontario started to recover from the economic recession.

Hourly uplift totalled $239 million in the period May 2010 to April 2011, down from $330 million in the preceding year. The main reason for the decrease was a reduction in CMSC payments and lower operating reserve prices. An important source of reduction in CMSC payments was a reduction in constrained-off payments to importers at the Manitoba interface.

At the start of 2011, a new method of allocating Global Adjustment (GA) charges was introduced. Before 2011, GA was allocated to all Ontario customers based on MWh of consumption. Under the new method, large industrial customers that meet certain criteria (called Class A customers) now pay a fixed percentage of monthly GA regardless of the amount of energy they consume. The new allocation method has reduced the amount of GA charges paid by Class A customers. For the period of January 1, 2011 to April 30, 2011, the first four months that the new allocation method was in place, GA paid by

Class A customers averaged $24.41/MWh, compared with $38.03/MWh for all other customers. During the May to December 2010 period, when the old volumetric allocation method was used, all customers paid $24.98/MWh of GA.

Market Outcomes

Coal units continued to be the most frequent marginal resources in real-time although they were at the margin far less often than in prior years (37 percent of intervals in May 2010 - April 2011 compared to 45 percent in 2009/2010). Shares for gas-fired units increased significantly to 36 percent of intervals, compared to 23 percent in the prior year.

Generators were at the margin in the final one hour ahead pre-dispatch run 67 percent of the time (up from 50% the year before) Exports were at the margin 18 percent of the time (24 percent a year earlier) and imports 15 percent of the time (26 percent a year earlier).

On average, there were improvements in 2010/2011 in both the average and absolute average differences between HOEP and final pre-dispatch prices. The average difference decreased from $3.23/MWh to -$1.06/MWh while the absolute average difference decreased from $6.41/MWh to $5.49/MWh. The average difference was negative in eight out of 12 months in 2010/2011, indicating that, on average, the HOEP was greater than the pre-dispatch price in these months, which is the opposite of the usual historic relationship.

Average internal zonal shadow prices were higher by 20 percent or more in 2010/2011 relative to the previous period, consistent with higher Ontario demand. The average Richview nodal price was $37.38/MWh in the most recent period, which is $7.50/MWh, or 25 percent, higher than the previous period. The average zonal price in the Northwest zone rose to -$167.59/MWh, compared with -$363.06/MWh during the 2009/2010 period. As observed in previous reports, bottled supply in the Northwest is the primary reason for the consistently large negative zonal prices in this area.

Operating Reserve (OR) prices dropped by approximately 60 percent over the prior year as the amount of offered reserve increased with new gas-fired units coming on-line and low water availability. Since October 2009, there also appears to be a convergence of the 10-minute spinning and non-spinning OR prices (which are typically similar) and the 30 minute OR prices (which historically have been lower).

In spite of increased demand in 2010/2011, supply cushions were higher this year than a year earlier. This was primarily due to new wind and gas-fired generation resources. The average monthly *pre-dispatch* (one-hour ahead) supply cushion increased from 16.6 percent in 2009/2010 to 20.4 percent in 2010/2011. The average monthly *real-time* supply cushion increased from 18.8 percent to 21.5 percent. In addition, the real-time supply cushion was 10 percent or lower in 918 hours (or 10.5 percent of the time) in 2010/2011 compared to 1,369 hours in 2009/2010.

Planned outages at fossil-fired and nuclear units remained stable in the past year, while planned outages at coal-fired generators increased. The increase in planned outages at coal units is consistent with the Government's coal phase-out policy. Forced outage rates at coal-fired generators also increased during the year. More noticeable is the increase in forced outage rates at gas-fired generators in the past two years, which reflected more new gas-fired generators under commissioning. On the other hand, the nuclear forced outage rate decreased after reaching a high of 30 percent in May 2009.

Changes in Ontario HOEP were generally consistent with price trends in neighbouring jurisdictions. Prices in New England, and to a lesser extent PJM, sometimes diverged considerably from prices in other interconnected markets. Those two jurisdictions were almost always the most expensive regions and saw prices soar above the other jurisdictional prices from December 2010 to February 2011. The average annual HOEP was persistently and materially lower than all other jurisdictions except MISO.

Anomalous Events

There was one hour in the winter period in which the HOEP exceeded $200/MWh in the period November 2010 – April 2011. The instance was consistent with normal supply/demand variation when at least one of the following occurred:

- real-time demand was higher than the pre-dispatch forecast of demand;
- one or more imports failed during real-time;
- one or more generating units available in pre-dispatch become unavailable in real-time as a result of a forced outage or derating; and/or
- a significant increase in net exports.

The interval MCP reached $2,000/MWh (the maximum permitted by the Ontario market rules) twice in the winter period, indicating a supply shortage condition in the two intervals.

There were 515 hours in which the HOEP was less than $20/MWh, of which there were 53 hours in which the HOEP was negative. The high frequency of low or negative-priced hours was a continuation of the trend in the past couple of years, mirroring the general trend of low Ontario demand and the increase to Ontario baseload supply or generation that is offered like baseload supply. Primary factors that contribute to a low or negative HOEP include:

- low market demand (Ontario demand plus external demand);
- abundant low-priced supply; and
- failed export transactions.

During the review period November 2010 to April 2011, there were no hours when the anomalous uplift criteria were met.

Matters to Report in the Ontario Electricity Marketplace

Wind Generation Forecast

Wind generators are treated as non-dispatchable in real-time by the IESO. In other words, their output is their schedules and is placed at the bottom of the real-time energy supply stack when the real-time market clearing price (MCP) is established. However, they are treated as dispatchable in pre-dispatch based on their forecast of output and their pre-dispatch schedules may be different from their actual output. This creates two major problems.

- First, the pre-dispatch price may be significantly distorted if the wind resources significantly over- or under-forecast their output. The distorted pre-dispatch price signal may induce inefficient intertie transactions and/or generation commitment decisions.
- Second, even though the wind resources have accurately forecast their output, the real-time price may turn out to be significantly lower than the pre-dispatch price when the wind resources are marginal or supra-marginal in pre-dispatch. In this case, the real-time price is distorted as it does not reflect the actual real-time supply/demand situation.

The Panel believes that a transparent wind output forecast would improve the rationality of price expectations by market participants and promote more efficient supply/demand decisions.

Pre-dispatch Frequency

The IESO runs its pre-dispatch algorithm hourly. Two important outcomes result from the pre-dispatch run: intertie transactions are scheduled and generators make their unit commitment decisions. All intertie transactions that are scheduled in the final one hour ahead pre-dispatch run are fixed for the whole dispatch hour.

The hourly pre-dispatch runs are based on forecast Ontario demand for the hour. The forecasts are made using estimated peak demand during the ramping-up hours (HE 6-9 and HE 16-19) and average demand during non-ramping-up hours. When demand over the course of the dispatch hour remains relatively flat, the use of a single hourly forecast (whether peak or average demand) for intertie scheduling and unit commitment does not have a significant effect on market efficiency. However, when demand is expected to increase or decrease significantly over the course of the dispatch hour, scheduling intertie transactions and making unit commitment based on a single forecast for the entire hour can lead to inefficient intertie transactions and unit commitment. A sharp change in intertie transaction from one hour to the next can also lead to a large ramping requirement. These negative consequences could be mitigated if more frequent intertie scheduling were implemented.

Change in GA Allocation

In 2010, the Government of Ontario amended Ontario Regulation 429/04 to change the way in which GA charges are allocated to customers. The amended regulation creates two classes of customers – Class A customers (which have an average peak demand of more than 5 MW for a defined base period), and Class B customers (all other customers). Given the significant demand threshold to be classified as a Class A customer, such customers tend to be large industrial or natural resource entities.

Beginning in January 2011, when the revised regulation took effect, total GA charges for each month have been allocated between Class A and Class B customers based on the relative contribution of each group to hourly Ontario demand during the five coincident peak hours in the preceding period (the Base Period). For example, if a Class A customer responsible for 1 percent of system demand (MW) during the five peak hours in the Base Period, it will be charged 1 percent of GA during the Billing Period. This is true even if the Class A customer has consumed more (or less) than 1 percent of the total energy (MWh) used in Ontario during all the remaining hours in the Base Period. In contrast, all Class B customers will continue to pay the GA based on their actual energy consumption in the month (i.e., the volumetric allocation method that had been used before 2011 to allocate GA to all customers). The Panel intends to analyze the market efficiency, demand response, and other consequences of the new GA allocation method in its next semi-annual report.

Constrained-on CMSC Payments to Dispatchable Loads and Exporters when their Bid Price is Negative

In its January 2010 Monitoring Report, the Panel recommended that the IESO should mitigate the CMSC payable to dispatchable loads and exporters by utilizing a replacement bid price such as $0/MWh when such customers bid at negative prices. After consultation with market participants, the IESO implemented a new rule on December 3, 2010 which uses a -$50/MWh replacement bid amount for dispatchable loads and a -$125/MWh replacement bid for exporters.

The replacement bid for dispatchable loads was set based on an estimate of all costs a load would incur when it is constrained-on by the IESO. GA charges are the largest single cost included in the -$50/MWh replacement bid for dispatchable loads. Given the change in the GA allocation in January 2011, dispatchable loads will not incur any extra GA charges when they are constrained-on unless the hour happens to be one of the five peak hours in a year. It seems highly unlikely there could be negative shadow prices (which may lead a load with a negative bid to be constrained-on) in the peak hours.

The Panel will take a further look at the replacement bid for exporters and determine if there are alternative replacement bids that could both improve market efficiency and reduce uplift charged to Ontario customers.

Wind Dispatchability

As of April 2011, the total installed wind capacity had grown to about 1,400MW. The introduction of the OPA's feed-in-tariff (FIT), which occurred subsequent to the publication of the Integrated Power Supply Plan (IPSP) in 2007, has led to a significant increase in expected installed capacity of renewable resources compared to what had been originally forecast under the IPSP. Under the IPSP, the OPA forecast approximately 3,000 MW of installed wind, solar and biomass capacity. The OPA is now anticipating as much as 6,600 MW of renewable resources may be contracted for under the FIT program by the end of 2013.

In the past, the Panel observed that an increased wind capacity will result in more incidents of surplus baseload generation (SBG) and supported the IESO's efforts to make wind resources dispatchable. In this report, the Panel further investigates the negative-price hours and finds that making wind resources dispatchable could improve market efficiency and the price signal.

The Panel's Activities

Investigations

In 2010 the Panel received a complaint from a trader regarding alleged withholding by Ontario Power Generation Inc. (OPG), the operator of the 15 coal-fired generation units in the province. The complaint alleged that OPG had exercised and abused market power by withholding supply of coal-fired generation, particularly during the months of September through November 2009.

The Panel examined various potential factors affecting OPG's supply of its coal-fired generation, including actions taken by OPG to implement its CO_2 emission reductions strategy. To assess the complaint, the Panel analyzed information provided by the complainant along with market information regarding supply, demand, pricing, and other relevant factors. The Panel also ran simulations to assess the potential impact on prices and generator output levels had OPG's coal units been offered into the market in their standard historical fashion. In addition, the Panel obtained and analyzed a significant amount of information from OPG regarding its offer strategies for coal-fired units. This included both high-level strategies and specific actions taken during the 13 days where OPG's alleged withholding had the highest potential market impact as identified by the Panel.

The Panel concludes that the negative financial impacts experienced by the complainant in its trading and contracting activities, including on its investments in transmission rights, were not the result of an exercise or abuse of market power by OPG.

The Panel currently has five investigations in progress. All relate to possible gaming issues involving Congestion Management Settlement Credit ("CMSC") payments and, in some cases, other related activities.

Advisory Opinion

MSP By-law #3 contemplates that the OEB Chair may assign activities to the Panel in relation to surveillance of electricity markets. In response to a market participant, the OEB Chair requested that the Panel provide an advisory opinion regarding proposed conduct. The Panel is currently awaiting responses to information requests before completing its analysis and preparing the advisory opinion.

Monitoring Document

As a result of the Panel's concerns about the magnitude of CMSC payments to ramping-down generators (approximately $1 million per month, much of which is self-induced through unnecessarily high offer prices), the Panel developed, consulted and finalized a Monitoring Document regarding offer prices used to signal an intention to come offline. In brief, it indicates that where there are *bona fide* business reasons for a generator to come offline the Panel will normally not consider a gaming investigation to be warranted if the generator utilizes an offer price that is not higher than the greater of (i) 130% of the generator's 3-hour ahead constrained schedule pre-dispatch price, or (ii) the generator's marginal (or other incremental or opportunity) cost.

Recommendations

The Panel has made four recommendations to the IESO in this report.

Transparency

Data transparency promotes efficient supply/demand decisions.

Recommendation 2-1
The Panel recommends that the IESO publish the most current aggregate wind generation forecast information that is available. The published information should be updated on an hourly basis and should cover all future hours for which wind generation forecasts are available.

Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market.

Recommendation 2-2

The Panel recommends that the IESO and the Electricity Market Forum investigate increasing the frequency with which interties are scheduled in order to improve market efficiency and price fidelity. In conjunction with any such increase, the IESO should explore parallel increases in the frequency of the forecasts of demand and the output from wind and other intermittent generation, as well as pre-dispatch schedules.

Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market.

Recommendation 2-3:
The Panel recommends that the IESO accelerate its efforts under Stakeholder Engagement (SE-91) to make wind generators dispatchable.

Uplift Payments

The Panel examines uplift payments both in respect of their contribution to the effective price and also their impact on the efficient operation of the market.

Recommendation 3-1
The Panel recommends that for the purposes of calculating constrained-on CMSC payments made to dispatchable loads that have bid at a negative price, the IESO should set a new replacement bid price that does not take into account any global adjustment charges. This new price would be higher than the current replacement bid price of -$50/MWh.

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Chapter 1: Market Outcomes

The Market Surveillance Panel (MSP) is responsible for monitoring and evaluating the operation of the IESO-administered wholesale electricity markets and the conduct of market participants.[1] This chapter reports the outcomes in the wholesale electricity market for the semi-annual period November 2010 to April 2011.[2] In addition, this chapter includes various data for the annual period between May 2010 and April 2011, with comparisons to prior annual periods.

1. Highlights of Market Indicators

This chapter focuses on market indicators related to pricing, demand, supply, and import/export activity.

1.1 Pricing

This period's average Hourly Ontario Energy Price (HOEP) was $35.64/MWh, representing an increase of 26 percent over the previous annual period's average of $28.27/MWh. The final cost of electricity to Ontario customers can be significantly higher than the wholesale price after the addition of delivery, the Global Adjustment (GA), and other regulatory charges.

The Global Adjustment (GA) averaged $28.64/MWh for all customers, a decrease of $6.37/MWh (or 18 percent) from the corresponding period a year earlier based on total consumption. The decrease in the GA is partly attributable to the increase in HOEP and reflects the inverse relationship between HOEP and GA. For the period of May to December 2010, the GA averaged $24.98/MWh for all customers. Effective January 1,

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[1] Ontario Energy Board By-law #3: Market Surveillance Panel, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf
[2] The Panel's February 2011 Monitoring Report provides additional detail regarding the six month period from May to October 2010.

2011, the GA allocation approach for Class A customers changed. (Class A customers are typically customers with large consumption volume. For details, see Section 3.1 in Chapter 3.) The change effectively increased the GA paid by smaller customers and reduced the GA paid by larger customers.[3] For the period of January 1, 2011 to April 30, 2011, the GA for the former averaged $38.03/MWh compared with $24.41/MWh for the latter.

Given the magnitude of the GA and uplift charges, the Panel also reports the effective wholesale market price for electricity. Effective price is the "all-in" price to domestic customers and is composed of average HOEP, the GA (and the OPG rebate until it was eliminated in 2009) and uplift charges. Over the period from May 2010 to April 2011, the effective price was $67.63/MWh, representing a 1 percent increase from the prior year. Broken down pre- and post- GA allocation change, the May 2010 to December 2010 effective price was $64.83/MWh, while the effective price for the period of January to April 2011 was $71.69/MWh for smaller customers and $56.96/MWh for larger customers.[4]

1.2 Ontario Demand

Total Ontario Demand was 144.03 TWh this period, up 5.8 TWh (4 percent) compared to the previous annual period. All months saw an increase this period over last, except October which saw a slight decrease. May and July experienced the largest proportional increases of 9 and 18 percent, respectively.

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[3] For a more detailed explanation of the change to the Global Adjustment allocation approach and the definitions of the larger (Class A) and smaller (Class B) customer groupings, see section 3.1 of Chapter 3.
[4] The discrepancy between the price paid by an average small customer and an average large customer is greater than what is reflected by the effective price for these two categories of customers. This is because between the two categories of customers, a greater percentage of large customers' consumption occurs during off-peak hours when actual HOEP is lower than the average HOEP, and a greater percentage of small customers' consumption occurs during on-peak hours when actual HOEP is higher than average HOEP. See Table 1-2 below.

1.3 Supply

There were several significant changes to Ontario's electricity supply sources between May 2010 and April 2011. There were 1,626 MW of capacity added into the market (roughly a 5 percent increase). Of this added supply 1,026 MW was from two large gas-fired generators, 330 MW from four large wind power generators, and 270 MW from new or returning small hydroelectric stations.

However, four coal-fired units totalling approximately 2,000 MW of generation capacity were shut down in October 2010, in advance of the Ontario Government's requirement that coal-fired generation be phased out by the end of 2014. These four units represented a reduction to Ontario's supply capacity of approximately 5 percent, and a 31 percent reduction of the coal-fired generating capacity.

1.4 Imports and Exports

Net exports increased slightly by 0.15 TWh (2 percent) to 9.25 TWh during the 2010/2011 period. A decline of 0.88 TWh in off-peak net exports was more than offset by the 1.03 TWh gain in on-peak net exports. [5]

This overall increase in net exports was the result of a 0.55 TWh drop in imports (8 percent decline) that exceeded the 0.40 TWh drop in exports (3 percent decrease).

2. Pricing

2.1 Hourly Ontario Energy Price

Table 1-1 presents the monthly average HOEP for May to April 2009/2010 and 2010/2011. The average HOEP for the May 2010 to April 2011 period was $35.64/MWh, up from $28.27/MWh (26.1 percent) one year earlier. Both on and off-

[5] In Ontario, off-peak hours are all hours during weekends and holidays and from delivery hour 24 to 7 during weekdays. All other hours are on-peak hours.

peak average HOEP increased this year, although the percentage change was lower during the on-peak hours than off-peak hours (21.4 percent increase in on-peak HOEP compared to a 31.8 percent increase in off-peak HOEP).

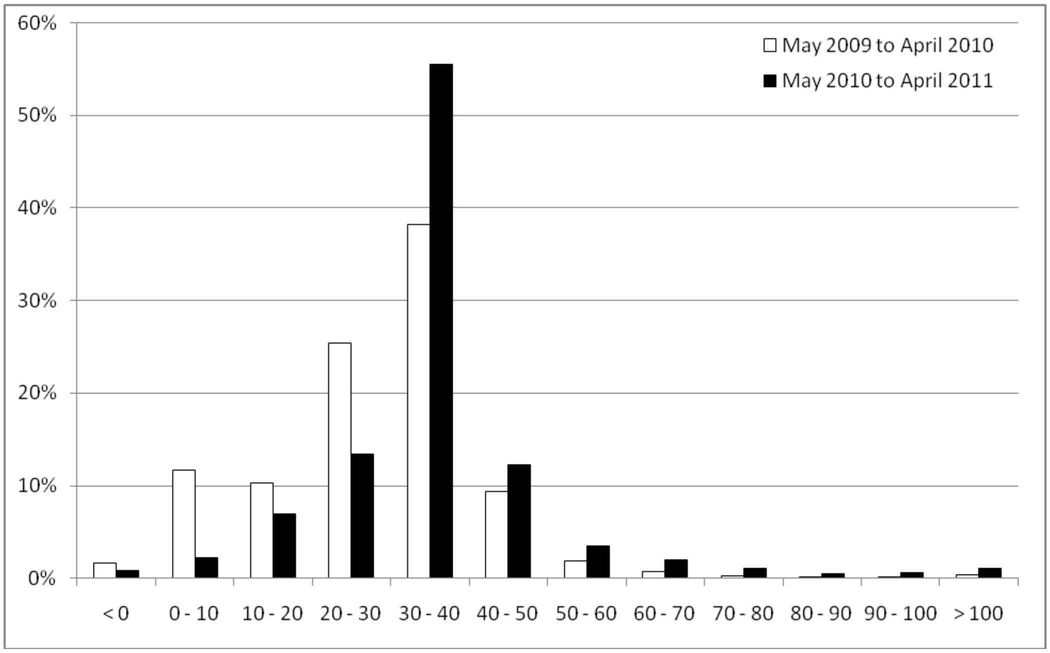
The average HOEP was higher in most months, with the most significant year-over-year changes occurring in the June, July, and August 2010. In July 2010, the HOEP was 168 percent higher than the previous July average. The higher prices in summer 2010 were primarily a result of higher demand, reduced peaking hydro supply due to dry weather, and increased fuel prices for both coal and natural gas.

Table 1-1: Average HOEP, On-peak and Off-peak May – April 2009/2010 & 2010/2011 ($/MWh)

Month	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
May	27.77	38.77	39.6	35.35	44.87	26.9	22.04	34.16	55.0
June	22.84	40.36	76.7	30.58	45.49	48.8	15.43	35.44	129.7
July	18.99	50.83	167.7	24.19	65.84	172.2	14.31	38.46	168.8
August	26.07	44.41	70.3	34.92	52.39	50.0	19.40	37.84	95.1
September	20.76	32.91	58.5	27.62	37.88	37.1	14.75	28.56	93.6
October	29.22	29.39	0.6	34.92	34.12	(2.3)	24.53	25.82	5.3
November	26.54	31.89	20.2	32.66	34.97	7.1	21.18	28.94	36.6
December	35.05	33.83	(3.5)	39.62	36.98	(6.7)	31.28	31.23	(0.2)
January	37.40	31.92	(14.7)	40.93	37.27	(8.9)	34.73	27.88	(19.7)
February	35.90	33.29	(7.3)	39.95	34.84	(12.8)	32.56	32.01	(1.7)
March	28.22	31.23	10.7	30.89	33.29	7.8	25.62	29.20	14.0
April	30.83	28.37	(8.0)	37.57	35.71	(5.0)	25.43	23.01	(9.5)
Average	28.27	35.64	26.1	33.92	41.19	21.4	23.52	31.01	31.8

Figure 1-1 presents the frequency distributions of HOEP over the last two years. During the May 2010 to April 2011 period, the HOEP fell into the $30-40/MWh price range in 55 percent of all hours, compared to 38 percent in the prior year. There was also an increase in frequency for all high price ranges in the 2010/2011 period, and a corresponding decline in all low price ranges.

***Figure 1-1: Frequency Distribution of HOEP
May – April 2009/2010 & 2010/2011
(% 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 2009/2010 and 2010/2011 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 un-weighted HOEP, there were significant increases in the load-weighted HOEP for all load types in 2010/2011.

As expected, the average load-weighted HOEP was lowest for the dispatchable load category at $34.74/MWh ($2.43/MWh, or 6.5 percent, less than the overall load-weighted HOEP for all loads). To the extent possible, these resources attempt to avoid higher price periods by reducing consumption or shifting it to lower-price periods. To some extent other wholesale loads follow a similar strategy and correspondingly paid an average load-weighted HOEP of $36.23/MWh ($0.94/MWh, or 2.5 percent, less than for all loads overall). However, these loads experienced the largest year-to-year increases in both absolute and percentage terms, implying that they were less effective at avoiding the on-peak price in the recent year, relative to other loads. Local Distribution Company (LDC) load, [6] which generally represents the least price responsive component of load, paid an average load-weighted HOEP of $37.39/MWh ($0.22/MWh, or 0.6 percent, more than for all loads overall).

Table 1–2 also shows the average load-weighted HOEP for Class A and B customers. As expected, Class A customers, who typically consume less at on-peak hours, have paid a lower price in both years. The average price differential between Class A and Class B customers was $1.83/MWh in 2010/2011, compared to $1.53/MWh a year ago.

Table 1-2: Load-Weighted Average HOEP by Load Category
May – April 2009/2010 & 2010/2011
($/MWh)

Year	Unweighted HOEP	Load-weighted HOEP					
		Dispatchable Load	Other Wholesale Loads	LDCs	All Loads	Class A	Class B
2009/2010	28.27	27.95	28.35	29.90	29.72	28.22	29.75
2010/2011	35.64	34.74	36.23	37.39	37.17	35.25	37.08
Difference	7.37	6.79	7.58	7.49	7.45	7.03	7.33
% Change	26.1	24.3	27.8	25.1	25.1	24.9	24.6

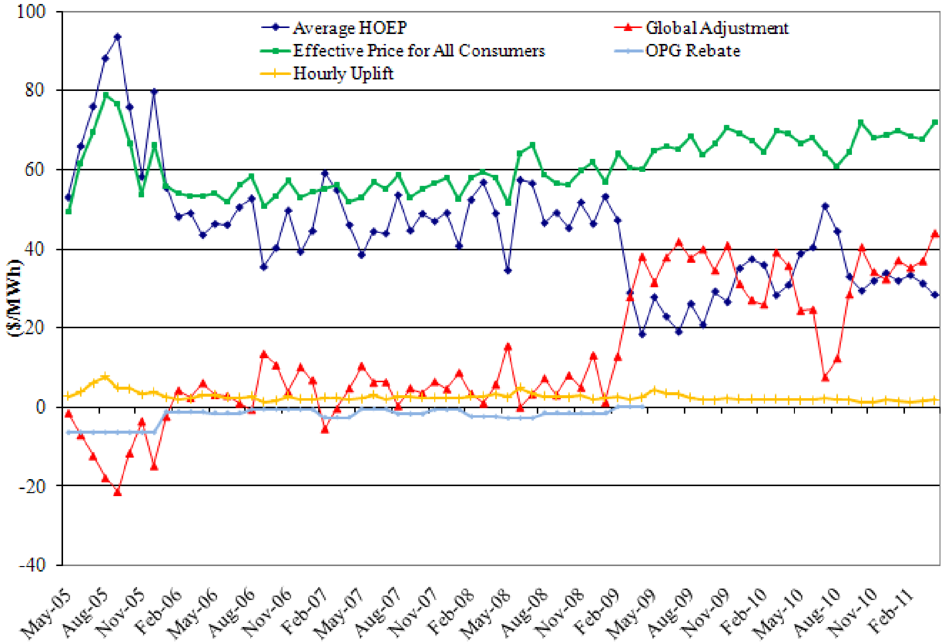
2.2 Effective Price (including Global Adjustment, OPG Rebate and Uplifts)

Figure 1-2 plots the monthly average HOEP and effective price between May 2005 and April 2011 as well as the GA and the OPG Rebate.[7] Uplift payments[8] are also included

[6] These are customers settled with local distribution companies and have no direct link with the IESO. The customers include those who are subject to the regulated rate plan and those who are charged based on interval wholesale pricing.
[7] The OPG Rebate was based on regulated compensation arrangements to OPG's non-prescribed assets. It was discontinued in April 2009.
[8] Historically the Panel had included hourly uplift but not monthly uplift in the effective price. The effective prices for prior years have been restated to incorporate the monthly uplifts.

in the effective price as they are additional payments by customers. From May 2005 to April 2011, the effective price for all customers has been gradually increasing, from about $50/MWh to roughly $70/MWh.

Figure 1-2: Monthly Average Effective Price (HOEP Adjusted for OPG Rebate, Global Adjustment, and Uplift)
May 2005 – April 2011
($/MWh)



*Note – OPG Rebate was discontinued after April 2009

The GA has been increasing since the beginning of 2009 mainly for two reasons. First, to the extent that the price paid to generators under price-guaranteed Ontario Power Authority (OPA) contracts exceeds the HOEP, the balance of the contract payment must be recovered from Ontario customers through the GA. Accordingly there is a negative correlation between the HOEP and the GA. The substantial decline in average HOEP beginning in March 2009 triggered substantial increases in the GA. Second, more OPA contracted energy has come online and the rates paid under these contracts (e.g. the contracts with wind and solar power generators) typically exceed the average HOEP by a significant margin.

2.2.1 *Hourly Uplift and Components*

Table 1-3 reports the monthly total hourly uplift charges for the last two reporting periods. Total hourly uplift charges dropped from $329.6 million in 2009/2010 to $239.1 million in 2010/2011, a reduction of 27 percent. Payments due to losses increased, while Import Offer Guarantee (IOG), Congestion Management Settlement Credits (CMSC) and Operating Reserve (OR) payments fell significantly.

Table 1-3: Total Hourly Uplift Charge by Component and Month May – April 2009/2010 & 2010/2011 ($ millions and % of total)

Month	Total Hourly Uplift		IOG		CMSC		Losses		Operating Reserve	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	45.6	19.9	1.0	0.5	25.0	9.6	8.8	9.5	10.8	0.4
June	37.4	21.3	1.5	0.1	21.4	11.2	7.6	8.8	7.0	1.1
July	36.5	30.1	5.7	0.5	18.0	13.7	5.7	14.5	7.1	1.5
August	28.5	25.3	1.4	0.3	12.2	10.3	8.4	12.6	6.5	2.1
September	20.0	20.5	2.4	0.5	11.0	8.5	3.7	8.3	3.0	3.3
October	21.0	14.1	2.0	0.3	10.3	5.5	7.5	7.1	1.2	1.3
November	25.0	14.8	0.5	0.1	14.7	6.6	6.7	7.0	3.1	1.1
December	24.9	23.0	1.1	0.4	10.4	8.5	10.3	10.4	3.1	3.7
January	26.0	18.7	0.9	0.5	11.6	5.9	10.1	10.1	3.4	2.2
February	22.7	14.2	0.5	0.4	10.6	5.0	9.2	7.5	2.4	1.3
March	23.7	17.0	0.9	0.4	12.5	7.1	7.5	8.4	2.8	1.1
April	18.4	20.2	0.7	0.4	10.5	7.7	6.9	7.3	0.3	4.7
Total	329.6	239.1	18.6	4.4	168.2	99.6	92.4	111.5	50.5	23.8
% of Total	100.0	100.0	5.6	1.8	51.0	41.7	28.0	46.6	15.3	10.0

Major factors contributing to the changes in uplift are summarized below:

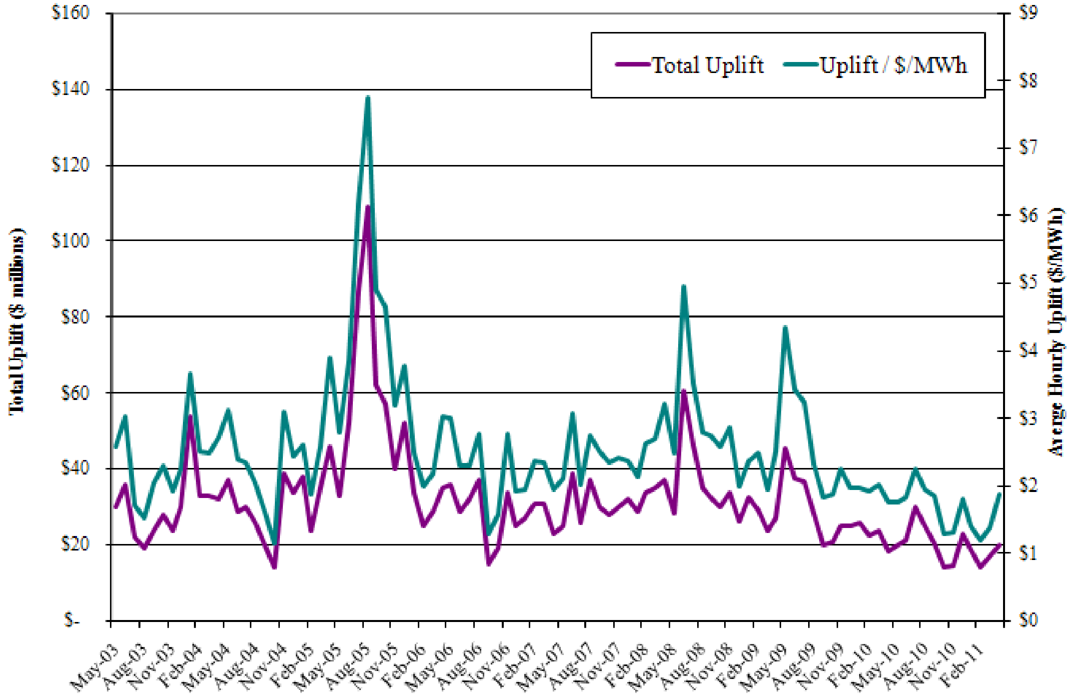
- IOG Payments – Annual IOG payments dropped over the last two annual reporting periods from $18.6 million to $4.4 million (a 76 percent decrease). There are two major reasons for the reduction: a smaller average difference between pre-dispatch and real-time prices, and a lower volume of imports receiving the guarantee payments.[9]

[9] See section 5.2 below for import volume statistics.

- CMSC Payments – CMSC payments decreased by $68.6 million (a 41 percent decrease). The largest monthly payment of $13.7 million occurred in July 2010 and the smallest monthly payment of $5.0 million occurred in February 2011.
- Losses – Total payments due to losses increased by $19.1 million (21 percent) this period over last. Increases occurred in nine months, with July experiencing the greatest increase of $8.8 million relative to the year prior. The increase in payments is consistent with the rise in HOEP that occurred in almost every month (as seen in Table 1-1) because payments to generators for losses are directly related to the price of energy as well as the quantity of losses incurred.
- Operating Reserve Payments – Annual OR payments fell by $26.7 million (52.9 percent) from $50.5 million in 2009/2010 to $23.8 million in 2010/2011. Eight out of twelve months saw substantial decreases in total OR payments compared to the previous year. This is consistent with the significant decline in OR prices observed in most months of 2010/2011, as reported in Tables 1-21 and 1-22 below.

Figure 1-3 plots hourly uplift charges in millions of dollars and in $/MWh between May 2003 and April 2011. Generally, the hourly uplift charges have been decreasing since early 2008 and reached all time lows in October 2010 and February 2011 at $14 million.

Figure 1-3: Total Hourly Market Uplift and Average Hourly Market Uplift
May 2003 – April 2011
($ millions and $/MWh)



2.2.2 *Monthly Uplift and Components*

Table 1-4 below reports the monthly uplift. The monthly uplift consists of charges that are not allocated to a specific hour, such as start-up costs under the Generation Cost Guarantee (GCG) programs, the cost of Automatic Generation Control (AGC), Voltage Support, Black Starts, Reliability Must Run contracts, etc. The total monthly uplift was marginally lower in 2010/2011, with the cost under the GCG program significantly higher, while the other cost components were significantly lower.

Table 1-4: Total Monthly Uplift Charge by Component May – April, 2009/2010 & 2010/2011 ($ millions and % of total)

Month	Total Monthly Uplift		GCG		AGC		All Others	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	11.7	10.6	3.8	8.1	2.3	1.9	5.7	0.6
June	12.9	14.9	3.9	12.3	4.2	2.0	4.9	0.6
July	19.5	16.0	8.9	13.9	3.5	2.0	7.1	0.1
August	19.0	14.2	9.4	12.3	3.2	2.3	6.5	-0.3
September	20.3	15.8	10.3	12.8	2.9	2.2	7.0	0.8
October	8.6	11.5	7.9	9.3	2.3	2.3	-1.6	-0.1
November	12.1	13.6	9.6	10.9	2.0	2.0	0.5	0.6
December	14.5	13.2	11.7	11.4	2.3	1.7	0.5	0.1
January	9.8	15.0	7.0	12.0	2.3	2.3	0.5	0.8
February	7.1	15.8	6.6	13.5	3.0	1.9	-2.6	0.5
March	13.7	13.4	11.0	11.6	2.1	1.8	0.6	0.0
April	12.7	9.1	9.6	7.1	2.2	1.9	0.8	0.1
Total	161.8	163.2	99.7	135.3	32.3	24.2	29.9	3.8
% of Total	100	100	61.6	82.9	19.9	14.8	18.5	2.3

2.3 Price Setters (Marginal Resources)

Over the most recent twelve-month period, there has been a noticeable difference in the resources that set prices (or are at the margin) in the wholesale market. Specifically, gas-fired units have increasingly been at the margin roughly as often as the coal-fired generators. Pre-dispatch prices saw a decrease in the share of hours where imports and exports were marginal, corresponding to a rise in the share in which some form of domestic generation was marginal.

2.3.1 Real-time Marginal Resources

Table 1-5 presents the monthly average share of real-time interval Market Clearing Price (MCP) in which particular resource types were marginal for the 2009/2010 and 2010/2011 periods.[10] The table shows that the average share by resource type shifted significantly towards gas-fired units. Coal-fired units narrowly continued to be marginal

[10] Dispatchable loads are also able to set the real-time MCP but are not included in Tables 1-4 to 1-7 since they do so rarely.

most frequently in real-time during the 2010/2011 period, after experiencing an eight percent share decline (from 45 percent to 37 percent) compared to the previous period. The shift in the average share from coal-fired units to gas-fired units is consistent with an annual decline in energy production from coal-fired generators (especially in light of four coal-fired generation units being shut down in October 2010), along with the growing capacity of gas-fired units over the past few years.[11] Nuclear units were marginal in 297 real-time MCP intervals this year. That is a significant decrease relative to the previous May to April period (840 intervals), which implies fewer surplus baseload generation (SBG) conditions.

Table 1-5: Share of Marginal Resources in Real-Time
May – April 2009/2010 & 2010/2011
(% of Intervals)

Fuel Type	2009/2010	2010/2011
Coal	45	37
Gas[12]	23	36
Hydro	31	27
Nuclear	~ 1	~ 0
Total	100	100

Tables 1-6 to 1-8 report the monthly share of marginal resources in real-time for the last two twelve-month periods for all intervals, on-peak intervals, and off-peak intervals respectively. Table 1-6 indicates that coal-fired generators' share was considerably higher in June through August, but lower between October and April, relative to the same months in the previous period.

[11] Power production from coal-fired units totalled 9.3 TWh between May 2010 and April 2011, a decline of 0.1 TWh (1.1 percent) compared to the same period one year earlier. However, in the unconstrained sequence, coal-fired generators were scheduled for 9.8 TWh, which is 1.2 TWh (or 11.9 percent) less than one year ago.

[12] The Lennox generating station can operate using either gas or oil as its fuel. All its output has been included in the gas-fired category.

Table 1-6: Monthly Share of Real-Time MCP by Marginal Resource Type May – April 2009/2010 & 2010/2011 (% of intervals)

Month	Coal		Gas		Hydro		Nuclear	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	47	42	22	36	30	22	1	0
June	35	50	16	36	45	14	3	0
July	26	48	16	32	57	20	1	0
August	35	51	27	31	37	18	1	0
September	32	34	27	27	39	38	2	0
October	39	17	27	39	34	45	1	0
November	38	37	30	41	31	22	1	0
December	61	37	23	37	16	25	0	0
January	70	38	15	39	14	23	0	1
February	66	35	23	42	11	24	0	0
March	52	33	20	40	28	27	0	0
April	37	17	32	29	32	52	0	2
Average	45	37	23	36	31	27	1	0

Tables 1-7 and 1-8 below show the marginal resource types at on-peak and off-peak, respectively. Coal-fired generators' share declined from 46 percent at on-peak and 44 percent at off-peak to 37 percent each. The largest on-peak decreases occurred in March (20 percent) and April (16 percent) and the largest off-peak decreases in January and February (48 percent for both). In contrast, gas-fired units have increasingly been marginal during both on and off-peak intervals, with a significant increase in their share of off-peak hours in almost all months. Hydro's share of on-peak hours remained modest and stable, while its off-peak share declined from 44 percent to 37 percent.

Table 1-7: Monthly Share of Real-Time MCP by Marginal Resource Type, On-Peak May – April 2009/2010 & 2010/2011 (% of intervals)

Month	Coal		Gas		Hydro		Nuclear	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	46	32	39	49	16	19	0	0
June	48	39	26	48	25	13	1	0
July	38	37	27	41	35	21	0	0
August	42	47	44	39	13	14	0	0
September	44	49	40	38	15	14	0	0
October	45	30	43	56	12	14	0	0
November	47	40	41	52	12	8	0	0
December	47	37	43	48	10	15	0	0
January	56	46	30	50	14	5	0	0
February	49	38	42	49	9	13	0	0
March	49	29	33	59	18	12	0	0
April	36	20	49	45	14	34	0	0
Average	46	37	38	48	16	15	0	0

Table 1-8: Monthly Share of Real-Time MCP by Marginal Resource Type, Off-Peak May – April 2009/2010 & 2010/2011 (% of intervals)

Month	Coal		Gas		Hydro		Nuclear	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	47	50	10	27	41	24	1	0
June	23	61	7	25	64	15	5	0
July	15	56	7	24	77	20	1	0
August	30	54	14	24	55	22	1	0
September	22	22	15	19	60	59	4	0
October	34	8	13	27	51	65	1	0
November	29	34	20	30	49	36	2	0
December	71	37	8	29	21	33	0	1
January	81	33	4	31	15	35	0	1
February	80	32	7	37	13	31	0	0
March	54	37	7	23	38	40	0	0
April	37	15	18	18	45	64	1	3
Average	44	37	11	26	44	37	1	1

2.3.2 *Pre-dispatch Marginal Resources*

Table 1-9 presents the percentage of hours that a specific resource type was marginal in the final (one-hour ahead) pre-dispatch price on a monthly basis for the 2009/2010 and 2010/2011 periods.[13] Overall, there was a decrease in both imports and exports as marginal resources this period, with minor monthly fluctuations. Imports or exports were marginal in the final pre-dispatch price 17 percent less often this period (down from 50 to 33 percent), with a corresponding increase in the frequency with which generators were marginal.

Table 1-9: Monthly Share of Final Pre-dispatch Price by Marginal Resource Type May – April 2009/2010 & 2010/2011 (% of hours)

Month	Imports		Exports		Generation	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	27	18	25	12	47	70
June	27	12	32	13	41	75
July	33	19	24	18	43	63
August	29	15	21	14	51	71
September	30	15	25	24	45	62
October	24	14	31	25	45	61
November	12	12	32	11	56	77
December	18	11	28	25	54	64
January	25	16	19	10	56	74
February	36	19	10	15	54	66
March	33	12	20	20	48	68
April	22	14	18	27	61	60
Average	**26**	**15**	**24**	**18**	**50**	**67**

2.4 *One-Hour Ahead Pre-dispatch Prices and HOEP*

Production and consumption decisions are improved when market participants can rely on accurate pre-dispatch price projections. Therefore, the differences between the one-hour ahead pre-dispatch price and HOEP is an important relationship to monitor. A sound pre-dispatch price signal can contribute to real-time dispatch efficiencies.

[13] The table excludes the very small (on the order of 0.1 percent) contribution from dispatchable loads.

2.4.1 *One-hour Ahead Pre-dispatch Price*

Table 1-10 presents the differences between the one-hour ahead pre-dispatch price and the HOEP for May to April 2009/2010 and 2010/2011. On average, there were improvements in both the average and absolute average differences over the last two periods. The average difference decreased from $3.23/MWh to -$1.06/MWh while the absolute average difference decreased from $6.41/MWh to $5.49/MWh (a 13.4 percent improvement). Similarly, the percentage of the difference relative to HOEP has decreased.

Table 1-10: Measures of Differences between One-Hour Ahead Pre-Dispatch Prices and HOEP May – April 2009/2010 & 2010/2011 ($/MWh)

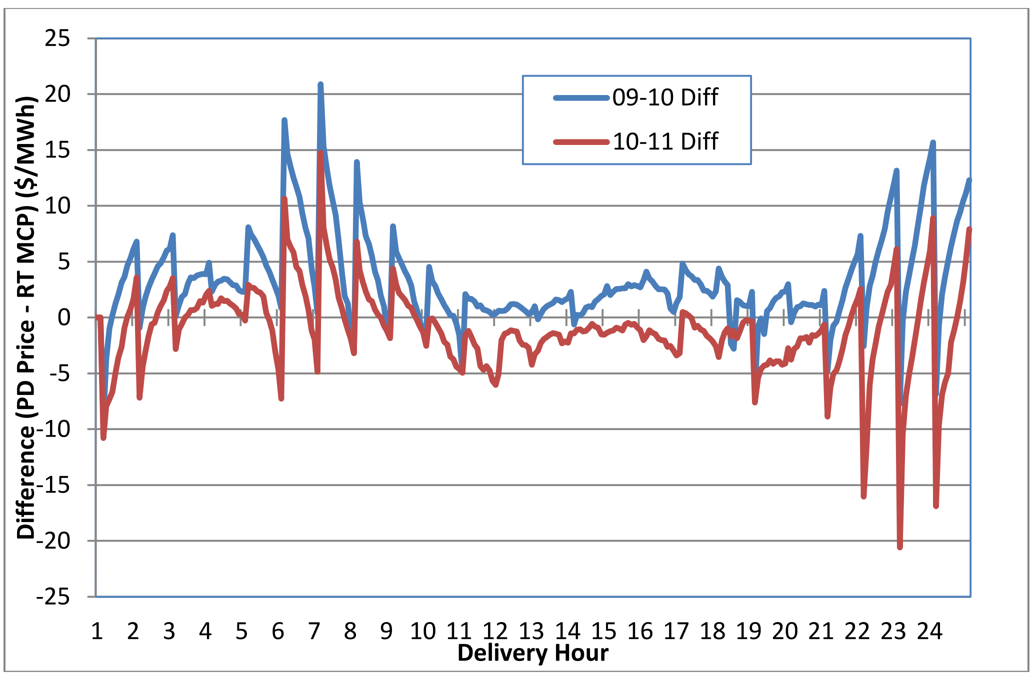
Month	Average Difference*		Absolute Average Difference		Standard Deviation		Average Difference as a % of Average HOEP[14]	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	3.57	(1.34)	7.49	3.82	11.46	7.81	12.9	(3.5)
June	5.73	(1.74)	8.74	3.96	11.19	13.09	25.1	(4.3)
July	8.92	(5.39)	10.79	8.80	11.84	25.99	47.0	(10.6)
August	1.80	(3.23)	8.01	5.64	22.54	11.47	6.9	(7.3)
September	4.60	(2.33)	6.11	6.81	8.08	16.84	22.2	(7.1)
October	3.59	(2.23)	7.88	5.41	16.82	20.19	12.3	(7.6)
November	3.30	(0.99)	6.31	3.33	12.01	6.46	12.4	(3.1)
December	2.71	0.99	4.66	6.80	7.76	24.67	7.7	2.9
January	0.26	2.46	4.63	4.42	18.18	12.69	0.7	7.7
February	0.93	1.02	2.83	2.94	5.20	5.61	2.6	3.1
March	2.48	0.69	4.05	3.80	5.59	7.95	8.8	2.2
April	0.87	(0.59)	5.39	10.17	12.69	25.81	2.8	(2.1)
Average	3.23	(1.06)	6.41	5.49	11.95	14.88	13.4	(2.48)

* A positive arithmetic average indicates that pre-dispatch prices are on average higher than real-time prices, while a negative figure indicates pre-dispatch prices that were lower than the real-time prices.

[14] This is an average price difference as a percentage of the average HOEP in each month (denominator being the monthly average HOEP reported in Table 1-1).

It is notable that the average difference was negative in eight out of 12 months in 2010/2011. This indicates that, on average, the HOEP was greater than the pre-dispatch price in these months, which is the opposite of the usual historic relationship. Figure 1-4 below depicts the average difference between pre-dispatch price and real-time interval MCP for the two comparison periods. A positive number indicates the pre-dispatch price is greater than the real-time MCP while a negative number indicates it is smaller. It can be seen that in the 2009/2010 period the pre-dispatch price was higher than the real-time MCP in the vast majority of intervals (i.e. a positive difference), while in 2010/2011 the pre-dispatch price was lower in most intervals except in morning ramping hours (HE 6 to 9). Roughly speaking the price difference has shifted downwards in all hours.

Figure 1-4: Average Difference Between Pre-Dispatch Price and Real-Time MCP May – April 2009/2010 & 2010/2011 ($/MWh)



Another notable observation is that during the morning ramping up (HE 6-9) and evening ramping down hours (HE 22-24) the price difference between the pre-dispatch price and the real-time MCP in the first few intervals has disproportionally changed compared to the last few intervals in the same hour. For HE 6-9, the pre-dispatch price is much closer to the real-time MCP in the first few intervals compared to last year, while in HE 22-24 they are further apart. The change in the pattern implies that hour-to-hour ramping was less of an issue in the morning hours of 2010/2011 compared to 2009/2010 and was more of an issue in the evening.

2.4.2 *Reasons for Differences in Pre-dispatch and Real-time MCP*

The Panel has identified four main factors that lead to differences between pre-dispatch and real-time prices:[15]

- Pre-dispatch to real-time demand forecast deviations (the deviation includes forecast error and the difference due to the profile of the real-time demand[16]);
- Production forecast errors of self-schedulers and intermittent (primarily wind) generators;
- Failures of scheduled imports and exports; and
- Frequency that imports or exports set the pre-dispatch price (and are then re-priced in real-time at the bottom of the supply stack for imports and at the top of demand stack for exports).

While the price impact of these factors cannot be measured directly, Table 1-11 presents the absolute average differences in MW of output for each of the first three factors listed above for the past twelve-month period.[17] Monthly absolute averages provide some indication as to which of the factors are the most important contributors to differences

[15] 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.

[16] In particular, when forecast demand is for the peak interval in the hour, the pre-dispatch to real-time price difference can be induced by either forecast error or the profile of real-time demand (i.e. demand in all other intervals will be lower than the peak demand in the hour even though the peak demand is accurately forecast). For further discussion, see section 2.1.1 of Chapter 2.

[17] The summary table does not report the frequency that imports (or exports) set the pre-dispatch price since the metric to measure the frequency (percentage of hours) does not necessarily translate into an hourly quantity (MW) statistic like the three other factors that lead to discrepancies between pre-dispatch and real-time prices.

between pre-dispatch and real-time prices. However, any one of these factors can lead to significant price discrepancies in a given hour.

Table 1-11: Factors Leading to Differences Between Final Pre-Dispatch and Real-Time Prices May 2010 – April 2011 (MW per hour and % of Ontario demand)

Factor	2009/2010		2010/2011	
	Absolute Average Difference (MW)	Absolute Average Difference as % of Ontario Demand*	Absolute Average Difference (MW)	Absolute Average Difference as % of Ontario Demand*
Pre-dispatch to Real-time Demand Forecast Error	161	1.0	188	1.2
Differences due to real-time Demand Profile	93	0.6	22	0.1
Pre-dispatch to Real-time Average Demand Forecast Deviation	254	1.6	210	1.3
Self-Scheduling and Intermittent Forecast Deviation	80	0.5	100	0.6
Net Export Failures	119	0.8	173	1.1

*Average hourly Ontario Demand (denominator) for the twelve month period was 15,703 MW for 2009/2010 and 16,441 MW for 2010/2011

Overall, the largest absolute average differences result from pre-dispatch to real-time demand forecast deviation (which includes demand forecast error and differences induced by the profile of RT demand), followed by net export failure. The self-scheduling and intermittent deviation was the smallest contributor in 2009/2010 but has increased in 2010/2011 and will likely continue to do so as more intermittent capacity comes online (subject to improvements that may result from the planned introduction of centralized wind forecasting).

2.4.2.1 Pre-dispatch to Real-time Average Demand Forecast Deviation

The difference between the pre-dispatch demand forecast and real-time average demand can lead to discrepancies between pre-dispatch prices and HOEP. To improve market efficiency and deal with increased SBG incidents, the IESO implemented a new procedure in December 2009 which uses average instead of peak demand as the forecast in pre-dispatch for non-ramping hours.[18] The move from peak demand forecast to average demand forecast in pre-dispatch would be expected to reduce demand forecast deviations in the non-ramping hours, and it indeed resulted in a smaller difference as evidenced in Figure 1-5 below.[19] In contrast to the sharp decrease in forecast error for non-ramping hours, there is little change in the forecast accuracy during ramping hours.

[18] More precisely, average demand is applied to non-ramping-up hours, including HE 1 to 5, 10 to 15 and 20 to 24 every day. For details, see http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4973 . At times, the IESO may apply the average forecast for the ramping hours when an SBG situation is credibly foreseeable.

[19] In its prior report, the Panel also observed an improvement in the forecast deviation. For details, see the Panel's August 2010 Monitoring Report, pp. 18-26.

Figure 1-5: Average Demand Forecast Deviation
May 2009 – April 2011
(pre-dispatch forecast minus real-time actual, MW)

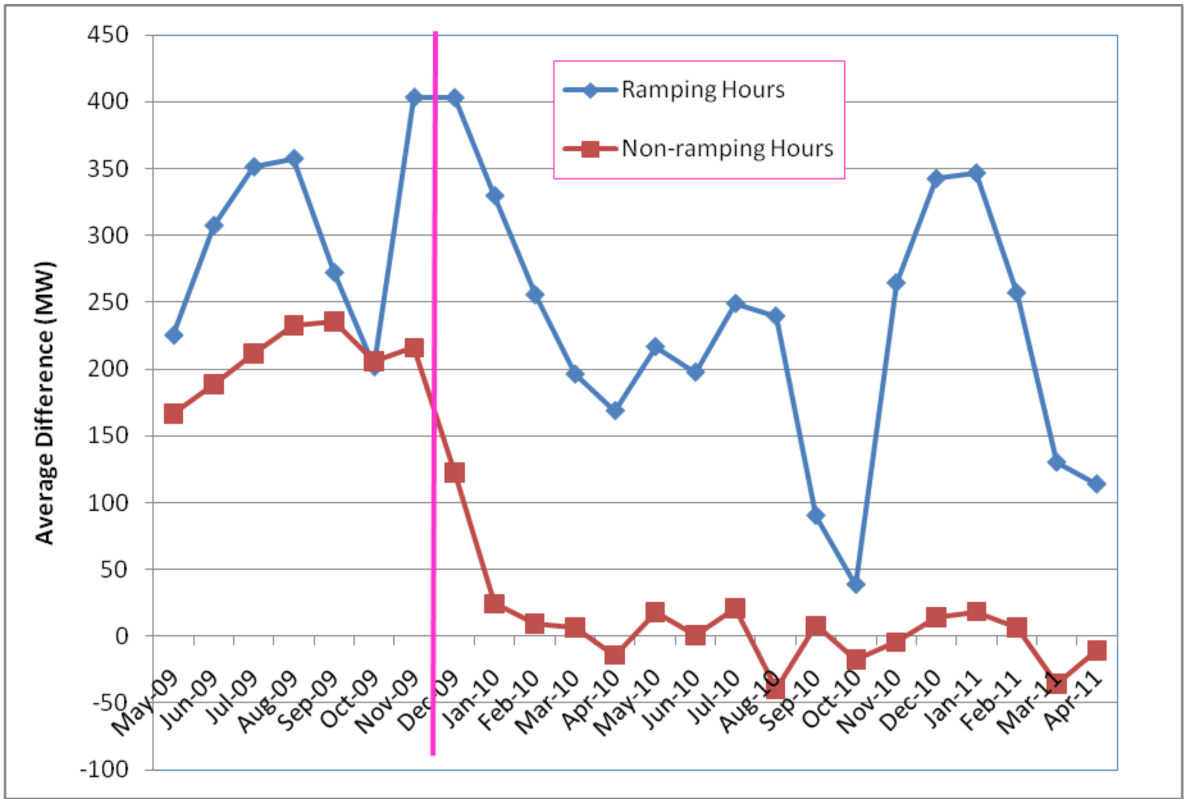


Table 1-12 presents the one-hour ahead pre-dispatch, and also three-hour ahead pre-dispatch, to real-time average demand deviation by month between May 2009 and April 2011.[20] Improvements in average monthly demand deviation are apparent in both the one-hour ahead and three-hour ahead metrics. The one-hour ahead deviation measure fell by 0.38 percentage points, from 1.66 percent last year to 1.28 percent in the most recent May to April period, while the three-hour ahead measure fell 0.28 percentage points, from 1.88 percent last year to 1.60 percent this year. It is also notable that the demand forecast deviation is much smaller from May to December, when compared to the same months in the previous year. This is consistent with the expected effect of moving from

[20] Pre-dispatch forecast to real-time average demand discrepancy is calculated as the absolute value of pre-dispatch minus real-time average demand divided by real-time average demand.

peak demand to average demand forecast during the non ramping-up hours beginning in December 2009.

Table 1-12: Pre-dispatch to Real-time Average Demand Forecast Deviation May – April 2009/2010 & 2010/2011 (% of real-time average demand)

Month	Three-Hour Ahead		One-Hour Ahead	
	2009/2010	2010/2011	2009/2010	2010/2011
May	2.03	1.86	1.85	1.48
June	2.09	1.79	1.93	1.36
July	2.33	2.00	2.04	1.52
August	2.38	1.93	2.09	1.49
September	2.06	1.36	1.89	1.05
October	1.83	1.14	1.68	0.92
November	2.15	1.53	2.04	1.30
December	1.98	1.57	1.69	1.34
January	1.50	1.61	1.22	1.33
February	1.28	1.45	1.06	1.13
March	1.44	1.50	1.15	1.20
April	1.51	1.50	1.24	1.23
Average	1.88	1.60	1.66	1.28

2.4.2.2 Pre-dispatch to Real-time Demand Forecast Error

This section will focus on the forecast error only. In other words, this section assesses how well the IESO demand forecast has performed.

Table 1-13 reports the one-hour and three-hour ahead mean absolute demand forecast errors on a monthly basis for the 2009/2010 and 2010/2011 reporting periods. Pre-dispatch to real-time demand forecast errors in all 2010/2011 months were greater than those of the previous reporting period. The error between May and October 2010 for each month was above the yearly average. On an annual basis, demand forecast errors increased by 46 percent for the three-hour ahead forecast, and by 57 percent for the one-hour ahead forecast.

Table 1-13: Pre-dispatch to Real-time Demand Forecast Error
May – April 2009/2010 & 2010/2011
(% of real-time demand)

Month	Mean Absolute Forecast Difference: (pre-dispatch minus real-time demand divided by real-time demand)			
	Three-Hour Ahead		One-Hour Ahead	
	2009/2010	2010/2011	2009/2010	2010/2011
May	1.32	2.06	1.11	1.68
June	1.42	1.99	1.22	1.71
July	1.54	2.22	1.20	1.77
August	1.53	2.25	1.19	1.89
September	1.25	1.86	1.05	1.70
October	1.17	1.80	0.97	1.72
November	1.26	1.68	1.03	1.49
December	1.49	1.50	1.21	1.35
January	1.38	1.67	1.19	1.38
February	1.30	1.51	1.21	1.29
March	1.60	1.79	1.39	1.55
April	1.76	1.83	1.52	1.72
Average	1.27	1.85	1.02	1.60

2.4.2.3 Wind Generation

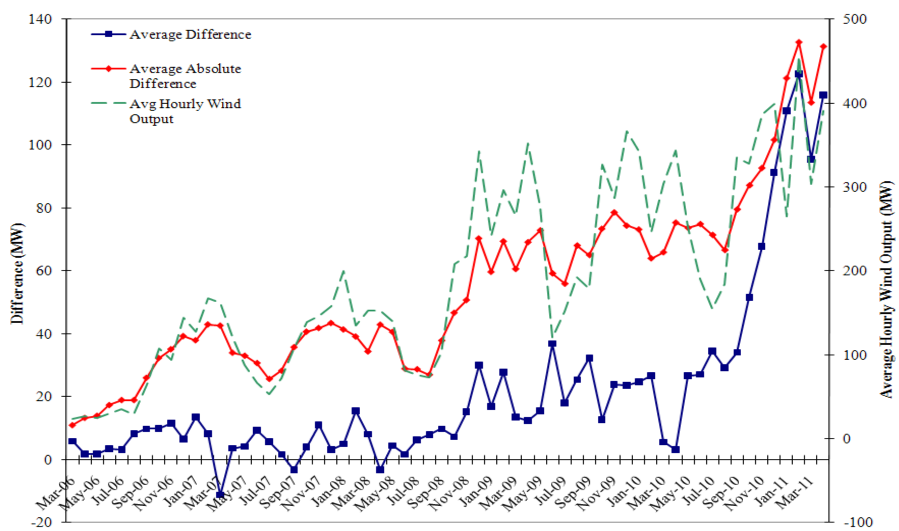
Since first entering the market in early 2006, the amount of wind generation has steadily increased and is the most important component within the self-scheduling and intermittent generation category. As of April 2011, there was a combined name-plate capacity of 1,429 MW of wind generation in Ontario, which is higher than the total capacity (about 1,000 MW) of all other self-scheduling and intermittent generation.[21]

Currently, the wind power generators forecast their own output on an hourly basis. Actual output by wind power generators may differ significantly from forecast output. Figure 1-6 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.[22]

[21] For details on wind projects that are currently operational and those under development, see the OPA's Wind-power webpage at: http://www.powerauthority.on.ca/current-electricity-contracts/wind-power.
[22] 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

Both the average and absolute average wind forecast error has been increasing since 2006 as installed wind capacity has increased. The overall average of the absolute forecast error was 96 MW per hour during the 2010/2011 reporting period, up from 69 MW per hour in 2009/2010. With wind generation capacity expected to increase significantly, the forecast error will likely also grow. The IESO's plan to implement a centralized wind forecasting system should offset some of the anticipated growth in wind forecast error.[23]

Figure 1-6: Average and Absolute Average Difference between Wind Generator Forecasted and Delivered Energy, and Relationship to Average Hourly Wind Output March 2006 – April 2011 (MW)



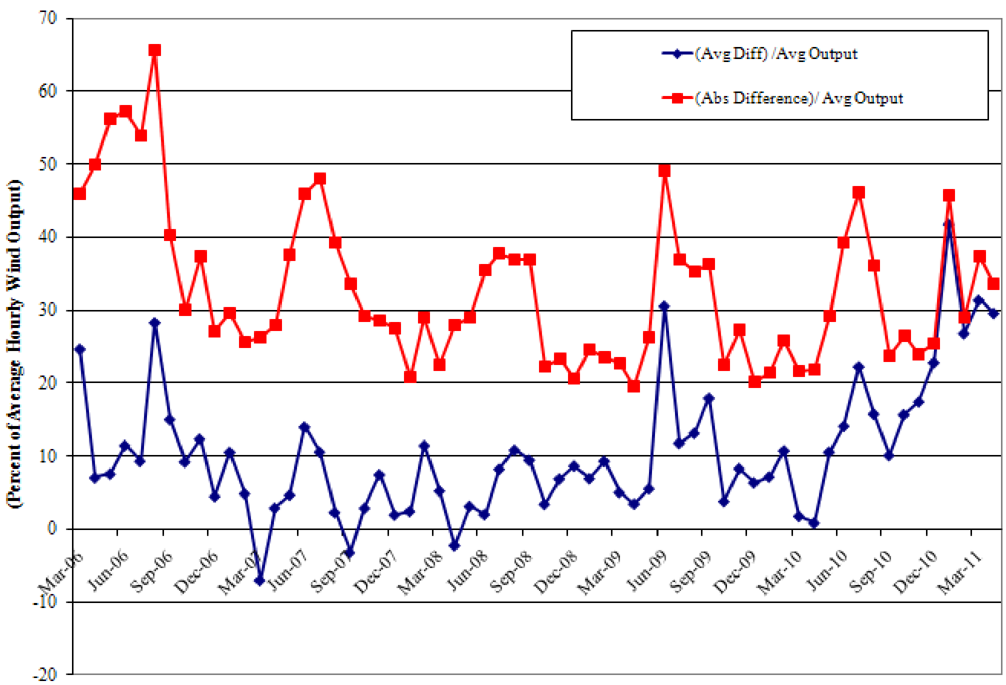
Although the average wind production forecast error has been increasing as new wind power generators become operational, the percentage error (absolute average forecast error relative to total wind power output) has been relatively stable. Figure 1-7 plots the average and absolute average difference between wind generators' forecasted energy and actual energy produced in each month since March 2006, as normalized using average hourly wind output for the month. Normalized absolute average difference as a

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.

[23] The Panel recommended centralized wind forecasting in its January 2009 Monitoring Report, pp. 253-256. IESO rule amendments (e.g. data obligation and cost recovery) have recently been passed by the IESO Board, paving the way for the final implementation of centralized wind forecasting. For details, see: http://ieso.ca/imoweb/news/bulletinItem.asp?bulletinID=5736 .

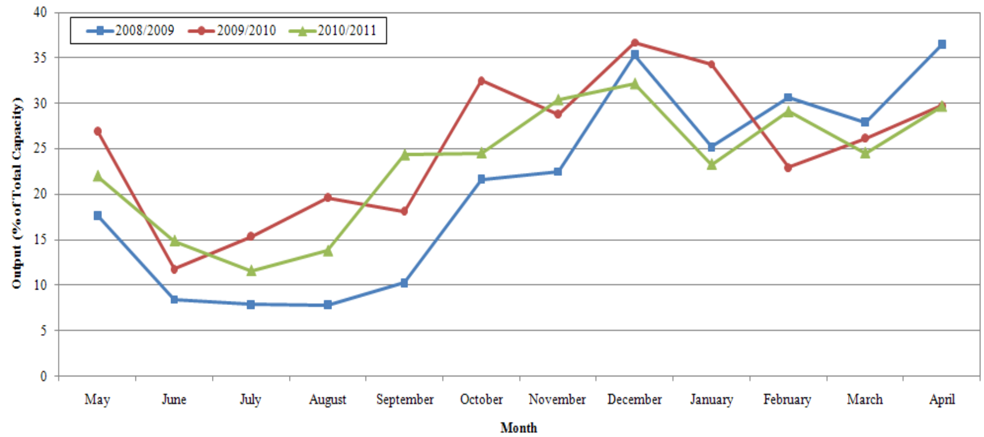
percentage of hourly wind output typically fluctuated between 20 to 40 percent. During 2011, the average difference has risen significantly and the gap between the two measures has diminished to the lowest levels since wind energy was introduced. This implies that the wind generators tend to persistently over-forecast their output.

Figure 1-7: Normalized Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy
March 2006 – April 2011
(% of average hourly wind output for the month)



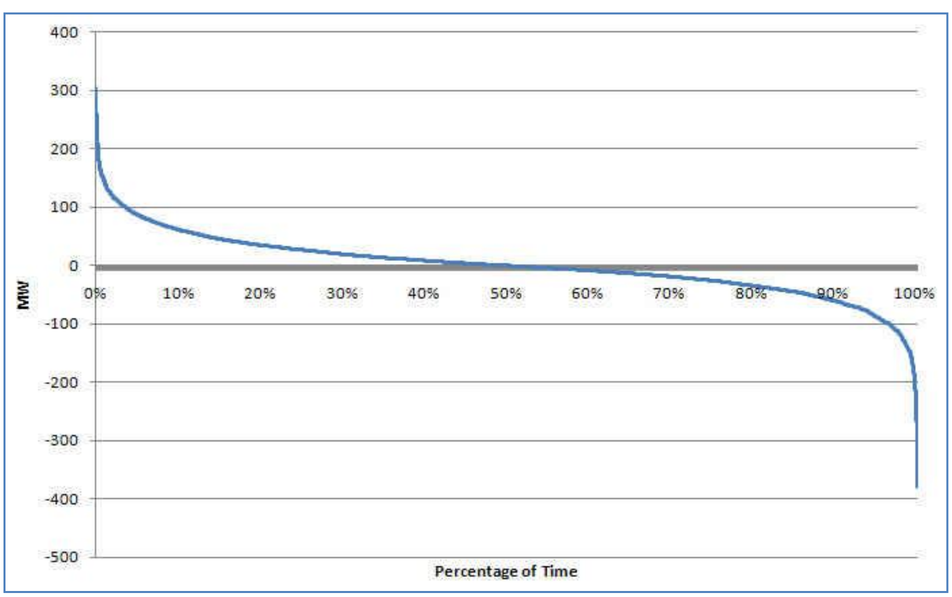
Power output from wind generation facilities show seasonal trends. As illustrated in Figure 1-8, wind generation tends be higher during the winter months, peaking in December and falling to a trough in the summer around July.

Figure 1-8: Normalized Monthly Average Wind Output
May – April 2008/2009 to 2010/2011
(% of total wind capacity)



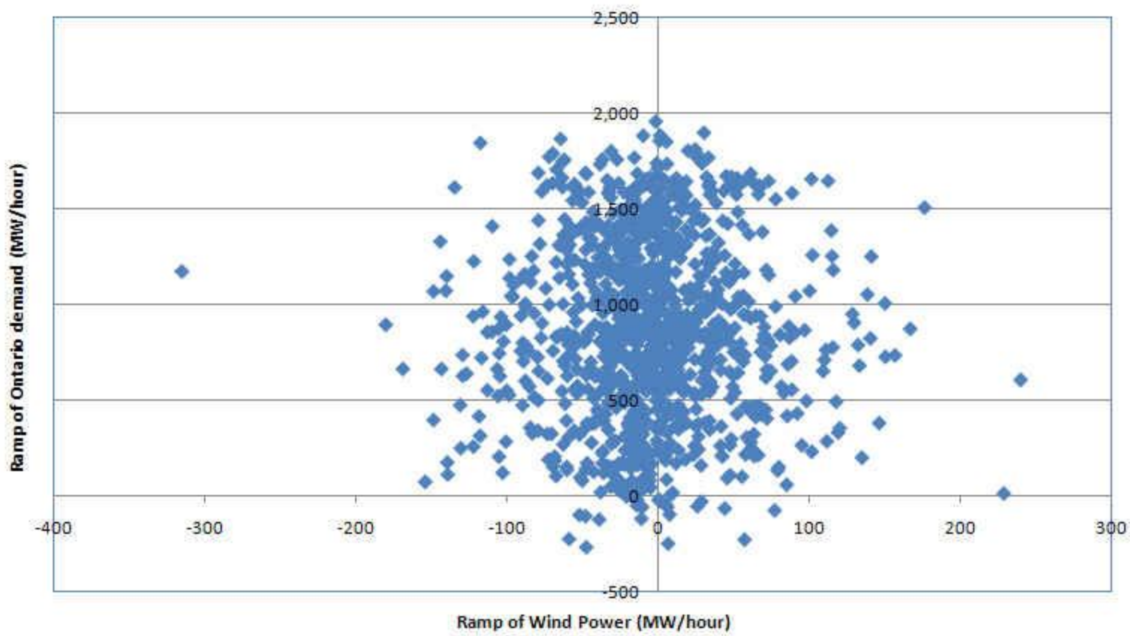
Wind output tends to be relatively stable hour-to-hour but can change quite rapidly. Figure 1-9 below depicts the duration curve of intra-hour wind output (i.e. the difference of output at interval 1 and interval 12 in the same hour).

Figure 1-9: Duration Curve of Hourly Change in Wind Power Production
May – April 2010/2011
(MW and %)



If wind output changes rapidly during hours when load is picking up this can pose operational challenges for the IESO, especially if wind output is declining. Figure 1-10 below plots the hourly change in Ontario demand against the hourly change in wind power production for HE 6 to HE 9. During these hours Ontario demand is typically ramping up, sometimes by as much as 2,000 MW in 12 intervals. In contrast, the wind power production can change up and down by up to 150 MW or more, with production decreasing roughly half of time and increasing roughly half of the time. When wind power output is increasing, it helps reduce the need for ramping capacity from other generation resources, whereas when wind power is decreasing other fast ramping resources have to provide additional ramping to meet the loss of wind output. As wind capacity increases the loss of wind output during hours when demand is ramping up could create operational challenges for the IESO.

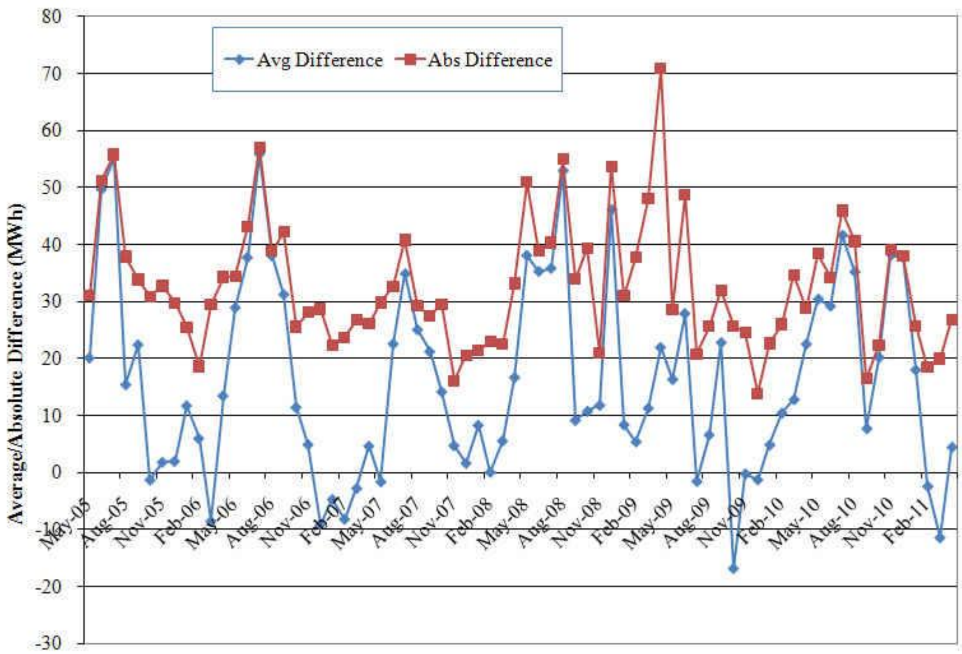
Figure 1-10: Hourly Wind Power Ramping vs. Hourly Ontario Demand Ramping May 2010 – April 2011 Delivery Hour 6 to 9 (MW/hour)



2.4.2.4 Forecast Errors of Other Self-Scheduling and Intermittent Generation

Figure 1-8 plots the average and absolute monthly difference between the energy that all non-wind, self-scheduling and intermittent generators forecasted and the quantity of energy they actually delivered in real-time. Both average and absolute error have been relatively stable in the past five years.

Figure 1-11: Average Production Forecast Error of Non-Wind Self-Scheduling and Intermittent Generators May 2005 – April 2011 (forecasted energy - delivered energy, MWh)



2.4.2.5 Real-Time Failed Intertie Transactions

Imports and/exports that are scheduled in the final one hour ahead pre-dispatch can fail before or in real-time. An intertie transaction can fail because it is not scheduled in other markets, because of an incorrect or missing North American Electric Reliability Corporation (NERC) tag,[24] or because it is curtailed by the IESO or external market

[24] All intertie transactions require an associated NERC tag in order to be scheduled by corresponding system operators.

operators for reliability reasons. Failed import and export transactions are another factor that can contribute to differences between 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 discrepancies between pre-dispatch and real-time prices.

Export Failures

Table 1-14 provides summary statistics on the frequency and magnitude of failed export transactions over the past two years. The number of hours when exports failed increased by 465 hours (5 percent) over the current annual period, from 4,657 hours to 5,122 hours. Although the frequency of export failures increased, the average amount of export failures per hour fell by 33 MW. The average amount of hourly failed exports was lower in ten of the twelve months when compared to the same month of the previous period. As a result, the failure rate (MW failed relative to MW scheduled) remained stable at 6 percent.

Table 1-14: Frequency, Magnitude, and Rate of Failed Exports from Ontario May – April 2009/2010 & 2010/2011 (MW and %)

Month	Number of Hours when Failed Exports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	341	295	1,342	806	165	137	4.9	6.9
June	392	357	1,144	1,484	236	191	5.3	5.7
July	527	415	1,739	838	330	149	8.5	4.5
August	429	411	1,844	850	212	137	5.5	4.4
September	385	408	989	950	172	146	5.2	3.4
October	314	469	1,050	683	134	145	4.0	4.5
November	174	259	779	431	118	80	2.0	1.6
December	431	483	1,430	800	187	185	5.5	4.0
January	434	628	1,280	1,260	209	331	5.8	11.9
February	393	501	935	1,251	245	205	7.7	9.3
March	457	512	892	917	227	225	8.0	10.2
April	380	384	980	824	233	145	9.6	5.2
Total/Average	4,657	5,122	1,200	925	206	173	6.0	6.0

* Incidents involving less than 1 MW and linked wheel failures are excluded.
** Based on those hours in which a failure occurs.

*** Total failed export MW divided by total scheduled export MW (excluding the export leg of linked wheels) in the unconstrained schedule in a month.

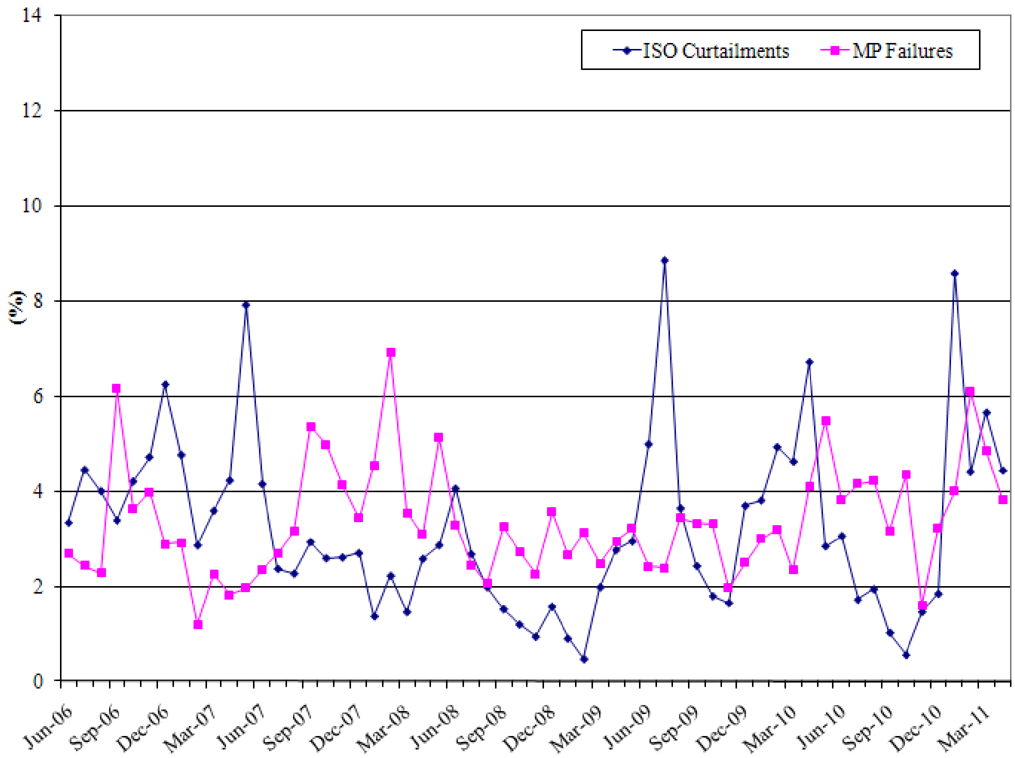
Causes of Export Failures

Export failures (and import failures below) are separated into those under the market participant's control (labelled 'MP failures') and those under the control of a system operator (labelled 'ISO curtailments').[25] The failure rate is determined as a percentage of failed to total exports (or imports) in MWh per month (excluding linked-wheel failures, which are rare).

Figure 1-9 plots the export failure rates beginning in June 2006.[26] MP failures have increased, fluctuating between 4 and 6 percent over 2010/2011 compared to between 2 and 4 percent in 2009/2010. A large spike in ISO curtailment failures occurred in January 2011, reaching its second highest level since 2006 at 8.6 percent. The increased export failure appeared to be related to transmission issues in both MISO and NYISO. For example, the Central to East interface in NYISO has been increasingly congested, due to a high clockwise loopflow around Lake Erie, leading to frequent curtailment of exports to PJM by the IESO.

[25] 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.
[26] The June 2006 start date is used because the IESO applied different coding practices that make it difficult to accurately compare the data from before and after June 2006.

Figure 1-12: Monthly Export Failures by Cause
June 2006 – April 2011
(% of total exports)



<u>Export Failures by Intertie Group</u>

Table 1-15 reports average monthly export failures by intertie group and failure cause for the period May 2010 to April 2011. Export failures at the Michigan intertie accounted for approximately 56 percent of all export failures during the reporting period.[27] Of those failures, 70 percent were ISO controlled failures. Despite this, it was the Manitoba intertie which had the highest ISO-induced failure rate at 27.6 percent of its total scheduled exports. The NYISO intertie was responsible for roughly 74 percent of total MP export failures and had the highest MP failure rate at 12.3 percent. Historically, MP failures have been the highest at the New York intertie.[28]

[27] Intertie transactions at the Michigan interface include the transactions between Ontario and PJM.
[28] 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

Table 1-15: Average Monthly Export Failures by Intertie Group and Cause May 2010 – April 2011 (GWh and % of failures)

Intertie Group	Average Monthly Exports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
New York	307.3	2.6	6.8	37.7	73.6	0.8	12.3
Michigan	511.3	21.4	55.7	9.4	18.4	4.2	1.8
Manitoba	21.7	6.0	15.6	2.5	4.9	27.6	11.5
Minnesota	26.0	4.9	12.8	0.3	0.6	18.8	1.2
Quebec	467.8	3.5	9.1	1.3	2.5	0.7	0.3
Total	1,334.1	38.4	100.0	51.2	100.0	2.9	3.8

Import Failures

Table 1-16 provides monthly summary statistics on the frequency and magnitude of failed import transactions during the last two May to April reporting periods. The total number of hours when failed imports occurred increased from 2,924 hours in 2009/2010 to 3,102 hours (35 percent of total hours in the period) in 2010/2011, a rise of 178 hours (6 percent). There was also a 31 MW (5 percent) increase in the magnitude of import failures. As a result, the import failure rate increased from 4.4 percent last year to 5.3 percent this year, contributing to a higher HOEP compared to the pre-dispatch price, everything else being equal.

Ontario. The potential for mismatched economic scheduling with NYISO is unique among the jurisdictions directly connected to Ontario. (This distinction also applies for imports to Ontario – see Table 1-17 below.)

Table 1-16: Frequency, Magnitude, and Rate of Failed Imports to Ontario May – April 2009/2010 & 2010/2011 (MW and %)

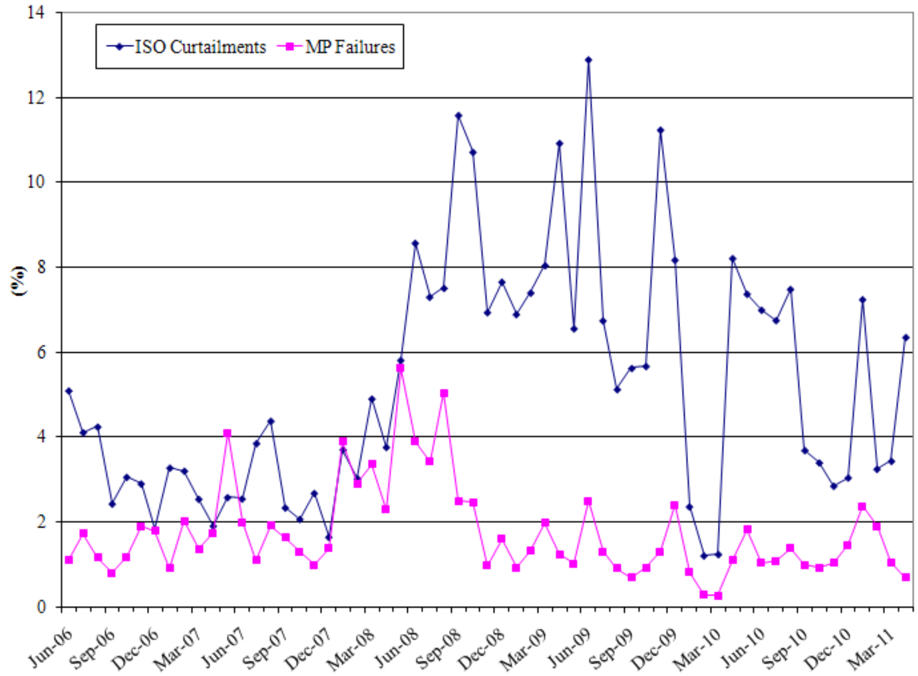
Month	Number of Hours when Failed Imports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	235	324	381	857	67	119	3.47	6.99
June	269	323	783	517	101	90	7.07	5.87
July	320	349	619	730	104	142	5.02	6.09
August	261	349	1,024	1,274	97	153	3.74	7.11
September	330	207	965	693	97	145	4.41	3.68
October	265	233	855	685	96	95	3.84	4.16
November	244	230	580	440	79	72	6.88	3.35
December	253	210	625	329	107	80	7.28	3.49
January	218	278	410	918	99	121	3.1	7.9
February	119	206	388	514	63	85	1.2	4.4
March	132	181	453	614	59	86	1.3	4.2
April	278	212	506	388	107	90	6.0	5.9
Total/Average	2,924	3,102	632	663	90	107	4.4	5.3

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

Causes of Import Failures

Figure 1-10 plots the import failure rates by cause since June 2006. Import failures due to ISO curtailments account for the majority of import failures since the middle of 2008. However, this has not been as pronounced in the current reporting period, with curtailment rates as low as 2.9 percent in November 2010. MP import failures continued to fluctuate around 1 to 2 percent, with a reporting period maximum of 2.4 percent during January 2011.

Figure 1-13: Monthly Import Failures by Cause
June 2006 – April 2011
(% of total imports)



Import Failures by Intertie Group

Table 1-17 reports average monthly import failures by intertie and cause for the period starting May 2010 and ending April 2011. Increased ISO curtailments have been experienced at the MISO interfaces (Michigan, Minnesota and Manitoba interfaces) beginning in May 2009. The majority of the curtailments were due to ramp limitations or transmission service unavailability in MISO. Michigan accounted for nearly 53 percent of all import failures. It had an ISO controlled failure rate of 6.5 percent and a market participant failure rate of just 1 percent. The Minnesota intertie had the highest ISO controlled import failure rate at 23.2 percent and the highest market participant controlled failure rate at 5.8 percent.

Table 1-17: Average Monthly Import Failures by Intertie Group and Cause May 2010 – April 2011 (GWh and % of failures)

Intertie Group	Average Monthly Imports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
New York	24.4	0.4	1.7	1.1	19.0	1.6	4.5
Michigan	241.4	15.8	67.5	2.5	43.1	6.5	1.0
Manitoba	66.0	3.7	15.8	1.1	19.0	5.6	1.7
Minnesota	13.8	3.2	13.7	0.8	13.8	23.2	5.8
Quebec	114.2	0.3	1.3	0.3	5.2	0.3	0.3
Total	459.8	23.4	100.0	5.8	100.0	5.1	1.3

2.4.2.6 Imports or Exports Setting Pre-dispatch Price

The fourth major factor identified by the Panel that leads to differences between pre-dispatch and real-time prices is the frequency of imports and exports setting the pre-dispatch price. 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.[29]

Table 1-18 shows the frequency of hours in which imports and exports set the pre-dispatch price for May to April 2009/2010 and 2010/2011. For the current reporting period, imports or exports set the pre-dispatch price in 2,854 hours, a significant drop (35 percent) from 4,376 hours in 2009/2010. The largest monthly decrease occurred in June, from 423 hours in 2009 to 180 hours in 2010 (a 57 percent drop).

[29] For a detailed explanation of why this occurs, see pp. 30-33 of the Panel's July 2007 Monitoring Report.

Table 1-18: Frequency of Imports or Exports Setting the Pre-Dispatch Price May – April 2009/2010 & 2010/2011 (number of hours and % of hours)

Month	2009/2010		2010/2011		Difference	
	Hours	%	Hours	%	Hours	% Change
May	392	53	223	30	(169)	(43)
June	423	59	180	25	(243)	(57)
July	427	57	275	37	(152)	(36)
August	366	49	216	29	(150)	(41)
September	395	55	281	39	(114)	(29)
October	413	56	290	39	(123)	(30)
November	314	44	166	23	(148)	(47)
December	341	46	268	36	(73)	(21)
January	326	44	193	26	(133)	(41)
February	308	46	228	34	(80)	(26)
March	389	52	238	32	(151)	(39)
April	283	40	295	41	12	4
Total	4,376	50	2,854	33	(1,522)	(35)

2.5 Internal Zonal (Shadow) Prices

Figure 1-14 and Table 1-19 summarize average nodal prices for the 10 internal Ontario zones for each 12 month period.[30] 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.[31]

Figure 1-14 presents the average zonal prices for the past reporting period. Average price differences between the remaining zones are moderate except between Northwest and the rest of the zones) and reflect the fact that congestion levels within Ontario (except Northwest) have not been particularly significant.

[30] For a detailed description of the IESO's ten zone division of Ontario, see the IESO's "Ontario Transmission System" publication at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2005jun.pdf.

[31] All nodal and zonal prices have been modified to +$2,000/MWh (or -$2,000/MWh) when the raw interval value was higher (or lower).

Figure 1-14: Average Internal Zonal Prices
May 2010 – April 2011
($ millions)

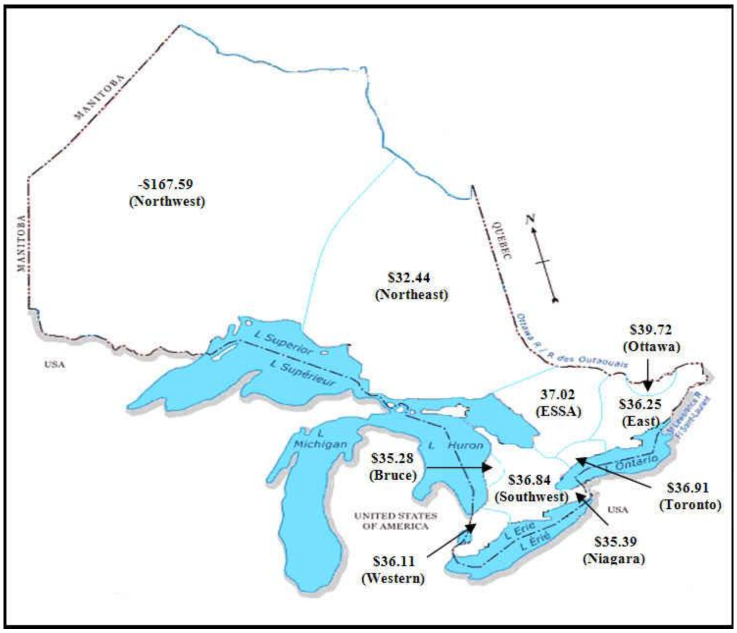


Table 1-19 shows that average internal zonal prices were higher by 20 percent or more in the current annual period relative to the previous period. The average Richview nodal price was $37.38/MWh in the most recent period, which is $7.50/MWh, or 25 percent, higher than the previous period.[32]

[32] The Richview bus is a node within the Toronto zone which is frequently used as a reference price given its central location.

Table 1-19: Internal Zonal Prices
May 2009 – April 2011
($/MWh and %)

Zone	May 2009 – April 2010	May 2010 – April 2011	% Change
Bruce	28.37	35.28	24.3
East	27.52	36.25	31.7
Essa	29.90	37.02	23.8
Niagara	29.04	35.39	21.8
Northeast	11.95	32.44	171.4
Northwest	(363.06)	(167.59)	53.8
Ottawa	30.00	39.72	32.4
Southwest	29.54	36.84	24.7
Toronto	30.18	36.91	22.3
Western	29.75	36.11	21.3
Richview Node	29.88	37.38	25.0

As observed in previous reports, bottled supply in the Northwest is the primary reason for the large negative zonal prices in this area. The average zonal price in the Northwest zone rose to -$167.59/MWh, compared with the -$363.06/MWh average price during the 2009/2010 period.

2.6 CMSC Payments

Figure 1-15 provides a summary of congestion management settlement credit (CMSC) payments across the 10 internal zones for the last annual reporting period.[33] For each zone, there is a total CMSC paid for constrained-off generation and "imports" plus constrained-on "exports" from the zone (in this analysis, imports or exports refer to the individual zone, not the province). 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 a zone), and so this amount is an indicator of the bottling of supply in the zone. The second total for each zone shows the CMSC for constrained-on generation or

[33] CMSC is often induced by transmission limits, losses or security requirements. In addition, the 3-times ramp rate, slow ramping of fossil units or technical / regulatory limitations can induce CMSC.

"imports", or constrained-off "exports". This is a measure of the need for additional or out-of merit supply in a zone (undersupply in a zone).[34]

Of the $47.7 million of CMSC for constrained-off supply or constrained-on exports, $26.9 million (58 percent) occurred in the Northwest zone, primarily as the result of the east-west flow limits which bottle the relatively low-cost supply in the area. The other major contributors to the total were the Western zone at $4.4 million (9 percent) and the Niagara zone at $5.4 million (12 percent).

CMSC payments for constrained-on supply and constrained-off exports totalled $43.1 million and were primarily isolated to four zones in Ontario. Significant payments were made in the Northwest zone at $11.9 million (28 percent), the Toronto zone at $9.8 million (23 percent), the Western zone at $8.5 million (20 percent) and the Northeast zone at $6.0 million (14 percent).

[34] CMSC paid to dispatchable load is omitted here since the largest portion of those payments is self-induced (e.g. deviation and ramping limitation), as opposed to being related to congestion, losses or security requirements. Historically, the CMSC payment to dispatchable loads was small. In its August 2010 Monitoring Report, however, the Panel observed a significant increase in CMSC payments to two dispatchable loads. Currently, the IESO is seeking to recover some of the CMSC payments and the Panel is investigating certain aspects of the market participants' behaviour.

Figure 1-15: Total CMSC Payments by Internal Zone May 2010 – April 2011 ($ millions)

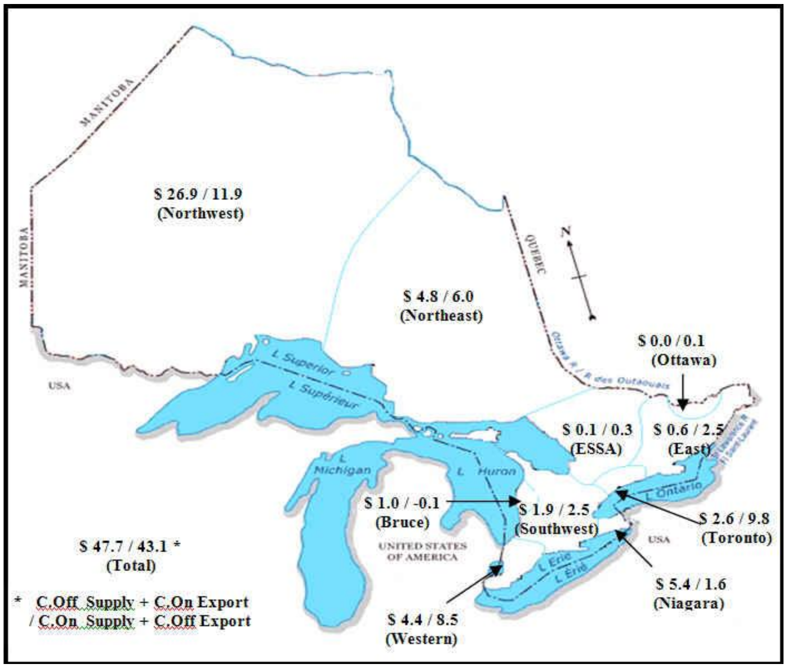


Table 1-20 summarizes the CMSC payments for past two years. Overall, there were significant decreases in the amount of payments made in most zones. The largest decreases were in constrained-off payments in the Northwest and the Northeast, as well as to constrained-on payments in the Western and the East Zones. The reduction in constrained-off payments was mainly due to a large reduction in available water this year in the Northwest and Northeast as well as lower intertie prices at the Manitoba interface. The reduction in constrained-on payments in the Western and East Zones was mainly due to improved supply conditions associated with new gas-fired generation.

Table 1-20: Total CMSC Payments by Internal Zone, May – April 2009/2010 & 2010/2011 ($ millions)

Zone	Constrained-off Supply plus Constrained-on Exports			Constrained-on Supply plus Constrained-off Exports		
	2009/2010	2010/2011	% Change	2009/2010	2010/2011	% Change
Bruce	1.8	1.0	(44.4)	0.0	(0.1)	n/a
East	-1.3	0.6	(146.2)	15.2	2.5	(83.6)
Essa	0.2	0.1	(50.0)	0.1	0.3	200.0
Niagara	7.9	5.4	(31.6)	0.3	1.6	433.3
Northeast	11.1	4.8	(56.8)	3.6	6.0	66.7
Northwest	36.4	26.9	(26.1)	18.8	11.9	(36.7)
Ottawa	0.0	0.0	n/a	0.2	0.1	(50.0)
Southwest	2.6	1.9	(26.9)	9.2	2.5	(72.8)
Toronto	1.2	2.6	116.7	14.9	9.8	(34.2)
Western	3.3	4.4	33.3	20.3	8.5	(58.1)
Total	63.2	47.7	(24.5)	82.6	43.1	(47.8)

Total yearly payments for constrained-off supply plus constrained-on exports fell by $15.5 million, or 25 percent, from the previous period's total. The largest contributors to the decrease in payments were the Northwest and Northeast regions which saw drops of $9.5 million (26 percent) and $6.3 million (57 percent), respectively.

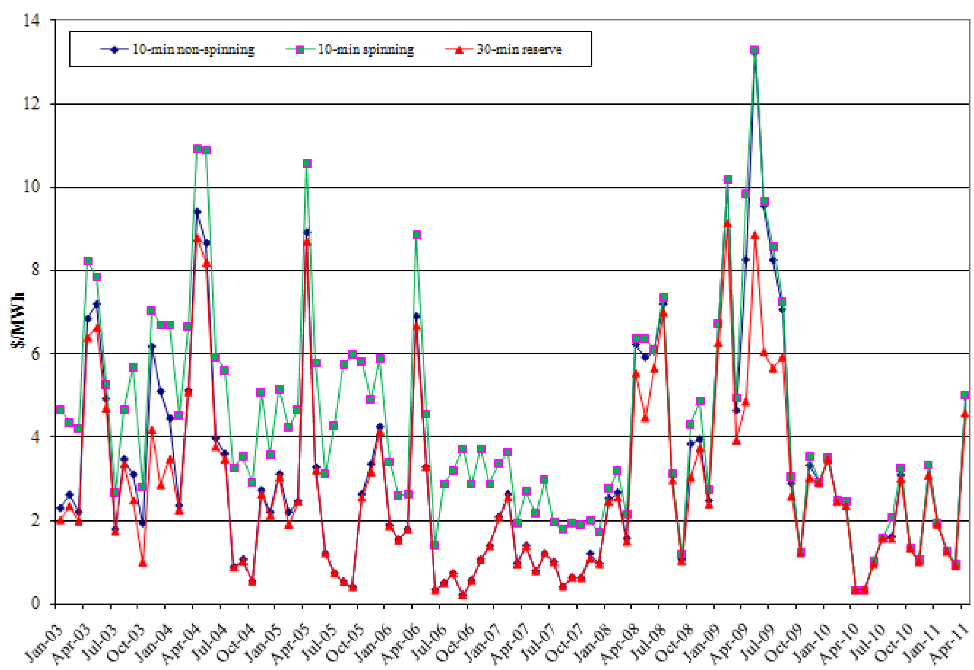
Total payments for constrained-on supply plus constrained-off exports decreased significantly by $39.5 million (48 percent) from 2009/2010 to 2010/2011. Most regions experienced a decrease in payments, with the greatest drop being in the East zone at $12.7 million (84 percent), followed by Western at $11.8 million (58 percent), Northwest at $6.9 million (37 percent), Southwest at $6.7 million (73 percent), and Toronto at $5.1 million (34 percent).

2.7 Operating Reserve Prices

Demand for operating reserve (OR) is reflected in the level of the OR requirement established by the IESO. The average OR requirement for the 2009/2010 annual period was 1,496 MW, while in 2010/2011 the requirement was slightly higher at 1,519 MW, an increase of 1.5 percent.

Figure 1-12 shows monthly average operating reserve prices since 2003 for the three categories of OR: 10-minute spinning, 10-minute non-spinning, and 30-minute reserve. From 2003 to early 2008, OR prices were generally declining. They then trended upwards from early 2008 to late 2009 as a result of a decline in OR resources available.[35] Since October 2009, OR prices have dropped and returned to pre-2008 levels. Contributing factors include increased OR supply from new fossil units coming on-line and the reduction in water availability in 2010 and 2011 (compared to the abnormally abundant water supply in 2009 that caused hydro generators to prefer to supply more energy but less OR).

Figure 1-16: Monthly Operating Reserve Prices by Category
January 2003 – April 2011
($/MWh)



[35] The factors leading to the increase in OR prices observed in 2008 and 2009 were discussed in the Panel's July 2009 Monitoring Report, pp. 45-46.

2.7.1 *On-Peak Operating Reserve Prices*

Table 1-21 presents average monthly OR prices during on-peak hours over the last two reporting periods. On-peak prices for all three types of OR have decreased by at least 49 percent when comparing 2010/2011 to 2009/2010 periods. All three categories saw decreases in OR prices in almost every month versus the prior period, with the exception of small increases in October and December and a dramatic increase during April. Dry weather in the spring and summer of 2010 resulted in lower water availability, which tends to induce hydro resources to offer OR rather than energy.[36]

Table 1-21: Operating Reserve Prices, On-Peak
May – April 2009/2010 & 2010/2011
($/MWh)

Month	10S			10N			30R		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
May	18.67	0.51	(97.3)	18.61	0.51	(97.3)	11.77	0.51	(95.7)
June	15.89	1.75	(89.0)	15.81	1.75	(88.9)	9.17	1.62	(82.3)
July	14.41	3.06	(78.8)	14.28	3.04	(78.7)	9.26	3.04	(67.2)
August	10.93	3.24	(70.4)	10.91	2.76	(74.7)	9.05	2.65	(70.7)
September	4.98	4.42	(11.2)	4.98	4.33	(13.1)	4.49	4.18	(6.9)
October	1.84	2.37	28.8	1.84	2.37	28.8	1.84	2.34	27.2
November	5.59	1.70	(69.6)	5.55	1.70	(69.4)	4.92	1.66	(66.3)
December	5.06	5.72	13.0	5.06	5.72	13.0	5.01	5.25	4.8
January	4.66	3.43	(26.4)	4.66	3.43	(26.4)	4.58	3.38	(26.2)
February	4.75	2.06	(56.6)	4.75	2.06	(56.6)	4.68	2.00	(57.3)
March	4.03	1.35	(66.5)	4.03	1.35	(66.5)	3.81	1.25	(67.2)
April	0.41	7.75	1,790.2	0.41	7.72	1,782.92	0.41	6.83	1,565.9
Average	7.60	3.11	(59.1)	7.57	3.06	(59.6)	5.75	2.89	(49.7)

Table 1-22 presents average monthly operating reserve prices during off-peak hours over the last two reporting periods. Off-peak prices for all three categories have seen decreases of at least 56 percent. All categories saw some price jumps in September, December and February, and a large increase in April 2010/2011, compared to a year ago.

[36] When water is storable, the hydro generator can provide OR (which only requires the generator to be ready to supply energy in case of OR activation) with a low price, while when water is abundant to the point of exceeding storage capacity, providing OR would mean a spill of water, which involves a potentially significant opportunity cost.

***Table 1-22: Operating Reserve Prices, Off-Peak
May – April 2009/2010 & 2010/2011
($/MWh)***

Month	10S			10N			30R		
	2009/ 2010	2009/ 2010	% Change	2009/ 2010	2009/ 2010	% Change	2009/ 2010	2009/ 2010	% Change
May	9.24	0.22	(97.6)	9.17	0.22	(97.6)	6.69	0.22	(96.7)
June	3.71	0.33	(91.1)	3.56	0.33	(90.7)	3.10	0.32	(89.7)
July	3.36	0.35	(89.6)	2.84	0.35	(87.7)	2.43	0.34	(86.0)
August	4.48	1.13	(74.8)	4.16	0.66	(84.1)	3.59	0.65	(81.9)
September	1.40	2.24	60.0	1.06	2.00	88.7	0.91	1.99	118.7
October	0.73	0.58	(20.5)	0.72	0.58	(19.4)	0.69	0.58	(15.9)
November	1.72	0.45	(73.8)	1.37	0.37	(73.0)	1.37	0.36	(73.7)
December	1.16	1.36	17.2	1.16	1.32	13.8	1.16	1.32	13.8
January	2.62	0.82	(68.7)	2.62	0.80	(69.5)	2.62	0.80	(69.5)
February	0.60	0.64	6.7	0.60	0.64	6.7	0.60	0.63	5.0
March	0.92	0.57	(38.0)	0.92	0.57	(38.0)	0.92	.57	(38.0)
April	0.28	3.00	971.4	0.27	2.97	1,000	0.27	2.93	985.2
Average	2.52	0.97	(61.5)	2.37	0.90	(62.0)	2.03	0.89	(56.2)

3. Demand

3.1 Aggregate Consumption

Table 1-23 compares monthly Ontario energy demand and net exports for the 2009/2010 and 2010/2011 reporting periods.

Table 1-23: Monthly Domestic Energy Demand and Net Export Schedules May – April 2009/2010 & 2010/2011 (TWh)

Month	Ontario Demand			Net Exports			Total		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
May	10.52	11.42	8.6	0.65	0.04	(93.8)	11.17	11.46	2.6
June	10.91	11.61	6.4	1.3	0.66	(49.2)	12.21	12.27	0.5
July	11.32	13.34	17.8	1.25	0.56	(55.2)	12.57	13.9	10.6
August	12.26	12.98	5.9	0.9	0.54	(40.0)	13.16	13.52	2.7
September	10.97	11.11	1.3	0.52	0.92	76.9	11.49	12.03	4.7
October	11.22	11.02	(1.8)	0.38	0.92	142.1	11.6	11.94	2.9
November	11.16	11.37	1.9	0.74	0.79	6.8	11.9	12.16	2.2
December	12.69	12.78	0.7	1.05	1.68	60.0	13.74	14.46	5.2
January	13.17	13.35	1.4	0.8	1.15	43.8	13.97	14.5	3.8
February	11.78	11.83	0.4	0.54	0.62	14.8	12.32	12.45	1.1
March	11.74	12.40	5.6	0.62	0.66	6.5	12.36	13.06	5.7
April	10.54	10.82	2.7	0.36	0.72	100.0	10.9	11.54	5.9
Total	138.28	144.03	4.2	9.11	9.26	1.6	147.39	153.29	4.0
Average	11.52	12.00	4.2	0.76	0.77	1.6	12.28	12.77	4.0

Annual Ontario Demand increased by 5.75 TWh, or 4.2 percent, from 138.28 TWh in 2009/2010 to 144.03 TWh in 2010/2011. Ontario Demand rose in every month except October. The month of July saw the largest increase (17.8 percent) in demand from the same month in the previous year.

Total annual net exports (in the unconstrained sequence) marginally increased from 9.11 TWh in 2009/2010 to 9.26 TWh in 2010/2011, or a 1.6 percent increase. There were large declines in May through August offset by increases in all other months.

Total Ontario demand plus net exports increased by 5.9 TWh, or 4 percent, and was higher in every month this year compared to the prior year. The largest monthly percentage increase occurred in July at 10.6 percent and the smallest increase in June at 0.5 percent.

3.2 Wholesale and LDC Consumption

Figure 1-17 plots the separate monthly energy consumption of wholesale loads and Local Distribution Companies (LDCs) between January 2003 and April 2011. There are clear seasonal fluctuations in LDC demand. Typically, LDC consumption is highest during the December/January and July/August months. Over the latest reporting period, LDC demand peaked in January 2011 at 10.80 TWh, and hit a low of 8.63 TWh in April 2011. Roughly speaking, the LDC demand had been decreasing from 2003 to early 2009, and since then staying at a relatively stable level outside of seasonal fluctuations.

Wholesale electricity consumption continued its downward trend since 2003 and hit its record low in early 2009. Since then, the demand has been increasing slightly, likely reflecting an improved economic environment.

Figure 1-17: Monthly Total Energy Consumption, LDC and Wholesale Loads
January 2003 – April 2011
(GWh)

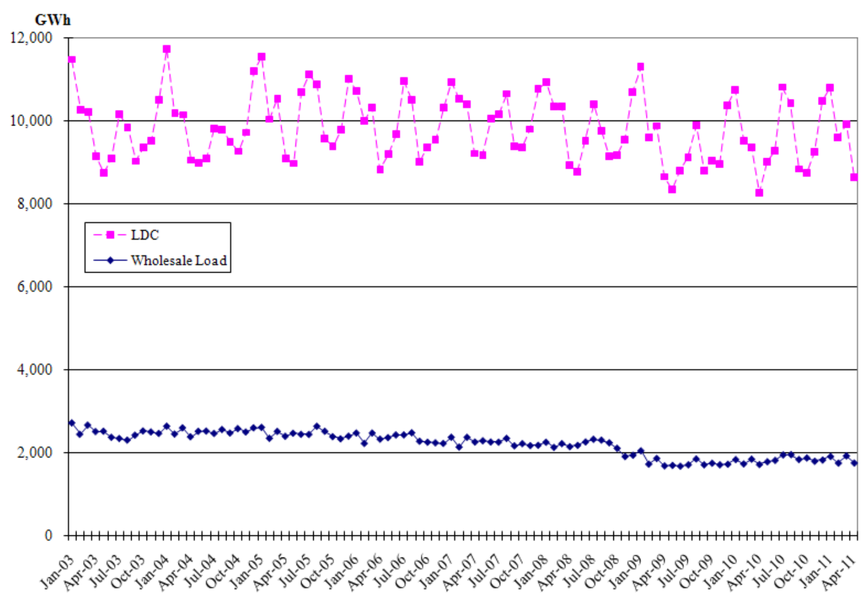
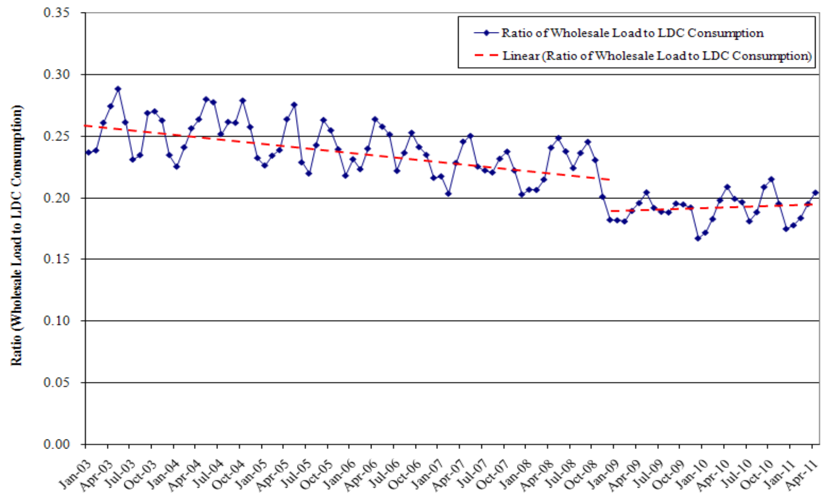


Figure 1-18 presents the ratio of wholesale load to LDC consumption since January 2003. The continued decrease in the ratio up to early 2009 is consistent with the more rapid decline of wholesale consumption compared to LDC consumption presented in Figure 1-17. The trend reversed beginning in early 2009 as the economy rebounded.

Figure 1-18: Ratio of Wholesale Load to LDC Consumption
January 2003 – April 2011
(wholesale load divided by LDC consumption)



4. Supply

4.1 New Generating Facilities

Between May 2010 and April 2011, 1,626 MW of domestic generation capacity was added to the Ontario wholesale market:

- two large gas-fired generation facilities (Thorold and Halton Hills) with a total generation capacity of 1,026 MW were brought online;
- several large wind power generators (Gosfield, Port Alma phase II, Dillon, and Spence) came online, with a maximum combined generation capacity of 330 MW; and
- a dozen small hydro electric generation stations were built or returned to service, adding roughly 270 MW into the market.

Offsetting the new supply was a decrease in coal-fired generation capacity. In October 2010, OPG permanently closed four coal-fired generating units (two Lambton and two Nanticoke units) with approximately 2,000 MW of generation capacity. The closure of these units is in response to the provincial government's policy of shutting down all coal-fired generation by the end of 2014.

4.2 The Supply Cushion

Tables 1-24 and 1-25 present monthly summary statistics on the pre-dispatch and real-time supply cushion for the last two annual reporting periods.[37] The final pre-dispatch supply cushion measure includes all sources of supply (including imports) while the real-time domestic supply cushion focuses only on supply ramping capability from internal generation.[38]

4.2.1 *Pre-dispatch (One-hour ahead) Supply Cushion*

Table 1-24 indicates that the average monthly pre-dispatch supply cushion rose from 16.6 percent in 2009/2010 to 20.4 percent in 2010/2011, with the largest monthly increases being observed between May and September. As shown in Tables A-6 and A-7 of the Statistical Appendix, the increase in the average pre-dispatch supply cushion was mainly attributable to increases observed in off-peak hours. The on-peak average increased from 23.2 percent last year to 30.3 percent (or by 7.1 percent) this year while the off-peak average increased even more, from 19.5 percent last year to 29.7 percent (or by 10.2 percent) this year.

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[37] The supply cushion measure used by the Panel was defined in the Panel's January 2009 Monitoring Report, pp. 205-206.

[38] Imports are scheduled on an hourly basis based whereas domestic resources are scheduled on a five minute basis (i.e. can be dispatched up and down in real-time). For wind, the real-time supply cushion uses the hourly output that had been projected in pre-dispatch.

Consistent with the improvement in the average supply cushion, Table 1-24 also indicates that the frequency with which the supply cushion fell below 10 percent was also lower this year. The total number of hours with a supply cushion less than 10 percent dropped from 1,988 hours to 1,173 hours, a reduction of 41 percent. This represents 13 percent of the total hours during the year.

Table 1-24: Final Pre-Dispatch Total Supply Cushion May – April 2009/2010 & 2010/2011 (% and number of hours under certain levels)

Month	Average Supply Cushion (%)		Supply Cushion Less Than 10% (# of Hours, % of Total Hours)			
	2009/ 2010	2010/ 2011	2009/ 2010	%	2010/ 2011	%
May	16.9	25.2	144	19.4	25	3.4
June	15.5	21.5	169	23.5	69	9.6
July	14.6	23.3	218	29.3	43	5.8
August	16.4	22.4	194	26.1	48	6.5
September	15.3	20.8	166	23.1	90	12.5
October	18.4	19.1	117	15.7	113	15.2
November	19.5	25.2	54	7.5	23	3.2
December	16.7	17.6	158	21.2	166	22.3
January	16.9	17.9	208	28.0	118	15.9
February	14.9	18.6	227	33.8	87	12.9
March	13.9	15.8	274	36.8	204	27.4
April	20.7	16.9	59	8.2	187	26.0
Total	16.6	20.4	1,988	22.7	1173	13.4

4.2.2 *Real-time Supply Cushion*

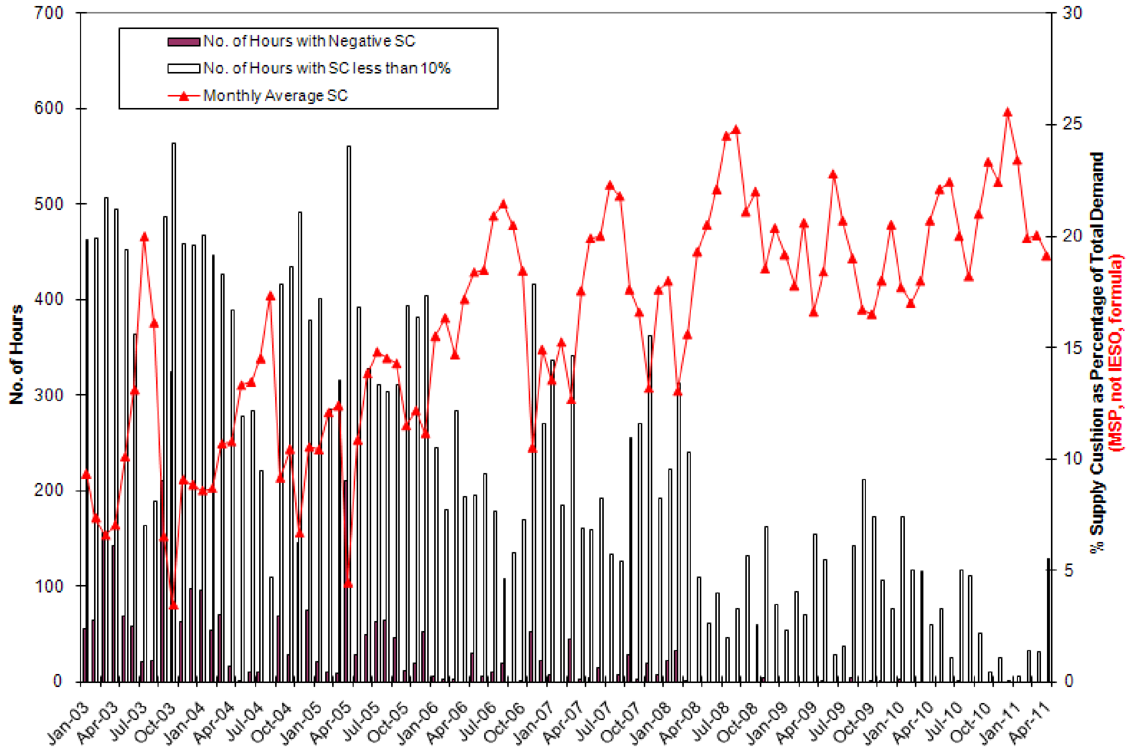
Table 1-25 indicates that the real-time supply cushion increased from 2009/2010 to 2010/2011. The average monthly supply cushion rose from 18.8 percent to 21.5 percent. The number of hours that experienced a supply cushion of 10 percent or less decreased from 1,369 hours to 918, a reduction of 32.9 percent. This represents 10.5 percent of total hours during the year. There were just 2 hours with a negative supply cushion 2010/2011 (both occurring in July), down from 12 instances in 2009/2010.

Table 1-25: Real-time Domestic Supply Cushion May – April 2009/2010 & 2010/2011 (% and number of hours under certain levels)

Month	Average Supply Cushion (%)		Supply Cushion Less Than 10% (# of Hours, % of Total Hours)			
	2009/ 2010	2010/ 2011	2009/ 2010	%	2010/ 2011	%
May	18.4	22.1	128	17.2	77	10.3
June	22.8	22.4	28	3.9	25	3.5
July	20.7	20.0	38	5.1	117	15.7
August	19.0	18.2	143	19.2	111	14.9
September	16.7	21.0	212	29.4	51	7.0
October	16.5	23.3	173	23.3	11	1.5
November	18.0	22.4	106	14.7	25	3.5
December	20.5	25.6	76	10.2	2	0.3
January	17.7	23.4	172	23.1	6	0.8
February	17.0	19.9	117	17.4	33	4.9
March	18.0	20.0	116	15.6	31	4.2
April	20.7	19.1	60	8.3	129	17.9
Total	18.8	21.5	1,369	15.6	918	10.5

Figure 1-19 plots real-time domestic supply cushion summary statistics between January 2003 and April 2011. The long-term trend indicates that the real-time supply cushion has been consistently improving since 2003, with a new maximum occurring in December 2010. Both the number of hours with a supply cushion less than 10 percent and the number of hours with a negative supply cushion have trended substantially downward since January 2003.

Figure 1-19: Monthly Real-time Domestic Supply Cushion Statistics
January 2003 – April 2011
(% and number of hours)



4.3 Baseload Supply

Table 1-26 presents average hourly market schedules of baseload generation by category over the last two May to April periods. Overall, average hourly baseload supply increased slightly by 2.4 percent, from 12.7 GW last year to 13.0 GW this year. Total baseload supply in every month was up in the most recent year relative to the prior period except for June through August.

Table 1-26 also shows the corresponding average Ontario demand and the portion which is covered by total baseload supply. The 4 percent increase in average hourly Ontario demand (from 15.8 GW last year to 16.4 GW this year) more than offset the increase in baseload supply. As a result the share of total Ontario demand covered by baseload supply fell slightly from 80.6 percent to 79.5 percent.

Table 1-26: Average Hourly Baseload Supply by Supply Type and Ontario Demand May – April 2009/2010 & 2010/2011 (GW per hour, unconstrained schedules)

Month	Nuclear		Baseload Hydro*		Self-Scheduling and Intermittent Supply		Total Baseload Supply		Ontario Demand		Total Baseload Supply as a % of Ontario Demand	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	6.7	7.7	2.4	2.1	1.1	1.0	10.2	10.8	14.1	15.3	72.1	70.4
June	9.5	9.1	2.3	2.1	1.2	1.1	13.0	12.3	15.2	16.1	85.8	76.3
July	10.0	9.5	2.3	2.0	0.9	1.1	13.3	12.6	15.2	17.9	87.4	70.3
August	10.0	9.6	2.3	1.9	0.9	1.1	13.3	12.6	16.5	17.4	80.7	72.2
September	9.4	10.0	2.3	1.9	0.9	1.1	12.6	13.0	15.2	15.4	82.7	84.2
October	8.6	9.6	2.2	2.0	1.2	1.2	12.0	12.8	15.1	14.8	79.6	86.4
November	9.1	9.5	2.1	2.1	1.2	1.3	12.4	12.9	15.5	15.3	80.0	84.4
December	10.2	11.0	2.1	2.1	1.3	1.4	13.6	14.5	17.1	17.2	79.7	84.4
January	9.9	11.0	2.1	2.1	1.3	1.3	13.3	14.4	17.7	17.9	75.1	80.3
February	10.0	10.1	2.1	2.0	1.2	1.6	13.3	13.7	17.5	17.6	75.9	77.8
March	9.5	10.0	2.2	2.3	1.4	1.4	13.1	13.7	15.8	16.7	83.0	82.2
April	8.5	9.4	2.1	2.2	1.2	1.4	11.8	13.0	14.2	14.5	83.3	89.4
Average	9.3	9.7	2.2	2.1	1.2	1.3	12.7	13.0	15.8	16.4	80.6	79.5

*Baseload hydro includes the Beck, Saunders and Decew hydro electric generators.

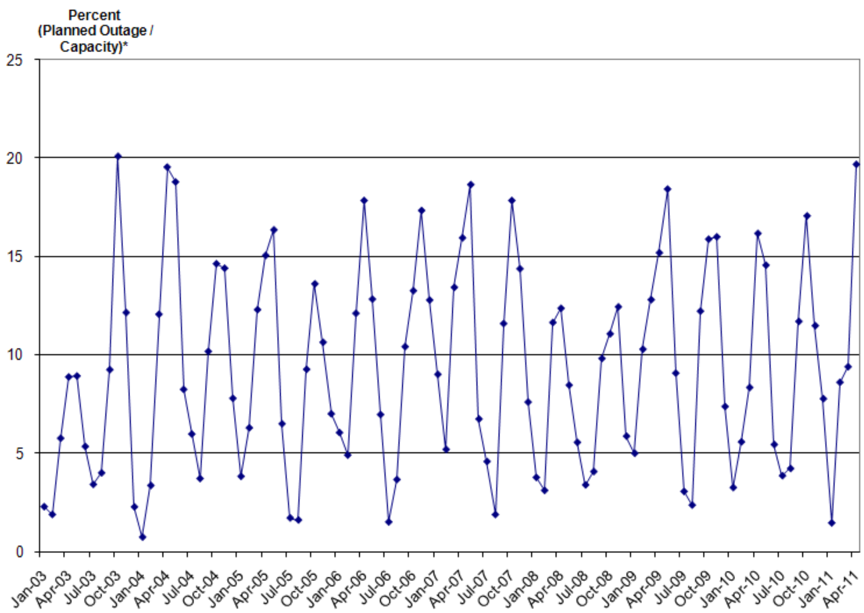
4.4 Outages

Generator outage patterns are important to monitor as there is upward pressure on market prices when 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 1-20 plots monthly planned outages as a percentage of capacity since 2003. Planned outage rates over the most recent May to April period showed seasonal fluctuations similar to those observed in previous years.

Figure 1-20: Planned Outages Relative to Capacity
January 2003 – April 2011
(% of capacity*)

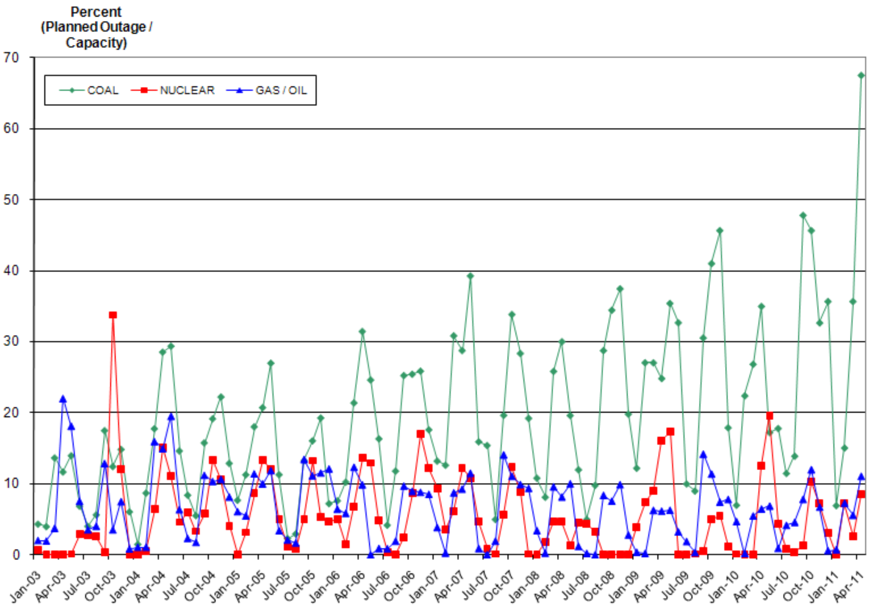


*Includes Nuclear, Coal, and Gas (or Oil) units.

Figure 1-21 presents planned outage rates as a percentage of total capacity for coal-fired, nuclear, and gas-fired generators since 2003. Planned outages for each fuel type shows seasonal patterns similar to the aggregate planned outage rate presented above.[39] The planned outage rate for coal-fired generators shows a generally increasing pattern while gas-fired generators have a generally decreasing planned outage rate.

[39] For the purposes of the outage statistics in this report, OPG's CO_2 outages are classified as planned outages rather than forced outages as done by the IESO (See the Panel's July 2009 Monitoring Report, pp. 58-59, for details on why this adjustment was made). This adjustment is only relevant for most 2009 summer months. OPG's 2010 and 2011 CO_2 emissions strategies eliminated the use of the CO_2 outage designation. Furthermore, the capacity that was effectively removed from the market by designating units as "NOBA" is not reflected in either the planned or forced outage statistics. The NOBA units are units that were designated as not offered, but available when needed. As a result, these units were technically available (subject to their start-up lead times).

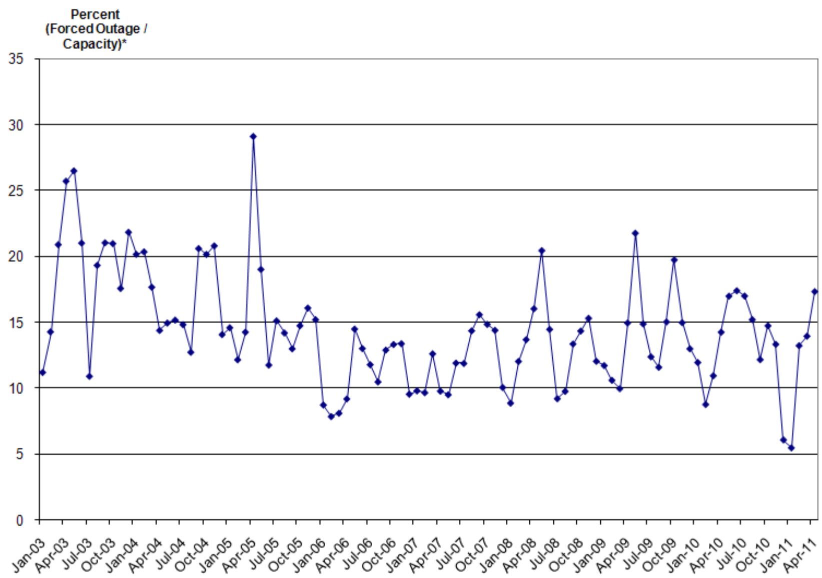
Figure 1-21: Planned Outages Relative to Capacity by Fuel Type
January 2003 – April 2011
(% of capacity)



4.4.2 *Forced Outages*

Given that forced outages occur unexpectedly, they do not exhibit the same level of seasonality as planned outage rates. Figure 1-22 plots aggregated forced outages as a percentage of capacity since January 2003. Over the most recent reporting period, the aggregate rate fluctuated between 10 and 17 percent with two exceptions; December 2010 at 6.1 percent, and January 2011 at 5.5 percent. These exceptions represent all time monthly lows in forced outages as a percentage of capacity since the market opened in 2002.

Figure 1-22: Forced Outages Relative to Capacity
January 2003 – April 2011
(% of capacity*)



*Includes Nuclear, Coal, and Gas (or Oil) units.

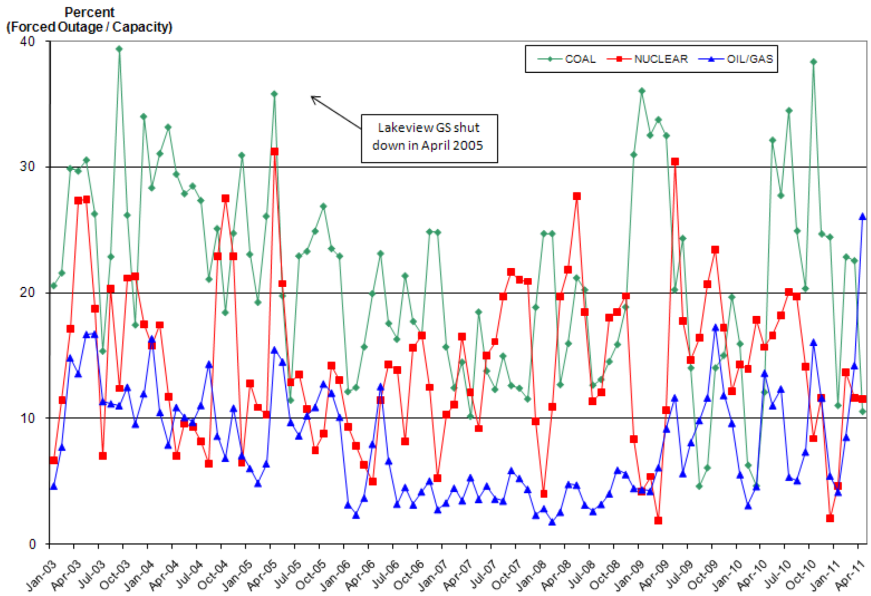
Figure 1-23 separates forced outage rates by fuel type since 2003 (i.e. the forced outage in a category relative to the total capacity for the category):

- The forced outage rate for coal-fired units was relatively high this reporting period compared to a year ago. With a starting point of 32 percent during May 2010, the forced outage rate for coal-fired units rose to as high as 38 percent during October before dropping to as low as 11 percent in January 2011.

- The nuclear forced outage rate was slightly more stable this period with most fluctuations occurring within the 10 to 20 percent range. In December 2010, the nuclear forced outage rate dropped to 2 percent for only the second month since market opening (the other month was March 2009).

- The forced outage rate for gas-fired units was no longer the lowest of the three fuel types in most months. The outage rate reached a historical high of 26 percent in April 2011, surpassing the previous record high of 17 percent in October 2009. The relatively high forced outage rate at gas-fired generators may have reflected the fact that new gas-fired generators were commissioning and becoming dispatchable during these months. A commissioning unit can have a high forced outage rate because the newly built or upgraded unit may require a period of testing in order to stabilize it.

Figure 1-23: Forced Outages Relative to Capacity by Fuel Type
January 2003 – April 2011
(% of capacity)



4.5 Changes in Fuel Prices

Tables 1-27 and 1-28 present average monthly coal and natural gas spot prices over the last two reporting periods. On average, coal prices have increased significantly from 2009/2010 levels while natural gas prices have decreased slightly.

4.5.1 *Coal Prices*

Average monthly Central Appalachian (CAPP) and Powder River Basin (PRB) coal spot prices are presented in Table 1-27 for the last two reporting periods.[40] In all months, the coal prices increased compared to one year ago. CAPP coal prices increased from a monthly average of $2.20/MMBtu in 2009/2010 to $2.69/MMBtu in 2010/2011, a rise of

[40] Coal prices have been converted from US$ to CDN$ on a daily basis using the Bank of Canada's noon exchange rate.

22.3 percent. PRB coal prices increased from $0.55/MMBtu last period to $0.67/MMBtu this period, or by 21.8 percent.

Table 1-27: Average Monthly NYMEX Coal Futures Settlement Prices by Type May – April 2009/2010 & 2010/2011 ($CDN/MMBtu)

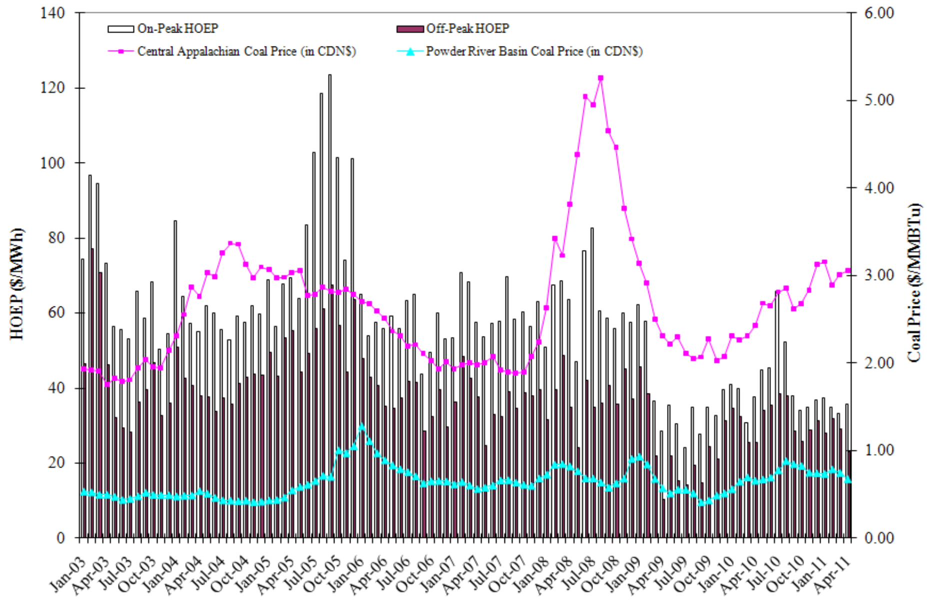
Month	NYMEX Central Appalachian (CAPP) Coal Price			NYMEX Western Rail Powder River Basin (PRB) Coal Price		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
May	2.22	2.69	21.2	0.51	0.67	31.4
June	2.30	2.65	15.2	0.56	0.69	23.2
July	2.11	2.82	33.7	0.55	0.78	41.8
August	2.06	2.86	38.8	0.51	0.89	74.5
September	2.07	2.62	26.6	0.41	0.85	107.3
October	2.27	2.68	18.1	0.43	0.83	93.0
November	2.02	2.84	40.6	0.49	0.75	53.1
December	2.08	3.13	50.5	0.52	0.74	42.3
January	2.31	3.16	36.8	0.56	0.74	32.1
February	2.26	2.89	27.9	0.65	0.79	21.5
March	2.32	3.01	29.7	0.70	0.75	7.1
April	2.44	3.05	25.0	0.66	0.68	3.0
Average	2.20	2.69	22.3	0.55	0.67	21.8

Source: EIA Coal News and Market Reports

Figure 1-24 plots the monthly average CAPP and PRB coal prices, along with the on-peak and off-peak HOEP. Historically the Panel has not found a close correlation between the CAPP/PRB prices and the HOEP.[41] However, in recent periods the on-peak and off-peak HOEP have roughly moved together with the PRB coal price.

[41] The lack of a close relationship between the coal price and the HOEP may be affected by the fact that only a small portion of coal is transacted in the spot market and the spot coal price accounts for only a portion of the final delivery cost (typically a significant portion of final delivery cost is the transportation costs, which can fluctuate from time to time based on transportation fuel costs).

Figure 1-24: Central Appalachian and Powder River Basin Coal Prices and HOEP January 2003 – April 2011 ($/MWh and $/MMBtu)



4.5.2 *Natural Gas Prices*

Natural gas prices, measured by the Henry Hub Spot and Dawn Daily gas prices,[42] are presented in Table 1-28 for the last two reporting periods. On average, both prices decreased from the 2009/2010 reporting period to the current 2010/2011 period. The Henry Hub price declined by $0.17/MMBtu (4 percent) while the Dawn Daily price fell by $0.1/MMBtu (2 percent) year-over-year. Natural gas prices were much higher in the months of June through September, but generally lower in other periods.

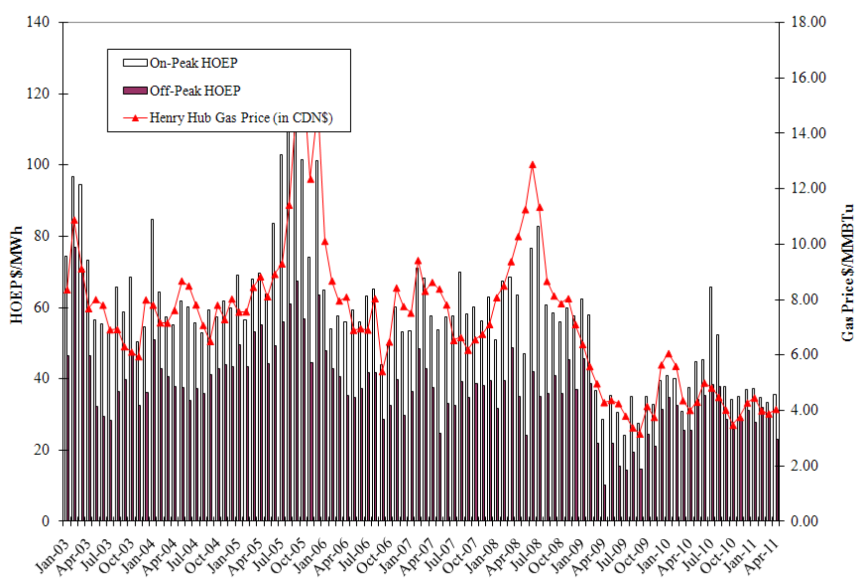
[42] The Henry Hub is a point on the natural gas pipeline located in Erath, Louisiana while the Union Dawn Hub is located near Sarnia, Ontario. Henry Hub prices are converted from US$ to CDN$ on a daily basis using the Bank of Canada’s noon exchange rate.

Table 1-28: Average Monthly Natural Gas Prices May – April 2009/2010 & 2010/2011 ($CDN/MMBtu)

Month	Henry Hub Spot Price			Dawn Daily Gas Price		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
May	4.37	4.31	(1.4)	4.81	4.67	(2.9)
June	4.26	5.01	17.6	4.47	5.30	18.6
July	3.81	4.83	26.8	4.05	5.06	24.9
August	3.39	4.49	32.4	3.53	4.72	33.7
September	3.16	4.03	27.5	3.42	4.44	29.8
October	4.16	3.48	(16.3)	4.76	4.04	(15.1)
November	3.77	3.77	0.0	4.47	4.53	1.3
December	5.65	4.29	(24.1)	6.10	4.70	(23.0)
January	6.07	4.47	(26.4)	6.23	4.86	(22.0)
February	5.60	4.00	(11.0)	5.88	4.47	(24.0)
March	4.37	3.89	(1.0)	4.71	4.39	(6.8)
April	4.01	4.05	(6.7)	4.45	4.45	(0.0)
Average	4.39	4.22	(3.9)	4.74	4.64	(2.1)

Figure 1-25 plots the monthly average Henry Hub spot price (in Canadian dollars) along with the on-peak and off-peak HOEP prices. As the Panel has observed in the past, movements in the HOEP appear to roughly coincide with movements in the spot market gas price.

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP January 2003 – April 2011 ($/MWh and $CDN/MMBtu)



5. Imports and Exports

This section reports the intertie activity based on the unconstrained schedules, which directly affect market prices.[43]

5.1 Overview

Table 1-29 presents monthly net exports (imports) from (to) Ontario during on-peak and off-peak hours. Ontario remained a net exporter during all months for both off-peak and on-peak hours. Off-peak net exports dropped by 877 GWh (14.6 percent) while on-peak net exports rose by 1,028 GWh (33.1 percent). As a result, overall net exports increased 150 GWh (1.6 percent) from 2009/2010 to 2010/2011. When comparing the current period to the previous period, on-peak net exports increased in almost all months (except the first three), while off-peak was more volatile after consistent losses during the first four months.

Table 1-29: Net Exports (Imports), Off-peak and On-peak May – April 2009/2010 & 2010/2011 (GWh)

Month	Off-Peak			On-Peak			Total		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
May	474	34	(92.7)	179	3	(98.4)	652	37	(94.3)
June	734	356	(51.5)	563	299	(46.8)	1,297	655	(49.5)
July	838	330	(60.6)	408	226	(44.7)	1,246	556	(55.4)
August	686	286	(58.3)	210	257	22.3	896	543	(39.4)
September	384	415	8.1	132	507	282.6	516	922	78.5
October	274	540	96.8	105	384	266.3	379	924	143.6
November	478	365	(23.6)	261	424	62.6	738	788	6.8
December	657	859	30.6	395	816	106.6	1,052	1,675	59.2
January	502	671	33.6	301	475	57.8	803	1,146	42.7
February	286	332	16.2	252	290	15.2	538	622	15.7
March	415	379	(8.7)	205	281	36.9	621	660	6.4
April	262	546	108.0	98	176	79.8	360	722	100.4
Total	5,991	5,114	(14.6)	3,108	4,136	33.1	9,100	9,250	1.6

[43] Although the schedules in the constrained sequence are also important to various monitoring and assessment activities, these schedules are related neither to the intertie congestion price nor to the Ontario uniform price (either in pre-dispatch or real-time).

Figure 1-26 reports the long-term trend in net exports since 2003. In the early years, Ontario was a net importer of electricity. Over the years it has become a net exporter as supply conditions in the province have changed.

Figure 1-26: Net Exports (Imports), On-peak and Off-peak January 2003 – April 2011 (GWh)

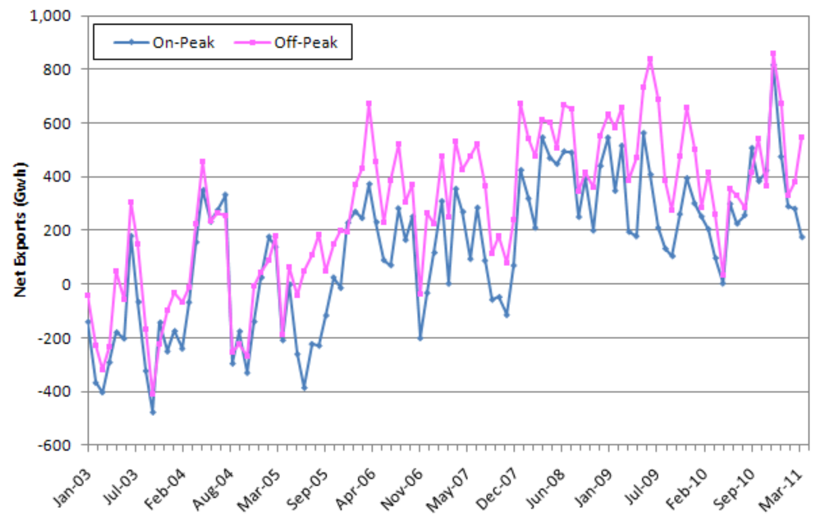


Table 1-30 presents net exports by neighbouring intertie group for the 2009/2010 and 2010/2011 periods. While Table 1-29 showed net exports excluding linked wheeling transactions (which have no impact because each transaction includes a simultaneous injection and withdrawal of energy to and from Ontario, thus netting to zero), linked wheeling transactions do have an impact on the net exports at a specific intertie or intertie group because the import and export legs are scheduled at different interties or intertie groups (i.e. they do not net to zero at a given intertie). Accordingly, Table 1-30 includes each leg of a linked wheel transaction.

Table 1-30: Net Exports (Imports) by Intertie Group
May – April 2009/2010 & 2010/2011
(GWh)

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	(130)	(94)	649	176	(36)	(38)	286	98	(118)	(104)	652	37
June	(133)	(126)	1,206	661	(38)	(43)	351	111	(88)	51	1,297	655
July	(161)	(156)	1,186	222	(15)	(40)	449	276	(213)	254	1,246	556
August	(170)	(172)	891	6	(39)	(35)	454	275	(239)	468	896	543
September	(125)	(156)	737	(158)	(17)	(36)	368	486	(446)	787	516	922
October	(164)	(145)	612	(47)	(32)	(30)	326	283	(364)	863	379	924
November	(141)	(146)	517	45	(16)	(32)	193	78	185	844	738	788
December	(97)	(152)	392	640	(27)	(39)	217	458	567	767	1,052	1,675
January	(110)	(108)	838	703	(33)	(28)	397	364	(288)	215	803	1,146
February	(69)	(120)	905	419	(15)	(18)	104	256	(388)	85	538	622
March	(121)	(139)	931	510	(22)	(22)	144	255	(311)	57	621	660
April	(117)	(118)	367	310	(26)	(16)	311	363	(174)	183	360	722
Total	(1,537)	(1,632)	9,231	3,487	(316)	(377)	3,600	3,303	(1,877)	4,470	9,100	9,250

Although Ontario remained a large net exporter as a whole, the situation varied significantly among interfaces:

- Ontario went from being an annual net importer from Quebec at 1,877 GWh in 2009/2010 to being an annual net exporter of 4,470 GWh in 2010/2011. Quebec was the largest export destination in the past 12 months, accounting for 48.3 percent of net exports.
- Net exports at the Michigan interface dropped from 9,231 GWh to 3,487 GWh, or 37.7 percent of total net exports. It ranked as the largest net exporting interface in 2009/2010 but fell to second largest in 2010/2011. The large decrease was mainly due to exports destined for PJM being curtailed due to congestion in NYISO.[44]
- New York remained a large export market in the past two years, despite an 8.3 percent decline in the volume of net exports.
- Ontario remained a net importer from Manitoba and Minnesota in every month of the 2010/2011 period. This resulted in annual net imports from

[44] For further discussion of the complex interrelationships involving exports and imports between PJM, MISO and New York as well as Lake Erie Circulation ("loop flow"), see the Panel's July 2009 Monitoring Report, pp. 164-181.

Manitoba increasing by 95 GWh (6.2 percent) and Minnesota by 23 GWh (7.3 percent).

Imports and exports are separately reported in Table 1-31 and 1-32, showing totals for each intertie over the last two annual periods. The tables also show the schedules at each intertie excluding linked wheels at that intertie.

5.2 Imports

As reported in Table 1-31, total imports fell to 6,241 GWh, a decrease of 545 GWh or 8 percent compared to last year. Excluding linked-wheel transactions, imports were down by 4.2 percent over the latest 12 month period.

The most significant increase in import volumes occurred at the Michigan interface. Total imports increased from 881 GWh last year to 2,598 GWh this year (or about 195 percent). In contrast, imports from Quebec decreased dramatically, from 3,146 GWh last year to 1,177 GWh this year. The decrease was likely related to dry weather that negatively affected water availability in Quebec (which primarily relies on hydro resources).

Table 1-31: Imports by Intertie
May – April 2009/2010 & 2010/2011
(GWh)

Intertie Group	Total			Total Excluding Linked Wheels		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
Manitoba	1,562	1,663	6.5	1,562	1,663	6.5
Michigan	881	2,598	194.9	880	2,593	194.7
Minnesota	416	417	0.2	416	417	0.2
New York	512	293	(42.8)	381	270	(29.1)
Quebec	3,415	1,270	(62.8)	3,146	1,177	(62.6)
Total	6,786	6,241	(8.0)	6,385	6,120	(4.2)

5.3 Exports

The decrease in total exports from the 2009/2010 to 2010/2011, as shown in Table 1-32, was 395 GWh or 2.5 percent. Excluding linked wheels, the decline was 0.7 percent.

With the exception of at the Quebec and Manitoba interties, total exports were down significantly, whether or not linked wheels are included. With the introduction of the new Quebec Outaouais interface in late 2009, exports to Quebec were up by 273 percent. Total exports at the recently constructed Outaouais interface were 5,462 GWh (not reported in the table), representing 95 percent of total Quebec export volumes.

Table 1-32: Exports from Ontario by Intertie
May – April 2009/2010 & 2010/2011
(GWh)

Intertie Group	Total			Total Excluding Linked Wheels		
	2009/ 2010	2010/ 2011	% Change	2009/ 2010	2010/ 2011	% Change
Manitoba	25	30	20.0	25	30	20.0
Michigan	10,112	6,084	(39.8)	9,717	5,973	(38.5)
Minnesota	100	41	(59.0)	100	41	(59.0)
New York	4,111	3,595	(12.6)	4,106	3,586	(12.7)
Quebec	1,538	5,740	273.2	1,538	5,740	273.2
Total	15,885	15,490	(2.5)	15,486	15,370	(0.7)

5.4 Congestion at Interties

Congestion refers to economic trades at an intertie being limited by the physical 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 intertie capability decreases. The congestion level can be measured by the price difference at both ends of the intertie, which effectively reflects the value of a scarce transmission resource.

Due to the two-sequence design in Ontario, there are two types of congestion: congestion in the constrained sequence and in the unconstrained sequence. Congestion may occur in the constrained sequence without occurring in the unconstrained sequence, or vice versa. Congestion in the constrained sequence reflects the power flow having reached the maximum physical capability allowed for the interface. Congestion in the unconstrained sequence reflects the economic transactions having reached the thermal limit at the interface. The former has little price implication, but traders may be compensated through CMSC payments for constrained-off exports or imports. In contrast, the latter generates a price difference between the external zone and the Ontario zone which is manifested in the Intertie Congestion Price. This section discusses congestion in the unconstrained sequence only, unless otherwise stated.

5.4.1 *Import Congestion*

Table 1-33 reports the number of occurrences of import congestion by month and intertie group over the last two reporting periods. There were notable increases at the Michigan and NYISO interties during the 2010/2011 reporting period, up from 0 hours during the previous reporting period. Congestion at the Manitoba and Minnesota interface increased significantly, from 1,219 hours to 3,813 hours (213 percent) and from 2,523 hours to 4,230 (68 percent), respectively. The substantial increase in import congestion at the Manitoba interface resulted in large part from more traders participating at the interface, possibly incented by the constrained-off payments for imports, while the substantial increase in import congestion at the Minnesota interface is primarily due to a reduction in import capacity at the interface due to outages. Sharply contrasted to other interfaces is the reduction in import congestion at the Quebec interfaces, which showed almost no import congestion in the past reporting period. The reduction is likely a result of a significant increase in intertie capacity at Quebec interfaces due to the introduction of the Outaouais interface in late 2009.

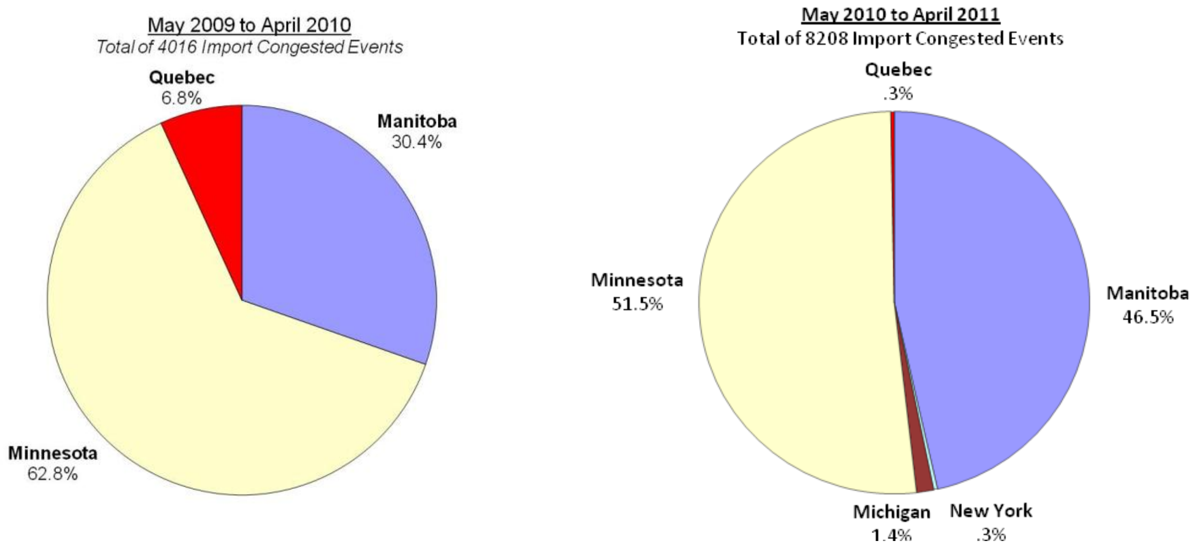
Table 1-33: Import Congestion by Intertie
May – April 2009/2010 & 2010/2011
(number of hours in the unconstrained schedule)

Month	Manitoba		Michigan		Minnesota		New York		Quebec	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	101	320	0	10	84	398	0	25	10	7
June	100	334	0	0	146	427	0	0	4	1
July	61	244	0	3	90	449	0	1	69	6
August	147	471	0	26	259	460	0	0	21	0
September	85	284	0	69	203	288	0	0	107	0
October	54	403	0	0	248	338	0	0	10	4
November	104	336	0	8	203	415	0	0	0	0
December	111	235	0	0	113	303	0	0	0	0
January	241	186	0	0	245	155	0	0	15	1
February	36	409	0	0	237	302	0	0	22	2
March	57	381	0	0	383	404	0	0	7	0
April	122	210	0	0	312	291	0	0	9	2
Total	1,219	3,813	0	116	2,523	4,230	0	26	274	23

Figure 1-27 compares the share of congestion events[45] by intertie group for the 2009/2010 and 2010/2011 reporting periods. Of the 8,760 total hours during the year, there were 8,208 import congested events in 2010/2011, which was more than double the 2009/2010 level. The interfaces in the Northwest, Manitoba, and Minnesota interface account for the vast majority of congestion hours in both periods. The share accounted for by the Manitoba interface increased significantly, with corresponding reductions at Minnesota and Quebec.

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

***Figure 1-27: Share of Import Congestion by Intertie Group
May – April 2009/2010 & 2010/2011
(% of congested events in the unconstrained schedule)***



5.4.2 *Export Congestion*

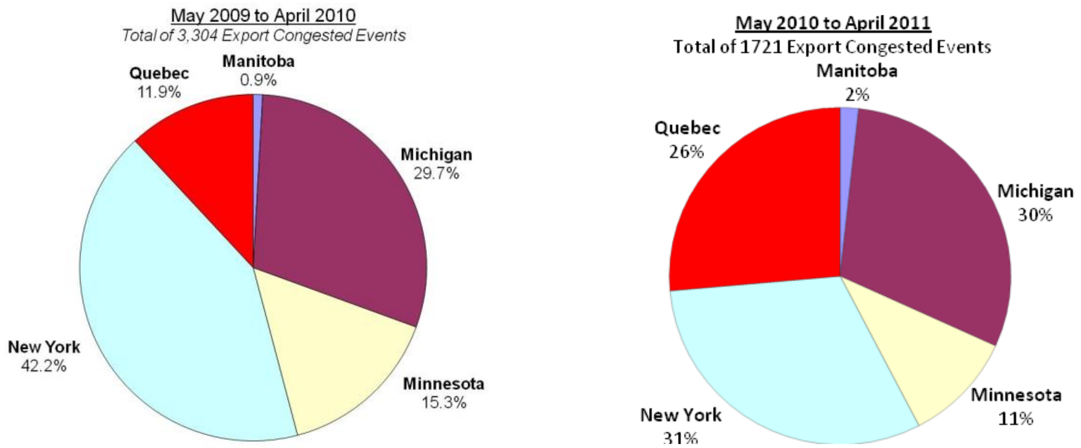
Table 1-34 provides the frequency of export congestion by month and intertie group for the 2009/2010 and 2010/2011 reporting periods. In comparison to 2009/2010, the number of hours that experienced export congestion in 2010/2011 dropped for almost all intertie groups, except Manitoba which was stable and Quebec which saw a modest increase. The significant drops at Michigan, Minnesota, and New York were consistent with the decline in net export volume at these interfaces. On the other hand, despite net exports increasing substantially at the Quebec interfaces, the number of hours with export congestion did not increase materially. This is because the large Outaouis interface is able to move 1,250 MW of energy in either direction before congestion arises.

Table 1-34: Export Congestion by Intertie Group May – April 2009/2010 & 2010/2011 (number of hours in the unconstrained schedule)

Month	Manitoba		Michigan		Minnesota		New York		Quebec	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	0	0	47	15	9	1	125	0	75	7
June	0	1	215	98	3	9	340	5	95	18
July	0	0	225	41	21	3	330	8	18	13
August	0	0	81	19	4	11	185	14	14	22
September	0	0	52	17	150	0	132	101	3	84
October	0	0	26	1	56	3	69	60	0	87
November	9	2	155	64	127	40	35	10	77	89
December	7	11	47	170	46	9	15	169	102	52
January	10	6	53	60	26	12	106	26	8	56
February	1	3	44	19	45	44	3	9	1	1
March	1	1	36	13	12	23	1	1	1	0
April	1	6	0	0	7	27	53	135	0	25
Total	29	30	981	517	506	182	1,394	538	394	454

Figure 1-28 compares the share of frequency of export congestion by intertie group for the last two periods. The total number of exported congestion events declined from 3,301 to 1,721, or by 47.9 percent. The New York interface remained the largest contributor to instances of export congestion, although it experienced a notable decline. The Quebec interfaces had the largest relative increase in the frequency of export congestion, although the number of hours with export congestion did not increase much.

Figure 1-28: Share of Export Congestion Events by Intertie Group May – April 2009/2010 & 2010/2011 (% of congested events in the unconstrained schedule)



5.4.3 *Congestion Rent*

Congestion rent occurs as the result of different market prices at the two ends of an interface with a neighbouring jurisdiction. These price differences are induced by congestion at the interface (i.e. net schedules of economic transactions have reached the maximum thermal limit at the interface), 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 uniform Ontario price, and congestion rent is collected from the exporters which have transactions in the constrained sequence. When there is import congestion, the intertie price falls below the uniform Ontario price, and congestion rent is the result of the lower price paid to importers which have transactions in the constrained sequence, relative to the uniform price.[46]

[46] When a transaction is not scheduled in the constrained sequence but scheduled in the unconstrained sequence, the transaction may be compensated through CMSC and IOG payments. The congestion rent is the price difference between the external zone and the Ontario zone (i.e. Intertie Congestion Price or ICP) times the net schedules (net imports or net exports). For example, an interface has export congestion with an ICP of $10/MWh and net exports are 100MWh, then the congestion rent is $1,000 for the hour.

Tables 1-35 and 1-36 report the congestion rent for the five intertie groups comparing the 2009/2010 and 2010/2011 reporting periods. Congestion rent is calculated as the MW of net imports or net exports that are actually scheduled in the constrained sequence 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 a reduction in the payment made to suppliers of 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 1-35 indicates that total congestion rent for import events increased dramatically by $4.5 million (or 622 percent), from 2009/2010 levels. The Manitoba intertie was almost solely responsible for this leap, which is consistent with the increased participation by traders who may be incented by the possibility of constrained-off payments to imports. The Michigan and New York interface also experienced increases in congestion rent, while the Quebec and Minnesota interface had decreases.

Table 1-35: Import Congestion Rent by Intertie
May – April 2009/2010 & 2010/2011
($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	5	(8)	0	51	(8)	(64)	0	264	0	0	(4)	242
June	75	317	0	0	58	(54)	0	0	0	3	133	266
July	53	628	0	7	13	(85)	0	1	58	57	124	608
August	51	1,114	0	79	(22)	(208)	0	0	42	0	72	984
September	28	522	0	499	14	(23)	0	0	178	0	220	997
October	66	637	0	0	(134)	(22)	0	0	16	0	(52)	615
November	53	550	0	0	(16)	(52)	0	0	0	0	37	497
December	(3)	236	0	0	3	0	0	0	0	0	0	236
January	38	169	0	0	22	13	0	0	27	1	86	182
February	7	204	0	0	(37)	56	0	0	44	1	15	260
March	13	303	0	0	(59)	(208)	0	0	13	0	(33)	94
April	91	340	0	0	5	(142)	0	0	23	1	119	198
Total	478	5,011	0	635	(161)	(788)	0	264	401	63	718	5,186

As can be seen from Table 1-36, total export congestion rent was considerately lower this period at just over $16 million, representing a reduction of almost $10 million or 38 percent. All interties saw significant reductions in export congestion rent except Quebec, which experienced a 293 percent increase. This coincides with a reduction in the number of hours experiencing export congestion at all intertie groups, except for Quebec.

Table 1-36: Export Congestion Rent by Intertie
May – April 2009/2010 & 2010/2011
($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	0	0	549	220	1	0	1,521	0	38	5	2,109	224
June	0	0	3,300	1,598	1	8	2,861	28	436	105	6,597	1,739
July	0	0	3,465	1,383	17	0	1,987	79	2	116	5,470	1,577
August	0	0	1,047	646	2	5	1,105	104	30	342	2,184	1,097
September	0	0	424	197	50	0	637	1,138	2	1,124	1,113	2,458
October	0	0	177	(3)	13	0	279	658	0	838	469	1,493
November	51	0	2,267	0	89	7	225	0	110	858	2,741	865
December	6	2	248	0	42	10	130	0	894	318	1,319	329
January	5	(4)	1,183	1,546	26	8	950	471	25	2,071	2,189	4,092
February	0	0	914	571	21	28	22	144	7	1	964	744
March	0	0	536	179	4	3	0	19	1	0	541	201
April	0	45	0	0	1	8	381	1,072	0	298	382	1,422
Total	62	43	14,109	6,338	266	77	10,097	3,713	1,544	6,076	26,079	16,248

There are several factors which can influence congestion rent since it is based on both the magnitude of actual net flow at the intertie and the Intertie Congestion Price (ICP). ICP is the difference between the uniform Ontario price (HOEP) and the intertie zonal price. It depends on the price of the marginal import or export at the intertie, relative to the marginal resource within Ontario in the unconstrained sequence. The magnitude of the actual net flow is dependent on:

- the maximum capability of the intertie;
- temporary reductions in the intertie capability;
- inadvertent flows, which use up part of (or add to) the intertie capability;
- import or export failures; and
- impact of parallel flow effects resulting from congestion on other transmission lines.[47]

[47] For example, due to congestion at the Queenston Flow West (QFW) interface within Ontario, the scheduled exports or imports at the New York interface may be reduced, even though there is still transfer room at the New York interface.

Congestion rent can be viewed as the risk that an importer may be paid less than the Ontario uniform price or an exporter may be charged more than the uniform price. To hedge the risk, the IESO makes available Transmission Rights (TR), which compensate the TR holder for differences between the intertie and uniform prices. In its August 2010 report, the Panel observed that TR payouts (the non-negative ICP times the TRs that have been sold) generally exceed congestion rent received by the IESO, leading to congestion rent shortfall which has to be offset by TR auction revenue.[48]

Tables 1-37 and 1-38 show TR payouts by intertie for each month of the 2009/2010 and 2010/2011 periods, separately for both import and export congestion. TR payouts for imports totalled $21.3 million, which is up more than $15.5 million (280 percent) over the previous period. The vast majority of the increase occurred at the Manitoba interface which showed a $12 million (347 percent) increase, followed by the Minnesota interface, another interface in the Northwest zone, which had a $2.0 million (121 percent) increase.

Table 1-37: Monthly Import Transmission Rights Payments by Intertie May – April 2009/2010 & 2010/2011 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	451	572	0	357	77	282	0	835	1	180	528	2,226
June	363	774	0	0	107	317	0	0	0	5	471	1,096
July	277	1,628	0	5	104	373	0	1	26	115	408	2,122
August	562	3,123	0	74	265	421	0	0	34	0	861	3,619
September	236	1,186	0	424	84	175	0	0	218	0	537	1,785
October	161	1,874	0	0	173	249	0	0	23	3	358	2,126
November	378	983	0	0	160	420	0	0	0	0	538	1,403
December	214	580	0	0	82	206	0	0	0	0	296	786
January	470	328	0	0	147	81	0	0	44	2	661	410
February	38	2,038	0	0	99	532	0	0	44	1	181	2,571
March	75	1,885	0	0	206	427	0	0	10	0	292	2,312
April	273	657	0	0	172	226	0	0	33	1	478	884
Total	3,498	15,628	0	860	1,677	3,709	0	836	434	307	5,609	21,340

[48] See the Panel's August 2010 Monitoring Report, pp. 140-167.

As presented in Table 1-38, total TR payouts for exports were $17.7 million, which is 46 percent lower than the prior period. As with export congestion rent, export TR payouts dropped at all interties except Quebec and Manitoba due primarily to the reduction in total hours of export congestion (in the unconstrained sequence) across all interties, with the exception of Quebec (Table 1-34). The largest percentage drop by jurisdiction was New York at 76 percent, while the smallest was Minnesota at 29 percent. The largest increase was in Manitoba at 408% from the previous period.

Table 1-38: Monthly Export Transmission Rights Payments by Interface May – April 2009/2010 & 2010/2011 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	0	0	537	159	12	0	1,995	0	71	3	2,615	162
June	0	5	3,332	1776	3	97	4,702	41	507	131	8,545	2,050
July	0	0	3,830	1,588	17	1	3,249	50	3	179	7,099	1,819
August	0	0	1,228	723	2	43	920	77	40	298	2,190	1,142
September	0	0	509	246	647	0	665	1,003	3	974	1,823	2,224
October	0	0	187	16	41	16	300	756	0	826	528	1,614
November	49	1	3,941	0	225	83	136	0	82	810	4,433	894
December	7	19	590	0	224	51	151	0	583	287	1,556	356
January	14	7	1,036	1,843	31	51	1,140	342	20	1,779	2,241	4,023
February	1	1	725	863	174	200	16	96	8	0	925	1,161
March	0	2	476	257	25	139	0	15	1	0	503	414
April	0	326	0	0	10	323	349	950	0	272	359	1,871
Total	71	361	16,391	7,471	1,412	1,004	13,623	3,330	1,318	5,559	32,815	17,730

Tables 1-39 and 1-40 provide the sum of monthly Intertie Congestion Prices (ICPs) by intertie for imports and exports, respectively.[49] The ICP represents the difference in the intertie price and the uniform price, representing the IESO's obligation on TR payouts.

Table 1-39 indicates that the cumulative ICP for imports was higher at every intertie in the recent annual period compared to the year before, particularly at the Manitoba intertie, where the cumulative ICP increased by about $58,000/MW year-over-year (or

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

354 percent). This is consistent with the observed increase in hours of import congestion at the intertie as shown in Table 1-33 above.

Table 1-39: Monthly Cumulative Import Congested Prices by Intertie Group May – April 2009/2010 & 2010/2011 ($/MW-month and $/MW-year)

Month	Manitoba		Michigan		Minnesota		New York		Quebec	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	2,002.5	3,059.5	n/a	431.3	1,149.2	3,134.1	n/a	925.2	16.9	292.9
June	1,780.6	4,140.1	n/a	n/a	1,603.2	3,521.5	n/a	n/a	2.1	5.0
July	1,238.8	7,941.3	n/a	4.7	1,153.6	5,742.2	n/a	0.9	43.8	114.8
August	2,753.2	13,879.7	n/a	80.4	2,949.3	6,481.7	n/a	n/a	74.0	n/a
September	1,154.5	5,786.6	n/a	507.4	1,401.3	2,691.1	n/a	n/a	481.4	n/a
October	790.1	8,329.4	n/a	0.1	2,662.4	2,764.0	n/a	n/a	63.9	9.3
November	1,696.2	4,793.8	n/a	n/a	2,465.4	4,669.5	n/a	n/a	n/a	n/a
December	954.0	2,321.2	n/a	n/a	909.6	2,288.6	n/a	n/a	n/a	n/a
January	1,842.4	1,598.2	n/a	n/a	1,635.3	894.6	n/a	n/a	92.5	1.5
February	218.8	9,943.7	n/a	n/a	1,101.1	5,908.7	n/a	n/a	69.9	2.0
March	434.8	9,197.5	n/a	n/a	2,372.1	4,744.6	n/a	n/a	13.7	n/a
April	1,461.8	3,204.6	n/a	n/a	1,925.1	2,511.5	n/a	n/a	52.3	1.1
Total	16,327.6	74,195.5	0.0	1023.8	21,327.5	45,352.2	0.0	926.13	910.5	426.59

Cumulative ICPs for exports fell at most interfaces this year compared to last year, as reported in Table 1-40. The most significant decline occurred at the New York interface.

Table 1-40: Monthly Cumulative Export Congested Prices by Intertie May – April 2009/2010 & 2010/2011 ($/MW-month and $/MW-year)

Month	Manitoba		Michigan		Minnesota		New York		Quebec	
	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011	2009/ 2010	2010/ 2011
May	n/a	n/a	402.9	151.3	87.8	1.9	2,102.3	n/a	831.3	60.3
June	n/a	35.3	2,353.1	950.0	21.0	691.4	5,538.7	56.4	5,969.3	130.6
July	n/a	n/a	2,637.9	849.3	121.8	13.0	3,900.1	70.0	44.2	179.4
August	n/a	n/a	673.9	386.7	11.3	375.1	1,365.3	107.2	64.0	298.1
September	n/a	n/a	334.8	186.6	4,619.9	n/a	862.1	1,016.7	4.1	985.8
October	n/a	n/a	132.1	14.6	818.4	111.1	367.2	694.8	n/a	846.6
November	2,040.8	6.0	3,481.0	n/a	4,505.3	594.7	250.1	n/a	421.8	825.3
December	40.4	68.0	340.9	n/a	1,601.2	362.8	179.4	n/a	793.1	331.2
January	53.2	45.3	670.0	931.0	224.7	367.1	1,236.8	409.8	26.6	1,739.9
February	9.0	6.7	418.0	436.0	1,245.0	1,431.1	18.8	115.4	10.8	6.0
March	1.0	14.6	274.6	130.0	180.4	992.0	0.2	17.7	0.9	n/a
April	1.2	2,173.5	n/a	n/a	69.8	2,304.3	502.5	2,000.9	n/a	325.0
Total	2,145.5	2,349.4	11,719.2	4,035.4	13,506.6	7,244.4	16,323.4	4,488.8	8,166.2	5,728.0

5.5 Wholesale Electricity Prices in Neighbouring Markets

5.5.1 Price Comparisons

Table 1-41 provides average wholesale market prices for Ontario and neighbouring jurisdictions over the last two reporting periods. [50] For several years, energy prices in Ontario have generally been the lowest of the five jurisdictions. In the past period, however, the Ontario price was slightly higher than the Michigan price, in both on-peak and off-peak hours. All markets saw an annual average price increase, with the Ontario market experiencing the largest percentage increase.

Table 1-41: Average HOEP Relative to Neighbouring Market Prices May – April 2009/2010 & 2010/2011 ($CDN/MWh)

Markets	All Hours			On-peak Hours			Off-peak Hours		
	2009/2010	2010/2011	% Change	2009/2010	2010/2011	% Change	2009/2010	2010/2011	% Change
Ontario - HOEP	28.3	35.64	25.9	34.10	41.19	20.8	23.44	31.01	32.3
MISO – ONT	30.44	34.13	12.1	36.59	40.87	11.7	25.30	28.52	12.7
NYISO – Zone OH	32.14	39.78	23.8	35.67	44.73	25.4	29.23	35.64	21.9
PJM – IMO	37.84	43.94	16.1	42.66	51.22	20.1	33.79	37.87	12.1
New England – Internal Hub	44.79	52.36	16.9	48.93	59.88	22.4	41.33	46.11	11.6
Average	34.70	41.17	18.6	39.59	47.58	20.2	30.62	35.83	17.0

*All $US amounts converted to $CDN at Bank of Canada noon exchange rates.

Figures 1-29 to 1-31 compare monthly average prices for Ontario and its neighbouring jurisdictions for the current reporting period, for all hours, on-peak hours, and off-peak hours respectively. The Richview shadow price is also shown since it is generally regarded as a more accurate indicator of the marginal cost of incremental output, particularly in southern Ontario. Ontario HOEP experienced no major diversions from

[50] To make these figures more comparable, all dollar values have been converted to Canadian dollars using the daily noon exchange rate published by the Bank of Canada. However, 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 customers to pay capacity charges.

other jurisdictional prices. Only New England, and to an extent PJM, diverged considerably from the group. New England is typically more expensive than other markets in northeastern North America. Ontario HOEP has been consistently lower than all jurisdictions except Michigan.

Figure 1-29: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, All Hours May 2010 – April 2011 ($CDN/MWh)

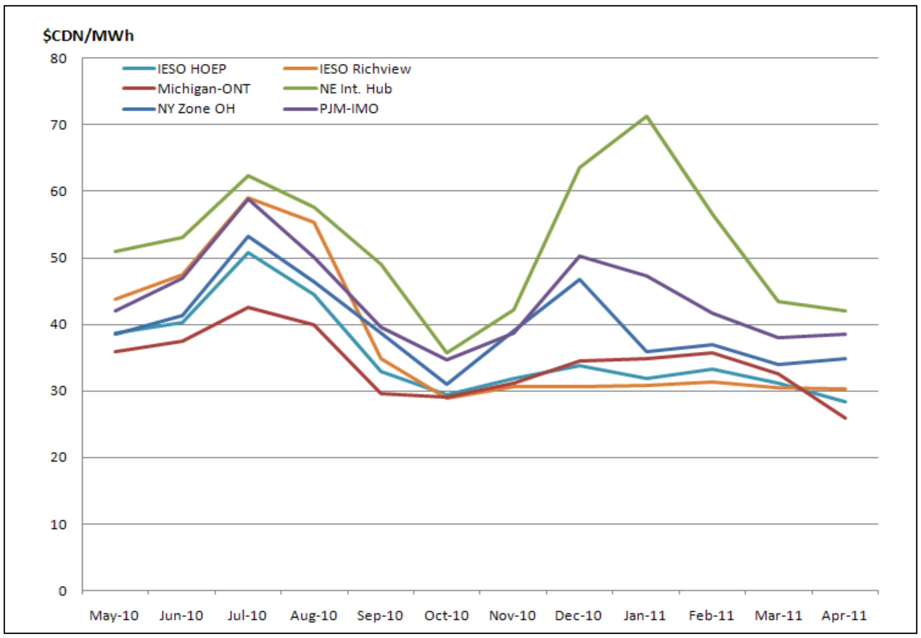


Figure 1-30: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, On-Peak May 2010 – April 2011 ($CDN/MWh)

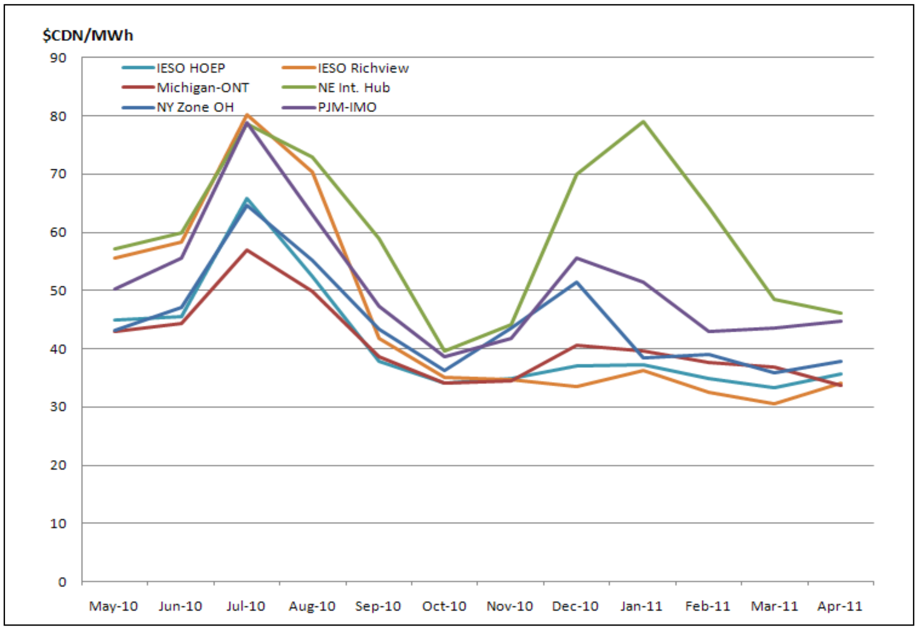
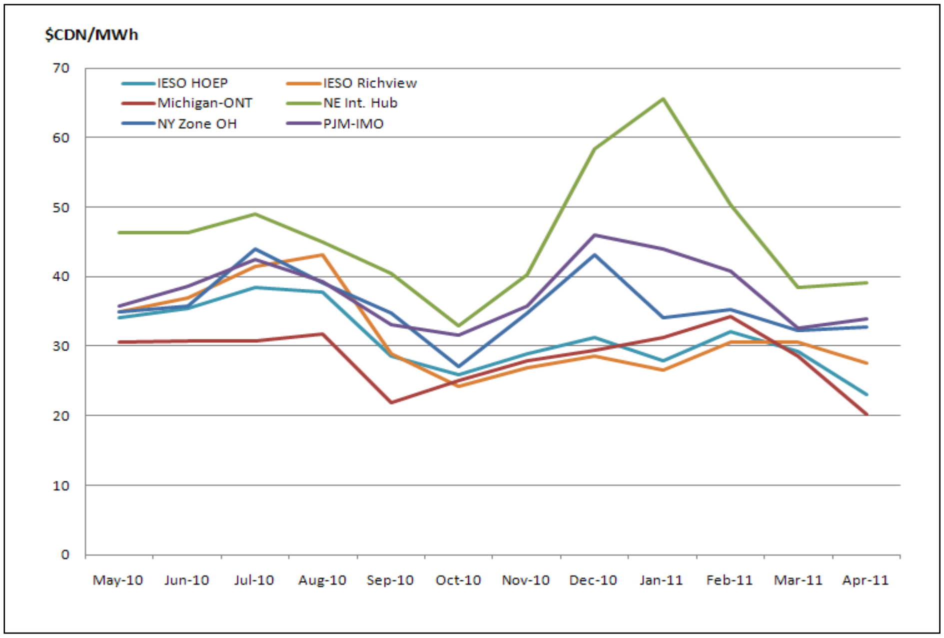


Figure 1-31: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, Off-Peak
May 2010 – April 2011
($CDN/MWh)



The foregoing charts also indicate that the Ontario HOEP was generally higher than the Richview zonal price in the latter months of the reporting period, which is very different from what has been observed in the past. Possible explanations for the shift may include, but are not limited to (1) a dry summer that led to less hydro generation being constrained-off,[51] and (2) the addition of gas-fired generation with their minimum loading point (MLP) quantity placed at the bottom of the supply stack when the Richview price is calculated, but economically stacked when the HOEP is calculated.[52]

[51] Low water availability tends to increase the HOEP relative to the Richview zonal price and thus reduces the gap when the HOEP is typically lower than the Richview price.

[52] More frequent operation of gas generators (which tend to have large MLPs) would reduce the Richview (and other) nodal prices, as their MLP quantities, (at whatever price it is offered) will be placed at the bottom of the supply stack when the constrained schedule is established, but in the middle of the supply stack (based on their offer price) when the HOEP is calculated. This reduces the Richview price and nodal prices relative to the HOEP.

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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 behaviours. Anomalous events are typically high-price or low-price hours (as defined below) or hours with high CMSC payments to market participants. Anomalous behaviours are actions by market participants or the IESO that may lead to market outcomes that fall outside of predictable patterns or norms.

The MAU monitors and reports to the Panel both high-price and low-price hours as well as other events that appear to be anomalous given the circumstances. The Panel believes that an explanation of these events provides transparency with respect to why certain outcomes occurred in the market, leading to learning by all market participants. As a result of this monitoring, the MSP may recommend changes to market rules, program design, or the tools and procedures that the IESO employs.

The MAU reviews the previous day's operations and market outcomes on a daily basis, 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 among market outcomes in Ontario and neighbouring markets.

The daily review process is an important part of market monitoring. Identification of anomalous events may lead to discussion with the relevant market participants, the IESO and/or other relevant parties. Certain events may trigger more detailed examinations or a formal investigation of potential abuse of market power, gaming or efficiency issues.

The Panel defines high-price hours as all hours in which the HOEP is greater than $200/MWh and low-price hours as all hours in which the HOEP is less than $20/MWh,[53] including negative-price hours.

There was one hour during the latest six-month review period (November 2010 - April 2011) where the HOEP was greater than $200/MWh. Section 2.1 of this chapter summarizes this event and the factors contributing to this high HOEP.

Between November 2010 and April 2011, there were 515 hours (11.9% of all hours) during which the HOEP was less than $20/MWh, including 53 hours (1.2% of all hours) where the HOEP was negative. The reporting period also included new records for negative prices. On January 1, 2011 the average daily HOEP set a new record low of -$20.24/MWh,[54] including the second lowest HOEP since market opening of -$138.43/MWh. April 30, 2011, hour-ending (HE) 24 set a new record low HOEP of -$138.79/MWh. Section 2.2 of this Chapter reviews the factors that typically drive prices to low levels. In addition, section 2.2 provides an assessment of: (i) the -$138.79/MWh HOEP on April 30, HE 24; (ii) the -$138.43/MWh HOEP on January 1, HE 9; and (iii) general conditions prevailing on January 1, 2011 that contributed to the record low average daily HOEP of -$20.24/MWh.

In addition to high-price and low-price hours, the Panel reports on anomalous uplift payments in excess of $500,000/hour for Congestion Management Settlement Credits (CMSC), $500,000 for Intertie Offer Guarantees (IOG) and $100,000/hour for operating reserve (OR) payments. Daily payments of $1,000,000 for CMSC or IOG in the intertie

[53] Depending on fuel prices, $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.
[54] Since market opening there have been 10 negative average daily HOEPs, including January 1, 2011.

zones are also considered anomalous.[55] No hours met any of these criteria for the period November 2010 to April 2011.

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 high prices. More importantly, it serves the purpose of determining whether further analysis of the design or operation of the market or market participant conduct is warranted.

Table 2-1 depicts the total number of hours per month where HOEP exceeded $200/MWh for the last four winter periods.

***Table 2-1: Number of Hours with a High HOEP
November – April, 2007/08 – 2010/11
(number of hours)***

	Number of Hours with HOEP >$200/MWh			
Month	**2007 /2008**	**2008 /2009**	**2009 /2010**	**2010 /2011**
November	0	0	0	0
December	0	2	0	0
January	0	3	1	0
February	1	2	0	0
March	0	1	0	0
April	1	0	0	1
Total	**2**	**8**	**1**	**1**

Prices change when the equilibrium between real-time supply and real-time demand changes.[56] The following are the most common direct contributors to a HOEP greater than $200/MWh:

- one or more imports fail after the final one hour-ahead pre-dispatch run;

[55] See the Panel's January 2009 Monitoring Report, pp. 178-184.

[56] Only changes that impact the unconstrained schedule will affect market prices. Changes that impact the constrained schedule but not the unconstrained schedule will affect CMSC payments (and "shadow" or nodal prices), but will not affect the MCP or the HOEP.

- one or more generating units are derated or forced out of service;
- infra-marginal generators reduce their quantity offered relative to the previous hour,[57] and/or
- net exports increase significantly relative to the previous hour.

The first two contributors relate to real-time losses of supply and are typically unpredictable.

The third factor, while at times predictable, can still lead to a sudden steepening of the supply curve from one hour to the next. When infra-marginal supply is removed from the unconstrained schedule the market must replace it with other, more expensive generation in order to meet demand.[58] This higher-priced generation causes the market price to increase but a large price increase will only occur when the supply stack is steep (i.e. the selected replacement supply is offered at a price that is significantly higher than the supply offered by the generator that had been the marginal resource prior to the real-time loss in supply).

The fourth factor that is commonly a direct contributor to high prices is a significant increase in net exports. Unlike domestic demand, which usually changes gradually and can be matched with supply on a five-minute basis, exports and imports are scheduled on an hourly basis. Accordingly, when there is an increase in net exports (i.e. exports less imports) the entire increase in demand materializes at the top of the hour. The IESO must account for this increase in demand in the unconstrained schedule in interval 1 of the hour. For example, a 500 MW increase in net exports from the previous hour means that, all else being equal, the IESO must move up the unconstrained supply stack by 500 MW by the end of the first interval of the hour.

[57] For example, a peaking hydro facility may have offered stored water in previous hours but once the stored water has been used it can no longer be offered as capacity.

[58] Real-time replacement of unconstrained supply cannot come from imports as imports are scheduled on an hourly basis, whereas generation is scheduled on a five minute basis. The availability of imports in subsequent hours typically prevents high prices (i.e. above $200/MWh) from enduring over multiple hours. Higher prices could endure, however, where there is supply scarcity in neighbouring markets as well as in Ontario.

Significant increases in net exports are sometimes caused by pre-dispatch supply forecast inaccuracies from self-scheduling and intermittent generators (primarily wind generators and non-utility generators (NUGs)) and/or by the IESO's pre-dispatch Ontario demand forecast inaccuracies. If real-time Ontario demand is under-forecast and/or self-scheduling supply is over-forecast, all else being equal, this will have the effect of suppressing pre-dispatch prices, which in turn encourages an increase in exports and/or a decrease in imports, (i.e. an increase in net exports) relative to the previous hour.

Low pre-dispatch prices can also indirectly contribute to high real-time prices. To the extent that generator expectations for real-time earnings are informed by pre-dispatch prices, generators may increase their offer prices to come offline (when they are not under any sort of cost guarantee programs). When non quick-start generators[59] come offline, their supply is no longer available and is removed from the unconstrained supply stack, thereby steepening the supply stack. A HOEP above $200/MWh is most likely to occur when the real-time supply cushion falls below 10 percent.[60]

2.1.1 *April 27, 2011 HE 22*

On Wednesday April 27, 2011 HE 22, the HOEP spiked to $410.70/MWh from $74.52/MWh in the previous hour. During the first three intervals of the hour, the five-minute MCPs were $2,000/MWh, $2,000/MWh and $516.72/MWh, respectively. In the fourth interval the MCP dropped to $130.00/MWh. In the fifth interval, the IESO curtailed 532 MW of exports for system adequacy reasons and the five-minute MCP

[59] Non-quick start generators are defined by the IESO as generating units that cannot synchronize and follow a dispatch instruction within a 5-minute dispatch interval (http://www.ieso.ca/imoweb/pubs/training/QT9_SGOL.pdf). For example nuclear, coal and some gas generators require a set amount of lead time before the unit can be brought online. Accordingly, when these units come offline, under normal circumstances, the IESO removes the supply from the unconstrained (and constrained) schedule.

[60] Generally speaking, the supply cushion is the excess supply above total demand (including operating reserve requirements) divided by total demand. The Panel's March 2003 Monitoring Report (pp. 11-16) 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, pp. 79-81. It remains the case that when the supply cushion is below 10 percent, a price spike becomes increasingly likely. For more information on the supply cushion, see Chapter 1 section 4.2.

dropped to $59.13/MWh. In each of the remaining seven intervals in the hour the MCP never exceeded $50/MWh, and by the final two intervals of the hour the MCP was less than $15/MWh. In addition to the export curtailment in interval 5, domestic demand declined by 1,133 MW over the hour.

The primary reason for the price spike was a 691 MW increase in net exports, only 9 MW less than the net inter-scheduling limit (NISL).[61] The spike in net exports appears to have been induced by price differences between Ontario and external markets, which in turn was signaled by low pre-dispatch prices in Ontario several hours ahead (as shown in Table 2-3 below). Pre-dispatch prices were depressed because self-scheduling and intermittent generators had significantly over-forecast their output and (to a lesser extent) Ontario demand had been under-forecast. In addition, the low pre-dispatch prices also signaled to some generators that they might be uneconomic in HE 22 and beyond. In HE 21, a combined cycle facility capable of providing approximately 940 MW of capacity shut down after its minimum run time.[62]

A more detailed assessment of the factors contributing to the price spike is set out below.

Prices, Demand and Supply

Table 2-2 lists real-time MCP, Ontario demand, and net exports for HE 21 and HE 22 on April 27, 2011.

[61] Net Intertie Scheduling Limit (NISL) is the maximum allowable change in net scheduled intertie transactions from the previous hourly schedule. The 700 MW limit is set so as to prevent sudden shifts in supply/demand from one hour to the next that could create system operability challenges. During circumstances of surplus baseload generation, the IESO may raise the NISL to 1,000 MW. For additional information and analysis about the NISL, see the Panel's July 2007 Monitoring Report, pp. 97-100.
[62] Two hours earlier another combined cycle facility had shut down after its minimum run time, removing approximately 440 MW of available capacity.

Table 2-2: Real-Time Market Clearing Price and Demand April 27, 2011, HE 21 and 22 (MW and $/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Real-Time Ontario Demand (MW)	Real-Time Net Exports (MW)	Real-Time Ontario Demand plus Net Exports (MW)	Change in Ontario Demand plus Net Exports from Previous Interval (MW)	Average Change in Net Exports from Previous Hour (MW)
21	1	55.23	16,508	378	16,886	(636)	(339)
21	2	60.10	16,530	378	16,908	22	(339)
21	3	85.10	16,499	378	16,877	(31)	(339)
21	4	149.00	16,492	378	16,870	(7)	(339)
21	5	135.00	16,351	378	16,729	(141)	(339)
21	6	60.10	16,208	378	16,586	(143)	(339)
21	7	57.23	16,162	378	16,540	(46)	(339)
21	8	60.10	16,176	378	16,554	14	(339)
21	9	57.23	16,123	378	16,501	(53)	(339)
21	10	60.10	16,137	378	16,515	14	(339)
21	11	60.10	16,107	378	16,485	(30)	(339)
21	12	55.00	15,974	378	16,352	(133)	(339)
Average		**$74.52**	**16,272**	**378**	**16,650**	**(97)**	**(339)**
22	1	2,000.00	15,805	1,069	16,874	522	691
22	2	2,000.00	15,803	1,069	16,872	(2)	691
22	3	516.72	15,620	1,069	16,689	(183)	691
22	4	130.00	15,223	1,069	16,292	(397)	691
22	5	59.13	15,409	537	15,946	(346)	159
22	6	48.31	15,328	537	15,865	(81)	159
22	7	47.87	15,263	537	15,800	(65)	159
22	8	31.48	15,223	537	15,760	(40)	159
22	9	47.87	15,075	537	15,612	(148)	159
22	10	18.31	14,924	537	15,461	(151)	159
22	11	14.37	14,798	537	15,335	(126)	159
22	12	14.31	14,672	537	15,209	(126)	159
Average		**$410.70**	**15,262**	**714**	**15,976**	**(95)**	**336**

In HE 21, the HOEP was $74.52/MWh but by interval 12 the MCP had fallen to $55/MWh. At the beginning of HE 22, however, real-time Ontario demand plus net exports surged by 522 MW reflecting the 691 MW increase in net exports (partially offset by a 169 MW decline in Ontario demand).

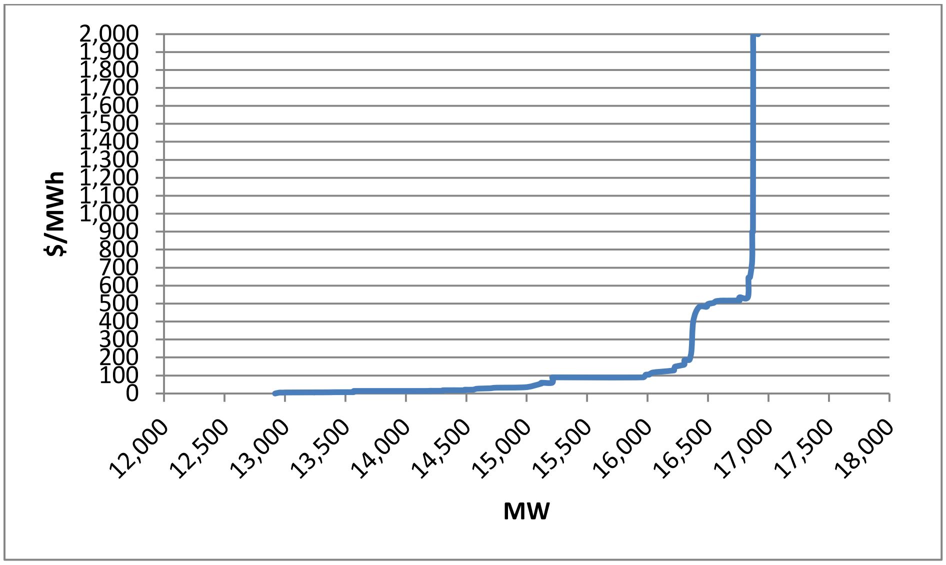
The increase in net exports is not surprising given that the pre-dispatch prices were low in the lead-up to HE 22, suggesting potential arbitrage opportunities for intertie traders. Table 2-3 below shows that the pre-dispatch price forecast five hours and four hours in advance of HE 22 was approximately $14/MWh, the three-hour ahead PD price which preceded the close of the offer/bid window was $22.90/MWh and in the final pre-dispatch run price was $25.20/MWh.

Table 2-3: Pre-dispatch Prices, Ontario Demand, and Exports/Imports April 27, 2011, HE 22 (MW and $/MWh, five to one hour ahead)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Notable Events
5	$14.29	15,270	609	964	355	
4	14.18	15,270	609	964	355	
3	22.90	15,518	594	1,346	752	440 MW combined cycle facility shut down
2	32.27	15,509	654	1,596	942	
1	25.20	15,145	602	1,671	1,069	940 MW combined cycle facility shut down

The lack of available coal-fired and gas-fired supply in HE 22 contributed to a steep real-time energy offer curve above approximately 16,300 MW and shortage pricing above approximately 16,800 MW. See Figure 2-1 below. Because of low projected prices in the late afternoon hours, several large gas-fired generators were sequentially shut down after their generation cost guarantee commitment with the IESO had expired. These generators and other fossil-fired generators were not quick-start supply sources and were not available in HE 22. They also did not appear to be needed given the low pre-dispatch prices at the relevant start-up lead times.

Figure 2-1: Real-time Energy Offer Curve
April 27, 2011, HE 22
($/MWh)



Ontario demand plus net exports increased by 522 MW from interval 12 of HE 21 to interval 1 of HE 22. The 522 MW interval-to-interval increase resulted in two intervals of shortage pricing ($2,000/MWh). Hydroelectric and gas-fired facilities were the marginal resources in the remaining intervals. See Table 2-4 below.

Table 2-4: Real-time MCP and Fuel Type of Price Setting Resource
April 27, 2011, HE 22
($/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)
22	1	2000.00	Shortage Pricing
22	2	2000.00	Shortage pricing
22	3	516.72	Hydroelectric
22	4	130.00	Hydroelectric
22	5	59.13	Gas
22	6	48.31	Hydroelectric
22	7	47.87	Hydroelectric
22	8	31.48	Gas
22	9	47.87	Hydroelectric
22	10	18.31	Hydroelectric
22	11	14.37	Hydroelectric
22	12	14.31	Hydroelectric
Average		410.70	

Pre-dispatch Demand and Wind Generation Forecasts

As noted above, inaccurate pre-dispatch self-scheduling and intermittent (particularly wind) supply forecasts and inaccurate IESO pre-dispatch demand forecasts can contribute to a price spike in real-time. An over-forecast of supply and/or an under-forecast of demand will depress the pre-dispatch price. (The opposite phenomenon can occur when there are under-forecasts of supply and / or over-forecasts of demand, causing the price to plunge.[63])

In real-time the combination of a large change in demand (often attributable to a change in net exports across the top of the hour) and a steeper real-time supply curve can cause a severe price spike, as occurred on April 27 HE 22.[64] The existing methodologies for forecasting pre-dispatch self-scheduling supply and pre-dispatch Ontario demand each directly contributed to this price spike.

Pre-Dispatch Wind Forecast Discrepancy

Pre-dispatch self-scheduling and intermittent generation forecasts (primarily for wind resources[65]) contribute to inaccurate pre-dispatch price projection in two ways.

First, there are often large differences between the pre-dispatch wind forecast and real-time actual production levels.[66] During HE 22, for example, self-scheduling and intermittent generators produced 667 MW less than had been projected one hour ahead.

[63] For an example of such a downward pricing suppression effect, see section 2.2 below.
[64] Similarly, an inflated pre-dispatch price may signal import arbitrage opportunities and lead to an increase in net imports.
[65] Because the majority of self-scheduling and intermittent generation forecast error is from wind generators, this section focuses on the wind forecast error.
[66] In a previous report, the Panel had identified the lack of incentives for wind generators to provide an accurate forecast and encouraged the IESO to review the process for wind forecasting. The inaccuracy of the forecasts was largely attributable to the current decentralized approach to wind forecasting, whereby each individual wind generator submits a pre-dispatch supply forecast (and there are no economic or operational consequences for the generator related to the level of accuracy of the forecast). As recommended by the Panel in its January 2009 Monitoring Report (pp. 253 - 256), the IESO is moving toward adopting a centralized forecasting model, whereby each individual wind farm will provide meteorological and output data to a single forecasting entity, which in turn will develop the pre-dispatch wind supply forecast. For more information, see: http://ieso.ca/imoweb/pubs/consult/se57/se57-20090616-Centralized-Wind-Forecasting.pdf and http://ieso.ca/imoweb/consult/consult_se91.asp.

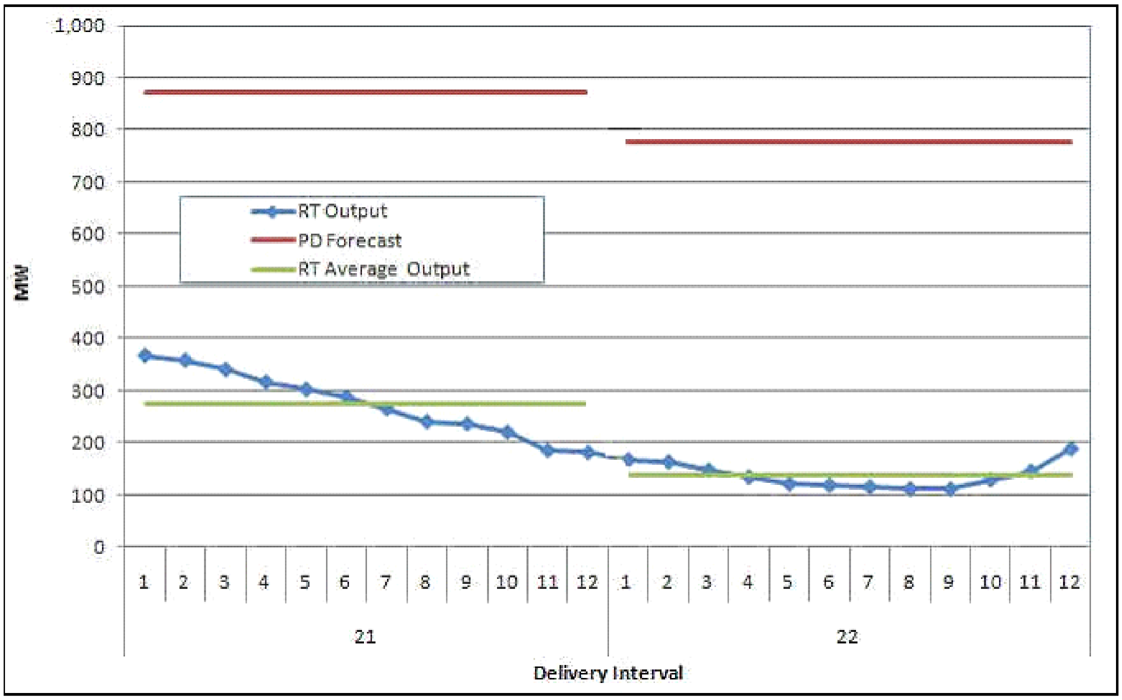
Over 90 per cent of the forecast inaccuracy (616 MW) was attributable to wind generators. Wind generators in aggregate had forecast an average output of 775 MW one hour ahead but produced at an average rate of only 159 MW (about 20 percent of the forecast level) in real-time. The inclusion of this 616 MW of unrealized supply in the pre-dispatch supply forecast depressed pre-dispatch prices and contributed to the scheduling of the large increase in net exports.

Second, wind (and other self-scheduling and intermittent generators) pre-dispatch supply forecasts take the form of an hourly forecast that reflects the expected average output over the hour. In some hours when the wind power generation was relatively stable, the actual average is close to the interval output (e.g. HE 22). Had the average wind output been forecast accurately, the average forecast would have been a good prediction of interval output. In contrast, in other hours when wind output is increasing or decreasing significantly during the hour, there are significant discrepancies for individual intervals between the projected average output and interval output. For example, in HE 21 on April 27, 2011, wind output steadily declined across the hour from a high of 367 MW in interval 1 to a low of 181 MW in interval 12, a decline of more than 50%. Even if the actual hourly average of 275 MW had been correctly forecast, actual output would have varied significantly from forecast output, especially in the first interval (which was 33 percent above the average) and the final interval (which was 34 percent below the average).

Absent changes to forecasting methodologies, the distortive effect of both these sources of discrepancies on pre-dispatch prices is expected to increase as installed wind capacity in Ontario increases.

Figure 2-2 below illustrates the two components of wind generation forecast discrepancies in the context of April 27, 2011 HE 21 and 22. In both hours real-time wind output was significantly over-forecast (the red line vs. the green line) and the interval output varied from the average output (the green line vs. the blue line), especially for HE 21.

Figure 2-2: Hourly and Interval Wind Generation Forecast and Actual Supply
April 27, 2011, HE 21 and 22
(MW)



The IESO currently publishes each generator's output one hour after the dispatch hour. [67] It also publishes the hourly pre-dispatch prices for the coming hours. Making this data transparent to the market helps market participants form their real-time price expectations and thus enables more efficient production, consumption or intertie trading decisions.

[67] Along with the actual output, the IESO publishes the available capacity of each generator. In the case of wind resources, the available capacity is their installed capacity, i.e. their maximum output capability.

As discussed above, however, the pre-dispatch prices may be distorted (sometimes significantly distorted) by the under- or over-forecast of wind generation. The Panel understands that market participants do not make business decisions entirely on the pre-dispatch prices. Market participants have incentives to make their business decisions based on their own expectation of the real-time prices. The Panel believes that a transparent wind output forecast would improve the rationality of such price expectations and promote more efficient supply/demand decisions. For example, a market participant may discount the pre-dispatch price if he or she has observed persistent over-forecasting by wind generation. Given that each pre-dispatch uses the most up to date supply forecasts, the publication of the aggregate wind output forecast would ideally accompany each pre-dispatch run and cover the same number of future hours as under the time horizon of the pre-dispatch..

Following the Panel's recommendation regarding centralized wind forecasting,[68] the IESO has conducted a lengthy consultation and has passed all necessary Market Rule changes related to the technical requirements for wind generation facilities and cost recovery. The Panel has been advised that the centralized wind forecast functionality is expected to be in place at the end of 2012 and the IESO intends to publish the wind forecast data thereafter, with the publication frequency and details yet to be determined. In the Panel's view, publication of aggregate wind forecast need not await the introduction of centralized wind forecasting.

Recommendation 2-1

The Panel recommends that the IESO publish the most current aggregate wind generation forecast information that is available. The published information should be updated on an hourly basis and should cover all future hours for which wind generation forecasts are available.

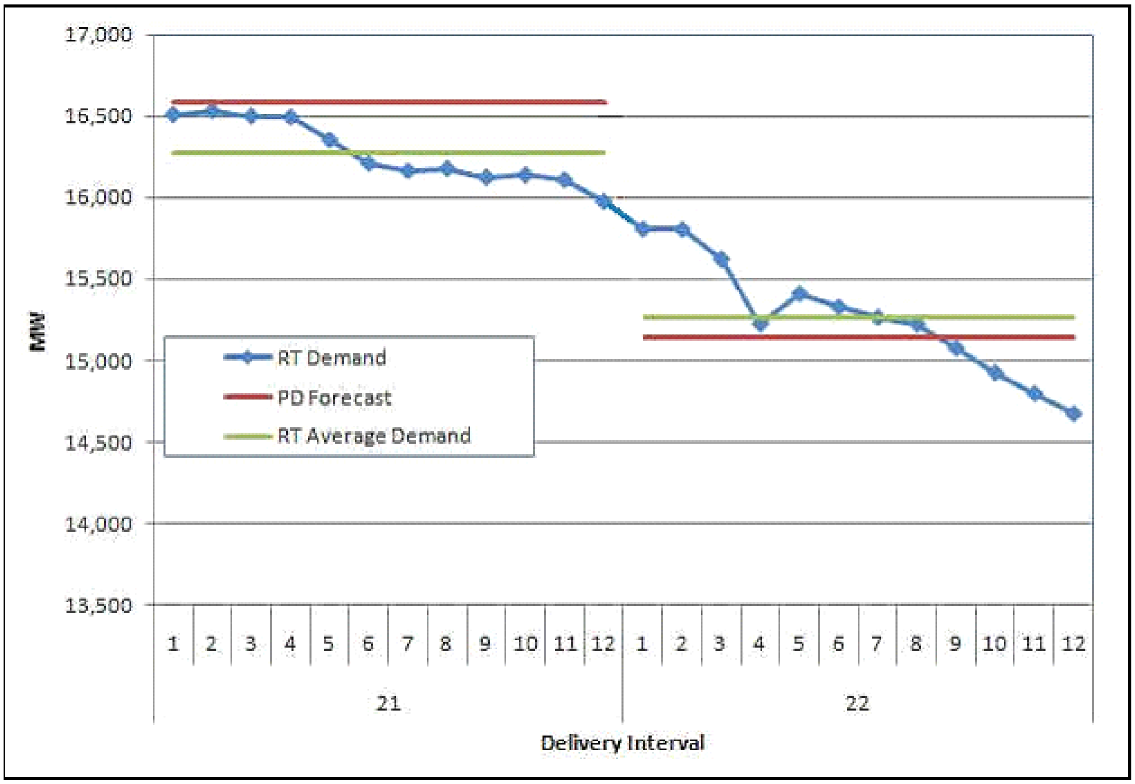
[68] The Panel's January 2009 Monitoring Report, pp 253-256.

Pre-Dispatch Demand Forecast Discrepancy

As with pre-dispatch self-scheduling and intermittent supply forecasts, an hourly pre-dispatch Ontario demand forecast cannot capture dynamic changes in interval demand within an hour. An accurate hourly forecast will be relatively accurate for individual intervals during hours when the system demand is not ramping up or down significantly. However, when real-time demand is changing significantly across the hour, even an accurate average demand forecast will not reflect interval-by-interval demand, which may vary greatly from the average demand forecast for the hour. For example, when demand is steadily dropping over the hour (like the current study hour), the demand in the first few intervals will be significantly higher than the average demand while the demand in the last few intervals will be significantly lower than the average demand.

Figure 2-3 below depicts the pre-dispatch demand forecast and the real-time interval and average demand for April 27, 2011 HE 21 and HE 22. In HE 22, average real-time demand was only slightly higher than the pre-dispatch average demand forecast. However, in HE 22 demand declined by 1,133 MW from a peak of 15,805 MW in interval 1 to a low of 14,672 MW in interval 12, a decline of 7.2%. The use of an average hourly Ontario pre-dispatch demand forecast resulted in demand being 660 MW higher than forecast in interval 1 (a 4.4% discrepancy) and 473 MW lower than forecast in interval 12 (a 3.1% discrepancy).

Figure 2-3: Hourly and Interval Forecast and Actual Demand
April 27, 2011, HE 21 and 22
(MW)



Combined Effect of Supply Over-forecast and Demand Under-forecast

Table 2-5 below shows the interval-by-interval difference between real-time Ontario demand and the hourly Ontario demand forecast, as well as wind forecast supply and output[69] for HE 21 and HE 22 on April 27, 2011. The last column of the table shows on an interval-by-interval basis the total pre-dispatch forecast discrepancy. For example, in interval 1 HE 22, real-time Ontario demand was 660 MW higher than forecast average demand and real-time wind supply was 608 MW lower than forecast in pre-dispatch, leading to 1,268 MW discrepancy in the interval compared to the hourly PD demand/supply forecast. Market efficiency can be improved if the pre-dispatch frequency is increased, as will be discussed further below.

[69] Wind power is reported here because it accounted for the vast majority of the self-scheduling and intermittent generation error.

Table 2-5: Differences between the Pre-Dispatch Forecast and Real-Time Actual Wind Output and Ontario Demand April 27, 2011, HE 21 and 22 (MW)

HE	Interval	Pre-dispatch Ontario Demand	Real-time Ontario Demand	Ontario Demand Difference	Pre-dispatch Wind Forecast	Real-Time Wind Output	Pre-dispatch Wind Forecast vs. Output Difference	Total Pre-dispatch Forecast Inaccuracy
21	1	16,654	16,508	(146)	871	366.5	(504.5)	(358.5)
21	2	16,654	16,530	(124)	871	358.0	(513.0)	(389)
21	3	16,654	16,499	(155)	871	340.1	(530.9)	(375.9)
21	4	16,654	16,492	(162)	871	316.1	(554.9)	(392.9)
21	5	16,654	16,351	(303)	871	302.1	(568.9)	(265.9)
21	6	16,654	16,208	(446)	871	287.9	(583.1)	(137.1)
21	7	16,654	16,162	(492)	871	265.1	(605.9)	(113.9)
21	8	16,654	16,176	(478)	871	240.3	(630.7)	(152.7)
21	9	16,654	16,123	(531)	871	236.1	(634.9)	(103.9)
21	10	16,654	16,137	(517)	871	220.3	(650.7)	(133.7)
21	11	16,654	16,107	(547)	871	184.9	(686.1)	(139.1)
21	12	16,654	15,974	(680)	871	181.4	(689.6)	(9.6)
Average		**16,654**	**16,272**	**(382)**	**871**	**274.9**	**(596.1)**	**(214.1)**
22	1	15,145	15,805	660	775	166.7	(608.3)	(1268.3)
22	2	15,145	15,803	658	775	163.3	(611.7)	(1269.7)
22	3	15,145	15,620	475	775	147.1	(627.9)	(1102.9)
22	4	15,145	15,223	78	775	134.2	(640.8)	(718.8)
22	5	15,145	15,409	264	775	121.0	(654.0)	(918)
22	6	15,145	15,328	183	775	118.4	(656.6)	(839.6)
22	7	15,145	15,263	118	775	115.4	(659.6)	(777.6)
22	8	15,145	15,223	78	775	111.1	(663.9)	(741.9)
22	9	15,145	15,075	(70)	775	111.3	(663.7)	(593.7)
22	10	15,145	14,924	(221)	775	128.6	(646.4)	(425.4)
22	11	15,145	14,798	(247)	775	144.6	(630.4)	(383.4)
22	12	15,145	14,672	(473)	775	187.5	(587.5)	(114.5)
Average		**15,145**	**15,262**	**117**	**775**	**137.4**	**(637.6)**	**(754.6)**

Increasing the Frequency of Intertie Dispatch and Associated Pre-Dispatch Forecasts

As illustrated in Figures 2-2 and 2-3 above, even if the forecasts of average Ontario demand and of supply by self-scheduling and intermittent generators are relatively accurate on an hourly basis, the actual demand or supply in a given interval can be significantly different from the average. If pre-dispatch Ontario demand forecasts were prepared more frequently (e.g. 15 minutes), the higher demand at the top of the hour could be more accurately reflected in the pre-dispatch price and may result in a smaller change in net exports being scheduled. [70] This would improve market efficiency and reduce the likelihood of a price spike.

In HE 22, 691 MW of additional net exports materialized at the top of the hour even though there was a scarcity of supply at the top of the hour. This created a price spike in the first few intervals of the hour. The increase in net exports also created operational challenges, resulting in the IESO curtailing 532 MW of exports for system adequacy reasons in interval 5. Increasing the frequency of intertie dispatch should smooth changes in net exports from one intertie dispatch period to the next. This would facilitate efficient transactions, reduce inefficient transactions, improve price fidelity and reduce the frequency with which the IESO would need to resort to export curtailments, to maintain system reliability.

In the past, the Panel recommended that the IESO investigate the possibility of 15-minute intertie dispatch, which is used between some northeastern electricity markets. [71] In addition the Panel recommended that the IESO consider implementing centralized wind forecasting as a means to improve the accuracy of wind forecasts. Had the IESO been using 15-minute intertie dispatch on April 27, 2011 and had wind output forecasts been accurate, the Panel has estimated that the market would have realized an efficiency gain of approximately $55,000 in HE 22 relative to what actually happened. As demonstrated in Table 2-6 below, the gains would have been primarily associated with reduced generation costs in Ontario that were incurred in order to allow inefficient exports to flow. The generation cost savings in Ontario would have been slightly offset

[70] As will be discussed below and captured by recommendation 2-2, the benefit associated with increasing the frequency and accuracy of pre-dispatch Ontario demand forecasts and pre-dispatch self-scheduling supply forecasts would likely be muted until such time as Ontario increases the frequency with which interties are dispatched.

[71] See the Panel's December 2007 Monitoring Report, pp. 151-160. The recommendation was reiterated in the Panel's January 2009 Monitoring Report, p. 256. The Panel also recommended that the IESO explore the possibility of 15-minute pre-dispatch for internal resources (which could include retaining 5-minute real-time dispatch). Theoretically, 5-minute intertie dispatch would likely be preferred over 15-minute intertie dispatch because this would allow faster responses to demand and supply variations. However, the Panel understands that 5-minute intertie scheduling may be difficult to achieve.

by a small loss in cost savings in the external markets (calculated as the external price in the export jurisdiction multiplied by the reduction in net exports to that jurisdiction).

Table 2-6: Estimated Efficiency Improvements had 15 Minute Pre-Dispatch Been Implemented and Had Wind Power Been Accurately Forecast April 27, 2011 HE 22 ($/MWH, MW and $)

HE	Interval	Simulated "Actual" MCP[72] ($/MWh)	15-Minute Dispatch				
			MCP ($/MWh)	Reduction in Net Exports (MW)	Reduced Generation Cost ($)	Lost Cost Savings in External Markets ($)	Total Efficiency Gains ($)
22	1	1,999.00	195.95	776	18,735	543	18,191
22	2	1,999.00	128.40	776	18,569	543	18,025
22	3	516.72	76.72	776	12,828	543	12,285
22	4	128.40	62.13	451	2,566	509	2,057
22	5	59.13	84.10	451	1,399	509	890
22	6	48.31	72.37	451	1,174	509	665
22	7	47.87	72.36	377	913	216	697
22	8	44.45	72.36	377	830	216	615
22	9	47.97	79.23	377	756	216	540
22	10	18.31	72.37	127	173	-149	322
22	11	14.37	61.06	127	147	-149	296
22	12	14.31	57.13	127	152	-149	300
Total /Average		411.49	86.18	432.75	58,240	3,358	54,883

In addition to efficiency implications, the simulation illustrates that there are wealth transfer effects resulting from forecast inaccuracies. Absent the inaccuracies caused by the reliance upon an hourly average demand forecast and the inaccuracy of the wind forecasts, the simulated HOEP in HE 22 would have been approximately $86/MWh instead of $411/MWh. This $325/MWh price discrepancy affects various classes of market participants differently. Specifically, generators would have received $86/MWh from the market instead of $411/MWh. The incremental $325/MWh paid to generators

[72] The 'actual' MCP or HOEP is simulated and slightly different from the actual outcome from the DSO in this case because the simulation tool has a different converging algorithm and some input information is slightly different from that actually used by the DSO. In the majority of cases, the simulation tool generates almost identical results as the DSO.

was charged to all Ontario loads. The total wealth transfer, however, is not a simple calculation because much of the generation assets in Ontario are under contract. Accordingly, for some contracted generators, they may have been required to repay a portion of the $411/MWh back to customers, or the high payment may offset the total amount of GA charges arising for production that occurred in other hours where the HOEP was below their contracted rate. While the Panel has not conducted a detailed generator-by-generator analysis, a preliminary estimation indicates that Ontario customers would have effectively transferred approximately $710,000 more to peaking hydro generators (which had an output of 2,180 MW in this hour).

The Panel understands that the IESO and industry stakeholders are presently considering intertie issues at the Electricity Market Forum.[73] The Panel has encouraged the Electricity Market Forum to address the issue of the frequency with which intertie transactions are scheduled.

To achieve the full benefits associated with increasing the frequency of intertie dispatch, the IESO would need to match the frequency of pre-dispatch demand and pre-dispatch self-scheduling supply forecasts to the intertie dispatch frequency. This would in turn produce pre-dispatch prices on a more granular frequency. For example, if the IESO were to adopt 15-minute intertie schedules, the benefit would be muted if the IESO did not concurrently adopt 15-minute demand forecasts, 15-minute self-scheduling and intermittent supply forecasts and 15-minute pre-dispatch runs for at least some period of time leading up to participants' final offers/bids and the final pre-dispatch.

Recommendation 2-2

The Panel recommends that the IESO and the Electricity Market Forum investigate increasing the frequency with which interties are scheduled in order to improve market efficiency and price fidelity. In conjunction with any such increase, the IESO should

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[73] The Electricity Market Forum was established in early 2011 and is expected to provide public recommendations by the end of 2011. Its Terms of Reference are available at: http://ieso.ca/imoweb/pubs/consult/sac/sac-20110321-Electricity_Market_Forum_Terms%20of%20Reference.pdf .

explore parallel increases in the frequency of the forecasts of demand and the output from wind and other intermittent generation, as well as pre-dispatch schedules.

2.2 Analysis of Low-Price hours

Table 2-7 below presents the number of hours when the HOEP was less than $20/MWh (low HOEP) as well as the number of hours when the HOEP was negative, by month, over the last four November to April periods.

Over the past three years, the number of low priced hours has been substantially higher than in the 2007/2008 winter period and all other winter periods prior to 2007/2008.[74] The greater frequency of low-price hours in this year and in the past two years mirrors the general trend of lower Ontario demand and also reflects the increase to Ontario baseload supply, or generation that is offered like baseload supply (i.e. generators with fixed price contracts per MWh delivered). Of the 53 negative-price hours this winter, approximately half occurred in April 2011. In addition, eight (15 per cent) of the negative-price hours, occurred on one day, January 1, 2011.

[74] All winter periods prior to 2007/08 had fewer than 200 low-priced hours.

Table 2-7: Number of Hours with Low and Negative HOEPs November – April, 2007 – 2011 (number of hours)

Month	Hours when HOEP<$20/MWh				Hours when HOEP<$0/MWh			
	2007 /2008	2008 /2009	2009 /2010	2010 /2011	2007 /2008	2008 /2009	2009 /2010	2010 /2011
November	10	31	181	75	0	0	16	3
December	78	62	50	62	0	5	0	9
January	59	25	11	73	0	0	1	11
February	30	25	2	27	4	0	0	0
March	0	192	112	67	0	58	0	3
April	84	354	104	211	1	156	9	27
Total	261	689	460	515	5	219	26	53

As noted in the analysis of high-price hours above, prices change when there are changes in the real-time supply and demand conditions that impact the unconstrained schedule. The following are the primary factors leading to a low (or negative) HOEP:[75]

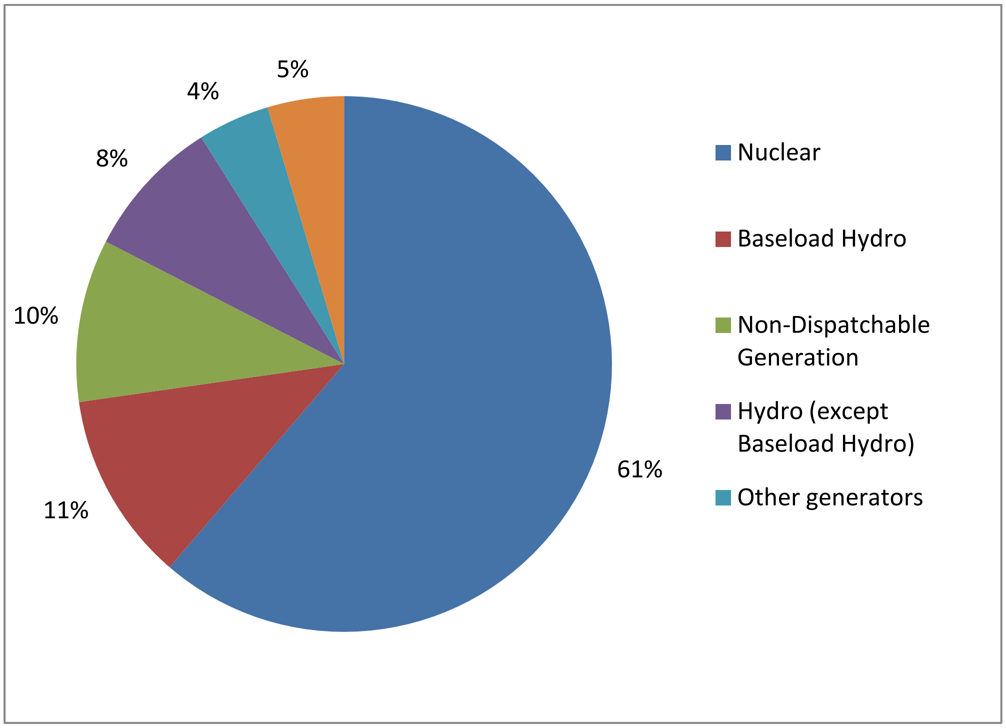
- Low market demand (Ontario demand plus net exports);
- Abundant low-priced supply (including baseload supply or contracted generation that is not exposed to the market clearing price); and
- Failed export transactions, which can place downward pressure on the MCP by reducing real-time demand.[76]

As with high-price events, low-price hours can arise as an indirect consequence of pre-dispatch forecast inaccuracies. For example, if the pre-dispatch forecast for Ontario demand is too high or the pre-dispatch forecast for self-scheduling and intermittent supply is too low, this will have the effect of increasing the pre-dispatch price, which tends to lead to an increase in imports and/or a decrease in exports (in other words, an increase in net imports). This increase in net imports will materialize at the top of the hour and could cause the price to plunge significantly relative to the previous hour.[77]

[75] These factors were first identified in the Panel's June 2004 Monitoring Report, pp. 84-85.
[76] Some exports may fail but have no impact on the market price because of the different treatment in the two dispatch sequence design. For example, when the IESO curtails an export for internal reliability, it does not remove these transactions from the unconstrained schedule.
[77] The price damping effect takes place when marginal and near marginal fossil-fired resources are ramping down at their maximum ramping capability and thus cannot set the price. At this time the interval price will be set by lower priced resources such as baseload hydro units.

Figure 2-4 below shows, by generation category, the source of low-priced supply (i.e. all domestic resources that had an offer price less than $20/MWh) offered into the market during low-price hours for the period November 2010 to April 2011. Some of the low-priced supply was scheduled and some was not scheduled due to a low demand. Generation categories are segmented into nuclear, baseload hydro, self-scheduling and intermittent resources that are non-dispatchable (including wind), and other hydroelectric resources (both run-of-the river and peaking).[78]

Figure 2-4: Low-Priced Supply Offered into the Market During Low-Price Hours November 2010 – April 2011 (% of total supply)



[*] Baseload hydro consists of Beck, Saunders, and DeCew Falls generation stations.

[78] Run-of-the-river and peaking hydro units may want to operate even when market prices are low, especially when an abundant supply of water is available and spilling is the only alternative. (At times spilling may be not an alternative because of safety or equipment issues.) Peaking units may effectively become run-of-the-river baseload hydro units when there is a lot of water that cannot be stored, for example, during the freshet period in spring. At other times, run-of-the-river hydro may have a limited capability of storage by controlling the forebay level, effectively making a portion of such supply peaking.

Nuclear generation is the main low-priced source of supply, accounting for 61 percent of total low-priced supply during the low-price hours. Baseload hydro is the second largest, accounting for 11 percent, and non-dispatchable generators (i.e. self-scheduling and intermittent generators) are the third largest, accounting for 10 percent.

Summary statistics related to the demand conditions during the low-price hours are presented in Table 2-8. The table includes monthly average Ontario demand and net exports during the low-price hours in the November 2010 to April 2011 period. Excess low-priced supply is the difference between this amount and the low-priced supply, as defined above.

Table 2-8: Average Demand and Excess Low-Priced Supply During Low-Price Hours November 2010 – April 2011 (MW)

Month	Number of Low-Price Hours	Demand			Total Low-Priced Supply	Average Excess Low-Priced Supply (Supply - Demand)
		Ontario Demand	Net Exports	Ontario Demand Plus Net Exports		
November	75	13,605	1,183	14,788	16,313	1,525
December	62	14,600	2,092	16,692	17,282	590
January	73	14,779	2,098	16,877	17,451	574
February	27	15,892	887	16,779	17,256	477
March	67	14,657	1,088	15,745	16,100	355
April	211	13,596	1.476	13,597	15,728	2,131
Total /Average	515	14,144	1,514	15,658	16,372	714

On average, excess low-priced supply was 714 MW per hour higher than total market demand during the low-price hours between November 2010 and April 2011, with an average maximum monthly difference of 2,131 MW per low-price hour in April 2011 when peaking hydro resources had abundant water supply. Excess low-priced supply was lowest in March 2011 at 355 MW per low-price hour.

Table 2-9 provides additional summary information by month for all low-price hours between November 2010 and April 2011. Deviations between pre-dispatch and real-time[79] hourly demand can result from demand forecast errors and, for ramping hours, the difference between peak and average demand within an hour. For the most recent winter period, pre-dispatch prices during the low-price hours were on average $10.71/MWh higher than the corresponding real-time prices. Abundant baseload supply relative to domestic demand (714 MW surplus on average) was the most important factor leading to the low HOEP outcomes over the latest winter period, followed by failed net exports (85 MW), and finally demand deviation (71 MW).

Table 2-9: Average Monthly Summary Data for Low-Price Hours November 2010 – April 2011 (MW and $/MWh)

Month	Excess Low-Priced Supply (MW)	Failed Net Exports (MW)	RT Average Demand (MW)	PD Demand Forecast (MW)	PD to RT Demand Deviation (MW)	HOEP ($/MWh)	Final Pre-dispatch Price ($/MWh)	Difference (RT - PD) ($/MWh)
November	1,525	7	13,605	13,691	86	12.26	15.29	(3.03)
December	590	89	14,600	14,758	158	5.42	17.74	(12.32)
January	574	234	14,779	14,868	89	(0.66)	18.77	(19.43)
February	477	62	15,892	16,016	124	15.78	24.71	(8.93)
March	355	90	14,657	14,705	48	13.32	22.28	(8.96)
April	2,131	61	13,596	13,630	34	4.49	16.10	(11.61)
Average	714	85	14,144	14,215	71	6.74	17.81	(11.07)

In its previous report, the Panel noted that an April 2010 change in offer strategy at a nuclear facility was the primary reason for a record low HOEP (at that time) set on April 2, 2010 HE 7.[80] This same change in offer strategy resulted in an increase to the number of intervals with MCPs below-$100/MWh over the recent winter period. Over the past six-month period, there were 275 intervals when the MCP fell below -$100/MWh,

[79] For further discussion of the deviation, refer to Section 2.1.1 of this chapter.

[80] See the Panel's August 2010 Monitoring Report, pp. 96-97. Specifically the Panel reported: "In previous reviews of low price hours, the MCP rarely fell below -$11/MWh to - $50/MWh because there was a large quantity of offered MW in this price range from a nuclear generating facility. ... the record low HOEP of -$128.15/MWh in HE 7 on April 2, 2010 was set due to and a change in offer prices at a nuclear generating facility. Had these nuclear units offered these MW at prices similar to historical levels, the MCP would not have reached such low record levels but would have been set at prices similar to previous negative price hours."

compared to only 32 intervals in the same period in 2009/2010. Over the past six-month period, the MCP in all but two of the 275 intervals was set by the nuclear facility that had changed its offer strategy.

A record low interval MCP of -$250.00/MWh was set twice in the six-month period ended April 30, 2011: once in January 1, HE 9, interval 1 and again in April 30, HE 24, interval 1. In both instances total demand dropped significantly from interval 12 of the previous hour, which in turn was primarily attributable to a decline in net exports that materialized at the top of the hour. The drop in total demand was sufficiently large that the nuclear facility identified above could not set the MCP during interval 1 because it had insufficient downward ramping capability to respond to the sudden, large drop in demand. As such, in both instances, a hydroelectric facility offering at -$250/MWh set the MCP in interval 1, with the nuclear facility becoming the price setter in intervals 2-12.

2.2.1 *April 30, 2011 HE 24*

The HOEP was -$138.79/MWh in the hour, which is the lowest HOEP on record since market opening.[81]

Prices, Demand and Supply

Table 2-10 lists the real-time and pre-dispatch information for HE 24 on April 30, 2011. The MCP reached a low of -$250/MWh in interval 1 and was slightly lower than -$128/MWh during each of the remaining 11 intervals in the hour. Real-time Ontario demand gradually declined over the hour from a high of 12,493 MW in interval 1 to a low of 11,825 MW in interval 12. There was a total of 1,488 MW of exports in real-time and no scheduled imports. Before real-time of HE 24, 201 MW exports failed.

Table 2-10: One-hour Ahead Pre-dispatch and Real-Time MCP

[81] The previous record low was -$128.15/ MWh in April 2, 2010, HE 7: see the Panel's August 2010 Monitoring Report, pp. 94-97.

Ontario Demand and Net Exports
April 30, 2011, HE 24
($/MWh and MW)

Hour	Interval	PD MCP ($/MWh)	RT MCP ($/MWh)	MCP Difference ($/MWh)	PD Ontario Demand (MW)	RT Ontario Demand (MW)	Ontario Demand Difference (MW)	PD Net Exports (MW)	RT Net Exports (MW)	Net Exports Difference (MW)
23	**1**	13.95	17.74	3.79	12,823	13,239	416	2,839	2,839	0
23	**2**	13.95	17.74	3.79	12,823	13,271	448	2,839	2,839	0
23	**3**	13.95	17.74	3.79	12,823	13,224	401	2,839	2,839	0
23	**4**	13.95	15.50	1.55	12,823	13,103	280	2,839	2,839	0
23	**5**	13.95	14.30	0.35	12,823	13,079	256	2,839	2,839	0
23	**6**	13.95	14.30	0.35	12,823	13,031	208	2,839	2,839	0
23	**7**	13.95	13.95	0.00	12,823	12,939	116	2,839	2,839	0
23	**8**	13.95	13.95	0.00	12,823	12,880	57	2,839	2,839	0
23	**9**	13.95	13.55	(0.40)	12,823	12,794	(29)	2,839	2,839	0
23	**10**	13.95	13.60	(0.35)	12,823	12,782	(41)	2,839	2,839	0
23	**11**	13.95	13.55	(0.40)	12,823	12,685	(138)	2,839	2,839	0
23	**12**	13.95	12.65	(1.30)	12,823	12,466	(357)	2,839	2,839	0
Average		**13.95**	**14.88**	**0.93**	**12,823**	**12,958**	**135**	**2,839**	**2,839**	**0**
24	**1**	(128.10)	(250.00)	(121.90)	12,095	12,493	398	1,689	1,488	(201)
24	**2**	(128.10)	(128.00)	(0.20)	12,095	12,343	249	1,689	1,488	(201)
24	**3**	(128.10)	(128.00)	(0.20)	12,095	12,343	248	1,689	1,488	(201)
24	**4**	(128.10)	(128.00)	(0.20)	12,095	12,302	208	1,689	1,488	(201)
24	**5**	(128.10)	(128.00)	(0.20)	12,095	12,148	54	1,689	1,488	(201)
24	**6**	(128.10)	(128.00)	(0.20)	12,095	12,223	128	1,689	1,488	(201)
24	**7**	(128.10)	(129.00)	(0.90)	12,095	12,156	61	1,689	1,488	(201)
24	**8**	(128.10)	(129.00)	(0.90)	12,095	12,114	19	1,689	1,488	(201)
24	**9**	(128.10)	(129.00)	(0.90)	12,095	12,079	(15)	1,689	1,488	(201)
24	**10**	(128.10)	(129.00)	(0.90)	12,095	12,057	(38)	1,689	1,488	(201)
24	**11**	(128.10)	(129.00)	(0.90)	12,095	11,997	(98)	1,689	1,488	(201)
24	**12**	(128.10)	(129.00)	(0.90)	12,095	11,825	(270)	1,689	1,488	(201)
Average		**(128.10)**	**(138.79)**	**(10.69)**	**12,095**	**12,173**	**79**	**1,689**	**1,488**	**(201)**

Assessment

In HE 23 the HOEP was $14.88/MWh with 2,839MW of net exports. In interval 1 of HE 24, net exports dropped by 1,351MW relative to interval 12 in the previous hour. The significant drop occurred at both the NYISO and MISO interfaces. The drop in exports through the NYISO interface appears to have been as a result of congestion at the interface that three hours ahead was signaling to traders a $2,000/MWh charge to export (if the congestion price persisted into real-time). The decline in exports to MISO appears to have been in response to an SBG alert that had been issued by MISO and which would have suggested that the exports would either be subject to negative prices upon delivery or would be curtailed.

The significant decrease in net exports resulted in the need to schedule down several generators at their maximum ramping capability. The marginal resource in HE 24 interval 1 would have been a nuclear resource priced at approximately -$129/MWh but because of ramping limitations the IESO was required to schedule a hydroelectric unit down by 4.1 MW in the unconstrained sequence. This hydroelectric unit was priced at -$250/MWh and set the MCP for the first interval of the hour. During each of the subsequent intervals in the hour the marginal resource was a nuclear generator, which set the five-minute MCP at either -$128/MWh or -$129/MWh.

2.2.2 *January 1, 2011 HE 9*

On January 1, 2011 HE 9, the HOEP was -$138.42/MWh, the second lowest HOEP since market opening.

Prices, Demand and Supply

Table 2-11 lists the real-time and pre-dispatch information for HE 9 on January 1, 2011. The MCP reached a low of -$250/MWh in interval 1 and was slightly lower than -$128/MWh for the remaining intervals. Ontario demand was relatively flat over the hour, with a small difference from the pre-dispatch forecast. There was a total of 3,187 MW of real-time net exports in HE 9, as well as 236 MW of export failures. There were no scheduled imports in the hour.

Table 2-11: Final Pre-Dispatch and Real-Time MCP, Ontario Demand and Net Exports January 1, 2011, HE 9 ($/MWh and MW)

Hour	Interval	Final PD MCP ($/MWh)	RT MCP ($/MWh)	MCP Difference ($/MWh)	PD ONT Demand (MW)	RT ONT Demand (MW)	ONT Demand Difference (MW)	PD Net Exports (MW)	RT Net Exports (MW)	Net Exports Difference (MW)
9	1	(1.00)	(250.00)	(249.00)	12,796	12,751	(45)	3,423	3,187	236
9	2	(1.00)	(128.30)	(127.30)	12,796	12,863	67	3,423	3,187	236
9	3	(1.00)	(128.30)	(127.30)	12,796	12,840	44	3,423	3,187	236
9	4	(1.00)	(128.30)	(127.30)	12,796	12,796	(10)	3,423	3,187	236
9	5	(1.00)	(128.30)	(127.30)	12,796	12,870	74	3,423	3,187	236
9	6	(1.00)	(128.30)	(127.30)	12,796	12,889	93	3,423	3,187	236
9	7	(1.00)	(128.30)	(127.30)	12,796	12,933	137	3,423	3,187	236
9	8	(1.00)	(128.30)	(127.30)	12,796	12,971	175	3,423	3,187	236
9	9	(1.00)	(128.30)	(127.30)	12,796	12,980	184	3,423	3,187	236
9	10	(1.00)	(128.30)	(127.30)	12,796	13,009	213	3,423	3,187	236
9	11	(1.00)	(128.20)	(127.20)	12,796	13,074	278	3,423	3,187	236
9	12	(1.00)	(128.20)	(127.20)	12,796	13,114	318	3,423	3,187	236
Average		**(1.00)**	**(138.42)**	**(137.42)**	**12,796**	**12,923**	**127**	**3,423**	**3,187**	**236**

Assessment

From interval 12, HE 8 to interval 1, HE 9 Ontario demand plus net exports dropped by 196 MW, of which 45 MW was associated with a drop in Ontario demand and 151 MW was associated with a drop in net exports. In the final pre-dispatch, the -$1.00/MWh price was set by a wind generator with an OPA Renewable Energy Supply (RES) contract. Under the terms of the OPA RES contract, wind generators are prohibited from offering into the market at a price below -$1.00/MWh.[82]

A -$1.00/MWh offer price normally implies that if the market price were to drop below -$1.00 /MWh that this resource would come offline. However, since wind generation is currently treated as non-dispatchable in real-time, it is placed at the bottom of the

[82] See section 3.2 of the Renewable Energy Supply II Contract (RES II Contract) available at: http://www.powerauthority.on.ca/gp/Storage/17/1148_RESIIContract%5B1%5D.pdf . Note that the RES and RES III contracts a similar contractual term. The RES contract is available at: http://www.powerauthority.on.ca/GP/Storage/16/1130_RESContract1_(RENEWABLE_ENERGY_SUPPLY_CONTRACT_(RES_Contract)).pdf ; and the RES III contract is available at: http://www.powerauthority.on.ca/GP/Storage/17/1227_SETOR1-5337536-v27-cm_Ontario_Power_Authority_-_Renewable_Energy_Supply_III_Contract.pdf. Under the RES contracts, wind generators are paid a fixed price per MWh of output, regardless of the prevailing MCP.

unconstrained supply stack and thus cannot set the real-time MCP. Accordingly, even though the wind resource set the pre-dispatch price at -$1.00/MWh, in real-time the unconstrained sequence was required to schedule down other resources that were offering at prices below the wind generator's offer price of -$1.00/MWh. These other resources were a hydroelectric and a nuclear facility. In interval 1, the MCP was set by a hydroelectric facility offering at -$250/MWh and in intervals 2 to 12 a nuclear facility offering at approximately -$128/MWh.

This low-price hour highlights the inconsistency between contract design and market design as well as between the pre-dispatch and real-time algorithms. The OPA RES contracts prohibit wind resources from offering at a price lower than -$1.00/MWh but when wind offers at -$1.00/MWh become marginal or supra-marginal, the market schedule treats wind as non-dispatchable. Compounding the problem, the IESO pre-dispatch tool treats wind as dispatchable (and therefore capable of setting the pre-dispatch price), but as non-dispatchable in real-time (and therefore not capable of setting the real-time price). Treating wind as non-dispatchable can result in a significant inefficiency.

Specifically, resources that may have short-term negative opportunity costs such as nuclear or baseload hydro set the MCP even though wind, with a marginal opportunity cost at or near $0/MWh, should be setting the MCP. The result is that Ontario may experience extreme negative prices when the price should have been at or near $0/MWh, if wind had been dispatchable. As is explained in greater detail later in this chapter, during the November 2010 to April 2011 reporting period there were 391 negative-price intervals and the average MCP during these intervals was -$97.63/MWh. If wind had been dispatchable at -$1.00/MWh it would have frequently set the MCP and the average MCP during these 391 intervals would have been to -$2.28/MWh.

In addition to causing market distortions, the fact that wind was allowed to set the price in pre-dispatch (and therefore considered as dispatchable in pre-dispatch) was also causing operational concerns. Because wind was marginal or supra-marginal in pre-dispatch, the pre-dispatch schedule suggested that wind would be dispatched down and that other facilities offering at prices lower than wind (including nuclear facilities) would not need to be dispatched down. In real-time, however, wind was treated as non-dispatchable so these other facilities offering at prices lower than -$1.00 had to be dispatched down. Where dispatch-down instructions were large this could have affected system reliability.[83]

Effective May 13, 2011 the IESO implemented a new procedure whereby when any forecast wind output is marginal or supra-marginal in pre-dispatch**,** the IESO will replace all wind generators' offers with -$2,000/MWh offers. The effect is to place all wind at the bottom of the stack and thus eliminate the ability for wind to set the pre-dispatch price with -$1.00/MWh offers.

Table 2-12 below lists the average Ontario supply mix for HE 9 on January 1, 2011. Much of this supply came from generators with fixed-priced arrangements, either through contracts with the OPA or the OEFC, or by virtue of regulated prices set by the OEB. These generation resources effectively were not exposed to the negative price, but instead received a set rate per MWh injected. Although some generators such as the 366 MW of dispatchable gas-fired generation were exposed to the market prices these facilities may have had a price hedge in place or otherwise had a business rationale for producing (e.g. a requirement to provide steam to an end-user from a combined heat and power facility). Absent a price hedge or other contractual commitments it is unlikely these facilities would have continued to produce during this hour, especially given that the six hours immediately preceeding HE 9 were also negative priced hours.

[83] For example, manoeuvering nuclear units can increase the risk of being forced out of service and/or impose operational challenges to the IESO because nuclear units may not be able to ramp as quickly as the system requires. In addition, wind resources being dispatchable in pre-dispatch but not in real-time may lead to other generators receiving security constrained pre-dispatch schedules that cannot be relied upon and which could contribute to real-time operational concerns.

Table 2-12: Contracts and Regulatory Payments Applicable to Generation Scheduled in the Unconstrained Sequence January 1, 2011, HE 9 (MW)

Month	Real Time			Pre-dispatch	Contracted/Regulated Revenue
	Dispatchable	Non-Dispatchable	Total		
Nuclear	10,715	0	10,715	11,395	Majority covered by fixed price contracts or paid regulated rates
Water	3,188	160	3,348	3,361	Majority of dispatchable are paid regulated rates.
Gas/Steam	366	612	978	1,110	Majority covered by fixed price contracts
Wind	0	965	965	241	All have fixed price contracts
Wood Waste	0	106	106	112	All have fixed price contracts
Total	15,757	1,843	16,112	16,219	

2.2.3 *January 1, 2011*

On January 1, 2011, the average daily HOEP was -\$20.24/MWh, by far the lowest daily HOEP on record. The previous low was the average daily HOEP of -\$13.96/MWh set on March 29, 2009. January 1, 2011 also represented one of only 10 days since market opening when the average daily HOEP was negative. As described above, the lowest HOEP during the day was -\$138.42/MWh and occurred in HE 9. There were eight hours when the HOEP was negative, occurring consecutively from HE 3 to HE 10. Among these eight hours were four hours when the HOEP was less than -\$100/MWh. HOEP never exceeded \$20/MWh during the day.

Table 2-13 reports the HOEP, real-time Ontario demand, exports and imports (in the unconstrained sequence) for January 1, 2011. Net exports were above 3,000 MW in most hours of the day.

Table 2-13: HOEP, Ontario Demand and Net Exports
January 1, 2011
($/MWh and MW)

Hour	HOEP ($/MWh)	RT Ontario Demand (MW)	Exports (MW)	Imports (MW)	Net Exports (MW)	Change in Net Exports From Prior Hour
1	28.93	13,486	3,285	361	2,924	n/a
2	13.74	12,942	3,529	0	3,529	605
3	(1.54)	12,496	3,710	0	3,719	190
4	(123.26)	12,241	3,530	9	3,421	(298)
5	(54.68)	12,060	3,846	0	3,846	425
6	(115.43)	12,092	3,658	0	3,638	(208)
7	(86.77)	12,297	3,451	0	3,451	(187)
8	(106.37)	12,661	3,338	0	3,338	(113)
9	(138.43)	12,923	3,187	0	3,187	(151)
10	(49.2)	13,473	3,330	0	3,330	143
11	9.62	14,103	3,570	0	3,570	240
12	14.14	14,646	3,364	0	3,364	(206)
13	15.34	14,973	3,339	0	3,339	(25)
14	10.50	15,096	2,907	165	2,742	(597)
15	13.70	15,062	3,071	61	3,010	268
16	8.62	15,123	2,900	176	2,724	(286)
17	8.02	15,702	2,623	353	2,270	(454)
18	8.11	16,402	2,285	353	1,932	(338)
19	7.42	16,184	2,306	263	2,043	111
20	6.79	15,828	2,770	196	2,574	531
21	8.90	15,549	3,299	180	3,119	545
22	14.74	15,193	3,800	371	3,429	310
23	9.66	14,567	3,446	44	3,402	(27)
24	10.42	13,786	3,469	0	3,469	67

As is typical for New Year’s Day, demand on January 1, 2011 was low. In anticipation of low demand the IESO issued an SBG alert on December 31, 2010.[84] This alert would have provided traders with sufficient lead time to arbitrage the potential price difference among neighbouring markets. As a complicating factor, however, Ontario’s SBG alert coincided with an SBG alert in the neighbouring MISO jurisdiction.

In addition to issuing an SBG alert, the IESO took several significant actions to deal with the expected SBG situations during the day:

[84] The IESO also provides an SBG forecast for the following month and updates the forecast on a daily basis. For details, see: http://www.ieso.ca/imoweb/marketdata/sbg.asp.

- The IESO communicated with a nuclear generator, advising of the potential need for a full shutdown of one of its nuclear units to address SBG conditions, an action that would be taken if partial output reductions at the units were insufficient to eliminate the SBG conditions.
- Several hours in advance of HE 1 on January 1, 2011, the IESO noticed a large increase in export bids, which made the full shutdown of the foregoing nuclear unit unnecessary although a partial reduction at three of the units totaling 850 MW was necessary during HE 5 to HE 11, as shown in Table 2-14 below.[85]
- In addition to constraining down the three nuclear units, the IESO curtailed imports in various hours in order to avoid further reductions at these units.[86]

[85] Previously this control action would have resulted in a price increase, because partial reductions were reflected in both the constrained and the unconstrained schedule in pre-dispatch. Following an MSP recommendation, on April 15, 2011 the IESO changed its operating practice such that decreases in nuclear output during SBG conditions would not be reflected in pre-dispatch. This change by the IESO eliminated the counter-productive signal sent by a higher pre-dispatch price caused by an IESO control action designed to address SBG conditions. See the Panel's January 2009 Monitoring Report, pp. 169-171.

[86] As a matter of practice, the IESO removed these imports from the unconstrained schedule. Removing the imports from the unconstrained schedule put upward pressure on the market price. Such an outcome is inconsistent with a control action designed to address conditions of oversupply. In its last report the Panel recommended that, when the IESO curtails imports during periods of SBG conditions, the IESO should leave the imports in the unconstrained schedule so as not to create the counter-productive signals sent by a higher price. The IESO has assigned a low priority to this recommendation. For details, see: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20110811.pdf.

Table 2-14: Reduction of Nuclear Output and Import Curtailment Due to Surplus Baseload Generation January 1, 2011 (MW in the constrained sequence)

	One Affected Nuclear Station				Intertie Transactions		
Delivery Hour	**Available Capacity**	**Real-Time Actual Output**	**Pre-Dispatch Schedules**	**Real-Time Minus Pre-Dispatch**	**Real-Time Exports**	**Real-Time Imports**	**Imports Curtailed**
1	4,805	4,805	4,805	0	3,099	150	0
2	4,805	4,530	4,805	-275	3,151	0	149
3	4,805	4,421	4,505	-84	3,242	0	149
4	4,805	4,045	4,505	-460	3,170	9	123
5	4,805	3,955	3,955	0	3,428	0	116
6	4,805	3,955	3,955	0	3,446	0	149
7	4,805	3,955	3,955	0	3,036	0	104
8	4,805	3,955	3,955	0	2,853	0	62
9	4,805	3,953	3,955	-2	3,123	0	0
10	4,805	3,955	3,955	0	2,917	0	0
11	4,805	3,955	3,955	0	3,085	0	0
12	4,805	4,203	4,255	-52	3,089	0	0
13	4,805	4,471	4,505	-34	2,918	0	128
14	4,805	4,755	4,805	-50	2,907	165	0
15	4,805	4,805	4,805	0	2,994	61	0
16	4,805	4,805	4,805	0	2,900	61	0
17	4,805	4,805	4,805	0	2,622	136	0
18	4,805	4,805	4,805	0	2,200	122	0
19	4,805	4,805	4,805	0	2,306	48	0
20	4,805	4,805	4,805	0	2,575	0	0
21	4,805	4,805	4,805	0	3,299	94	0
22	4,805	4,805	4,805	0	3,731	115	0
23	4,805	4,605	4,805	-200	3,100	88	176
24	4,805	4,505	4,805	-300	3,134	0	149

Market Inefficiencies and Price Distortions

During periods of SBG, a series of factors can result in MCP levels that do not represent the marginal costs (or opportunity costs) of generation. Two of the primary factors for the divergence between marginal (or opportunity) cost and market prices are:

- *Contracts/Regulation*: Much of Ontario's baseload and self-scheduling generation capacity has little incentive to offer at prices that reflect marginal cost or opportunity cost. These generation facilities are subject to either fixed-price bilateral contracts with the OPA or the OEFC (e.g. NUG contracts) or OEB-regulated prices (e.g. regulation on OPG's nuclear assets). In a previous report, the Panel recommended that the OEFC or OPA or any agencies that are responsible to renew the NUG contracts should design the contracts in a way to motivate generators to respond to the market price, at least when it is negative.[87] Payments to these generators are independent of market clearing prices, with the result that their hourly offers into the market are essentially just a means to ensure they are dispatched. To get paid their contracted or regulated prices, they have to produce energy. Because the level of hourly market prices has little economic consequence for these generators, there is little incentive for them to offer prices that are tied to their marginal costs or opportunity cost. In fact, these generators have an incentive to offer at a price that will ensure that they will produce at their maximum output level.
- *Non-dispatchability of Intermittent Resources*: During negative-price hours, the IESO cannot dispatch down (or off) wind generators even though market prices are below their offer prices because the current IESO practices treat these intermittent generators as non-dispatchable. By not dispatching down wind generators in such circumstances, the IESO has to dispatch down other generation such as nuclear units, which typically have short-term opportunity costs that are negative.[88] Accordingly, dispatching down nuclear as opposed to wind facilities

[87]See the Panel's July 2007 Monitoring Report, pp. 218-235.
[88] The short-term opportunity cost for a nuclear facility is typically negative because when a nuclear facility comes offline it typically needs to remain offline for as long as 72 hours. Accordingly, a nuclear facility may be willing to pay to generate for several hours so as not to lose 72 potentially profitable hours of

is inefficient. Furthermore, because wind resources cannot set the market price, this may lead to a lower market price being set by nuclear resources.

Together, these factors can lead to dispatch inefficiencies as well as a lower market price that does not reflect the cost of marginal output. Dispatch inefficiency occurs when nuclear units which have a high cost of being dispatched down/off are constrained down/off ahead of wind resources that have a lower cost of being dispatched down/off. In addition, prices that are well below marginal cost can induce inefficient exports and/or lost opportunities for efficient imports.

Non-dispatchability of Wind Generation

The non-dispatchability of wind resources can have significant efficiency implications and cause extreme negative prices as were seen on January 1, 2011 between HE 3 and HE 10. Wind generators have a marginal cost at or near $0/MWh because their fuel source (wind) is free. In addition wind is capable of being dispatched down (and up, as long as its maximum output capability at the time is not reached). At a market clearing price above its marginal cost, one would expect wind to generate. If the price falls to its marginal cost one would expect wind to be indifferent between producing and not producing. If the price is below its marginal cost one would expect wind generators to be dispatched offline. However, since wind generators are presently treated by the IESO as non-dispatchable, they are moved to the bottom of the supply stack in real-time and will not be dispatched down in a negative priced environment. Instead the IESO must dispatch down generators designated as dispatchable and offering at prices lower than -$1.00/MWh. As noted, if these lower-priced generators' marginal cost of production is less than -$1.00/MWh, it is inefficient to dispatch them down ahead of wind generators.

generation. In addition, Ontario's nuclear facilities have historically been treated and operated as baseload capacity. There are operational costs associated with manoeuvering nuclear facilities, including the risk that the facility will trip offline and become unavailable.

The MAU simulated the impact on HOEP had wind been dispatchable on January 1, 2011. The simulation considered wind resources to be dispatchable on a five minute basis and a wind offer price of -$1.00/MWh. Table 2-15 below shows that wind would have frequently replaced other lower priced resources as the marginal resource during HE 4 to HE 10 and that the HOEP during these hours would have risen from an average of -$96.31/MWh to an average of -$0.96/MWh.[89] If wind had been dispatchable during these seven hours, average wind output would have dropped by 211 MW or 21.0%.

Table 2-15: Actual and Simulated Wind Generator Production and HOEP January 1st, 2011, HE 4 to HE 10 ($/MWh and MW)

Hour	HOEP ($/MWh)			Wind Production (MW)		
	Actual Average	Simulated Average	Difference	Actual Wind Production	Simulated Wind Dispatch	Difference
4	-123.26	-1.00	122.26	1066	855	211
5	-54.68	0.20	54.88	1007	965	42
6	-115.43	-1.00	114.43	1025	882	143
7	-86.77	-1.00	85.77	970	889	81
8	-106.37	-1.00	105.37	1032	820	212
9	-138.43	-2.51	135.91	965	226	739
10	-49.20	-0.40	48.80	969	921	48
Average	-96.31	-0.96	95.35	1005	794	211

The MAU also simulated the impact on HOEP for the entire day. If wind had been dispatchable on a five minute basis at -$1.00/MWh on January 1, 2011 the average HOEP would have been $7.74/MWh instead of -$20.24/MWh and average wind output during the day would have declined by 5.9% relative to potential output (from an average of 1,046 MW per hour to an average of 984 MW per hour).

The MAU ran a further simulation for the entire period November 2010 to April 2011. If wind had been dispatchable at a price of -$1.00/MWh, total wind output would have

[89] HE 3 was excluded from the simulation because the real-time HOEP was only -$1.54/MWh.

declined by approximately 8,400 MWh, or by 0.4% (see Table-2-16 below). About 20% of the 8,400 MWh reduction would have occurred on January 1, 2011.

Table 2-16: Actual and Simulated Wind Output had Wind Generators been Dispatchable
November 2010 – April 2011
(GWh and %)

Month	Wind Production (MW)			Estimated Reduction in Wind Generator Revenue if Wind had been Dispatchable (%) – same as previous column
	Total Actual Wind Production (GWh)	Simulated Wind Dispatch if Wind had Been Dispatchable (GWh)	Reduction in Wind Production had Wind been Dispatchable (%)	
November	324.7	324.4	0.1	0.1
December	369.8	369.1	0.2	0.2
January	262.3	260.4	0.7	0.7
February	436.0	436.0	0.0	0.0
March	322.1	321.9	0.1	0.1
April	401.9	396.6	1.3	1.3
Total	2,116.8	2,108.4	0.4	0.4

While the reduction in total wind output would have been *de minimis* had wind been dispatchable at -$1.00/MWh, this change would have had a meaningful impact on price. During the reporting period (November 2010 to April 2011) there were 391 negative-price intervals and the average MCP during these intervals was -$97.63/MWh. If wind had been dispatchable at -$1.00/MWh it would have frequently set the MCP and the average MCP during these intervals would have been -$2.28/MWh. Averaged over all intervals in the period, the HOEP would have increased by $0.71/MWh from $31.75 to $32.46/MWh. For further details see Table 2-17 below.

Table 2-17: Actual and Simulated Price if Wind Generators Had Been Dispatchable November 2010 – April 2011 ($/MWh, except number of intervals)

Month	Negative-Price Hours				All Hours		
	Number of Negative-price Intervals	Average MCP in Negative-price Intervals	Average Simulated MCP in Negative-price Intervals had Wind been Dispatchable	Difference	Average HOEP in all Hours	Average Simulated HOEP in all Hours had Wind been Dispatchable	Difference
November	25	-17.46	-0.96	16.50	31.89	31.93	0.04
December	64	-83.36	-0.98	82.38	33.83	34.42	0.59
January	99	-106.04	-1.18	104.86	31.92	33.08	1.16
February	0	N/A	N/A	0	33.29	33.29	0.00
March	18	-82.25	-1.82	80.43	31.23	31.39	0.16
April	185	-110.41	-5.16	105.25	28.37	30.65	2.28
Total	**391**	**-97.63**	**-2.28**	**95.35**	**31.75**	**32.46**	**0.71**

It is important to note that for modern wind generation facilities there are no technical limitations preventing wind generators from becoming a dispatchable resource. Indeed, wind has the potential to be a highly flexible resource, capable of rapid, controlled changes in output that are bounded only by the maximum output associated with existing wind conditions. For example, if a wind farm is generating at 100 MW, it can rapidly and in a controlled manner adjust its output between 0 MW and 100 MW but cannot adjust output above 100 MW. The IESO has been making efforts through Stakeholder Engagement (SE) 91 to make renewable resources dispatchable. This process was commenced on November 4, 2010. [90] The Panel encourages the IESO to expedite its efforts in this regard.

[90] For more information on SE-91, see: http://www.ieso.ca/imoweb/consult/consult_se91.asp, including the IESO's Dispatching Variable Generation Resources Whitepaper, which is available at: http://ieso.ca/imoweb/pubs/consult/se91/se91-20110512-Dispatch_Whitepaper.pdf .

Recommendation 2-3:
The Panel recommends that the IESO accelerate its efforts under Stakeholder Engagement (SE-91) to make wind generators dispatchable.

3. Anomalous Uplift

During November 2010 to April 2011, there were no hours when the anomalous uplift criteria were met. There were no hours when CMSC payments or IOG payments were greater than $500,000 in a single hour, CMSC payments at an intertie group exceeded $1 million for a day, or hourly OR payments were greater than $100,000.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This chapter summarizes notable changes and developments that impact the efficient operation of the IESO-administered markets. Section 2 of this chapter identifies material changes that have occurred in the market related to Panel activities and prior reports. In Section 3, the Panel comments on two new issues:

- a new Global Adjustment allocation methodology; and
- new market rules to reduce CMSC payments to dispatchable loads and exporters when their bid prices are negative.

2. Changes Related to Panel Activities and Previous Reports

This section covers three issues:

- investigations by the Panel;
- the Panel's new monitoring document regarding offer prices of generators seeking to come offline; and
- a request for an advisory opinion from the Panel.

2.2 Investigations by the Panel

2.2.1 <u>*Alleged Withholding of Coal-Fired Generation*</u>

In 2010, the Panel received a complaint from a trader regarding allegations of withholding by Ontario Power Generation Inc. (OPG), the operator of the 15 coal-fired generation units in the province. OEB By-law #3 (the "MSP By-law") sets out a framework for the conduct of investigations by the Panel.[91] The Panel did not consider the complaint to be "frivolous, vexatious or otherwise not material"[92] and both OPG and the Chair of the OEB were notified of the Panel's decision to commence an investigation. The complaint alleged that OPG withheld capacity at its coal-fired generation units beyond the levels set out in OPG's CO2 emission reductions strategy for 2009, particularly during the months of September through November 2009.[93] The Panel examined various potential factors affecting OPG's supply of its coal-fired generation, including actions taken by OPG to implement its CO_2 emission reductions strategy. To assess the complaint, the Panel analyzed information provided by the complainant along with market information regarding supply, demand, and pricing as well as other relevant factors. The Panel also ran simulations to assess what the market impact would have been had OPG's coal units been offered into the market in their standard historical fashion. In addition, the Panel obtained and analyzed a significant amount of information from OPG regarding its offer strategies for the coal-fired units. This included both high-level strategies and specific actions taken during the 13 days where OPG's alleged withholding had the highest potential market impact as identified by the Panel.

In August 2011, the Panel issued its report on this investigation (the public version of which is available on the OEB's website).[94] The Panel concluded that:

> *"…OPG's offer strategies for coal-fired generation during the period September – November 2009 did not constitute an exercise of market power. The units in question generally did not have enough lead time to come online on those days where it appeared, on an ex post basis, that they would have become economic as tighter supply /demand conditions emerged closer to or in real time.*

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[91] Ontario Energy Board, By-law #3 – Market Surveillance Panel, particularly article 5, available online at: http://www.ontarioenergyboard.ca/OEB/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf.
[92] *Ibid*., article 5.1.4.
[93] This CO_2 emission reductions strategy was established further to a resolution of OPG's sole shareholder setting annual maximum CO2 emission levels for 2009.
[94] The report is available on the OEB website, with confidential information redacted. See Market Surveillance Panel, Report on an Investigation into Allegations of Withholding of Coal-fired Generation, Investigation #2010-1, August 30, 2011, available online at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Coal-Withholding-Complaint.pdf, p. 7.

The Panel also finds that OPG did not engage in any anti-competitive conduct related to coal-fired generation that would constitute an abuse of market power.
The Panel concludes that the negative financial impacts experienced by the complainant in its trading and contracting activities, including on its investments in transmission rights, were not the result of an exercise or abuse of market power by OPG.
The Panel does not make any recommendations related to market design or market participant conduct arising from this investigation."

2.2.2 Other Investigations

The Panel currently has five investigations in progress. All relate to possible gaming issues involving Congestion Management Settlement Credit ("CMSC") payments and, in some cases, other related activities. Pursuant to the MSP By-law, the Panel will submit reports to the Chair of the OEB when these investigations are completed, and such reports will be published on the OEB's website.

2.3 Monitoring Document

The MSP By-law authorizes the Panel to issue monitoring documents which set out the evaluative criteria that will be used by the Panel in its market monitoring activities.[95] As a result of the Panel's concerns about the magnitude of CMSC payments to ramping-down generators (approximately $1 million per month, much of which is self-induced through unnecessarily high offer prices[96]), the Panel developed a Monitoring Document regarding offer prices used to signal an intention to come offline. The proposed version was published for consultation on June 16, 2011.[97] Five submissions were received from

[95] MSP By-law, article 4.2. The first such document was the "Monitoring of Offers and Bids Document" issued in March 2010 (see: http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Monitoring+Offers+and+Bids)
[96] See the Panel's August 2010 Monitoring Report, pp. 268-273.
[97] MSP, Proposed Monitoring Document: Generator Offer Prices Used to Signal an Intention to Come Offline, June 16, 2011, available online at http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Proposed_Monitoring_Document.pdf.

interested parties.[98] The Monitoring Document as adopted by the Panel was published on August 19, 2011. In brief, it provides that where there are *bona fide* business reasons for a generator to come offline the Panel normally would not consider a gaming investigation to be warranted where the generator's offer price does not exceed the greater of (i) 130% of the generator's 3-hour ahead pre-dispatch constrained schedule (shadow) price, or (ii) the generator's marginal (or other incremental or opportunity) cost.[99]

The Panel is monitoring generator offer prices in the manner set out in the Monitoring Document, and will take further steps if warranted in any particular case.

2.4 Advisory Opinions

Section 3.1.7 of the MSP By-law contemplates that the OEB Chair may assign activities to the Panel in relation to surveillance of electricity markets. In response to a market participant, the OEB Chair requested that the Panel provide an advisory opinion regarding proposed conduct. The Panel is currently awaiting responses to information requests before completing its analysis and preparing the advisory opinion.

[98] The submissions are available online at http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Monitoring+Document+-+Generator+Offers**.**

[99] Market Surveillance Panel, "Monitoring Document: Generator Offer Prices Used to Signal an Intention to Come Offline," August 19, 2011, available online at http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Proposed_Monitoring_Document.pdf.

3. New Matters

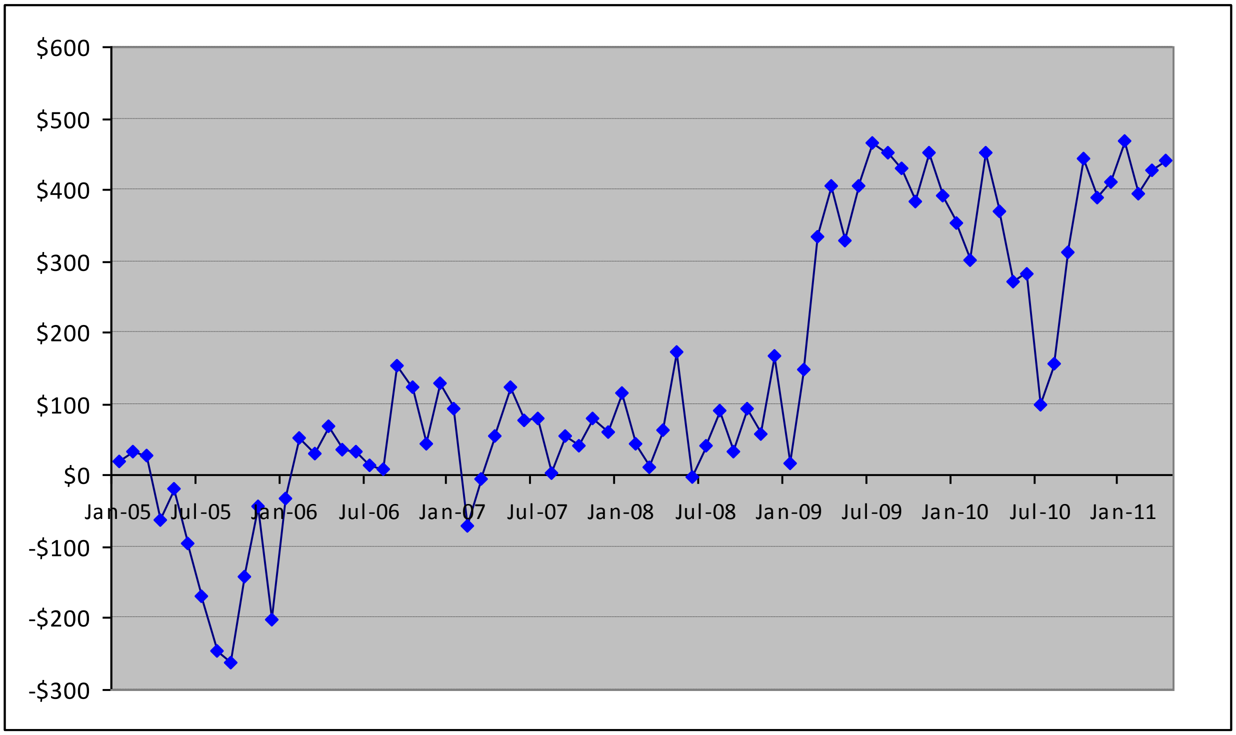
3.1 Changes to the Allocation of the Global Adjustment

3.1.1 Introduction

Since 2005, Ontario electricity customer bills have reflected either a credit or a charge in the form of the Global Adjustment (GA). Most of the GA is made up of the difference between (a) the total payments made to generators whose supply price is subject to a contract with an Ontario government agency or regulated by the OEB, and (b) energy revenues earned by those generators in the IESO-administered markets. The costs of certain Ontario Power Authority (OPA) conservation programs are also included in the GA.

The GA in 2005 was a net *credit* (i.e. a bill reduction) of approximately $1.1 billion for customers in that year. This occurred largely because the regulated prices payable to OPG for output from its nuclear and baseload hydro assets were less than the prevailing wholesale market prices. Since 2006, the GA has been a net *charge* to electricity customers in each year and for almost all months. GA charges increased substantially in 2009 and have continued at a high level except for a drop in the summer of 2010. The GA amounts by month from January 2005 to April 2011 are shown in Figure 3-1. Positive amounts are charges to customers; negative amounts are bill reductions.

Figure 3-1: Global Adjustment Charges (Credits) by Month
January 2005 – April 2011
($ millions)



The amount of the GA has grown substantially in the past few years to the point where the average GA per MWh of energy consumed is roughly equal to the average HOEP. In 2009 and 2010, the average annual GA amounts were $32.27/MWh and $31.05/MWh respectively, compared with average HOEPs of $29.52/MWh and $36.25/MWh, respectively.

Table 3-1 shows the major components of the GA from January 2008 through April 2011. The largest source of GA in this period was OPA contracts. GA related to regulated prices for certain OPG generation assets and to OEFC contracts was also substantial.

Table 3-1: Source of Global Adjustment Charges
January 2008 – April 2011
($ millions)

Source	January - December			January - April	
	2008	2009	2010	2010	2011
OEFC Ontario Electricity Financial Corporation contracts with generators including non-utility generators	$479.5	$961.5	$959.6	$414.6	$387.7
OPG OPG's price-regulated nuclear and baseload hydroelectric generation	(190.4)	1,551.4	899.4	362.6	424.5
OPA Ontario Power Authority contracts with generators and costs associated with conservation programs	611.8	1,705.7	1,998.4	698.2	918.5
Total	**$900.9**	**$4,218.6**	**$3,847.4**	**$1,475.4**	**$1,730.7**

The IESO calculates the GA on a monthly basis after receiving invoices from the OPA and OEFC. The IESO charges the GA to Ontario customers that are market participants, including local distribution companies (LDCs). Until the end of 2010, the GA was allocated to all Ontario customers based on their monthly consumption in accordance with Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*. [100, 101] This volumetric allocation method was similar to average cost pricing.

[100] Amended O. Reg. 429/04 is available online at http://www.elaws.gov.on.ca/html/regs/english/elaws_regs_040429_e.htm.
[101] The GA charge is shown as a separate line item on the monthly bills for customers that are IESO-administered market participants, larger customers embedded in LDC service territories, and smaller customers that purchase their energy from retailers. For many of these customers, the GA was shown on their bills before 2011 as the "Provincial Benefit".

3.1.2 *Change in GA Allocation*

In 2010, the Government of Ontario amended Ontario Regulation 429/04 to change the way in which the GA is allocated to customers. The amended regulation creates two classes of customers – Class A customers (which have an average peak demand of more than 5 MW for a defined base period), and Class B customers (all other customers).[102] Given the significant demand threshold to be classified as a Class A customer, such customers tend to be large industrial or natural resource entities.

Beginning in January 2011, when the revised regulation took effect, the GA has been allocated monthly between Class A and Class B customers based on the relative contribution of each group to hourly Ontario demand during the five coincident peak hours in the preceding period (the Base Period).[103] For example, if Class A customers are responsible for 10% of system demand (MW) during the five peak hours in the Base Period, that group will be allocated 10% of the GA for the Billing Period. This is true even if Class A customers as a group consume more or less than 10% of the total energy (MWh) used in Ontario during all the remaining hours in the Billing Period.

Once the GA is divided between the two groups, it is allocated to the members of each group as follows:

- Each Class A customer pays its share of the aggregate Class A GA amount based on its consumption during the five coincident peak hours in the Base Period. For

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Residential, small business, farm other smaller customers that purchase electricity from their distributor pay commodity prices set by the OEB (known as the Regulated Price Plan or RPP) do not pay the actual amount of the GA each month. Instead, the RPP prices, which are adjusted every six months as required, include an OEB forecast of the GA for the ensuing 12-month period. The difference between the forecast GA included in the RPP prices and the actual GA each month is recorded in an OPA variance account, which is “cleared” each time that RPP prices are adjusted and included in the determination of the updated RPP prices. Electricity bills issued to low-volume consumers therefore do not include a separate line item for the GA.

[102] A market participant can elect to be a Class B customer up to June 2012 (i.e. the Adjustment Period of January 2011 to June 2011 and/or the Adjustment Period of July 2011 to June 2012).

[103] The coincident peak hours are the five hours (occurring on different days) in which the greatest number of megawatts of electricity was used in Ontario. For an IESO description of changes to allocation of the GA, please see: http://www.ieso.ca/imoweb/pubs/ga/Backgrounder_Changes_to_the_GA.pdf.

example, a Class A facility responsible for 1% of the total Ontario demand during these hours will pay 1% of the total GA amount in the following Billing Period.

- GA allocated to Class B customers as a whole is apportioned to each member of this group based on energy consumption during the month (i.e., the same volumetric allocation method that had been used before 2011 to allocate GA to all customers).

Other than for an initial six month period, the Base Period and Adjustment (Billing) Period are each 12 months in length. Table 3-2 below shows, for different Billing Periods, the Base Period used by the IESO to allocate the GA based on the new allocation method.

Table 3-2: Global Adjustment Allocation Base and Adjustment Periods[104]

Base (Peak-setting) Period	Five Peak Hours	Adjustment (Billing) Period
May 1, 2010 to October 31, 2010	July 6 HE 16 July 7 HE16 July 8 HE 15 August 31 HE16 September 1 HE 16	January 1, 2011 to June 30, 2011
May 1, 2010 to April 30, 2011	Same hours as initial Base Period	July 1, 2011 to June 30, 2012
May 1, 2011 to April 30, 2012	Not yet determinable	July 1, 2012 to June 30, 2013
May 1, (Year X) to April 30, (Year X+1)	Not yet determinable	July 1, (Year X+1) to June 30, (Year X+2)

Table 3-2 identifies the five peak hours for the first two Base Periods, which have already ended. The same five peak hours will be used for both the initial six-month Base Period and the subsequent Base Period for the 12 months ended April 30, 2011. Thus, Class A customers as a group, and each individual Class A customer, will be allocated the same

[104] Source: IESO website at http://www.ieso.ca/imoweb/b100/ga_changes.asp

percentage of monthly GA for each of the first 18 months that the new allocation method is in effect (the two Billing Periods that cover January 1, 2011 to June 30, 2012).

3.1.3 *First Four Months Under the New Allocation Method*

In general, large loads in Ontario tend to have flatter load profiles than other customers. That is, as a percentage of their total energy consumption, large loads in Ontario typically consume less on-peak power, and more off-peak power, than other Ontario customers. For electricity intensive industries, lower on-peak consumption as a percentage of total consumption may reflect the nature of their industrial processes, load shifting to avoid higher on-peak prices, reductions in peak period demand pursuant to OPA demand response contracts, or other factors.

Given the energy consumption profiles of large electricity users, one would expect that the new peak-hour GA allocation method would lead to lower GA charges to Class A customers than the old volumetric method. This is evident in the GA allocations for the first four months of the new method, January through April 2011, as shown in Table 3-3.

Table 3-3: Global Adjustment Charges and Estimated Impact of the New Allocation Method
January – April 2011
(TWh and $ millions)

Month	Consumption (TWh & %)			Global Adjustment ($ million & %)			
	Class A	Class B	Total	Class A	Class B	Total	Estimated GA no Longer Paid by Class A Customers
January 2011	2.0	11.3	13.3	$51.1	$418.0	$469.1	$19.0
	14.9%	85.1%	100%	10.9%	89.1%	100%	
February 2011	1.8	10.0	11.8	$42.9	$350.6	$393.5	$18.0
	15.4%	84.6%	100%	10.9%	89.1%	100%	
March 2011	2.0	10.3	12.3	$46.6	$381.3	$427.7	$22.7
	16.2%	83.8%	100%	10.9%	89.1%	100%	
April 2011	1.9	9.0	10.9	$48.0	$392.4	$440.4	$29.6
	17.4%	82.6%	100%	10.9%	89.1%	100%	
Total	**7.7**	**40.6**	**48.3**	**$188.6**	**$1,542.2**	**$1,730.8**	**$89.3**
	15.9%	84.1%	100%	10.9%	89.1%	100%	

As Table 3-3 shows, Class A customers paid 10.9% of total GA in each of the first four months of 2011. Given that the five peak hours for the second Base Period (May 2010 - April 2011) are the same hours as for the first Base Period (May-October 2010), Class A customers' share of total GA will remain at 10.9% through June 2012. The last column in Table 3-3 (Estimated GA No Longer Paid by Class A Customers) is calculated using the difference between Class A customers' share of Ontario domestic energy consumption (for example, 14.9% in January) and the constant 10.9% rate used in the new GA allocation method.

A further indication of the impact of the new GA allocation method (absent any change in consumption by Class A customers) is provided by the Regulated Price Plan (RPP) report issued by the OEB when it announced new RPP prices in April 2011.[105] The OEB

[105] See Ontario Energy Board, *Regulated Price Plan Price Report: May 1, 2011 to April 30, 2012*, April 19, 2011, pp. 5, 11 and 12.

adjusts the RPP prices every six months as required, based on forecasts of the cost of supplying RPP consumers, including the GA. The OEB stated that the new GA allocation method caused 39% (or $1.79/ MWh) of the $4.60/ MWh increase in the estimated cost of RPP supply for the 12 months ending April 30, 2012. Based on the OEB's forecast of RPP consumption of 57 TWh, representing approximately 47.7% of annual Class B consumption, the additional GA costs allocated to Class B customers would be around $209 million per year.

3.1.4 *Expected Market Impact of the New Allocation Method*

Based on the "Purpose of Regulation" section of the Regulation Proposal Notice that was published when the GA allocation proposal was issued for comment in 2010, the principal reasons for adopting the new allocation method were (a) to provide an incentive to large loads to curtail consumption in peak periods, and (b) to reduce inefficient price signals in off-peak periods:

> *"The proposed changes to the global adjustment mechanism would provide large consumers with a strong incentive to reduce consumption at critical times, consistent with the government's commitment to creating a culture of conservation. By reducing peak demand, the proposal is expected to avoid costly investments in new peaking generation resources and imports of electricity from jurisdictions reliant on coal-fired generation.*
>
> *Currently, a global adjustment rate is published monthly by the Independent Electricity System Operator (IESO). This is calculated as the sum of total global adjustment costs divided by the total volume of electricity consumed. This flat rate credit or charge is passed on to electricity consumers on a volumetric basis, regardless of when electricity was actually consumed. In recent years this had led to inefficient price signals to consumers in the market since electricity consumed during off-peak periods is charged the same global adjustment rate as electricity consumed during on-peak periods. Concerns have also been raised that large volume consumers, who are not the primary drivers of costs to meet peak demand, are paying more than their fair share of costs. …*
>
> *Compared to the current approach, the proposed methodology more accurately reflects large consumers' contribution to global adjustment cost. It also provides large consumers with the incentive to reduce consumption during peak periods when the system is under*

> *greatest duress[sic], reducing the need for expensive peaking resources*."[106]

The IESO has published its own views about the benefits of the new GA allocation method. It claims that the new method has very broad benefits,[107] including:

- reducing the amount of high-priced, high-emissions power required during those peak hours;
- reducing electricity demand peaks, which reduces the infrastructure (power plants and power lines) needed to meet those peaks;
- encouraging more efficient use of existing supply resources;
- reducing the occasions of surplus power; and
- reducing the costs in the Global Adjustment overall.

The Panel intends to analyze the market efficiency, demand response,[108] and other consequences of the new GA allocation method once sufficient data is available. In the Panel's view, it is too early to make meaningful assessments of the potential impact of the new allocation because the new method has only been in effect for a short time, and the summer months where peak demand hours for the 2011 Base Period are expected to occur are not the subject of this Report. The Panel anticipates presenting an assessment of the market efficiency and demand response implications of the new GA allocation method in its next semi-annual report covering the summer of 2011.

3.2 Constrained-on CMSC Payments to Dispatchable Loads and Exporters when their Bid Price is Negative

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[106] Ministry of Energy, *Proposal to Make a Regulation under the Electricity Act to Amend O. Reg. 429/04*, EBR Registry Number 011-0973, August 27, 2010, available at http://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTEwNzI0&statusId=MTY2MTgw.
[107] IESO, *Global Adjustment – Qs and As*, February 2011, p. 1, available at http://www.ieso.ca/imoweb/pubs/ga/Global_Adjustment-QAs.pdf.

[108] In past reports, the Panel has analyzed the efficiency and cost effectiveness of various OPA demand response programs. See the following MSP Monitoring Reports: December 2007, pp. 142-146; January 2009, pp. 197-213; July 2009, pp. 191-197; and January 2010, pp. 49-63.

In its January 2010 Monitoring Report,[109] the Panel recommended that the IESO should mitigate the CMSC payable to dispatchable loads and exporters by utilizing a replacement bid price such as $0/MWh when such customers bid at negative prices. After consultation with market participants, the IESO implemented a new rule on December 3, 2010 which uses a -$50/MWh replacement bid amount for dispatchable loads and a -$125/MWh replacement bid amount for exporters.[110]

3.2.1 *Negative Offer and Bid Prices*

Generally speaking, when prices are relatively high, power suppliers seek to increase the quantity of energy offered into to the market, while price sensitive loads will reduce energy consumption. In contrast, when prices are relatively low, many exporters and price sensitive domestic loads will increase energy consumption, while some higher priced sources of supply will find it uneconomic to generate. In a well-functioning electricity market, these contradictory forces create equilibrium and the prevailing market clearing price is an accurate reflection of the supply and demand conditions at that time. In other words, the market price tends to reflect the incremental cost of supplying the next MW needed to meet demand at that time.

On various occasions, including in its January 2010 Monitoring Report, the Panel observed that Ontario's two-sequence design can distort this equilibrium and lead to market prices which deviate from the incremental cost of the next MW supplied.[111] For example, this can materialize when some supply is unavailable due to transmission constraints, but that supply is still included in the pricing determination. This leads to a uniform market price that is higher than the incremental cost of providing the next MW in some areas, and that is lower than the incremental cost of providing the next MW in other areas. In Ontario, this is a chronic issue as there are areas with abundant power supply but limited transmission. In these areas generators or importers can offer at a

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[109] See the Panel's January 2010 Monitoring Report, p. 101.
[110] Market Rule Amendment-00370 (MR-00370). For details, see: http://www.ieso.ca/imoweb/pubs/mr2010/MR-00370-R00-BA.pdf.

[111] See the Panel's January 2010 Monitoring Report, pp. 100-104.

negative price with little or no financial consequence (i.e. limited exposure to being settled on a negative price). In such situations, generators and/or importers are paid the uniform Ontario market price even though their offered energy is not taken by the market.

The Northwest zone of the province highlights this disconnect between prices and the underlying economics associated with the cost of producing electricity. Table 3-4 below summarizes the average hourly internal zonal price for the annual periods from May 2008 to April 2011. In theory, the zonal price reflects the incremental cost of providing the next MW in the area, which is set by the offer price of the marginal generator in that area.[112]

Table 3-4: Average Hourly Internal Zonal Price
May 2008 – April 2011
($/MWh)

Zone	May 08 / Apr 09	May 09 / Apr 10	May 10 / Apr 11
Bruce	51.95	28.44	35.28
East	51.29	27.77	36.25
Essa	52.35	28.66	37.02
Northeast	30.11	12.47	35.39
Niagara	52.00	26.76	32.44
Northwest	(190.37)	(404.08)	(167.59)
Ottawa	55.07	30.05	39.72
Southwest	52.10	28.84	36.84
Toronto	54.41	29.66	36.91
Western	53.64	29.62	36.11
Richview Nodal Price	54.14	29.88	37.38

Table 3-4 indicates that there are only small differences between the average prices in most zones (typically no more than a few dollars, due primarily to line losses). The exceptions are the Northeast and Northwest zones. The Northeast zone prices tend to be

[112] A zonal price is an average of all of the nodal prices in a given zone. Physical dispatch is based on nodal prices. For illustrative purposes the Panel may refer to zonal prices as the basis for dispatch in this section.

lower than most other Ontario zones, reflecting transmission limitations and the greater losses suffered when moving power from this region to the Toronto zone (the major load area in Ontario). The Northwest average hourly zonal price is often negative with an average zonal price of below -$150/MWh over the past three years. In the most recent annual period covered by Table 3-4, the average hourly zonal price in the Northwest was -$167.59/MWh.

If offer prices reflected suppliers' costs, a -$167.59/MWh zonal price would imply that the marginal generators (and importers) were willing to pay, on average, $167.59/MWh to supply power during the period May 2010 to April 2011.[113] While it is possible that a generator (or importer) may from time to time be willing to pay to produce (or export from its own jurisdiction) power (e.g. in order to avoid the costs of shutting down and restarting), this would not explain the systemic negative zonal prices over the past few years.

As noted above, generators and importers often make offers that result in significantly negative zonal prices in the Northwest. Generators and importers are paid based on the uniform price (MCP or HOEP) for every MW they have supplied (or not supplied in the case of constrained-off supply) rather than the zonal price. For example, when the zonal price is -$150/MWh and the HOEP is $50/MWh, all generators that are scheduled in the zone (i.e. offering at or below -$150/MWh) will be paid $50/MWh to generate. They will not be charged $150/MWh to generate as their offer price would imply they are willing to do. In addition, all generators that were offering above -$150/MWh but below the $50/MWh HOEP will be constrained-off. These constrained-off generators would not be required to supply power in the region, but would still be economic in the province-wide market schedule based on the HOEP and would therefore receive constrained-off payments.[114] Generators offering above $50/MWh would not supply power in the region

[113] Moreover, it implies that many scheduled generators (and importers) were willing to pay even more than $167.59 to provide power to area, since the infra-marginal suppliers must have been offering below -$167.59/MWh in order to be scheduled.

[114] For CMSC calculation purposes, where a generator is constrained-off with a negative offer price, the offer is set at $0/MWh.

(i.e. would not be scheduled in the constrained sequence) and would not be economic in the province-wide market schedule based on HOEP (i.e. would not be scheduled in the unconstrained sequence) and would not deliver any energy nor receive any payments. In a region with negative nodal prices, dispatchable loads and exporters may be constrained-on (i.e. they are not economic compared to the uniform price (HOEP on MCP), but economic compared to their negative nodal price) and receive a constrained-on payment equal to the difference between the uniform price and their bid price. In other words, a dispatchable load or exporter in a negative-priced zone may be paid to consume or export power. The lower the nodal price, the higher the constrained-on payment the dispatchable load (or exporter) is likely to receive (assuming they always bid slightly above the nodal price). This may lead to inefficient consumption as the load or exporter has the incentive to increase consumption or exports based on an artificially low price that does not reflect the actual incremental cost of the additional MWs supplied and consumed.

3.2.2 *New Replacement Bids for Dispatchable Loads Bidding at Negative Price*

According to the amended market rule, when a dispatchable load is eligible for a CMSC payment and has a negative bid of less than -$50/MWh (and the bid is less than the applicable energy market clearing price), the price used for the CMSC payment calculation would be the lesser of -$50/MWh or the applicable market clearing price. For example, assume a load bids at -$149/MWh to consume in an environment where the nodal price is -$150/MWh and HOEP is $50/MWh. The load is constrained-on, pays the $50/MWh HOEP, and receives a CMSC payment. Under the amended rules, it will be paid a $100/MWh constrained-on payment (i.e. $50/MWh HOEP – (- $50/MWh Replacement Bid), in contrast to the $199/MWh constrained-on payment ($50/MWh – (-$149/MWh)) that would have been made before the rule change.

The IESO's rationale for a replacement bid price of -$50/MWh was to allow a constrained-on dispatchable load to recover all costs, including non-energy costs, associated with consumption. The IESO calculated these non-energy costs to be approximately -\$46.93/MWh, and this amount was rounded to -\$50/MWh. The details of the IESO calculations are summarized in Table 3-5 below:

Table 3-5: IESO's Calculation of Non-Energy Costs incurred by Dispatchable Loads
Based on January – June, 2010
($/MWh)

IESO Wholesale Market Charges	Average Arithmetic (Year-to-Date)	% of Total
Global Adjustment	$29.30	62
Wholesale Market Service Charges:		
CMSC	$0.87	2
IOG	$0.06	0
Other Hourly Uplift	$0.71	2
Monthly Uplift	$0.92	2
IESO Administration	$0.82	2
OPA Administration	$0.55	1
Rural/Remote Settlement	$1.30	3
Debt Retirement Charge	$7.00	15
Subtotal	$41.53	88
HST	$5.40	12
Total	**$46.93**	**100**

*Source: Market Rule Amendment-00370.

The GA amount in Table 3-5 was calculated based on the GA allocation method that was in effect to the end of 2010. Under that method, every MWh of consumption each month attracted a GA charge. As described in section 3.1 above, a new GA allocation method went into effect on January 1, 2011 and dispatchable loads are no longer charged GA for each MWh of consumption. Instead, their monthly GA allocation is now based on their consumption in just five peak hours in the Base Period. It is highly improbable that an hour in which a dispatchable load bids at a negative price and is constrained-on would be one of the five peak demand hours in Ontario. During the five coincident peak hours in the May 2010 to April 2011 Base Period, there were no dispatchable loads constrained-on. Similarly, during the five highest price coincident peak hours between May 2011 and

September 2011, which are likely to provide all or most of the peaks for the next GA Base Period, there were no dispatchable loads constrained-on.[115]

Given that dispatchable loads no longer pay GA on a purely volumetric basis, the cost of being constrained-on is considerably less than the amount calculated by the IESO in Table 3-5(about $33/MWh lower, i.e. the $29.30/MWh GA amount plus the related portion of the HST). Using a replacement bid of -$50/MWh for CMSC payments over-compensates the dispatchable load customers.[116]

Recommendation 3-1

> ***The Panel recommends that for the purposes of calculating constrained-on CMSC payments made to dispatchable loads that have bid at a negative price, the IESO should set a new replacement bid price that does not take into account any global adjustment charges. This new price would be higher than the current replacement bid price of -$50/MWh.***

3.2.3 New Replacement Bids for Exporters Bidding at a Negative Price

For exporters, the CMSC replacement bid price established under the amended rule is the lesser of -$125/MWh or the applicable market clearing price. Exporters pay the wholesale charges listed in Table 3-5, but not the GA.

The IESO's rationale for a replacement bid price of -$125/MWh for exporters was, in large part, to create a price that would not hinder potentially efficient trades. For example, it would be economic for a trader to export from a market with a -$125/MWh price and deliver to a market with a -$50/MWh price. In such a transaction, the exporter is paid $125/MWh to take the energy and is charged $50/MWh to deliver the energy, but

[115] This excludes dispatchable loads that are technically "constrained on" as a result of self-induced consumption deviations between their actual usage and their scheduled dispatch in the unconstrained schedule. For details about how such deviations and CMSC payments occur, see the Panel's August 2010 Report, pp. 121-123.
[116] The CMSC payment is included in the uplift charges. This in turn effectively imposes an additional financial burden on other Ontario customers and exporters who pay the uplift.

still makes a profit of $75/MWh. This type of analysis could be valid in a market with locational clearing prices that reflect the value of incremental megawatts supplied or consumed. It might not be valid, however, where the export is sourced from a zone where the prices are consistently negative and where resources in that area are effectively not exposed to the negative zonal price. As noted above, the zonal price in the Northwest is chronically disconnected from the underlying cost of delivering energy in that area. For the last three years the average hourly price in the Northwest zone has been lower than -$150/MWh. Accordingly, any analysis that is based on the assumption that the zonal price reflects the cost of delivering power in an area such as the Northwest is flawed and may over-compensate exporters. The Panel intends to conduct further analysis of the -$125/MWh replacement bid price for constrained-on exports to determine whether it achieves the purpose of facilitating efficient trades.

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Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is the Panel's 18th semi-annual Monitoring Report on the IESO-administered markets. It covers the winter period, November 2010 to April 2011. As in previous reports, the Panel has concluded that the market has operated reasonably well having regard to its hybrid design, although there were occasions where the design of generation contracts, actions by market participants, or actions taken by the IESO led to inefficient outcomes.

2. Future Development of the Market

The Electricity Market Forum (the EMF) was established by the IESO in early 2011 to identify and assess the practicality of market changes that might improve a number of aspects of the market, including the ability of the market to efficiently deliver reliable and sustainable electricity. A member of the Market Assessment Unit attends EMF meetings as an observer.

The EMF currently is developing a market 'roadmap'– an actionable set of recommendations for the implementation of market improvements.

In March 2011, the Chair of the Panel addressed the Forum, and provided the Panel's views on four changes to the market design or the market rules that could improve efficiency:

- *Replacement of the two-schedule system*. In several previous monitoring reports, the Panel has observed that the existing market design contributes to inefficiencies, undermines transparency, leads to unwarranted uplift charges, and gives rise to market gaming opportunities. The original Market Design Committee considered the two-schedule system to be a transitional expedient to locational pricing. The volume and nature of unintended inefficiencies arising from the CMSC regime have been substantial. The Panel encouraged the EMF to investigate alternatives to the two-schedule system. Such alternatives could include, but are not limited to, a market with full locational pricing or a market where dispatchable resources would face prices that reflect local conditions and non-dispatchable loads would be charged a uniform price (for example, based on a weighted average of dispatchable resource prices).

- *Improving Ontario's ability to interact efficiently with neighbouring jurisdictions*. This issue is inter-related with the two-schedule system issue. The Panel has noted many examples of inefficient imports and exports caused by our current market design. (Recommendation 2-2 in this monitoring report, which is addressed to the IESO and the EMF, concerns the frequency of dispatching intertie transactions). Imports and exports provide important flexibility and competitive discipline for the Ontario market and facilitate efficient arbitrage opportunities.
- *Making new generation and demand response contracts more "market friendly*." Better alignment of contract provisions with the operation of the market can increase efficiency and provide more reliable price signals.
- *Reviewing the efficacy and continuing need for the Generation Cost Guarantee Program*. The Panel has made several recommendations in recent years on the efficiency implications of the GCG program. Market conditions have changed considerably since the implementation of the GCG program. Specifically, the supply/demand scenario has changed from a situation of occasional supply shortage to situation of frequent supply surplus. In addition, in October 2011 the IESO implemented an Enhanced Day Ahead Commitment process, which may reduce or eliminate the need for a GCG program. Under the circumstances, a cost/benefit analysis of that program would be timely.

3. Implementation of Panel Recommendations from Previous Reports

The Panel's February 2011 report contained four recommendations, all of which were directed at the IESO.

3.1 Recommendations to IESO from the Prior Report

The IESO formally reports on the status of actions it has taken in response to the Panel's 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 to the IESO Board of Directors (SAC).

In this section we review the status of the recommendations from our last Monitoring Report, released in February 2011. The IESO responses are summarized in Table 4-1 below.

Table 4-1: IESO Responses to Recommendations in the Panel's February 2011 Monitoring Report

Recommendation	IESO Response
Recommendation 3-1 *The IESO should not remove imports curtailed to address surplus baseload generation conditions from the unconstrained market schedule. This could be accomplished by changing how the ADQh code operates with respect to the market schedule.*	"There are several issues regarding the appropriate market price during curtailment of intertie transactions due to adequacy. The IESO's current practices are based on the belief that the resultant price impacts of curtailed transactions do not represent a distortion. Not removing these transactions from the unconstrained algorithm would also result in further differences between the constrained and unconstrained sequences, which would create an additional uplift burden for Ontario consumers and would be opposite in direction from the IESO's goal of aligning pricing with actual dispatch. However, the IESO is sensitive to counter-intuitive prices and as stated previously will consider this within the policy review of SE-67, currently assigned a low priority."

Recommendation 3-2 *Where there are transfer capability reductions outside Ontario that prohibit power flow out of or into Ontario, the IESO should not make CMSC payments. Possible methods might include but are not limited to: removing the related offers/bids, reducing intertie transfer capability to zero, or establishing a mechanism for clawback of the CMSC payments.*	The IESO agrees that CMSC payments for external congestion are inappropriate. Furthermore, removing these transactions from the market schedule will result in a more accurate price signal to the market. There are several options that can be looked at in order to resolve this issue, some having negative consequences. The option of reducing the intertie capability would send incorrect congestion signals by moving external congestion to congestion on the intertie. This congestion can create possible shortages in the Transmission Rights market and prevent other efficient trade from occurring. A second option could see the removal of offers/bids from the pre-dispatch sequence. While this method would address transactions receiving CMSC payments for external reasons, it may inappropriately remove CMSC payments for transactions legitimately constrained off for internal limitations (deserving of CMSC). Another option would be to clawback the inappropriate CMSC. This however, is not a trivial task as they would require complex, resource intense manual assessments. The complexity is driven by knowing which limitation - either internal or external- drove the two schedules to diverge, thus generating CMSC - our tools do not recognize this. The final option, and the IESO preference, would be to address the root of the issue: participant behaviour. Recognizing the inability to flow in the external market as a result of the lack of transmission service, participants should remove their dispatch data when conditions permit. The Market Assessment Unit should continue to monitor and take appropriate action as required to address these issues as they occur. We believe this action would be best suited to resolve such issues and mitigate reoccurrence in the future.

Recommendation 3-3 *As part of its "market road map" process, the IESO should work with stakeholders to examine the feasibility of replacing the two-sequence design with locational pricing, variable pricing for dispatchable resources or other alternatives.*	"The IESO accepts this recommendation and acknowledges the Ontario Energy Board's support for examining alternatives to replace the two-sequence design. This recommendation is a fundamental change to current market design and would require broad stakeholder consultation. The IESO has initiated the Electricity Market Forum to consider the future role and development path for the IESO-administered markets. The Electricity Market Forum is expected to produce a final report which will be made public prior to year-end, 2011".

Recommendation 3-4 (i) *The IESO should resume work on Stakeholder Engagement 84 regarding elimination of self-induced CMSC payments for ramping down generators and should amend the Generation Cost Guarantee program to ensure that all guaranteed costs are considered as part of the dispatch optimization.*	"The Technical Panel assigned a medium priority to this issue (MR-00252), recognizing that the IESO has the ability to seek an urgent amendment at any time if market participants seek to exploit this identified flaw in the market rules. After meeting with generators at the Technical Panel's request the IESO presented a revised amendment submission to the Technical Panel at its meeting on July 6, 2010. On June 17, 2011 the MSP posted a monitoring document to provide guidance to generators regarding offer prices for signaling an intention to come offline. The IESO will monitor the impact of the MSP guidelines on CMSC payments during ramp down. In the meantime, the IESO is pursuing the other amendments identified under MR-00252 to address self-induced CMSC payments to generators. In response to a recommendation from the January 2009 MSP report, the IESO initiated a market rule amendment to revise the method of calculating guarantees to improve the effectiveness of day-ahead scheduling decisions. These changes, implemented in December 2009 under MR-00356, linked the guarantee payment to the market participant's offer price and introduced more stringent eligibility requirements for the real-time GCG program. As a result of the changes implemented under MR-00356, approximately 40% of generators costs are reflected in their offers. This is a significant improvement compared to the initial design where none of the costs were reflected in offers. At this time the IESO continues to believe a reliability program is warranted and some changes to the day-ahead guarantee program are part of the Enhanced Day-Ahead Commitment (EDAC) initiative which will be in service later in 2011. Consistent with the MSP recommendation, this process will consider all costs in the optimization of the day-ahead commitments or resources. Upon gaining experience with the operation of EDAC, the IESO intends to re-examine the real-time GCG program".

Recommendation 3-4 (ii) *On an interim basis until after-the-fact start-up cost submissions are capped by generator offer prices and CMSC payments to ramping down generators are eliminated, the IESO should amend the Generation Cost Guarantee program to limit generators to one start-up cost guarantee submission per day unless the IESO requests a second start during the day.*	"The IESO has considered this recommendation. The IESO's concern is that limiting generators to one start-up cost guarantee per day may prevent the use of the least-cost option later in the day simply because the generator has operated earlier in the day. Instead, the IESO will ensure that the costs recovered from any second start-up are limited to a level that reflects that the unit is already hot and would have both reduced start-up time and a shorter minimum run time".
Recommendation 3-4 (iii) *The IESO should re-examine whether the GCG program continues to provide a net benefit to the Ontario market once the Enhanced Day-Ahead Commitment (EDAC) process is implemented or as part of its "Market Roadmap" process.*	The Enhanced Day-Ahead Commitment (EDAC) initiative will be in service later in 2011. Consistent with the MSP recommendation, this process will consider all costs in the optimization of the day-ahead commitments of resources. Upon gaining experience with the operation of EDAC, the IESO intends to re-examine the real-time GCG program.

3.2 Recommendations to IESO from Previous Reports

Panel recommendations from previous reports as well as IESO responses to those recommendations are available on the IESO website.[117] The Panel reports on the change to the status of recommendations from previous reports.

In its January 2010 Report the Panel made the following recommendation:

> The Panel recommends that, for the purposes of calculating Congestion Management Settlement Credit (CMSC) payments, the IESO should revise its constrained-on payment calculation using a replacement bid (such as $0/MWh) when market participants (both exporters and dispatchable loads) bid at a

[117] See: http://ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20110811.pdf

negative price. This would create more consistent treatment with generators and importers that are constrained-off.[118]

On December 3rd 2010, the IESO implemented a market rule amendment that addressed the issue of constrained-on payments given to exporters and dispatchable loads bidding at negative prices. After consultation with market participants, the IESO implemented a new rule on December 3, 2010 which uses a -$50/MWh replacement bid amount for dispatchable loads and a -$125/MWh replacement bid for exporters.[119]

4. Summary of Recommendations

The Panel groups its recommendation thematically by category: price fidelity, dispatch, transparency and hourly uplift payments. Some recommendations could have impacts in more than one category (e.g. a scheduling change could affect prices as well as uplift). In such cases the recommendation is included in the category of its primary effect. Within each category of price fidelity, dispatch and hourly uplift payments[120], the recommendations in this report have been prioritized based on the Panel's view of their relative importance.

4.1 Transparency

Data transparency promotes efficient supply/demand decisions.

Recommendation 2-1
The Panel recommends that the IESO publish the most current aggregate wind generation forecast information that is available. The published information should be updated on an hourly basis and should cover all future hours for which wind generation forecasts are available.

[118] See the Panel's January 2010 Report at p. 104.
[119] See Market Rule Amendment Proposal MR-00370-R00 at http://www.ieso.ca/imoweb/pubs/mr2010/MR-00370-R00-BA.pdf
[120] The Panel does not have any recommendations in this report relating to transparency.

4.2 Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market.

Recommendation 2-2

The Panel recommends that the IESO and the Electricity Market Forum investigate increasing the frequency with which interties are scheduled in order to improve market efficiency and price fidelity. In conjunction with any such increase, the IESO should explore parallel increases in the frequency of the forecasts of demand and the output from wind and other intermittent generation, as well as pre-dispatch schedules.

4.3 Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market.

Recommendation 2-3:
The Panel recommends that the IESO accelerate its efforts under Stakeholder Engagement (SE-91) to make wind generators dispatchable.

4.4 Uplift Payments

The Panel examines uplift payments[121] both in respect of their contribution to the effective price and also their impact on the efficient operation of the market.

[121] Uplift Settlement Charges are collected from customers in the wholesale market to pay for Operating Reserve, Congestion Management Settlement Credits, Intertie Offer Guarantee payments and other costs such as energy losses on the IESO-controlled grid and cost guarantee programs.

Recommendation 3-1

The Panel recommends that for the purposes of calculating constrained-on CMSC payments made to dispatchable loads that have bid at a negative price, the IESO should set a new replacement bid price that does not take into account any global adjustment charges. This new price would be higher than the current replacement bid price of -$50/MWh.

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 2010 – April 2011

PUBLIC **November 2011**

List of Tables

Table A-1: Outages, May 2009 - April 2011 (TWh)*

	Total Outage		Planned Outage**		Forced Outage	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	7.70	5.98	2.94	3.45	3.85	3.04
Jun	4.89	4.79	1.18	2.94	2.88	3.61
Jul	3.70	4.55	0.97	1.18	2.76	3.58
Aug	3.57	4.57	1.40	0.97	2.61	3.17
Sep	6.01	5.17	2.76	1.40	2.87	2.41
Oct	7.52	6.51	3.88	2.76	3.68	2.63
Nov	6.26	5.19	2.69	3.88	2.67	2.50
Dec	4.35	2.94	1.76	2.69	2.62	1.18
Jan	3.39	1.73	0.47	1.76	2.46	1.26
Feb	2.99	3.97	1.66	0.47	1.65	2.31
Mar	4.16	4.79	2.05	1.66	2.19	2.74
Apr	5.96	6.87	4.04	2.05	2.51	2.83
May – Oct	33.39	31.57	14.74	12.7	18.65	18.44
Nov - Apr	27.11	25.49	13.01	12.51	14.10	12.82
May - Apr	60.50	57.06	27.75	25.21	32.75	31.26

* 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.
** CO_2 Outages are recorded as forced outages by the IESO but are classified as planned outages for purposes of our statistics.

Table A-2: Ontario Consumption by Type of Usage
May 2009 – April 2011
(TWh)

	LDC's*		Wholesale Loads		Generators		Metered Energy Consumption**		Transmission Losses		Total Energy Consumption***	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	8.34	9.01	1.71	1.79	0.09	0.12	10.14	10.92	0.36	0.44	10.50	11.36
Jun	8.80	9.29	1.69	1.83	0.07	0.09	10.56	11.21	0.32	0.34	10.88	11.55
Jul	9.11	10.81	1.73	1.96	0.10	0.09	10.97	12.86	0.35	0.45	11.32	13.31
Aug	9.89	10.43	1.85	1.96	0.09	0.12	11.89	12.51	0.34	0.41	12.23	12.92
Sep	8.81	8.84	1.71	1.85	0.08	0.13	10.65	10.81	0.28	0.24	10.93	11.05
Oct	9.03	8.75	1.76	1.88	0.08	0.10	10.92	10.74	0.26	0.19	11.18	10.93
Nov	8.96	9.24	1.72	1.80	0.08	0.11	10.81	11.15	0.30	0.15	11.11	11.30
Dec	10.37	10.48	1.73	1.83	0.09	0.10	12.28	12.42	0.39	0.29	12.67	12.71
Jan	10.75	10.80	1.84	1.92	0.11	0.11	12.79	12.83	0.36	0.47	13.15	13.30
Feb	9.53	9.59	1.73	1.76	0.08	0.11	11.41	11.46	0.34	0.32	11.75	11.78
Mar	9.38	9.91	1.85	1.93	0.07	0.11	11.35	11.95	0.34	0.4	11.69	12.35
Apr	8.26	8.63	1.73	1.76	0.12	0.11	10.11	10.50	0.36	0.29	10.47	10.79
May –Oct	53.98	57.13	10.45	11.27	0.50	0.65	65.14	69.05	1.91	2.07	67.04	71.12
Nov - Apr	56.37	58.65	10.43	11.00	0.52	0.65	67.74	70.31	2.09	1.92	70.84	72.23
May -Apr	110.35	115.78	20.88	22.27	1.02	1.30	132.88	139.36	4.00	3.99	137.88	143.35

* 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-3: Total Hourly Uplift Charge by Component, May 2009 – April 2011 ($ Millions)

	Total Hourly Uplift*		RT IOG**		DA IOG*		CMSC***		Operating Reserve		Losses	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	45.58	19.89	0.80	0.16	0.15	0.34	24.99	9.57	10.81	0.35	8.84	9.47
Jun	37.39	21.3	1.36	0.12	0.10	0.02	21.40	11.22	6.98	1.14	7.55	8.8
Jul	36.54	30.11	5.61	0.37	0.11	0.13	18.01	13.68	7.07	1.46	5.74	14.47
Aug	28.51	25.28	1.30	0.23	0.12	0.03	12.19	10.28	6.52	2.12	8.38	12.62
Sep	20.02	20.49	2.19	0.45	0.16	0.08	11.01	8.45	2.98	3.25	3.68	8.27
Oct	21.03	14.14	1.81	0.23	0.22	0.04	10.32	5.54	1.18	1.28	7.51	7.05
Nov	24.98	14.76	0.49	0.1	0.05	0.04	14.70	6.58	3.05	1.08	6.70	6.96
Dec	24.85	23	1.06	0.33	0.05	0.03	10.40	8.48	3.07	3.72	10.27	10.44
Jan	25.98	18.72	0.85	0.46	0.02	0.04	11.64	5.94	3.39	2.21	10.09	10.07
Feb	22.65	14.21	0.53	0.43	0.01	0.03	10.56	4.99	2.38	1.3	9.18	7.46
Mar	23.65	17.01	0.93	0.42	0.01	0.02	12.46	7.09	2.75	1.1	7.49	8.38
Apr	18.41	20.19	0.61	0.4	0.05	0.04	10.49	7.71	0.31	4.7	6.94	7.34
May- Oct	189.07	131.21	13.07	1.56	0.86	0.64	97.92	58.74	35.54	9.6	41.70	60.68
Nov - Apr	140.52	107.89	4.47	2.14	0.19	0.2	70.25	40.79	14.95	14.11	50.67	50.65
May -Apr	329.59	239.1	17.54	3.7	1.05	0.84	168.17	99.53	50.49	23.71	92.37	111.33

* 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-4: CMSC Payments, Energy and Operating Reserve, May 2009 – April 2011 ($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	9.31	5.73	10.84	3.13	20.46	8.86	3.94	0.30	24.40	9.16
Jun	13.33	6.87	6.75	3.46	20.69	10.33	2.86	0.59	23.55	10.92
Jul	15.20	8.87	4.93	3.93	20.54	12.79	2.24	0.58	2.28	13.37
Aug	0.91	7.23	3.04	3.08	12.70	10.32	1.03	0.99	13.73	11.31
Sep	7.60	5.27	2.85	3.43	10.69	8.70	1.72	1.07	12.41	9.77
Oct	9.20	3.66	2.61	1.67	12.11	5.33	0.07	1.45	12.85	6.78
Nov	8.97	3.77	0.37	2.02	13.27	5.79	2.49	1.31	15.75	7.10
Dec	7.86	5.67	3.73	1.59	11.92	7.25	1.12	1.37	13.04	8.62
Jan	7.67	3.15	2.96	2.37	11.07	5.52	0.70	0.62	11.76	6.14
Feb	6.70	3.12	3.44	1.73	13.30	4.85	0.76	0.33	14.06	5.18
Mar	6.70	4.56	3.05	1.84	14.10	6.40	1.14	0.55	15.24	6.95
Apr	4.30	3.86	2.60	2.33	10.48	6.19	0.35	1.21	10.83	7.40
May- Oct	55.55	37.63	31.02	18.7	97.19	56.33	11.86	4.98	89.22	61.31
Nov - Apr	42.21	24.13	16.15	11.88	74.14	36.00	6.56	5.39	80.68	41.39
May -Apr	97.75	61.76	47.17	30.58	171.33	92.33	18.42	10.37	169.9	102.70

* 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-5: Share of Constrained On Payments for Energy by Type of Supplier, May 2009 – April 2011 (%)

	Domestic Generators		Imports	
	2009 / 2010	2010 / 2011	2009 / 2010	2010 / 2011
May	99.2	99.9	0.8	0.1
Jun	92.7	99.7	7.3	0.3
Jul	89.7	100.9	10.3	(0.9)
Aug	103.6	100.0	(3.6)	0.0
Sep	99.0	99.8	1.0	0.2
Oct	101.9	100.3	(1.9)	(0.3)
Nov	99.0	100.0	1.0	0.0
Dec	98.7	98.1	1.3	1.9
Jan	97.1	99.6	2.9	0.4
Feb	97.1	98.9	2.9	1.1
Mar	98.6	99.7	1.4	0.3
Apr	100.0	100.4	0.0	(0.4)
May- Oct	97.7	100.1	2.3	(0.1)
Nov - Apr	98.4	99.4	1.6	0.6
May -Apr	98.0	99.8	2.0	0.2

Table A-6: Supply Cushion Statistics, On-Peak, May 2009 – April 2011 (% 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)*	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	15.1	19.3	0	0	66	25	14.2	16.8	0	0	75	77
Jun	13.8	16.1	0	0	95	70	18.5	17.8	0	0	27	25
Jul	12.7	17.0	0	0	120	45	15.4	15.2	0	2	34	117
Aug	12.7	17.0	0	0	111	49	12.0	14.6	5	0	124	110
Sep	12.7	16.5	0	0	110	91	11.6	17.4	0	0	155	50
Oct	15.3	14.8	0	0	62	103	11.9	18.3	1	0	131	10
Nov	16.3	19.8	0	0	43	22	14.1	17.7	0	0	81	24
Dec	12.2	12.6	0	0	121	167	14.2	21.1	0	0	66	2
Jan	11.2	14.2	0	0	141	116	11.5	19.5	0	0	124	6
Feb	10.4	15.2	0	0	156	88	12.4	16.6	0	0	66	33
Mar	10.3	12.4	0	0	198	181	13.0	15.8	0	0	92	31
Apr	16.0	13.5	0	0	49	168	15.2	14.2	0	0	49	122
May- Oct	13.7	16.8	0	0	564	383	13.9	16.7	6	2	546	389
Nov - Apr	12.7	14.6	0	0	708	742	13.4	17.5	0	0	478	218
May -Apr	13.2	15.7	0	0	1,272	1125	13.7	17.1	6	2	1,024	607

* This category includes hours with a negative supply cushion

Table A-7: Supply Cushion Statistics, Off-Peak, May 2009 – April 2011 (% 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)*	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	18.3	37.0	0	0	78	0	21.7	32.8	1	0	53	0
Jun	17.2	32.3	0	0	74	0	27.0	31.8	0	0	1	0
Jul	16.2	35.7	0	0	98	0	25.6	29.6	0	0	4	0
Aug	19.2	33.3	0	0	83	1	24.3	25.5	0	0	19	1
Sep	17.5	29.3	0	0	56	3	21.2	28.2	0	0	57	1
Oct	20.9	27.7	0	0	55	10	20.2	33.4	0	0	42	1
Nov	22.3	36.1	0	0	11	2	21.4	31.8	2	0	25	1
Dec	20.3	27.6	0	0	37	0	25.7	34.6	0	0	10	0
Jan	21.1	25.4	0	0	67	3	22.4	31.3	3	0	48	0
Feb	18.6	25.3	0	0	71	0	20.7	26.5	0	0	51	0
Mar	17.5	22.8	0	0	76	24	22.9	28.5	0	0	24	0
Apr	24.4	23.5	0	0	10	21	25.0	29.0	0	0	11	7
May- Oct	18.2	32.6	0	0	444	444	23.3	30.2	1	0	176	3
Nov - Apr	20.7	26.8	0	0	272	272	23.0	30.3	5	0	169	8
May -Apr	19.5	29.7	0	0	716	716	23.2	30.3	6	0	345	11

* This category includes hours with a negative supply cushion

Table A-8: Resources Selected in the Real-time Market Schedule, May 2009 – April 2011 (TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Wind		Domestic Generation*	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	0.47	0.51	1.12	0.55	0.85	1.28	0.97	1.53	4.08	2.47	4.96	5.74	0.21	0.21	11.07	11.23
Jun	0.37	0.52	1.67	1.18	0.45	1.73	1.23	1.4	3.46	2.14	6.87	6.55	0.09	0.16	12.10	11.98
Jul	0.63	0.77	1.88	1.32	0.34	2.07	1.09	2.08	3.43	2.15	7.47	7.04	0.11	0.14	12.44	13.48
Aug	0.71	0.70	1.6	1.25	0.76	1.75	1.33	2.06	3.39	2.04	7.47	7.14	0.14	0.16	13.09	13.15
Sep	0.76	0.79	1.27	1.71	0.33	0.51	1.3	1.31	2.83	2.34	6.79	7.23	0.13	0.26	11.38	11.65
Oct	0.65	0.51	1.03	1.44	0.59	0.12	1.35	1.25	2.91	2.70	6.37	7.15	0.24	0.28	11.46	11.50
Nov	0.26	0.48	1.00	1.26	0.49	0.49	1.29	1.38	3.21	2.64	6.55	6.82	0.21	0.33	11.75	11.66
Dec	0.35	0.47	1.41	2.14	1.41	0.64	1.1	1.64	3.19	3.13	7.6	8.19	0.27	0.36	13.57	13.96
Jan	0.74	0.41	1.55	1.56	2.1	0.54	0.93	1.76	3.14	3.16	7.36	8.2	0.25	0.28	13.78	13.94
Feb	0.7	0.38	1.23	1.00	1.5	0.32	0.85	1.61	2.87	2.79	6.74	6.77	0.17	0.39	12.13	11.88
Mar	0.67	0.37	1.29	1.03	0.62	0.26	1.03	1.4	3.21	3.1	7.06	7.4	0.23	0.30	12.15	12.46
Apr	0.47	0.34	0.84	1.06	0.63	0.12	1.08	0.93	2.64	3.03	6.12	6.76	0.25	0.36	10.72	11.20
May – Oct	3.59	3.8	8.57	7.45	3.32	7.46	7.27	9.63	20.1	13.84	39.93	40.85	0.92	1.21	71.54	72.99
Nov - Apr	3.19	2.45	7.32	8.05	6.75	2.37	6.28	8.72	18.26	17.85	41.43	44.14	1.37	2.02	74.09	75.10
May - Apr	6.78	6.25	15.89	15.5	10.07	9.83	13.55	18.35	38.36	31.69	81.36	84.99	2.29	3.23	145.63	148.09

* Domestic generation is the sum of Coal, Oil/Gas, Hydroelectric, and Nuclear.

Table A-9: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2009 – April 2011 (MW and %)

	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	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	278	283	252	223	186	320	157	261	2.0	1.9	1.9	1.5	1.3	2.1	1.1	1.7
Jun	313	285	286	216	219	321	187	274	2.1	1.8	1.9	1.4	1.4	2.0	1.2	1.7
Jul	346	348	299	266	235	399	183	319	2.3	2.0	2.0	1.5	1.5	2.2	1.2	1.8
Aug	381	332	333	256	256	393	200	331	2.4	1.9	2.1	1.5	1.5	2.3	1.2	1.9
Sep	308	211	281	164	194	285	161	262	2.1	1.4	1.9	1.1	1.3	1.9	1.1	1.7
Oct	270	167	247	136	177	265	147	254	1.8	1.1	1.7	0.9	1.2	1.8	1.0	1.7
Nov	325	240	307	205	194	264	159	236	2.2	1.5	2.0	1.3	1.3	1.7	1.0	1.5
Dec	329	266	282	227	252	254	207	229	2.0	1.6	1.7	1.3	1.5	1.5	1.2	1.4
Jan	264	293	213	241	247	300	214	250	1.5	1.7	1.2	1.4	1.4	1.7	1.2	1.4
Feb	220	253	182	198	227	266	214	229	1.3	1.5	1.1	1.1	1.3	1.5	1.2	1.3
Mar	224	249	179	199	252	299	221	261	1.4	1.5	1.2	1.2	1.6	1.8	1.4	1.6
Apr	217	227	178	185	257	275	223	259	1.5	1.5	1.2	1.2	1.8	1.8	1.5	1.7
May – Oct	316	271	283	210	211	331	173	284	2.1	1.7	1.9	1.3	1.4	2.1	1.1	1.8
Nov – Apr	263	255	224	209	238	276	206	244	1.7	1.6	1.4	1.3	1.5	1.7	1.3	1.5
May - Apr	290	263	253	210	225	303	189	264	1.9	1.6	1.7	1.3	1.4	1.9	1.2	1.6

Table A-10: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2009 – April 2011
(%)*

	> 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	
	2009/2010	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**	**2009/2010**	**2010/2011**
May	1	2	12	8	15	7	21	10	20	17	15	15	17	29	1	13	49	27	53	74
Jun	4	0	13	10	14	6	18	10	18	14	14	15	18	29	1	15	49	26	51	73
Jul	3	3	18	9	16	7	17	9	17	11	15	13	14	30	1	19	54	28	47	73
Aug	3	2	18	9	14	6	20	8	15	10	9	14	18	30	3	22	55	25	45	76
Sep	1	1	17	5	14	6	21	11	19	15	14	17	11	31	2	14	53	23	46	77
Oct	1	0	13	4	13	4	18	11	24	16	17	19	15	33	1	13	45	19	57	81
Nov	2	0	16	8	18	8	21	13	18	15	14	18	10	27	1	12	57	29	43	72
Dec	2	1	15	8	10	9	17	15	17	15	14	14	21	29	5	9	44	33	57	67
Jan	1	2	7	11	8	8	15	12	17	15	18	15	27	26	7	10	31	33	69	66
Feb	0	1	6	8	8	7	15	13	17	17	16	16	28	29	8	9	29	29	69	71
Mar	0	1	7	5	8	6	12	11	17	16	18	14	30	34	8	13	27	23	73	77
Apr	0	1	6	8	6	8	11	12	19	14	19	15	31	28	8	14	23	29	77	71
May – Oct	2	1	15	8	14	6	19	10	19	14	14	16	16	30	2	16	51	25	50	76
Nov – Apr	1	1	10	8	10	8	15	13	18	15	17	15	25	29	6	11	35	29	65	71
May - Apr	2	1	12	8	12	7	17	11	18	15	15	15	20	30	4	14	43	27	57	73

* Data includes both dispatchable and non-dispatchable load.

Table A-11: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities,
May 2009 – April 2011
*(MW and %)**

	Pre-Dispatch (MW)		Pre-Dispatch (MW)						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2009 / 2010	2010 / 2011	2009 / 2010	2010 / 2011	2009 / 2010	2010 / 2011	2009 / 2010	2010 / 2011	2009 / 2010	2010 / 2011
May	870,407	783,768	333.3	390.2	(297.8)	(254.3)	32.0	49.6	3.1	4.9
Jun	885,315	839,507	916.1	312.8	(423.0)	(413.1)	64.8	49.7	6.0	4.5
Jul	719,422	875,636	217.2	410.3	(227.2)	(285.9)	19.4	70.7	2.1	6.1
Aug	722,427	823,801	328.4	414.8	(306.5)	(256.8)	35.6	58.2	3.7	5.5
Sep	710,740	792,001	291.0	302.1	(252.9)	(336.2)	58.5	23.2	6.5	2.4
Oct	927,991	959,747	312.1	328.6	(392.0)	(382.4)	(1.7)	43.3	(0.1)	3.7
Nov	878,206	1,030,041	307.1	472.0	(331.4)	(272.2)	25.1	82.6	2.5	6.2
Dec	1,013,138	1,140,816	386.3	458.2	(308.7)	(265.4)	24.0	86.9	1.9	6.1
Jan	996,683	1,033,636	291.0	453.3	(313.2)	(704.6)	31.6	84.2	2.4	6.2
Feb	848,610	1,068,883	358.6	376.4	(324.3)	(453.8)	38.4	(15.0)	3.2	(0.3)
Mar	1,020,117	1,020,602	348.0	458.5	(309.0)	(563.6)	18.5	(0.5)	1.4	0.4
Apr	888,135	998,323	523.9	669.2	(388.7)	(556.7)	26.5	8.9	2.1	1.2
May – Oct	806,050	845,743	399.7	359.8	(316.6)	(321.5)	34.8	49.1	3.6	4.5
Nov – Apr	940,815	1,048,717	369.2	481.3	(329.2)	(469.4)	27.3	41.2	2.3	3.3
May - Apr	873,433	947,230	384.4	420.5	(322.9)	(395.4)	31.0	45.2	2.9	3.9

* 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-12: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2009 – April 2011

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	217,700	207,596	280.6	320.2	(301.9)	(320.1)	15.6	26.8	11.2	14.2
Jun	113,192	156,607	194.7	277.5	(279.5)	(416.4)	36.9	27.1	30.1	19.5
Jul	126,285	140,646	200.5	228.2	(212.7)	(296.4)	18.0	34.6	16.0	24.7
Aug	162,390	158,271	269.9	326.0	(285.7)	(275.2)	25.5	29.2	21.2	17.2
Sep	151,860	264,568	307.3	303.0	(264.5)	(307.8)	32.3	34.1	25.9	15.5
Oct	252,763	282,782	309.8	344.2	(356.7)	(293.1)	12.7	51.7	8.3	17.7
Nov	223,722	327,404	277.1	400.1	(291.6)	(273.7)	24.0	67.8	13.4	22.4
Dec	290,193	364,588	352.2	426.1	(297.5)	(189.6)	23.6	91.3	10.4	26.2
Jan	273,083	279,316	284.2	399.8	(302.1)	(488.0)	24.8	110.9	13.6	36.0
Feb	183,677	389,229	258.7	491.5	(238.3)	(188.2)	26.7	122.7	16.6	26.5
Mar	229,711	296,744	250.7	505.4	(307.1)	(360.9)	5.6	95.5	6.9	29.0
Apr	249,059	364,285	317.8	631.8	(388.8)	(326.7)	3.2	116	4.3	30.0
May – Oct	170,698	201,745	260.5	299.9	(283.5)	(318.2)	23.5	33.9	18.8	18.1
Nov – Apr	241,574	336,928	290.1	475.8	(304.2)	(304.5)	18.0	100.7	10.9	28.4
May - Apr	206,136	269,336	275.3	387.8	(293.9)	(311.3)	20.7	67.3	14.8	23.2

* Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-13: Failed Imports into Ontario, On-Peak, May 2009 – April 2011 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	74	120	220	380	5	67	1.6	4.2
Jun	132	142	455	600	94	71	5.2	4.1
Jul	160	170	582	679	90	96	3.7	5.4
Aug	122	165	1,079	650	11	85	3.2	6.4
Sep	170	76	642	475	66	130	2.8	1.8
Oct	107	78	224	249	58	114	2.0	2.2
Nov	89	95	270	289	69	78	4.8	2.7
Dec	100	99	689	329	102	63	5.8	4.1
Jan	100	103	410	360	10	59	2.4	4.9
Feb	89	90	300	514	65	78	1.4	3.5
Mar	113	80	453	614	67	118	1.6	2.8
Apr	113	85	429	388	72	84	2.9	3.0
May-Oct	765	751	534	506	54	94	3.1	4.0
Nov-Apr	604	552	425	490	64	80	3.1	3.5
May-Apr	1369	1303	479	445	59	87	3.1	3.8

* 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-14: Failed Imports into Ontario, Off-Peak, May 2009 – April 2011 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	164	207	381	857	82	131	5.3	9.8
Jun	138	189	783	517	109	97	9.7	7.1
Jul	164	180	619	730	118	153	6.9	6.8
Aug	151	192	750	1274	94	208	4.6	8.6
Sep	173	133	965	693	14	181	6.2	5.0
Oct	160	155	855	685	122	112	5.4	5.5
Nov	155	135	580	440	85	81	8.6	3.9
Dec	162	111	625	329	118	82	9.3	3.1
Jan	131	176	300	918	100	125	3.9	11.1
Feb	72	118	388	364	98	91	2.5	5.8
Mar	76	106	371	500	64	90	2.3	7.1
Apr	171	143	506	373	132	101	10.4	9.7
May-Oct	950	1056	726	793	90	147	6.3	7.1
Nov-Apr	767	789	462	723	100	95	6.1	6.8
May-Apr	1,717	1845	594	692	95	121	6.2	7.0

* 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-15: Failed Exports from Ontario, On-Peak, May 2009 – April 2011 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	144	162	1,342	566	118	139	4.1	7.8
Jun	179	204	1,120	1524	260	192	5.6	6.3
Jul	254	234	1,739	838	389	168	11.3	6.1
Aug	182	236	1,968	850	260	168	7.1	7.0
Sep	168	229	908	806	127	156	4.0	4.1
Oct	125	226	485	545	1	156	3.1	5.5
Nov	67	151	350	350	104	86	1.8	2.0
Dec	190	226	1,430	788	23	180	7.3	3.9
Jan	192	279	1,280	1298	247	357	6.2	12.3
Feb	184	257	939	1251	264	256	6.8	11.7
Mar	244	295	1,019	943	289	275	9.6	13.4
Apr	202	151	980	824	228	137	11.0	5.2
May-Oct	1,052	1291	1,260	855	193	163	5.8	6.1
Nov-Apr	1,079	1359	1,000	819	192	215	7.1	8.1
May-Apr	2,131	2650	1,130	696	193	189	6.5	7.1

* 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-16: Failed Exports from Ontario, Off-Peak, May 2009 – April 2011 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	198	135	1,160	806	204	135	5.4	6.1
Jun	216	156	1,144	1241	215	193	5.0	4.8
Jul	274	182	1,563	575	276	124	6.5	3.1
Aug	254	181	1,117	701	18	122	4.5	3.0
Sep	225	180	989	950	218	133	6.2	2.7
Oct	190	243	1,050	683	153	136	4.5	3.8
Nov	107	108	779	431	127	71	2.2	1.2
Dec	241	257	1,176	800	16	189	4.4	4.1
Jan	243	349	1,005	1,030	186	312	5.2	11.4
Feb	212	244	933	1,064	250	154	8.6	6.9
Mar	215	217	830	775	176	161	5.7	6.5
Apr	180	241	830	665	239	152	8.6	5.1
May-Oct	1,357	1,077	1,170	826	181	141	5.3	3.9
Nov-Apr	1,198	1,416	926	764	166	173	5.8	5.9
May-Apr	2,555	2,493	1,048	690	173	157	5.5	4.9

* 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-17: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2009 – April 2011

	Average Hourly Reserve (MW)		% of Total Requirements												Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import			
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	1,453	1,354	7.4	13.1	24.0	62.5	39.5	2.3	18.2	7.9	10.8	11.5	0.0	0.8	0.0	0.0
Jun	1,478	1,495	6.4	10.1	37.5	58.2	34.8	6.2	9.8	8.0	11.6	11.4	0.0	6.9	0.0	0.0
Jul	1,511	1,466	7.1	11.9	43.5	59.9	34.0	2.4	7.1	6.8	7.2	7.7	1.1	3.7	0.0	0.0
Aug	1,516	1,648	12.6	9.1	47.4	77.7	30.7	3.8	5.8	11.6	3.5	3.1	0.0	6.1	0.0	0.0
Sep	1,555	1,503	12.2	11.0	49.4	47.7	24.9	6.4	9.3	12.4	3.7	3.8	0.4	10.8	0.0	0.0
Oct	1,412	1,441	13.0	14.9	60.1	38.1	15.2	7.3	10.4	15.2	1.3	1.3	0.0	10.3	0.0	0.0
Nov	1,487	1,539	11.8	10.6	41.9	47.0	26.9	8.3	11.2	18.4	6.4	5.9	1.8	11.9	0.0	0.0
Dec	1,514	1,617	12.3	13.4	56.0	45.6	18.3	10.7	8.8	17.3	1.4	1.3	3.2	9.5	0.0	0.0
Jan	1,514	1,594	12.6	13.1	57.7	56.9	19.7	5.9	8.5	18.1	1.4	1.3	0.1	4.8	0.0	0.0
Feb	1,519	1,567	15.2	15.6	55.3	55.3	19.9	1.6	8.2	16.5	1.3	1.3	0.1	6.5	0.0	0.0
Mar	1,547	1,553	14.8	17.3	56.8	51.0	19.2	1.6	7.4	18.0	1.1	1.1	0.7	5.4	0.0	0.0
Apr	1,396	1,553	15.0	17.8	72.7	44.5	3.6	4.4	7.0	16.7	0.9	0.9	0.8	8.2	0.0	0.0
May-Oct	1,488	1,485	9.8	11.7	43.6	57.4	29.9	4.7	10.1	10.3	6.3	6.5	0.2	6.4	0.0	0.0
Nov-Apr	1,496	1,571	13.6	14.6	56.7	50.0	17.9	5.4	8.5	17.5	2.1	2.0	1.1	7.7	0.0	0.0
May-Apr	1,492	1,528	11.7	13.2	50.2	53.7	23.9	5.1	9.3	13.9	4.2	4.2	0.7	7.1	0.0	0.0

Table A-18: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2009 – April 2011

	Average Hourly Reserve (MW)		% of Total Requirements												Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import			
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	1,453	1,332	10.8	13.1	45.3	71.2	27.6	0.4	10.9	5.1	5.4	5.9	0.0	0.2	0.0	0.0
Jun	1,498	1,467	9.7	11.3	71.4	65.3	7.8	1.3	8.2	4.3	2.8	2.9	0.0	7.5	0.0	0.0
Jul	1,504	1,472	10.2	13.5	71.8	67.4	7.3	1.4	7.1	5.6	2.0	2.0	1.6	6.1	0.0	0.0
Aug	1,510	1,526	12.9	11.3	68.8	74.7	10.7	1.1	6.0	5.0	1.6	1.6	0.0	3.6	0.0	0.0
Sep	1,578	1,505	12.1	14.8	71.1	59.4	6.2	1.8	7.1	5.6	1.3	1.3	2.2	7.6	0.0	0.0
Oct	1,398	1,433	12.7	21.5	74.1	60.5	3.7	0.6	9.0	6.4	0.6	0.5	0.0	3.9	0.0	0.0
Nov	1,483	1,534	11.8	17.5	64.2	57.0	10.1	1.3	9.6	6.5	3.9	3.9	0.4	6.2	0.0	0.0
Dec	1,522	1,605	10.6	14.7	72.7	63.3	5.3	2.8	10.0	6.7	0.6	0.6	0.8	6.8	0.0	0.0
Jan	1,514	1,605	11.6	17.5	75.2	64.2	3.3	1.0	9.2	6.5	0.5	0.5	0.3	5.2	0.0	0.0
Feb	1,520	1,560	13.0	17.7	72.7	56.8	4.4	0.2	9.1	5.6	0.3	0.3	0.6	9.6	0.0	0.0
Mar	1,585	1,572	14.4	17.6	69.1	61.9	6.8	1.5	8.8	7.1	0.4	0.4	0.5	4.4	0.0	0.0
Apr	1,434	1,553	14.6	18.8	77.6	57.2	1.1	2.9	6.5	7.3	0.2	0.2	0.0	8.9	0.0	0.0
May-Oct	1,490	1,456	11.4	14.3	67.1	66.4	10.5	1.1	8.0	5.3	2.3	2.4	0.6	4.8	0.0	0.0
Nov-Apr	1,510	1,572	12.7	17.3	71.9	60.1	5.1	1.6	8.9	6.6	1.0	1.0	0.4	6.8	0.0	0.0
May-Apr	1,500	1,514	12.0	15.8	69.5	63.2	7.8	1.4	8.5	6.0	1.6	1.7	0.5	5.8	0.0	0.0

Table A-19: Monthly Payments for Reliability Programs, May 2009 – April 2011 ($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		Total	
	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011	2009/2010	2010/2011
May	0.15	0.34	0.80	0.15	11.02	0.35	3.07	4.12	0.69	3.99	15.73	8.95
Jun	0.10	0.02	1.29	0.12	7.40	1.14	2.85	9.58	1.03	2.74	12.67	13.6
Jul	0.11	0.13	5.19	0.34	7.37	1.46	7.26	6.76	1.60	7.16	21.53	15.85
Aug	0.12	0.03	1.30	0.22	6.71	2.10	8.12	7.74	1.25	4.52	17.50	14.61
Sep	0.16	0.08	2.18	0.40	3.04	3.25	9.37	7.71	0.94	5.13	15.69	16.57
Oct	0.22	0.04	1.79	0.20	1.20	1.31	6.79	3.98	1.14	5.34	11.14	10.87
Nov	0.05	0.04	0.50	0.10	3.05	1.08	9.07	4.84	0.52	6.07	13.19	12.13
Dec	0.05	0.03	1.03	0.26	3.09	3.72	9.62	2.8	2.09	8.58	15.88	15.39
Jan	0.02	0.04	0.78	0.43	3.39	2.22	2.48	2.44	4.49	9.59	11.16	14.72
Feb	0.01	0.03	0.50	0.37	2.39	1.30	1.26	3.39	5.40	10.08	9.56	15.17
Mar	0.01	0.02	0.90	0.36	2.75	1.10	2.11	4.13	8.93	7.47	14.70	13.08
Apr	0.05	0.04	0.59	0.38	0.31	4.70	1.47	3.32	8.16	3.78	10.58	12.22
May – Oct	0.85	0.64	12.54	1.43	36.74	9.61	37.45	39.89	6.65	28.88	94.23	80.45
Nov – Apr	0.19	0.20	4.31	1.90	14.99	14.12	26.01	20.92	29.58	45.57	75.08	82.71
May - Apr	1.04	0.84	16.85	3.33	51.73	23.73	63.46	60.81	36.23	74.45	169.31	163.16

* 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 $3.30 million has been received through the IOG reversal. The data reported in this table does not account for the IOG reversal.

Table A-20: Summary Statistics for Hours when HOEP < $0/MWh, May 2010 – April 2011

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
May	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
June	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
July	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
August	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
September	9	13,254	13,163	(0.7)	91	13.52	(11.76)	(187.0)	(38.02)
October	10	11,458	11,441	(0.1)	174	6.97	(9.96)	(242.8)	(21.69)
November	3	12,661	12,571	(0.7)	9	7.43	(5.91)	(179.6)	(13.18)
December	9	13,133	12,981	(1.2)	149	8.07	(41.56)	(615.2)	(128.12)
January	11	12,461	12,599	(1.1)	243	3.68	(77.63)	(2,209.60)	(138.43)
February	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
March	3	14,228	14,189	(0.3)	259	24.14	(20.55)	(185.2)	(54.44)
April	27	12,432	12,399	(0.3)	75	7.14	(56.76)	(894.9)	(138.79)
Total	72	12,576	12,547	(0.2)	130	8.22	(42.3)	(614.5)	(138.79)

* 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.