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 2012 – April 2013

January 2014

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Executive Summary

This is the Panel's 22nd semi-annual Monitoring Report on the IESO-administered markets. Chapter 1 reports on market outcomes spanning the May 2012 to April 2013 period (the "2012/13 Annual Period"), and compares them with outcomes in previous annual periods. The next chapter focuses on high-price hours, negative-price hours and other anomalous market outcomes during the period from November 2012 to April 2013 (the "Winter 2013 Period"). In Chapter 3, the Panel examines both new and previously-reported matters affecting the wholesale markets. In the final chapter, the Panel summarizes issues concerning the market's future development and the implementation of prior Panel recommendations. Where relevant in this report, the Panel makes recommendations in relation to the promotion of market objectives.

1. *Overall Assessment*

Ontario's wholesale electricity market continued to operate reasonably well over the 2012/13 Annual Period, given its hybrid design and two-schedule system. However, the Panel has identified elements of the market design that have given rise to inefficient or potentially inefficient market participant behaviour and/or inefficient market outcomes. The Panel has noted areas for improvement in the design and rules associated with the markets, in particular in relation to Congestion Management Settlement Credit (CMSC) payments related to intertie transactions and to the Independent Electricity System Operator's (IESO) generation cost guarantee programs.

The Panel currently has investigations under way in relation to four market participants (two generators and two dispatchable loads), all of which relate to potential gaming.

2. *Demand and Supply Conditions*

Ontario demand totalled 142.11 TWh in the 2012/13 Annual Period, an increase of 2.3 TWh relative to the period May 2011 to November 2012 (the "2011/12 Annual Period"). A month-to-month comparison shows that Ontario demand was higher in every month relative to the 2011/12 Annual Period, with the exception of September and December 2012.

In total, 1,601 MW of new capacity was added to the grid during the 2012/13 Annual Period. The most significant addition came from the return to service of units 1 and 2 of the Bruce nuclear facility, which contributed 1,552 MW of additional capacity. New renewable energy projects connected to the IESO-controlled grid accounted for the remaining 49 MW of increased capacity. Offsetting those additions was the closure of the Atikokan coal-fired plant, which reduced capacity in the province by 211 MW.

3. *Market Prices and the Global Adjustment*

For the 2012/13 Annual Period, the average Hourly Ontario Energy Price (HOEP) was $25.89/MWh, a 1.56% decrease from the 2011/12 Annual Period's average of $26.30/MWh. Changes in the HOEP during the 2012/13 Annual Period roughly followed changes in natural gas prices over the same period.

The Global Adjustment (GA) for the 2012/13 Annual Period averaged $45.16/MWh for all Ontario consumers, representing a $2.82/MWh or 6.7% increase from the 2011/12 Annual Period. However, while the average GA paid by large industrial consumers directly connected to the IESO-controlled grid remained largely unchanged at $23.58/MWh, other consumers saw a 7.2% average increase in their GA (to $47.88/MWh).[1]

The average effective electricity price (the sum of HOEP, GA, and uplift charges) increased by 2.8% in the 2012/13 Annual Period to $74.71/MWh. The effective price averaged $51.57/MWh for large industrial consumers connected to the IESO-controlled grid, and $77.61/MWh for other consumers.

4. *Market Outcomes*

The HOEP exceeded $200/MWh in five hours during the during the Winter 2013 Period. The high-price hours were primarily caused by high demand conditions precipitated by extreme weather conditions, as well as by reductions in available supply.

[1] The GA is allocated to large industrial consumers differently than it is to other consumers. For further detail, see section 2.2 of Chapter 1.

The HOEP was negative in 43 hours during the Winter 2013 Period. The negative-price hours resulted from ample baseload supply (including nuclear, renewable and some hydroelectric resources) continuing to offer at negative prices, and from relatively low demand.

The Panel's anomalous uplift thresholds were met on a number of occasions during the Winter 2013 Period. CMSC payments exceeded the Panel's thresholds during two multi-day periods when a transmission constraint obstructed power flows from the supply-rich Western zone to the remainder of the province. There were three hours in which operating reserve payments exceeded the Panel's threshold of $100,000. There were no instances in which Intertie Offer Guarantee (IOG) payments exceeding the Panel's $500,000 (hourly) or $1,000,000 (daily) thresholds.

5. *Matters to Report in the Ontario Electricity Marketplace*

Impact of Elimination of Constrained-off Payments in the Northwest

In October 2012, a market rule change came into effect that eliminated constrained-off CMSC payments to market participants offering to import energy into any area designated as a chronically congested area (currently, only the Northwest). As a result, not only was uplift reduced, but imports into the Northwest also decreased both in terms of offered quantities and the number of participants. Despite the reduction in participation, however, the Panel has observed an increase in effective competition following the rule change as the incentive to maximize CMSC payments with inefficient offers was eliminated. Import congestion also decreased following the rule change, better reflecting the Northwest's status as an oversupplied area.

The Enhanced Day Ahead Commitment Process and Generation Cost Guarantees

In October 2011 the IESO introduced an enhanced day-ahead commitment process (EDAC), which included a number of improvements relative to the day-ahead commitment process that was then in place. With the introduction of EDAC, there was an expectation that the overall costs of committing "non-quick start" generators (typically coal- and gas-fired units) would be reduced. The Panel undertook an analysis of the IESO's day-ahead and real-time generation cost guarantee programs with a view to ascertaining the extent to which anticipated cost savings have materialized. Based on that analysis, the Panel believes that EDAC has been unable to fully deliver the anticipated reductions in commitment costs, and this largely because of the continued co-existence of the real-time generation cost guarantee program. The Panel is also of the view that the inclusion of exports in EDAC could enhance the ability of EDAC to achieve the cost reductions that it was intended to provide.

6. *Recommendations*

The Panel makes four recommendations in this report. The first recommendation is related to CMSC payments associated with constrained-off intertie transactions. The remaining three recommendations are related to EDAC and the IESO’s generation cost guarantee programs.

Recommendation 2-1

> ***The Panel recommends that the IESO eliminate constrained-off Congestion Management Settlement Credit (CMSC) payments for all intertie transactions, with due consideration to the interplay between the elimination of negative CMSC payments and Intertie Offer Guarantee payments.***

Recommendation 3-1

> ***The Panel recommends that the IESO provide a detailed analysis to confirm whether the real-time generation cost guarantee (RT-GCG) program continues to be needed in light of the implementation of the enhanced day-ahead commitment process (EDAC), of changes in Ontario’s generation capacity, and of other changes in the market since the RT-GCG program was introduced.***

Recommendation 3-2

> ***If the IESO, after performing its detailed analysis, determines that the RT-GCG program continues to be needed, the Panel recommends that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any profit (revenues less incremental operating costs) earned (a) on output above a generation facility’s minimum loading point during its***

minimum generation block run time (MGBRT), and (b) on output generated after the end of the facility's MGBRT.

<u>Recommendation 3-3</u>

The Panel recommends that the IESO re-examine the question of integrating exports into EDAC to reduce the need to commit additional generation in real-time to meet export demand that currently only appears in the market in real-time. While the Panel is not recommending a specific approach for integrating exports, the following have been identified as potential options:

a) introduce a mechanism that encourages exports to bid in EDAC; or
b) include a forecast of exports when commitments are made under EDAC.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets over the period May 2012 to April 2013, with comparisons to the same period one year earlier as well as other periods where relevant.[2] It focuses on market indicators related to electricity pricing, demand, supply and import and export activity, and also discusses outcomes in the transmission rights and operating reserve markets.

For convenience, the period May 2012 to April 2013 is referred to as the "2012/13 Annual Period" and the period May 2011 to April 2012 is referred to as the "2011/12 Annual Period". Except as otherwise noted, references to changes experienced in the 2012/13 Annual Period are expressed relative to the 2011/12 Annual Period.

1 Highlights of Market Indicators

1.1 *Energy Price*

While the average Hourly Ontario Energy Price (HOEP) decreased relative to the 2011/12 Annual Period, the Global Adjustment (GA) and the effective price (which aggregates HOEP, GA and uplift) were both higher.

For the 2012/13 Annual Period, the average HOEP was $25.89/MWh, a 1.6% decrease from the 2011/12 Annual Period's average of $26.30/MWh.

The average monthly HOEP was lower each month in May through December 2012 than in the same months in the 2011/12 Annual Period, but was higher each month from January to April 2013. The largest monthly year-over-year increase was in March, with the average HOEP rising from its 2012 low of $14.33/MWh in March 2012 to $28.86/MWh in March 2013, a 101.4% increase. Price fluctuations are largely attributable to changes in the price of natural gas, which is to be expected as gas-fired generation units are the marginal resource that most frequently sets real-time and final pre-dispatch prices.

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[2] Market data and related reports from the IESO-administered markets are available at: http://ieso.ca/imoweb/marketdata/marketSummary.asp.

The cost of electricity to Ontario consumers is higher than HOEP. Additional costs include delivery charges (transmission and distribution), regulatory charges (including uplift) and the GA.

The GA for the 2012/13 Annual Period averaged $45.16/MWh for all Ontario consumers. This represents a $2.82/MWh (or 6.7%) increase from the 2011/12 Annual Period. However, while the average GA paid by large industrial consumers directly connected to the transmission system remained largely unchanged relative to the 2011/12 Annual Period at $23.58/MWh, other consumers on average saw a 7% increase in their GA of $3.2/MWh (to $47.88/MWh).[3]

Given the magnitude of the GA and uplift charges, the Panel also reports the effective wholesale market price for electricity. The effective price is the aggregate of the HOEP, the GA and uplift charges. Over the 2012/13 Annual Period, the average effective price was $74.71/MWh for all Ontario consumers, representing a 2.8% increase from the 2011/12 Annual Period. The effective price over the 2012/13 Annual Period averaged $51.57/MWh for large industrial consumers directly connected to the transmission system and $77.61 for other consumers.

1.2 *Ontario Demand*

Total Ontario electricity consumption was 142.11 TWh in the 2012/13 Annual Period, an increase of 2.30 TWh (1.7%) relative to the 139.81 TWh consumed in the 2011/12 Annual Period. Ontario demand was higher in every month when compared to the 2011/12 Annual Period, with the exception of September and December 2012.

1.3 *Ontario Supply*

Overall, there was a 1,390 MW (4.0%) increase in generation capacity in the wholesale market during the 2012/13 Annual Period. 1,601 MW of new capacity was added to the market; 1,552 MW from two units coming back online at the Bruce Nuclear Facility near

[3] The GA is allocated to large industrial consumers differently than it is to other consumers. Further detail regarding the allocation of the GA as between classes of consumers is set out in section 2.2, and was discussed at length in the Panel's November 2011 Monitoring Report, pp. 125-133, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf. For an explanation of the methodology by which the GA is calculated and allocated, see http://www.ieso.ca/imoweb/b100/ga_changes.asp.

Tiverton, Ontario and 49 MW from the Pointe Aux Roches wind farm near Lake St. Clair in the Western region. Offsetting that increase in supply was the closure of the 211 MW Atikokan coal-fired facility, which was taken out of service in 2012 in advance of the Ontario government's requirement that coal-fired generation be phased out by the end of 2014.[4] This represents a 6% reduction from the 3,504 MW of coal-fired generating capacity available at the beginning of the 2012/13 Annual Period.

1.4 *Imports and Exports*

Ontario remained a net exporter in the 2012/13 Annual Period. Net exports (exports minus imports) increased by 1.86 TWh (21%) to 10.86 TWh during the 2012/13 Annual Period. Increases of 0.49 TWh in off-peak net exports and 1.37 TWh in on-peak net exports were observed in the 2012/13 Annual Period.[5]

Exports increased by 1.91 TWh (14.4%) and imports increased by 0.05 TWh (1.2%),[6] resulting in the rise in net exports noted above.

1.5 *Operating Reserve*

The average hourly operating reserve (OR) requirement in the 2012/13 Annual Period was 1,450 MW, which is 66 MW less than the 1,516 MW requirement in the 2011/12 Annual Period. OR prices in the 2012/13 Annual Period were consistent with what they have been since the end of 2009.

1.6 *Transmission Rights*

Transmission rights (TR) payouts for imports fell from $15.6 million in the 2011/12 Annual Period to $8.6 million in the 2012/13 Annual Period, a 45.1% decline. This large drop can be attributed in part to a market rule amendment implemented in October 2012

[4] For details, see Ontario Regulation 496/07 (Cessation of Coal Use – Atikokan, Lambton, Nanticoke and Thunder Bay Generation Stations), available at: http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_070496_e.htm.
[5] 'Off-peak' refers to the hours of the day between 7pm and 7am while 'on-peak' refers to the hours of the day between 7am and 7pm. During weekends and holidays all hours of the day are considered off-peak.
[6] In both cases excluding linked wheeling transactions.

that eliminated constrained-off CMSC payments for import transactions in the Northwest.[7]

The effect of the market rule amendment appears to also be reflected in the auction prices paid for Northwest import TRs. For example, average auction prices for long-term and short-term import TRs at the Manitoba interface declined by 80% and 91%, respectively.

2 Pricing

2.1 *Hourly Ontario Energy Price*

Table 1-1 presents the monthly average HOEP for the 2011/12 and 2012/13 Annual Periods. The average HOEP across all hours in the 2012/13 Annual Period was \$25.89/MWh, a 1.6% decrease from the \$26.30/MWh average in the 2011/12 Annual Period. The average on-peak and off-peak HOEP decreased by 2.0% and 1.2%, respectively.

Year-over-year, the average monthly HOEP was lower each month from May to December 2012, and higher each month from January to April 2013. The largest monthly year-over-year decrease occurred in June, with the average monthly HOEP going from \$32.09/MWh in 2011 to \$19.96/MWh in 2012, a 37.8% decline. The greatest year-over-year increase occurred in March, with the average monthly HOEP rising by 101.4% from \$14.33/MWh to \$28.86/MWh. Price fluctuations are mostly attributable to changes in the price of natural gas. For example, while the Dawn Daily gas price in March 2012 averaged \$2.56/MMBtu, by March 2013 it had risen to \$4.21/MMBtu, a 64.4% increase.[8] As discussed in more detail below, the marginal resource that most frequently sets the real-time and final pre-dispatch prices are gas-fired generation units. HOEP therefore is most closely aligned with the market price of natural gas, and is expected to be strongly influenced by the price of natural gas for the foreseeable future.

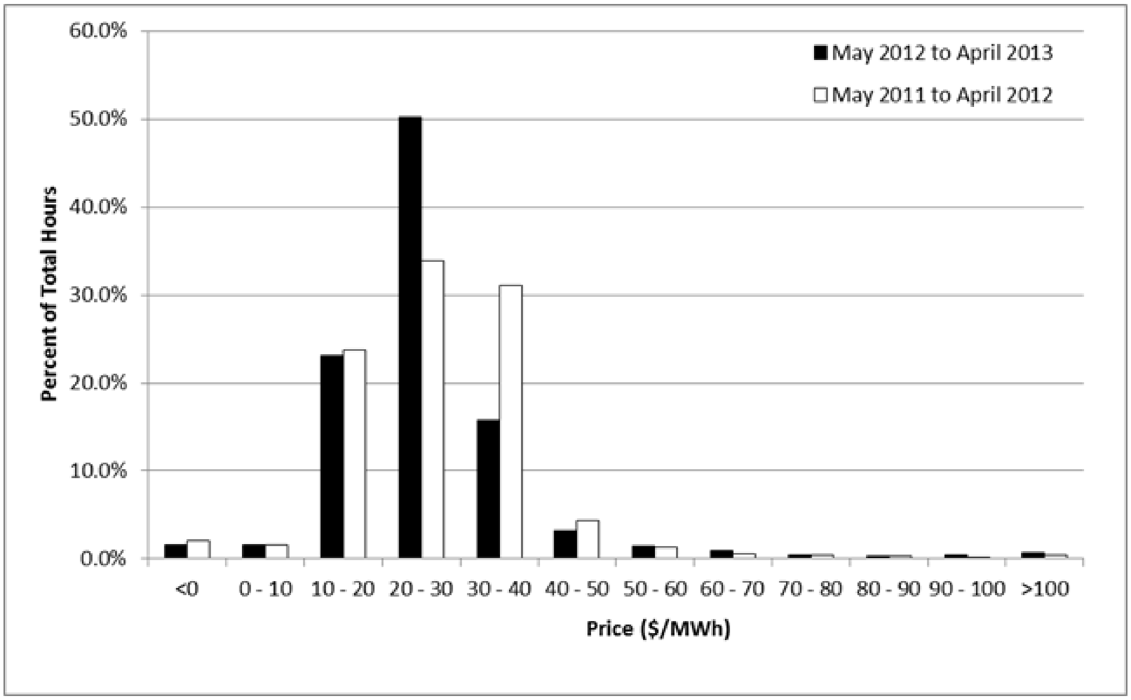
[7] See Chapter 3 of this report for a detailed analysis of the effects of the market rule amendment.
[8] Average monthly gas prices are presented in Table 1-26 below.

Table 1-1: Average HOEP, On-peak and Off-peak May – April 2011/2012 & May – April 2012/2013 ($/MWh and %)

Month	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	24.42	19.26	(21.13)	31.21	21.87	(29.93)	18.83	16.92	(10.14)
June	32.09	19.96	(37.8)	42.49	26.53	(37.56)	22.15	14.22	(35.8)
July	35.29	31.39	(11.05)	41.76	39.44	(5.56)	30.41	24.77	(18.55)
August	32.62	27.64	(15.27)	39.25	31.01	(20.99)	26.66	24.61	(7.69)
September	31.18	24.89	(20.17)	34.05	28.91	(15.1)	28.68	21.95	(23.47)
October	28.53	21.55	(24.47)	32.14	25.74	(19.91)	25.81	17.78	(31.11)
November	27.97	25.79	(7.79)	32.52	29.41	(9.56)	23.61	22.32	(5.46)
December	25.18	24.83	(1.39)	28.78	27.9	(3.06)	22.46	22.71	1.11
January	24.83	29.71	19.65	28.35	38.04	34.18	21.92	22.23	1.41
February	22.09	28.78	30.29	22.67	31.01	36.79	21.59	26.94	24.78
March	14.33	28.86	101.4	17.46	31.02	77.66	11.53	27.23	136.17
April	16.94	28.02	65.41	18.71	32.2	72.1	15.64	24.36	55.75
Average	26.30	25.89	(1.56)	30.91	30.3	(1.97)	22.46	22.2	(1.16)

Figure 1-1 presents the frequency distribution of HOEP over the 2011/12 and 2012/13 Annual Periods. In the vast majority (89.1%) of hours in the 2012/13 Annual Period, the HOEP was within the $10/MWh to $40/MWh range, with a large concentration in the $20-$30/MWh range.

Figure 1-1: Frequency Distribution of HOEP
May – April 2011/2012 & May – April 2012/2013
(% of total hours)



2.2 *Load-weighted HOEP*

Table 1-2 presents the average load-weighted HOEP by load type for the 2011/12 and 2012/13 Annual Periods. The load-weighted HOEP provides a more accurate representation of the actual price paid by loads since it is weighted by hourly demand. Just as the average (un-weighted) HOEP decreased in the 2012/13 Annual Period across all consumers, so too did the average load-weighted HOEP across all load types.

The average load-weighted HOEP was lowest for the dispatchable load category at $24.79/MWh ($2.21/MWh or 8.1% less than the load-weighted average HOEP for all loads). Dispatchable loads tend to consume less during high-price hours and more during low-price hours. To some extent, the consumption of other wholesale loads follows a similar pattern, and their average load-weighted HOEP was $25.82/MWh ($1.18/MWh or 4.4% less than the load-weighted average HOEP for all loads). Consumption by loads connected at the distribution level,[9] some of which are directly exposed to the market price and others of which are not, had an average load-weighted HOEP of $27.24/MWh ($0.24/MWh or 0.9% more than the average load-weighted HOEP for all loads). These consumers generally use more electricity during high-price hours than they do during low-price hours.

Table 1–2 also shows the average load-weighted HOEP by class of consumer based on the manner in which the GA is allocated to them. The GA is allocated to a “Class A” consumer - one with average peak demand over 5 MW – based on the Class A consumer’s share of energy demand during the five hours with the highest total demand in a 12-month base period. The GA charged to all other consumers – referred to as “Class B” – is determined on a volumetric basis. Hourly consumption data for Class A consumers that are connected at the distribution level (referred to as “Embedded Class A”) is not readily available, and they are therefore grouped together with Class B consumers for the purposes of this report. Data for Class A consumers that are connected to the transmission system (referred to as “Direct Class A”) is presented separately. In the 2012/13 Annual Period, there were 65 Direct Class A consumers representing just under 6% of total Ontario demand.

Direct Class A consumers have a lower average load-weighted HOEP since their load profile is generally flatter or even opposite to that of Class B + Embedded Class A consumers as a whole. These consumers in turn tend to have higher consumption during the day (on-peak hours) and lower consumption at night (off-peak hours). The differential in average load-weighted HOEP as between Direct Class A and Class B + Embedded Class A consumers decreased slightly from $1.79/MWh to $1.74/MWh between the two Annual Periods.

[9] These are consumers that are settled by the distributor to whose system they are connected. They include consumers that are on the Ontario Energy Board’s Regulated Price Plan and those who are charged by the distributor based on wholesale pricing.

Table 1-2: Average Load-Weighted HOEP by Load Category
May – April 2011/2012 & May – April 2012/2013
($/MWh)

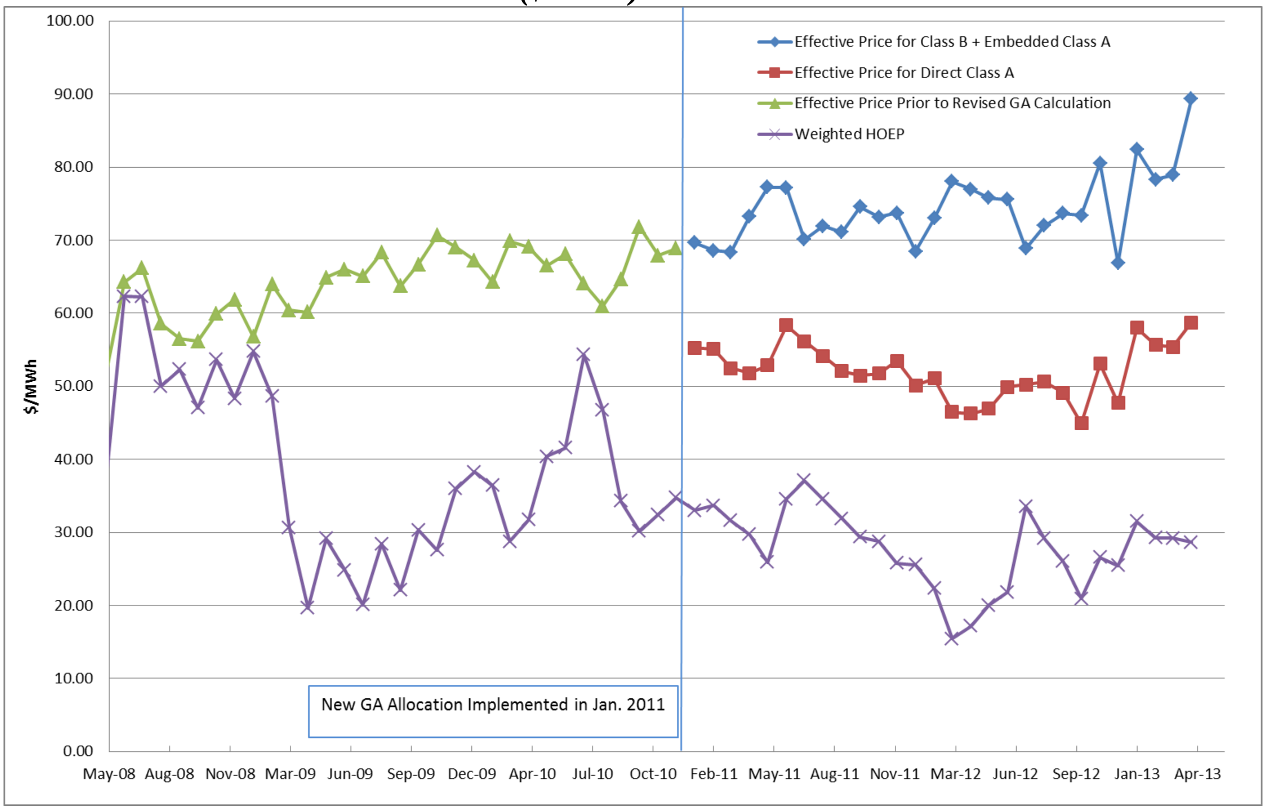
Year	Unweighted HOEP	Load-weighted HOEP					
		Dispatchable Loads	Other Wholesale Loads	Loads within Distributors	All Loads	Direct Class A	Class B + Embedded Class A
2011/2012	26.30	24.98	26.39	27.77	27.51	25.90	27.69
2012/2013	25.89	24.79	25.82	27.24	27.00	25.44	27.18
Difference	(0.40)	(0.19)	(0.57)	(0.53)	(0.51)	(0.46)	(0.51)
% Change	(1.56)	(0.76)	(2.16)	(1.91)	(1.85)	(1.78)	(1.84)

2.3 *Effective Price (including Global Adjustment and Uplift)*

Figure 1-2 plots the monthly effective price of electricity, which comprises the load-weighted HOEP,[10] uplift and the GA, between May 2008 and April 2013. While the average annual HOEP has generally been declining since 2009, the effective price has been increasing due to increases in the GA. As a result of the 2011 change in how the GA is allocated, Direct Class A consumers have experienced a decline in their effective price and Class B + Embedded Class A consumers have, on average, seen their effective price increase.

[10] The effective price is calculated using the average load-weighted HOEP presented in Table 1-2 rather than the average HOEP presented in Table 1-1. This takes into account the fact that a greater percentage of large consumers' consumption occurs during off-peak hours when the actual HOEP is lower than the average HOEP, and that a greater percentage of small consumers' consumption occurs during on-peak hours when the actual HOEP is higher than the average HOEP.

Figure 1-2: Monthly Average Effective Price
May 2008 – April 2013
($/MWh)



The GA has been increasing since the beginning of 2009 mainly for two reasons. First, generators that have contracts with the Ontario Power Authority (OPA) are paid the contract price. When that price is higher than the HOEP, which is typically the case, the difference is included in the GA. Accordingly, there is a negative correlation between the HOEP and the GA – as the HOEP declines, which has been the case since 2009, the difference between the HOEP and the OPA contract prices increases and so too does the GA. Second, more OPA-contracted energy has come online. The prices paid under these more recent contracts (e.g., contracts with wind and solar power generators) also typically exceed the average HOEP by a significant margin.

Table 1-3 presents the effective electricity price for all Ontario consumers, and separately for Direct Class A consumers and Class B + Embedded Class A consumers. The average effective price for all Ontario consumers during the 2012/13 Annual Period was

$74.71/MWh, 2.8% higher than in the 2011/12 Annual Period. On average, Direct Class A consumers paid $23.10/MWh (31.0%) less than this price while Class B + Embedded Class A consumers on average paid $2.90/MWh (3.9%) more than the average effective price paid by all consumers.

This differential is largely the result of differences in the GA payable by the two Classes, which in turn is a function of the way in which the GA is allocated among them. The average GA paid by Direct Class A consumers was basically unchanged relative to their GA payments in the 2011/12 Annual Period. However, Class B + Embedded Class A consumers on average saw their GA payments increase by $3.2/MWh (7.2%) in the 2012/13 Annual Period.

Table 1-3: Effective Electricity Price
May – April 2011/2012 & May – April 2012/2013
($/MWh)

Consumer Class	Weighted HOEP		Global Adjustment		Average Uplift		Effective Price	
	2011-2012	2012-2013	2011-2012	2012-2013	2011-2012	2012-2013	2011-2012	2012-2013
Direct Class A	25.90	25.44	23.24	23.58	2.86	2.55	52.00	51.57
Class B plus Embedded Class A	27.69	27.18	44.66	47.88	2.86	2.55	75.21	77.61
All Consumers	27.51	27.00	42.34	45.16	2.86	2.55	72.71	74.71

2.3.1 *Hourly Uplift and Components*

Table 1-4 reports the monthly total hourly uplift charges for the 2011/12 and 2012/13 Annual Periods. The total hourly uplift charges dropped from $212.3 million to $200.7 million in the 2012/13 Annual Period, a 5.5% decrease.

Table 1-4: Total Hourly Uplift Charge by Component and Month May – April 2011/2012 & May – April 2012/2013 ($ millions and %)

Month	IOG		CMSC*		Losses		Operating Reserve		Total Hourly Uplift	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	0.4	1.0	10.8	6.9	7.2	4.8	12.2	0.8	32.8	14.2
June	0.8	1.2	17.7	11.7	9.8	5.8	4.7	0.6	33.7	18.8
July	0.4	4.1	9.9	10.8	11.3	8.7	1.5	0.7	22.7	23.9
August	0.4	3.8	7.1	9.4	7.8	6.9	2.4	0.8	17.5	20.8
September	1.1	3.7	6.6	7.5	7.3	5.9	0.7	0.8	15.7	17.4
October	0.4	0.7	5.8	4.6	6.7	2.6	0.5	2.7	13.1	10.0
November	0.5	0.7	10.5	6.8	4.8	5.5	0.6	2.7	15	15.2
December	0.7	0.6	4.3	4.0	6.9	5.5	1.2	1.1	12.3	10.8
January	0.8	0.6	3.5	7.4	6.3	7.1	1.3	2.2	11.1	16.8
February	1.2	2.1	4.2	11.6	4.9	6.4	0.6	2.2	10.5	22.4
March	1.5	0.9	7.3	6.5	4	5.7	4	0.9	15.6	14.3
April	0.4	0.5	4.0	4.4	4.2	6.0	1.2	2.9	9.3	14.1
Total	8.6	19.9	91.6	91.5	81.2	70.9	30.9	18.3	212.3	200.7
% of Total	4.1	9.9	43.1	45.6	38.2	35.3	14.6	9.2	100.0	100.0

*The Congestion Management Settlement Credit figures include payments to all market participants, but do not reflect clawbacks by the IESO. IESO clawbacks have been omitted from this table because they are dynamic throughout the Annual Period, making data difficult to consistently measure.

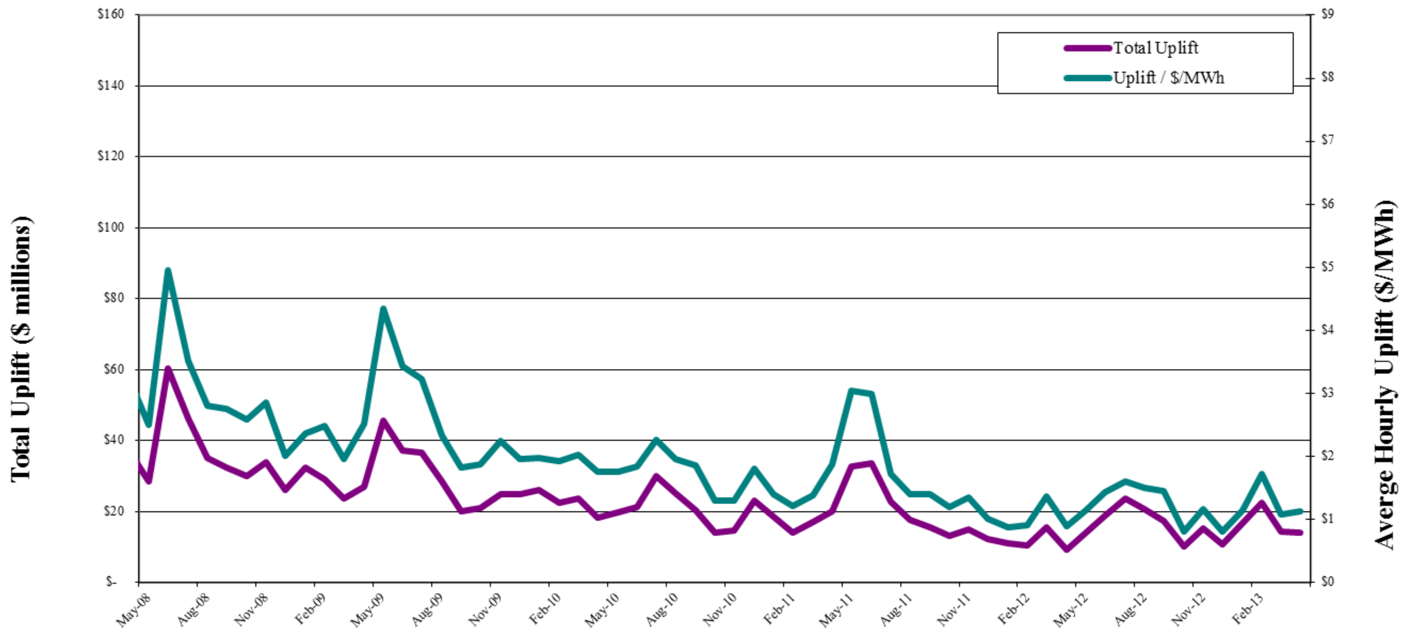
Major factors contributing to the change in uplift are summarized below:

- Total Intertie Offer Guarantee (IOG) payments more than doubled (131.4% increase) from $8.6 million to $19.9 million. IOG payments for transactions over the Michigan and New York interfaces were particularly high, with increases of $4.3 million (205%) and $5.2 million (1,700%) respectively. One reason for the large increase in IOG payments is that under the enhanced day-ahead commitment process (EDAC) many imports are being scheduled day-ahead. Those imports were offered at a lower price in order to increase the likelihood of being scheduled in real-time and to avoid being charged in case of failure. When the real-time price turns out to be lower than the day-ahead offer price, these imports receive a day-ahead IOG payment.

- Total Congestion Management Settlement Credit (CMSC) payments decreased by \$0.1 million (0.1%), and continued to represent roughly half of the total hourly uplift payments. During the 2012/13 Annual Period, June 2012 had the highest total CMSC payments (\$11.7 million).
- Total payments due to losses decreased by \$10.3 million (12.7%). Since total demand in the province increased during the 2012/13 Annual Period, the decrease in payments due to losses could be attributable to the decrease in the HOEP, especially during the summer months.
- Total OR payments declined substantially from \$30.9 million to \$18.3 million, a 40.6% decrease. Low OR prices in the 2012/13 Annual Period may be the result of less spring water when compared to the previous Annual Period. OR pricing is discussed further in section 6.

Figure 1-3 plots hourly uplift charges in millions of dollars and \$/MWh between May 2008 and April 2013. Hourly uplift charges have generally been decreasing since 2008 and now average roughly \$1.00/MWh.

***Figure 1-3: Total and Average Hourly Uplift Charges
May 2008 – April 2013
($ millions and $/MWh)***



As is the case with energy, OR can be constrained on or off. OR can be constrained on when an OR offer is not economic in the unconstrained schedule but is required in the constrained schedule. Conversely, OR can be constrained off when OR is economic in the unconstrained schedule but does not receive a corresponding dispatch in the constrained schedule.11

[11] Being constrained on in the OR market does not mean that the resource supplies power (or reduces the consumption of electricity); it is merely on standby to do so if an activation occurs.

Table 1-5 below provides the total constrained-off CMSC payments in the OR market by region for the 2011/12 and 2012/13 Annual Periods. Constrained-off payments for OR have totalled about $6.1 million per year, with most of it paid to generators located in the Northeast and Northwest regions (the same areas where generators, importers and dispatchable loads also received the vast majority of constrained-off CMSC payments for energy). Dispatchable loads in the Northwest also receive a large amount of CMSC payments in respect of the OR market.

In the 2012/13 Annual Period there was a substantial decline ($4.45 million or 77.5%) in the amount of constrained-off CMSC payments for OR paid to generators in the Northeast. This represents a large portion of the 65.5% decline in total constrained-off CMSC payments to suppliers of operating reserve in the 2012/13 Annual Period. A large year-over-year decrease in the price of OR helps to explain that 65.5% decrease.

Table 1-5: Constrained-off CMSC Paid to Suppliers of Operating Reserve, by Region May – April, 2011/2012 & May – April 2012/2013 ($ thousands)

Area (Zone)	Resource Type	May 2011 - April 2012	May 2012 - April 2013
Bruce	Generators	0	0
East	Generators	522	290
ESSA	Generators	12	5
Northeast	Generators	5,706	1,281
	Dispatchable Loads	142	124
Niagara	Generators	155	132
Northwest	Generators	1,364	686
	Dispatchable Loads	688	346
Ottawa	Generators	0	0
Southwest	Generators	50	25
	Dispatchable Loads	7	2
Toronto	Generators	111	145
	Dispatchable Loads	21	2
Western	Generators	284	91
Total		9,062	3,128

2.3.2 *Non-Hourly Uplift and Components*

Non-hourly uplift consists of charges that are not allocated to a specific hour. These include payments to generators under the IESO's day-ahead and real-time generation cost guarantee programs, and costs associated with regulation (previously referred to as automatic generation control or AGC), voltage support and black start capability. Table 1-6 reports non-hourly uplift for the 2011/12 and 2012/13 Annual Periods. Total non-hourly uplift declined by $3.3 million (1.8%) in the 2012/13 Annual Period. The majority of the decrease is attributable to a decrease in generation cost guarantee payments (decrease of $8.8 million or 6.1%). That was offset somewhat by an increase in charges for regulation (increase of $9.5 million or 56.5%).

Table 1-6: Non-Hourly Uplift Charges, by Component
May – April 2011/2012 & May – April 2012/2013
($ millions and %)

Month	Generation Cost Guarantees*^		Regulation		All Others		Total Non-Hourly Uplift	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	8.2	9.7	2.2	1.5	0.6	(0.1)	11.0	11.0
June	10.0	11.9	3.5	1.6	0.6	0.4	14.1	13.9
July	12.3	13.7	2.3	1.8	0.6	(0.4)	15.2	15.2
August	13.4	19.0	1.8	1.9	(0.2)	0.9	15.0	21.7
September	15.1	9.5	2.0	5.7	0.9	0.0	18.0	15.3
October	12.8	6.8	1.5	1.9	0.0	0.1	14.3	8.8
November	12.8	12.0	1.4	2.1	0.8	(0.4)	15.0	13.6
December	12.8	15.1	5.2	7.9	0.6	0.5	18.6	23.4
January	9.4	10.6	4.0	8.5	(0.1)	(0.2)	13.3	18.9
February	13.2	9.2	2.5	2.3	1.4	0.5	17.1	12.0
March	13.2	9.4	1.5	2.5	0.8	0.5	15.5	12.3
April	10.2	7.7	2.4	2.2	0.2	0.5	12.8	10.4
Total	143.4	134.6	30.3	39.8	6.2	2.2	179.9	176.6
% of Total	79.7	76.2	16.8	22.5	3.5	1.3	100	100

*Uplift associated with generation cost guarantees does not include clawbacks of previous overpayments to generators.
^ Settlement amounts for generators are calculated on a monthly basis under the real-time program, but daily under the day-ahead program. The daily settlement amounts from the day-ahead program have been aggregated to a monthly figure for this table.

2.4 *Price Setters (Marginal Resources)*

During the 2012/13 Annual Period, gas-fired units and hydroelectric units continued to more frequently replace coal-fired generators as the marginal resource. Based on pre-dispatch prices, there was an increase in the share of hours in which imports and exports were marginal, corresponding to a decline in the share of hours in which domestic resources (specifically coal, gas and hydro) were marginal.

2.4.1 *Real-Time Marginal Resources*

Table 1-7 presents the share of real-time intervals in which particular resource types were the marginal resource and therefore set the market clearing price (MCP) during the 2011/12 and 2012/13 Annual Periods. The table shows that the average share by resource type shifted the most towards gas-fired units. The share of hours in which coal-fired units set the real-time MCP declined by 2.0%, while gas-fired units' share of hours increased by 2.9%. This is not unexpected given the gradual phasing out of coal-fired generation capacity in the province.

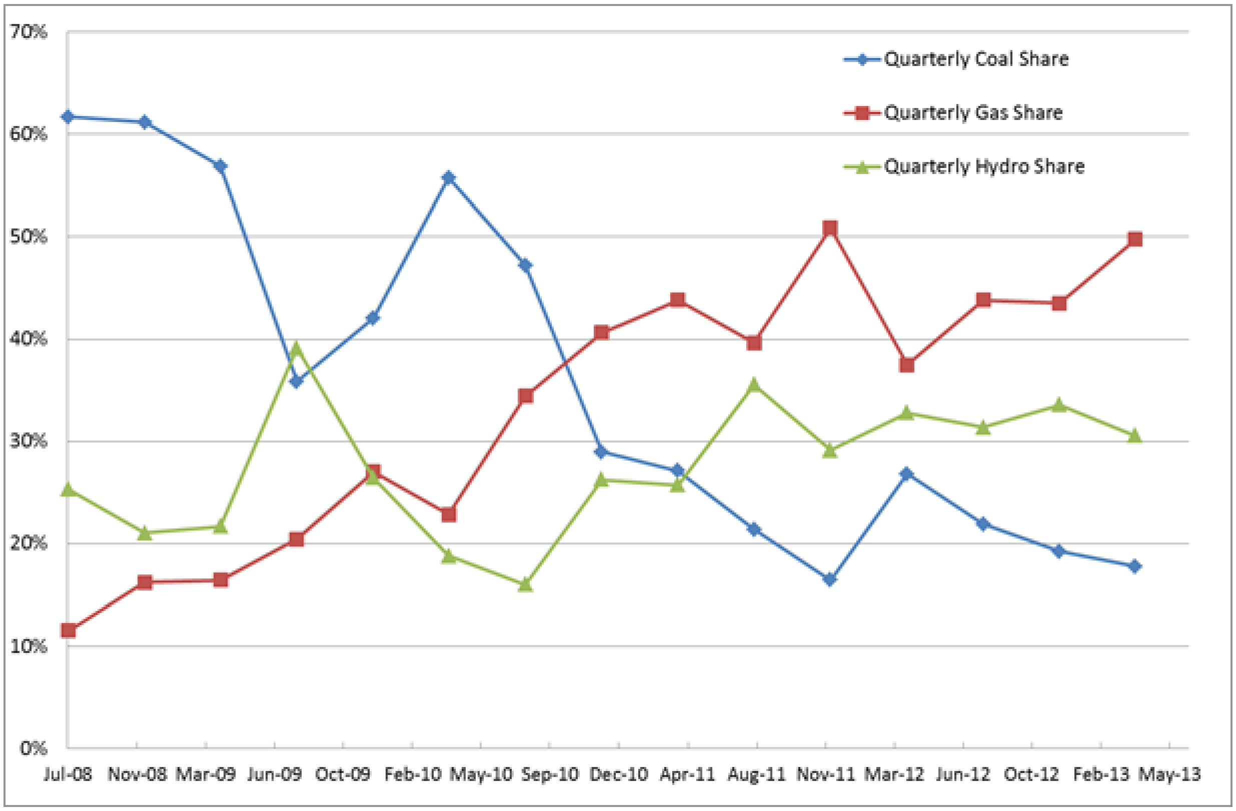
Table 1-7: Share of Marginal Resource Setting Real-Time MCP
May – April 2011/2012 & May – April 2012/2013
(% of intervals)

Resource Type	2011/2012	2012/2013
Coal	21.6	19.6
Gas	42.5	45.4
Hydro	32.6	32.1
Nuclear	0.9	0.8
Dispatchable Load	2.4	2.0
Total	100	100

Figure 1-4 shows the relationship between coal, gas and hydroelectric generation in terms of the hours in which each resource type has set the real-time MCP since May 2008. In the summer of 2008, coal-fired units set the MCP in more than 60% of all hours and gas-fired units set the MCP in only 12% of hours. This relationship has fully inverted, with gas-fired units setting the MCP in approximately 45% of all hours in the 2012/13 Annual

Period, while coal units only did so in 20% of the hours. Hydroelectric units' share of hours setting the real-time MCP has not increased substantially since 2008. Its share has been steady since the fall of 2011, ranging between 29% and 34% of all hours.

Figure 1-4: Share of Marginal Resources Setting Real-Time MCP
May 2008 – April 2013
(%)



2.4.2 *Pre-Dispatch Marginal Resources*

The final, one-hour ahead pre-dispatch sequence schedules imports and exports for the upcoming delivery hour and provides advisory schedules for generators and dispatchable loads, based on forecast Ontario demand. This final pre-dispatch sequence also generates a pre-dispatch price, which can serve as a predictor of the HOEP. Imports and exports are scheduled based on their offers and bids, respectively, in the final pre-dispatch sequence, and could be marginal.

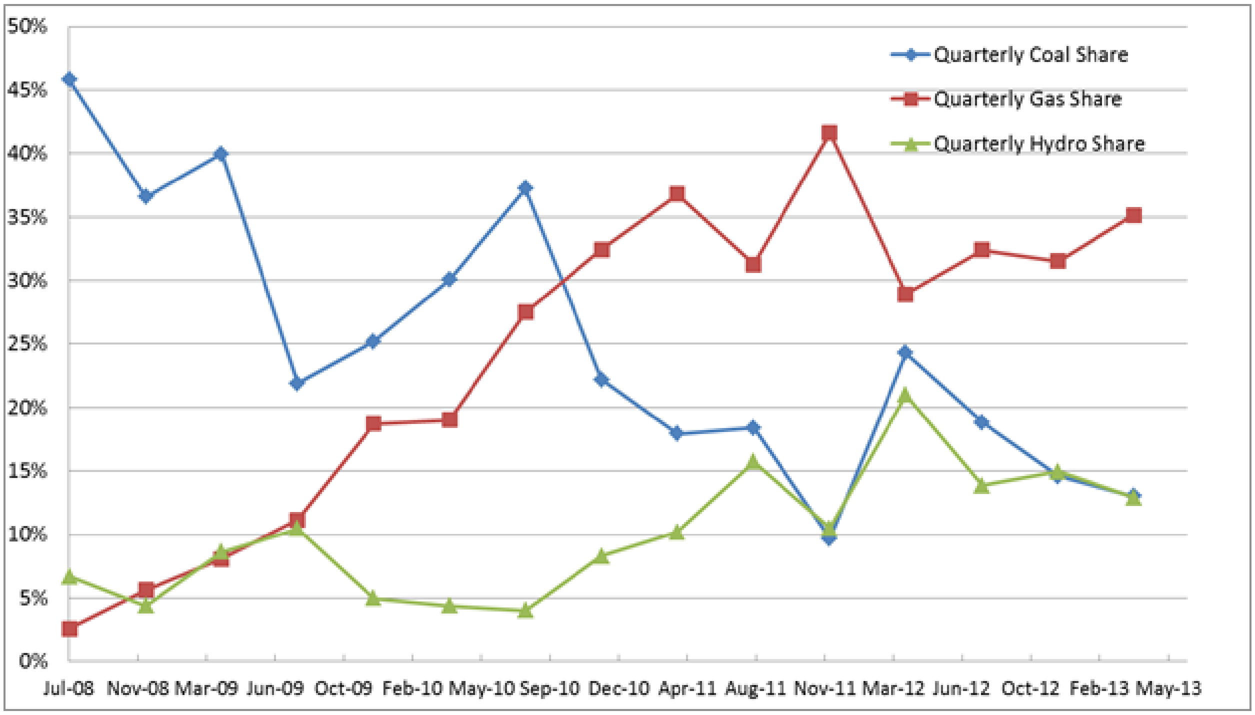
Table 1-8 presents the percentage of hours that a specific resource or transaction type was marginal in the final pre-dispatch schedule for the 2011/12 and 2012/13 Annual Periods. During the 2012/13 Annual Period, imports and exports increased the share of hours in which they set the pre-dispatch price by 2.8% and 2.6%, respectively, while domestic generation was marginal in the pre-dispatch 4.7% less frequently in the 2012/13 Annual Period. Gas-fired generation was the resource that most frequently set the final pre-dispatch price, doing so in 32.9% of the intervals.

Table 1-8: Marginal Resources Setting Final Pre-Dispatch Price
May – April 2011/2012 & May – April 2012/2013
(% of intervals)

Resource/Transaction Type	2011/2012	2012/2013
Coal	17.4	15.5
Gas	33.9	32.9
Hydro	15.8	14.0
Nuclear	0.1	0.1
Import	11.2	14.0
Export	19.6	22.2
Dispatchable Load	2.0	1.3
Total	100	100

Figure 1-5 shows the relationship between coal, gas and hydroelectric generation in terms of the hours in which each resource type has set the final pre-dispatch price since May 2008. In the summer of 2008, coal-fired units set the final pre-dispatch price in more than 45% of all hours and gas-fired units set the pre-dispatch price in less than 5% of hours. This relationship has changed substantially, again as a result of the phase-out of coal-fired generation in the province. Gas-fired units set the final pre-dispatch price in approximately 33% of hours in the 2012/13 Annual Period and coal-fired units did so in only 16% of the hours. Hydroelectric units have seen their share of hours rise from approximately 6% in the summer of 2008 to 14% in the 2012/13 Annual Period

Figure 1-5: Share of Marginal Resources Setting Final Pre-Dispatch Price May 2008 – April 2013 (%)



2.5 *Pre-Dispatch Prices and HOEP*

An accurate pre-dispatch price signal can contribute to real-time dispatch efficiencies. Production and consumption decisions are improved when market participants can use pre-dispatch prices as an informative signal. Given that a market participant can only submit offers or bids no later than two hours before the delivery hour, the three-hour ahead pre-dispatch price is the last signal for market participants to submit or adjust their final offers or bids. The Panel monitors the three-hour ahead pre-dispatch price relative to the real-time and one-hour ahead pre-dispatch prices to assess the accuracy of pre-dispatch prices as signals.

An important difference between the pre-dispatch and the real-time scheduling systems is that in pre-dispatch, imports and exports are placed in the supply or demand stacks according to their competitive offer or bid. In real-time, regardless of offer price, imports are placed at the bottom of the supply stack (the last to be dispatched), and exports, regardless of bid price, are placed at the top of the demand stack (the first to be dispatched). This difference can have price implications when imports or exports set the final pre-dispatch price and/or when imports or exports fail between pre-dispatch and real-time.

2.5.1 *Three-Hour Ahead Pre-Dispatch Price*

Table 1-9 presents the differences between the three-hour ahead pre-dispatch price and the average HOEP for the 2011/12 and 2012/13 Annual Periods. In the 2012/13 Annual Period, the three-hour ahead pre-dispatch price on average was less than the real-time price by $1.81/MWh. This represents a year-over-year increase of $0.10/MWh (0.6%) in the price differential. The average absolute difference between the real-time and the three-hour ahead pre-dispatch price was $6.74/MWh in the 2012/13 Annual Period, which is unchanged from the 2011/12 Annual Period.

Table 1-9: Measures of Differences between Three-Hour Ahead Pre-Dispatch Price and HOEP May – April 2011/2012 & May – April 2012/2013 ($/MWh and %)

Month	Average Difference (PD-RT)*		Average Absolute Difference		Standard Deviation		Average Difference as a % of Average HOEP**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	(3.45)	(1.68)	10.41	6.15	28.23	16.06	(14.13)	(8.72)
June	(1.62)	(0.13)	11.71	6.11	28.11	16.17	(5.05)	(0.65)
July	(3.17)	(1.08)	6.14	8.09	14.57	16.78	(8.98)	(3.44)
August	(4.76)	(3.78)	10.25	6.84	23.47	15.02	(14.59)	(13.68)
September	(2.45)	(2.06)	5.11	5.67	8.79	12.81	(7.86)	(8.28)
October	(4.67)	(2.83)	8	8.52	16.8	18.64	(16.37)	(13.13)
November	(0.46)	(4.06)	6.38	7.33	14.44	17.29	(1.64)	(15.74)
December	(1.08)	(1.63)	6.49	4.29	14.62	12.56	(4.29)	(6.56)
January	(0.02)	(0.27)	4.52	12.46	11.94	85	(0.08)	(0.91)
February	(0.39)	(0.22)	2.13	5.46	10.97	16.7	(1.77)	(0.76)
March	1.74	(0.92)	7.38	3.68	26.12	7.1	12.14	(3.19)
April	(0.23)	(3.1)	2.33	6.29	5.69	12.21	(1.36)	(11.06)
Average	(1.71)	(1.81)	6.74	6.74	16.98	20.53	(5.33)	(7.18)

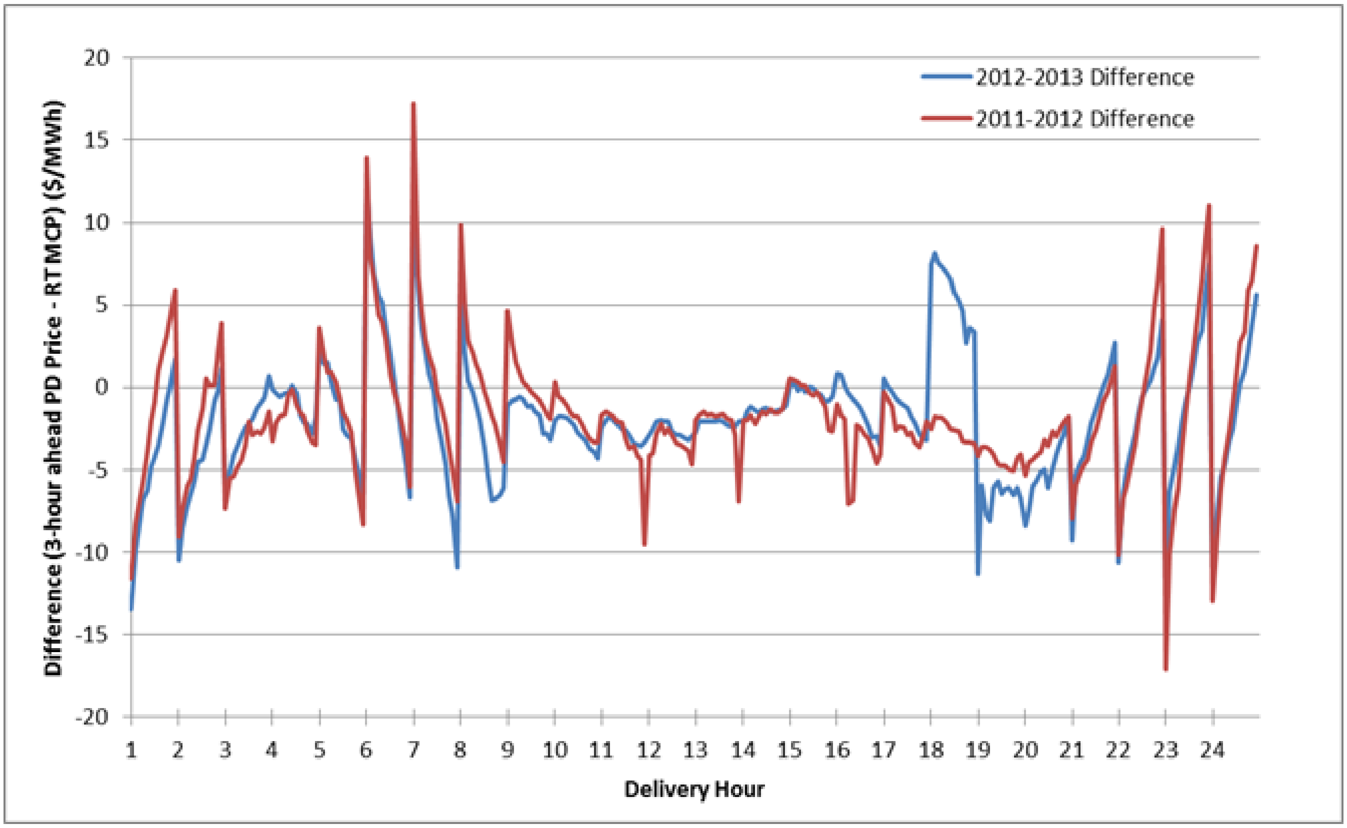
* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.

** This calculation expresses the average price difference (from the first and second data columns) as a percentage of the average HOEP in each month (the denominator being the monthly average HOEP reported in Table 1-1).

Figure 1-6 illustrates the average difference between the three-hour ahead pre-dispatch price and the real-time MCP for every delivery hour in each of the 2011/12 and 2012/13 Annual Periods. The average difference between the three-hour ahead pre-dispatch price and the real-time MCP in the 2012/13 Annual Period followed the same pattern as in the 2011/12 Annual Period, but was relatively less volatile.

The pre-dispatch sequence forecasts an hourly price based on the peak interval demand during ramp-up hours. When demand is steadily increasing or decreasing, which is typically reflected by a price increase or decrease respectively, there may be a significant difference in both demand and price between the beginning and end of an hour. On average over the hour, the three-hour ahead pre-dispatch price generally overestimates the MCP in ramp-up and ramp-down hours.

Figure 1-6: Average Difference between Three-Hour Ahead Pre-Dispatch Price and Real-Time MCP, by Delivery Hour May – April 2011/2012 & May – April 2012/2013 ($/MWh) *^



* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.
^ Real-time MCP is calculated using average demand over the interval, while pre-dispatch prices are calculated using peak interval demand.

2.5.2 *One-hour Ahead Pre-Dispatch Price*

Table 1-10 presents the differences between the final, one-hour ahead pre-dispatch price and the average HOEP for the 2011/12 and 2012/13 Annual Periods. On average, one-hour ahead pre-dispatch prices were higher than the average HOEP during the 2012/13 Annual Period. The average difference went from $0.09/MWh in the 2011/12 Annual Period to $0.75/MWh in the 2012/13 Annual Period, with the greatest average difference occurring in February 2013 ($3.97/MWh).

The average difference as a percentage of the average HOEP shifted from 1.4% to 3.0% and the average absolute difference increased marginally from $5.97/MWh to $6.03/MWh (a 1.0% increase). These values indicate slightly less accurate one-hour ahead pre-dispatch prices as a predictor of HOEP in the 2012/13 Annual Period. Particularly large average differences between the one-hour ahead pre-dispatch price and the average HOEP occurred in June 2012 and in January and February 2013. For the second year in a row, the month of January had an unusually high standard deviation, indicating large forecast errors in certain hours.

Table 1-10: Measures of Differences between One-Hour Ahead Pre-Dispatch Price and HOEP May – April 2011/2012 & May – April 2012/2013 ($/MWh and %)

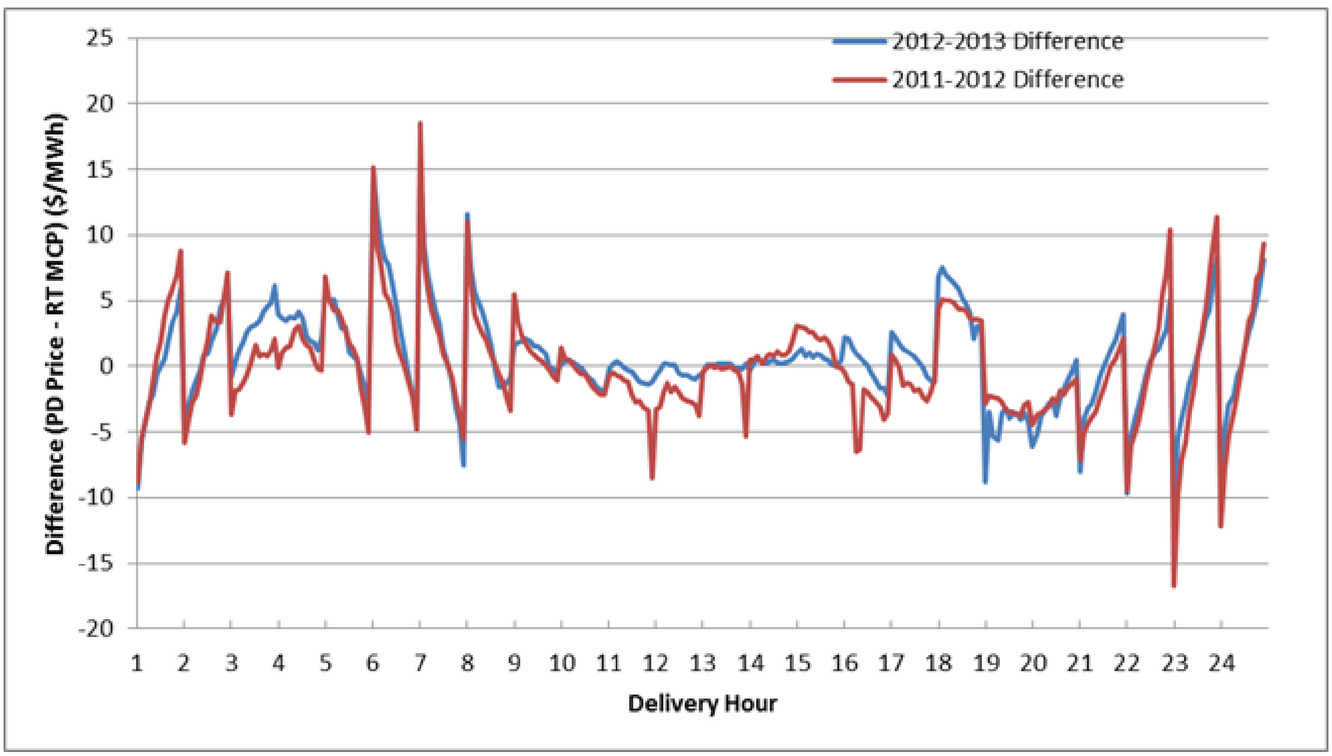
Month	Average Difference (PD-RT)*		Average Absolute Difference		Standard Deviation		Average Difference as a % of Average HOEP**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	(0.63)	0.04	8.64	4.96	25.9	14.77	(2.6)	0.21
June	0.11	2.35	11.35	5.64	34.79	16.91	0.3	11.77
July	(1.3)	(0.66)	5.08	7.06	12.08	16.0	(3.7)	(2.10)
August	(2.58)	(1.92)	8.33	5.41	20.49	13.58	(7.9)	(6.95)
September	(1.3)	(0.14)	4.3	4.8	8.01	12.15	(4.2)	(0.56)
October	(1.93)	0.69	5.96	6.95	12.49	17.46	(6.8)	3.20
November	0.94	0.21	6.0	6.21	14.42	14.26	3.4	0.81
December	0.87	0.74	4.86	4.21	11.67	12.2	3.5	2.98
January	4.3	3.56	6.45	10.91	70.14	78.55	17.3	11.98
February	0.05	4.02	1.73	7.35	10.64	27.09	0.2	13.97
March	2.32	0.62	6.91	3.39	25.49	6.45	16.2	2.15
April	0.17	(0.55)	1.97	5.42	5.35	11.56	1.0	(1.96)
Average	0.09	0.75	5.97	6.03	20.96	20.08	1.39	2.96

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

** This calculation expresses the average price difference (from the first and second data columns) as a percentage of the average HOEP in each month (the denominator being the monthly average HOEP reported in Table 1-1).

Figure 1-7 depicts the average difference between the one-hour ahead pre-dispatch price and the real-time MCP by delivery hour in the 2011/12 and 2012/13 Annual Periods. The trends and magnitudes are similar to those shown in Figure 1-6. However, the one-hour ahead pre-dispatch prices are marginally closer to the HOEP for non-ramping hours and to the hourly peak MCP for ramping hours than are the three-hour ahead pre-dispatch prices. This is to be expected, as the one-hour ahead pre-dispatch price incorporates exports and imports that have submitted their final bids or offers into the market after the three-hour ahead pre-dispatch, which makes the one-hour ahead pre-dispatch price a more accurate predictor of the real-time price.

Figure 1-7: Average Difference between One-Hour Ahead Pre-Dispatch Price and Real-Time MCP, by Delivery Hour
May – April 2011/2012 & May – April 2012/2013
($/MWh) *^



* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.
^ Real-time MCP is calculated using average demand over the interval, while pre-dispatch prices are calculated using peak interval demand.

2.5.3 *Reasons for Differences in Pre-Dispatch Prices and Real-Time MCP*

The Panel has identified four main factors that contribute to differences between final (one-hour ahead) pre-dispatch and real-time prices:[12]

- Pre-dispatch to real-time demand forecast deviations (the deviations include forecast error and differences due to the profile of real-time demand)[13];
- Production forecast errors of self-scheduling and intermittent (primarily wind) generators;
- Failures of scheduled imports and exports; and
- The frequency with which imports or exports set the pre-dispatch price.[14]

Except for intertie transaction failures, all other factors also contribute to differences between three-hour ahead pre-dispatch and real-time prices.

While the price impact of these factors cannot be measured directly, Table 1-11 presents the average absolute differences in MW for each of the first three factors listed above for the 2011/12 and 2012/13 Annual Periods.[15] Monthly average absolute differences provide some indication as to which of the factors are the most important contributors to differences between pre-dispatch and real-time prices. However, any one of these factors can lead to significant price discrepancies in a given hour.

[12] 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 (through joint optimization). Until September 2008, there were 400 MW of CAOR available in pre-dispatch and 800 MW of CAOR available in real-time. Subsequently, the 400 MW in pre-dispatch was dropped due to the continued failure of exports that were used to back the scheduled CAOR. For details, see the Panel's January 2009 Monitoring Report, pp. 191-193, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf.

[13] 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). See the Panel's November 2011 Monitoring Report, pp. 22-23, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf.

[14] Imports and exports are re-priced in real-time at the bottom of the supply stack (imports) and the top of the demand stack (exports).

[15] The table does not report the frequency with which imports (or exports) set the pre-dispatch price, since the metric to measure that frequency (percentage of hours) does not translate into an hourly quantity (MW) statistic that can be compared with the three other factors.

Table 1-11: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices May - April 2011/2012 & May- April 2012/ 2013 (MW per hour and % of Ontario demand)

Factor	2011/2012		2012/2013	
	Average Absolute Difference (MW per hour)	Average Absolute Difference as % of Ontario Demand*	Average Absolute Difference (MW per hour)	Average Absolute Difference as % of Ontario Demand*
Pre-dispatch to Real-time Demand Forecast Deviation	190	1.2	196	1.2
Differences due to Real-time Demand Profile	15	0.1	21	0.1
Pre-dispatch to Real-time Average Demand Forecast Deviation (sum of two above rows)	205	1.3	217	1.3
Self-Scheduling and Intermittent Forecast Deviation	121	0.8	97	0.6
Net Export Failures	134	0.8	97	0.6

*Average hourly Ontario demand (denominator) was 15,916 MW for the 2011/12 Annual Period and 16, 222MW for the 2012/13 Annual Period.

Overall, the largest average absolute differences result from pre-dispatch to real-time demand forecast deviations (which as noted above include demand forecast error and differences induced by the profile of real-time demand).

Self-scheduling and intermittent generation forecast deviation decreased its contribution to the average differences by 24 MW in the 2012/13 Annual Period, and its contribution as a percentage of Ontario demand declined by 0.2%.   The contribution of net export failures decreased by 37 MW (0.2% decline as a percentage of Ontario demand).

In the aggregate, there was very little change in the contribution of these three factors in terms of percentage of Ontario demand from the 2011/12 Annual Period (2.9%) to the 2012/13 Annual Period (2.5%).

The following sections provide data pertaining to each of the four factors that have been identified by the Panel as contributing to differences between pre-dispatch and real-time prices.

2.5.3.1 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 address increased surplus baseload generation (SBG) incidents, the IESO implemented a new procedure in December 2009 whereby it uses average instead of peak demand as the forecast in pre-dispatch for non ramp-up hours.[16] This was expected to reduce demand forecast deviations in the non ramp-up hours and has done so. Figure 1-8 indicates that the deviation for non ramp-up hours is quite small. This is in contrast to the average demand forecast deviation during ramp-up hours, which continues to be significant.

[16] More precisely, peak demand is applied to ramp-up hours: from November 1st to January 31st, hour ending (HE) 6 to 9 and HE 17 to 18 and from February 1st to October 31st, HE 6 to 9. For details, see http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4973 . The IESO may also use the average forecast for the ramp-up hours when a surplus baseload generation situation is credibly foreseeable.

Figure 1-8: Average Demand Forecast Deviation
May 2008 – April 2013
(one-hour ahead pre-dispatch forecast minus real-time actual, MW)

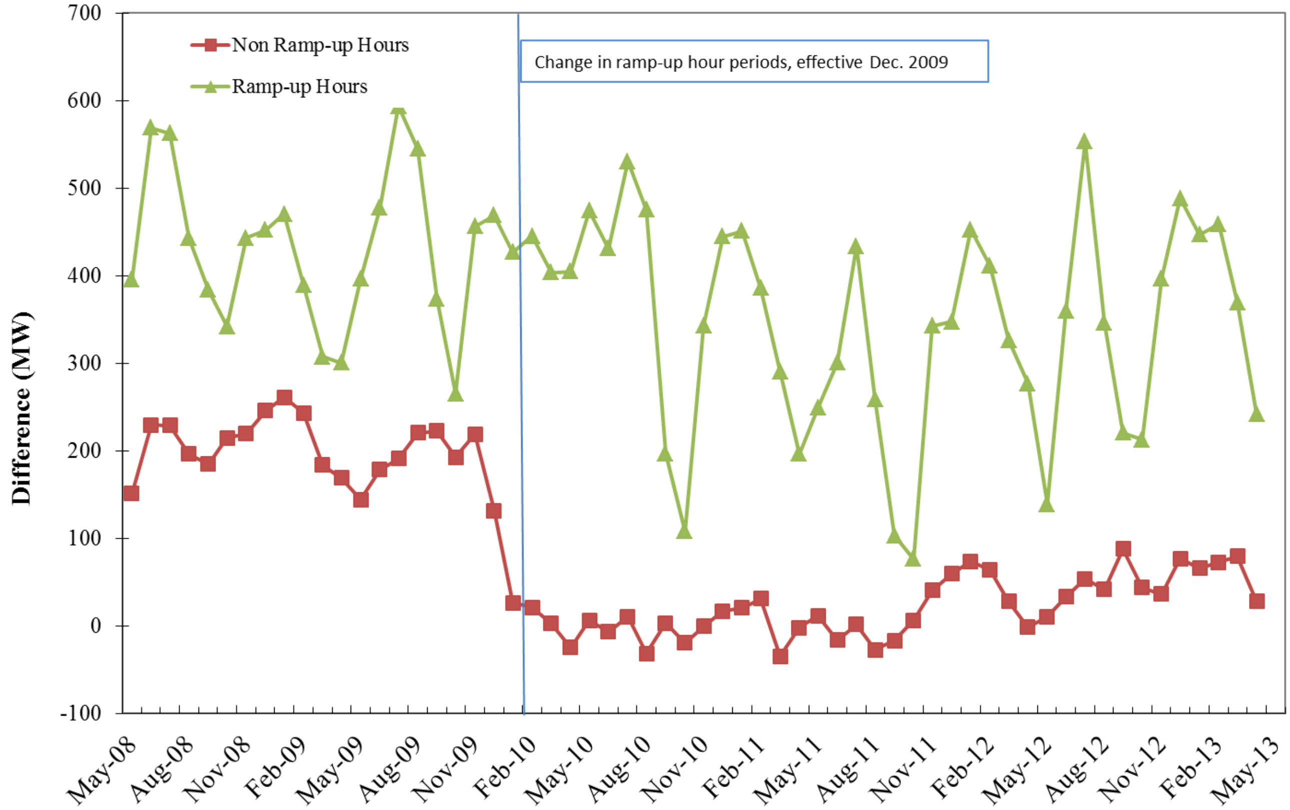


Table 1-12 presents the average demand forecast deviation by month between pre-dispatch (both one-hour ahead and three-hour ahead) and real-time for the 2011/12 and 2012/13 Annual Periods.[17] Both the three-hour ahead and one-hour ahead deviation measures increased slightly, moving from 1.62% to 1.65% and from 1.28% to 1.33%, respectively.

[17] 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 in each hour.

Table 1-12: Pre-Dispatch to Real-Time Demand Forecast Deviation
Three-Hour and One-Hour Ahead
May – April 2011/2012 & May – April 2012/2013
(% of real-time demand)

Month	Three-Hour Ahead		One-Hour Ahead	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	1.34	1.46	1.16	1.13
June	1.78	1.71	1.35	1.31
July	1.91	2.16	1.43	1.61
August	1.90	1.86	1.39	1.40
September	1.48	1.60	1.11	1.26
October	1.19	1.38	0.97	1.11
November	1.57	1.60	1.34	1.35
December	1.60	1.79	1.36	1.56
January	1.75	1.62	1.44	1.37
February	1.64	1.53	1.27	1.31
March	1.62	1.67	1.26	1.33
April	1.67	1.45	1.33	1.20
Average	1.62	1.65	1.28	1.33

2.5.3.2 Pre-Dispatch to Real-Time Demand Forecast Error

This section focuses on the forecast error; in other words, on how well the IESO's demand forecast has performed. It differs from the pre-dispatch demand forecast deviation in that the forecast deviation compares the pre-dispatch demand with the average demand for the hour, whereas the forecast error instead uses the interval peak demand for the hour.

Table 1-13 reports the one-hour ahead and three-hour ahead average absolute demand forecast errors on a monthly basis for the 2011/12 and 2012/13 Annual Periods. On an annual basis, there was a decline in both the three-hour ahead and one-hour ahead average absolute demand forecast errors, expressed as a percentage of real-time demand, from 1.9% to 1.8% and from 1.7% to 1.5%, respectively. The demand forecast error in the three-hour ahead forecast remained virtually unchanged at 0.3% higher than the one-hour ahead forecast.

Table 1-13: Pre-Dispatch to Real-Time Demand Forecast Error Three-Hour and One-Hour Ahead May – April 2011/2012 & May – April 2012/2013 (% of real-time demand)

Month	Average Absolute Forecast Error*			
	Three-Hour Ahead		One-Hour Ahead	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	1.66	1.97	1.55	1.69
June	2.20	2.02	1.87	1.67
July	2.16	2.41	1.79	1.85
August	2.37	2.18	1.96	1.78
September	2.22	1.88	1.89	1.64
October	1.86	1.72	1.79	1.56
November	1.61	1.62	1.49	1.42
December	1.62	1.53	1.43	1.33
January	1.64	1.50	1.37	1.24
February	1.70	1.52	1.38	1.29
March	1.77	1.64	1.52	1.37
April	2.00	1.75	1.75	1.57
Average	1.9	1.81	1.65	1.53

*Absolute difference between pre-dispatch and real-time demand divided by real-time demand.

2.5.3.3 Wind Generation Forecast Errors

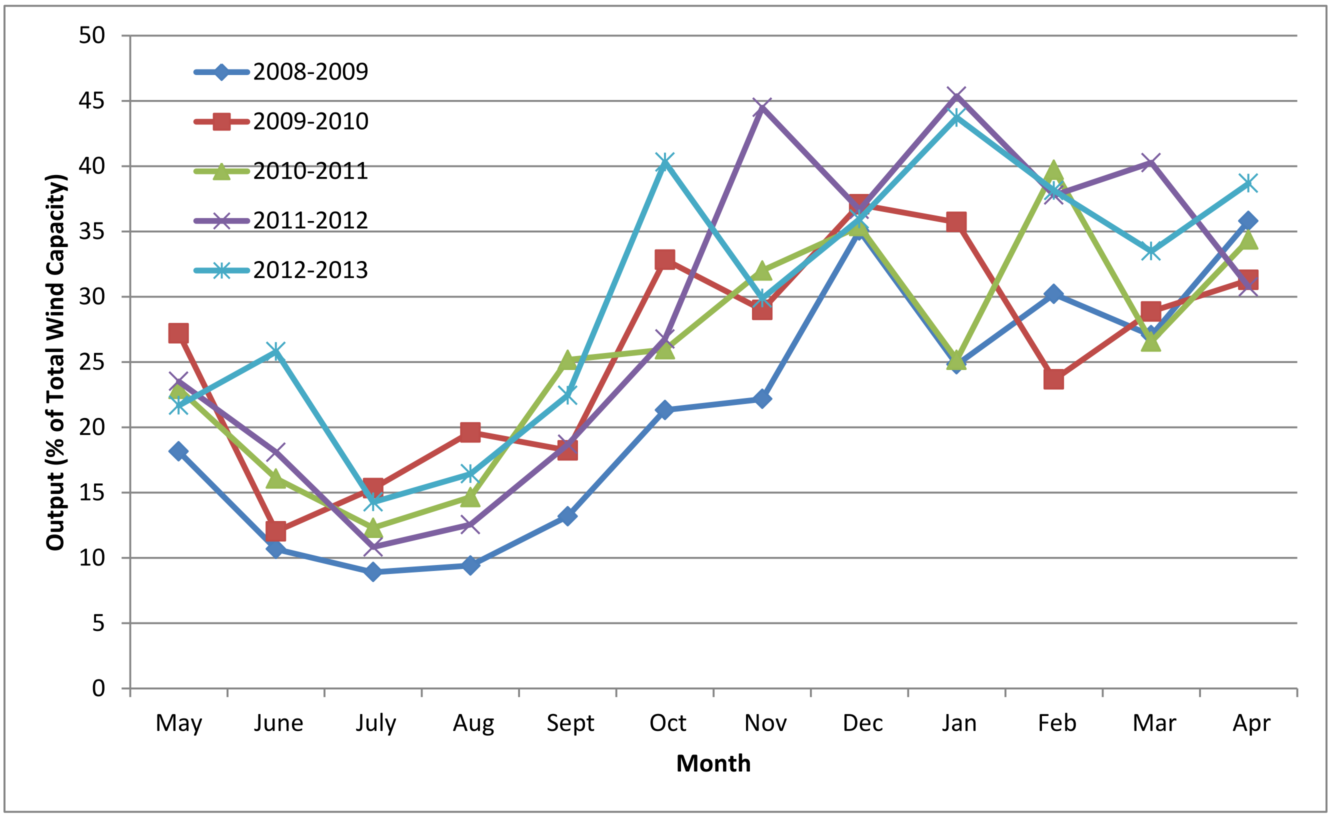
The amount of wind generation has increased steadily since the first wind facility was connected to the IESO-controlled grid in early 2006.[18] As of April 2013, there was a combined name-plate capacity of 1,704 MW of wind generation connected to the IESO-controlled grid (approximately 4.7% of total Ontario installed generating capacity).[19]

[18] For details on wind projects that are currently operational and those under development, see the OPA's wind contracts webpage at http://www.powerauthority.on.ca/current-electricity-contracts/wind-power.
[19] Wind generation (among others) can also be connected at the distribution level. Generation that is not directly connected to the IESO-controlled grid is not included in the data contained in this report.

This capacity is greater than the total capacity of all other self-scheduling and intermittent generation connected to the IESO-controlled grid.[20]

Output from wind generation facilities has seasonal trends. As illustrated in Figure 1-9, wind generation tends to be higher during the winter months, peaking in or around December and falling to a summer trough in or around July when the Ontario demand tends to be highest in the year.

Figure 1-9: Monthly Average Wind Output Relative to Installed Capacity May – April 2008/2009 to May – April 2012/2013 (% of total wind capacity)

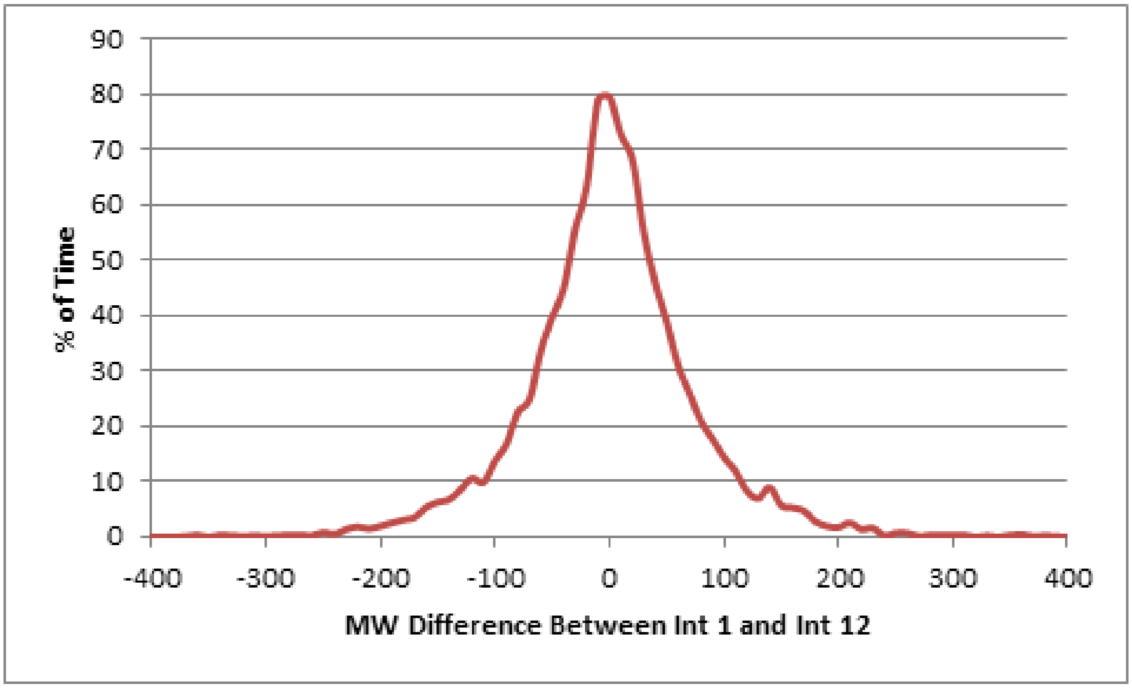


Wind output tends to be relatively stable hour-to-hour, but, at times, can change quite rapidly. Figure 1-10 depicts the distribution curve of the change in intra-hour wind output (i.e., the difference in output at interval 1 and interval 12 in the same hour) during the 2012/13 Annual Period. It can be seen that with approximately 1,700 MW of

[20] For details regarding new capacity that came online in the 2012/13 Annual Period, see section 4.1 of this chapter.

installed wind capacity, in approximately 86% of hours wind output increased or decreased by only 100 MW or less from the beginning of the hour to the end of hour.

Figure 1-10: Distribution Curve of Intra-Hour Change in Wind Power Production
May 2012 – April 2013
(%)

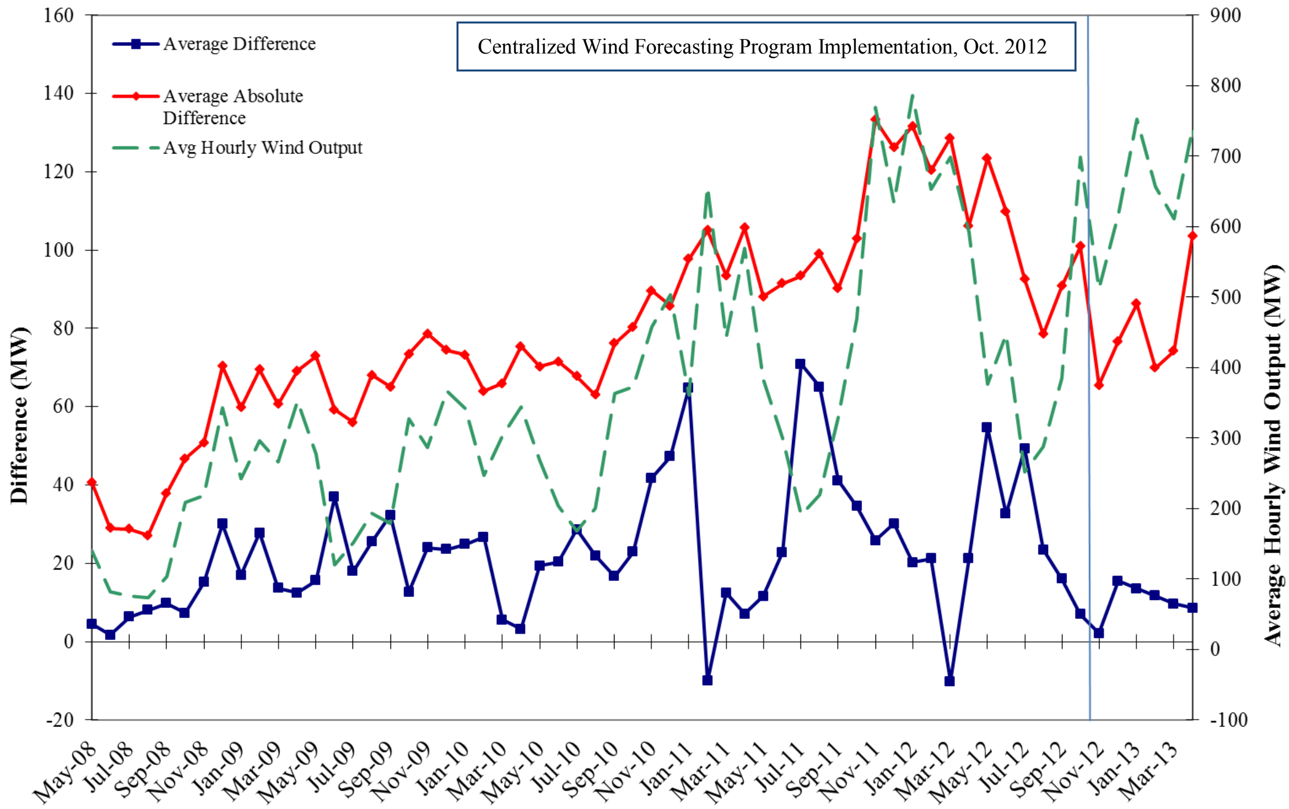


Before October 1, 2012, wind generators forecast their own output on an hourly basis.[21] Since October 2012 the IESO has implemented a centralized wind forecasting program. Figure 1-11 below presents the average and average absolute difference between one-hour ahead forecast output and delivered energy. Average hourly wind output is also plotted.[22]

[21] The Panel recommended centralized wind forecasting in its January 2009 Monitoring Report, at pp. 253-256, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf. A centralized forecast program for wind developed by the IESO was implemented on October 1, 2012. A day-ahead forecast has been incorporated into the enhanced day-ahead commitment process and a pre-dispatch forecast into the pre-dispatch sequence. For details, see: http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=6184 and http://ieso.ca/imoweb/news/bulletinItem.asp?bulletinID=5736. The IESO is still working on making wind resources dispatchable in real-time. For details, see: http://www.ieso.ca/imoweb/consult/consult_se91.asp.

[22] In previous Panel reports, nameplate capacity was plotted to show the 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 since outages and other factors constraining wind generation at specific facilities are reflected in actual output levels but not in the nameplate capacity value. Average hourly wind output is also used to determine the percentage average and average absolute error in Figure 1-11.

Figure 1-11: Average and Average Absolute Differences between Forecast and Delivered Energy, and Relationship to Average Hourly Wind Output May 2008 – April 2013 (MW)



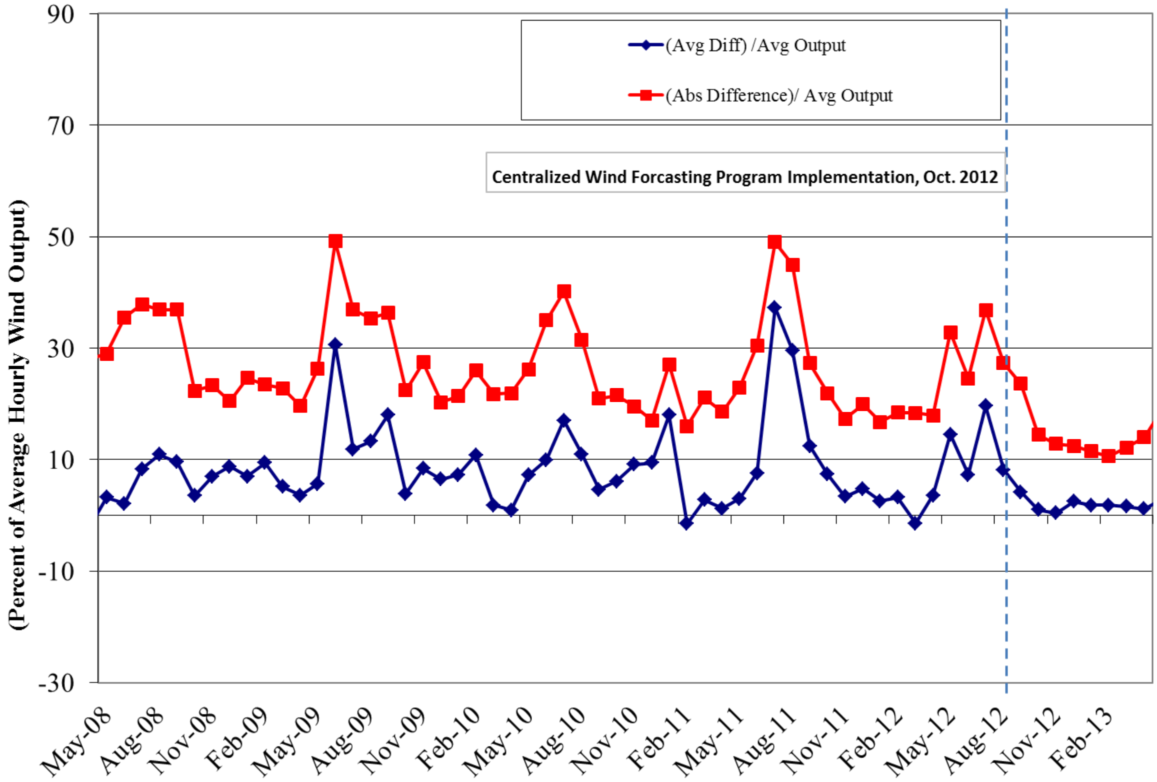
The average absolute wind forecast error has been increasing since 2008 as installed wind capacity and output has increased. The average error is an indication of whether supply tends to be over or under forecast, and can be quite volatile, while the absolute error is an indication of how far the forecast deviates from actual production. The overall average of the absolute forecast error was 86.6 MW per hour during the 2012/13 Annual Period, down 31.1% from 125.6 MW per hour in the 2011/12 Annual Period.

The IESO's implementation of a centralized wind forecasting program in October 2012 appears to have had a positive effect on the average difference and the average absolute difference between forecasted and delivered wind energy. The average absolute difference had highs in fall 2011 of 130 MW per hour with average hourly wind output at approximately 775 MW. In fall 2012, after the implementation of the centralized wind forecasting system, the maximum average hourly wind output was 750 MW with an average absolute difference of 80 MW per hour, a substantial decrease in the magnitude of absolute forecast difference.

Although the average wind production forecast error had been increasing as new wind generators come online, the percentage error (average absolute forecast error relative to total wind power output) has been relatively stable. Figure 1-12 plots the average and average absolute difference between wind generators' forecast and actual production in each month since May 2008 normalized against average hourly wind output for the month. During the 2012/13 Annual Period, the normalized average absolute difference as a percentage of hourly wind output typically fluctuated between 10-30%. The consistent peaks in the summer months are the result of lower hourly output of wind in the summer, which causes the fraction of average difference over average output to become relatively large; the average differences were not anomalous in those months.

Since the centralized wind forecasting program was implemented in October 2012, the normalized average absolute difference as a percentage of hourly wind output has reached all-time lows and hovered around 10% for fall 2012 and the winter of 2013. Additionally, the normalized average difference has been very low in volatility and magnitude since October 2012. The IESO's centralized wind forecasting program appears to be having the intended result of decreasing wind generation forecast deviation.

Figure 1-12: Normalized Average and Average Absolute Differences between Forecasted and Delivered Wind Energy
May 2008 – April 2013
(% of average hourly wind output for the month)



2.5.3.4 Forecast Errors of Other Self-Scheduling and Intermittent Generation

Non-wind self-scheduling and intermittent generators include small gas-fired, biomass and hydro-electric plants.[23]

Figure 1-13 plots the average and average 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 since May 2008. During that time, both the average and the average absolute error have been relatively constant in magnitude and volatility. The average absolute difference has ranged between 20 and 40

[23] As of the end of April 2013, no solar resources have been directly connected to the IESO-controlled grid.

MW per hour while the average difference has consistently been between 30 and -10 MW per hour.

Figure 1-13: Average and Average Absolute Production Forecast Errors of Non-Wind Self-Scheduling and Intermittent Generators
May 2008 – April 2013
(forecast-delivered energy, MW)

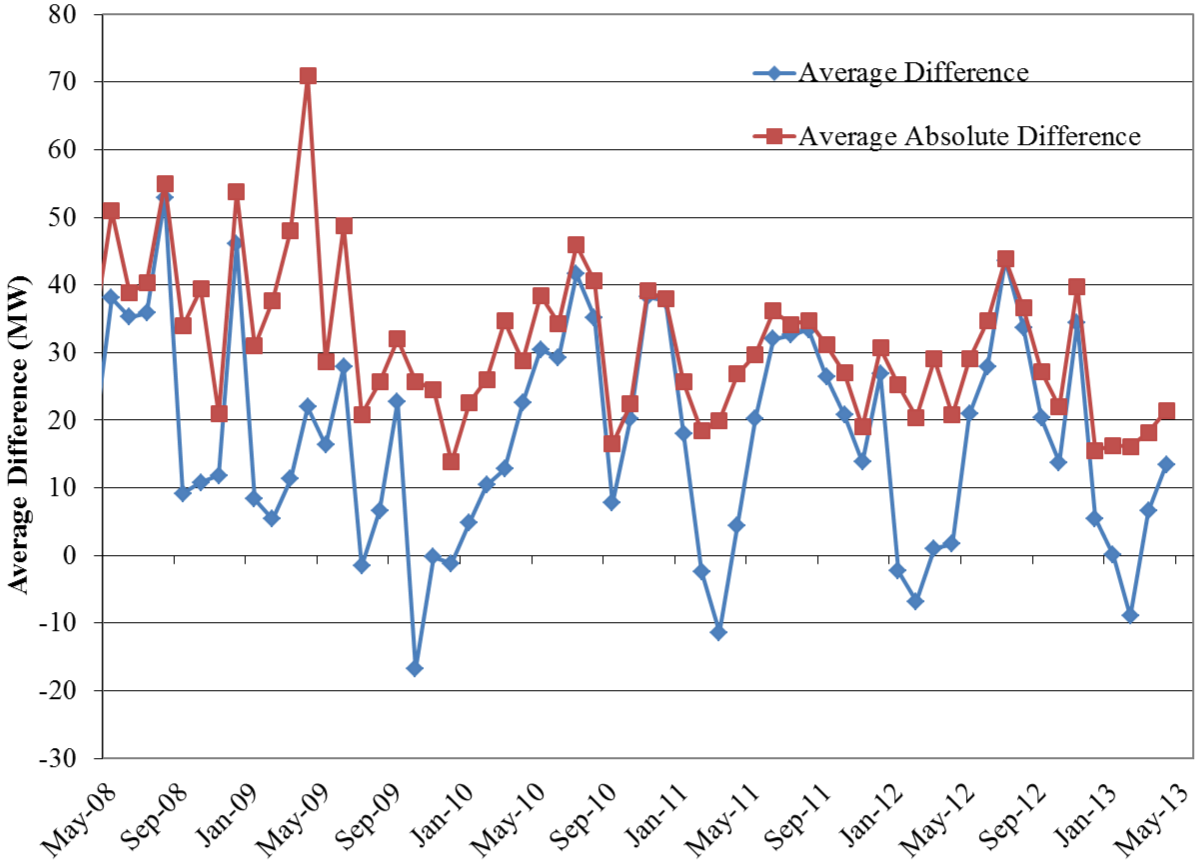
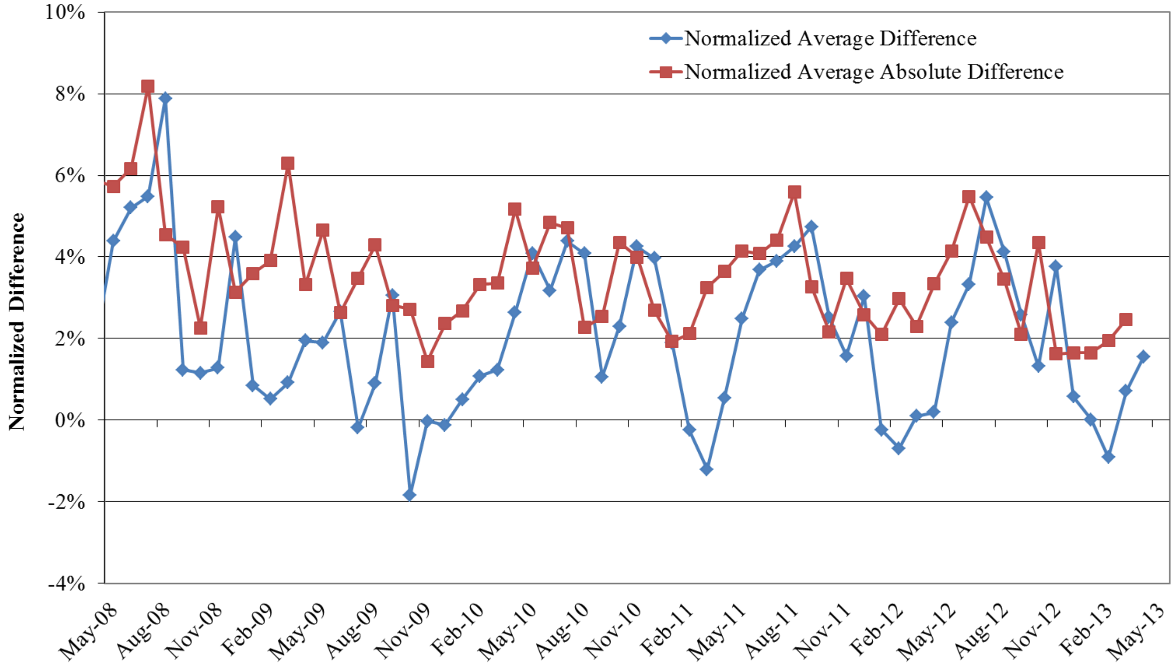


Figure 1-14 normalizes the production forecast error in a month against the average hourly output for the month since May 2008. As commissioning units are considered self-scheduling, this normalization helps to eliminate some of the impact of fluctuations in output arising when units become and cease to be commissioning. The normalized errors have also been relatively constant in magnitude and volatility.

Figure 1-14: Normalized Average and Average Absolute Production Forecast Errors of Non-Wind Self-Scheduling and Intermittent Generators by Average Hourly Output May 2008 – April 2013 (% of average hourly output for the month)



2.5.3.5 Real-Time Failed Intertie Transactions

Imports and exports that are scheduled in the final pre-dispatch can fail before or in real-time. An intertie transaction can fail because it is not scheduled in the other market (including failure due to an inability to obtain transmission service or a ramping limitation), because of an incorrect or invalid North American Electric Reliability Corporation (NERC) tag[24] or because it is curtailed by the IESO or an external system operator for reliability reasons. Import failures represent a loss of supply while export failures represent a decline in demand, both of which can result in discrepancies between pre-dispatch and real-time prices.

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

Export Failures

Table 1-14 provides summary statistics on the frequency and magnitude of failed export transactions over the 2011/12 and 2012/13 Annual Periods. The number of hours with failed exports was basically unchanged year-over-year. However, the average magnitude of export failures per hour declined substantially (29.3%). The decrease in the average magnitude of hourly failures also contributed to a decrease in the average failure rate from 6.0% to 3.8%.

Table 1-14: Frequency, Magnitude and Rate of Failed Exports from Ontario May – April 2011/2012 & May – April 2012/2013 (MW and %)

Month	Number of Hours with Failed Exports*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	535	477	437	300	160	142	5.4	5.9
June	409	508	500	250	184	136	7.2	5.4
July	477	452	300	270	159	110	6.2	3.7
August	499	421	200	300	163	79	7.3	2.7
September	494	338	310	200	124	70	6.9	2.8
October	441	314	200	205	93	98	3.9	2.6
November	344	532	345	200	98	100	3.8	3.5
December	315	373	211	175	135	105	5.3	3.1
January	479	435	300	200	120	108	5.0	2.9
February	447	590	300	233	180	131	7.0	6.3
March	542	614	211	212	182	78	7.7	3.9
April	540	454	300	219	160	95	5.8	3.1
Total/ Average	5522	5508	n/a	n/a	147	104	6.0	3.8

* Incidents involving less than 1 MW per hour (integrated value) and linked wheeling transaction 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 wheeling transactions) in the unconstrained schedule in a month.

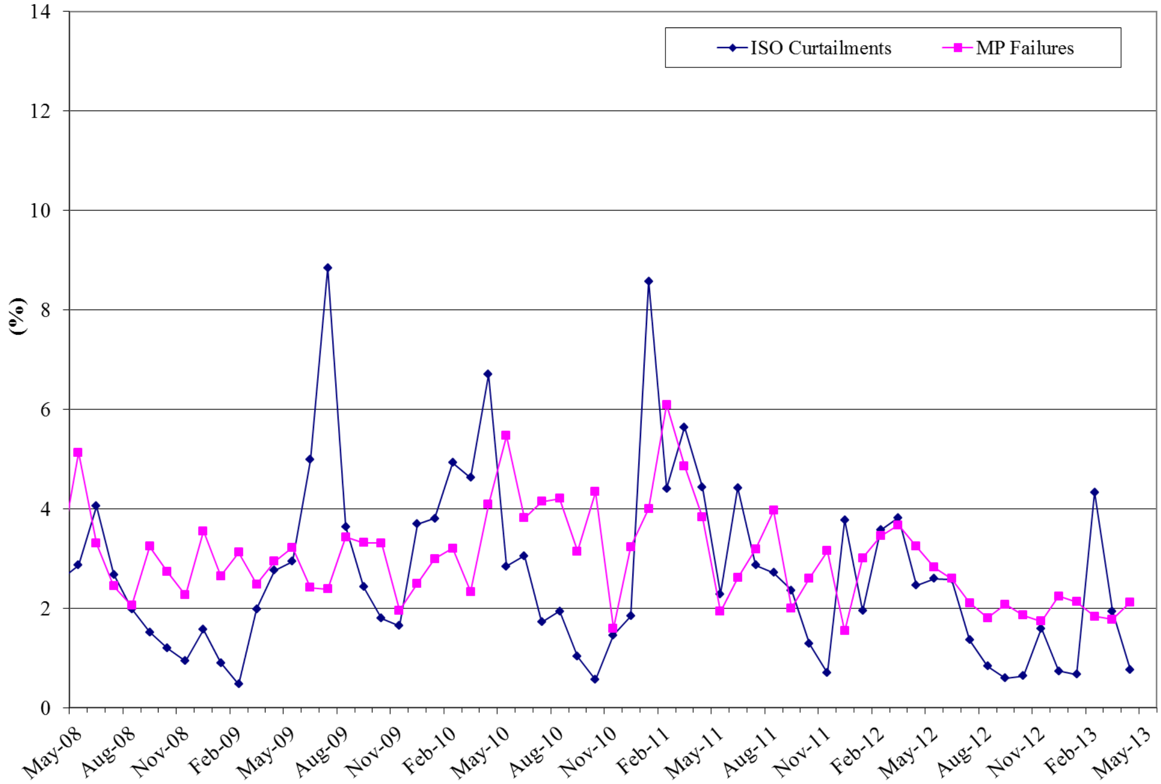
Causes of Export Failures

Export failures (and import failures, discussed below) can be either under the market participant's control (labelled "MP failures") or under the control of a system operator, either the IESO or an external system operator (labelled "ISO curtailments").[25]

Figure 1-15 plots the export failure rates by cause since May 2008. The failure rate is determined as a percentage of failed to total exports in MWh per month (excluding linked wheeling transaction failures, which are rare). ISO curtailments had a high of 4.3% in February 2013 and a low of 0.6% in November 2012, but were at or below 2% for most of the 2012/13 Annual Period. MP failures were steady at approximately 2% from August 2012 to April 2013, and had a high of 2.8% in May 2012 and a low of 1.7% in November 2012.

[25] The IESO Compliance database that separates failures into ISO curtailments and MP failures does so for constrained schedule failures only. Therefore, actual failure rates vary slightly from the statistics reported in Tables 1-15 and 1-17 below, which report unconstrained schedule failures in aggregate. Some failures in the constrained schedule may not appear as failures in the unconstrained schedule, and vice versa.

Figure 1-15: Monthly Export Failures by Cause
May 2008 – April 2013
(% of total exports)



Export Failures by Interface Group

Table 1-15 reports average monthly export failures by interface group and by cause for the 2012/13 Annual Period. Export failures at the Michigan interface averaged 7.9 GWh per month or approximately 16.5% of total export failures. Of those export failures at the Michigan interface, 65% were from from ISO curtailments. 79% of total MP failures occurred on the New York interface. This is largely a result of the process that must be used to schedule transactions on that interface.[26]

The Québec interface had the largest average monthly amount of ISO curtailments at 9.3 GWh (representing 45.8% of average monthly ISO curtailments).

[26] Participants selling into New York must place offers to sell the energy in real-time, which allows for the possibility that transactions are not economic and not scheduled in New York even when scheduled in Ontario. The potential for mismatched economic scheduling with the New York ISO is unique among the jurisdictions directly connected to Ontario. This distinction also applies for imports to Ontario from New York: see Table 1-17 below.

Table 1-15: Average Monthly Export Failures by Interface Group and Cause
May 2012 – April 2013
(GWh and % of failures)

Interface Group	Average Monthly Exports*	Average Monthly Export Failures				Failure Rate	
-	-	ISO Curtailment		MP Failure		ISO Curtailment	MP Failure
	GWh	GWh	%	GWh	%	%	%
New York	544.4	2.3	11.5	21.7	78.9	0.4	4.0
Michigan	539.8	5.1	25.0	2.8	10.2	0.9	0.5
Manitoba	10.5	1.2	5.7	1.3	4.6	11.1	12.1
Minnesota	19.3	2.4	12.0	0.6	2.0	12.7	2.9
Québec**	141.0	9.3	45.7	1.2	4.2	6.6	0.8
Total	1254.9	20.3	100.0	27.5	100.0	1.6	2.2

*As determined by the one-hour ahead constrained schedule.

** The Québec interface group includes all interties linking the Ontario grid with the Québec grid.

Import Failures

Table 1-16 provides monthly summary statistics on the frequency and magnitude of failed import transactions over the 2011/12 and 2012/13 Annual Periods. The total number of hours when failed imports occurred decreased from 3,442 in the 2011/12 Annual Period to 2,111 in the 2012/13 Annual Period, a decrease of 1,331 hours (39%). The import failure rate decreased from 9.4% to 5.3%, while the magnitude of the average hourly failure was approximately unchanged.

Table 1-16: Frequency, Magnitude and Rate of Failed Imports to Ontario May – April 2011/2012 & May – April 2012/2013 (MW and %)

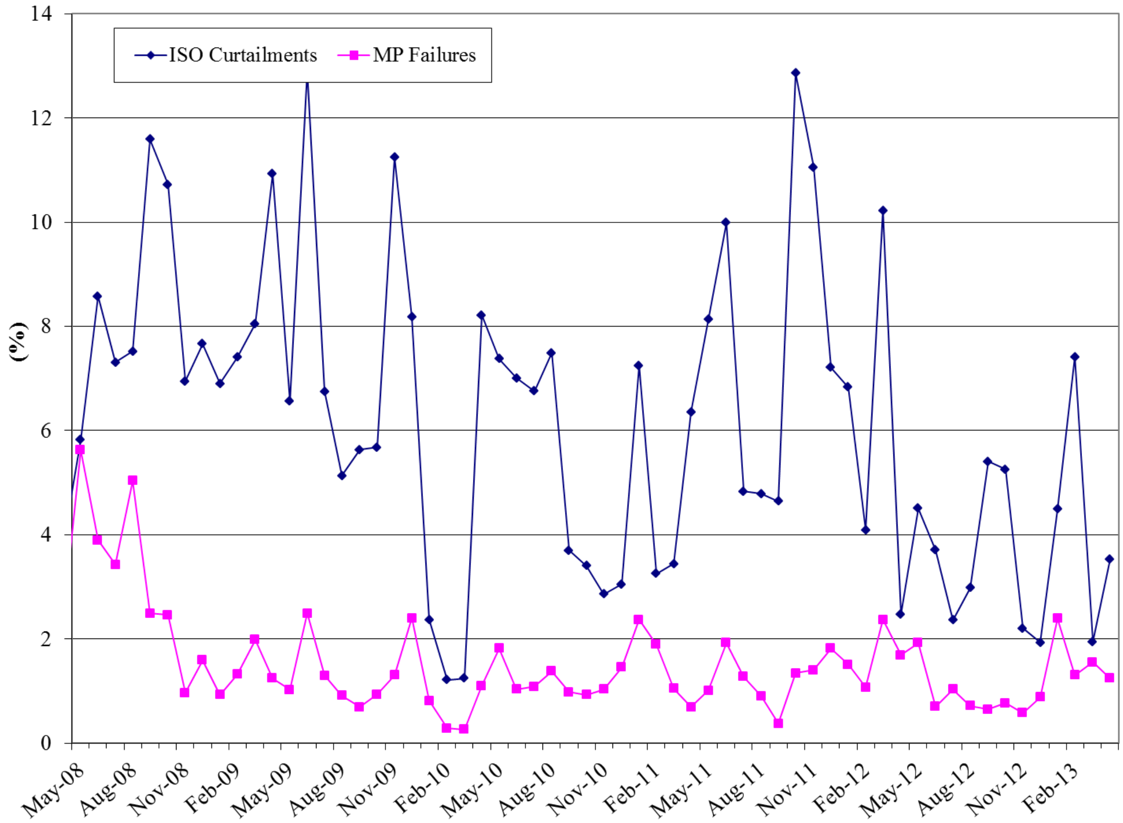
Month	Number of Hours with Failed Imports*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rates (%)***	
	2011/ 2012	2012/ 2013	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2013	2011/ 2012	2011/ 2012
May	259	228	413	400	82	100	10.0	6.9
June	249	196	500	374	135	89	12.4	4.6
July	314	242	350	614	115	104	6.3	3.7
August	340	278	406	464	94	90	6.6	4.2
September	360	288	500	418	96	88	9.4	6.4
October	357	247	243	313	111	106	14.9	6.5
November	302	92	400	325	123	84	12.9	3.2
December	249	59	300	363	85	92	9.0	3.2
January	341	93	300	500	67	140	8.7	6.8
February	180	125	428	500	67	133	5.4	8.9
March	315	116	396	600	98	87	12.7	3.9
April	176	147	358	400	80	80	4.3	5.4
Total/Average	3,442	2,111	383	439	96	99	9.4	5.3

* Incidents involving less than 1 MW per hour and linked wheeling transaction 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 wheeling transactions) in the unconstrained schedule in a month.

Causes of Import Failures

Figure 1-16 plots the import failure rates by cause since May 2008. The failure rate is determined as a percentage of failed to total imports in MWh per month (excluding linked wheeling transaction failures, which are rare). ISO curtailments continue to account for the majority of import failures. ISO curtailments as a percentage of monthly imports ranged from approximately 1.9% (in December 2012) to approximately 7.5% (in February 2013). MP failures continued to range between 0.5% and 2% in the 2012/13 Annual Period, with a maximum of 2.4% in January 2013.

Figure 1-16: Monthly Import Failures by Cause
May 2008 – April 2013
(% of total imports)



__Import Failures by Interface Group__

Table 1-17 reports average monthly import failures by interface group and by cause for the 2012/13 Annual Period. Average monthly import failures due to ISO curtailments at the Manitoba interface decreased substantially from the 2011/12 Annual Period. In the 2012/13 Annual Period, the Manitoba interface experienced an average of 3.8 GWh per month of ISO curtailments, a year-over-year decrease of 43.3%. The reason for this large decline in ISO curtailments is decreased import activity at the Manitoba interface due to the implementation of a market rule amendment that eliminated constrained-off CMSC payments for imports in the Northwest.[27]

[27] See Chapter 3 of this report for a detailed analysis of the effects of that market rule amendment.

The Michigan interface accounted for 29.4% of average import failures per month. The Québec interface (including several interconnected interties along the Ontario – Québec border) had the second highest average import failures per month (27.2%).

Table 1-17: Average Monthly Import Failures by Interface Group and Cause May 2012 – April 2013 (GWh and % of failures)

Interface Group	Average Monthly Imports*	Average Monthly Import Failures				Failure Rate	
		ISO-Curtailments		MP Failure		ISO Curtailment	MP Failure
	GWh	GWh	%	GWh	%	%	%
New York	25.7	0.2	2.3	0.7	8.9	0.9	2.5
Michigan	34.5	2.1	21.5	3.2	43.8	6.1	9.3
Manitoba	31.6	3.8	39.6	0.8	10.9	12.2	2.5
Minnesota	2.1	0.1	1.2	1.2	16.1	5.6	56.0
Québec**	240.5	3.4	35.4	1.5	20.3	1.4	0.6
Total	334.5	9.7	100.0	7.3	100.0	2.9	2.2

*As determined by the one-hour ahead constrained schedule.

** The Québec interface group include all interties linking the Ontario grid with the Québec grid.

Imports or Exports Setting the Final Pre-dispatch Price

As noted in section 2.5.3, the fourth factor identified by the Panel as contributing to differences between pre-dispatch and real-time prices is the frequency with which imports and exports set the pre-dispatch price. A higher frequency will lead to a greater divergence between pre-dispatch and real-time prices.[28]

Table 1-18 shows the frequency of hours in which imports and exports set the one-hour ahead pre-dispatch price in the 2011/12 and 2012/13 Annual Periods. In the 2012/13 Annual Period, imports or exports set the final pre-dispatch price in 3,156 hours, an increase of 15.4% from the 2,734 hours in which this occurred in the 2011/12 Annual Period.

[28] For a detailed explanation of why this occurs, see the Panel's July 2007 Monitoring Report, pp. 30-33, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf.

Table 1-18: Frequency of Imports or Exports Setting the Final Pre-Dispatch Price May – April 2011/2012 & May – April 2012/2013 (number of hours and % of hours)

Month	2011/2012		2012/2013		Difference	
	Hours	%	Hours	%	Hours	% Change
May	315	42.34	271	36.42	(44)	(13.97)
June	235	32.64	246	34.17	11	4.68
July	177	23.79	264	35.48	87	49.15
August	247	33.20	201	27.02	(46)	(18.62)
September	262	36.39	222	30.83	(40)	(15.27)
October	282	37.90	247	33.20	(35)	(12.41)
November	260	36.11	276	38.33	16	6.15
December	256	34.41	237	31.85	(19)	(7.42)
January	205	27.55	248	33.33	43	20.98
February	141	20.98	231	34.38	90	63.83
March	170	22.85	303	40.73	133	78.24
April	184	25.56	310	43.06	126	68.48
Total/Average	2,734	31.21	3,156	36.03	322	15.44

2.6 *Internal Zonal Prices*

Figure 1-17 and Table 1-19 summarize average internal zonal prices (also referred to as nodal prices) [29] for the 10 internal Ontario zones.[30]

As in the past, the average internal zonal prices in the Northwest and Northeast zones are much lower than in the rest of the zones. The differences among the remaining zones are moderate.

[29] Nodal prices are generated from the constrained schedule. The average nodal price for a zone is calculated as the average of the nodal prices for generators in that zone. All nodal and zonal prices have been modified to +$2000/MWh (or -$2000/MWh) when the raw interval value was higher (or lower).
[30] For a detailed description of the IESO's ten-zone division of Ontario, see IESO, "Ontario Transmission System", available at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2013jun.pdf.

Figure 1-17: Average Internal Zonal Prices
May 2012 – April 2013
($/MWh)

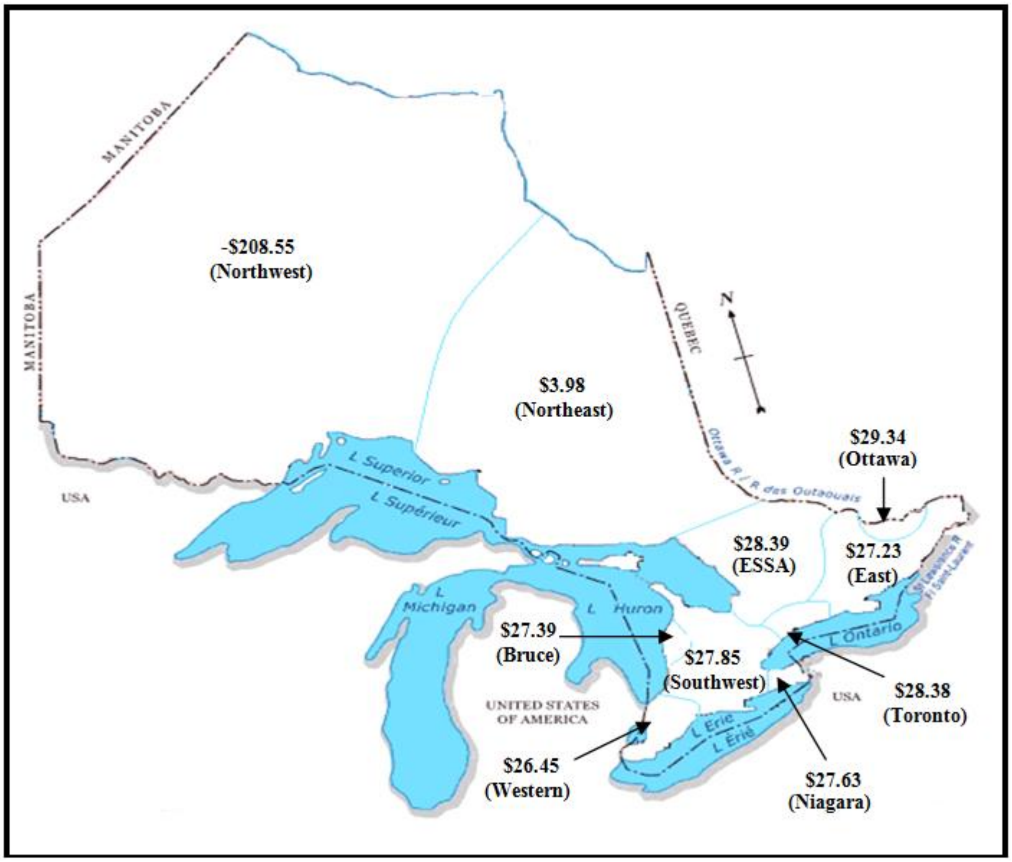


Table 1-19 shows that, with the exception of the two northern regions, most average internal zonal prices fluctuated between +/- 5% in the 2012/13 Annual Period relative to the 2011/12 Annual Period. The average East internal zonal price increased by 12.5% (from $24.21/MWh to $27.23/MWh) and was the largest fluctuation recorded outside of the two northern regions. The average Richview nodal price increased marginally from $28.40/MWh to $28.71/MWh (1.1%).[31]

Table 1-19: Average Internal Zonal Prices
May – April 2011/2012 & May - April 2012/2013
($/MWh and %)

Zone	May 2011 to April 2012	May 2012 to April 2013	% Change
Bruce	26.45	27.39	3.55%
East	24.21	27.23	12.47%
ESSA	28.23	28.39	0.57%
Niagara	26.36	27.63	4.82%
Northeast	13.40	3.98	(70.30%)
Northwest	(93.32)	(208.55)	(123.48%)
Ottawa	30.67	29.34	(4.34%)
Southwest	27.52	27.85	1.20%
Toronto	27.85	28.38	1.90%
Western	26.91	26.45	(1.71%)
Richview Node	28.40	28.71	1.09%

Average internal zonal prices in the Bruce, ESSA, East, Toronto, Niagara, Southwest and Western zones were all comparatively similar, which reflects the relatively low frequency of transmission congestion between these zones. As observed in previous Panel reports, bottled supply in the Northwest is the primary reason for the large negative internal zonal prices in that zone. The average internal zonal price in the Northwest zone was -$208.55/MWh in the 2012/13 Annual Period, which is a large decrease (123.5%) relative to the -$93.32/MWh average internal zonal price in the 2011/12 Annual Period. This zone clearly remains an outlier in terms of internal zonal prices. The Northeast region also experienced a large drop in its internal zonal price, falling to $3.98/MWh from $13.40/MWh, a 70.3% decrease.

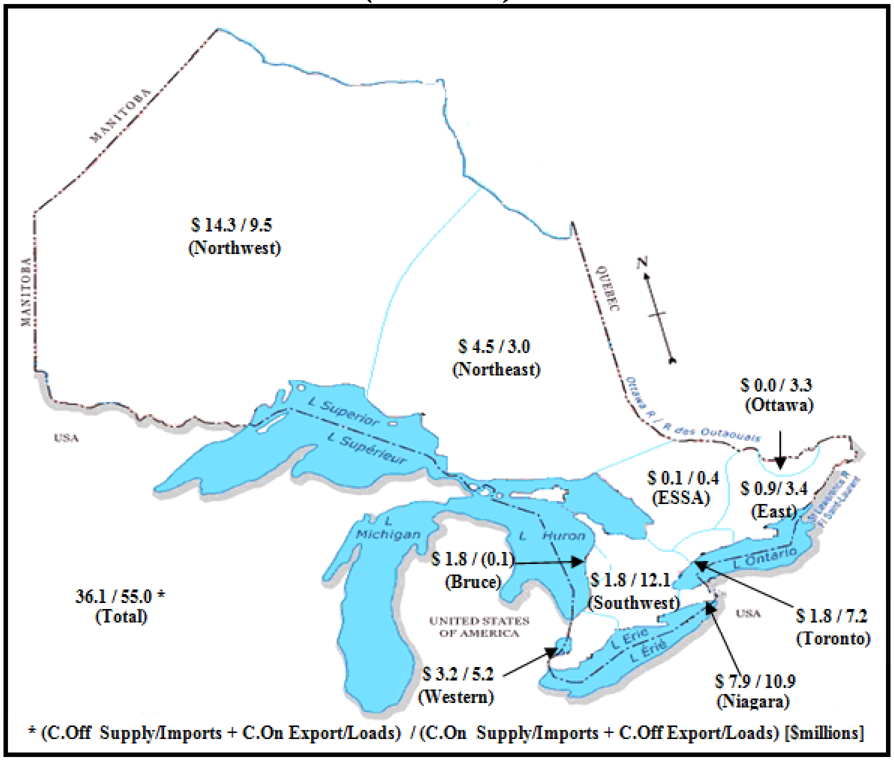
[31] The Richview bus is a node within the Toronto zone which is frequently used as a reference price given its central location (i.e., in the major load area).

2.7 *CMSC Payments*

Figure 1-18 identifies the total CMSC payments for each of the 10 internal zones for the 2012/13 Annual Period.[32] For each zone, the left portion of the data on the figure shows the total CMSC paid for constrained-off generation and imports plus constrained-on loads and exports from the zone (in this analysis, imports and exports are allocated to the respective zone where they flow in or out). The data is presented in this manner given that the constraining on of exports or loads is an alternative to the constraining off of supply (generation and imports) when supply is bottled (i.e., where there is oversupply in a zone). This approach therefore provides an indicator of the bottling of supply in a given zone. The right portion of the data on the figure shows, for each zone, the CMSC payments made for constrained-on generation and imports plus constrained-off loads and exports. This provides an indication of the need for additional or out-of merit supply in a given zone (i.e., where there is a shortage of supply to a zone, possibly due to system constraints).

[32] CMSC payments are often a consequence of transmission limits, losses or security requirements. In addition, the 3-times ramp rate multiplier, slow ramping of fossil-fired units and technical / regulatory limitations can each give rise to CMSC payments. CMSC payments can also be “self-induced” through, for example, voluntary ramping actions by dispatchable loads or generators.

Figure 1-18: Total CMSC Payments by Internal Zone May 2012 – April 2013 ($ millions)*



* The numbers are based on the estimation tables in the IESO database, and may be slightly different from the actual payments.

Of the $36.1 million of CMSC payments for constrained-off supply plus constrained-on demand, $14.3 million (39.5% of the total paid) occurred in the Northwest zone, primarily as the result of the west-east flow limits that constrain the relatively low-cost supply in the area. However, the vast majority of these CMSC payments (approximately $12.5 million) were made prior to October 1, 2012, after which a market rule amendment came into effect that eliminated constrained-off CMSC payments in the Northwest for imports.[33]

The other major contributors to total constrained-off CMSC payments were the Niagara zone at $7.9 million (21.8%) and the Northeast zone at $4.5 million (12.5%). The CMSC payments in the Niagara zone were usually a consequence of Lake Erie Circulation (LEC or "loop-flow" around Lake Erie), which leads to congestion at the New York

[33] See Chapter 3 of this report for a detailed analysis of the effects of this market rule amendment.

Independent System Operator (NYISO) and Midcontinent Independent System Operator (MISO) interfaces.

CMSC payments for constrained-on supply plus constrained-off demand totalled $55.0 million and were focused in four zones in Ontario. Significant payments were made in the Southwest zone ($12.1 million, 22% of the total), the Niagara zone ($10.9 million, 19.9% of the total), the Northwest zone ($9.5 million, 17.3% of the total) and the Toronto zone ($ 7.2 million, 13.2% of the total).

2.7.1 *Changes in Payments by Zone*

Table 1-20 compares the CMSC payments for each zone in the 2011/12 and 2012/13 Annual Periods. The payments decreased in most zones in the 2012/13 Annual Period. Total CMSC payments decreased in both oversupply and undersupply situations.

Total CMSC payments for constrained-off supply plus constrained-on demand were basically unchanged in the 2012/13 Annual Period. The largest zonal increase was seen in the Western zone, where constrained-off CMSC payments increased from $0.1 million to $3.2 million.[34] This year-over-year increase represents a return to constrained-off CMSC payment levels ($4.6 million) that were present during the 2010/11 Annual Period.

There was a large percentage decline in the amount of CMSC payments for constrained off supply plus constrained-on demand in the Bruce region. Constrained off payments declined by 81.1% or $7.2 million. The completion of enhancements to the Bruce-Milton transmission corridor in June 2012 likely contributed to this decrease. In the 2011/12 Annual Period, the large amount of Bruce region constrained-off CMSC payments is likely attributable to two factors, Bruce units reducing their generation in order to manage oversupply situations in the province and periodic outages at the major transmission lines that transfer power out of the Bruce station, which led to Bruce nuclear units being partially constrained off.

[34] Section 1.3.1 of Chapter 2 of this report discusses constrained–off CMSC payments made to market participants in the Western region.

Total CMSC payments for constrained-on supply plus constrained-off demand increased slightly by $ 4.0 million (7.9%) from the 2011/12 Annual Period to the 2012/13 Annual Period. The largest increase was in the Southwest region which saw an increase of $5.7 million (88.7%). The largest decline was in the Western region, which experienced a $5.9 million reduction (53.2%) in CMSC payments for constrained-on supply plus constrained-off demand.

Table 1-20: Total CMSC Payments by Internal Zone May – April 2011/2012 & May – April 2012/2013 ($ millions)*

Zone	Constrained-off Supply, Constrained-off Imports, Constrained-on Loads and Constrained-on Exports			Constrained-on Supply, Constrained-on Imports, Constrained-off Loads and Constrained-off Exports		
	2011/2012	2012/2013	% Change	2011/2012`	2012/2013	% Change
Bruce	9.0	1.8	(81.1)	(0.1)	(0.1)	(29.3)
East	1.1	0.9	(17.2)	3.7	3.4	(9.2)
ESSA	0.2	0.1	(50.5)	0.4	0.4	(5.9)
Niagara	4.1	7.9	92.9	6.7	10.9	63.9
Northeast	6.6	4.5	(32.0)	2.3	3.0	32.6
Northwest	11.4	14.3	25.0	11.7	9.5	(18.7)
Ottawa	0.4	0.0	(90.3)	2.3	3.3	41.5
Southwest	1.4	1.8	29.2	6.4	12.1	88.7
Toronto	1.6	1.8	6.9	6.4	7.2	13.0
Western	0.1	3.2	3197.5	11.1	5.2	(53.2)
Total	35.9	36.1	0.6	50.9	55.0	7.9

*The total CMSC payments are slightly different from the numbers in Table 1-4. The numbers here are based on the estimation tables in the IESO database, which can separate CMSC payments by resource type and by constraint type. In contrast, the numbers in Table 1-4 are actual CMSC payments which are derived from the IESO settlement tables which are not separated by resource type or constraint type.

3 Demand

3.1 Aggregate Consumption

Table 1-21 compares monthly Ontario energy demand and net exports (in the unconstrained schedule) in the 2011/12 and 2012/13 Annual Periods. Total Ontario demand plus net exports increased by 4.16 TWh or 2.8% in the 2012/13 Annual Period relative to the 2011/12 Annual Period. Total energy demand plus net exports increased year-over-year for each month during the 2012/13 Annual Period. The largest monthly percentage increase occurred in November, 2012 (8.9%).

Annual Ontario demand (without accounting for net exports) increased by 2.3 TWh, or 1.6%, from 139.81 TWh in the 2011/12 Annual Period to 142.11 TWh in the 2012/13 Annual Period. Ontario demand was greater year-over-year in every month except September and December 2012. June 2012 saw the largest year-over-year percentage increase (4.6%) in demand relative to the same month in the 2011/12 Annual Period, likely due to warmer than usual weather.[35] Considering that there continues to exist additional embedded supply from solar and wind (which acts to decrease total demand as explained in section 4 below), this increase in Ontario demand seems to confirm that the Ontario economy is indeed growing[36] no doubt assisted by improving economic conditions in the United States.

Total annual net exports increased from 9.01 TWh in the 2011/12 Annual Period to 10.86 TWh in the 2012/13 Annual Period, a 20.5% increase. Exports and imports are discussed in greater detail in section 5 below.

[35] The mean monthly temperature in Toronto for June 2012 was 20.6^{o} Celsius, compared with 19.1^{o} Celsius in June 2011.
[36] The Ontario Ministry of Finance reported real GDP growth of 1.0% year-over-year for the first quarter of 2013

***Table 1-21: Monthly Domestic Energy Demand and Net Exports
May – April 2011/2012 & May – April 2012/2013
(TWh)***

Month	Ontario Demand			Net Exports			Total		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	10.83	11.12	2.7	1.30	0.83	(36.2)	12.13	11.95	(1.49)
June	11.28	11.80	4.6	0.69	0.81	16.7	11.97	12.61	5.31
July	13.32	13.44	0.9	0.57	0.53	(6.8)	13.89	13.97	0.59
August	12.56	12.61	0.4	0.53	0.51	(4.7)	13.09	13.12	0.19
September	11.18	11.03	(1.3)	0.47	0.42	(10.8)	11.65	11.45	(1.72)
October	11.04	11.11	0.6	0.75	0.80	6.9	11.79	11.91	1.03
November	11.09	11.47	3.4	0.60	1.26	110.5	11.69	12.73	8.92
December	12.10	12.10	0.0	0.48	1.08	124.0	12.58	13.18	4.73
January	12.72	12.86	1.1	0.79	1.41	78.6	13.51	14.27	5.63
February	11.58	11.73	1.3	0.74	1.03	38.9	12.32	12.76	3.56
March	11.48	11.92	3.8	1.00	1.02	1.8	12.48	12.94	3.67
April	10.63	10.92	2.7	1.09	1.17	7.5	11.72	12.09	3.17
Total	139.81	142.11	1.6	9.01	10.86	20.5	148.81	152.97	2.80
Average	11.65	11.84	1.6	0.75	0.90	20.5	12.4	12.75	2.80

3.2 *Wholesale and Distributor Consumption*

Figure 1-19 plots the monthly total energy withdrawals from wholesale loads and distributors, respectively, between May 2008 and April 2013. There are clear seasonal fluctuations in distributor demand. Typically, distributor withdrawals are highest in December/January (the heating season) and July/August (the cooling season). In the 2012/13 Annual Period, distributor demand peaked in July 2012 at 11.58 TWh, and hit a low of 9.19 TWh in April 2013.

Figure 1-19: Monthly Total Energy Withdrawals, Distributors and Wholesale Loads May 2008 – April 2013 (TWh)

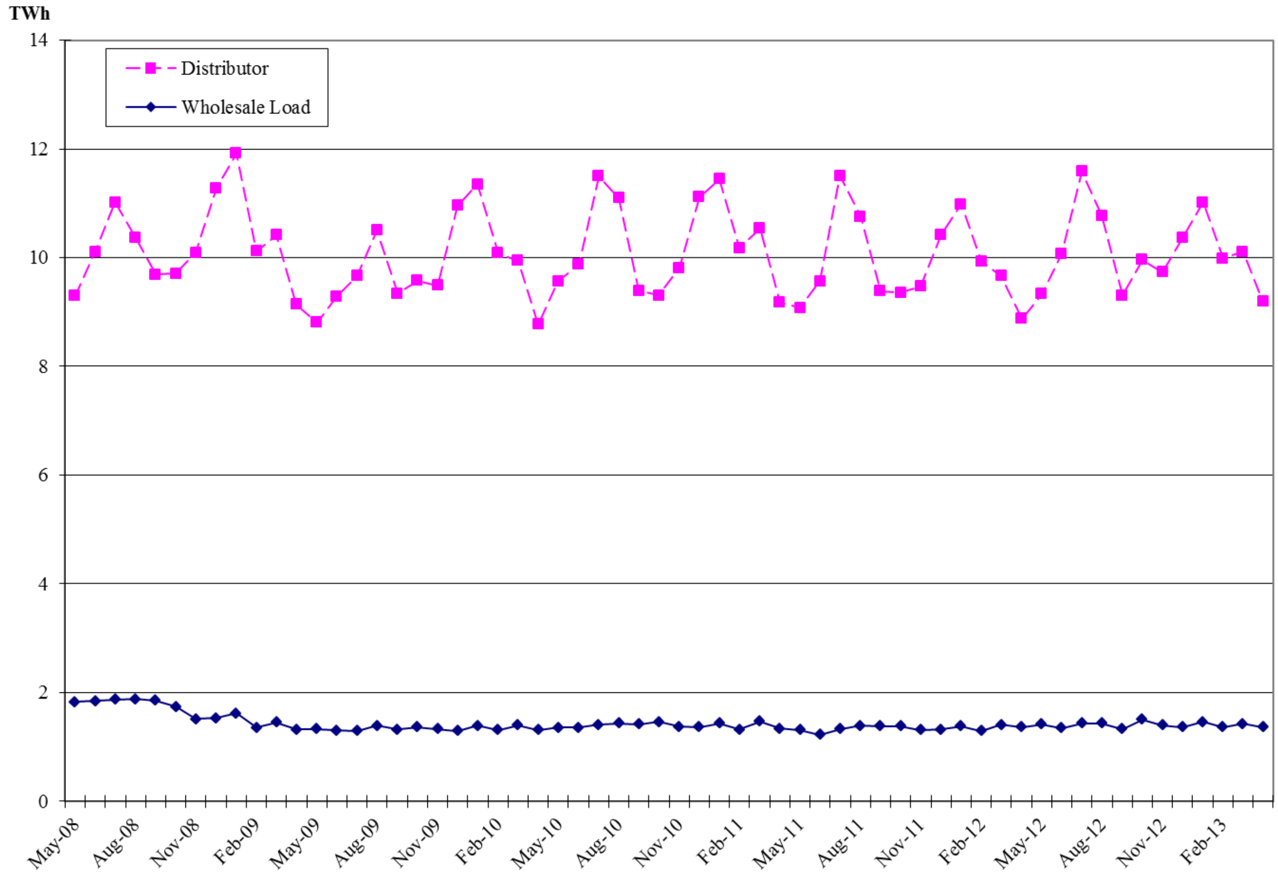
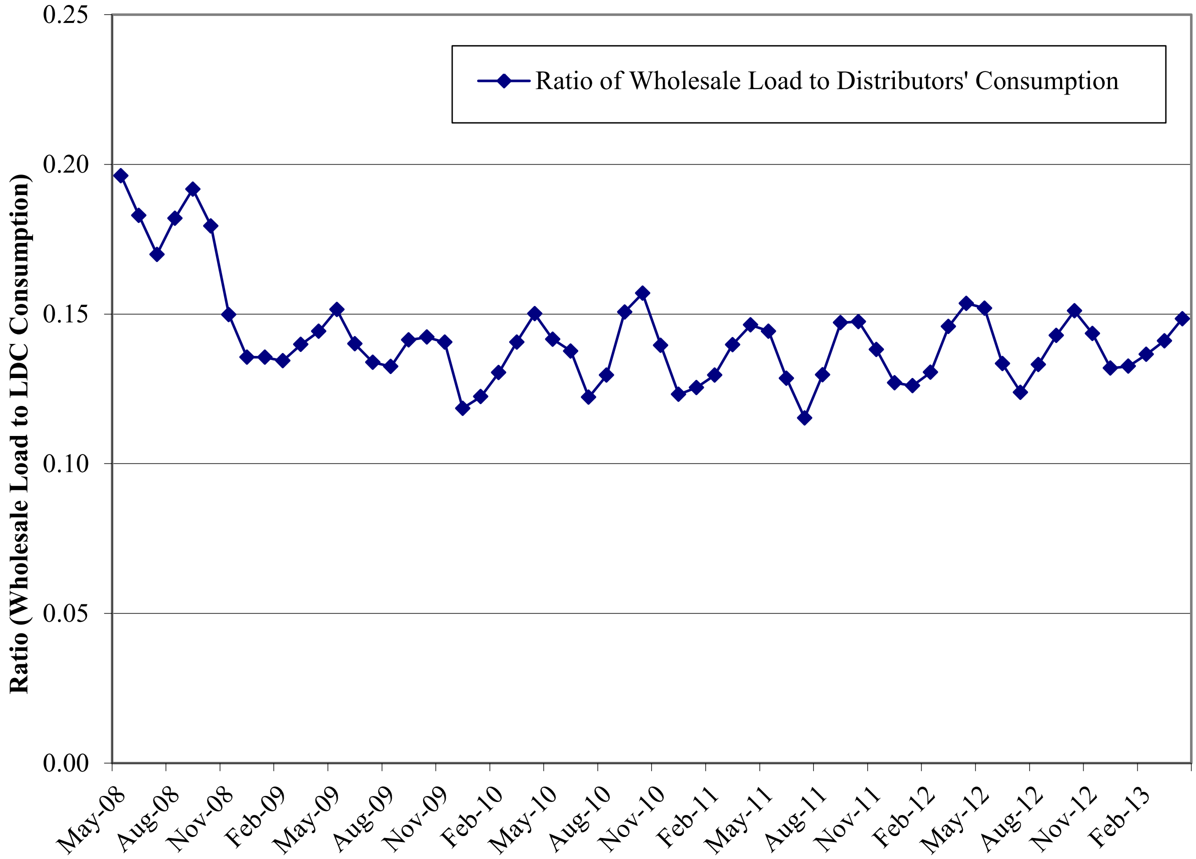


Figure 1-20 presents the ratio of wholesale load to distributor withdrawals from May 2008 to April 2013.

The short-term fluctuations in the ratio are inversely proportional to changes in distributor withdrawals, since wholesale load consumption is less volatile. The decrease in the ratio during the summer of 2008 to the fall of 2009 was due to a decline in wholesale load usage, possibly attributable to the global recession. Since the fall of 2009, the ratio has been stable, ranging between 0.12 and 0.15.

Figure 1-20: Ratio of Wholesale Load to Distributor Consumption
May 2008 – April 2013
(wholesale load divided by distributor withdrawals)



4 Supply

4.1 New Generation Facilities

During the 2012/13 Annual Period, 1,601 MW of new domestic generation capacity that is directly connected to the IESO-controlled grid was added to the Ontario wholesale market as follows:

- Bruce Nuclear brought two units back online (Units 1 and 2) with a generating capacity of 1,552 MW
- One wind energy centre added 49 MW of generation capacity (Pointe aux Roches Wind Farm in Essex County)

In addition, 178 MW of renewable generation capacity (a combination of wind, solar/photovoltaic and bioenergy) under the feed-in tariff (or "FIT") program came online in the 2012/13 Annual Period, as did 24 MW of renewable generation capacity under the micro-FIT program (for projects that are 10 kW or less).[37] These generators are embedded with the service areas of distributors and are not directly connected to the IESO-controlled grid. They are not counted as additions to Ontario's installed generation capacity as reported by the IESO, nor are they generally included in the analyses set out in this report. Rather, when a generator that is embedded within the service area of a distributor produces power, the distributor's demand for power from the IESO-controlled grid decreases. Embedded generation capacity is therefore reflected as a reduction in Ontario demand.

Ontario also saw another reduction in its coal-fired generating capacity due to the provincial government's policy of eliminating coal-fired generation by the end of 2014. The Atikokan coal-fired generation facility was taken offline by Ontario Power Generation in September 2012, removing 211 MW of capacity from service.

[37] Calculated using information from biweekly reports posted on the OPA's website (capacity in commercial operation on April 14, 2013 minus capacity in commercial operation on April 29, 2012). The reports are available at: http://fit.powerauthority.on.ca/bi-weekly-fit-and-microfit-program-reports.

This loss of capacity, when combined with the 1,601 MW of new directly-connected capacity referred to above, yields a net increase in domestic generating capacity of 1,390 MW or 4.0% at the wholesale level.

4.2 *The Supply Cushion*

Tables 1-22 and 1-23 present monthly summary statistics on the pre-dispatch and real-time supply cushion for the 2011/12 and 2012/13 Annual Periods.[38] The final pre-dispatch supply cushion measure includes all sources of supply (including imports) while the real-time domestic supply cushion focuses on supply ramping capability from domestic generation.[39] Both metrics measure the available but unutilized supply relative to Ontario demand (plus total OR requirements).

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

Table 1-22 shows an increase of 6.0% in the average pre-dispatch supply cushion for the 2012/13Annual Period.

Consistent with the increase in the average pre-dispatch supply cushion, the frequency with which the supply cushion fell below 10% in the pre-dispatch was significantly reduced in the 2012/13 Annual Period. The total number of hours with a pre-dispatch supply cushion of less than 10% decreased dramatically, from 1,631 hours in the 2011/12 Annual Period to 252 hours in the 2012/13 Annual Period, an 85.4 % decrease.

[38] The supply cushion measure used by the Panel was refined in the Panel's January 2009 Monitoring Report, pp. 205-206, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf. It differs from the supply cushion published by the IESO.

[39] Imports are scheduled on an hourly basis, whereas domestic resources are scheduled on a five minute basis (i.e., they can be dispatched up and down in real-time).

Table 1-22: Final Pre-Dispatch Total Supply Cushion[40]
May – April 2011/2012 & May – April 2012/2013
(% of Ontario demand and number of hours under a 10% level)

Month	Average Supply Cushion (%)		Supply Cushion of Less Than 10% (# of Hours, % of Total Hours)			
	2011/ 2012	2012/ 2013	2011/ 2012	%	2012/ 2013	%
May	11.1	20.3	362	48.7	75	10.1
June	17	24.5	96	13.3	33	4.6
July	18.8	22.6	137	18.4	35	4.7
August	18.3	23.2	113	15.2	10	1.3
September	19.7	22.1	55	7.6	18	2.5
October	19.7	19.2	41	5.5	52	7
November	22.4	25.2	47	6.5	4	0.6
December	18.7	26.3	125	16.8	1	0.1
January	16.3	24.3	210	28.2	5	0.7
February	18.1	22.1	108	15.5	14	2.1
March	16.6	27.5	145	19.5	1	0.1
April	15.7	27.3	192	26.7	4	0.6
Average/Total	17.7	23.7	1631	18.5	252	2.9

4.2.2 *Real-time Supply Cushion*

Table 1-23 compares the real-time supply cushion between the 2011/12 and 2012/13 Annual Periods. The real-time supply cushion has increased year-over-year by 1.8%. Correspondingly, the number of hours in which the supply cushion was less than 10% of Ontario demand in real-time decreased by 414 hours, a 41.7% year-over-year reduction.

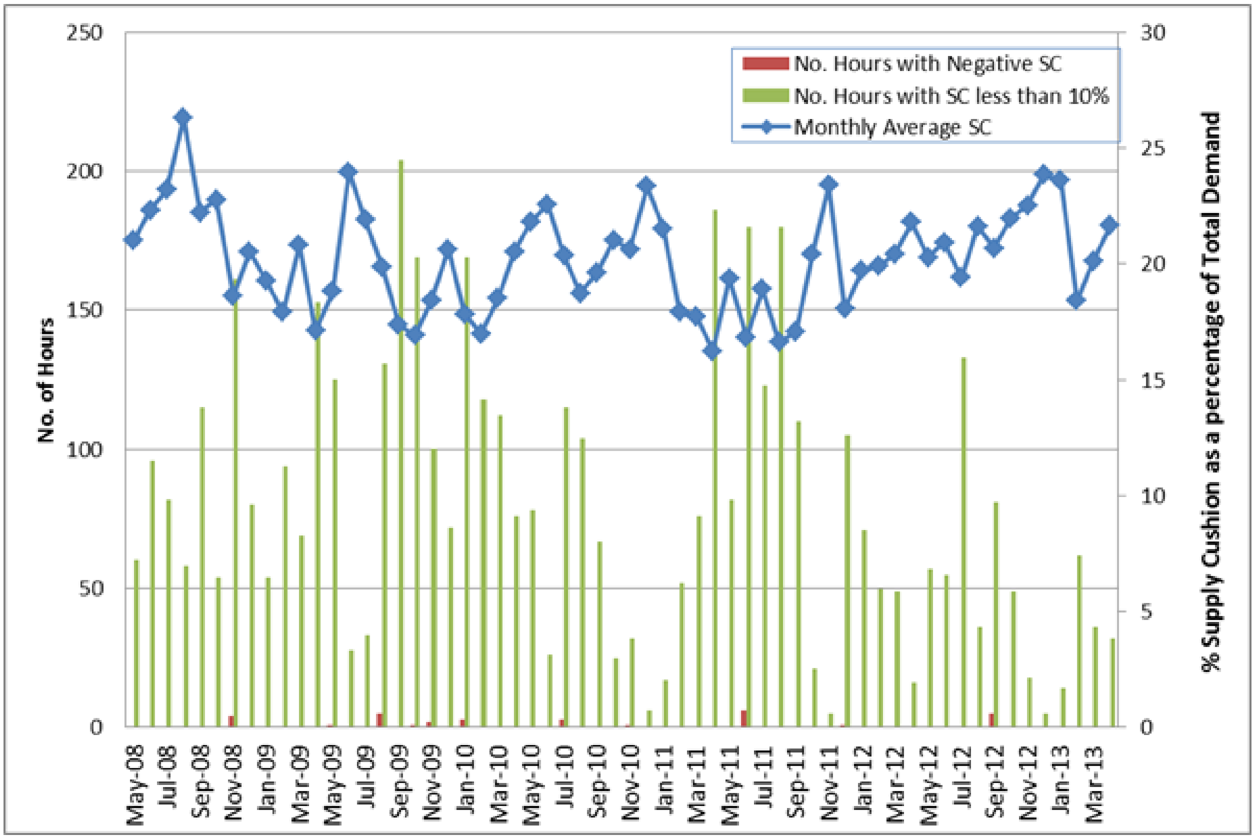
[40] The 2011/12 figures presented in Table 1-22 and Table 1-23 have been updated relative to the numbers presented in the Panel's November 2011 Monitoring Report (pp. 49-50, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf), and now more accurately reflect the available supply from newly installed gas-fired generators.

Table 1-23: Real-Time Domestic Supply Cushion May – April 2011/2012 & May – April 2012/2013 (% of Ontario demand and number of hours under a 10% level)

Month	Average Supply Cushion (%)		Supply Cushion of Less Than 10% (# of Hours, % of Total Hours)			
	2011/ 2012	(# of Hours, % of Total Hours) 2013	2011/ 2012	%	2012/ 2013	%
May	19.4	20.3	82	11	57	7.7
June	16.8	20.9	180	25	55	7.6
July	18.9	19.4	123	16.5	133	17.9
August	16.6	21.6	180	24.2	36	4.8
September	17.1	20.7	110	15.3	81	11.3
October	20.4	22.0	21	2.8	49	6.6
November	23.4	22.5	5	0.7	18	2.5
December	18.1	23.8	105	14.1	5	0.7
January	19.7	23.6	71	9.5	14	1.9
February	19.9	18.4	50	7.2	62	9.2
March	20.4	20.1	49	6.6	36	4.8
April	21.8	21.6	16	2.2	32	4.4
Average/Total	19.4	21.2	992	11.3	578	6.6

Figure 1-21 plots real-time domestic supply cushion summary statistics between May 2008 and April 2013. The 2012/13 Annual Period demonstrated the standard pattern of a relatively low number of hours where the supply cushion was less than 10% of Ontario demand during the winter months, with a relatively high number of those hours arising in the summer. The monthly average supply cushion ranged between 18% and 24%, which is consistent with values observed in the past five years.

Figure 1-21: Monthly Real-Time Domestic Supply Cushion Statistics May 2008 – April 2013 (% of Ontario demand, and number of hours)



4.3 *Baseload Supply*

Table 1-24 presents average hourly baseload generation (unconstrained schedule) by category over the 2011/12 and 2012/13 Annual Periods. Overall, average hourly baseload supply increased marginally (by 0.4%), from 13.1 GW during the 2011/12 Annual Period to 13.5 GW during the 2012/13 Annual Period. Monthly baseload supply was greater in all months except for August and September when compared to the 2011/12 Annual Period.

Table 1-24 also shows the corresponding average Ontario demand and the portion of that demand that is covered by total baseload supply. There was a 4.7% increase in the average hourly Ontario demand (from 15.9 GW in the 2011/12 Annual Period to 16.2 GW in the 2012/13 Annual Period). As a result, the share of total Ontario demand covered by baseload supply decreased from 84.5% to 83.7%.

Table 1-24: Average Hourly Baseload Supply by Supply Type and Ontario Demand May – April 2011/2012 & May – April 2012/2013 (GW, unconstrained schedules)

Month	Nuclear		Baseload Hydro*		Self-Scheduling and Intermittent Supply		Total Baseload Supply		Ontario Demand		Total Baseload Supply as a % of Average Ontario Demand	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	9.3	9.3	2.3	2.3	1.2	1.2	12.8	12.9	14.6	14.9	90.8	86.0
June	9.2	10.0	2.5	2.2	1.2	1.3	12.8	13.4	15.7	16.4	84.2	81.8
July	9.8	10.6	2.3	2.1	1	1.1	13.2	13.7	17.9	18.1	75.4	75.9
August	10.5	10.3	2.3	2.0	1	1.1	13.8	13.4	16.9	17.0	83.6	78.9
September	10.3	9.3	2.2	2.0	0.9	1.2	13.3	12.4	15.5	15.3	88.1	81.2
October	9.5	10.0	2.1	1.9	1.3	1.7	12.9	13.6	14.8	14.9	89.6	91.1
November	8.8	10.7	2.2	2.0	1.6	1.4	12.6	14.1	15.4	15.9	84	88.4
December	9.8	10.3	2.2	2.1	1.5	1.6	13.4	14.0	16.3	16.3	84.3	86.2
January	9.5	10.6	2.2	2.1	1.8	1.7	13.4	14.4	17.1	17.3	80.2	83.2
February	9.2	9.9	2.4	2.0	1.6	1.6	13.1	13.6	16.6	17.5	80.4	77.9
March	9.3	9.4	2.3	2.4	1.7	1.5	13.3	13.3	15.4	16.0	88.7	83.2
April	8.8	9.9	2.3	2.1	1.5	1.6	12.6	13.7	14.8	15.2	88.1	90.1
Average	9.5	10.0	2.3	2.1	1.4	1.4	13.1	13.5	15.9	16.2	84.5	83.7

*Baseload hydro includes the Beck (net of pump storage operation), Saunders and DeCew hydroelectric generators.

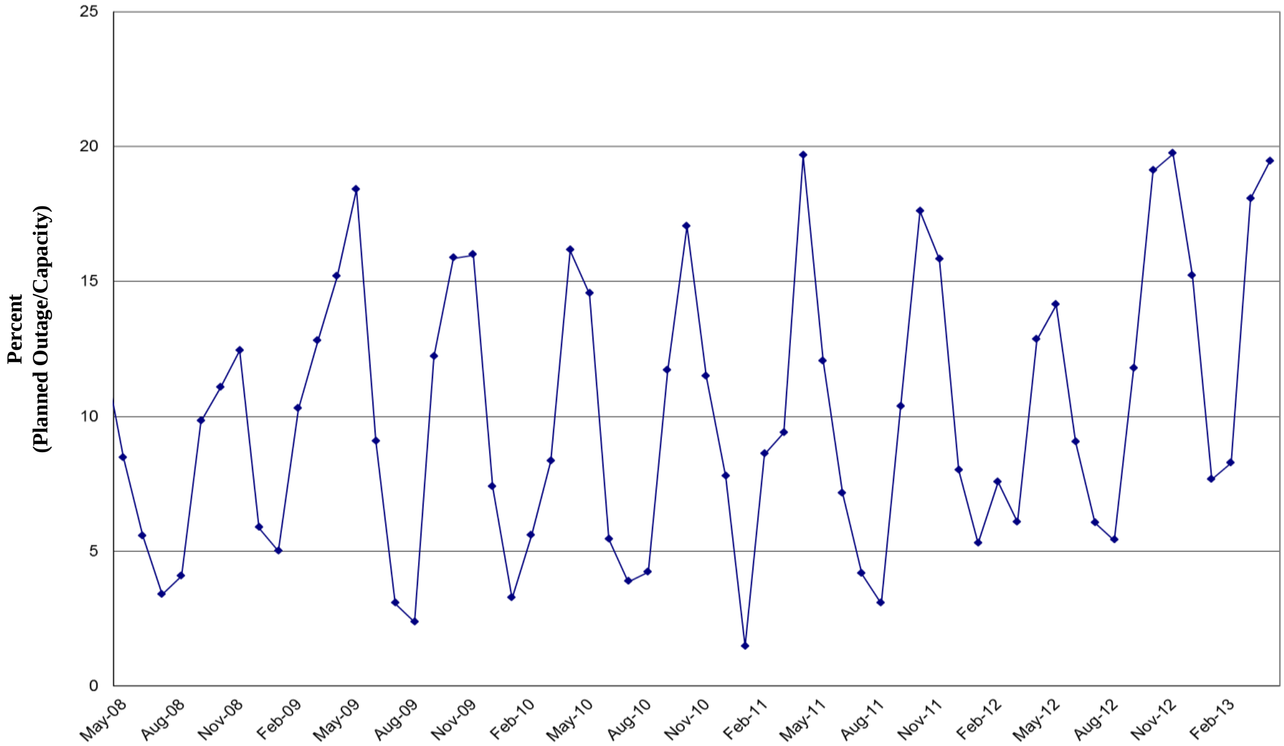
4.4 *Outages*

It is important to monitor generator outage patterns, as there is upward pressure on market prices when supply is removed from the market. The discussion below reports on generator planned and forced outage rates.

4.4.1 *Planned Outages*

Planned outages are typically taken during the spring and fall months, which are periods of lower demand. Figure 1-22 plots monthly total planned outages as a percentage of total generation capacity since 2008. Planned outage rates over the 2012/13 Annual Period showed seasonal fluctuations similar to those observed in previous years.

Figure 1-22: Planned Outages Relative to Capacity
May 2008 – April 2013
(% of capacity)*

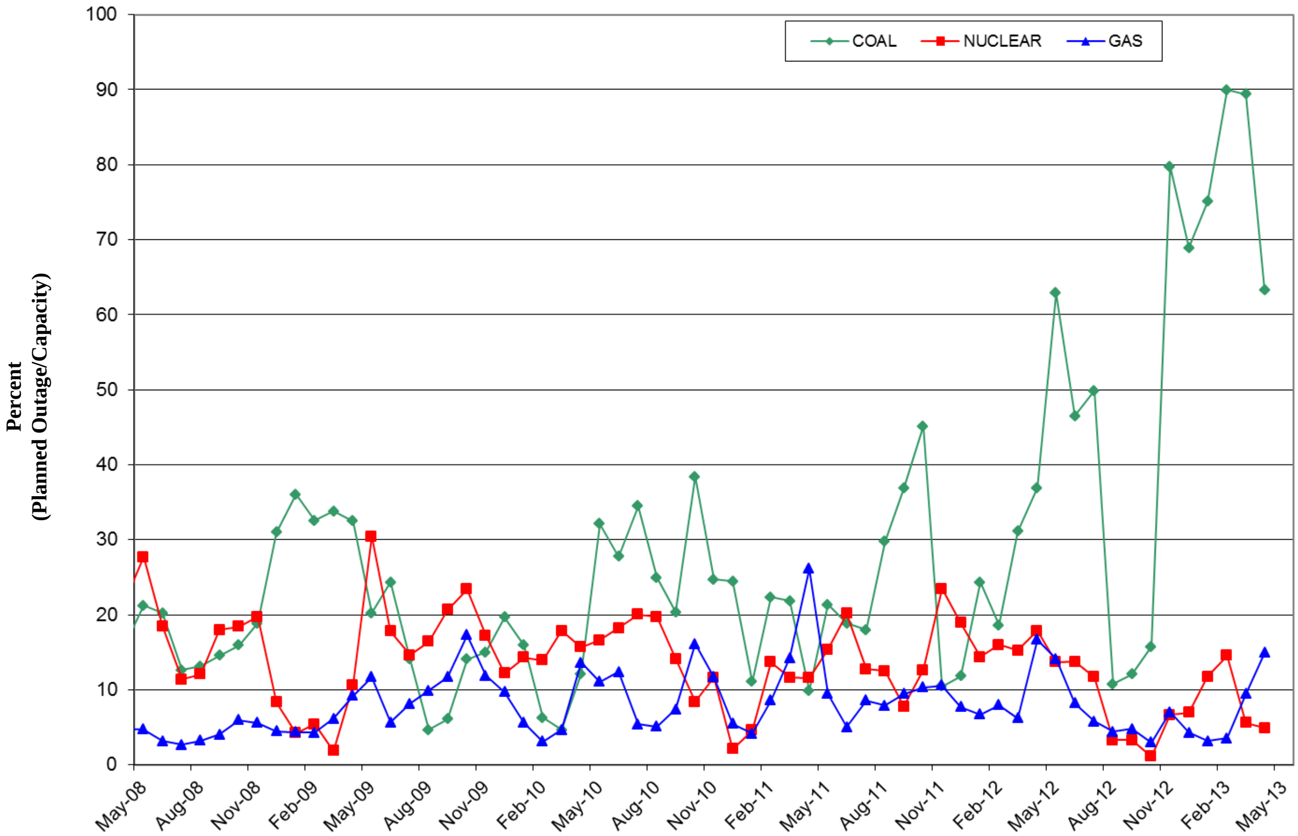


*Includes nuclear, coal-fired and gas-fired units.

Figure 1-23 presents planned outage rates by fuel type as a percentage of capacity since 2008. The planned outages for each fuel type show seasonal patterns similar to those that are reflected in the aggregate planned outage information presented in Figure 1-22;[41] in other words, planned outages tend to occur during the spring and fall for all fuel types. Coal-fired units continued to have a much higher amount of planned outages (as a % of capacity) than other types of generation.

[41] For the purposes of the outage statistics in this report, Ontario Power Generation's (OPG) "CO_2 outages" are classified as planned outages (rather than as forced outages, which is how they are treated by the IESO). The rationale for this approach is discussed in the Panel's July 2009 Monitoring Report, at pp. 58-59, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf. This approach is only relevant for most 2009 summer months. Under OPG's 2010 and 2011 CO_2 emissions strategies, the "CO_2 outage" designation was no longer used. In addition, the capacity that was effectively removed from the market by OPG's designation of 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).

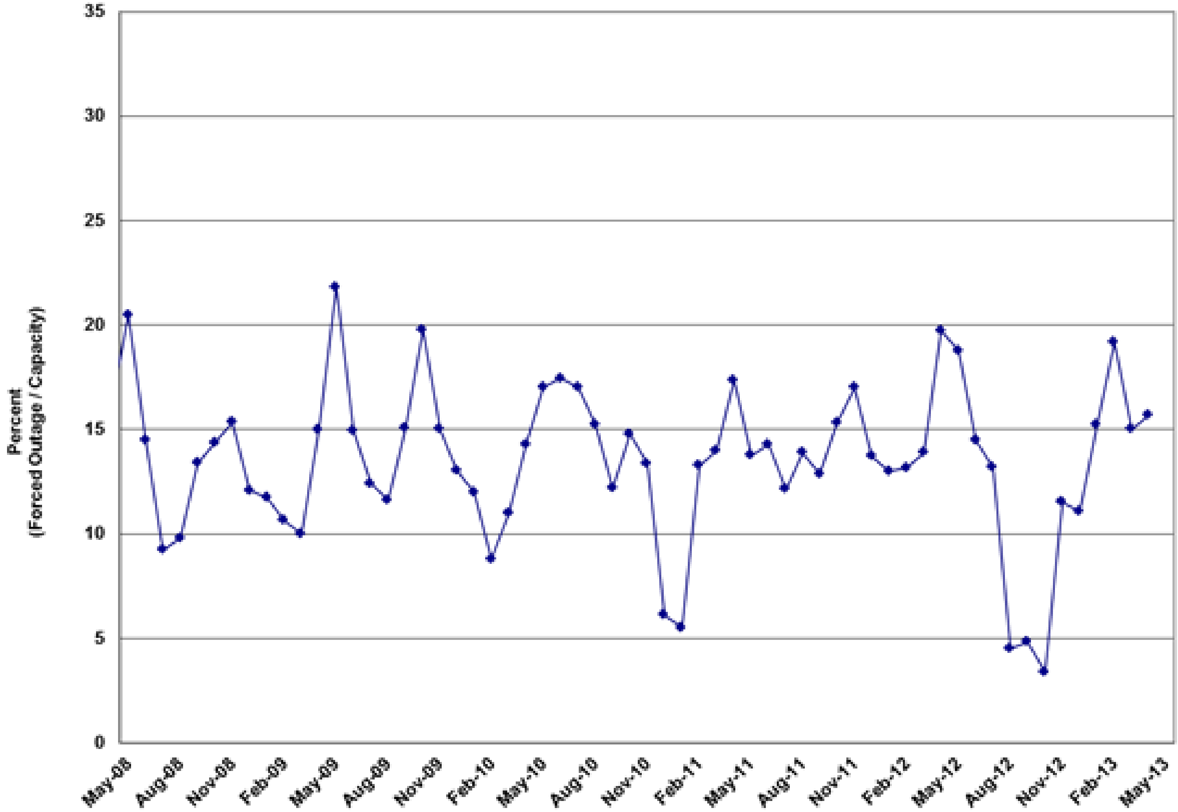
Figure 1-23: Planned Outages Relative to Capacity by Fuel Type
May 2008 – April 2013
(% of capacity)



4.4.2 *Forced Outages*

Given that forced outages occur unexpectedly, they do not exhibit the same level of seasonality as do planned outages. Figure 1-24 plots total forced outages as a percentage of total generation capacity since May 2008.

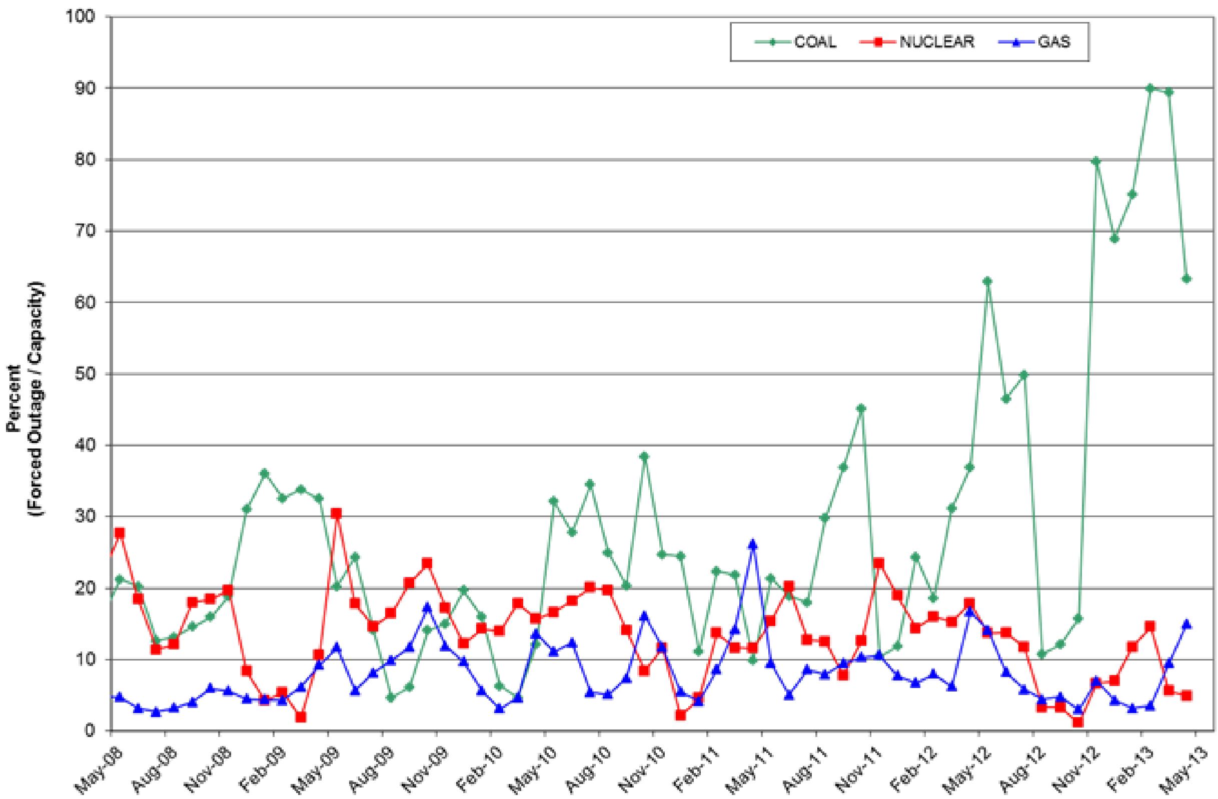
Figure 1-24: Forced Outages Relative to Capacity
May 2008 – April 2013
(% of capacity)*



*Includes nuclear, coal-fired and gas-fired units.

Figure 1-25 shows forced outage rates by fuel type as a percentage of capacity since 2008. Forced outages of coal-fired units continued to occur at a significantly high rate relative to capacity in the 2012/13 Annual Period. Forced outage rates for coal-fired units have increased year-over-year because as coal-fired generation capacity has decreased, forced outages have had having a correspondingly greater effect on the forced outage rate.

Figure 1-25: Forced Outages Relative to Capacity by Fuel Type
May 2008 – April 2013
(% of capacity)



4.5 *Changes in Fuel Prices*

Tables 1-25 and 1-26 present average monthly coal and natural gas spot prices, respectively, for the 2011/12 and 2012/13 Annual Periods. Both coal and natural gas prices have decreased from 2011/12 Annual Period levels.

4.5.1 *Coal Prices*

Average monthly Central Appalachian (CAPP) and Powder River Basin (PRB) coal prices for prompt (i.e., immediate next) month are presented in Canadian dollars in Table 1-25 for the 2011/12 and 2012/13 Annual Periods. CAPP coal prices decreased from a monthly average of \$2.87/MMBtu in the 2011/12 Annual Period to \$2.35/MMBtu in the 2012/13 Annual Period, a decline of 18.1%. PRB coal prices decreased by nearly 25%, from \$0.68/MMBtu to \$0.51/MMBtu.

*Table 1-25: Average Monthly NYMEX Coal Futures Settlement Prices by Type May - April 2011/2012 & April - May 2012/2013 ($CDN/MMBtu)**

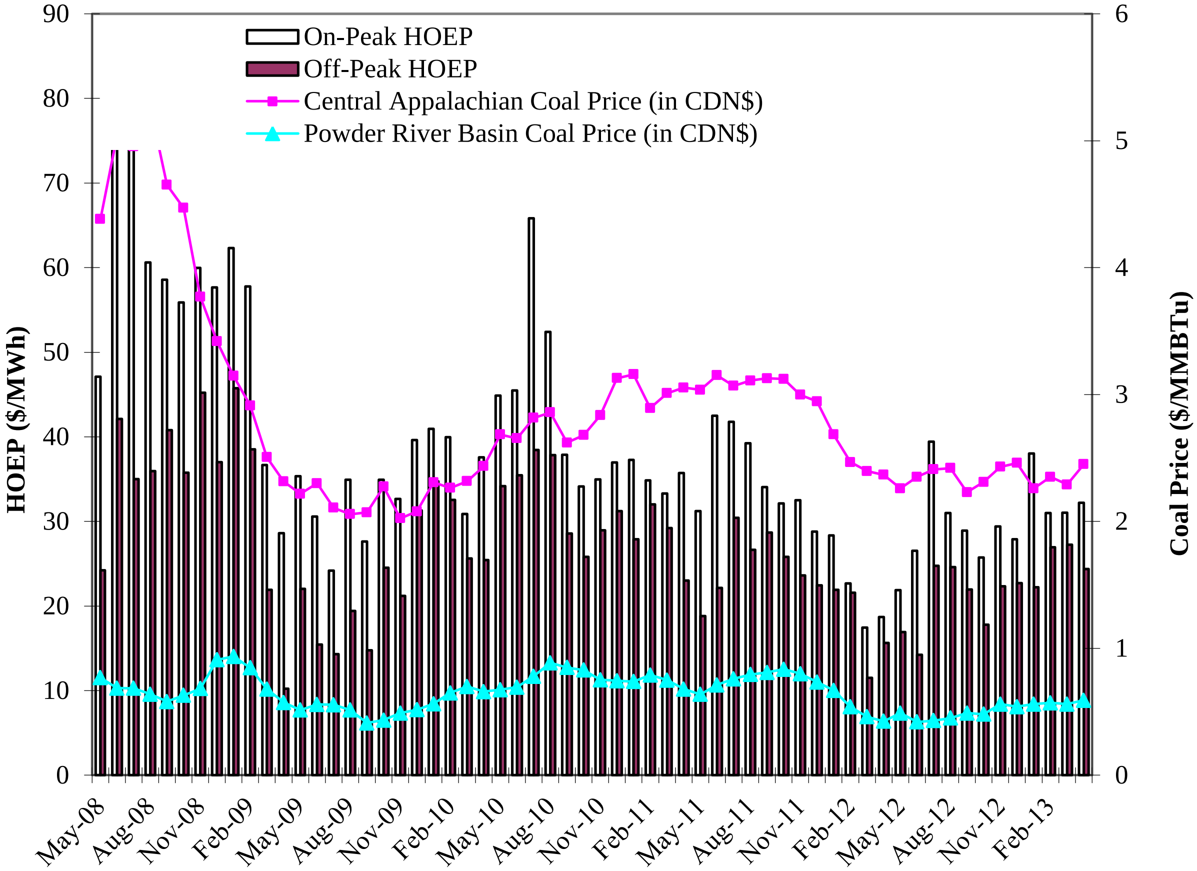
Month	NYMEX Central Appalachian (CAPP) Coal Price			NYMEX Western Rail Powder River Basin (PRB) Coal Price		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	3.04	2.26	(25.7)	0.64	0.49	(23.4)
June	3.15	2.35	(25.4)	0.71	0.42	(40.9)
July	3.07	2.41	(21.5)	0.76	0.43	(43.4)
August	3.11	2.42	(22.2)	0.79	0.45	(43.0)
September	3.13	2.23	(28.8)	0.81	0.49	(39.5)
October	3.12	2.31	(26.0)	0.83	0.48	(42.2)
November	3	2.43	(19.0)	0.8	0.56	(30.0)
December	2.95	2.46	(16.6)	0.73	0.54	(26.0)
January	2.68	2.26	(15.7)	0.67	0.56	(16.4)
February	2.47	2.35	(4.9)	0.54	0.57	5.6
March	2.4	2.29	(4.6)	0.46	0.56	21.7
April	2.37	2.45	3.4	0.42	0.59	40.5
Average	2.87	2.35	(18.1)	0.68	0.51	(24.8)

* Coal prices have been converted from $US to $CDN using the Bank of Canada's daily noon exchange rate. The data in this table is based on information from EIA Coal News and Market Reports.

Figure 1-26 plots the monthly average CAPP and PRB coal prices, along with the on-peak and off-peak HOEP, since May 2008 (all prices are in Canadian dollars). In recent years, on-peak and off-peak HOEP have roughly moved together with the PRB coal price.[42] This may be due to the increase in hours in which imports set final pre-dispatch prices, which rose to 14% in the 2012/13 Annual Period, as neighboring jurisdictions continue to use coal-fired generation for a substantial proportion of their energy needs. For the 2012/13 Annual Period, the correlations decreased to levels more in line with correlations observed in 2008-2011. [43]

[42] The correlation coefficient in the 2011/12 Annual Period was 0.80 for on-peak HOEP and 0.85 for off-peak HOEP.
[43] The correlation coefficient in the 2012/13 Annual Period was 0.13 for on-peak HOEP and 0.60 for off-peak HOEP. The coefficients for the period 2003 to 2010 were 0.23 for on-peak HEOP and 0.19 for off-peak HOEP.

Figure 1-26: Central Appalachian and Powder River Basin Coal Prices and HOEP May 2008 – April 2013 ($/MWh and $CDN/MMBtu)



4.5.2 *Natural Gas Prices*

The Henry Hub Spot and Dawn Daily gas prices[44] are presented in Table 1-26 for the 2011/12 and 2012/13 Annual Periods. On average, both prices decreased in the 2012/13 Annual Period compared to the 2011/12 Annual Period. The Henry Hub Spot price declined by $0.13/MMBtu (4.0%) while the Dawn Daily price fell by $0.25/MMBtu (6.6%). However, average monthly natural gas prices in the 2012/13 Annual Period saw a substantial increase in price (at both locations) between May 2012 and April 2013. Over the course of the 2012/13 Annual Period, the Henry Hub Spot price increased 72.1%, and the Dawn Daily Price rose 72.5%. This large increase in the price of natural gas was also apparent in the HOEP, as Ontario monthly average prices rose from May 2012 to April 2013 commensurate with the increase in the price of natural gas.

[44] The Henry Hub is located in Erath, Louisiana, while the Union Dawn Hub is located near Sarnia, Ontario.

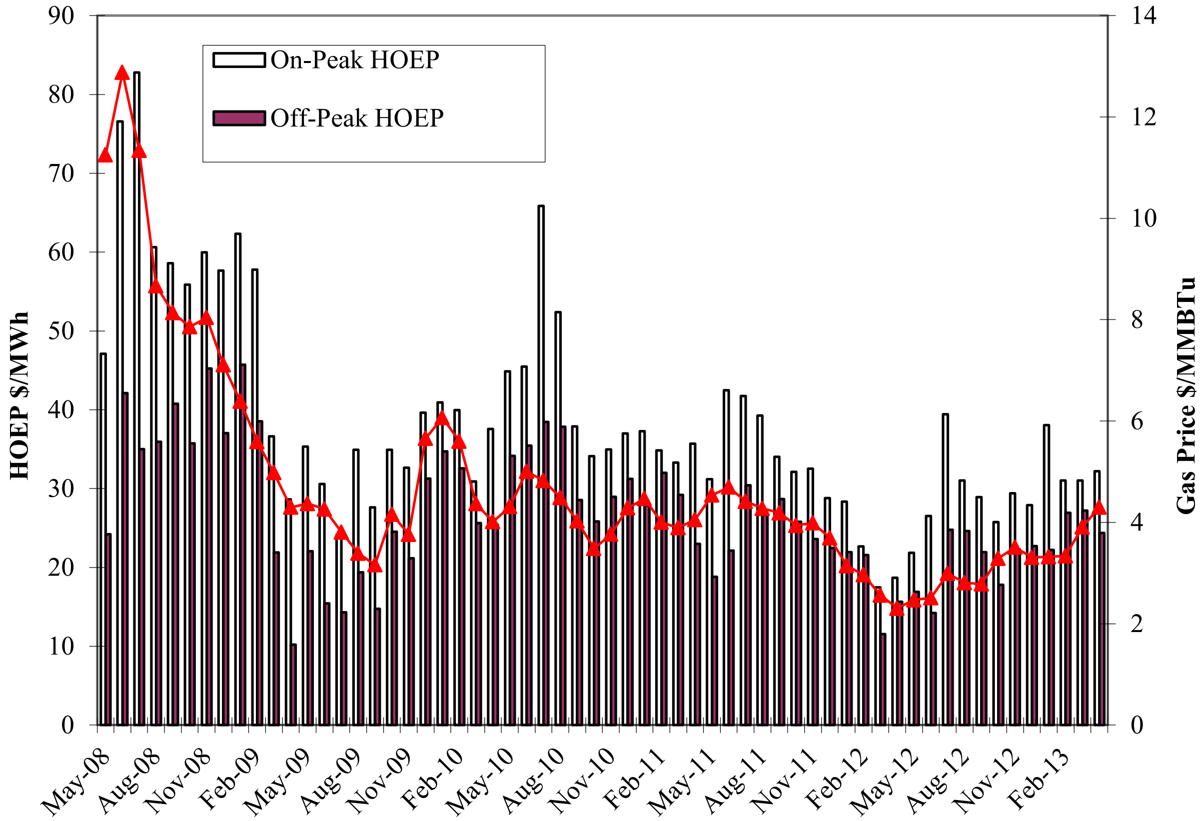
Table 1-26: Average Monthly Natural Gas Prices May – April 2011/2012 & May – April 2012/2013 ($CDN/MMBtu)

Month	Henry Hub Spot Price*			Dawn Daily Gas Price		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	4.15	2.47	(40.58)	4.54	2.69	(40.75)
June	4.43	2.51	(43.45)	4.69	2.42	(48.40)
July	4.2	2.99	(28.79)	4.41	3.15	(28.57)
August	3.98	2.81	(29.37)	4.27	3.03	(29.04)
September	3.91	2.78	(28.82)	4.19	3.06	(26.97)
October	3.63	3.29	(9.48)	3.94	3.6	(8.63)
November	3.29	3.51	6.60	3.99	4.05	1.50
December	3.23	3.31	2.51	3.7	3.72	0.54
January	2.71	3.32	22.32	3.15	3.6	14.29
February	2.51	3.34	33.03	2.97	3.64	22.56
March	2.15	3.91	81.72	2.56	4.21	64.45
April	1.93	4.25	120.21	2.31	4.64	100.87
Average	3.34	3.21	(4.01)	3.73	3.48	(6.59)

* Henry Hub Spot prices converted to $CDN at the Bank of Canada daily noon exchange rates

Figure 1-27 plots the monthly average Henry Hub Spot price, along with the on-peak and off-peak HOEP, since May 2008 (all prices are in Canadian dollars). As the Panel has observed in the past, movements in the HOEP appear to roughly coincide with movements in the spot market gas price. This is not surprising since gas units were the most frequent marginal resource in neighbouring markets, such as NYISO and ISO-New England (ISO-NE) and are the marginal resource that most frequently set the MCP in Ontario. Since 2008, the correlation coefficient for the spot price of natural gas and on-peak HOEP has been 0.84, and the correlation coefficient for the spot price of natural gas and off-peak HOEP has been 0.62.

Figure 1-27: Henry Hub Natural Gas Spot Price and HOEP May 2008 – April 2013 ($/MWh and $CDN/MMBtu)



5 Imports and Exports

This section reports on intertie activity, using data that is based on the unconstrained schedules as these directly affect market prices.[45]

5.1 *Overview*

Table 1-27 presents monthly net exports from Ontario during on-peak and off-peak hours. Ontario remained a net exporter in both off-peak and on-peak hours during all months in the 2012/13 Annual Period. Off-peak net exports increased by 487 GWh (8.2%) while on-peak net exports increased by 1,367 GWh (44.1%). As a result, overall net exports increased by 1,857 GWh (20.6%) from the 2011/12 Annual Period to the 2012/13 Annual Period. Relative to the 2011/12 Annual Period, total net exports grew in

[45] Although the constrained schedules are also important for various monitoring and assessment purposes, they are not related to intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).

8 of 12 months, with the largest growth rates occurring in November 2012, December 2012 and January 2013 at 110.2%, 123.6% and 79.3% respectively.

Table 1-27: Net Exports, On-peak and Off-peak
May – April 2011/2012 & May – April 2012/2013
(GWh)

Month	On-Peak			Off-Peak			Total		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	390	325	(16.7)	915	505	(44.8)	1303	830	(36.3)
June	153	333	117.9	536	472	(12.0)	689	805	16.9
July	173	169	(2.5)	401	363	(9.6)	574	531	(7.4)
August	113	163	44.5	415	342	(17.6)	528	505	(4.3)
September	121	95	(21.7)	346	324	(6.2)	466	419	(10.1)
October	267	228	(14.4)	481	573	19.2	748	802	7.2
November	233	563	141.7	368	700	90.2	601	1263	110.2
December	155	410	164.3	326	666	104.2	481	1075	123.6
January	324	697	115.2	463	714	54.1	787	1411	79.3
February	308	469	52.2	433	559	29.2	741	1028	38.7
March	410	504	22.9	588	514	(12.6)	999	1018	1.9
April	452	510	12.9	634	662	4.4	1086	1172	7.9
Total	3,099	4,466	44.1	5,906	6,393	8.2	9,003	10,860	20.6

Figure 1-28 reports the long-term trend in net exports since 2008. A positive number indicates a net export, while a negative number shows a net import. In the five-year data set presented, Ontario has been a consistent net exporter in both on-peak and off-peak hours.

Figure 1-28: Net Exports, On-peak and Off-peak
May 2008 – April 2013
(GWh)

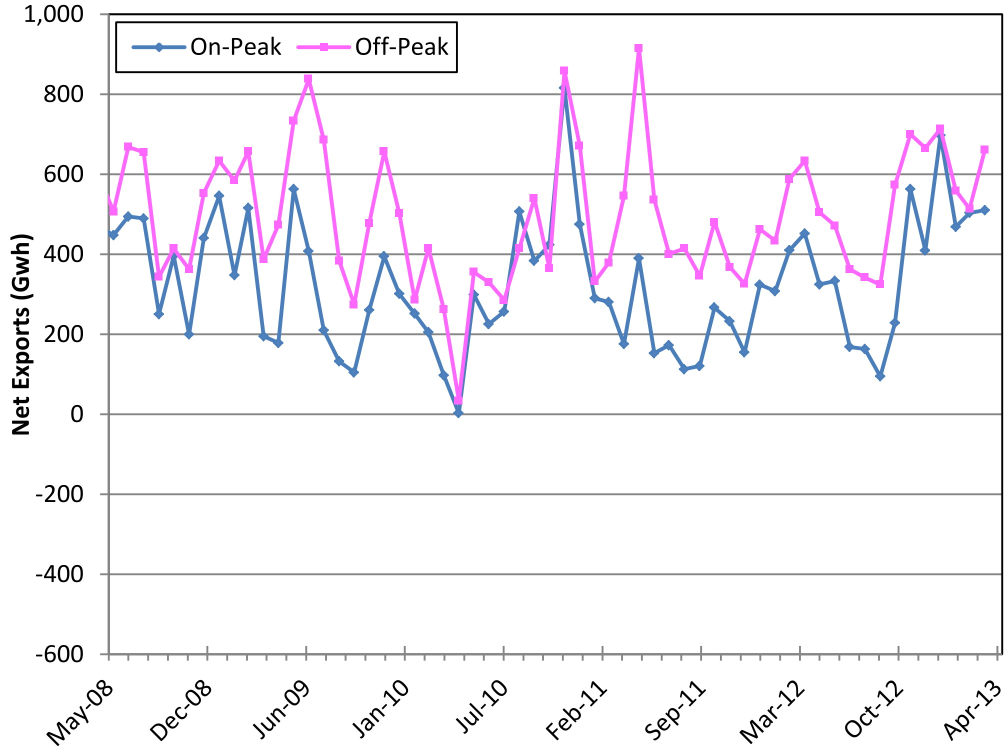


Table 1-28 presents net exports by interface group for the 2011/12 and 2012/13 Annual Periods. It is worth noting that the sum of net exports in Table 1-28 is not equal to the numbers in Table 1-27 because of the impact of linked wheeling transactions. Linked wheeling transactions net out to zero for Ontario as a whole. These transactions, however, do have an impact on the net exports at a specific interface because the import and export legs are scheduled at different interfaces (i.e., they do not net to zero at a given interface).

Table 1-28: Net Exports (Imports) by Interface Group May – April 2011/2012 & May –April 2012/2013 (GWh)

Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	(113)	(48)	569	608	(26)	9	590	549	287	(288)
June	(154)	(91)	407	461	(9)	(2)	299	619	146	(181)
July	(156)	(141)	606	582	(20)	(10)	398	559	(254)	(459)
August	(112)	(150)	393	414	(20)	(26)	315	569	(47)	(303)
September	(115)	(95)	207	440	(33)	(10)	244	342	163	(257)
October	(123)	(50)	366	718	(21)	0	301	342	225	(208)
November	(120)	(47)	430	811	(26)	7	164	624	154	(131)
December	(112)	(32)	455	592	(10)	11	155	484	(7)	21
January	(127)	(39)	484	512	(17)	13	431	640	14	285
February	(108)	(60)	528	392	(18)	3	378	642	(39)	50
March	(83)	(83)	541	680	(9)	1	667	571	(117)	(151)
April	(78)	(50)	726	671	(2)	2	738	727	(298)	(179)
Total	(1,401)	(885)	5,712	6,880	(212)	(2)	4,680	6,667	227	(1,800)

Although Ontario remained a large net exporter as a whole over the 2012/13 Annual Period, the situation varied significantly among interfaces:

- Ontario electricity exports at the Québec interface fell sharply for the second year in a row. In the 2012/13 Annual Period net exports decreased by 2,027 GWh from 227 GWh of exports to a net import of 1,800 GWh. In the 2010/11 Annual Period, net exports to Québec were 4,470 GWh. The increase in imports from Québec may be due to declining electricity prices in ISO-NE and NYISO as a result of the relatively low cost of natural gas and/or a result of increased generation capacity in Québec. There has also been an increase in transmission capacity between Ontario and Québec with the opening of the 1,250 MW Hawthorne/Outaouais intertie in 2010.

- Net exports at the Michigan interface rose from 5,712 GWh to 6,880 GWh (a 20.4% increase). Michigan remained the largest export interface for Ontario electricity, narrowly ahead of New York. The increase is likely due in part to an increase in linked wheeling transactions originating from Québec.

- New York saw a substantial growth in net exports during the 2012/13 Annual Period, with a year-over-year increase of 1,987 GWh (42.5%).
- Ontario remained a net importer from Manitoba in every month of the 2012/13 Annual Period. However, many of the imports in the unconstrained schedule were constrained off because of surplus supply in the Northwest zone of the province.
- Ontario was only a small net importer from Minnesota (2 GWh) marking a significant change from previous years when Ontario consistently imported energy each month.

Imports and exports during the 2011/12 and 2012/13 Annual Periods are separately reported in Tables 1-29 and 1-30, showing for each interface both the total imports or exports and the total imports or exports net of the components of linked wheeling transactions.

5.2 *Imports*

As reported in Table 1-29, total imports increased to 5,082 GWh in the 2012/13 Annual Period, an increase of 399 GWh or 8.5% compared to the 2011/12 Annual Period. Excluding linked wheeling transactions, imports were up marginally by 52 GWh, or 1.2%.

The largest increase in import volumes occurred at the Québec interface, where total imports increased from 2,561 GWh in the 2011/12 Annual Period to 3,429 GWh in the 2012/13 Annual Period (an increase of 33.9%). Québec imports accounted for 67.5% of all imports during the 2012/13 Annual Period. As noted earlier, the increase in imports from Québec may be due to declining electricity prices in ISO-NE and NYISO as a result of the relatively low cost of natural gas and/or a result of increased generation capacity in Québec.

Linked wheeling transactions increased from 454 GWh in the 2011/12 Annual Period to 801 GWh in the 2012/13 Annual Period, which represents 15.8% of total imports and 5.3% of total exports in the 2012/13 Annual Period. This is likely due in large part to a substantial increase in transmission capacity between Ontario and Québec as a result of the 1,250 MW Hawthorne/Outaouais intertie between Ontario and Québec. Since completion of the line in 2010, Hydro Québec has substantially increased its electricity imports into Ontario (including an increase in linked wheeling transactions, to reach electricity markets in MISO or PJM Interconnection (PJM) as well as to provide additional electricity to NYISO). In the 2012/13 Annual Period, linked wheeling transactions from Québec through Ontario increased by 89.0% to 792 GWh. Of those linked wheeling transactions, 31% settled in MISO, 22.5% in NYISO and 45% in PJM.[46]

Table 1-29: Imports by Interface Group
May – April 2011/2012 & May - April 2012/2013
(GWh)

Interface Group	Total Imports			Total Excluding Linked Wheeling Transactions		
	2011/2012	2012/2013	%Change	2011/2012	2012/2013	% Change
Manitoba	1,412	927	(34.35)	1,412	927	(34.35)
Michigan	330	368	11.52	329	361	9.73
Minnesota	265	83	(68.68)	265	83	(68.68)
New York	115	275	139.13	81	273	237.04
Québec	2,561	3,429	33.89	2,142	2,637	23.11
Total	4,683	5,082	8.52	4,229	4,281	1.23

5.3 *Exports*

As shown in Table 1-30, total exports increased year-over-year by 2,254 GWh or 16.5% in the 2012/13 Annual Period. Excluding linked wheeling transactions, the increase was 1,908 GWh or 14.4%. The largest increase was at the New York interface, which saw an increase in total exports of 2,148 GWh (44.8%). In contrast, the Québec interface saw a decrease in total exports of 1,159 GWh (41.6%), a decrease of 759 GWh (32%) excluding linked wheeling transactions.

[46] Ontario does not have a direct interconnection with PJM; instead two linked wheeling transactions are utilized in order to send electricity from Québec through Ontario and MISO and into PJM.

Table 1-30: Exports by Interface Group
May – April 2011/2012 & May – April 2012/2013
(GWh)

Interface Group	Total			Total Excluding Linked Wheeling Transactions		
	2011/2012	2012/2013	% Change	2011/2012	2012/2013	% Change
Manitoba	11	42	281.82	11	42	281.82
Michigan	6,041	7,248	19.98	6,040	6,651	10.12
Minnesota	53	80	50.94	53	80	50.94
New York	4,795	6,943	44.80	4,761	6,759	41.97
Québec	2,788	1,629	(41.57)	2,369	1,610	(32.04)
Total	13,688	15,942	16.47	13,234	15,142	14.42

5.4 *Congestion at Interties*

In general, intertie congestion levels tend to increase as the volume of inter-jurisdictional transactions increase or intertie capability decreases. Due to the two-schedule design of the Ontario market, there are two types of intertie congestion: congestion in the constrained schedule and congestion in the unconstrained schedule.[47] The congestion level can be measured by the intertie congestion price (unconstrained) or nodal price (constrained) difference at the two ends of an intertie. Congestion may occur in the constrained schedule without occurring in the unconstrained schedule and vice versa. Except as otherwise noted, this section discusses congestion in the unconstrained schedule only.

5.4.1 *Import Congestion*

Table 1-31 reports the number of occurrences of import congestion by month and interface group over the 2011/12 and 2012/13 Annual Periods. Total hours of import congestion declined from 4,573 to 1,804 (a 60.6% decline). This represents an import congestion rate of 4.1% of total hours during the 2012/13 Annual Period (down from

[47] Congestion in the constrained schedule reflects that the power flow has reached the maximum capability allowed for the interface. Congestion in the unconstrained schedule reflects that the economic transactions have reached the thermal limit at the interface. The former has little impact on price, but traders may be compensated through CMSC payments for constrained-off exports or imports (or uneconomic exports/imports that are constrained on to relieve congestion). In contrast, the latter generates a price difference between the external zone and the Ontario zone, which is manifested in the Intertie Congestion Price (ICP).

10.4% in the 2011/12 Annual Period). Congestion at the Minnesota interface saw a pronounced 72.1% decline from 2,042 hours to 570 hours. The Manitoba interface also saw a large decline in congestion hours of 1,327 (from 2,499 to 1,172), which represents a 53.1% decrease. These decreases can be attributed to a market rule amendment that eliminated constrained-off CMSC payments for imports at the Manitoba and Minnesota interfaces starting in October 2012. [48]

Of the remaining three import regions, the New York interface saw a small rise in congestion from 0 to 2 hours; the Québec interface saw a 22-hour increase in congestion to 55 hours; and the Michigan interface saw an increase in congestion from 1 to 7 hours.

Table 1-31: Import Congestion by Interface Group May – April 2011/2012 & May – April 2012/2013 (number of hours in the unconstrained schedule)

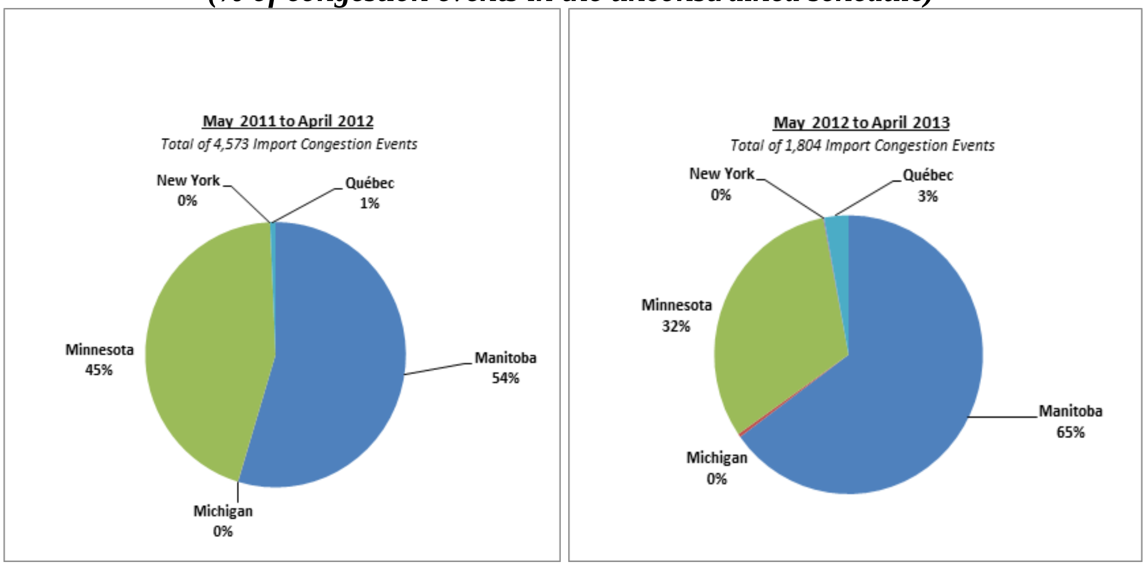
Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	230	65	0	0	273	17	0	0	1	8
June	314	188	1	0	90	44	0	0	7	2
July	264	330	0	0	150	79	0	0	8	13
August	167	332	0	0	113	223	0	0	6	14
September	215	226	0	0	216	195	0	2	2	9
October	198	0	0	0	230	2	0	0	0	0
November	172	0	0	0	181	0	0	0	0	0
December	129	1	0	0	66	0	0	0	0	0
January	297	11	0	4	291	0	0	0	0	0
February	232	4	0	3	72	6	0	0	0	0
March	141	13	0	0	205	3	0	0	0	1
April	140	2	0	0	155	1	0	0	7	6
Total	2,499	1,172	1	7	2,042	570	0	2	31	53

Figure 1-29 compares the share of import congestion events by interface group for the 2011/12 and 2012/13 Annual Periods. [49] The interfaces in the Northwest (Manitoba and Minnesota) have accounted for the vast majority of congestion hours in both the 2011/12 and 2012/13 Annual Periods, with the Manitoba interface accounting for 65% of the

[48] See Chapter 3 for a detailed analysis of the effects of this market rule amendment.
[49] It is possible to have more than one intertie import (export) congested during the same hour. For the purposes of Figures 1-29 and 1-30, these are treated as individual import (export) congestion events.

import congestion events in the 2012/13 Annual Period (up from 54% in the 2011/12 Annual Period).

Figure 1-29: Share of Import Congestion by Interface Group May – April 2011/2012 & May – April 2012/2013 (% of congestion events in the unconstrained schedule)



5.4.2 *Export Congestion*

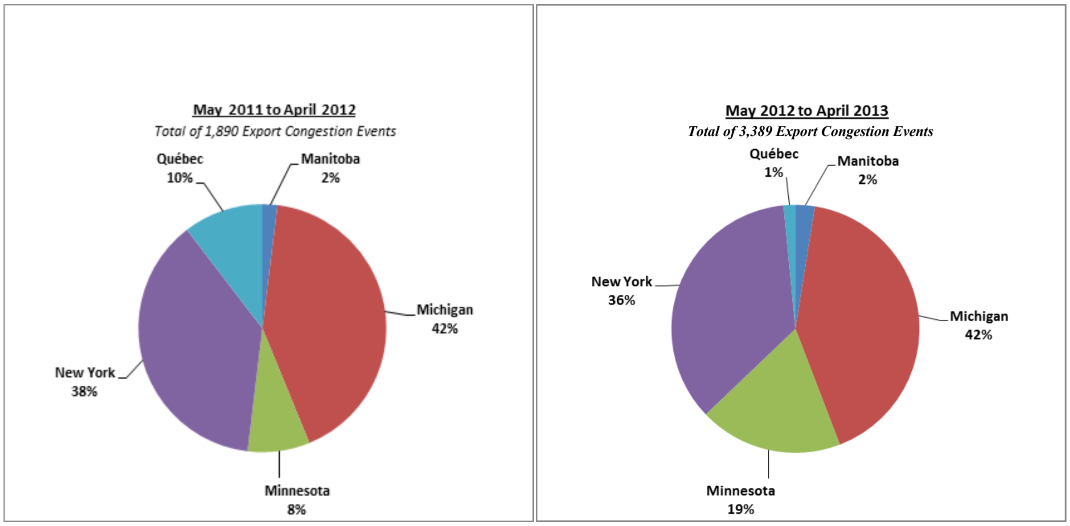
Table 1-32 reports the number of occurrences of export congestion by month and interface group for the 2011/12 and 2012/13 Annual Periods. The total number of export congestion events increased from 1,890 to 3,389 hours (79.3%). This represents an export congestion rate of 7.7% of total hours during the 2012/13 Annual Period (up from 4.3% in the 2011/12 Annual Period). The largest year-over-year increase was seen at the Michigan interface, with export congestion increasing by 647 hours (81.8%). The New York interface also saw a large increase in export congestion hours of 517 (72.6%). Export congestion at the Québec interface decreased by 144 hours (73.1%).

Table 1-32: Export Congestion by Interface Group May – April 2011/2012 & May – April 2012/2013 (number of hours in the unconstrained schedule)

Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	0	23	77	206	14	129	170	196	63	9
June	0	23	55	94	3	50	80	125	13	1
July	0	0	138	147	23	35	51	107	8	0
August	2	0	26	63	22	4	12	68	2	1
September	2	0	9	48	26	6	30	33	11	3
October	2	3	6	196	1	21	90	93	79	0
November	1	17	12	270	5	42	0	243	20	0
December	3	0	86	19	8	14	0	24	0	3
January	2	3	28	17	3	46	11	107	0	26
February	1	0	105	14	6	3	8	23	0	9
March	11	3	99	137	14	22	122	86	1	0
April	13	15	150	227	28	274	138	124	0	1
Total	37	23	791	1438	153	646	712	1229	197	53

Figure 1-30 compares the share of export congestion events by interface group for the 2011/12 and 2012/13 Annual Periods. The Michigan interface was again the most congested interface, experiencing 42% of the export congestion events. The Minnesota interface increased its share of export congestion hours by 11%, while the Québec and the New York interfaces saw their shares decline by 9% and 2%, respectively. The increase in congestion (year-over-year) at the Minnesota interface was due to a lengthy outage in the Fort Frances area that led to reduced export/import limits.

Figure 1-30: Share of Export Congestion Events by Interface Group May – April 2011/2012 & May – April 2012/2013 (% of congestion events in the unconstrained schedule)



5.4.3 *Congestion Rent*

Congestion rent is the result of different prices in the unconstrained schedule at either end of an intertie. These price differences are induced by congestion at the interface (i.e., the net schedules of economic transactions have reached the maximum thermal limit at the interface). In such situations, the importers or exporters are receiving or paying the intertie price, while Ontario generators and loads are receiving or paying the uniform Ontario price (either the interval MCP or HOEP).

When there is export congestion, the intertie price rises above the uniform Ontario price, and congestion rent results from the IESO collecting a higher price from exporters while paying the (lower) uniform price to generators. When there is import congestion, the intertie price falls below the uniform Ontario price, and congestion rent results from the IESO paying a lower price to importers relative to the (higher) uniform price.[50] The congestion rent then accrues into the IESO's transmission rights clearing account.

[50] The congestion rent is the price difference between the external zone and the Ontario zone (the Intertie Congestion Price or ICP), multiplied by the net schedules (net imports or net exports) on the intertie. For example, if an intertie has export congestion with an ICP of $10/MWh and net exports are 100 MW, then the congestion rent is $1,000 for the hour. The congestion arises in respect of those exports or imports that are scheduled in the constrained schedule and

Tables 1-33 and 1-34 present the congestion rent by interface group during the 2011/12 and 2012/13 Annual Periods.

Table 1-33 indicates that total congestion rent for imports in the 2012/13 Annual Period decreased by approximately $2.5 million (56.3%) from the 2011/12 Annual Period. The largest decrease was at the Manitoba interface, where import congestion rent declined year-over-year by approximately $1.46 million to $1.72 million (45.5%). The Michigan interface had a small amount of negative import congestion rent (-$35,000) compared with none at all in the 2011/12 Annual Period. The New York interface generated very little import congestion rent ($6,000), also compared with none at all in the 2011/12 Annual Period. Year-over-year, import congestion rent at the Minnesota interface decreased by approximately $1.0 million to a net negative import congestion rent of -$146,000. Negative congestion rents can accrue when instead of importing energy as scheduled in the pre-dispatch, energy is actually exported in the constrained schedule due to constrained-on exports. The only interface to show an increase in import congestion rent was Québec, which saw a small increase of $9,000 to $369,000 in the 2012/13 Annual Period.

that flow in real-time. When a transaction is not scheduled in the constrained schedule but is scheduled in the unconstrained schedule, the transaction may attract CMSC and/or Intertie Offer Guarantee (or IOG) payments. Congestion rent can be negative if power flows in the direction opposite to that of the unconstrained congestion. For example, if an intertie is import congested in the pre-dispatch due to cheaper import offers, but power actually flows out of Ontario due to exports being constrained on, then congestion rents will be negative.

Table 1-33: Import Congestion Rent by Interface Group
May – April 2011/2012 & May – April 2012/2013
($ thousands)*

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	119	306	-	-	(110)	3	-	-	-	5	8	314
June	341	28	-	-	(74)	(55)	-	-	10	4	276	(23)
July	396	56	-	-	(175)	(33)	-	-	222	124	443	147
August	138	117	-	-	8	(132)	-	-	83	80	230	65
September	252	1,118	-	-	89	(76)	-	6	5	95	345	1,143
October	142		-	-	150	1	-	-	-	-	292	1
November	105	-	-	-	37	-	-	-	-	-	142	-
December	74	29	-	75	4	-	-	-	-	-	77	104
January	104	8	-	(110)	282	3	-	-	-	-	386	(99)
February	503	2	-	-	18	31	-	-	-	-	520	33
March	930	1	-	-	524	-	-	-	-	21	1,454	22
April	54	54	-	-	112	112	-	-	40	40	206	206
Total	3,155	1,719	-	(35)	865	(146)	-	6	360	369	4,379	1,913

*Negative amounts represent net flows in the direction opposite to the congestion as indicated in the unconstrained schedule.

Table 1-34 shows total export congestion rent increasing in the 2012/13 Annual Period by $5.6 million or 19.9%. The largest increase (both $ and %) was at the New York interface, where export congestion rent increased by approximately $3.8 million to $12.9 million (42.2%). The only interface to experience a decline in export congestion rent was the Québec interface, which had a 24.2% ($895,000) year-over-year decrease to $2.8 million. The interface with the largest total amount of export congestion rent was Michigan at $17.9 million, a $2.4 million or 15.5% rise from the 2011/12 Annual Period.

The increases in export congestion rents (especially at the Michigan and New York interfaces) could be caused by a change in the spread between the HOEP and prices in surrounding jurisdictions; when the spread is larger, export congestion rents will increase as more traders attempt to export relatively low-priced electricity to other jurisdictions.[51]

[51] Table 1-39 below compares the HOEP with prices in neighbouring markets. As shown in that table, the price spread between Ontario and New York increased in the 2012/13 Annual Period.

Table 1-34: Export Congestion Rent by Interface Group
May – April 2011/2012 & May – April 2012/2013
($ thousands)*

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	-	2	3,580	2,403	5	50	2,622	1,109	948	530	7,154	4,094
June	-	(4)	1,389	1,215	-	33	810	969	76	-	2,273	2,213
July	-		5,987	2,446	16	22	2,409	916	31		8,443	3,384
August	-		805	894	15	-	95	408	9	-	923	1,302
September	(4)		81	562	20	2	173	238	171	2	441	804
October	-	-	86	1,990	-	2	622	332	2,374		3,082	2,324
November	-	-	195	3,480	-	18	-	2,586	79		274	6,084
December	-		531	147	11	9	-	68	-	3	542	227
January	-	-	267	123	(1)	29	141	2,506	-	1,984	407	4,642
February	-		573	127	-	(1)	35	374	-	258	610	758
March	5	1	816	1,762	(13)	3	1,158	677	2		1,967	2,443
April	1	76	1,174	2,733	4	103	1,036	2,757	-	18	2,217	5,687
Total	2	75	15,484	17,882	57	270	9,101	12,940	3,690	2,795	28,333	33,962

*Negative amounts represent net flows in the direction opposite to the congestion as indicated in the unconstrained schedule.

However, there are several factors which can influence congestion rent since it is based on both the magnitude of the actual net schedule in the constrained schedule at the intertie and the Intertie Congestion Price or ICP. The ICP in turn depends on the offer price of the marginal import or export at the intertie, relative to the offer price of the marginal resource within Ontario in the unconstrained schedule. The magnitude of the actual net schedule in the constrained schedule is dependent on:

- The maximum thermal capability of the intertie;
- Any temporary reductions in the intertie capability;
- Any inadvertent flows, which use up part of the intertie capability in the direction of the inadvertent flow but increase the capability in the opposite direction;
- Import or export failures; and

- The impact of parallel flow effects resulting from congestion on other transmission lines.[52]

5.4.4 *Transmission Rights*

Congestion on an intertie represents a financial risk to traders, as it can result in an exporter having to pay more, or an importer being paid less, than the uniform Ontario price. Transmission rights (TRs) are financial instruments auctioned by the IESO that provide a financial hedge against that risk by compensating the TR holder for differences between the intertie and Ontario prices.

Tables 1-35 and 1-36 show TR payouts by interface group for each month in the 2011/12 and 2012/13 Annual Periods for imports and exports, respectively. As shown in Table 1-35, TR payouts for imports totalled approximately $8.6 million in the 2012/13 Annual Period, which is a decrease of more than $7.0 million (45.1%) relative to the 2011/12 Annual Period. There were virtually no TR payouts (only $2,000) associated with the New York interface, reflecting the lack of import congestion at this interface. However, the Michigan interface saw a jump in import TR payouts from $4,000 to $678,000. The Manitoba interface had a relatively large decrease in TR payouts ($2.2 million) to $7.2 million in the 2012/13 Annual Period (a 23.2% decrease). TR payouts associated with the Minnesota interface decreased by a substantial amount ($5.3 million) to $453,000, a decline of 92.1%. This can partially be attributed to a market rule amendment that eliminated constrained-off CMSC payments for imports at the Manitoba and Minnesota interfaces and resulted in decreased activity on those interfaces.[53]

[52] For example, due to congestion at the Queenston Flow West (QFW) interface within Ontario, scheduled exports or imports at the New York intertie may be reduced even though there is still transfer room at the New York intertie.
[53] See Chapter 3 for a detailed analysis of the effects of this market rule amendment.

Table 1-35: Monthly Import Transmission Rights Payouts by Interface Group May – April 2011/2012 & May - April 2012/2013 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	985	446	-	-	228	7	-	-	1	4	1,214	456
June	1,693	392	4	-	153	44	-	-	11	2	1,860	438
July	1,203	1,708	-	-	155	64	-	-	232	68	1,590	1,841
August	322	1,482	-	-	45	145	-	-	213	87	581	1,713
September	682	3,046	-	-	261	115	-	2	5	48	948	3,212
October	377	-	-	-	897	2	-	-	-	-	1,275	2
November	254	-	-	-	78	-	-	-	-	-	332	-
December	120	-	-	-	21	-	-	-	-	-	141	-
January	343	84	-	121	1,300	-	-	-	-	-	1,643	204
February	709	14	-	557	42	10	-	-	-	-	751	581
March	1,774	14	-	-	1,938	66	-	-	-	2	3,713	81
April	897	3	-	-	606	-	-	-	21	20	1,523	23
Total	9,359	7,189	4	678	5,724	453	-	2	483	231	15,571	8,551

As shown in Table 1-36, total TR payouts for exports were $45.0 million in the 2012/13 Annual Period, which is a 16.1% increase from the 2011/12 Annual Period. The largest increase in monthly export TR payouts was at the New York interface, which saw a $6.6 million (65.8%) increase. The Michigan and Minnesota interfaces also had higher TR payouts in the 2012/13 Annual Period, with year-over-year increases of $3.2 million (14.9%) and $0.95 million (160%), respectively. The Québec interface was the only region to show a decrease in export TR payouts; those payments declined substantially by $4.6 million or 72.5% to $1.7 million for the 2012/13 Annual Period.

Table 1-36: Monthly Export Transmission Rights Payouts by Interface Group May – April 2011/2012 & May – April 2012/2013 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	-	2	4,844	5,466	309	158	1,489	1,441	1,182	280	7,824	7,347
June	-	4	2,504	1,830	32	47	1,258	1,146	72	-	3,867	3,026
July	-		7,264	3,152	32	42	3,375	1,079	44		10,714	4,274
August	2		866	1,127	25	11	114	460	8	13	1,015	1,611
September	12		86	737	25	7	119	52	237	2	480	797
October	56	1	102	2,169	5	7	761	110	4,676		5,600	2,287
November	-	4	213	5,001	21	39	-	3,661	88		321	8,704
December	1		1,013	201	12	10	-	93	-	2	1,026	307
January	-	1	456	137	6	33	275	1,982	-	1,221	738	3,373
February	-		1,097	156	11	7	43	694	-	206	1,151	1,063
March	5	-	1,559	1,776	91	20	1,103	435	1		2,759	2,232
April	2	77	1,748	3,246	27	1,170	1,512	5,512	-	12	3,289	10,016
Total	78	89	21,752	24,998	596	1,551	10,049	16,665	6,308	1,736	38,784	45,037

The IESO offers both short-term and long-term TRs for sale. Short-term TRs are valid for the following month, while long term TRs are valid for a period of 12 months. Both guarantee the TR holder a payout for each hour in which there is congestion during the period when the TR is valid. Tables 1-37 and 1-38 report data on TR auction prices.

Table 1-37 presents average long-term TR auction prices by interface and direction for the 2011/12 and 2012/13 Annual Periods. The numbers presented in the table are weighted average prices for two rounds at each auction. Since many small, import-only interfaces exist between Ontario and Québec, only the prices at the Outaouais interface are reported in this table.

Of particular interest is that the October 2012 market rule amendment eliminating constrained-off CMSC payments for imports into the Northwest appears to have had an effect on the auction prices paid for import TRs for that zone. Average long-term import TR auction prices for the Manitoba and Minnesota interfaces declined substantially in the three auctions held after October 2012 relative to the prices prevailing for auctions held between July 2011 and July 2012. This demonstrates a decrease in the value that market participants attribute to import TRs for the Northwest.

The auction price for long-term export TRs at the Michigan interface increased by 32.5% in the 2012/13 Annual Period, and there was also an increase in the number of auctions that drew interest (only one in 2011/12 vs. three in 2012/13).

Table 1-37: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction
May – April 2011/2012 & May – April 2012/2013
($/MW)

Direction	TR Period	Manitoba		Michigan		Minnesota		New York		Outaouais	
		2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
Import	July-June	49,549	31,731	-	-	34,816	-	503	-	-	136
	October-September	59,337	18,291	-	-	38,105	34,591	-	-	977	269
	February-January	-	4,355	421	242	-	7,200	356	281	475	206
	April-March	41,612	4,791	-	646	-	-	-	573	163	239
	Average	50,166	14,792	451	444	36,461	20,896	430	427	538	213
Export	July-June	-	-	-	-	-	6,955	-	-	-	1,301
	October-September	2,293	1,164	-	16,375	6,334	6,938	-	-	2,513	499
	February-January	-	-	11,439*	17,730	-	1,846	11,044	16,581	4,132	926
	April-March	-	-	-	11,383	-	-	-	10,622	2,332	2,219
	Average	2,293	1,164	11,439	15,163	6,334	5,246	11,044	13,601	2,993	1,236

Table 1-38 displays average auction prices for short-term TRs by interface and direction for the 2011/12 and 2012/13 Annual Periods.

Average auction prices for short-term import TRs at the Manitoba interface declined substantially, from $4,266 (May 2011 to September 2012) to $356 (October 2012 to April 2013), for the same reason as noted above in respect of the similar decrease in prices for long-term import TRs at that interface.

As was the case with long-term export TRs at the Michigan interface, the price of short-term export TRs at that interface increased substantially (from $542 to $1,031, a 90.2% rise).

Table 1-38: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction
May – April 2011/2012 & May – April 2012/2013
($/MW)

Direction	TR Period	Manitoba		Michigan		Minnesota		New York		Québec	
		2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012	2011/ 2012
Import	May	7,641	2,293	-	4	-	-	-	12	52	18
	June	9,389	2,794	25	7	-	-	29	7	14	22
	July	9,702	2,284	30	7	-	-	49	15	20	45
	August	4,500	2,748	31	14	-	-	30	8	10	58
	September	5,436	4,834	-	22	-	-	-	-	79	60
	October	3,378	652	82	30	-	-	-	-	60	60
	November	5,306	868	12	22	-	1,455	10	14	75	60
	December	3,489	140	-	1	-	225	-	32	18	30
	January	2,009	179	2	4	-	454	5	15	9	45
	February	1,650	188	1	-	-	-	1	-	2	45
	March	1,548	230	1	15	-	-	2	23	2	31
	April	3,522	237	1	25	-	-	1	8	14	44
	Average	4,798	1,454	21	14	-	711	16	15	15	43
Export	May	-	50	-	930	-	-	-	975	100	107
	June	-	250	382	1,504	-	-	636	1,188	501	52
	July	-	250	1,250	1,719	-	759	841	1,272	501	55
	August	-	90	1,438	1,691	-	789	871	1,488	239	60
	September	-	75	-	1,034	-	-	-	-	101	60
	October	54	-	258	243	-	-	601	-	532	149
	November	-	-	310	488	-	-	494	403	1,159	115
	December	-	78	-	1,074	-	156	-	888	388	82
	January	150	-	650	1,362	-	185	488	989	382	82
	February	77	-	77	356	-	310	71	88	44	82
	March	-	-	104	743	-	-	223	804	51	372
	April	45	-	410	1,232	-	-	388	1,008	77	116
	Average	82	132	542	1,031	-	440	513	910	340	111

5.5 *Wholesale Electricity Prices in Neighbouring Markets*

Table 1-39 provides average wholesale market prices for Ontario and neighbouring jurisdictions over the 2011/12 and 2012/13 Annual Periods.[54] In the 2012/13 Annual Period, Ontario once again had the lowest average price relative to neighbouring markets. The greatest year-over-year percentage increase in the ‘All Hours’ average price among the five jurisdictions was New England-Internal Hub, which saw a substantial price increase of 32.6%. PJM-IMO had the biggest decline in the ‘All Hours’ average price year-over-year, as prices fell 2.3% to $36.3/MWh ($CDN).

Table 1-39: Average HOEP Relative to Average Neighbouring Market Prices May – April 2011/2012 & May – April 2012/2013 ($CDN/MWh)*

Markets	All Hours			On-peak Hours			Off-peak Hours		
	2011/2012	2012/2013	% Change	2011/2012	2012/2013	% Change	2011/2012	2012/2013	% Change
Ontario - HOEP	26.29	25.89	(1.56)	30.91	30.30	(1.97)	22.44	22.20	(1.16)
MISO – ONT[55]	29.03	28.83	(0.69)	34.92	33.48	(4.12)	23.76	24.18	1.77
NYISO – Zone OH	32.04	32.26	0.69	36.1	38.73	7.29	28.26	29.79	5.41
PJM – IMO	37.15	36.3	(2.29)	43.68	42.65	(2.36)	31.18	29.96	(3.91)
New England – Internal Hub	38.47	51.02	32.62	42.78	57.19	33.68	34.41	44.85	30.34

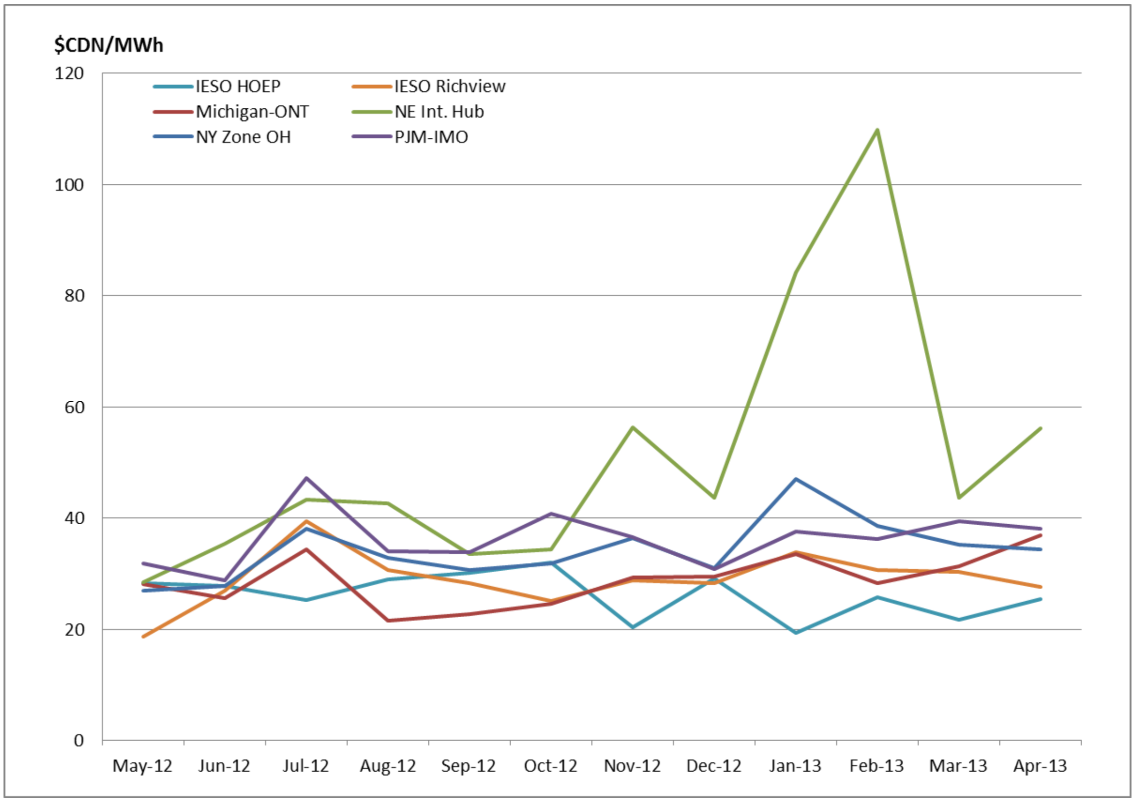
*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

Figures 1-31 to 1-33 compare monthly average prices for Ontario and its neighbouring jurisdictions for the 2012/13 Annual Period, for all hours, on-peak hours and off-peak hours respectively. The Richview nodal price is also shown, since it is regarded as a representative node for the overall market conditions in Ontario. The HOEP followed the same general trends as prices in neighbouring jurisdictions. The New England and PJM electricity prices are regularly higher than those of their neighbours (as they have been

[54] These price comparisons can provide a useful overall indicator of the export and import market opportunities available to traders. However, caution should be used when comparing market prices across jurisdictions for other purposes due to the differing market designs and payment structures. For example, in Ontario the Global Adjustment and various uplift charges represent charges to domestic loads that are not reflected in the average HOEP or the price paid by exporters. As another example, other jurisdictions such as ISO New England, New York ISO and PJM have capacity markets where consumers pay capacity charges.

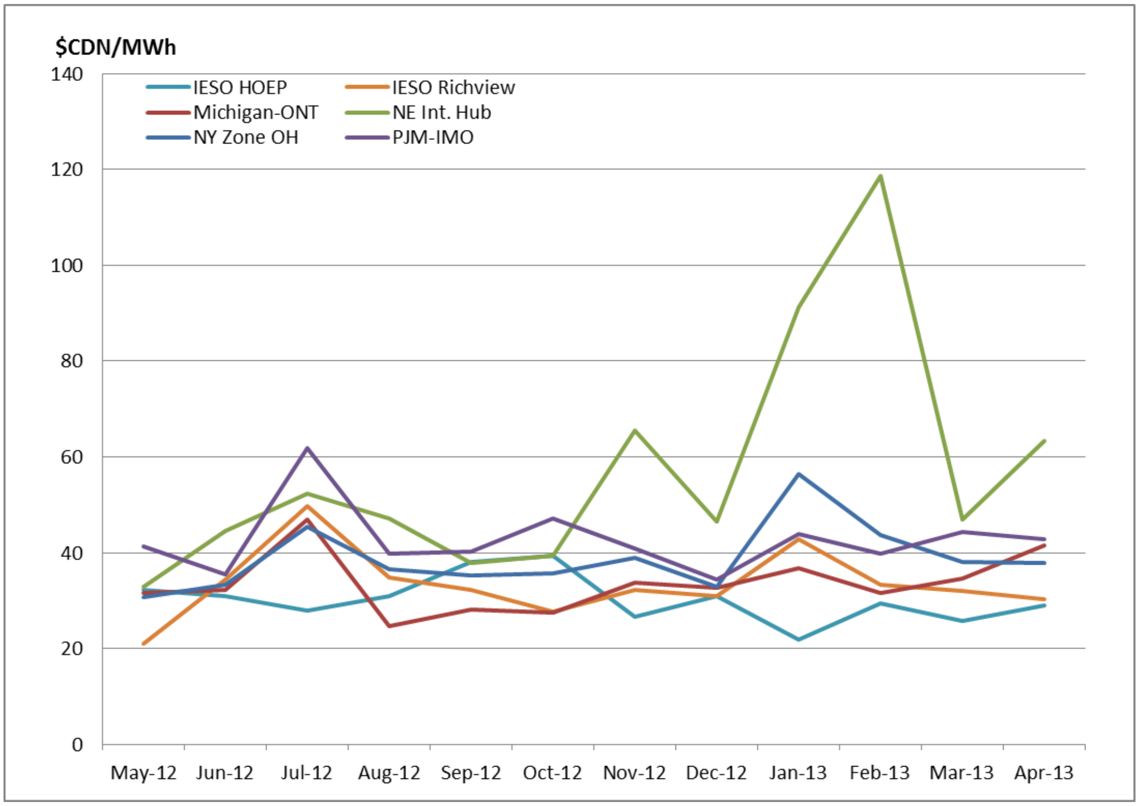
historically). While the HOEP is generally the lowest price, it is occasionally greater than the Michigan electricity price. The same trends hold true in both on-peak and off-peak.

Figure 1-31: Average Monthly HOEPs and Richview Nodal Prices Relative to Average Neighbouring Market Prices, All Hours
May 2012 – April 2013
($CDN/MWh)*



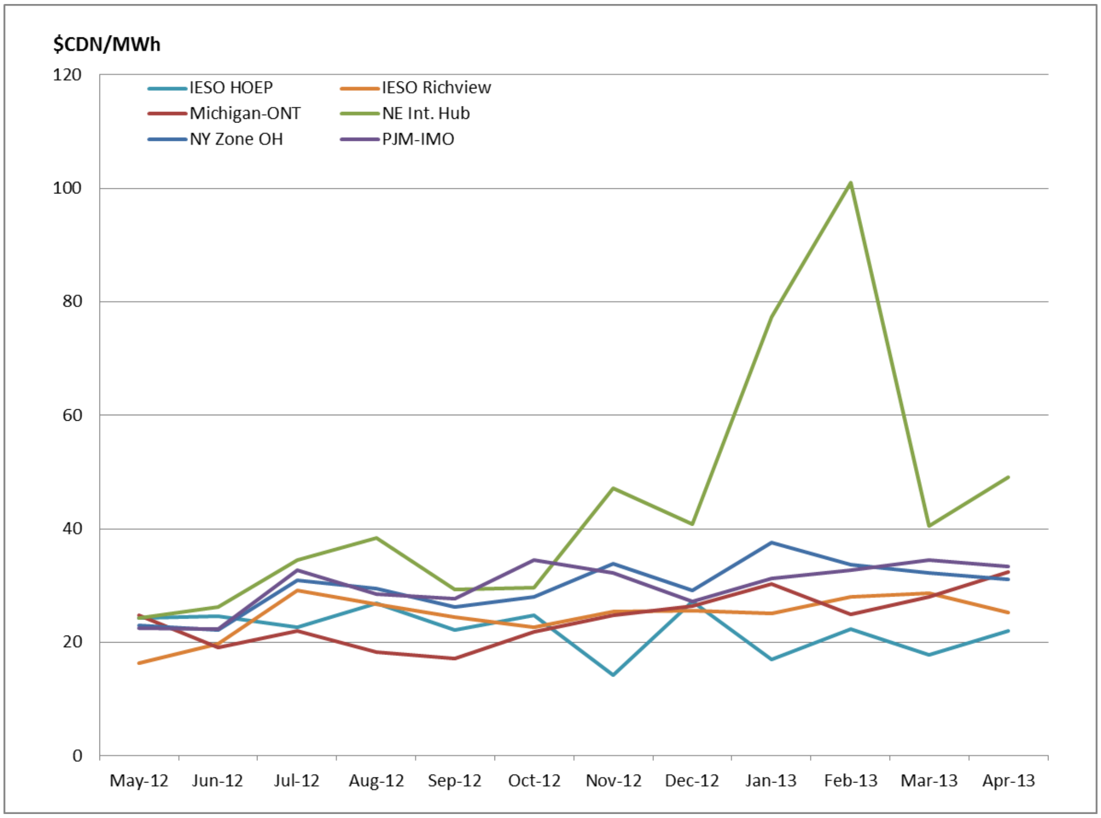
*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

Figure 1-32: Average Monthly HOEPs and Richview Nodal Prices Relative to Average Neighbouring Market Prices, On-Peak May 2012 – April 2013 ($CDN/MWh)*



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

Figure 1-33: Average Monthly HOEPs and Richview Nodal Prices Relative to Average Neighbouring Market Prices, Off-Peak May 2011 – April 2012 ($CDN/MWh)*



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

6 Operating Reserve

6.1 *Operating Reserve Requirements*

The operating reserve (OR) requirement is determined by the IESO in accordance with reliability standards established by authorities such as NERC and the Northeast Power Coordinating Council. OR requirements (in MW) are based on the largest single unexpected event (contingency) plus half of the second largest contingency. However, during shortage conditions or when OR is activated, the OR requirement can be reduced. The average OR requirement for the 2012/13 Annual Period was 1,450 MW, 66 MW lower than in the 2011/12 Annual Period.

6.2 *Supply*

Table 1-40 below reports OR scheduled in real-time, by resource or transaction type and by month during the 2012/13 Annual Period. Hydro resources provided slightly less than half of the total required OR in the 2012/13 Annual Period (44.1%), with gas-fired generators and dispatchable loads supplying approximately 34.2% and 18.0%, respectively. Gas-fired generators increased their percentage of scheduled OR by 19.2% (from 15% to 34.2%). The balance of the required OR was provided by coal-fired generators, imports and control action OR (CAOR).[56]

[56] In real-time, CAOR has a standing offer of 800 MW, at $30/MW per hour for 400 MW, $75/MW per hour for the next 200 MW and $100/MW per hour for the last incremental 200 MW. CAOR is backed by reducing the grid voltage, which rarely happens. The reduction in voltage can lead to decreased electricity consumption.

Table 1-40: Operating Reserve Scheduled by Resource or Transaction Type May 2012 – April 2013 (%)

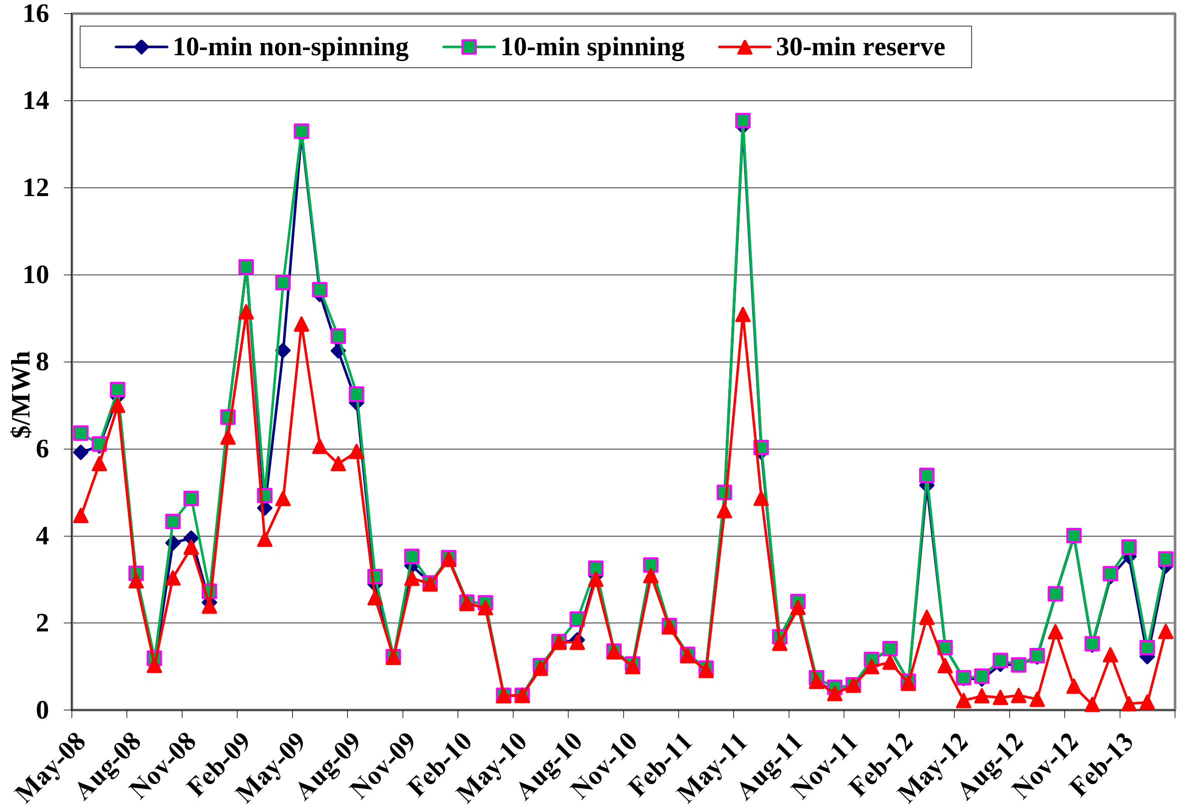
Month	Coal	Gas/Oil	Hydro	Dispatchable Loads	Imports	CAOR
May	2.55	28.54	45.02	20.21	3.12	0.55
June	2.3	33.62	43.52	18.44	1.55	0.57
July	1.2	34.15	42.51	21.45	0.06	0.63
August	2.24	34.94	41.98	19.69	0.07	1.08
September	1.14	37	41.45	19.44	0.01	0.97
October	2.06	32.72	41.09	20.5	2.74	0.89
November	2	35.19	42.83	18.16	0.51	1.32
December	2.07	35.78	47.57	13.88	0	0.7
January	0.9	35.34	47.3	15.55	0	0.91
February	2.35	38.86	41.01	16.07	0.03	1.68
March	2.42	35.78	46.28	14.1	0.69	0.72
April	0.42	28.39	48.91	17.94	3.26	1.09
Average	1.80	34.19	44.12	17.95	1.00	0.93

6.3 *Prices*

Figure 1-34 shows monthly average prices since 2008 for the three categories of OR: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30-minute reserve (30R). Prices trended upwards from early 2008 to late 2009 as a result of a decline in available OR resources.[57] Since October 2009, OR prices have dropped to levels that have been consistent for the past 3 years. The main exception is a spike in May 2011, which is attributable to a few hydro generators offering into the OR market at an increased price or not at all (typically, these generators supply OR at a low price when water doesn't have to be spilled).

[57] 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, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf.

Figure 1-34: Monthly Operating Reserve Prices by Category, All Hours May 2008 – April 2013 ($/MW per hour)



6.3.1 *On-Peak Operating Reserve Prices*

Table 1-42 presents average monthly OR prices during on-peak hours over the 2011/12 and 2012/13 Annual Periods. On-peak prices for 10-minute spinning, 10-minute non-spinning and 30-minute reserve decreased year-over-year by 23.2%, 23.5% and 69.6% respectively. All three categories saw a large percentage decrease in OR prices in May through August, 2012 and in March 2013 relative to the same months in the 2011/12 Annual Period, signalling a return to price levels more in line with prices in the latter part of the 2010/11 Annual Period. Abundant water supplies in May and June, 2011 had caused many peaking hydro facilities to stop offering OR, leading to a surge in OR prices in those months. This contributed to the very large year-over-year average price increases between the 2010/11 and 2011/12 Annual Periods.

Table 1-41: Average Monthly Operating Reserve Prices by Category, On-Peak May – April 2011/2012 & May – April 2012/2013 ($/MW per hour)

Month	10S			10N			30R		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	20.10	1.30	(93.53)	19.95	1.28	(93.58)	11.40	0.21	(98.16)
June	10.41	1.39	(86.65)	10.27	1.32	(87.15)	8.41	0.62	(92.63)
July	3.34	2.05	(38.62)	3.29	1.86	(43.47)	3.12	0.40	(87.18)
August	4.27	1.74	(59.25)	4.22	1.74	(58.77)	4.20	0.51	(87.86)
September	1.16	2.59	123.28	1.13	2.56	126.55	1.10	0.46	(58.18)
October	0.68	3.69	442.65	0.63	3.68	484.13	0.61	2.05	236.07
November	0.94	6.82	625.53	0.93	6.80	631.18	0.93	0.79	(15.05)
December	1.83	3.04	66.12	1.83	3.02	65.03	1.53	0.24	(84.31)
January	2.34	5.64	141.03	2.34	5.56	137.61	1.73	2.53	46.24
February	0.69	6.50	842.03	0.69	6.31	814.49	0.62	0.10	(83.87)
March	7.94	2.33	(70.65)	7.48	2.22	(70.32)	1.49	0.19	(87.25)
April	2.08	5.78	177.88	2.08	5.63	170.67	1.21	2.96	144.63
Average	4.65	3.57	(23.17)	4.57	3.50	(23.45)	3.03	0.92	(69.6)

6.3.2 *Off-Peak Operating Reserve Prices*

Table 1-43 presents average monthly operating reserve prices during off-peak hours over the 2011/12 and 2012/13 Annual Periods. Average off-peak prices for 10-minute spinning, 10-minute non-spinning and 30-minute reserve decreased by 47.7%, 50.0% and 74.2%, respectively.

Table 1-42: Average Monthly Operating Reserve Prices by Category, Off-Peak May – April 2011/2012 & May – April 2012/2013 ($/MW per hour)

Month	10S			10N			30R		
	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change	2011/ 2012	2012/ 2013	% Change
May	8.13	0.23	(97.17)	8.03	0.23	(97.1)	7.19	0.22	(96.9)
June	1.84	0.25	(86.41)	1.77	0.17	(90.4)	1.48	0.09	(93.9)
July	0.42	0.39	(7.14)	0.38	0.39	2.6	0.36	0.21	(41.7)
August	0.90	0.41	(54.44)	0.70	0.41	(41.4)	0.70	0.19	(72.9)
September	0.38	0.27	(28.95)	0.29	0.24	(17.2)	0.29	0.09	(69.0)
October	0.41	1.75	326.83	0.21	1.74	728.6	0.21	1.58	652.4
November	0.25	1.32	428.00	0.22	1.31	495.5	0.22	0.33	50.0
December	0.66	0.46	(30.30)	0.62	0.44	(29.0)	0.60	0.05	(91.7)
January	0.63	0.88	39.68	0.63	0.84	33.3	0.59	0.14	(76.3)
February	0.65	1.45	123.08	0.65	1.24	90.8	0.61	0.19	(68.9)
March	3.09	0.75	(75.73)	3.08	0.48	(84.4)	2.70	0.17	(93.7)
April	0.95	1.45	52.63	0.95	1.28	34.7	0.88	0.79	(10.2)
Average	1.53	0.80	(47.7)	1.46	0.73	(50.0)	1.32	0.34	(74.2)

Chapter 2: Analysis of Market Outcomes

1 Introduction

The Market Surveillance Panel is responsible for monitoring activities related to the IESO-administered markets. Market monitoring occurs over several timeframes, ranging from the day-to-day monitoring activities of the Market Assessment Unit, to the longer term analysis of the Panel. Central to this monitoring function is the identification and study of market outcomes that fall outside of the predicted patterns or norms. Analysis of these anomalous events contributes to greater transparency and enhances market participant understanding of the market, and often leads to recommendations aimed at improving market efficiency and effective competition.

Of particular interest to the Panel are anomalous price events; these events typically entail prices that are higher or lower than normally observed. The Panel defines a high-price hour as an hour in which the Hourly Ontario Energy Price (HOEP) exceeds $200/MWh, while prices below $0/MWh are considered low-price hours, henceforth referred to as negative-price hours.[58]

The Panel also reports on high uplift events associated with the various IESO-administered markets and programs. The Panel set payment thresholds to identify uplift events in which anomalous market outcomes, or market participant behaviour, generated uplift payments that exceed normally observed levels.

This chapter reports on anomalous price and uplift events over the period November 2012 to April 2013 (the "Winter 2013 Period"), with comparative data from preceding years as relevant. References in this chapter to a "Winter Period" are to the period running from November to April, inclusive.

[58] In previous reports the Panel defined low-price hours as hours with a HOEP below $20/MWh. That threshold was established in 2004 and was believed to best represent the low end marginal cost of fossil-fired generators. Since that time, more efficient gas-fired generators have come online and the price of natural gas has declined. In the Panel's view, $20/MWh is therefore no longer a meaningful threshold for defining low-price hours, and the Panel has therefore changed the threshold to $0/MWh.

2 Anomalous HOEP

2.1 Analysis of High-price Hours

High-price hours signal tight supply conditions in the province. These conditions arise as a result of relatively high demand or relatively low supply, or a combination of the two. High demand conditions are normally driven by weather conditions, as well as by the day of the week and seasonal effects. Low supply conditions may arise in part due to any one of more of the following (among others): planned or unplanned generator outages; import failures; and ramping limitations. Additionally, net imports, which are scheduled based on pre-dispatch forecasts of supply and demand, may be less than optimal if forecasts fail to predict tight real-time supply conditions.

Table 2-1 displays the number of hours per month in which the HOEP exceeded $200/MWh in the Winter 2013 Period and the preceding four Winter Periods.

Table 2-1: Number of High-price Hours
November – April, 2008/2009 to November – April 2012/2013

Month	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013
November	0	0	0	0	3
December	2	0	0	0	0
January	3	1	0	0	0
February	2	0	0	1	0
March	1	0	0	2	0
April	0	0	1	0	2
Total	**8**	**1**	**1**	**3**	**5**

During the Winter 2013 Period there were five high-price hours. This represents an increase over the previous three Winter Periods, but is generally in line with totals observed in earlier Winter Periods.

The following analysis examines the circumstances surrounding two of the five high-price hours. These hours were chosen for inclusion in this report due to the unusual conditions that precipitated the high-price events. The three high-price hours not analyzed in this report involved conditions frequently observed during high-price events; these conditions have been extensively analyzed in previous Panel reports.[59]

2.1.1 *January 23, 2013 Hour Ending 19*

The HOEP reached $575.58/MWh in hour ending (HE) 19 on Wednesday January 23, 2013, the highest HOEP since February 2009. On the demand side, extreme cold weather conditions led to high demand, while outages and curtailed import transactions reduced available supply.

From January 21 to January 24, 2013 the city of Toronto was under an extreme cold weather alert, as was most of the province. On January 23 the daily average temperature was -15°C plus wind chill, with a low of -21°C, far and away the coldest day of the Winter 2013 Period. In HE 19 of this day, real-time Ontario demand averaged 22,379 MW, the highest average hourly demand of the Winter 2013 Period. With extreme cold weather conditions gripping Ontario and the surrounding jurisdictions, residential and commercial heating greatly increased demand.

Table 2-2 displays the real-time market clearing price (MCP), Ontario demand and net exports for HE 18 and 19 on January 23, 2013.

[59] Factors that contributed to the three high-price events omitted from this report include: generator outages; import curtailments or failures; and supply and demand forecast discrepancy.

Table 2-2: Real-Time MCP, Ontario Demand and Net Exports
January 23, 2013 HE 18 & 19
(MW & $/MWh)

Delivery Hour (HE)	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)
18	**1**	32.17	21,625	2,205	23,830		-675
18	**2**	35.37	21,709	2,205	23,914	84	-675
18	**3**	48.02	21,770	2,205	23,975	61	-675
18	**4**	48.02	21,908	2,205	24,113	138	-675
18	**5**	56.66	22,094	2,205	24,299	186	-675
18	**6**	75.23	22,286	2,205	24,491	192	-675
18	**7**	103.78	22,374	2,205	24,579	88	-675
18	**8**	139.03	22,507	2,205	24,712	133	-675
18	**9**	139.04	22,533	2,205	24,738	26	-675
18	**10**	255.87	22,642	2,205	24,847	109	-675
18	**11**	158.00	22,617	2,205	24,822	-25	-675
18	**12**	257.89	22,932	2,205	25,137	315	-675
Average		**112.42**	**22,250**	**2,205**	**24,455**		**-675**
19	**1**	2,000.00	22,609	2,783	25,392	255	578
19	**2**	488.30	22,474	2,783	25,257	-135	578
19	**3**	1,100.13	22,544	2,783	25,327	70	578
19	**4**	1,100.13	22,504	2,783	25,287	-40	578
19	**5**	257.90	22,368	2,783	25,151	-136	578
19	**6**	257.90	22,375	2,783	25,158	7	578
19	**7**	488.20	22,444	2,783	25,227	69	578
19	**8**	257.89	22,308	2,783	25,091	-136	578
19	**9**	232.89	22,245	2,783	25,028	-63	578
19	**10**	257.89	22,299	2,783	25,082	54	578
19	**11**	232.89	22,246	2,783	25,029	-53	578
19	**12**	232.88	22,127	2,783	24,910	-119	578
Average		**575.58**	**22,379**	**2,783**	**25,162**		**578**

On the supply side, the derating of two coal-fired units at the beginning of HE 18 resulted in 620 MW of lost capacity, steepening the supply stack. In addition to the loss of domestic supply, large volumes of imports were curtailed by neighbouring jurisdictions, as described below.

Table 2-3 displays pre-dispatch prices, Ontario demand and net exports for the five pre-dispatch hours leading up to HE 19.

Table 2-3: Pre-Dispatch Demand, MCP and Net Exports
Hours leading up to January 23, 2013 HE 19
(MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Ontario Demand plus Net Exports (MW)
5	80.00	22,557	1,931	3,537	1,606	24,163
4	70.00	22,580	1,960	3,537	1,577	24,157
3	48.77	22,572	2,012	3,587	1,575	24,147
2	124.36	22,585	2,545	4,190	1,645	24,230
1	84.63	22,575	2,413	4,240	1,827	24,402

Although the IESO's final forecast of Ontario demand was true to eventual real-time conditions, unforeseeable circumstances relating to curtailed real-time imports supressed the pre-dispatch prices relative to real-time prices.

With a final pre-dispatch MCP of $84.63/MWh, Ontario was an inexpensive source of electricity relative to surrounding jurisdictions. Québec, a winter peaking jurisdiction, was experiencing high demand due to extreme weather conditions in the province. On the morning of January 23, 2013, Québec reached an all-time peak demand of 38,910 MW.[60] Many other markets across the Northeastern United States were also dealing with high prices as a result of supply adequacy issues. Day-ahead natural gas prices across New York, New England and various other jurisdictions exceeded $20/MMBtu (US$), pushing up offer prices from gas-fired generators. Comparatively, the day-ahead price of natural gas in Ontario at the Union Dawn Hub was $3.78/MMBtu (US$).

Based on the pre-dispatch price signals, market participants expected profitable export opportunities from Ontario to other jurisdictions. When the final pre-dispatch sequence ran, net exports totalling 1,827 MW were scheduled. Prior to the real-time implementation of these schedules, the Tennessee Valley Authority (TVA) requested Transmission Loading Relief (TLR) to relieve transmission concerns in its jurisdiction (see below for a discussion on TLR procedures). The TLR requested by TVA resulted in the curtailment of 1,532 MW of imports from Michigan to Ontario.

[60] http://www.cbc.ca/news/canada/montreal/quebec-hits-all-time-high-for-power-consumption-during-cold-snap-1.1308251

Having lost a considerable amount of supply due to the import curtailments, the Net Intertie Scheduling Limit (NISL) was being violated. NISL is a threshold which limits swings in net exports from one hour to the next; this ensures that the ramping capabilities of internal resources are respected. In addition to the NISL violation, the IESO was projecting an operating reserve (OR) supply shortfall in HE 19. To resolve these issues the IESO curtailed 756 MW of exports over the Michigan, New York and Québec interties. While this alleviated much of the concern, the OR market still experienced a shortfall in interval 1 of HE 19, driving prices in both the OR and energy markets to $2,000/MWh. The shortage ended in interval 2 when Ontario demand dropped 101 MW and supply from self-scheduling and intermittent resources increased 6 MW.

Following all curtailments, Ontario had net exports of 2,783 MW, representing a 956 MW increase in market demand relative to the 1,827 MW scheduled in pre-dispatch. This increase in market demand, coupled with an average supply from intermittent and self-scheduling generation that was 172 MW less than forecasted, increased real-time prices well above the pre-dispatch prices.

Transmission Loading Relief (TLR)

TLR is a North American Electric Reliability Corporation (NERC) procedure which allows reliability coordinators along the Eastern Interconnection to mitigate operating security limit violations while respecting transmission service reservation priorities.[61] Risk mitigation is achieved by curtailing transactions to reconfigure power flows across the Eastern Interconnection. The order of transaction curtailments is based on how each transaction contributes to the transmission constraint in question, and the relative transmission priorities of the transactions.

In jurisdictions outside of Ontario, transmission capacity must be reserved in order to flow power across the transmission system. Capacity can be reserved on a firm or non-firm basis, and for varying lengths of time (typically ranging from five years to fifteen minutes). All else being equal, when a TLR is requested non-firm transmission is curtailed before firm, and short-term transmission before long-term, making short-term non-firm transmission the most likely to be curtailed.

Unlike neighbouring jurisdictions, the Ontario market does not require transmission reservations to import or export from the province, but instead grants access based on the economic merit of a participant’s transaction. As a result, access to Ontario’s market and transmission system can only be guaranteed as frequently as intertie scheduling occurs, i.e. hourly.[62] With no assurances from one hour to the next as to whether they will have access to Ontario’s transmission system, market participants have little incentive to purchase firm long-term transmission in other jurisdictions in order to complete transactions to and from Ontario.

For instance, a market participant looking to import power from Michigan into Ontario must reserve transmission capacity in Michigan. With access to the Ontario transmission system only guaranteed for one hour, the participant only has the incentive to reserve hourly transmission in the other jurisdiction. Additionally, the market participant does not know whether it will have access to Ontario’s transmission system until intertie scheduling occurs approximately 47

[61] http://www.nerc.com/pa/rrm/TLR/Pages/default.aspx
[62] Intertie traders that receive day-ahead commitments as part of the day-ahead commitment process would be informed of their transactions anywhere between 9 and 32 hours in advance of the delivery hour. Currently, relatively few importers, and no exporters, participate in and receive commitments under the day-ahead commitment process.

minutes before real-time. With uncertainty around access to Ontario's grid, the participant has the incentive to hold off on reserving transmission in Michigan until their transaction is scheduled in Ontario. When attempting to reserve hourly transmission so close to real-time, non-firm transmission is often the only reservation still available.

Based on NERC procedures, intertie transactions associated with non-firm hourly transmission reservations are one of the first tranches of transactions curtailed. Ontario's market design inadvertently incents the use of non-firm hourly reservations, and to the extent that it does Ontario experiences a disproportionate amount of curtailed transactions when a TLR occurs than would otherwise be the case.

2.1.2 *April 18, 2013 Hour Ending 19*

The HOEP reached $203.56/MWh in HE 19 on Thursday April 18, 2013. While barely meeting the Panel's high-price threshold, this hour was of interest due to the low demand conditions during the hour. With prices in neighbouring jurisdictions all below $50/MWh, one would expect Ontario to be a net importer during the hour in question; however, a failure to foresee tight supply conditions in pre-dispatch resulted in the scheduling of considerable net exports, contributing to the high-price event.

Temperatures in Toronto were mild throughout the day, reaching a high of 16°C, with a low of 5°C. Mild weather conditions resulted in low demand throughout the day, with Ontario demand averaging 16,647 MW in HE 19.

Table 2-4 displays real-time MCP, Ontario demand and net exports for HE 19 on April 18, 2013.

***Table 2-4: Real-Time MCP, Ontario Demand and Net Exports
April 18, 2013 HE 19
(MW & $/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)
19	1	57.13	16,288	2,418	18,706	-25	-19
19	2	78.90	16,403	2,418	18,821	115	-19
19	3	135.00	16,460	2,418	18,878	57	-19
19	4	123.63	16,454	2,418	18,872	-6	-19
19	5	271.11	16,570	2,418	18,988	116	-19
19	6	246.90	16,660	2,418	19,078	90	-19
19	7	246.90	16,688	2,418	19,106	28	-19
19	8	246.90	16,695	2,418	19,113	7	-19
19	9	247.00	16,833	2,418	19,251	138	-19
19	10	271.11	16,877	2,418	19,295	44	-19
19	11	271.11	16,931	2,418	19,349	54	-19
19	12	247.00	16,907	2,418	19,325	-24	-19
Average		**203.56**	**16,647**	**2,418**	**19,065**	**50**	**-19**

Table 2-5 displays pre-dispatch prices, Ontario demand and net exports for the five pre-dispatch hours leading up to HE 19.

***Table 2-5: Pre-Dispatch Demand, MCP and Net Exports
Hours leading up to April 18, 2013 HE 19
(MW & $/MWh)***

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Ontario Demand plus Net Exports (MW)
5*	---	---	---	---	---	---
4	32.64	16,278	447	2,869	2,422	18,700
3	32.98	16,236	549	2,869	2,320	18,556
2	35.61	16,309	549	2,967	2,418	18,727
1	35.61	16,314	549	2,967	2,418	18,732

*The pre-dispatch sequence failed to run 5 hours ahead.

Iterative pre-dispatch runs leading up to real-time forecasted adequate supply in the province and pre-dispatch prices in the $35/MWh range. Based on a final pre-dispatch price of $35.61/MWh, 2,418 in net exports were scheduled, increasing real-time market demand in Ontario.

Supressed pre-dispatch prices not only lead to an over commitment of exports, but also an under commitment of supply resources. "Non-quick start" facilities (typically coal- and gas-fired generators) rely on pre-dispatch price signals to make start-up and shut-down decisions. In hours such as HE 19 on April 18, 2013, where low pre-dispatch prices give no indication of the eventual tight real-time conditions, non-quick start units that are offline cannot increase generation levels in response to high prices. For the day in question, many non-quick start units either never ran, or shut-down before HE 19.

Table 2-6 displays pre-dispatch versus real-time supply and demand conditions for each interval in HE 19 on April 18, 2013.

Table 2-6: Pre-Dispatch and Real-Time Demand and Supply Conditions April 18, 2013 HE 19 (MW)

HE	Interval	Ontario Demand			Self-Scheduling and Intermittent			Net Exports			Total PD vs. RT Discrepancy
		PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	
19	1	16,314	16,288	26	2,310	1,819	-491	2,418	2,418	0	-465
19	2	16,314	16,403	-89	2,310	1,790	-520	2,418	2,418	0	-609
19	3	16,314	16,460	-146	2,310	1,779	-531	2,418	2,418	0	-677
19	4	16,314	16,454	-140	2,310	1,776	-534	2,418	2,418	0	-674
19	5	16,314	16,570	-256	2,310	1,770	-540	2,418	2,418	0	-796
19	6	16,314	16,660	-346	2,310	1,766	-544	2,418	2,418	0	-890
19	7	16,314	16,688	-374	2,310	1,781	-529	2,418	2,418	0	-903
19	8	16,314	16,695	-381	2,310	1,763	-547	2,418	2,418	0	-928
19	9	16,314	16,833	-519	2,310	1,779	-531	2,418	2,418	0	-1,050
19	10	16,314	16,877	-563	2,310	1,778	-532	2,418	2,418	0	-1,095
19	11	16,314	16,931	-617	2,310	1,847	-463	2,418	2,418	0	-1,080
19	12	16,314	16,907	-593	2,310	1,882	-428	2,418	2,418	0	-1,021
Average		**16,314**	**16,647**	**-333**	**2,310**	**1,794**	**-516**	**2,418**	**2,418**	**0**	**-849**

Ontario demand was under forecast by an average of 333 MW in HE 19, with the discrepancy topping out at 617 MW in interval 11. IESO revisions to forecasted demand played a role in the discrepancy. Experiencing sunnier conditions than originally forecasted, the IESO reduced their primary demand forecast by up to 200 MW for HE 14 through HE 20. This revision would prove incorrect as real-time demand tracked closer to the IESO's original forecast.

In addition to demand in excess of forecasted levels, self-scheduling and intermittent generation resources under-delivered by an average of 516 MW (68 MW from self-scheduling and 448 MW from wind). In all, there was an average 849 MW of additional demand or unrealized supply in real-time relative to pre-dispatch, ultimately leading to the real-time price spike.

2.2 *Analysis of Negative-price Hours*

Negative-price hours signal the availability of abundant supply relative to demand, and arise as a result of low demand, relatively plentiful supply or a combination of the two. Just like high demand hours, low demand hours are largely driven by weather conditions, with low demand occurring frequently during the mild shoulder seasons (spring and fall). Weekend and overnight hours also regularly experience low demand. Failed export transactions also reduce total market demand and contribute to negative prices.

The amount of baseload supply is a factor of available nuclear, hydroelectric and intermittent generation, as well as scheduled imports.[63] While available generation from nuclear facilities remains fairly constant over time, generation from baseload hydroelectric facilities and wind generators tend to be higher during the shoulder seasons, particularly spring.

Table 2-7 displays the number of hours per month in which the HOEP was below $0/MWh in the Winter 2013 Period and the preceding four Winter Periods. The Winter 2013 Period experienced 43 negative-price hours, which is at the lower end of the range in terms of the five Winter Periods noted in the table.

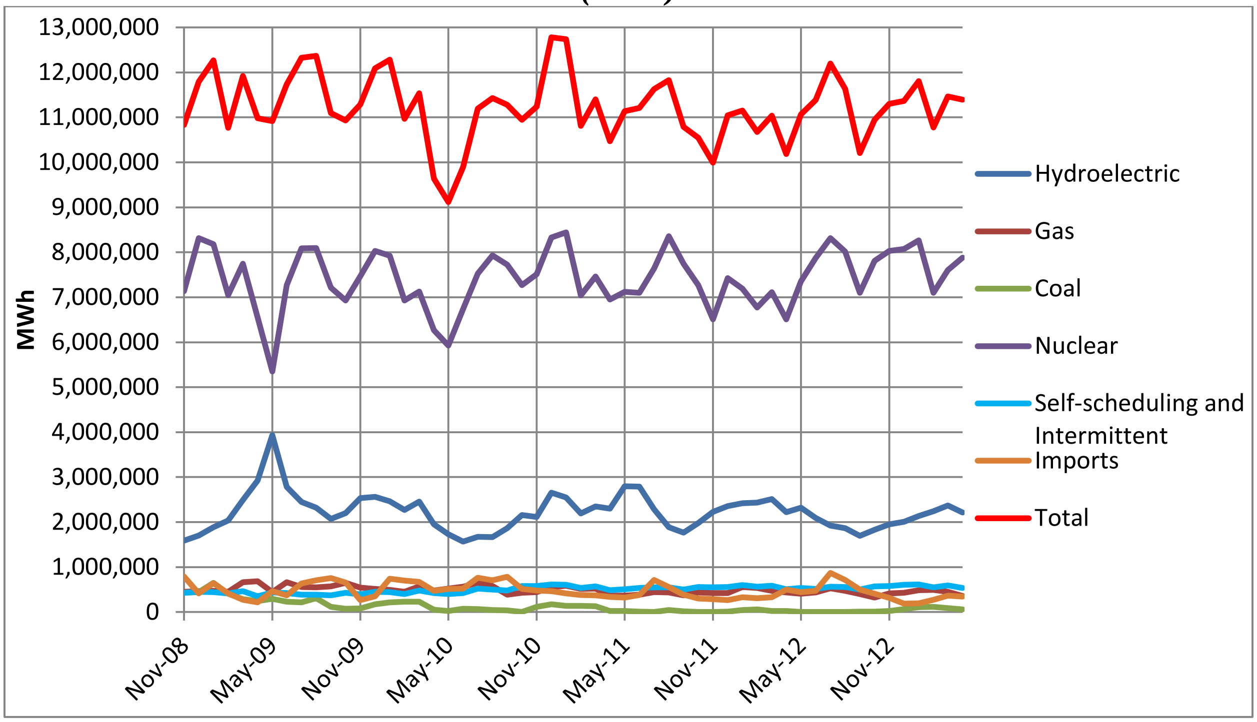
Table 2-7: Number of Hours with Negative HOEP
November – April 2008/2009 to November – April 2012/2013

Month	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013
November	0	16	3	13	11
December	5	0	9	14	4
January	0	1	11	9	13
February	0	0	0	2	0
March	58	0	3	44	3
April	156	9	27	5	12
Total	**219**	**26**	**53**	**87**	**43**

[63] Imports scheduled in pre-dispatch are offered at -$2,000/MWh in real-time.

Figure 2-1 displays the total monthly supply offered at negative prices by generators (by fuel type) and imports since late 2008.

Figure 2-1: Negative-priced Offers by Month and Fuel/Transaction Type November 2008 – April 2013 (MWh)



NOTE: Import quantities are scheduled quantities, not offered quantities. Imports scheduled in pre-dispatch are priced at -$2,000/MWh in real-time to ensure that their pre-dispatch schedules are respected. While imports are priced at -$2,000/MWh in real-time for price setting purposes, they may have been offered at positive prices.

Total supply offered at negative prices has remained relatively constant since late 2008, averaging 11,200,000 MWh per month. The offered quantities from nuclear and hydroelectric generators trended neither up nor down, reflecting the relatively unchanged capacity of these resources across reporting periods. Monthly fluctuations in nuclear and hydroelectric quantities primarily reflect transient capacity changes associated with outages and seasonal trends (such as high water conditions during spring and low water conditions during summer). The continuing retirement of coal-fired plants led to a gradual decline in the quantity of negative-priced offers from coal-fired generators, with negligible offer quantities by mid-2010. Increases in the installed capacity of intermittent resources saw total negative-priced supply from self-scheduling and intermittent resources increase gradually since 2008. Gas-fired generation, which is not typically offered at negative prices, had relatively constant negative-priced offered quantities despite increases in installed capacity.

3 Anomalous Uplift Payments

The Panel monitors uplift payments associated with the various IESO administered markets. Below the Panel reports on several anomalous events that generated large Congestion Management Settlement Credit (CMSC) payments or Intertie Offer Guarantee (IOG) payments.

3.1 *Congestion Management Settlement Credits*

CMSC payments in excess of $500,000 for a given hour or in excess of $1,000,000 for a given day are considered anomalous by the Panel. There were seven such days and two such hours during the Winter 2013 Period. All CMSC events that exceeded the Panel's thresholds occurred over two multiday spans; January 23 to 25 and February 4 to 8, 2013. Over the course of these two periods, over $9 million in CMSC was paid in respect of various intertie transactions, representing 77% of all CMSC payments made to intertie traders during the Winter 2013 Period.

3.1.1 *February 4-8, 2013*

Over a 5 day period, $8,637,687 in CMSC was paid, of which $7,256,479 (84%) was paid in respect of various intertie transactions. Table 2-8 displays CMSC payments by intertie, transaction type and constraint type.

Table 2-8: CMSC by Intertie and Transaction Type
February 4 – 8, 2013
($) *

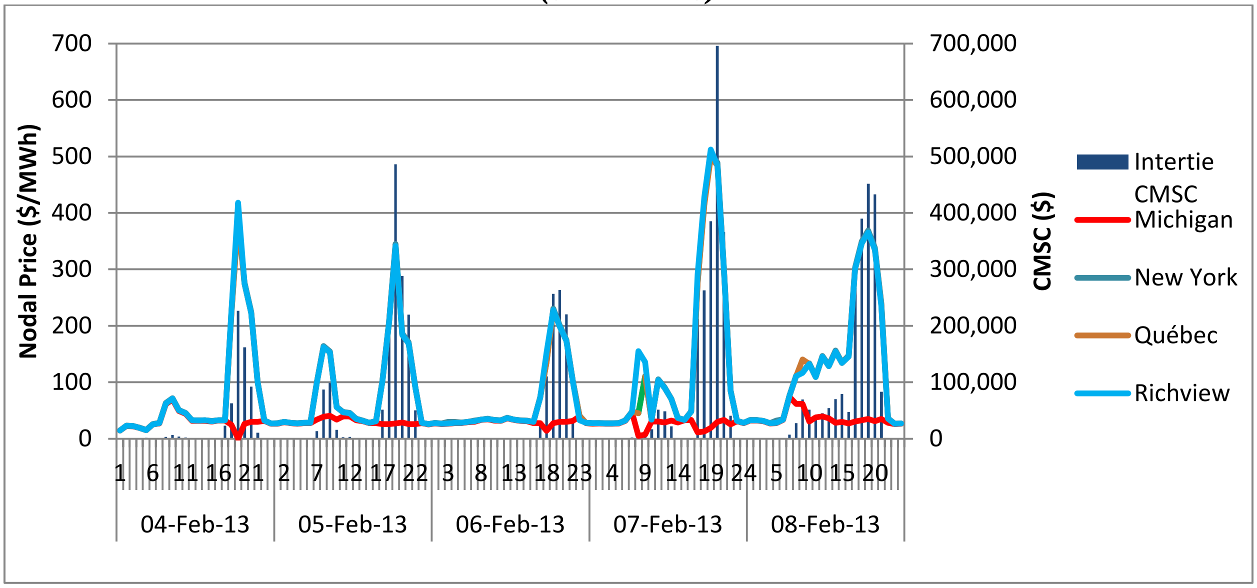
Intertie Zone	Import		Export		Total
	C. Off	C. On	C. Off	C. On	
Manitoba	423	30,210	(411)	1,416	31,638
Michigan (Cal)	(8,414)	326,625	10,586	(211,924)	116,873
Michigan (Lud)	(590,984)	0	0	(13,892)	(604,876)
Minnesota	0	23,121	77,180	808	101,109
New York	0	1,267,441	4,067,256	1,308	5,336,005
Québec	242	884,631	1,390,858	0	2,275,731
Total	**(598,733)**	**2,532,028**	**5,545,469**	**(222,284)**	**7,256,479**

* In some circumstances, CMSC payments can be negative, meaning that the CMSC payment is a charge to the market participant. As discussed in section 3.1.2, this occurs when a market participant avoids incurring an operating loss on a transaction when the transaction is constrained on or off.

The majority of these payments were the result of an internal transmission flow constraint that prevented power from flowing from generators in the western zone of the province, to the load centres in the east. With an ongoing outage to L37G, a 230kv transmission line in the western zone, IESO control room operators were concerned about overloading the neighbouring V43N transmission line. In order to reduce the flow on V43N, supply from importers and generators in the western zone needed to be reduced. Iterative pre-dispatch runs continued to schedule supply in the western zone that violated the flow limit on V43N, so in order to force the Dispatch Scheduling Optimizer (DSO) to constrain off additional supply the IESO reduced the allowable flow on the Negative Buchanan Longwood Input (NBLIP) internal transmission interface. NBLIP controls power flows from the western zone to the east. Limiting this interface forced the DSO to constrain off imports from Michigan and internal generation in the western zone, which alleviated the concern about overloading V43N. The limit on the NBLIP interface, which has an all elements in-service limit of 1,500 MW, was reduced by between 250 MW and 800 MW during multiple hours.

A considerable amount of supply is located in the western zone. Large gas-fired generators such as Greenfield, TA Windsor, TA Sarnia, St. Clair and Brighton Beach, along with numerous wind farms and the Michigan intertie, are all located in the zone. With NBLIP limiting the amount of supply from these economic sources, resources in the rest of the province were constrained to provide more power to make up the difference. Imports over the New York and Québec interties were constrained on to serve load in the Greater Toronto Area and Ottawa zone, respectively. Additionally, exports over these interties were constrained off to compensate for the lack of available supply. This happened repeatedly over the course of several days. Figure 2-2 displays the 1-hour ahead pre-dispatch nodal prices over the affected interties, as well as the nodal price at the Richview transmission station (used as a representative node for the overall market conditions in Ontario).

Figure 2-2: Nodal Prices and Intertie CMSC
February 4 – 8, 2013
($/MWh & $)



NOTE: Although not easily visible from this figure, the New York and Québec nodal prices moved in step with the Richview nodal price for the majority of hours.

Hours in which the nodal prices at New York, Québec and Richview spiked relative to the Michigan nodal price indicate a binding NBLIP constraint.[64] These hours correspond with spikes in CMSC payments related to intertie transactions. The nodal price spikes occurred primarily during the early evening hours of each day, typically the highest demand hours. As demand increased during these hours, additional supply resources in the western zone were brought up in the unconstrained schedule to meet demand. In the constrained schedule the increased power flow coming out of the western zone rendered the NBLIP limit binding. With power flow out of the west limited, more expensive supply resources to the east of NBLIP were dispatched on, causing nodal prices to spike in those zones.

Examining the constrained magnitudes during the hour with the largest total CMSC payment related to intertie transactions provides a sense of the strain that the grid was under. Table 2-9 displays the constrained magnitude of intertie transactions by intertie, transaction type and constraint type for HE 20 on February 7, 2013, when $717,168 in CMSC payments were

[64] Once the thermal limit of a line has been reached, a constraint becomes binding in the sense that no additional power can flow on the line.

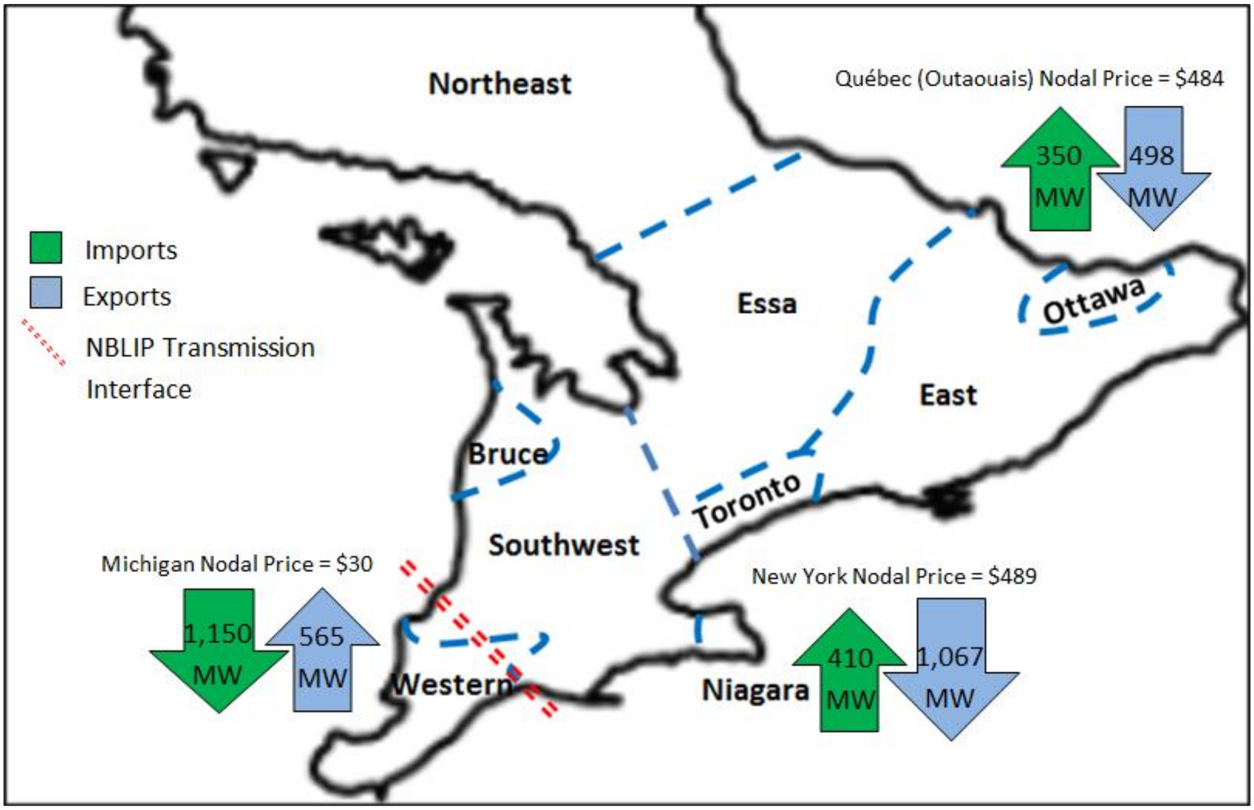
incurred ($688,066 of which was paid with respect to intertie transactions, as shown in Figure 2-2).

Table 2-9: Constrained Megawatts by Intertie and Transaction Type
February 7, 2013 HE 20
(MWh)

Intertie Zone	Import		Export		Total
	C. Off	C. On	C. Off	C. On	
Manitoba	77	0	0	0	77
Michigan (Cal)	0	0	0	565	565
Michigan (Lud)	1,150	0	0	0	1,150
Minnesota	0	0	40	0	40
New York	0	410	1,067	0	1,477
Québec	0	350	498	0	848
Total	**1,227**	**760**	**1,605**	**565**	**4,157**

On interties alone, net constrained schedule transactions deviated from their economic unconstrained schedules by 4,157 MW. Figure 2-3 provides a visual representation of the constrained dispatches given to market participants transacting on interties in the southern part of the province on February 7, 2013 in HE 20. Constrained transactions on these three interties accounted for 97% of the total constrained magnitude of intertie transactions during the hour.

Figure 2-3: Intertie Schedules (Constrained Schedule relative to Unconstrained Schedule) February 7, 2013 HE 20



During the illustrative hour identified above, the pre-dispatch MCP was $275.01/MWh; with no intertie congestion the intertie zonal prices equalled the pre-dispatch MCP. However, when intertie nodal prices (constrained prices) became considerably higher than the pre-dispatch MCP (unconstrained price), there existed a large price range in which intertie transactions would be constrained either on or off. Imports offering above the pre-dispatch MCP but below the nodal prices at New York and Québec would be constrained on. Similarly, exports bidding above the pre-dispatch MCP but below the intertie nodal prices would be constrained off. While intertie transactions are scheduled based on the pre-dispatch MCP and nodal price, they are compensated based on the real-time MCP (i.e., the HOEP) plus any intertie congestion pricing. As it relates to constrained-on imports and constrained-off exports, as long as the HOEP settles below a participant's offer or bid price, CMSC will be paid. During the hour in question the pre-dispatch MCP was $275.01/MWh, while the HOEP was $33.42/MWh. The drop in price from pre-dispatch to real-time increased the amount of CMSC payments made for the constrained transactions identified in Figure 2-3.

3.1.2 *January 23-25, 2013*

Over a period of three days $3,999,652 in CMSC payments was incurred, of which $1,890,280 (47%) related to various intertie transactions. Table 2-10 displays CMSC payments by intertie, transaction type and constraint type.

Table 2-10: CMSC by Intertie and Transaction Type
January 23 - 25, 2013
($)

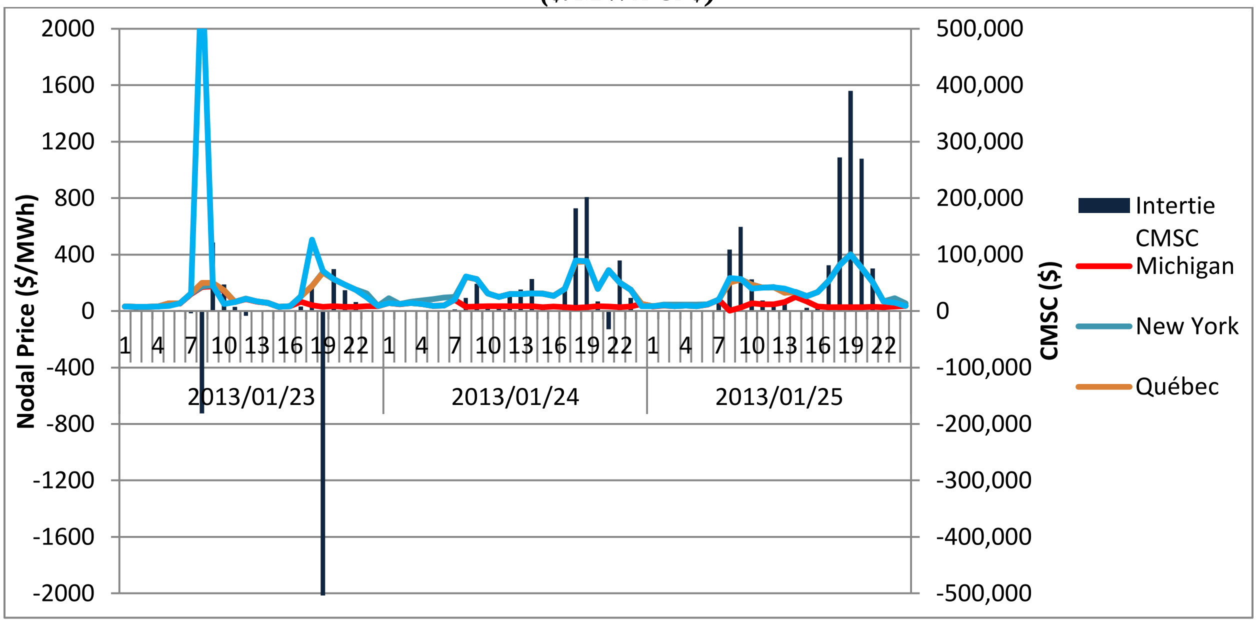
Intertie Zone	Import		Export		Total
	C. Off	C. On	C. Off	C. On	
Manitoba	3,577	2,419	0	2,683	8,679
Michigan (Cal)	26,804	0	(184,402)	64,557	(93,041)
Michigan (Lud)	573,689	(16,832)	(64,808)	31,491	523,539
Minnesota	0	0	0	0	0
New York	0	(2,439)	774,146	0	771,708
Québec	0	140,549	538,846	0	679,395
Total	**604,070**	**123,696**	**1,063,782**	**98,730**	**1,890,280**

As discussed in section 2.1.1, Ontario was experiencing extreme cold weather conditions during the period that includes the January 23-25 timeframe. The anomalous CMSC event had little to do with out-of-market control actions or planned outages, and more to do with rapid load increases and a transmission system that was considerably constrained.

Much like the anomalous CMSC event from February 4-8, 2013, a constraint on the NBLIP transmission interface was binding during many hours, bottling supply in the western zone and preventing it from flowing to the load centres to the east of the NBLIP interface. The interface constraint required that supply be constrained off in the western zone (including the Michigan intertie) and load be constrained on, whilst supply had to be constrained on and load constrained off in zones to the east (including the New York and Québec interties) to compensate for a lack of supply from the western zone.

Figure 2-4 shows the pre-dispatch nodal prices over the affected interties, as well as the nodal price at the Richview transmission station (as noted above, used as a representative node for the overall market conditions in Ontario).

Figure 2-4: Nodal Prices and Intertie CMSC
January 23 - 25, 2013
($/MWh & $)



NOTE: Although not easily visible from this figure, the New York and Québec nodal prices moved in step with Richview for the majority of hours.

Pre-dispatch nodal prices at Richview and at the New York and Québec interties routinely spiked relative to the nodal price at the Michigan intertie. These divergences occurred primarily during the peak demand hours as more and more generation in the western zone was scheduled in the unconstrained schedule. The generation increases could not be accommodated in the constrained scheduled as the NBLIP limit restricted power flow out of the west. While the real-time MCP was high during many of the hours in which the nodal prices spiked, it was persistently lower than the nodal prices because the unconstrained schedule ignores internal constraints, allowing it to schedule all economic generation in the western zone when setting the price.

On January 23, 2013 net CMSC payments related to intertie transactions totalled -$510,452 in HE 19. These negative CMSC payments were a result of a low pre-dispatch MCP relative to the eventual high real-time price, and positive net exports in the unconstrained schedule. In pre-dispatch the MCP was $85/MWh, including a Québec intertie zonal price of $200/MWh due to export congestion on the intertie. When supply conditions tightened in real-time, the MCP spiked to $575.58/MWh.[65] Exporters who were scheduled based on the lower pre-dispatch MCP would have had to pay the higher real-time MCP when their pre-dispatch schedules were carried over to real time. If the real-time price exceeded their pre-dispatch bid price, the transactions would have incurred an operating loss. However, due to the binding NBLIP constraint, many export transactions over the New York and Québec interties were constrained off to increase supply to the Greater Toronto Area and Ottawa area, respectively. Because these constrained-off transactions were not required to flow, the market participants avoided paying the higher real-time MCP. The CMSC regime is designed to return transactions to the operating profit that would have been earned had the transactions flowed as scheduled in the unconstrained schedule, and the IESO charged the market participants CMSC accordingly. During the hour Ontario had net exports of 2,738 MW in the unconstrained schedule, and many transactions attracted negative CMSC.

Aside from CMSC payments related to intertie transactions, $2,109,372 in CMSC payments were also incurred in respect of dispatchable resources within the province over the same three days (January 23 to 25), representing roughly half of the total net CMSC payments for those days. Table 2-11 displays CMSC by internal zone, resource type and constraint type.

Table 2-11: CMSC by Internal Zone and Transaction Type
January 23 - 25, 2013
($)

Internal Zone	Generators		Loads		Total
	C. Off	C. On	C. Off	C. On	
Bruce	74	0	0	0	74
East	33,506	169,590	0	0	203,096
Niagara	262,675	27,066	171	235	290,147
Northeast	174,802	110,904	23,131	1,274	310,111
Northwest	150,305	66,323	3,198	0	219,826
Southwest	100,746	49,383	7,435	0	157,564
Toronto	273,001	174,184	0	0	447,185
Western	496,703	(15,335)	0	0	481,368
Total	**1,491,813**	**582,115**	**33,935**	**1,509**	**2,109,372**

[65] Section 2.1.1 provides a detailed explanation as to why real-time prices spiked relative to the pre-dispatch MCP on January 23, 2013.

Of the total CMSC payments made in respect of internal resources, $1,491,813 (71%) was paid to constrained-off generators. The combination of the binding NBLIP constraint and high real-time prices contributed to large CMSC payments to constrained-off generators in the western zone, and any supply resources that were constrained off in the rest of the province also received large CMSC payments on account of the high real-time prices. Over the three-day period there were 12 hours (17% of total hours) in which the HOEP exceeded $100/MWh, including 1 hour in which it was higher than $500/MWh and 2 hours in which it was higher than $200/MWh.[66] As market prices increase, the difference between the economically scheduled offers of a given generator and the MCP increases, implying a larger operating profit and therefore triggering a higher CMSC payment in the event that the generator is constrained off.

3.1.3 *Payments to Constrained-off Intertie Transactions*

The Panel has long questioned the benefits of constrained-off CMSC payments. In 2003, the Panel issued an extensive discussion paper on several of the issues associated with constrained-off CMSC payments to importers and generators, and invited comment on it.[67] Among other things, the discussion paper identified five arguments that had been offered to justify those constrained-off CMSC payments (these are noted further below). In their comments on the discussion paper, generators and intertie traders supported those arguments while an association representing large loads refuted them.[68] Ultimately the Panel concluded the following:

> *The Panel concludes that should [locational marginal pricing] not go ahead…then constrained off CMSC payments should be eliminated and other aspects of the CMSC framework reviewed.*[69]

As constrained-off CMSC payments for generators and importers remained in place, and recognizing the potential for gaming in respect of those payments, the Panel revisited the issue in

[66] See section 2.1.1 for a detailed explanation of the high real-time prices.
[67] Market Surveillance Panel Discussion Paper, *Congestion Management Settlement Credits (CMSC) in the IMO-administered Electricity Market: Issues Related to Constrained Off Payments to Generators and Importers,* February 2003, available at: http://www.ontarioenergyboard.ca/documents/msp/consultation_discussionpaper_180203.pdf
[68] Stakeholder comments on the Panel's discussion paper are available at: http://www.ontarioenergyboard.ca/OEB/Industry/About%20the%20OEB/Electricity%20Market%20Surveillance/Consultation%20on%20CMSC
[69] Market Surveillance Panel Report, *Constrained Off Payments and Other Issues in the Management of Congestion*, July 2003, available at: http://www.ontarioenergyboard.ca/documents/msp/consultation_ms_cmsc_030703.pdf. When the Panel released this report, consideration was still being given to transitioning the market to locational prices, which would have addressed the issues of concern to the Panel.

2006 and again in 2008, both times recommending the elimination of all constrained-off CMSC payments.[70]

Constrained-off CMSC payments remain a major concern. While the Panel's view that all constrained-off CMSC payments should be discontinued has not changed, the analysis below advocates a more targeted approach. The recommendation that follows addresses a subset of constrained-off CMSC payments (those paid for intertie transactions), and is made within the context of the Panel's previous analysis and broader recommendations. While the focus of the Panel's initial analysis was on constrained-off CMSC payments for imports and generation, it is equally applicable to exports.

Table 2-12 displays total constrained-off CMSC payments by intertie transaction type since 2008.

Table 2-12: Constrained-off CMSC by Intertie Transaction Type
January 2008 - September 2013
($ millions)

Year	Imports	Exports	Total
2008	32.0	19.1	51.1
2009	16.1	20.1	36.2
2010	13.0	7.9	20.9
2011	9.9	7.1	17
2012	6.5	5.9	12.4
2013 thru Sept	1.1	13.7	14.8
Total	**78.5**	**73.8**	**152.3**

Since 2008, $152.3 million in CMSC payments have been made in relation to constrained-off intertie transactions. Annual constrained-off CMSC payments related to intertie transactions have declined considerably since 2008, driven in large part by reductions in CMSC payments for constrained-off imports. These reductions are in turn largely attributable to two factors. First, the average HOEP has declined since 2009 (see Figure 1-2). All else being equal, this reduces

[70] See the Panel's June 2006 Monitoring Report, pages 123 and 124, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf and the Panel's July 2008 Monitoring Report, page 205, available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200807.pdf.

the lost operating profit associated with being constrained off, thus reducing the magnitude of CMSC payments.

Second, in October 2012 a market rule change came into effect that eliminated constrained-off CMSC payments for imports into a "designated chronically congested area" (CCA) when those imports are constrained off in the final pre-dispatch run.[71] Currently, only the Northwest (NW) zone is designated as a CCA. Table 2-13 displays constrained-off CMSC payments made with respect to import transactions on the two NW interties; Manitoba and Minnesota.

Table 2-13: Constrained-off CMSC Payments for Imports in the Northwest January 2008 – September 2013 ($ millions)

Year	Manitoba Intertie	Minnesota Intertie	Manitoba + Minnesota	Total to all Other Interties	NW as a Percentage of Total
2008	30.2	2.7	33.0	(1.0)	103%
2009	16.9	1.6	18.4	(2.4)	115%
2010	10.7	2.1	12.8	0.2	99%
2011	8.2	1.0	9.2	0.7	93%
2012	5.7	0.7	6.4	0.1	98%
2013 thru Sept	0.3	0.0	0.3	0.8	25%
Total	**71.9**	**8.1**	**80.0**	**(1.6)**	**102%**

From 2008 to 2011, the NW interties on average accounted for 103% of all net CMSC payments related to constrained-off import transactions.[72] In the case of the NW, constrained-off payments for imports equate to payments for not delivering power into an area with abundant low-cost electricity. The IESO therefore examined whether these payments were benefitting the market.

In its review, the IESO turned to the Panel's 2003 discussion paper on constrained-off CMSC payments, measuring the merit of these payments against the five benefits that the Panel had identified as having been raised to support the continuation of those payments:

[71] See Chapter 3 for a detailed analysis of this market rule amendment.
[72] As discussed below, CMSC payments can be negative if a participant avoids incurring a negative operating profit on account of its transaction being constrained off. A negative operating profit can arise because of the intertie scheduling process, which schedules transactions in pre-dispatch (based on the pre-dispatch intertie zonal price), but settles them based on the real-time zonal price. When intertie transactions are economic in pre-dispatch, but become uneconomic in real-time, the market participant incurs a negative operating profit. In the case of import transactions, a negative CMSC payment is often offset by a positive Intertie Offer Guarantee (IOG) payment. Negative CMSC payments to importers in Tables 2-12 and 2-13 are net of offsetting IOG payments.

1. Constrained-off payments keep wholesale prices lower than they would otherwise be.
2. Constrained-off payments enhance reliability by maintaining critical plant in the marketplace, even though such plant may be needed only in certain periods.
3. Constrained-off payments, together with the corresponding constrained-on payments, provide information about transmission bottlenecks that is helpful in identifying areas of investment.
4. Constrained-off payments provide certain operational benefits to the marketplace with respect to incenting compliance with dispatch instructions.
5. Constrained-off payments compensate for departures from optimality of the configuration of the existing generation and transmission endowment in the province.

With regards to constrained-off CMSC payments to import transactions, the IESO concluded as follows:

> *The reasons for justification of constrained-off payments are either not applicable or do not provide sufficient value with respect to imports into a chronically congested area.*[73]

In the Panel's view, the same conclusion can be drawn in relation to constrained-off CMSC payments for all intertie transactions.[74]

While the Panel has long advocated for the elimination of all constrained-off CMSC payments, recent events on the interties (including the events discussed earlier in this Chapter where substantial CMSC payments were incurred in relation to intertie transactions over a period of days) have highlighted the need for a solution regarding constrained-off CMSC payments for intertie transactions in particular.

The elimination of constrained-off CMSC payments for import transactions in the Northwest has allowed for a timely case study (see Chapter 3) on which to assess the possible effects of eliminating constrained-off CMSC payments for intertie transactions. The Panel believes that the elimination of constrained-off CMSC payments for all intertie transactions will be of

[73] For more information on the IESO's rationale see the Market Rule Amendment Submission, available at: http://www.ieso.ca/imoweb/pubs/mr2012/MR-00395-Q00.pdf

[74] It is worth noting that the process by which imports and exports are handled by the IESO and system operators in neighbouring jurisdictions is such that there is no possibility of dispatch deviation. The argument pertaining to incenting compliance with dispatch instructions is therefore inapplicable in relation to intertie transactions.

significant benefit to the market in terms of uplift payments, market efficiency and participant behaviour.

Constrained-off CMSC payments can lead to inefficient dispatch and consumption decisions. Constrained-off supply resources represent resources that are unable to deliver electricity to the market, yet their offers are still used to set the MCP. While a load makes consumption decisions on the basis of the MCP, the incremental cost borne by the market may be very different. An incremental megawatt of demand will result in the scheduling of an additional megawatt of supply in the unconstrained schedule, where the MCP is set. If that incremental supply cannot economically reach the market due to transmission constraints, the facility offering to produce that supply is constrained off while a unit whose offer exceeds the MCP, but whose output can physically reach the market, is constrained on. Both of these units receive CMSC payments. While a load will be making its consumption decision based only on the MCP, the total incremental cost of consumption is equal to the MCP plus the uplift generated by the CMSC payments (an amount that is not known until after the trading period). The lack of transparency regarding the true incremental cost of production at the time of consumption can lead to inefficient dispatch decisions.

The same principle applies to constrained-off sources of demand. When a load or export is constrained off, there is no need to produce energy to meet the constrained-off portion of their demand. However, their bids to consume energy are used to set the MCP in the unconstrained schedule, which artificially increases the MCP relative to the true cost of the next megawatt of supply.

A MCP that better reflects the incremental cost of production will lead to more efficient consumption decisions. Eliminating constrained-off CMSC payments removes the incentive for market participants to "chase" nodal prices with offers or bids that diverge from the marginal cost or lost opportunity cost of their transaction. These offers and bids target CMSC payments while purposefully avoiding the physical delivery or withdrawal of electricity.[75] The elimination of such offers and bids will increase market efficiency. While nodal price chasing behaviour is more prevalent in zones where nodal prices routinely diverge from the MCP (such as in a

[75] For more information on nodal price chasing behaviour, see Chapter 3.

constrained-off watch zone, as discussed further in Chapter 3), the behaviour can arise in any zone, and is facilitated by the publication of pre-dispatch nodal prices.[76]

All constrained-off resources, not just those chasing nodal prices, can lead to market inefficiency. Market participants offering or bidding at their marginal cost or lost opportunity cost, who believe there is a reasonable chance their transactions will be accepted in the constrained schedule, will likely continue to participate despite the elimination of constrained-off CMSC payments. This is especially true in the case of domestic generators and loads, as the Ontario market is their only option for buying or selling power. By contrast, intertie traders offering or bidding at their marginal cost or lost opportunity cost may choose not to participate in Ontario if they believe that their transactions will be constrained off. These entities have the option of participating in many markets, and may pick and choose which to transact in based on their capital and risk constraints. In cases where the elimination of constrained-off CMSC payments discourages participation from market participants that would otherwise be constrained off, market efficiency can be increased. Where legitimate arbitrage opportunities exist, the Panel fully expects the continued participation of intertie traders.

As stated in previous reports, the Panel does not believe that constrained-off CMSC payments provide commensurate value to the market. Moreover, they are susceptible to gaming as identified by the Panel over the years. The opportunities for gaming not only increase uplift charges to electricity consumers, but also incent inefficient behaviour.

In light of the above, the Panel is recommending that constrained-off CMSC payments be eliminated for all intertie transactions (see below). However, there are related issues associated with negative CMSC payments and Intertie Offer Guarantee (IOG) payments that require consideration in that context.

In some cases, constrained-off CMSC payments can be negative (in other words, a charge to the market participant). If a market participant avoids incurring a negative operating profit as a result of being constrained off, a negative CMSC payment returns the market participant to the negative operating profit it would have incurred had its transaction been dispatched in

[76] The publication of pre-dispatch nodal prices and the MCP allows market participants to structure their offers or bids in such a way as to increase their likelihood of being constrained off whilst maximizing their CMSC payments.

accordance with the unconstrained schedule. In the case of constrained-off imports, the constrained-off transaction may also be eligible for an IOG payment. IOG payments guarantee that import transactions receive at least the average of their offer price over the course of the trading hour, ensuring that they do not suffer a negative operating profit. These payments are intended to remove pre-dispatch to real-time price uncertainty. By providing importers with greater price certainty, IOGs encourage imports and help to ensure adequate supply in Ontario. In the majority of cases, a constrained-off import transaction that generates a negative CMSC payment will also receive a positive IOG payment. The payments offset each other, returning the market participant to an operating profit of zero dollars.

The elimination of constrained-off CMSC payments for intertie transactions would eliminate negative CMSC payments. Trades that would have incurred a negative operating profit would instead incur an operating profit equal to zero dollars. In the case of constrained-off import transactions that are also eligible for an IOG payment, the elimination of constrained-off CMSC payments would result in transactions that generate a positive operating profit equal to the IOG payment (because there would be no offsetting negative CMSC payment). If constrained-off CMSC payments are eliminated but IOG payments for constrained-off imports remain, situations will arise where importers will prefer to be constrained off rather than to have their transaction flow as scheduled in the unconstrained schedule. This can incent inefficient offer behaviour in much the same way as constrained-off CMSC payments currently do.

If constrained-off CMSC payments are eliminated for intertie transactions, IOG payments for constrained-off imports will no longer be needed to offset any negative operating profit and keep the importer whole relative to its offer price. Constrained-off CMSC payments aside, IOG payments for constrained-off imports are, in the Panel's view, inconsistent with the underlying purpose of IOG payments to promote supply adequacy in the province.

<u>Recommendation 2-1</u>

> ***The Panel recommends that the IESO eliminate constrained-off Congestion Management Settlement Credit (CMSC) payments for all intertie transactions, with due consideration to the interplay between the elimination of negative CMSC payments and Intertie Offer Guarantee payments.***

3.2 *Intertie Offer Guarantee Payments*

IOG payments in excess of $500,000 for a given hour or in excess of $1,000,000 for a given day are considered anomalous by the Panel. There were no such hours or days during the Winter 2013 Period.

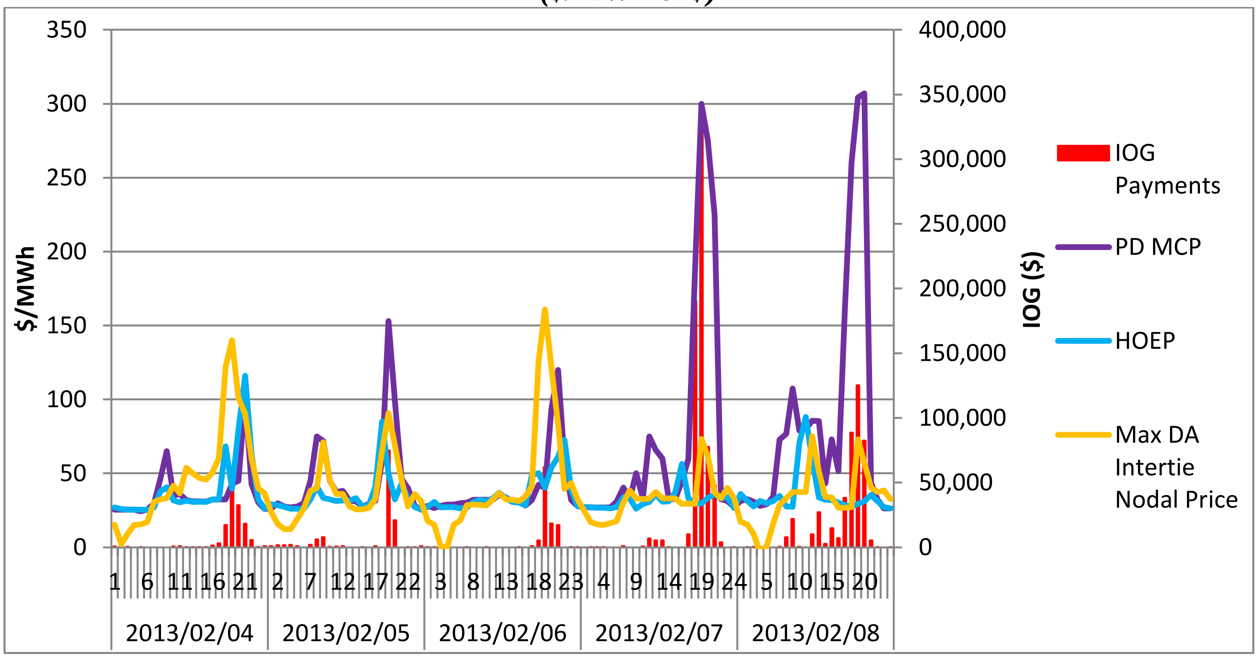
As noted above, an IOG payment is intended to protect importers from incurring a negative operating profit due to day-ahead or pre-dispatch to real-time price uncertainty. By providing greater price certainty, IOGs encourage imports and increase supply adequacy. When the real-time price drops below the price at which an import was scheduled (be it day-ahead or in pre-dispatch), an IOG payment is made equalling the difference between the real-time price and the offer price on each megawatt.

There are two types of IOG payments: day-ahead IOG payments and real-time IOG payments. A day-ahead IOG payment is made when a market participant's import transaction is committed under the day-ahead commitment process and the real-time price clears below the participant's day-ahead offer price. A real-time IOG payment is made when an import transaction is scheduled in the final pre-dispatch run and the real-time price subsequently drops below the participant's offer price.

While no days or hours met the Panel's thresholds for anomalous IOG payments, five of the largest six daily IOG payments during the Winter 2013 Period occurred from February 4-8, 2013, including the largest daily IOG payment of $687,080 on February 7, 2013. This period coincides with the anomalous CMSC event examined earlier in this Chapter. Over the 5-day period, a total of $1,488,975 in IOG payments was made to various importers across the province.

Figure 2-5 displays IOG payments by hour, as well as the HOEP, pre-dispatch MCP and the highest day-ahead intertie nodal price in the province (this approximately represents the maximum price an import could be scheduled day-ahead) on the days in question.[77]

Figure 2-5: IOG Payments, HOEP, Pre-Dispatch MCP and Intertie Nodal Price February 4 – 8, 2013 ($/MWh & $)



Save for several moderate spikes, the maximum day-ahead intertie nodal price rarely exceeded the HOEP. Consequently, revenue received for importing in the real-time market was more often than not sufficient to cover the amount guaranteed by the day-ahead schedule. Conversely, the pre-dispatch MCP experienced several pronounced spikes relative to the HOEP, causing large implied negative operating profits for importers whose transactions were scheduled at the high pre-dispatch price but compensated based on the lower real-time price. The largest hourly IOG payments of the five-day period coincided with spikes in the pre-dispatch MCP. For example, in HE 19 on February 7, 2013, for which the largest hourly IOG payment was made, imports offered below $300/MWh would have been scheduled based on the pre-dispatch nodal price at the interties (absent import congestion). When the real-time market cleared at

[77] Resources committed day-ahead are scheduled based on average cost across the 24 hour optimization period, not necessarily the marginal cost during any one hour.

$30/MWh, imports scheduled with pre-dispatch offers between $30/MWh and $300/MWh incurred negative operating profits, triggering IOG payments. With considerable imports scheduled based on offer prices in that range, IOG payments for the hour were significant.

3.3 *Operating Reserve Payments*

OR payments in excess of $100,000 for a given hour are considered anomalous by the Panel. There were three such hours during the Winter 2013 Period.

High OR payments are associated with instances of high OR prices. Due to the joint optimization of the energy and OR markets, energy and OR prices typically move in the same direction as supply and demand conditions change. Instances of high OR prices and payments are typically associated with tight supply conditions in both the energy and OR markets.

The hour with the highest OR payments in the Winter 2013 Period was HE 19 on January 23, 2013, when OR payments totalled $563,902. During that hour, the prices for 10-minute spinning reserve, 10-minute non-spinning reserve and 30-minute reserve were $423.44/MWh, $423.44/MWh and $423.35/MWh, respectively. As discussed earlier in this Chapter, the HOEP during the hour was $575.58/MWh, the highest of the Winter 2013 Period, as a result of high demand caused by extreme cold weather and of reductions in available supply.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this Chapter, the Panel summarizes notable changes and developments that affect the efficient operation of the IESO-administered markets, and makes recommendations where relevant to promote market objectives. Section 2 provides an update on Panel investigations. In section 3, the Panel discusses two matters: the elimination of Congestion Management Settlement Credit (CMSC) payments for imports in the Northwest; and an assessment of the IESO's generation cost guarantee programs, including the enhanced day-ahead commitment process.

2 Panel Investigations

The Panel currently has investigations under way in relation to four market participants (two generators and two dispatchable loads), each relating to potential gaming involving CMSC and other payments. As each of these investigations is completed, the Panel will submit its investigation report to the Chair of the Ontario Energy Board (OEB) and the report will be published on the OEB's website.[78]

3 New Matters

3.1 *Elimination of CMSC Payments to Importers in the Northwest*

3.1.1 *Introduction*

In October 2012, the IESO implemented a market rule change that eliminated constrained-off CMSC payments to market participants offering to import energy into a "designated chronically congested area", if the import transaction was constrained off in the final pre-dispatch run.[79] The IESO implemented this rule change as it did not believe that this subset of CMSC payments was consistent with the original intent underlying constrained-off CMSC payments to importers.[80]

[78] The submission and posting of Panel investigation reports is addressed in Article 7 of the OEB's By-law #3 (Market Surveillance Panel), available at: http://www.ontarioenergyboard.ca/OEB/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf
[79] Chapter 9, section 3.5.10 of the Market Rules, http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter9.pdf
[80] IESO Market Rule Amendment Proposal, available at: http://www.ieso.ca/imoweb/pubs/mr2012/MR-00395-R00_Amendment_Proposal_v5_Board_Approved.pdf

The IESO defines a “designated chronically congested area” as an area that is designated as a constrained-off watch zone (“COWZ”) for injections (generators and importers). Currently, only the Northwest (NW) zone of the province is designated as a COWZ for injections, and therefore is also the only area of the province that is a designated chronically congested area.

The COWZ designation characterizes a zone that has an abundance of relatively inexpensive supply in relation to the load and transmission capacity in the area. In a zone designated as COWZ for injections, the bottling of excess low-priced supply results in nodal prices that are persistently lower than the Ontario-wide market clearing price (MCP). This persistent gap between nodal prices and the MCP results in regular constrained-off dispatches to generators and importers in the region, generating considerable constrained-off CMSC payments. The persistent and repetitive nature of constrained-off dispatches provides an opportunity for constrained-off resources to earn profits in excess of levels induced by effective competition, by engaging in strategic offer behaviour known as “chasing the nodal price”. This behaviour increases CMSC payments,[81] and can give rise to dispatch inefficiencies.

Implementation of the October 2012 market rule change has eliminated the incentive for importers to chase nodal prices in the NW, and has resulted in many changes in market participant behaviour and market outcomes.

Following the market rule change, importer participation in the NW has decreased, both in terms of offered quantities and number of participants. While this may seem like a reduction in competition, the elimination of inappropriate market incentives has improved efficient competition on the interties. Import congestion has also decreased, better reflecting the NW’s status as an oversupplied area. The rule change also contributed to decreases in constrained dispatches to other resources, all else being equal leading to a reduction in the cost of dispatching resources to respect transmission constraints. These findings are discussed in further detail below.

[81] CMSC payments are recovered from domestic loads and exporters via uplift.

3.1.2 *Market Characteristics in the NorthWest*

The NW possesses an abundance of supply relative to the modest demand in the area. With hydroelectric generation and hydroelectric-backed imports comprising the majority of supply, most generation in the area has a relatively low marginal cost of production. While the province benefits from low cost power, there is limited transmission capacity linking the NW to the load centers in the rest of Ontario, which causes bottled supply. Persistently low nodal prices[82] in the NW relative to the Ontario-wide MCP reflect the state of supply and demand in the area, with ample supply offered at low prices relative to demand.

Table 3-1 displays the real-time and 1-hour ahead pre-dispatch price differences between the MCP and nodal prices in the NW from October 2010 to September 2012 (the two-year period preceding the rule change). Both scheduling timeframes are relevant as intertie transactions are scheduled in pre-dispatch while internal resources are scheduled in real-time.

Table 3-1: Average Nodal Price at NW Representative Nodes October 2010 to September 2012 ($/MWh)

	Average MCP	Average Nodal Price	Nodal Price - MCP
1-Hr Ahead Pre-dispatch	27.51	-107.75	-135.26
Real-Time	27.44	-73.47	-100.91

On average, nodal prices were considerably lower than the MCP in both pre-dispatch and real-time. Such a large divergence in prices increases the likelihood of a generator or import being economic in the unconstrained sequence (based on the MCP), but uneconomic in the constrained sequence (based on the nodal price); this leads to a constrained-off dispatch and a corresponding CMSC payment. Since market opening, imports in the NW have received 99% of all CMSC payments made for constrained-off imports across all interties, despite representing only 5.7% of total import capacity.[83]

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[82] Nodal prices can be thought of as a "local price", though no transactions are settled on this basis.
[83] Since market opening, all but three interties (Manitoba, Minnesota and Québec-Outaouais) have experienced net constrained-off import CMSC payments that were negative. In most cases, these negative CMSC payments were offset by Intertie Offer Guarantee payments.

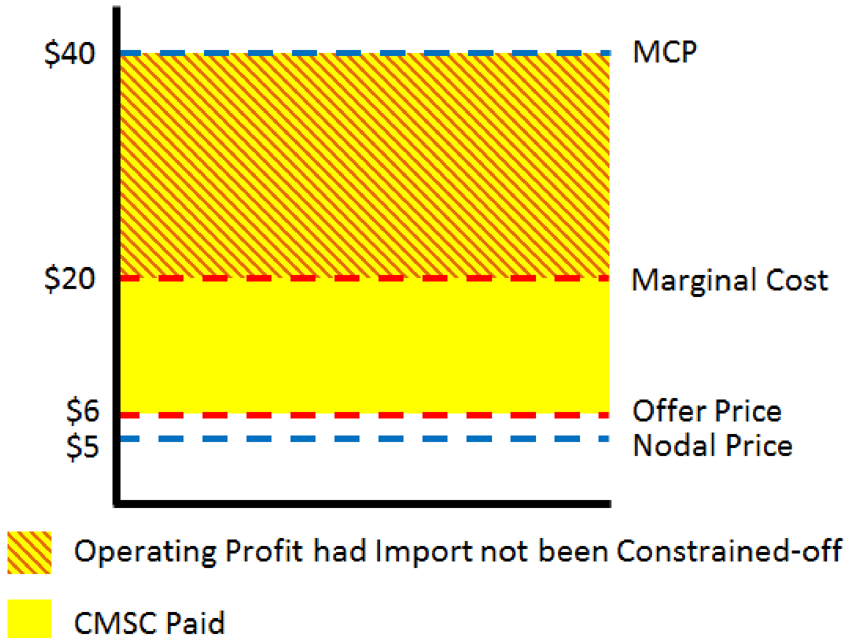
3.1.3 *"Chasing the Nodal Price"*

The persistent gap in prices creates an opportunity for generators and importers to earn profits in excess of what they would have earned had their transaction flowed as economically scheduled and not been constrained off. Generators and importers targeting CMSC payments may offer at prices well below the MCP, but above the nodal price, in order to be constrained off and receive CMSC payments.[84] Knowing with reasonable certainty that they will be constrained off and will not have to actually deliver power, generators and importers are free to offer at prices well below their actual marginal cost of delivering energy. Constrained-off CMSC payments can be increased by maximizing the delta between the higher MCP and the lower offer price. By offering just above the nodal price, but well below the MCP, the market participant is able to maximize its CMSC payment. This practice has come to be known as "chasing the nodal price". Pre-dispatch nodal prices are published and made available to market participants each and every hour. For market participants chasing the nodal price, these projected nodal prices inform the price at which they should be offering if their intention is to receive a constrained-off dispatch while maximizing CMSC payments.

Figure 3-1 illustrates how an importer may take advantage of the MCP and nodal price differential by chasing the nodal price at an intertie.

[84] CMSC payments for constrained-off generators and importers are limited by the difference between $0 and the MCP, even if the participant offered at a negative price. In its July 2003 discussion paper on constrained-off CMSC payments (discussed in Chapter 2), the Panel posited as follows: "If the MCP is sufficient compensation for supplying energy it must also be sufficient compensation for not supplying it." In January 2004, the IESO implemented the Panel's recommendation to limit constrained-off CMSC payments for negative offers.

Figure 3-1: Example of Nodal Price Chasing Behaviour



For purposes of the illustrative example set out in Figure 3-1, it is assumed that the importer estimates a cost of purchasing power in Minnesota of $15/MWh, with an additional $5/MWh charge for transmission reservations. Accordingly, the market participant estimates the marginal cost of importing power from Minnesota to Ontario to be $20/MWh. Three hours ahead of real-time, a pre-dispatch sequence is run that projects an Ontario MCP of $40/MWh. Based on projected prices in Minnesota and Ontario, the market participant stands to make a profit of $20/MWh if its import is scheduled and there is no congestion on the intertie.

Recognizing the opportunity to receive constrained-off CMSC payments that increase profitability beyond the $20/MWh that would be earned if the import flows, the market participant offers into Ontario at a price of $6/MWh. In real-time, all pre-dispatch projections in Minnesota and Ontario hold true, and with an offer price below the MCP but above the nodal price the import is constrained off. To compensate for the lost operating profit implied by its $6/MWh offer price, the market participant receives a CMSC payment of $34/MWh. Since the market participant was constrained off and directed not to deliver power into Ontario, it forgoes purchasing electricity and transmission in Minnesota. By avoiding these costs, the market participant accrues all of the $34/MWh in CMSC payments as profit. Relative to the $20/MWh profit that the market participant would have earned had its import been scheduled, it is more profitable for the market participant not to deliver power into Ontario than it is to deliver power.

3.1.4 *Development of the October 2012 Rule Change*

Market participants chasing nodal prices with below-cost import offers has long been an issue in the NW. In its December 2005 monitoring report, the Panel noted the emergence of nodal price chasing behaviour and identified that the issue was being raised with the IESO's market rules group.[85] In response to the Panel's concerns, the IESO implemented the COWZ framework in 2006 to help mitigate constrained-off CMSC payments in the NW.

The COWZ framework was intended to return importers in the NW to the profit that they would have earned had their imports not been constrained off. In order to achieve that objective, the IESO would estimate the underlying marginal cost of the transaction in question, and replace the participant's below-cost offer price with the IESO's estimate of marginal cost. For instance, in the above example the participant's $6/MWh import offer would be replaced with an offer of $20/MWh, which better reflects the marginal cost associated with purchasing power in Minnesota and delivering it to Ontario (the $15/MWh Minnesota price plus $5/MWh for transmission reservations). Replacement of a participant's offer price was done after-the-fact, and only for the purposes of recalculating CMSC payments; the market was not re-settled based on the replacement offer price.

The COWZ framework represented a step in the right direction. While the CMSC recalculation process was intended to return the market participant to the profit they would have earned had they not chased the nodal price, materiality thresholds and exceptions in the market rules often prevented the IESO from recovering all targeted CMSC payments. To the extent that this was the case, the participant was still better off chasing the nodal price. For the reasons outlined below, the persistence of below-cost offers also had negative impacts on market efficiency.

When it was determined that the COWZ framework was not sufficient to discourage nodal price chasing behaviour, the IESO proceeded with a market rule amendment that came into effect in

[85] See the Panel's December 2005 Monitoring Report, pp. 29-30, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report%20final_131205.pdf.

October 2012 (the "October 2012 Rule Change") and that eliminated constrained-off CMSC payments to market participants importing into a COWZ when their transactions are constrained-off in the final pre-dispatch run. As a result, constrained-off CMSC payments for imports in the NW are only payable where the importer receives a constrained schedule in the final pre-dispatch run, but the import is curtailed by the IESO for reliability reasons.

The October 2012 Rule Change has led to changes in participant behaviour and market outcomes in the NW as discussed below.

3.1.5 *Impact of the October 2012 Rule Change*

In order to examine the effect of the October 2012 Rule Change, the Panel assessed the monthly averages of several metrics both before and after the Rule Change. For the period prior to the October 2012 Rule Change, a two-year period from October 2010 to September 2012 was used. For the post-Rule Change analysis, the most recently available data was utilized, spanning a nine-month period from October 2012 to June 2013.[86]

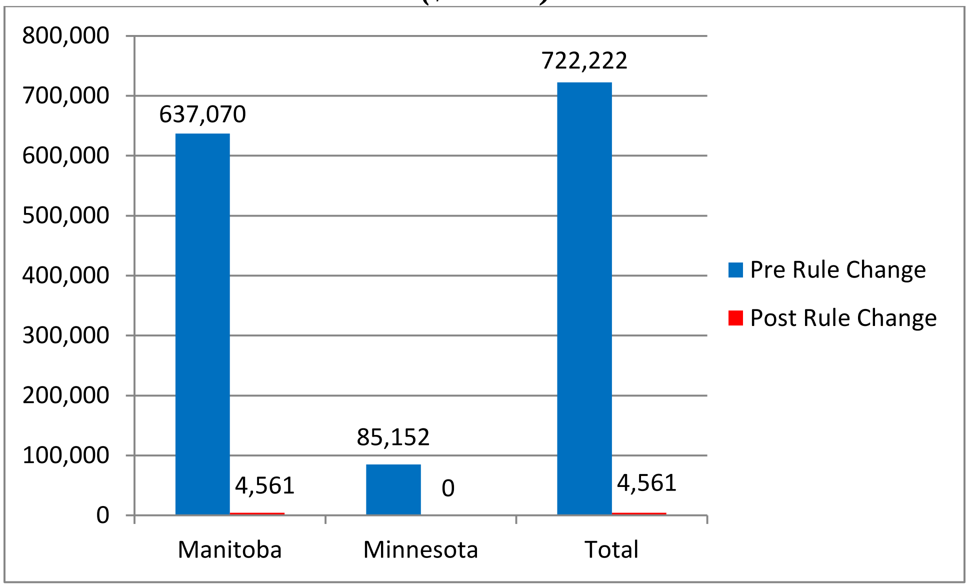
3.1.5.1 Decline in Constrained-off CMSC Payments and Uplift

Prior to the implementation of the October 2012 Rule Change, CMSC comprised a large portion of total payments to importers in the NW.

Figure 3-2 displays the average monthly amount of CMSC payments made to importers in the NW.

[86] The nine-month period that makes up the post-Rule Change period will not reflect all of the seasonal effects captured by the two-year pre-Rule Change period. While this affects the results, the Panel believes that the impact should be minimal.

Figure 3-2: Average Monthly Constrained-off CMSC Payments to Importers Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013) ($/month)



As can be seen, CMSC payments for constrained-off imports have been all but eliminated in the NW. Extrapolated, the data above suggests that CMSC payments of $8.6 million per year have been avoided, representing a corresponding savings to domestic loads and exporters.

3.1.5.2 Market Participant Behaviour

In an area where constrained-off CMSC payments were a major source of funds for importers, the elimination of those payments should affect market participation. Market participation can be measured by the number of participants transacting on the interties, as well as by the quantity of imports being offered by those participants.

Frequency of Participation

Figures 3-3 and 3-4 display the frequency with which multiple participants were offering to import over the Manitoba and Minnesota interties, respectively, in any given hour.

Figure 3-3: Number of Participants Offering to Import on the Manitoba Intertie Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013) (% of total hours)

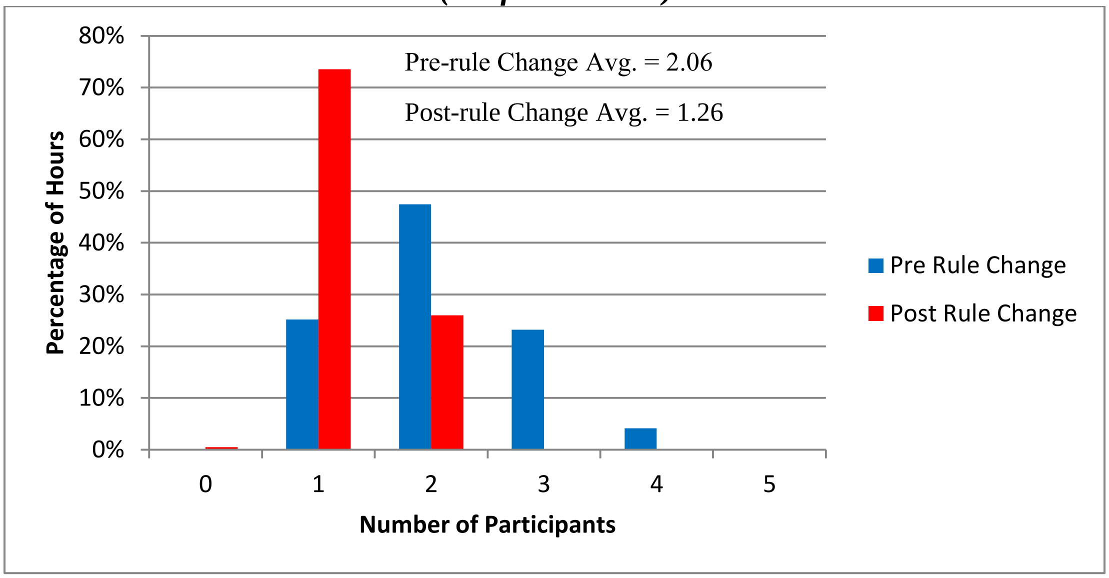
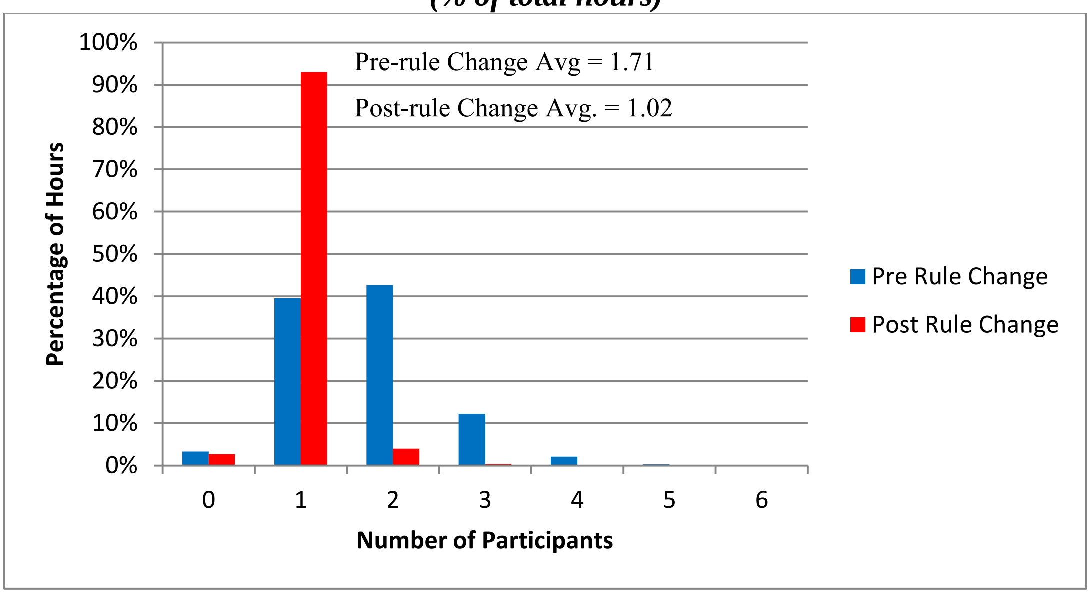


Figure 3-4: Number of Participants Offering to Import on the Minnesota Intertie Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013) (% of total hours)

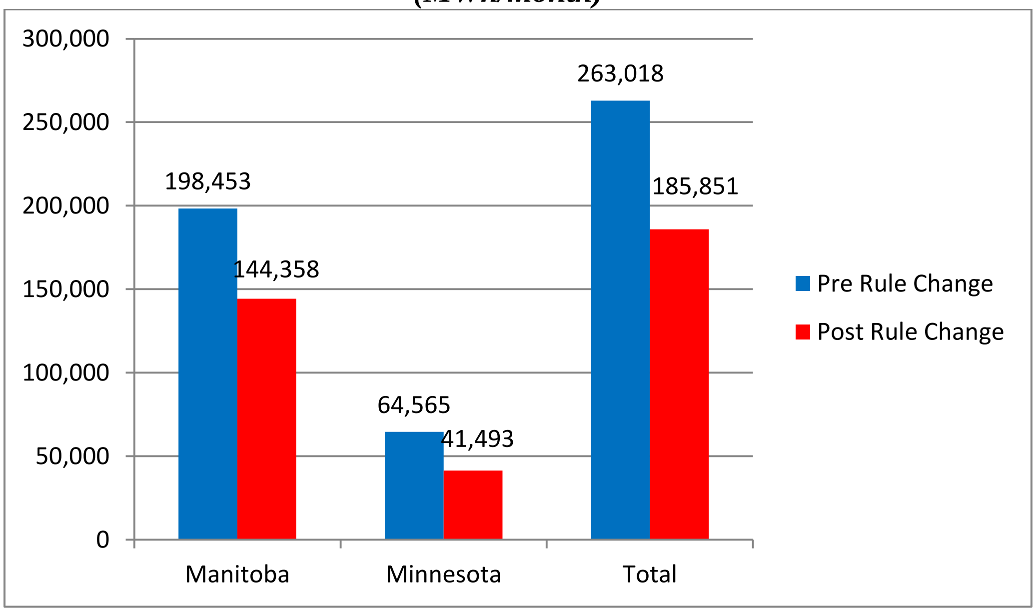


The number of participants offering to import over the Manitoba and Minnesota interties has decreased significantly since the October 2012 Rule Change, suggesting that CMSC payments were the primary driver in the decision of whether or not to offer imports into the NW. Aside from Manitoba Hydro, which continues to participate in nearly every hour, most participants have greatly reduced their frequency of participation. The average number of participants offering to import over the Manitoba intertie dropped from 2.06 participants to 1.26 participants following the Rule Change. Post-Rule Change, only 26% of hours saw multiple participants offering to import over the Manitoba intertie, down from 75% prior to the Rule Change. On the Minnesota intertie, the average number of participants offering to import in a given hour dropped from 1.71 to 1.02. Prior to the October 2012 Rule Change there were multiple participants offering to import in 57% of all hours, while only 4% of all hours saw multiple participants offering to import following the Rule Change.

Import Quantities

Figure 3-5 displays average monthly offer quantities from market participants looking to import into the NW.

Figure 3-5: Average Monthly Import Offer Quantities
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
(MWh/month)



Average monthly import offer quantities have dropped 29% since the October 2012 Rule Change (27% at the Manitoba intertie and 36% at the Minnesota intertie). The average import offer quantity on the Minnesota intertie from market participants other than Manitoba Hydro was 35.2 MW per hour prior to the rule change, and 1.4 MW per hour afterwards. While there are other factors that drive import offer quantities on interties, most notably price differentials, the reductions in import offer quantities appear to be largely attributable to the October 2012 Rule Change.

Tables 3-2 and 3-3 present the percentage of total hours in which the purchase price in the source jurisdiction was less than the sale price in Ontario, including the average profitability spread during these hours.[87]

Table 3-2: Manitoba to Ontario Import Price Spreads
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
(% of total hours & $/MWh)

	Percentage of Hours Import Spread was Positive (%)	Average Spread during Positive Spread Hours ($/MWh)
Pre Rule Change	52.9	11.93
Post Rule Change	57.9	9.73

NOTE: The Manitoba price (i.e. the purchase price) is the MISO Manitoba nodal price, located in Minnesota at the Minnesota-Manitoba border. As there is no wholesale electricity market in Manitoba, most intertie traders must first purchase power in MISO to transmit through Manitoba to Ontario. The Ontario price (i.e. the sale price) is the Manitoba zonal MCP.

Table 3-3: Minnesota to Ontario Import Price Spreads
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
(% of total hours & $/MWh)

	Percentage of Hours Import Spread was Positive (%)	Average Spread during Positive Spread Hours ($/MWh)
Pre Rule Change	52.6	10.72
Post Rule Change	53.5	12.43

NOTE: The Minnesota price (i.e. the purchase price) is the MISO Ontario West nodal price, located at the Minnesota-Ontario border. The Ontario price (i.e. the sale price) is the Minnesota zonal MCP.

For market participants looking to import over the Manitoba intertie, the opportunity to earn a profit on a positive price spread increased from 52.9% of total hours to 57.9%. However, there was a decrease in the average spread during hours with a positive spread from $11.93/MWh to $9.73/MWh. With an increase in profit opportunities but a decrease in average profitability, the effect that prices may have had on offer quantities is unclear. However, the nature of the price differentials is such that they cannot explain the 27% drop in import offer quantities at the Manitoba intertie following the October 2012 Rule Change.

[87] The profitability spread tables do not take into account transaction costs such as transmission reservations, which are assumed to be comparable across the pre- and post-Rule Change periods.

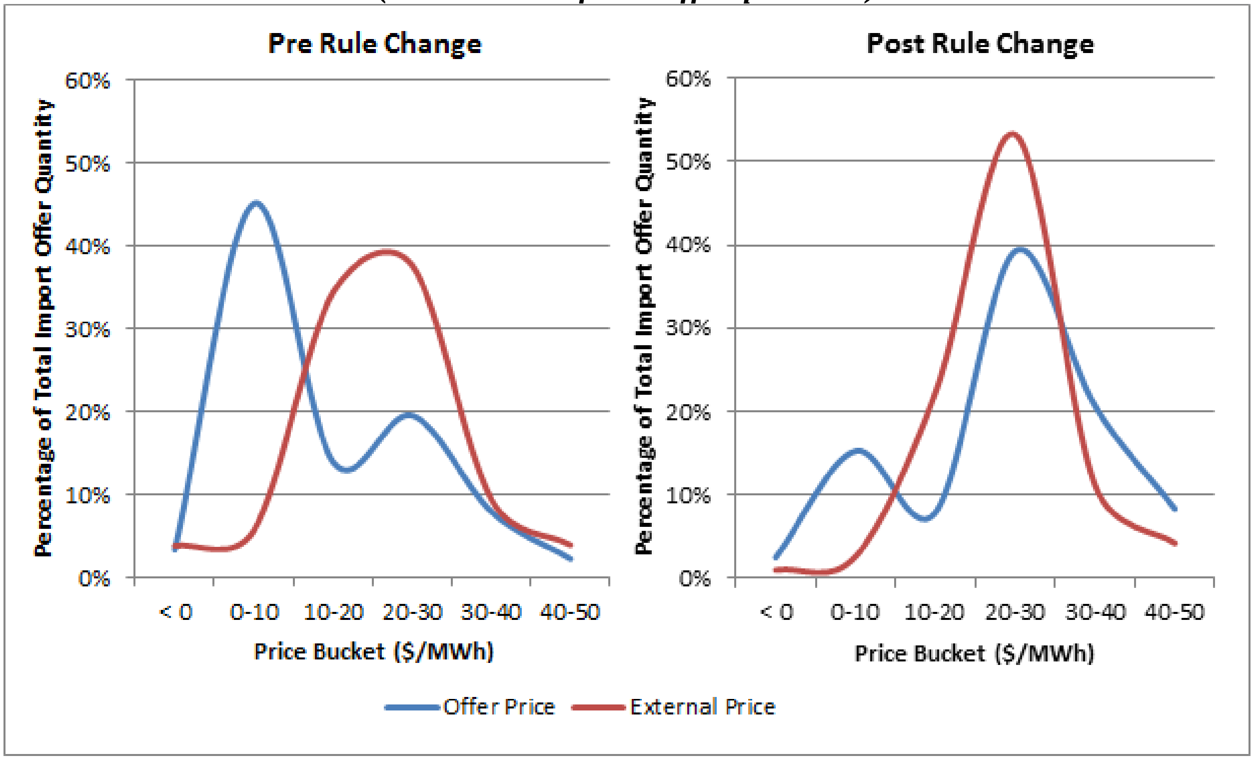
On the Minnesota intertie, both the frequency of positive price spreads and the average spread during those hours increased following the October 2012 Rule Change. Despite the increase in profit opportunities, import offer quantities over the Minnesota intertie dropped 36% following the October 2012 Rule Change.

With reductions in both the frequency of import participation and in import offer quantities in the NW following the October 2012 Rule Change, overall import competition has decreased considerably, especially at the Minnesota intertie. While this may superficially appear to be an undesirable outcome, competition prior to the Rule Change was largely in the form of importers undercutting one another with below-cost offers in order to receive CMSC payments. As discussed further below this competition often led to undesirable market outcomes rather than driving offer prices towards marginal cost (the intended benefit of competition).

Figure 3-6 compares import offer prices over the Manitoba intertie to the corresponding purchase prices in the relevant external zone (the Manitoba node in MISO) in the periods before and after the October 2012 Rule Change. The external price for a given hour is weighted by the import offer quantity during that hour. Accordingly, the external price frequency distribution shows the percentage of total import offer quantities that occurred when the external price was within the price range specified on the x-axis.

In a competitive market, one would expect to see import offer prices that reflect the marginal cost of purchasing and delivering power. In the case of the Manitoba intertie, that cost is typically equal to the cost of purchasing power at the Manitoba node, plus any associated transaction costs (such as transmission reservations). With marginal cost-based offers, the offer price distribution would approximately follow the external price distribution, but be slightly to the right to reflect the addition of transaction costs.

Figure 3-6: Import Offer Price Distribution and External Price Distribution at the Manitoba Intertie
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
($/MWh & % of total offer quantities)

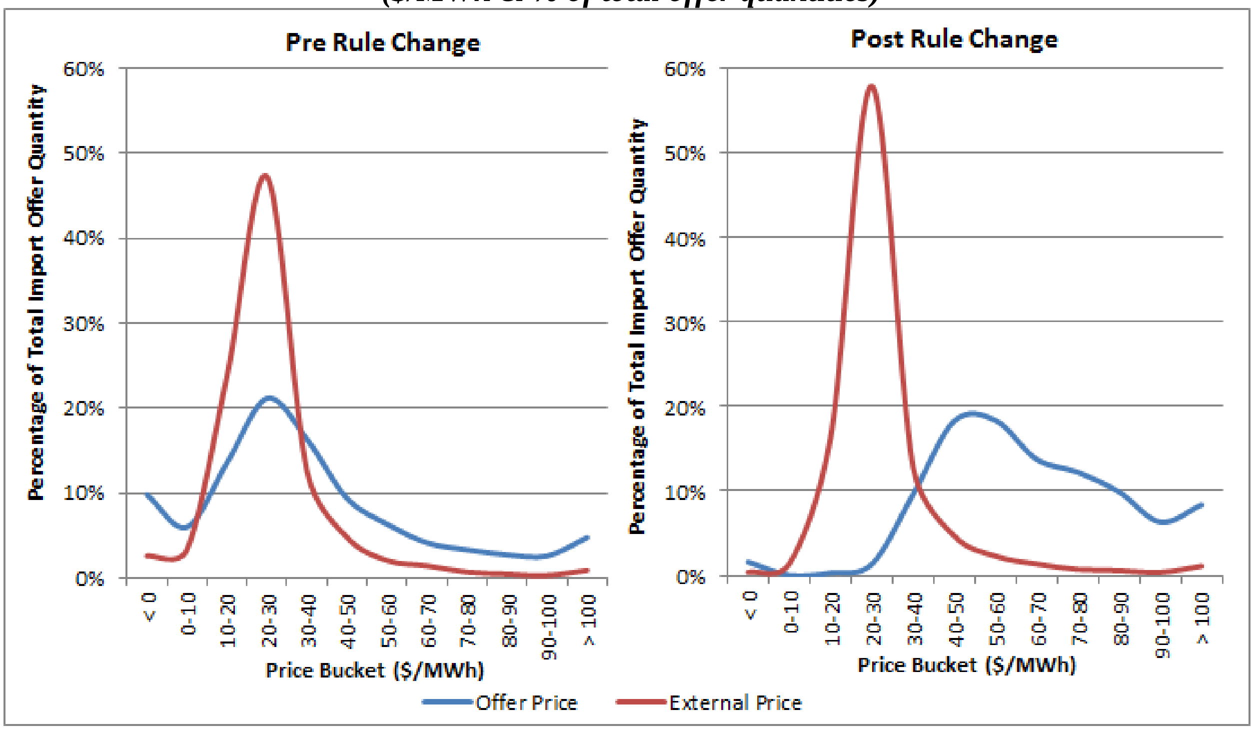


Prior to the October 2012 Rule Change, import offer prices at the Manitoba intertie were frequently less than the external purchase price. As a percentage of total import offer quantities, 48% of import offers were priced at $10/MWh or less; however, only 10% of total import offers were made when there was a prevailing external price of $10/MWh or less. This means that offers into Ontario were frequently priced at less than the external market price, and thus at less than the marginal cost of importing. This is indicative of market participants routinely chasing low nodal prices with below-cost offers, in order to maximize constrained-off CMSC payments.

Since the October 2012 Rule Change, import offers over the Manitoba intertie have more closely reflected the marginal cost of importing (as represented by the external purchase price). Following the Rule Change, 17% of all imports were offered at $10/MWh or below (down from 48%), while offers during hours in which the external prices were below $10/MWh made up 4% of all offers (down from 10%). By eliminating the CMSC payment incentive to chase nodal prices with below-cost offers, market forces have been allowed to drive offer prices towards marginal cost. All else being equal, this should increase market efficiency.

Figure 3-7 compares import offer prices over the Minnesota intertie to the corresponding purchase prices in Minnesota in the periods before and after the October 2012 Rule Change.

Figure 3-7: Import Offer Price Distribution and External Price Distribution at the Minnesota Intertie
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
($/MWh & % of total offer quantities)



Prior to the October 2012 Rule Change, offers priced below $10/MWh accounted for 16% of all offers, while only 6% of total offers occurred during hours with an external price below $10/MWh. The nodal price chasing behaviour that was evident on the Manitoba intertie is less evident here. Nonetheless, following the Rule Change offer prices regularly exceeded the external purchase price. Below-cost offers on the Minnesota intertie have been rare since the Rule Change, and are likely associated with differences between expected external prices at the time that import offers are submitted to Ontario and actual real-time external prices.

In summary, although overall participation on the NW interties decreased, effective competition has nonetheless increased due to the October 2012 Rule Change.

3.1.6 *Related Market Outcomes*

With the elimination of constrained-off CMSC payments to importers in the NW, and the corresponding reduction in import participation that followed, the economics of transacting in the NW, particularly at the interties, has changed.

3.1.6.1 Intertie Congestion

Figures 3-8 and 3-9 display the frequency of congestion on the Manitoba and Minnesota interties, respectively.

Figure 3-8: Congestion on the Manitoba Intertie
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
(% of hours)

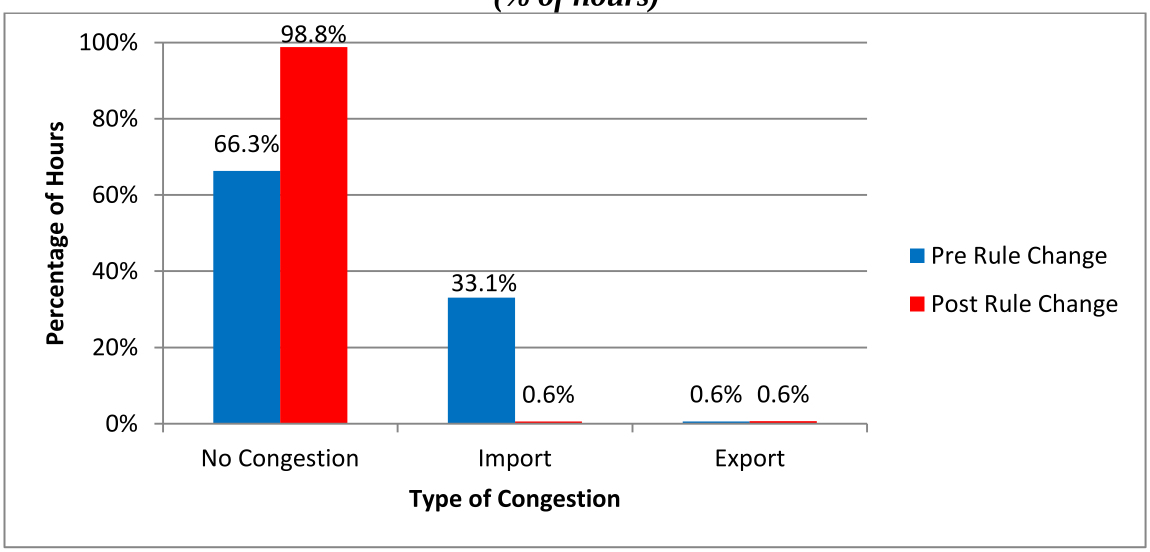
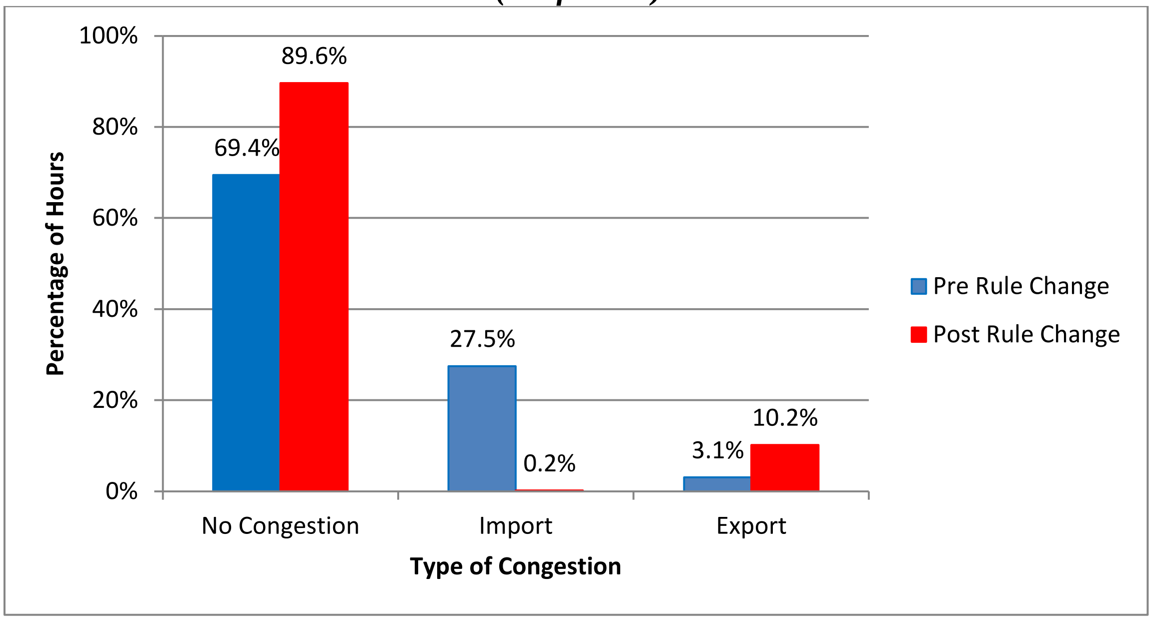


***Figure 3-9: Congestion on the Minnesota Intertie
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
(% of hours)***



Since the October 2012 Rule Change, the frequency of import congestion at the Manitoba intertie has declined dramatically, while export congestion has remained unchanged. The decrease in import congestion is consistent with the reduction in market participation and import offer quantities at the intertie.

Congestion on an intertie is not only a function of offer quantities; it is also a function of intertie transfer capacity. The average hourly import transfer capacity on the Manitoba intertie was 223 MW before the October 2012 Rule Change, and was 216 MW after the Rule Change. All else being equal, this would lead to more congestion. However, the effect of the Rule Change has far outweighed the impact of the 7 MW decrease in transfer capacity.

Import congestion at the Minnesota intertie has been all but eliminated; this is consistent with the reduced import offer quantities at the intertie. The average hourly import transfer capacity was 54 MW before the Rule Change and 56 MW after it. While the 2 MW average transfer capacity increase suggests less congestion (all else being equal), it can only account for a modest portion of the drop in import congestion that has been observed.

The frequency of export congestion at the Minnesota intertie has increased markedly following the October 2012 Rule Change, primarily due to reduced transfer capacity. While the average hourly export transfer capacity at the Minnesota intertie actually increased slightly from 87 MW to 88 MW following the October 2012 Rule Change, some notable transmission constraints did occur and contributed to increased export congestion. In the two years that constitute the pre-Rule Change period, there were four hours in which the intertie export transfer capacity was 15 MW or less (but above 0 MW, at which point the intertie is considered unavailable). In the nine months that constitute the post-Rule Change period, there were 1,515 hours in which the intertie export capacity was 15 MW or less, including 1,182 hours where the limit was 10 MW or less. Of the 1,515 severely constrained hours, the intertie was export congested in 511 of those hours, accounting for 76% of the total export-congested hours on the Minnesota intertie following the Rule Change. Removing these 511 hours from the analysis, export congestion on the Minnesota intertie decreased from 3.1% of all hours prior to the Rule Change to 2.6% following the Rule Change.

That said, the reduction in import offer quantities also contributed to increased export congestion at the Minnesota intertie following the October 2012 Rule Change. Fewer offered imports means fewer imports available to relieve congestion when economic exports exceed the intertie transfer capacity.

Increased export congestion on the Minnesota intertie since the October 2012 Rule Change has led to an average zonal price that exceeds the HOEP. All else being equal, higher zonal prices should incent market participants to once again import into the NW. However, if participants believe that they will be constrained off but will receive no compensation of any kind, they may continue to refrain from importing into the NW, in which case the increased frequency of export congestion would likely persist.[88]

[88] Despite a reduction in offered import quantities, the Manitoba intertie did not experience the same increase in export congestion as did the Minnesota intertie. Historically there have been limited export transactions over the Manitoba intertie, likely due to the lack of a market-based sale opportunity in Manitoba. While offered import quantities decreased, offered export quantities remained low, leading to continued infrequent export congestion.

3.1.6.2 Other Constrained Transactions

Imports were routinely constrained off in the NW because of low nodal prices resulting from the bottling of inexpensive supply in the region. In situations where importers were chasing the nodal price, but offered too low and were therefore economic in the constrained schedule (i.e., they were not constrained off), a local generator would need to be constrained off, or a load or export constrained on, to accommodate the import transaction. Had that import offer never entered the market, or been offered at marginal cost, there may have been no need to constrain an additional transaction and pay CMSC payments for it, and the cost of managing the energy surplus would have been reduced.

Figures 3-10 and 3-11 display the average monthly scheduled quantities (unconstrained and constrained) of imports and exports on the Manitoba and Minnesota interties, respectively, both prior to and following the October 2012 Rule Change.

Figure 3-10: Average Monthly Scheduled Quantities at the Manitoba Intertie Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013) (MWh)

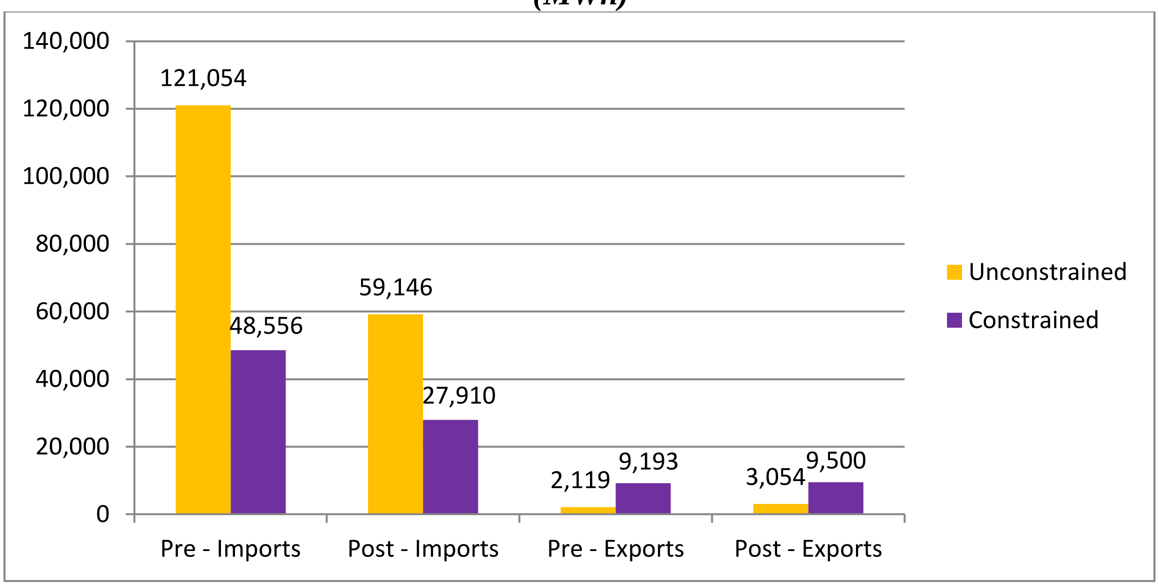
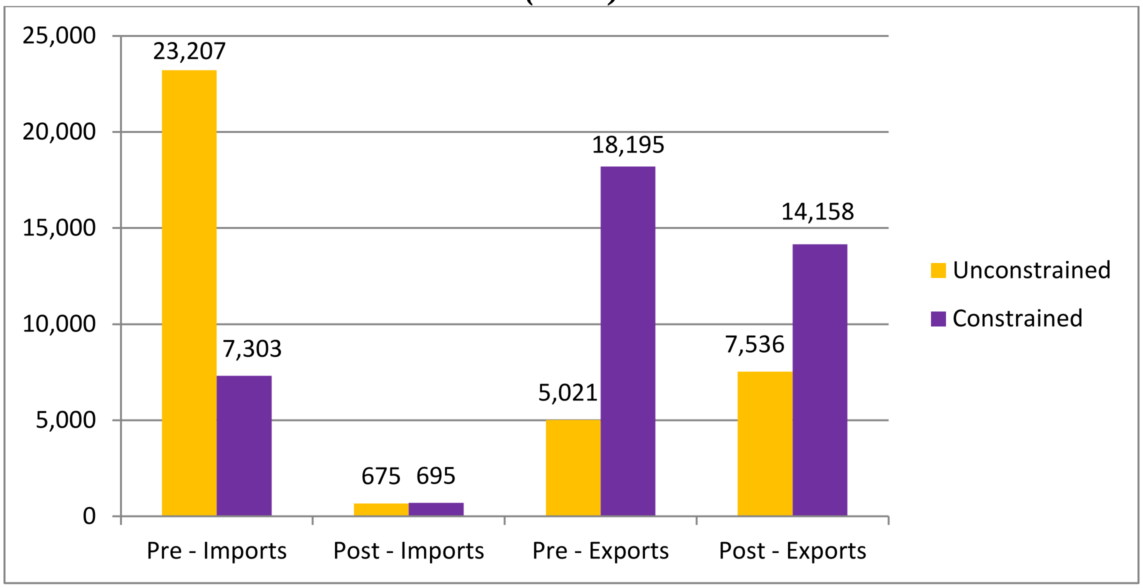


Figure 3-11: Average Monthly Scheduled Quantities at the Minnesota Intertie
Pre Rule Change (October 2010 to September 2012) and Post Rule Change (October 2012 to June 2013)
(MWh)



On the Manitoba intertie, imports have been constrained off less, while exports have been constrained on less, since the October 2012 Rule Change. Of the imports scheduled in the unconstrained sequence, 60% of total import quantities were constrained off prior to the Rule Change, while only 53% were following the Rule Change. Prior to the Rule Change, exports in the constrained schedule outpaced those in the unconstrained schedule at a rate of 4.3 to 1, while the ratio decreased to 3.1 to 1 following the Rule Change, indicating fewer constrained-on exports both in relative and absolute terms.

The same is true of the Minnesota intertie, where imports have also been constrained off less and exports have been constrained on less. Of the imports scheduled in the unconstrained sequence, 69% of total import quantities were constrained off prior to the Rule Change, but following the Rule Change imports were constrained on more than they were constrained off in terms of total quantity. Prior to the Rule Change, exports in the constrained schedule outpaced those in the unconstrained schedule at a rate of 3.6 to 1; following the Rule Change the ratio decreased to 1.9 to 1.

With fewer imports being scheduled in the constrained schedule, both by absolute volume and as a proportion of the unconstrained schedule, the need to constrain on exports has been reduced at both the Manitoba and Minnesota interties. All else being equal, the reduction in import offers into the NW should reduce CMSC payments to other resources in the area, again reducing uplift for domestic loads and exporters.

3.1.6.3 Transmission Rights Market

Market participants who own transmission rights (TRs) get paid the equivalent of the intertie congestion price (ICP) every time congestion occurs in the direction (import or export) covered by the TRs (for example, Manitoba import TRs get paid when there is import congestion on the Manitoba intertie). Accordingly, the conceptual value of a TR is equal to the expected sum of the ICPs over the period covered by the TR.[89] As seen in Figures 3-8 and 3-9 above, the frequency of import congestion on both the Manitoba and Minnesota interties has declined significantly since the October 2012 Rule Change. That market participants have adjusted their expectations of future congestion is reflected in the value that they assign to import TRs for the NW; as shown in Tables 1-37 (long-term TRs) and 1-38 (short-term TRs) in Chapter 1, auction prices for import TRs over both NW interties have decreased significantly following the Rule Change. The effect of the Rule Change on export TR auction prices is less clear.

3.1.6.4 The Marketing Clearing Price

The market clearing price (MCP) is calculated every five minutes and is theoretically intended to reflect the marginal cost of supplying the next megawatt of non-dispatchable demand. The MCP is calculated in the unconstrained schedule, which ignores most grid constraints and some operational limitations on scheduling resources based on economic merit. While not included in the constrained schedule, offers associated with constrained-off imports are included in the unconstrained schedule and used to establish the MCP. Specifically, these import offers represent incremental supply in the unconstrained schedule, and therefore put downward pressure on the MCP.

With the elimination of constrained-off CMSC payments to importers in the NW, and the subsequent reduction in import offer quantities and scheduled imports, there is less supply available in the unconstrained schedule. All else being equal, less supply will lead to higher

[89] The duration of a TR is either short-term, which covers one month, or long-term, which covers one year.

market prices. While higher market prices are neither “good” nor “bad”, a market price that is more reflective of the marginal cost of supplying the next megawatt is a desirable outcome. A constrained-off import is not physically capable of delivering the next megawatt of supply due to the physical transmission limitations in the area of the intertie. By including constrained-off imports in the unconstrained schedule and, consequently, in the determination of the MCP, supply which cannot physically deliver power (referred to as “phantom supply”) is nonetheless relevant in establishing the marginal cost of delivering the next megawatt of electricity.

Prior to the October 2012 Rule Change, 61% of all imports into the NW were constrained off, adding a significant amount of phantom supply to the unconstrained schedule. This had the effect of depressing the MCP relative to the actual cost of supplying the next megawatt of non-dispatchable demand, which would ultimately be supplied by constraining on a more expensive generator, or constraining off a more expensive load or export. Following the Rule Change, the quantity of phantom supply from imports in the NW has decreased, both in absolute and relative terms. The decrease in phantom supply has served to increase market prices, but has led to a MCP that is more reflective of the marginal cost of supply, a good market outcome.

The elimination of constrained-off CMSC payments has removed the incentive to chase nodal prices. Formerly, importers would chase the nodal price with below-cost offers, which inefficiently supressed the MCP. Importers now compete to deliver energy, not to get constrained off. As seen in Figures 3-6 and 3-7 above, this more desirable form of competition has driven import offers towards marginal cost. That, in turn, improves the quality of the MCP as an indicator of the marginal cost of supply, a good market outcome.

3.2 The Enhanced Day-Ahead Commitment Process and Generation Cost Guarantees

3.2.1 *Introduction*

Operating an electricity system reliably requires that sufficient generation capacity be available to meet demand at all times. System operators must have resources online and available to deal with changing demand and supply conditions. In the IESO-administered market, generators are paid the market price for the electricity that they inject into the grid.[90] When market prices are high, generators should be willing to produce. However, many generators incur significant costs to start up their facilities and, for equipment reasons, they must ramp to a minimum level of output (referred to as the "minimum loading point" or MLP) and remain online for a minimum period of time (referred to as the "minimum generation block run time" or MGBRT) before their units can be shut down. These generators face the risk that market prices might fall during the course of their minimum run, resulting in insufficient revenue to cover their start-up costs. To ensure that generators are willing to start up when needed, the IESO has developed cost guarantee programs for fossil-fueled non-quick start generators that minimizes their risk of exposure to such market price changes. Non-quick start generators are generation facilities that do not meet the IESO's definition of "quick start facilities" (these being facilities that are able to provide energy to the grid within 5 minutes of the IESO's request).

The IESO currently has two cost guarantee programs available for eligible non-quick start generation facilities: the real-time generation cost guarantee program (RT-GCG), which was introduced in 2003; and the generation cost guarantee program under the enhanced day-ahead commitment process (EDAC), which was introduced in 2011 and replaced the day-ahead generation cost guarantee program (DA-GCG) available under an earlier iteration of the day-ahead commitment process (DACP). The following are key features of each of these generation cost guarantee programs, which are also summarized in Table 3-4:

a. The RT-GCG[91] is a voluntary program that was introduced in 2003 and that remains in effect today. The guarantee covers start-up costs as well as costs over the generation facility's "minimum run-time", defined as the number of hours required for the generation facility to ramp from a cold start to its MLP and to complete its MGBRT. The generator will receive a payment under the program to the extent that the market revenues earned for output up to the facility's MLP to

[90] Most generators in the Province operate (and are compensated under) long-term contracts with the Ontario Power Authority or have the payment amounts for their output set by the Ontario Energy Board. Given the nature of the analysis conducted by the Panel, these arrangements have been ignored.
[91] See Market Manual 5.5, s. 1.6.4, "The Real-Time Generation Cost Guarantees" at http://www.ieso.ca/imoweb/pubs/settlements/se_RTEStatements.pdf. This program is sometimes referred to as the "Spare Generation On-line" program (SGOL). Rules relating to the RT-GCG program are set out in sections 2.2B, 5.7 and 6.3A of Chapter 7 of the market rules and in section 4.7B of Chapter 9 of the market rules.

the end of its MGBRT are less than the generator's submitted costs. One of the key features of the program is that the IESO schedules eligible generators under the RT-GCG without knowing the amount of their start-up costs; those costs are submitted to the IESO up to 16 business days after the end of a guaranteed run.

b. In 2006, the IESO introduced DACP, which included the DA-GCG program. Under the DA-GCG program, eligible generators would be scheduled day-ahead based on their energy offers for the next day. The DA-GCG program shared many of the features of the RT-GCG program, including after-the-fact submissions of start-up costs. The DA-GCG program was discontinued in October 2011 when it was replaced by EDAC.

c. The IESO introduced EDAC in October 2011.[92] Unlike the RT-GCG program, EDAC does not allow for after-the-fact cost submissions; the IESO uses three-part offers (start-up, speed-no-load, and incremental energy costs) submitted day-ahead by market participants to optimize the energy and operating reserve markets for the next 24-hour dispatch day. The guarantee under EDAC covers costs for the generator's full day-ahead schedule (as opposed to the DA-GCG and the RT-GCG programs, where costs were/are guaranteed only up to the generation facility's MLP and for the duration of its MGBRT). The generator will receive a payment under the EDAC program to the extent that the market revenues earned from production are less than the generator's offered costs over its day-ahead guaranteed schedule. Participation in EDAC is mandatory, although as discussed below generators can avoid getting a day-ahead commitment by submitting uneconomic day-ahead offers.

One of the anticipated outcomes from the introduction of EDAC was a reduction in the overall costs of committing non-quick start generators. According to the IESO, there are two features

[92] See Market Manual 9, "Day-Ahead Commitment Process" at http://www.ieso.ca/imoweb/pubs/dacp/MM9-dacp-manual.pdf. Rules relating to the EDAC generation cost guarantee program are set out in sections 2.2C, 5.8 and 6.3B of Chapter 7 of the market rules and in section 4.7D of Chapter 9 of the market rules. Under the market rules, the guarantee under EDAC is referred to as a "production cost guarantee".

of EDAC that were expected to lead to that result.[93] First, 24-hour optimization and the ability to schedule generators up to their maximum capacity (as opposed to MLP under the DA-GCG) suggested that fewer units should need to be committed under a generation cost guarantee program to meet a given level of demand. Since starting up a generator can be costly, fewer commitments (and, hence, fewer start-ups and fewer costs) should yield lower overall costs. Second, the IESO anticipated that generators could negotiate more favourable gas or other fuel rates when they have a day-ahead guarantee that extends over their full schedule. Competitive forces would cause these lower fuel prices to be reflected in lower offer prices, which in turn would lower the costs of committing these units.

The Panel undertook an analysis of the IESO's generation cost guarantee programs, with a view to ascertaining the extent to which anticipated cost savings have materialized with the introduction of EDAC. That analysis, described in section 3.2.3, reveals that the overall cost of committing gas-fired units (expressed as $ per MWh of guaranteed output), after adjusting for inflation and changes in fuel prices, has increased by 3.5% following the replacement of the DA-GCG program with EDAC.

In section 3.2.4, the Panel considers some of the reasons why the inflation-adjusted commitment costs have not declined with the introduction of EDAC. While the Panel believes that EDAC is an improvement over the original day-ahead commitment process, the continued operation of the RT-GCG program in its present form and in parallel with EDAC weakens the incentive for generators to make competitive offers for a guaranteed schedule in EDAC. A generator that is not cost-competitive in EDAC can still receive a guarantee under the RT-GCG program, which has a lower hurdle for obtaining a guaranteed schedule (because start-up costs are submitted after the fact, and are therefore not considered by the IESO at the time a commitment is made) and which also has a guarantee that sometimes may be more attractive than an EDAC guarantee. In addition, the fact that very few exports participate in EDAC creates opportunities for generators without a day-ahead commitment to receive a guarantee under the RT-GCG program.

[93] See the IESO's report titled "Day-ahead Market Evolution Preliminary Assessment" available at: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080505_DAM_Assessment_Report.pdf

3.2.2 *EDAC Compared to Other Guarantee Programs*

Table 3-4 summarizes the key features of the RT-GCG, DA-GCG and EDAC programs.

Table 3-4: Generation Cost Guarantee Programs

	Real-Time RT-GCG	**Day-Ahead DA-GCG**	**Day-Ahead EDAC**
Effective Dates	2003 to **Present** (Last modified in 2009)	2009 to October 2011 (Replaced with EDAC)	October 2011 to **Present**
Eligible Generators	Non-quick start resources can receive guarantee payments	Same as RT-GCG	All generation resources must participate in EDAC, but only non-quick start resources can receive guarantee payments
Participation	Voluntary	Same as RT-GCG	Mandatory
Scheduling Requirements for Obtaining a Guarantee	Scheduled in pre-dispatch to at least MLP for half of the generator's MGBRT hours	Scheduled day-ahead to at least MLP for the generator's full MGBRT	Same as DA-GCG
Generator's Costs Covered by the Guarantee	Start-up costs and incremental energy costs for MLP for the duration of MGBRT	Same as RT-GCG	Start-up costs, speed-no-load costs and incremental energy costs for the full day-ahead schedule (which may be above MLP and extend beyond MGBRT)
Cost Submissions Relative to the Granting of the Guarantee	Incremental energy costs submitted before the guarantee is granted, start-up costs submitted after	Same as RT-GCG	All costs submitted before the guarantee is granted
Revenue Used to Offset Generator's Costs Covered by the Guarantee	Revenues for MLP for the duration of start-up and MGBRT (minimum run-time)	Same as RT-GCG	Revenues for the full day-ahead schedule (which may be above MLP and extend beyond MGBRT)

EDAC was intended to address the shortcomings of the DA-GCG program. One of the changes introduced with EDAC was to make participation mandatory. All generators are required to submit three-part day-ahead offers. Under the DA-GCG program, if a generator's offer was economic and it received a commitment for the next day, it could reject the commitment in favour of either participating in the RT-GCG program or operating in real-time without a guarantee. EDAC removed that possibility; a generator that receives a commitment in EDAC is held to that level of production and cannot decline the commitment.[94]

Intuitively, making participation in EDAC mandatory should increase the level of commitments made under EDAC, and that has been the case. Table 3.5 shows the total level of commitments made under the day-ahead (DA-GCG or EDAC, as applicable) and RT-GCG programs for both natural gas- and coal-fired generators in the year before and the year after the introduction of EDAC. The level of commitments made day-ahead increased from 5.7 TWh in the year before EDAC was introduced to 8.3 TWh in the year after introduction. The total in each year is a fraction of the total market demand, as generators that are not eligible to participate in the generation cost guarantee programs also produce electricity to meet total demand.

Table 3-5: Committed Generation under the Day-Ahead and Real-Time Programs Before and After Introduction of EDAC (TWh)

Timeframe	Generation due to Day-Ahead Commitments	Generation due to Real-Time Commitments	Total Commitments
Pre-EDAC (Oct 13, 2010- Oct 12, 2011)	5.7	9.9	15.6
Post-EDAC (Oct 13, 2011 – Oct 12, 2012)	8.3	8.3	16.7

Although commitments made day-ahead increased substantially, this was not matched by a comparable decrease in commitments made under the RT-GCG program. One of the reasons that commitments under the RT-GCG program continue to be substantial appears to be that exporters have not fully participated in EDAC.

Importers have an incentive to participate in EDAC and to submit day-ahead offers – the IESO guarantees part of the revenue they will earn the next day through an intertie offer guarantee. Exporters, however, have no such incentive, and can in some cases be forced to pay a withdrawal

[94] More specifically, if a generator does not produce energy that was guaranteed day-ahead (and if it is dispatched to its full schedule in real-time), it is subject to a failure charge.

charge if they are scheduled day-ahead and fail to honour their commitments. Thus, very few exporters have participated in EDAC. The end result is that the IESO commits day-ahead generation and imports to meet a forecasted level of demand that excludes most exports. When additional exports appear the next day in real-time, those generators that were not scheduled day-ahead will often be committed under the RT-GCG program to produce energy to satisfy export demand.

Another major change introduced by EDAC is that all costs, including start-up costs, are submitted day-ahead and are therefore considered by the IESO when it decides which generators should be committed for the next day. Under the DA-GCG program (and the same remains true under the RT-GCG program), start-up costs were submitted after-the-fact and where therefore not considered by the IESO when deciding which generators should be scheduled. As a result, dispatch decisions were made based only on offered incremental energy costs, creating the potential for uneconomic dispatch. Specifically, the IESO could instruct a generator to start up – and to incur start-up costs that would be guaranteed by the IESO – because its offer price was the next cheapest offer in the supply stack even though it might be more economic to ask another, seemingly more expensive, generator that was already online to increase its output.

A further key difference between EDAC and the DA-GCG program is the costs that are subject to a guarantee and the market revenues that are used to offset those costs in calculating the amount of the guarantee payment. Under the DA-GCG program, only costs related to production up to a generation facility's MLP (and only to the end of its MGBRT) were subject to a guarantee, and the offsetting revenues were limited to the same production. None of the revenues earned by the generator as a result of operating at a level above its MLP (and/or beyond its MGBRT) during a guaranteed run were considered by the IESO in determining the amount of any guarantee payment. The RT-GCG program is the same. Under EDAC, however, the IESO can schedule, and guarantee the costs of, generators up to their maximum offered output, and all of the market revenues earned by a generator during a run guaranteed under EDAC are counted by the IESO when it determines whether a guarantee payment needs to be made to the generator (and, if so, the amount of that payment).

3.2.3 *Analysis of Costs under the Generation Guarantee Programs*

This section describes the analysis that was conducted by the Market Assessment Unit (MAU) to compare unit commitment costs in the year before and the year after the introduction of EDAC. The analysis is limited to gas-fired generators that participated in the IESO's guarantee programs.[95] Further detail about the study is presented in Appendix 3-A.

3.2.3.1 Calculation of Average Offered Costs

To calculate the average cost for production over each run guaranteed under the RT-GCG and DA-GCG programs, each generator's offered incremental energy cost was multiplied by its injections into the grid. This represents the amount required by the generator to cover the cost of fuel for energy production. Start-up fuel costs and the start-up operation, maintenance, and administration (OM&A) costs, both of which are submitted after-the-fact, were also included as they are covered by the RT-GCG and DA-GCG programs.

To eliminate the impact of changes in the prices of natural gas and other inputs over the two-year period, the generators' offers were normalized for changes in gas prices at the Dawn Hub, and OM&A costs were adjusted for changes in the Canadian GDP Implicit Price Index (a broad measure of inflation). Because the level of demand was very similar from one period to the next, no adjustment was made for changes in demand when calculating the average.[96]

A generator may choose not to submit start-up costs after-the-fact when it has earned enough revenue in the market to cover its start-up costs, because submitting these costs under the RT-GCG program (or the DA-GCG program) will not provide any additional payments. When start-up costs were not submitted by a generator after a RT-GCG or DA-GCG run, it was assumed that the start-up cost incurred by the generator would have been equal to the average submitted start-

[95] Although all generation resources must submit offers under EDAC, only some generation facilities are eligible for the guarantee programs. Eligible generators include more than just gas-fired generation facilities. However, comparing the average costs in each period for other eligible generators is misleading given a change in offer behaviour by some of these other resources as well as the impact of Automatic Generation Control contracts. This issue is discussed further in Appendix 3-B.
[96] Data on the level of demand in each period, as well as the level of wind production and net exports, is presented in Appendix 3-C.

up cost for other runs. That amount was included in the total costs for the run to ensure that all costs were included in the calculation.[97]

To calculate the average cost for production during a run guaranteed under EDAC, the offered incremental energy cost (multiplied by each generator's energy injections over the run), the speed no-load cost, and the start-up costs were used. As noted above, under EDAC these three costs are offered in advance as part of the generator's day-ahead offer; there are no after-the-fact cost submissions under EDAC. The three costs were adjusted for inflation and changes in fuel costs, in the same way as for costs under the RT-GCG and DA-GCG programs. An additional cost component included in the EDAC analysis is linked to unused energy (energy that, while scheduled in EDAC, is not needed in real-time; that energy is covered by the guarantee provided that the generator lowers its day-ahead offer moving in to real-time).[98]

The calculated average represents the as-offered cost per MWh that generators sought for their output. The average offered cost represents the revenue required by the generator to cover its costs as those costs were submitted to the IESO (those submitted costs may or may not reflect the generator's actual costs). A generator may cover its offered costs through market revenue (when it operates profitably) or a combination of market revenue and guarantee payments.

3.2.3.2 Changes in Average Offered Cost

Table 3.6 shows the average offered cost for gas-fired generation units pre- and post-EDAC. The average offered cost for these gas-fired units in the year after EDAC was introduced, after accounting for changes in fuel costs and inflation, increased by 3.5% compared to the average offered cost in the prior year.

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[97] Various checks were completed to ensure that the absence of an after-the-fact start-up cost submission was in fact due to the generator's run being profitable, and not for other reasons (such as, for example, because the generator tripped offline briefly but returned to complete an earlier run). These checks and other assumptions are listed in detail in Appendix 3-A.

[98] If a generator produces less output than was committed day-ahead, and it also lowers its day-ahead offer (to increase its chance of being dispatched to its full day-ahead schedule), the IESO will pay that generator for the difference between its day-ahead offer and its revised offer for the unused energy—energy that was guaranteed in advance but was not needed during real-time operations. This payment gives generators committed day-ahead an incentive to lower their offers, which increases the likelihood that the IESO will dispatch them to their full day-ahead schedule. While this payment may offset any costs incurred from storing or rescheduling gas that a generator has procured in anticipation of production, it represents a portion of guaranteed costs, not offered costs. Note that any payouts imply that even though the generator had lowered its offer, the output that was committed the day before is uneconomic (perhaps due to an unanticipated reduction in demand, or an increase in low cost supply). Failing to include this payment in the calculations would mean omitting a portion of the costs that are guaranteed by the IESO. This would underestimate the total costs of committing generation day-ahead and lower the average cost of commitment. These payments were not adjusted for inflation.

Table 3-6: Average Offered Cost for Gas-fired Generation under Day-Ahead and Real-Time Cost Guarantee Programs
($/MWh)

Timeframe	Average Offered Cost
Pre-EDAC (Oct 13, 2010-Oct 12, 2011)	$35.45
Post-EDAC (Oct 13, 2011-Oct 12 2012)	$36.69

The average offered cost in the post-EDAC time frame in Table 3.6 represents the average offered cost under both the RT-GCG and EDAC guarantee programs. The average offered costs under each program post-EDAC are shown separately in Table 3.7. This table shows that the EDAC average offered cost is slightly lower than the RT-GCG average offered cost post-EDAC; however, both of these costs are above the pre-EDAC average offered cost of $35.45.[99]

Table 3-7: Average Offered Cost for Gas-fired Generation under Day-Ahead and Real-Time Cost Guarantee Programs
(adjusted for changes in fuel cost and inflation)
($/MWh)

Time Frame	Program	Average Offered Cost
Post-EDAC (Oct 13, 2011- Oct 12 2012)	EDAC	$35.89
	RT-GCG	$37.22

The changes introduced through EDAC should put downward pressure on the average cost of output committed under the program. Because more energy has been subject to a day-ahead commitment since the introduction of EDAC, a higher average cost for commitments post-

[99] Because of the similar nature of the DA-GCG and RT-GCG programs pre-EDAC, the average offered cost under each of the programs pre-EDAC is not presented separately.

EDAC does not necessarily mean that EDAC has not been scheduling resources more efficiently. Higher commitments made day-ahead have two effects: committing more energy from each generator will tend to reduce the average cost (economies of scale effect), but committing more energy may also require committing higher cost resources (upward sloping supply curve effect).

If the upward sloping supply curve effect outweighs the economies of scale effect, then the commitment of higher cost resources would raise the average cost for energy committed under EDAC. To determine whether this is the case, we turn to the average cost from individual generators.

3.2.3.3 Average Offered Costs of Individual Generators

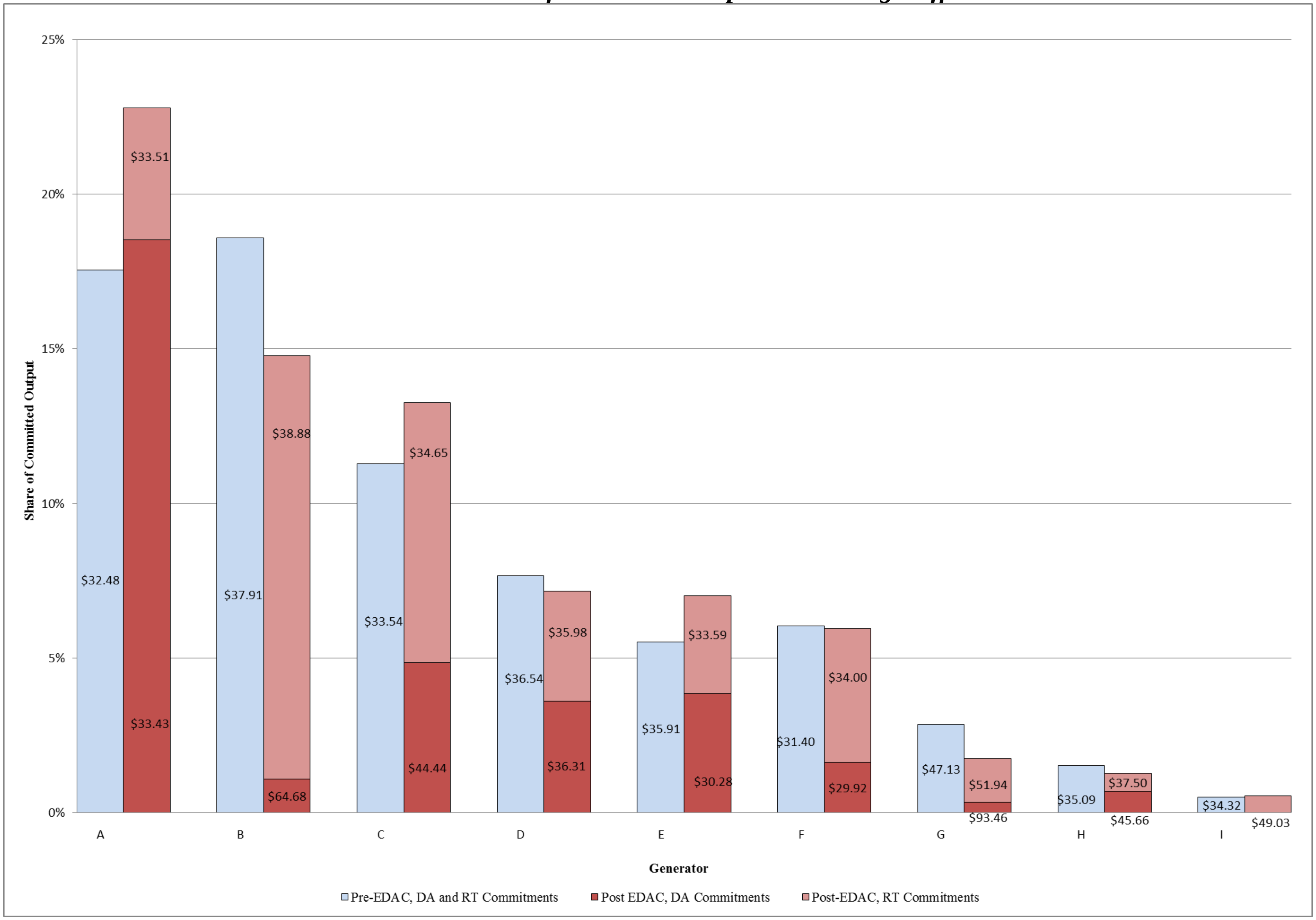
Figure 3.12 shows each eligible gas-fired generator's share of commitments under the RT-GCG and the day-ahead programs (DA-GCG or EDAC, as applicable) pre- and post-EDAC. The average cost information for both programs (RT-GCG and DA-GCG) pre-EDAC is combined in the graph because the differences between the two guarantee programs prior to EDAC were not significant. The share of commitments represents each generator's share of the total output produced by eligible generators through a commitment under each program (the shares do not sum to 100% as the graph presents the offered costs of gas-fired generators only, not all eligible generators). The average offered cost was calculated for each generator in the manner described in section 3.2.3.1 above, and is included in the graph as the number overlaying each bar (as above, the costs include both energy costs and start-up costs to in order to capture the full cost of production, which is then divided by each generator's output).

Figure 3.12 shows that each generator's average offered costs differed under the different programs, for some generators quite significantly. In particular:

- Generator A has offered costs that are roughly similar in both the pre- and post-EDAC time frames, and has produced a larger share of committed output post-EDAC.
- Generators B and C have higher average offered costs in the day-ahead portion of their commitments post-EDAC, while their average costs under the RT-GCG post-EDAC are closer to their average offered costs pre-EDAC. Generator B in particular has received few commitments under EDAC. Generators G and H, though smaller units, show a trend

similar to Generators B and C, offering a higher average cost for the day-ahead portion of their commitments compared to their RT-GCG offered cost post-EDAC and their average offered cost post-EDAC. These generators have also received few day-ahead commitments post-EDAC.

Figure 3-12: Individual Gas-Fired Generator Shares of Committed Output and Average Offered Cost Pre-EDAC and Post-EDAC



The fact that some generators have such different average offered costs as between the two post-EDAC programs, and also as compared to their pre-EDAC average offered costs, suggests that generators are making different offers under each program. If a generator fails to get a committed schedule in EDAC, it will likely have a second opportunity to get a guaranteed run under the RT-GCG program. For this reason, some generators may choose to offer at a premium in EDAC. If they receive a commitment it will be at a favourable rate, and if they do not receive a commitment they have a second opportunity to get a commitment under the RT-GCG program.

To the extent that generators are pursuing this strategy, there are adverse consequences for the cost of commitments. The IESO will be forced to choose from among a set of higher cost offers, while at the same time generators that are not committed day-ahead can lower their offers in real-time, receive a guarantee and recover their incremental energy and start-up costs. This is compounded by two important factors:

- The RT-GCG program can give generators more generous guarantee payments compared to commitments made under EDAC. This is because the RT-GCG program counts less of a generator’s revenues during a run against its guaranteed costs (incremental energy and start-up) when determining the amount of any guarantee payment. As discussed below, this effect can be heightened for plants with both combustion and steam turbine units, although the heightened effect is likely not material.

- Generators are committed under the RT-GCG program based on their incremental energy offers only, as start-up costs are submitted after-the-fact (but are still covered by the guarantee). This puts less pressure on generators to submit competitive start-up costs under the RT-GCG program than under EDAC.

As noted earlier, higher average offered costs in EDAC could be the result of the higher level of day-ahead commitments made post-EDAC. However, the above observations regarding individual generators’ offered costs casts doubt on the validity of that assumption. If it were true that the additional resources committed day-ahead are those with higher costs (an upward sloping supply-curve), we would not expect to see these same resources offering a lower average cost under the RT-GCG program.

If generators offered in the same way under both programs, one would expect EDAC to schedule the lowest cost resources first and move up the supply curve to meet the forecast level of demand. Although EDAC can optimize costs by scheduling units over longer intervals, taking into account the full costs of commitments, the optimization occurs over a different set of offered costs than are subsequently offered in real-time. Because some generators have a higher average offered cost under EDAC than under the RT-GCG program (see Figure 3-12), the cost of commitments under EDAC will be higher than they would be if those generators offered the same (lower) costs under EDAC as they have under the RT-GCG program. This is not caused by anything specific to EDAC itself, but rather is a result of differences between the EDAC and RT-GCG programs. Because of these differences, it is unlikely that EDAC has exhausted the potential benefits that could be achieved from improved scheduling efficiency day-ahead.

3.2.4 *Guarantee Payments under the RT-GCG Program*

As noted above, some generators may prefer the RT-GCG program over EDAC. For example, Figure 3-12 shows that Generator I produced no output under a day-ahead commitment post-EDAC. One reason for such a preference may be that guarantee payments under the RT-GCG program can be more generous because less of a generator's market revenues over the guaranteed run are counted against the guaranteed costs (incremental energy and start-up) under the RT-GCG program than is the case under EDAC. Differences in the way in which some combined cycle facilities are settled under the EDAC and RT-GCG programs can also contribute to more generous payments under the RT-GCG program (but see below regarding the likely immaterial nature of the difference).

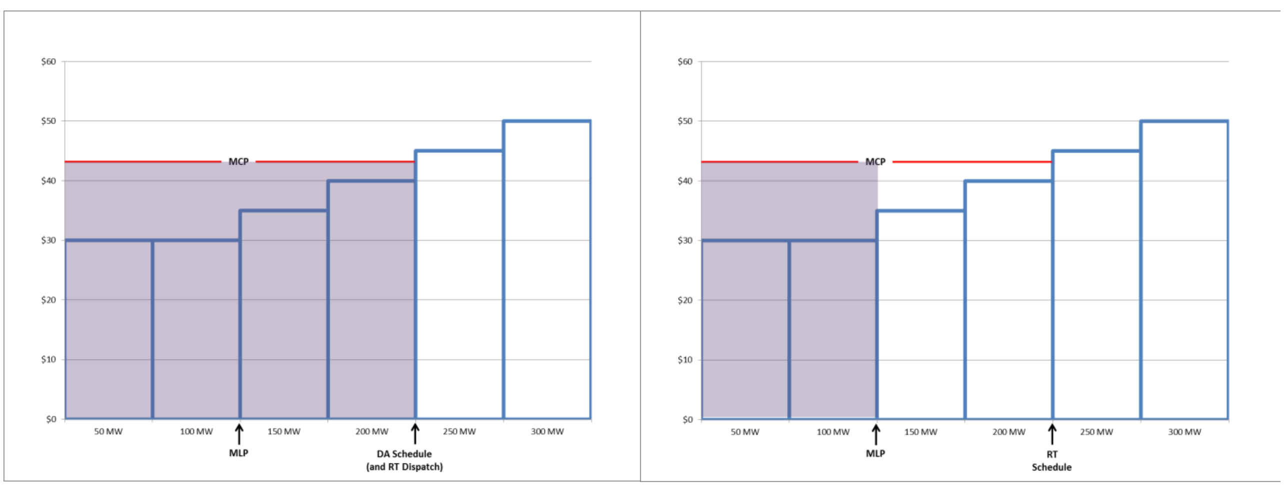
Under the RT-GCG program, the revenues that are counted against the guaranteed costs are limited to the generation facility's MLP output and to the end of the facility's MGBRT rather than being based on total actual output. As such, none of the market revenues earned by the generator as a result of operating above the facility's MLP (and/or for longer than the facility's MGBRT) are considered by the IESO in determining the amount of any guarantee payment. In contrast, under EDAC the IESO considers the revenues on the total (day-ahead) scheduled production (even if higher than the facility's MLP and/or extending beyond the facility's MGBRT) when determining the amount of any guarantee payment.

3.2.4.1 Revenues under RT-GCG Limited to MLP

Figure 3-13 illustrates the difference in the market revenues that are counted against the guaranteed costs under each of EDAC and the RT-GCG programs in relation to a generation facility's level of output. The figure assumes that the generator offered its output day-ahead under EDAC starting at $30/MW for the first 100 MW and increasing $5 for each additional 50 MW block of output. If the generator receives a day-ahead schedule for 200 MW, the market revenues that it earns on all of its guaranteed output (200 MW) will be counted against its guaranteed costs. The guarantee will then be paid only if, and to the extent that, the revenues are insufficient to cover those costs.

If the same generator were to start under the RT-GCG program, however, only revenues earned on output up to the facility's MLP (assumed to be 100 MW) will be counted against its guaranteed costs. While the unit may earn revenues over the entire 200MW of its output, only the revenues earned on production up to MLP will be taken into account in calculating the amount of the guarantee. This could lead to situations where a generator earns sufficient revenues over its total run to cover its guaranteed costs, but still receives a guarantee payment.

Figure 3-13: Revenue over output Considered under EDAC and RT-GCG Programs over a Generator's Run



EDAC guarantees all scheduled output and counts revenues on all production against guaranteed costs

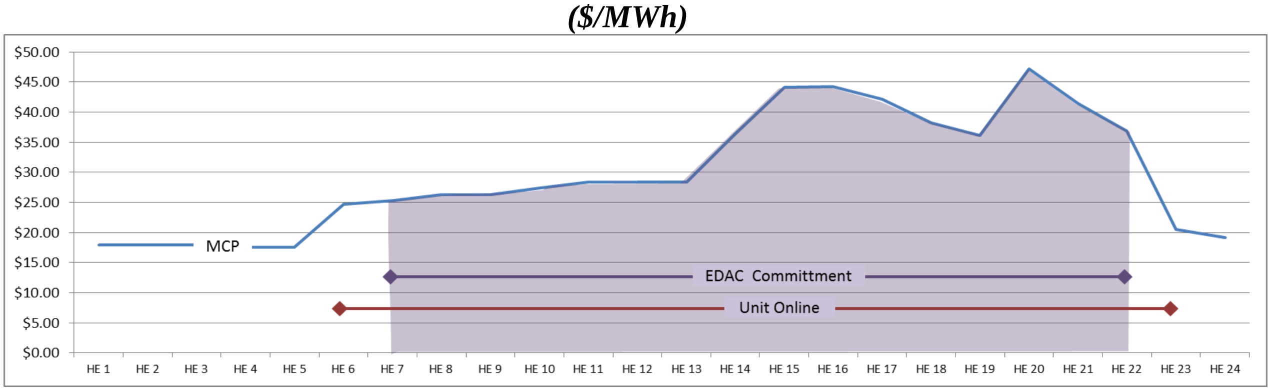
RT-GCG guarantees up to MLP and does not count revenues for production above MLP against guaranteed costs

3.2.4.2 Revenues under RT-GCG Limited to MGBRT

Commitments made under EDAC provide a generator with a guarantee for all of the hours covered by its day-ahead schedule, and revenues earned over all of those hours are considered by the IESO when determining the amount of any guarantee payment. In contrast, under the RT-GCG program only revenues earned during the generator's minimum run-time (start up to end of MGBRT) are considered by the IESO in determining the amount of the guarantee. If the generator does not earn sufficient revenues over its minimum run-time (and up to MLP) to cover its guaranteed costs, it will receive a guarantee payment under the RT-GCG program. If the generator operates above its MLP and/or continues its run beyond its MGBRT, the generator will nonetheless receive the guarantee payment even if its revenues over the total run exceed its guaranteed costs.

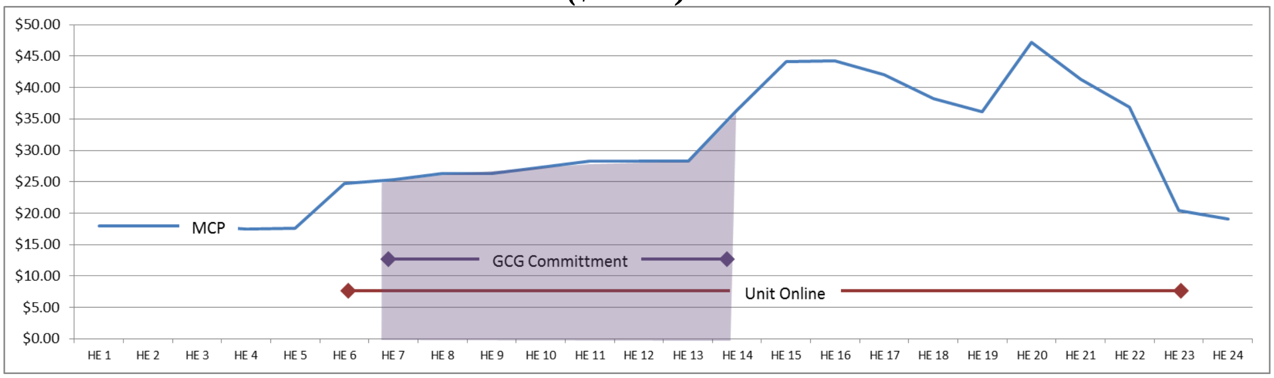
By way of example, suppose a generator receives a commitment in EDAC between hours ending (HE) 7 and 22. If the generator offered its output at $25/MW, then the generator earns a profit when the MCP exceeds $25/MWh. If the unit is committed under EDAC for the sixteen hours, then the revenues earned over those sixteen hours will be counted against the generator's guaranteed costs in determining the amount of the guarantee payment. The revenue counted against the guaranteed costs under EDAC is illustrated in the shaded area in Figure 3-14.

Figure 3-14: Revenue Per MW Considered under EDAC over Generator's Run ($/MWh)



Under the RT-GCG program, the same generator committed to start at the same time will have the only the revenues that it earns over its minimum run-time counted against its guaranteed costs. If the unit is committed in HE 7, and has a MGBRT of 8 hours, it will be committed until HE 14. If its offers are still economic post-HE 14, it may continue the run and earn additional revenues, but only the revenues earned to the end of its MGBRT will be counted against its guaranteed costs when determining the amount of the guarantee payment. This is illustrated in the shaded area in Figure 3-15.

Figure* 3-15: *Revenue* C*onsidered under* EDAC *over Generator's* Run *($/MWh)



Because the RT-GCG program limits the revenue that is taken into account when making the guarantee payment calculation, it leads to more frequent and larger guarantee payments. This provides an incentive to participate in the RT- GCG program in preference to EDAC. Any resulting reduction in participation in EDAC tends to put upward pressure on the costs at which generators are committed under EDAC.

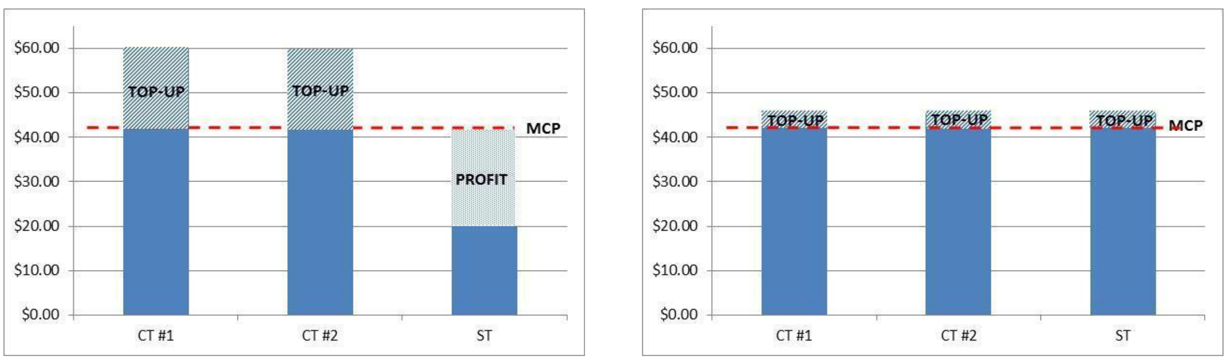
3.2.4.3 Pseudo-Unit Modelling for Combined Cycle Plants

Combined cycle plants have both combustion turbine and steam turbine units. Some generators have arrangements such that each unit can be scheduled separately, with separate offers and cost submissions. However, these units must nonetheless operate in a fixed sequence: a combustion turbine must start before the steam turbine can start, and as more combustion units start the minimum output of the steam turbine increases.

This can create complications for a guarantee program, because a combustion turbine may have large start-up costs while a steam turbine may have low start-up costs, and each may offer their energy output at different prices. However, the steam turbine can only operate when at least one of the combustion turbines is also operating.

The impact on guarantee payments under the RT-GCG program is illustrated in the left hand panel of Figure 3-16. The example in the figure assumes that the average offered cost of a generator is $60/MW for the combustion turbine and $20/MW for the steam turbine. If the average MCP over the generator's guaranteed run is $43/MWh, it will not receive sufficient revenue to fully cover its guaranteed costs for the combustion turbine, and so it will receive a guarantee (top up) payment for the combustion turbine units. However, the generator will earn revenues for every MW of output from the steam turbine. Because the steam turbine is treated as a separate unit, these revenues (less incremental operating costs) are not considered by the IESO when calculating the amount of the guarantee payment for the combustion turbine units, as shown in Figure 3-16.

Figure 3-16: Guarantee Payments for Combined Cycle Plants under Generation Cost Guarantee Programs
($/MWh)



RT-GCG **EDAC (Pseudo Unit Modeling)**

When EDAC was introduced, the IESO began to use "pseudo-unit modeling". With pseudo-unit modeling, the combustion turbine and a portion of the steam turbine are scheduled together, and their costs are aggregated in a manner that reflects their respective operating characteristics. When the guarantee payment is calculated, a proportion of the steam turbine's output is associated with each combustion turbine (creating "pseudo-units" for settlement purposes) and the revenues earned by each pseudo-unit are counted against the pseudo-unit's guaranteed costs in determining the amount of any guarantee payment. Overall, this results in lower guarantee payments than under the RT-GCG program, as shown in the right hand panel of Figure 3-16 above. Specifically, under EDAC each of the pseudo-units in the example will receive a guarantee (top-up) payment of $2.44/MWh, considerably less than the guarantee payable to the same generator under the RT-GCG program.

As noted below, however, it appears based on an IESO analysis that the savings that could be achieved by introducing pseudo-unit modeling to the RT-GCG program are not likely to be material.

3.2.5 *Conclusions and Recommendations*

EDAC represents an improvement over the original day-ahead commitment process. However, based on the analysis set out above the Panel believes that EDAC has been unable to fully deliver the anticipated reductions in commitment costs, and this largely because of the continued co-existence of the RT-GCG program and the differences that exist between the two programs.

The Panel has previously recommended that the IESO re-examine whether the RT-GCG program continues to provide a net benefit to the Ontario market following implementation of EDAC.[100]

The Panel acknowledges that some re-examination of the RT-GCG program has taken place in the context of the IESO's stakeholder engagement pertaining to the review of the IESO's generation cost guarantee programs (referred to as "SE-111"). However, based on materials from SE-111, it would not appear that the IESO has conducted a detailed analysis that demonstrates a continued need for the RT-GCG program in light of changes that have occurred in the market since that program was introduced, including the increasing number of generation facilities that operate under contracts with the Ontario Power Authority or whose payment amounts are set by the Ontario Energy Board and the implementation of EDAC, among other potentially relevant developments.

[100] See the Panel's February 2011 Monitoring Report, p. 96, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf

Recommendation 3-1

The Panel recommends that the IESO provide a detailed analysis to confirm whether the real-time generation cost guarantee (RT-GCG) program continues to be needed in light of the implementation of the enhanced day-ahead commitment process (EDAC), of changes in Ontario's generation capacity, and of other changes in the market since the RT-GCG program was introduced.

Based on the Panel's analysis above, the Panel believes that generators have an incentive to participate in the RT-GCG program in preference to EDAC. In the Panel's view, this incentive – which results from differences in the revenues that are used to offset guaranteed costs when determining the amount of a guarantee payment as between the two programs – may be hindering EDAC in its ability to fully deliver on reduced commitment costs. The Panel therefore believes that, if the RT-GCG program is retained, the revenue offsets should be harmonized as between the two programs. While the Panel has noted the benefits of pseudo-unit modeling under EDAC, based on an analysis conducted by the IESO in the context of SE-111 the savings attainable from moving to pseudo-unit style settlements for the RT-GCG program are not likely to be material.[101] The Panel is therefore not recommending that the IESO introduce pseudo-unit modeling in the RT-GCG program.

Recommendation 3-2

If the IESO, after performing its detailed analysis, determines that the RT-GCG program continues to be needed, the Panel recommends that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any profit (revenues less incremental operating costs) earned (a) on output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and (b) on output generated after the end of the facility's MGBRT.

The Panel has also noted that the absence of significant export participation in EDAC creates a further opportunity for generators without a day-ahead commitment to receive a guarantee in real-time. This may be contributing to higher levels of commitments under the RT-GCG program

[101] See slides 13-16 in the IESO's SE-111 November presentation, available at: http://www.ieso.ca/imoweb/pubs/consult/se111/se111-20131107-Presentation_Revised.pdf .

post-EDAC. In 2008, the IESO considered the issue of incentives to encourage exports to participate in EDAC, recognizing that this could lead to improved efficiency through better day-ahead commitment and that efficiency gains would be realized through reduced overall commitment costs that otherwise would not have been achieved. The IESO explored seven options, and concluded that the incentives would be difficult to structure and would likely not provide significant benefits in terms of reducing overall commitment costs under EDAC.[102] However, in the Panel's view the benefits of including export demand day-ahead extend beyond EDAC because doing so is likely to reduce the need to commit additional resources in real-time. Accounting for export demand day-ahead would ensure that more generation is subject to 24 hour optimization and would help to strengthen competition among generators for a day-ahead commitment in EDAC.

Recommendation 3-3

The Panel recommends that the IESO re-examine the question of integrating exports into EDAC to reduce the need to commit additional generation in real-time to meet export demand that currently only appears in the market in real-time. While the Panel is not recommending a specific approach for integrating exports, the following have been identified as potential options:

- ***a) introduce a mechanism that encourages exports to bid in EDAC; or***
- ***b) include a forecast of exports when commitments are made under EDAC.***

[102] A summary is available in the IESO's report "EDAC-Options for Export Incentives", October 29, 2008, available at: http://www.ieso.ca/imoweb/pubs/consult/se21-dagei/se21-20081106-Export_Discussion.pdf .

Appendix 3-A

Details of the Average Offered Cost Analysis

The following provides further detail regarding the assumptions used and the adjustments and checks performed in conducting the analysis of the average offered costs of gas-fired generators.

3B.1 Assumptions

1.) Start-up costs not submitted but incurred were substituted based on historical values: Average values for each generator's start-up fuel and OM&A costs were calculated based on historical submissions. Separate start-up costs have been calculated for each unit for each of the two time periods (pre-EDAC and post-EDAC) based on submissions in the respective time period.
2.) Whenever a unit incurred a DA-GCG start, a portion was counted as OM&A costs, with the remainder being attributed to fuel costs. This portion was calculated based on the average OM&A submissions for each generator under the RT-GCG program. The OM&A portion was subtracted from the start-up costs and adjusted for inflation, while the remainder was attributed as fuel cost and adjusted for changes in fuel prices.
3.) Generators that ramped off in a new day (or phantom starts) were excluded: Generators that injected for less than 24 intervals (two hours) over a daily period that did not have a submitted start had no start-up costs added in. These instances are related to ramping off in a new day, or phantom starts, related to compliance aggregation where injection from one unit is split between two units.
4.) CMSC payments were excluded: The analysis did not include any CMSC payments related to ramping, congestion or or any other differences between constrained and unconstrained schedules.
5.) Calculated costs were not adjusted for after-the-fact administrative actions affecting settlement: Start-up costs used in the analysis were limited to the original submissions made by market participants and were not adjusted for any change that may have taken place due to recovery actions or a disagreements as to settlement amounts (as these were not the as-offered costs).
6.) Actual output, and not scheduled amounts, was used: Injected quantities were not adjusted to account for any deviation by a generator from its schedule. Depending on the direction and

size of the deviation, the calculated costs may not necessarily reflect the economic (scheduled) point of the unit.

7.) One cogeneration resource was excluded. The operation of this resource is based on the needs of its steam load, and it does not expose its true operating costs during long run periods. There is no reasonable way to estimate this unit's true operating costs, as the unit does not operate in response to market signals.

8.) Injections associated with periods of ramp up during start-up and ramp down during shut down were excluded. For these periods, generators may be submitting offers which do not necessarily reflect their true costs. During start-up, a generator may submit offers below cost in order to signal its intention to ramp the unit online. During shut down, a generator may submit offers above costs in order to signal its intention to come offline. For simplification purposes, periods of ramp up and ramp down were identified as any period in which a generator was injecting below a value that is equivalent to 10 percent below its MLP. The costs for these periods were assumed to have been accounted for in the generators' start-up cost submissions.

3B.2 Adjusting for changes in fuel prices and inflation

Given that the analysis spanned a two-year period, costs were adjusted to account for changes in fuel prices and inflation. After this adjustment, the results of the analysis for each period can be compared as if the underlying prices had remained constant over the two year period. Cost components attributed to natural gas costs were normalized using the applicable daily commodity market clearing price. OM&A costs for other goods and services were normalized against the Canadian GDP Implicit Price Index (GDP IPI, a broad measure of inflation), using a rolling quarterly average.

Table 3A-1 shows the changes in natural gas prices and inflation. Over the two year period, the average commodity cost of gas decreased by 30.6%, along with a moderate increase in inflation of 1.7% on other goods and services.

Table 3A-1: Change in Fuel Costs and Inflation
($CAD/MMBtu)

Prices and Inflation	Pre-EDAC	Post-EDAC	% Change
Gas (Dawn Hub)	$4.46	$3.09	(30.6)%
GDP IPI	113.6	115.3	1.7%

Appendix 3-B

Generators Excluded from the Average Offered Cost Analysis

Non-quick start resources include not only gas-fired generation facilities but also facilities that are fuelled by coal or oil. Although these resources are eligible to receive cost guarantees under the IESO's generation cost guarantee programs, they were excluded from the average offered cost analysis due to unique changes in the way that they offered over the two-year period under study.

One of the excluded generation facilities had a contract to provide automatic generation control (AGC). Because this generator was always scheduled for availability (because of the AGC contract), its offers into the day-ahead program were not necessarily reflective of its true costs. Absent the AGC contract, the calculation engine may not have chosen this facility's higher cost offers. For this reason, it would be misleading to include this unit in the analysis.

Furthermore, a 2011 change to the market rules relating to settlement for generators that offer at negative prices led to a significant change in the way certain units were offered into the market. As the increase in offered costs that was observed for these units is attributable to the disappearance of negative offer behaviour, inclusion of these units in the analysis would have been misleading in terms of post-EDAC average offered costs.

Appendix 3-C

Demand, Net Exports and Wind Production Pre- and Post-EDAC

Table 3A-2 sets out Ontario demand, net exports and wind production in the twelve-month period prior to the introduction of EDAC (October 2010 to September 2011 - roughly equivalent to the "pre-EDAC" period used in the average offered cost analysis) and in the following twelve-month period (October 2011 to September 2012 - roughly equivalent to the "post-EDAC" period used in the average offered cost analysis). This data is also plotted in Figure 3A-1. The levels of demand, net exports and wind production were all broadly similar over the two time periods; year-over-year Ontario demand decreased by approximately 2 TWh, net exports decreased by approximately 1.5 TWh and wind production increased by approximately 1.2 TWh.

Given the relatively minor nature of the changes in demand, net exports and wind production as between the two periods, it was not considered necessary to control for these variables in the analysis of offered costs.

Figure 3A-1: Ontario Demand, Net Exports and Wind Production
October 2010 - September 2012
(TWh)

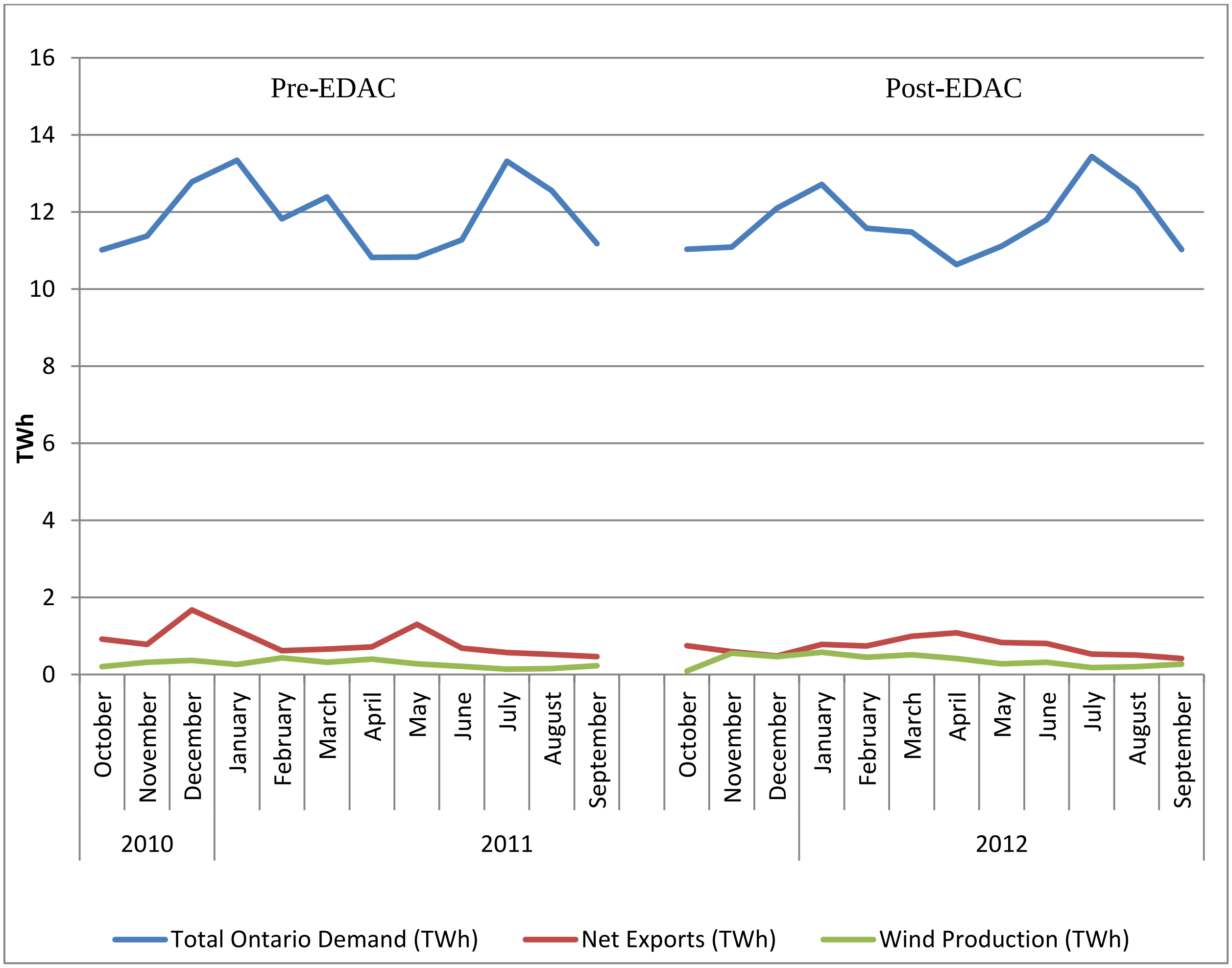


Table 3A-2: Ontario Demand, Net Exports and Wind Production (TWh)

Year	Month	Total Ontario Demand	Net Exports	Wind Production
2010	October	11.02	0.92	0.20
	November	11.37	0.79	0.32
	December	12.78	1.67	0.37
2011	January	13.35	1.15	0.26
	February	11.83	0.62	0.44
	March	12.40	0.66	0.32
	April	10.82	0.72	0.40
	May	10.83	1.31	0.28
	June	11.28	0.69	0.21
	July	13.32	0.57	0.14
	August	12.56	0.53	0.16
	September	11.18	0.47	0.23
EDAC introduced October 13, 2011				
	October	11.04	0.75	0.10
	November	11.09	0.60	0.55
	December	12.10	0.48	0.47
2012	January	12.72	0.79	0.58
	February	11.58	0.74	0.45
	March	11.48	1.00	0.52
	April	10.63	1.09	0.42
	May	11.12	0.83	0.28
	June	11.80	0.81	0.32
	July	13.44	0.53	0.18
	August	12.61	0.51	0.21
	September	11.03	0.42	0.27
Total Pre-EDAC		142.75	10.02	3.44
Total Post-EDAC		140.70	8.48	4.67
Difference		(2.05)	(1.54)	1.23

Chapter 4: The State of the IESO-Administered Markets

1 General Assessment

This is the Panel's 22nd semi-annual Monitoring Report on the IESO-administered markets. It covers the period from November 2012 to April 2013. The wholesale electricity market continued to operate reasonably well, given its hybrid design and use of the two-schedule system. However, the Panel has identified elements of the market design that have given rise to inefficient or potentially inefficient market participant behaviour and/or inefficient market outcomes.

2 Future Development of the Market

The Panel acknowledges that the IESO continues to address the issues identified in the December 2011 Electricity Market Forum report.[103] The IESO has completed a stakeholder engagement (SE-105) related to a review of the Hourly Ontario Energy Price. The consultation culminated with the publication of a paper entitled "Review of the Efficiency of the Hourly Ontario Energy Price", which assesses whether or not the Ontario pricing system is sending accurate price signals to consumers and suppliers.[104] The IESO is also at an advanced stage in its stakeholder engagement regarding the review of the Global Adjustment (SE-106).

Through these and other initiatives, the IESO is actively working on issues that are important to the future development of Ontario's wholesale electricity markets.

The Panel is also following with interest the IESO's review of its generation cost guarantee programs (SE-111). These programs have been the subject of recommendations in a number of Panel reports, including this one. The Panel is encouraged that the IESO is also addressing, as part of SE-111, the Panel's earlier

[103] The report, entitled "Reconnecting Supply and Demand: How Improving Electricity Pricing Can Help Integrate A Changing Supply Mix, Increase Efficiency and Empower Customers", is available at: https://www.ieso.ca/imoweb/pubs/consult/Market_Forum_Report.pdf.
[104] The report is available at: http://www.ieso.ca/imoweb/pubs/consult/se105/se105-20130724-review_efficiency_hoep.pdf.

recommendations that Congestion Management Settlement Credit (CMSC) payments to generators when they are ramping down be eliminated.[105]

3 Response to Panel Recommendations from Prior Reports

Following the release of each of the Panel's semi-annual monitoring reports, the IESO posts on its public website its responses to any Panel recommendations that have been directed to it.[106] The IESO also discusses the recommendations and its responses with its Stakeholder Advisory Committee and the IESO Board of Directors.

3.1 *Recommendations to the IESO from the June 2013 Report*

The Panel's June 2013 monitoring report contained two recommendations, both directed to the IESO. The IESO responses to those recommendations are set out in Table 4-1.

Table 4-1: IESO Responses to Recommendations in the Panel's June 2013 Monitoring Report

Recommendation	IESO Response
Recommendation 2-1 *The IESO should consider expanding the current local market power framework to cover analogous circumstances that arise as part of the day-ahead commitment process.*	"The IESO agrees that this recommendation warrants further consideration. However, with over ten years of market history and numerous market rule amendments, we believe an overall review would be appropriate and would allow the IESO to assess whether the existing local market power framework is achieving its intended purposes, and whether the present framework should be extended to the day-ahead commitment process. This review will commence in the first quarter of 2014."
Recommendation 3-1 *The IESO should implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping down generators.*	"The IESO continues to believe that there are legitimate costs to a generator when ramping down that should be accounted for in a generator's revenue requirement, but in that context generators should only be compensated for legitimate costs incurred. The IESO also believes that this recommendation is better addressed as part of a more comprehensive review of the real-time and day-ahead guarantee programs. This review has already been initiated, and will address this recommendation. The stakeholder engagement process began in May 2013, with findings and recommendations targeted for Q4 2013. The market rules process, if applicable, will flow from those findings and recommendations."

[105] See the Panel's July 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf.
[106] All responses are available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20130718.pdf .

As noted earlier, the IESO has included consideration of Recommendation 3-1 above in a stakeholder engagement that is currently under way. Given the IESO's reiteration of its belief that there are legitimate costs to a generator when ramping down for which they should be compensated,[107] the Panel reaffirms its view that it could only be by coincidence, and not by design, that CMSC payments during a voluntary ramp-down would equal a generator's shut-down costs. As such, if it is in fact appropriate for generators to be compensated for higher costs incurred during ramp down, the Panel believes that this is better addressed by a market rule aimed directly at the issue rather than by use of the CMSC mechanism.

3.2 *Recommendations to the IESO from the January 2013 Report*

In its January 2013 monitoring report, the Panel made several recommendations related to the design of the transmission rights market.[108] Since that time, the IESO has made several strides towards addressing the Panel's recommendations. The IESO commenced a stakeholder engagement (SE-110) to review the design of the transmission rights market, and in phase one of that review recommended "a confidence level such that congestion rents collected on each path are approximately sufficient to cover the payouts to transmission rights holders on that same path" .[109] Once implemented, this IESO recommendation will address Recommendation 3-2 from the Panel's January 2013 report. The IESO also promptly addressed Recommendation 3-3(A) from that report when the IESO Board of Directors authorised the disbursement of $42 million to market participants from the Transmission Rights Clearing Account.[110] The Panel recognizes the IESO's efforts to address these two recommendations, and understands that the remaining Panel recommendations will be considered in phase two of the IESO's stakeholder engagement.

[107] A statement to this effect was also made in the IESO's responses to a recommendation set out in the Panel's April 2012 Monitoring Report. See "IESO Response to MSP Recommendations", available at: http://ieso.ca/imoweb/marketSurveil/surveil.asp.
[108] Available at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf
[109] "Transmission Rights Market Review (SE-110): Phase 1 Analysis: Results and Recommendations", July 22, 2013, at p. 16, available at: http://www.ieso.ca/imoweb/pubs/consult/se110/se110-20130725-TR-Market-Review-Phase-1-Analysis.pdf
[110] Participant News, April 11, 2013, available at: http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=6431

4 Recommendations in this Report

The Panel groups its recommendations into four categories: price fidelity, efficiency, transparency and hourly uplift payments. Some recommendations may have impacts in more than one category (for example, a scheduling change could affect prices as well as uplift) and, where this is the case, the recommendation is included in the category of its primary effect.

The first of the Panel's recommendations in this report relates to uplift payments. The remainder relate primarily to efficiency, and to a lesser extent to uplift payments.

Recommendation 2-1

> ***The Panel recommends that the IESO eliminate constrained-off Congestion Management Settlement Credit (CMSC) payments for all intertie transactions, with due consideration to the interplay between the elimination of negative CMSC payments and Intertie Offer Guarantee payments.***

Recommendation 3-1

> ***The Panel recommends that the IESO provide a detailed analysis to confirm whether the real-time generation cost guarantee (RT-GCG) program continues to be needed in light of the implementation of the enhanced day-ahead commitment process (EDAC), of changes in Ontario's generation capacity, and of other changes in the market since the RT-GCG program was introduced.***

Recommendation 3-2

> ***If the IESO, after performing its detailed analysis, determines that the RT-GCG program continues to be needed, the Panel recommends that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any profit (revenues less incremental operating costs) earned (a) on output above a generation facility's minimum loading point* during its minimum generation**

block run time (MGBRT), and (b) on output generated after the end of the facility's MGBRT.

Recommendation 3-3

The Panel recommends that the IESO re-examine the question of integrating exports into EDAC to reduce the need to commit additional generation in real-time to meet export demand that currently only appears in the market in real-time. While the Panel is not recommending a specific approach for integrating exports, the following have been identified as potential options:

a) introduce a mechanism that encourages exports to bid in EDAC; or
b) include a forecast of exports when commitments are made under EDAC.

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 2012 – April 2013

List of Tables

Table A-1: Outages
May – April 2011/2012 & May – April 2012/2013
(TWh)

	Total Outage		Planned Outage*		Forced Outage	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	5.41	6.77	2.48	3.13	2.93	3.64
June	4.54	5	1.61	2.16	2.93	2.84
July	3.66	4.49	1.1	1.68	2.56	2.81
August	4.05	5.12	1.08	2.21	2.97	2.91
September	5.04	7.17	2.49	4.17	2.55	3
October	6.92	7.91	4.17	5.7	2.75	2.21
November	6.72	6.82	3.72	4.73	3	2.09
December	4.63	5.76	1.94	3.53	2.69	2.23
January	3.97	5.05	1.27	1.77	2.7	3.28
February	4.12	5.53	1.65	1.76	2.47	3.77
March	4.61	7.09	1.48	4.17	3.13	2.92
April	6.26	7.25	2.63	4.46	3.63	2.79
May – Oct	29.62	36.46	12.93	19.05	16.69	17.41
Nov - Apr	30.31	37.5	12.69	20.42	17.62	17.08
May - Apr	59.93	73.96	25.62	39.47	34.31	34.49

* For the purposes of these outage statistics, OPG's "CO_2 Outages" are classified as planned outages (rather than as forced outages, which is how they are treated by the IESO). See section 4.4.1 of Chapter 1 for further detail regarding the treatment of OPG's outages for statistical purposes.

Table A-2: Ontario Consumption by Type of Usage May – April 2011/2012 & May – April 2012/2013 (TWh)

	Distributors*		Wholesale Loads		Generators		Metered Energy Consumption**		Transmission Losses***		Total Energy Consumption	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	9.08	9.33	1.31	1.42	0.11	0.10	10.50	10.84	0.28	0.30	10.78	11.14
June	9.56	10.07	1.23	1.34	0.10	0.07	10.90	11.49	0.34	0.31	11.24	11.80
July	11.51	11.58	1.33	1.44	0.09	0.07	12.93	13.09	0.37	0.37	13.30	13.46
August	10.75	10.78	1.39	1.44	0.08	0.10	12.22	12.32	0.31	0.31	12.53	12.63
September	9.38	9.31	1.38	1.33	0.07	0.12	10.84	10.76	0.31	0.27	11.14	11.03
October	9.36	9.34	1.38	1.43	0.07	0.09	10.82	10.86	0.19	0.28	11.01	11.14
November	9.48	9.74	1.31	1.40	0.07	0.07	10.86	11.21	0.26	0.28	11.12	11.49
December	10.42	10.36	1.32	1.37	0.07	0.07	11.82	11.80	0.32	0.34	12.13	12.14
January	10.98	11.02	1.38	1.46	0.08	0.07	12.44	12.55	0.27	0.34	12.72	12.89
February	9.93	9.99	1.30	1.36	0.06	0.07	11.29	11.42	0.32	0.32	11.61	11.74
March	9.66	10.11	1.41	1.43	0.10	0.08	11.17	11.62	0.32	0.34	11.49	11.96
April	8.88	9.19	1.36	1.36	0.09	0.11	10.34	10.67	0.31	0.27	10.64	10.94
May –Oct	59.64	60.41	8.02	8.39	0.52	0.55	68.21	69.35	1.80	1.85	70.00	71.20
Nov - Apr	59.35	60.40	8.08	8.38	0.47	0.48	67.92	69.26	1.80	1.90	69.71	71.16
May -Apr	118.99	120.81	16.10	16.77	0.99	1.03	136.13	138.61	3.60	3.75	139.71	142.36

* Withdrawals by distributors are net of any generation embedded within their service areas
** Metered Energy Consumption = Distributors + Wholesale Loads + Generators
*** Transmission Losses = Total Energy Consumption - Metered Energy Consumption

Table A-3: Total Hourly Uplift Charge by Component
May – April 2011/2012 & May – April 2012/2013
($ millions)

	Total Hourly Uplift*		IOG**		CMSC***		Operating Reserve		Losses	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	32.76	14.17	0.37	1.04	13.01	7.54	12.20	0.77	7.17	4.83
June	33.66	18.79	0.76	1.22	18.36	11.17	4.74	0.57	9.81	5.82
July	22.74	23.85	0.36	4.05	9.55	10.39	1.51	0.71	11.32	8.70
August	17.53	20.76	0.37	3.81	6.95	9.31	2.45	0.76	7.77	6.89
September	15.71	17.41	1.13	3.74	6.56	7.00	0.71	0.78	7.31	5.89
October	13.09	10.04	0.39	0.66	5.58	4.10	0.45	2.69	6.65	2.59
November	15.01	15.16	0.54	0.71	9.13	6.24	0.60	2.73	4.74	5.47
December	12.28	10.83	0.67	0.55	3.48	3.65	1.17	1.14	6.96	5.50
January	11.09	16.81	0.77	0.63	2.75	6.85	1.28	2.22	6.29	7.11
February	10.49	22.37	1.16	2.10	3.77	11.63	0.58	2.20	4.98	6.44
March	15.64	14.29	1.46	0.85	6.19	6.81	3.99	0.88	3.99	5.73
April	9.32	14.08	0.40	0.52	3.52	4.68	1.25	2.92	4.15	5.97
May- Oct	135.50	105.03	3.38	14.52	60.02	49.51	22.06	6.28	50.03	34.71
Nov - Apr	73.83	93.54	5.00	5.36	28.85	39.86	8.87	12.09	31.11	36.22
May -Apr	209.33	198.56	8.38	19.88	88.87	89.38	30.93	18.37	81.14	70.93

* Total Hourly Uplift = Real-time IOG + Day-ahead IOG + CMSC + Operating Reserve + Losses
**The real-time and day-ahead IOGs have been billed as one charge starting on October 13, 2011.
*** 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 – April 2011/2012 & May – April 2012/2013
($ millions)

	Constrained-off		Constrained-on		Total CMSC for Energy*		CMSC for Operating Reserves		Total CMSC Payments**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	5.87	3.83	3.46	2.23	9.33	6.06	2.76	0.48	12.09	6.54
June	9.24	5.88	3.41	2.94	12.66	8.82	1.67	0.31	14.32	9.13
July	5.55	6.54	2.69	3.42	8.23	9.96	0.40	0.19	8.63	10.15
August	3.64	5.36	3.00	3.05	6.64	8.41	0.82	0.23	7.46	8.64
September	2.83	4.22	3.00	2.21	5.84	6.44	1.06	0.18	6.90	6.62
October	3.09	2.59	1.51	1.84	4.61	4.43	0.52	0.32	5.12	4.75
November	6.15	3.81	4.06	2.70	10.21	6.51	0.45	0.45	10.66	6.96
December	2.34	2.13	1.84	1.96	4.17	4.09	0.34	0.24	4.51	4.33
January	2.12	3.89	1.39	2.19	3.51	6.08	0.39	(0.28)	3.90	5.80
February	1.91	6.81	1.72	2.94	3.63	9.75	0.17	0.45	3.80	10.20
March	3.75	3.93	2.75	1.69	6.50	5.62	1.01	0.45	7.51	6.07
April	3.60	2.93	1.31	1.13	4.91	4.06	0.54	0.62	5.45	4.68
May- Oct	30.22	28.42	17.07	15.69	47.31	44.12	7.23	1.71	54.52	45.83
Nov - Apr	19.87	23.50	13.07	12.60	32.93	36.10	2.90	1.94	35.83	38.04
May -Apr	50.09	51.93	30.14	28.29	80.24	80.22	10.13	3.65	90.35	83.87

* The sum for energy being constrained on and constrained off does not equal the total CMSC payments for energy in some months. This is due to the fact that the process for assigning the constrained-on and constrained-off labels to individual intervals is not yet complete. Note that these numbers are the net CMSC payment amounts.
** The totals for CMSC payments in this table do not equal the totals for CMSC payments in Table A-3. The CMSC data presented in Table A-3 includes adjustment data. In Table A-4, in order to extract constrained-off and constrained-on CMSC data, the adjustments are not included. Neither Table includes local market power adjustments.

Table A-5: Supply Cushion Statistics, On-Peak
May – April 2011/2012 & May – April 2012/2013
(% and number of hours)

	One Hour-ahead Pre-dispatch						Real-time					
	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)*	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	9.0	15.3	0	0	216	59	12.9	15.1	0	0	73	47
June	14.0	19.7	0	0	83	29	10.8	16.2	6	0	161	35
July	13.0	18.1	0	0	109	26	12.5	14.7	0	0	108	78
August	14.6	20.1	0	0	87	10	11.0	18.1	0	0	162	22
September	15.3	17.5	0	0	50	18	12.5	15.3	0	5	101	73
October	15.3	15.6	0	0	40	27	16.5	15.4	0	0	17	45
November	17.4	21.2	0	0	44	3	18.3	18.9	0	0	4	11
December	13.5	21.9	0	0	97	1	13.3	19.5	0	0	79	3
January	10.7	19.7	0	0	168	3	13.7	19.4	0	0	60	7
February	13.6	17.6	0	0	83	11	15.2	14.7	0	0	35	41
March	13.8	23.4	0	0	97	1	16.2	18.2	0	0	25	12
April	11.8	23.1	0	0	126	4	18.1	17.6	0	0	11	15
May- Oct	13.5	17.7	0	0	585	169	12.7	15.8	6	5	622	300
Nov - Apr	13.5	21.1	0	0	615	23	15.8	18.1	0	0	214	89
May -Apr	13.5	19.4	0	0	1200	192	14.2	16.9	6	5	836	389

* This category includes hours with a negative supply cushion.

Table A-6: Supply Cushion Statistics, Off-Peak May – April 2011/2012 & May – April 2012/2013 (% and number of hours)

	One Hour-ahead Pre-dispatch						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)*	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	12.7	24.7	0	0	146	16	24.7	24.9	0	0	9	10
June	19.8	28.8	0	0	13	4	22.6	25.1	0	0	19	20
July	23.1	26.3	0	0	28	9	23.7	23.3	0	0	15	55
August	21.5	25.9	0	0	26	0	21.7	24.8	0	0	18	14
September	23.4	25.4	0	0	5	0	21.1	24.6	0	0	9	8
October	22.8	22.4	0	0	1	25	23.4	27.9	0	0	4	4
November	27.3	29.0	0	0	3	1	28.3	26.0	0	0	1	7
December	22.6	29.3	0	0	28	0	21.6	26.8	1	0	26	2
January	20.9	28.3	0	0	42	2	24.7	27.4	0	0	11	7
February	22.0	25.8	0	0	25	3	23.9	21.4	0	0	15	21
March	19.1	30.5	0	0	48	0	24.2	21.5	0	0	24	24
April	18.4	30.8	0	0	66	0	24.5	25.2	0	0	5	17
May- Oct	20.6	25.6	0	0	219	54	22.9	25.1	0	0	74	111
Nov - Apr	21.7	29.0	0	0	212	6	24.5	24.7	1	0	82	78
May -Apr	21.1	27.3	0	0	431	60	23.7	24.9	1	0	156	189

* This category includes hours with a negative supply cushion

Table A-7: Resources Selected in the Real-Time Market Schedule May – April 2011/2012 & May – April 2012/2013 (TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Wind		Domestic Generation*	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	0.32	0.44	1.63	1.27	0.11	0.29	1.06	1.23	3.67	3.07	6.91	6.96	0.28	0.28	12.04	11.82
June	0.38	0.47	1.07	1.28	0.22	0.55	1.43	1.68	3.38	2.76	6.62	7.18	0.21	0.32	11.87	12.48
July	0.71	0.87	1.29	1.40	1.35	0.80	1.99	2.58	2.99	2.46	7.30	7.85	0.14	0.18	13.77	13.88
August	0.55	0.72	1.08	1.22	0.64	0.51	1.85	2.27	2.50	2.39	7.81	7.63	0.16	0.21	12.97	13.01
September	0.39	0.50	0.85	0.92	0.27	0.45	1.46	1.73	2.20	2.20	7.41	6.69	0.23	0.28	11.58	11.34
October	0.30	0.40	1.05	1.21	0.20	0.33	1.69	1.07	2.34	2.45	7.09	7.41	0.34	0.52	11.67	11.78
November	0.29	0.31	0.89	1.58	0.42	0.42	1.63	1.23	2.60	2.90	6.36	7.68	0.55	0.37	11.56	12.61
December	0.27	0.19	0.75	1.26	0.35	0.62	1.39	1.28	2.96	3.02	7.27	7.68	0.47	0.46	12.45	13.06
January	0.33	0.19	1.12	1.60	0.40	0.71	2.21	1.94	3.10	3.07	7.06	7.88	0.58	0.56	13.36	14.15
February	0.31	0.28	1.05	1.30	0.47	0.55	1.79	2.12	3.09	2.87	6.37	6.66	0.45	0.44	12.18	12.64
March	0.33	0.37	1.33	1.38	0.41	0.47	1.22	1.70	3.27	3.16	6.92	7.01	0.52	0.45	12.34	12.80
April	0.50	0.34	1.58	1.51	0.22	0.25	1.42	1.16	3.21	2.85	6.32	7.16	0.43	0.52	11.60	11.95
May – Oct	2.65	3.40	6.97	7.30	2.79	2.93	9.48	10.56	17.08	15.33	43.14	43.71	1.36	1.79	73.90	74.31
Nov - Apr	2.03	1.68	6.72	8.64	2.27	3.02	9.66	9.43	18.23	17.87	40.30	44.07	3.00	2.81	73.49	77.19
May - Apr	4.68	5.08	13.69	15.94	5.06	5.95	19.14	19.98	35.31	33.20	83.44	87.78	4.36	4.59	147.39	151.50

* Domestic generation includes all generation connected to the IESO-controlled grid.

Table A-8: Demand Forecast Error - Pre-Dispatch versus Average and Peak Hourly Demand May – April 2011/2012 & May _ April 2012/2013 (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	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	201/1 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	195	218	169	169	243	293	228	252	1.3	1.5	1.2	1.1	1.7	2.0	1.6	1.7
June	282	282	214	217	345	331	293	273	1.8	1.7	1.4	1.3	2.2	2.0	1.9	1.7
July	337	389	253	286	388	440	321	335	1.9	2.2	1.4	1.6	2.2	2.4	1.8	1.9
August	318	316	233	238	399	368	330	299	1.9	1.9	1.4	1.4	2.4	2.2	2.0	1.8
September	230	251	173	196	343	292	293	252	1.5	1.6	1.1	1.3	2.2	1.9	1.9	1.6
October	176	206	144	167	276	257	267	233	1.2	1.4	1.0	1.1	1.9	1.7	1.8	1.6
November	240	254	206	216	250	256	232	224	1.6	1.6	1.3	1.4	1.6	1.6	1.5	1.4
December	258	290	220	252	264	249	234	215	1.6	1.8	1.4	1.6	1.6	1.5	1.4	1.3
January	299	276	246	235	280	260	236	216	1.8	1.6	1.4	1.4	1.6	1.5	1.4	1.2
February	271	265	209	226	285	270	232	231	1.6	1.5	1.3	1.3	1.7	1.5	1.4	1.3
March	248	268	195	214	274	264	236	221	1.6	1.7	1.3	1.3	1.8	1.6	1.5	1.4
April	246	220	196	182	296	268	260	239	1.7	1.5	1.3	1.2	2.0	1.8	1.8	1.6
May – Oct	256	277	198	212	332	330	289	274	1.6	1.7	1.3	1.3	2.1	2.0	1.8	1.7
Nov – Apr	260	262	212	221	275	261	238	224	1.7	1.6	1.3	1.4	1.7	1.6	1.5	1.4
May - Apr	258	270	205	217	304	296	264	249	1.6	1.7	1.3	1.3	1.9	1.8	1.7	1.5

*Table A-9: Discrepancy between Self-Scheduling*and Intermittent Generators' Offered and Delivered Quantities May – April 2011/2012 & May – April 2012/2013 (MW and %)*

	Pre-Dispatch (MW)		Discrepancy Between Offered and Delivered Quantities (MW) Maximum		Minimum		Average		Discrepancy Rate** (%)	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	915,174	951,611	450.6	491.1	(437.6)	(388.0)	34.2	76.1	3.5	6.1
June	883,235	966,652	382.6	488.1	(369.4)	(458.1)	61.6	60.4	5.5	5.0
July	839,723	811,960	424.1	573.9	(331.2)	(551.1)	106.2	89.5	9.5	8.1
August	820,450	860,090	400.1	395.9	(364.9)	(473.5)	99.2	57.2	9.3	5.2
September	680,730	864,779	485.2	488.8	(307.9)	(416.1)	66.8	36.3	7.5	3.5
October	994,553	1,308,232	345.5	572.6	(318.9)	(341.8)	58.0	20.7	5.1	1.7
November	1,213,412	1,052,649	585.5	519.2	(477.5)	(329.7)	39.5	36.6	2.6	2.9
December	1,170,263	1,134,213	556.6	550.7	(540.8)	(285.1)	57.0	23.4	4.2	1.6
January	1,318,597	1,298,465	600.5	516.6	(505.6)	(427.2)	18.3	13.6	1.2	1.2
February	1,142,862	1,099,679	576.1	371.1	(477.2)	(298.9)	16.0	2.8	1.7	0.4
March	1,248,420	1,161,398	593.9	333.0	(535.7)	(387.5)	3.7	16.2	0.7	1.3
April	1,081,747	1,170,893	566.4	921.9	(505.7)	(477.4)	24.3	22.0	1.9	1.6
May – Oct	855,644	960,554	414.7	501.7	(354.9)	(438.1)	71.0	56.7	6.7	4.9
Nov – Apr	1,195,884	1,152,883	579.8	535.4	(507.1)	(367.6)	26.5	19.1	2.0	1.5
May - Apr	1,025,764	1,056,718	497.2	518.6	(431.0)	(402.9)	48.7	37.9	4.4	3.2

* Self-scheduling generators include wind, small gas-fired, biomass and hydroelectric facilities as well as commissioning units and dispatchable units that are temporarily classified as self-scheduling during testing phases following an outage for major maintenance.
** Discrepancy rate is calculated as the hourly difference between offered and delivered MWs, divided by the hourly offered MWs averaged over the month.

Table A-10: Discrepancy between Wind Generators' Offered and Delivered Quantities May – April 2011/2012 & May – April 2012/2013 (MW and %)

	Pre-Dispatch (MWh)		Difference Between Offered and Delivered Quantities (MW						Discrepancy Rate* (%)	
			Maximum		Minimum		Average			
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	294,124	318,953	441.6	495.7	(488.1)	(413.7)	13.9	54.7	9.6	16.6
June	233,070	343,841	331.0	480.8	(377.1)	(457.0)	29.6	32.6	14.3	10.5
July	193,803	220,052	390.4	527.8	(395.2)	(591.6)	73.6	49.3	32.8	19.6
August	210,386	227,959	344.1	360.4	(400.5)	(556.1)	65.8	23.5	31.6	13.3
September	261,841	285,515	384.3	414.8	(331.2)	(439.2)	40.4	16.0	16.2	6.5
October	367,524	522,868	359.0	546	(344.7)	(389.4)	37.4	7.0	15.9	5.0
November	571,271	369,119	546.4	495.3	(480.2)	(382.7)	25.6	2.1	5.6	5.7
December	492,913	470,296	533.2	513.4	(622.6)	(272.9)	30.2	15.5	9.1	6.6
January	596,989	568,742	599.2	517.1	(488.4)	(430.2)	20.5	13.6	5.8	5.4
February	468,624	448,309	540.2	391	(488.7)	(261.8)	22.8	11.7	11.3	5.7
March	521,327	461,286	520.7	309.5	(497.8)	(386.2)	2.7	9.6	4.8	3.7
April	437,220	535,048	478.2	831.4	(523.4)	(467.0)	22.6	6.1	7.9	2
May – Oct	1,560,748	1,919,188	441.6	546.0	(488.1)	(591.6)	43.4	30.5	20.1	11.9
Nov – Apr	3,088,344	2,852,800	599.2	831.4	(622.6)	(467.0)	20.8	9.8	7.4	4.9
May - Apr	4,649,092	4,771,988	599.2	831.4	(622.6)	(591.6)	32.1	20.1	13.7	8.4

* Discrepancy rate is calculated as the hourly difference between offered and delivered MWs, divided by the hourly offered MWs averaged over the month.

Table A-11: Failed Imports into Ontario, On-Peak May – April 2011/2012 & May – April 2012/2013 (MW and %)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	142	185	346	400	53	57	4.9	4.5
June	253	133	500	374	62	56	8.1	2.6
July	274	220	350	600	58	59	4.1	2.7
August	271	211	406	413	41	55	3.3	2.6
September	256	242	363	342	42	50	5.0	4.1
October	186	102	243	313	60	59	7.6	2.1
November	152	68	400	325	56	75	4.8	2.8
December	112	9	250	138	63	94	5.3	0.7
January	231	157	300	500	46	49	5.4	7.7
February	113	123	428	300	52	48	3.3	5.5
March	191	83	316	232	65	64	7.0	4.3
April	75	86	188	400	48	69	1.9	5.0
May-Oct	1,382	1,093	500	600	53	56	5.5	3.1
Nov-Apr	874	526	428	500	55	67	4.6	4.3
May-Apr	2,256	1,619	500	600	54	61	5.0	3.7

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of on-peak failed imports divided by the sum of pre-dispatch on-peak imports in the month.

Table A-12: Failed Imports into Ontario, Off-Peak May – April 2011/2012 & May – April 2012/2013 (MW and %)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	209	210	413	354	65	58	24.3	12.6
June	275	139	211	352	65	72	23.7	10.6
July	285	200	350	614	69	60	11.1	6.3
August	363	225	350	464	58	58	14.2	9.4
September	421	305	500	418	56	44	15.8	13.2
October	509	302	242	274	56	66	23.7	18.8
November	477	52	206	200	60	50	26	4.7
December	256	64	300	363	55	71	14.1	8.8
January	303	57	200	500	40	80	18.8	5.7
February	148	178	171	500	43	58	12.5	14
March	338	60	396	600	54	81	28.1	3.5
April	168	119	358	150	62	49	7.5	5.9
May-Oct	2062	1381	500	614	61.5	59.7	18.8	11.8
Nov-Apr	1690	530	396	600	52.3	64.8	17.8	7.1
May-Apr	3752	1911	500	614	56.9	62.3	18.3	9.5

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of off-peak failed imports divided by the sum of pre-dispatch off-peak imports in the month.

Table A-13: Failed Exports from Ontario, On-Peak May – April 2011/2012 & May – April 2012/2013 (MW and %)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	1,104	865	300	225	40	47	7.7	7.5
June	934	705	250	250	47	52	10.9	5.8
July	985	532	300	270	48	45	7.7	3.5
August	783	404	200	300	46	42	7.2	2.6
September	726	229	270	200	52	41	10.3	2.4
October	395	270	200	205	49	55	4.4	2.9
November	305	791	211	200	57	39	4.2	4.0
December	654	294	211	150	45	55	8.6	3.0
January	561	500	300	200	55	49	5.4	3.1
February	1,062	682	300	200	44	50	8.2	6.0
March	1,017	637	211	150	47	37	7.9	4.0
April	1,072	468	300	200	42	46	6.8	3.4
May-Oct	4,927	3,005	300	300	47.0	47.0	8.0	4.1
Nov-Apr	4,671	3,372	300	200	48.3	46.0	6.9	3.9
May-Apr	9,598	6,377	300	300	47.7	46.5	7.4	4.0

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of on-peak failed exports divided by the sum of pre-dispatch on-peak exports in the month.

Table A-14: Failed Exports from Ontario, Off-Peak May – April 2011/2012 & May – April 2012/2013 (MW and %)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	823	534	437	300	49	46	4.1	4.3
June	600	551	500	230	52	55	4.9	5.1
July	554	482	244	250	51	51	4.6	4.0
August	779	385	200	250	57	40	7.5	2.9
September	461	308	310	200	50	46	4.4	3.1
October	426	275	200	200	50	56	3.6	2.4
November	276	507	345	200	58	45	3.5	3.0
December	349	439	200	175	36	52	2.8	3.1
January	589	387	167	150	45	54	4.5	2.6
February	703	794	300	233	45	54	5.8	6.5
March	1051	610	200	212	47	40	7.5	3.7
April	712	450	300	219	53	48	4.9	2.8
May-Oct	3643	2535	500	300	51.5	49.0	4.9	3.6
Nov-Apr	3680	3187	345	233	47.3	48.8	4.8	3.6
May-Apr	7323	5722	500	300	49.4	48.9	4.8	3.6

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of off-peak failed exports divided by the sum of pre-dispatch off-peak exports in the month.

Table A-15: Sources of Operating Reserve, On-Peak
May – April 2011/2012 & May – April 2012/2013
(MW and %)

	Average Hourly Reserve (MW)		% of Total Requirements											
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	1,553	1,484	17.6	17.2	28.8	43.1	4.3	4.0	33.4	30.9	8.3	1.1	8.0	3.7
June	1,491	1,478	14.8	15.2	37.7	43.6	10.8	4.6	23.9	33.7	6.3	1.1	7.2	1.7
July	1,530	1,422	13.5	18.5	52.5	43.0	13.7	2.4	12.3	35.0	3.3	1.2	5.2	0.1
August	1,596	1,417	12.5	17.3	54.5	41.0	7.5	4.1	14.9	35.9	2.2	1.6	8.8	0.1
September	1,559	1,418	15.9	17.2	53.8	40.3	5.3	2.3	15.8	38.2	2.0	1.9	7.4	0.0
October	1,521	1,537	16.1	18.7	52.8	39.1	1.4	3.9	24.0	34.2	0.9	1.2	4.9	2.9
November	1,510	1,434	15.9	16.7	49.9	40.8	3.2	3.6	23.7	36.5	1.3	1.9	6.0	0.5
December	1,553	1,467	11.6	11.9	57.0	45.3	6.2	4.1	17.8	37.5	0.5	1.2	7.1	0.0
January	1,553	1,417	15.3	14.4	55.0	46.3	8.1	1.4	13.7	36.2	2.0	1.7	6.2	0.0
February	1,438	1,467	16.2	14.3	51.5	37.1	8.8	3.9	14.7	41.8	0.4	2.8	8.6	0.1
March	1,418	1,418	17.0	13.2	36.6	39.5	9.0	4.6	24.4	40.8	3.5	1.2	10.0	0.8
April	1,448	1,510	18.2	16.9	45.5	43.0	10.9	0.7	15.5	33.8	1.0	1.8	9.3	3.8
May-Oct	1,542	1,459	15.1	17.4	46.7	41.7	7.2	3.6	20.7	34.7	3.8	1.4	6.9	1.4
Nov-Apr	1,487	1,452	15.7	14.6	49.3	42.0	7.7	3.1	18.3	37.8	1.5	1.8	7.9	0.9
May-Apr	1,514	1,456	15.4	16.0	48.0	41.8	7.4	3.3	19.5	36.2	2.6	1.6	7.4	1.1

Table A-16: Sources of Operating Reserve, Off-Peak
May – April 2011/2012 & May – April 2012/2013
(MW and %)

	Average Hourly Reserve (MW)		% of Total Requirements													
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	1,553	1,440	19.1	30.4	51.4	61.8	1.1	1.6	17.1	2.7	3.2	0.1	8.1	3.4
June	1,485	1,458	16.8	31.0	58.6	63.3	3.8	0.3	14.7	3.3	1.7	0.1	4.5	2.0
July	1,505	1,420	15.2	33.6	57.7	59.0	7.2	0.3	9.7	6.7	1.0	0.3	9.3	0.1
August	1,586	1,419	15.4	31.0	66.7	60.7	2.1	0.7	7.1	6.7	0.8	0.8	7.9	0.1
September	1,564	1,424	16.6	30.5	65.3	61.1	1.5	0.4	8.0	7.6	0.4	0.4	8.1	0.0
October	1,510	1,546	16.5	31.3	64.2	60.7	1.2	0.6	10.6	2.8	0.2	0.9	7.3	3.7
November	1,512	1,427	16.8	28.6	62.0	65.3	1.8	0.6	11.4	3.7	0.1	1.1	7.7	0.8
December	1,565	1,422	14.8	22.2	63.0	71.3	3.3	0.8	9.2	5.3	0.3	0.5	9.3	0.0
January	1,553	1,418	17.2	24.2	62.9	70.3	3.5	0.6	10.4	4.6	0.3	0.3	5.7	0.0
February	1,456	1,435	17.7	24.9	57.3	62.7	4.0	1.4	9.1	10.0	0.5	1.0	11.4	0.0
March	1,418	1,418	19.7	19.8	46.0	68.8	2.3	1.0	16.7	9.0	1.3	0.5	14.0	0.8
April	1,497	1,498	20.1	23.5	53.5	67.7	1.9	0.2	15.0	4.6	0.6	0.6	8.9	3.4
May-Oct	1,534	1,451	16.6	31.3	60.7	61.1	2.8	0.7	11.2	5.0	1.2	0.4	7.5	1.6
Nov-Apr	1,500	1,436	17.7	23.9	57.5	67.7	2.8	0.8	12.0	6.2	0.5	0.7	9.5	0.8
May-Apr	1,517	1,444	17.2	27.6	59.1	64.4	2.8	0.7	11.6	5.6	0.9	0.6	8.5	1.2

Table A-17: Monthly Payments for Operating Reserve and Reliability Programs May – April 2011/2012 & May – April 2012/2013 ($ millions)

	IOG		OR		Day-Ahead Generation Cost Guarantee *^		Real-Time Generation Cost Guarantee		Total	
	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013	2011/2012	2012/2013
May	0.37	1.04	12.20	0.77	2.68	2.71	5.50	6.98	20.78	11.36
June	0.76	1.22	4.74	0.57	3.40	4.64	6.56	7.27	15.50	13.63
July	0.36	4.05	1.51	0.71	5.12	7.40	7.23	6.35	14.26	18.51
August	0.37	3.81	2.45	0.76	9.39	13.21	3.99	5.79	16.23	23.56
September	1.13	3.74	0.71	0.78	8.22	4.51	6.80	4.99	16.83	14.02
October	0.39	0.66	0.45	2.69	4.23	1.21	3.84	5.61	8.92	10.17
November	0.54	0.71	0.60	2.73	7.45	6.55	5.06	4.40	13.61	14.39
December	0.67	0.55	1.17	1.14	5.85	7.94	6.95	7.13	14.67	9.06
January	0.77	0.63	1.28	2.22	5.17	1.79	5.03	8.67	12.28	7.06
February	1.16	2.10	0.58	2.20	6.52	3.08	7.25	6.13	15.55	13.33
March	1.46	0.85	3.99	0.88	3.84	2.48	10.04	6.89	19.37	11.11
April	0.40	0.52	1.25	2.92	2.93	0.57	7.60	7.11	12.18	11.11
May – Oct	3.38	14.52	22.06	6.28	33.04	33.67	33.92	36.99	92.52	91.25
Nov – Apr	5.00	5.36	8.87	12.09	31.76	22.42	41.93	40.33	87.66	66.08
May - Apr	8.38	19.89	30.93	18.37	64.80	56.09	75.85	77.32	180.18	157.33

*Prior to Oct 13, 2011, day-ahead guarantee payments were made under the day-ahead commitment process, and since that time are made under the enhanced day-ahead commitment process. The day-ahead payments as presented in this table are not necessarily the finalized settlement amounts. Payments may be subject to IESO clawbacks, which are not reflected in this table.

Table A-18: Summary Statistics for Hours when HOEP < $0/MWh May 2012 _ April 2013 (MW, $/MWh and %)

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	19	12,110	12,065	(0.4)	99	11.98	(51.95)	(533.5)	(128.1)
June	24	12,099	12,021	(0.6)	156	8.41	(55.92)	(765.1)	(128.1)
July	8	12,889	12,614	(2.1)	63	11.59	(46.76)	(503.5)	(128.1)
August	9	12,863	12,792	(0.6)	63	14.91	(27.95)	(287.4)	(128.0)
September	5	12,529	12,483	(0.4)	46	9.38	(73.87)	(887.7)	(108.5)
October	27	12,544	12,449	(0.8)	64	2.91	(58.95)	(2,124.9)	(128.1)
November	11	12,696	12,609	(0.7)	140	-5.82	(63.26)	986.0	(128.1)
December	4	12,556	12,636	0.6	293	12.27	(67.60)	(651.0)	(128.1)
January	13	13,456	13,262	(1.4)	78	9.09	(43.14)	(574.5)	(106.4)
February	0	0	0	0	0	0	0	0	0
March	3	12,826	12,601	(1.8)	239	8.10	(1.80)	(122.2)	(2.7)
April	12	12,110	12,103	(0.1)	138	1.18	(3.38)	(387.7)	(4.8)
Average	12.3	12,607	12,512	(1.0)	125	7.64	(44.96)	(532.0)	(101.7)

* Monthly figures reflect the average of hourly re-dispatch and real-time demand, net failed exports, and pre-dispatch and HOEP prices over all hours when HOEP was negative.

Table A-19: Share of Marginal Resource Setting Real-Time MCP, All Hours May – April 2011/2012 & May – April 2012/2013 (% of intervals)

Month	Coal		Gas		Hydro		Nuclear		Load	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	2.2	18.0	38.5	29.2	56.1	49.6	1.7	1.2	1.5	2.0
June	14.0	25.1	46.6	39.4	35.9	31.6	1.7	1.7	1.7	2.2
July	40.8	22.3	34.7	54.5	22.0	21.1	0.1	0.4	2.5	1.7
August	28.5	22.2	38.7	52.2	28.3	23.2	1.5	0.4	3.0	2.0
September	16.5	15.5	45.3	57.6	32.9	23.4	0.2	0.4	5.1	3.1
October	11.5	17.4	53.2	33.8	31.4	42.8	0.9	1.8	3.0	4.2
November	20.5	12.6	59.3	45.7	19.1	39.4	1.1	0.8	0.0	1.5
December	17.3	31.4	45.8	36.9	33.1	28.7	0.7	0.3	3.1	2.7
January	29.8	24.7	45.8	42.6	21.6	30.7	0.6	0.6	2.1	1.4
February	39.2	21.9	41.7	64.8	16.1	13.0	0.1	0.0	2.9	0.3
March	23.2	17.1	20.8	55.4	52.2	26.3	2.2	0.4	1.7	0.9
April	15.0	7.5	41.7	36.2	41.3	52.2	0.2	2.2	1.8	2.1
Average	21.5	19.6	42.7	45.7	32.5	31.8	0.9	0.9	2.4	2.0

Table A-20: Share of Marginal Resource Setting Real-Time MCP, On-Peak May – April 2011/2012 & May – April 2012/2013 (% of intervals)

Month	Coal		Gas		Hydro		Nuclear		Load	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	3.8	31.8	53.2	38.5	42.5	29.6	0.3	0.1	0.1	0.0
June	19.5	37.5	60.5	43.6	19.8	18.9	0.1	0.0	0.1	0.0
July	37.7	30.4	48.8	54.3	13.5	15.2	0.0	0.0	0.0	0.1
August	33.5	31.6	50.4	58.8	16.0	9.5	0.0	0.0	0.1	0.0
September	21.6	19.8	57.4	66.9	20.8	13.1	0.1	0.2	0.0	0.1
October	14.6	25.7	74.2	49.8	10.9	24.1	0.2	0.4	0.0	0.1
November	25.0	15.8	69.2	66.1	5.8	18.0	0.0	0.1	0.0	0.0
December	18.9	32.9	63.7	53.8	17.4	13.3	0.0	0.0	0.0	0.0
January	32.6	19.1	51.4	62.8	16.1	18.1	0.0	0.0	0.0	0.0
February	46.2	10.6	44.8	82.6	9.0	6.8	0.0	0.0	0.0	0.0
March	28.9	18.7	25.5	76.2	45.2	5.0	0.5	0.0	0.0	0.0
April	25.2	7.1	52.7	53.0	22.1	39.7	0.1	0.2	0.0	0.0
Average	25.6	23.4	54.3	58.9	19.9	17.6	0.1	0.1	0.0	0.0

Table A-21: Share of Marginal Resource Setting Real-Time MCP, Off-Peak May – April 2011/2012 & May – April 2012/2013 (% of intervals)

Month	Coal		Gas		Hydro		Nuclear		Load	
	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013	2011/ 2012	2012/ 2013
May	0.9	5.6	26.3	20.8	67.2	67.5	2.9	2.1	2.7	3.9
June	8.8	14.2	33.3	35.8	51.4	42.8	3.3	3.1	3.2	4.1
July	43.1	15.6	24.0	54.6	28.4	25.9	0.2	0.8	4.3	3.0
August	24.0	13.7	28.2	46.3	39.3	35.6	2.9	0.7	5.7	3.8
September	12.0	12.4	34.8	50.7	43.5	31.0	0.2	0.6	9.5	5.3
October	9.0	9.9	35.8	19.5	48.3	59.6	1.4	3.1	5.5	7.9
November	16.2	9.6	49.9	26.2	31.9	59.9	2.0	1.4	0.0	2.9
December	16.0	30.3	32.3	25.3	44.9	39.3	1.2	0.5	5.5	4.6
January	27.6	29.7	41.2	24.5	26.2	42.0	1.1	1.1	3.9	2.7
February	33.1	32.3	39.1	48.4	22.2	18.8	0.2	0.0	5.3	0.5
March	18.1	15.8	16.5	39.6	58.6	42.3	3.7	0.6	3.1	1.6
April	7.5	7.8	33.7	21.4	55.4	63.1	0.3	3.8	3.1	3.9
Average	18.0	16.4	32.9	34.4	43.1	44.0	1.6	1.5	4.3	3.7