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

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from

November 2013 – April 2014

April 2015

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Executive Summary

This is the Panel's 24th semi-annual Monitoring Report on the IESO-administered markets. In Chapter 1 the Panel summarizes market outcomes spanning the May 1, 2013 to April 30, 2014 period (the "Current Annual Period"). Chapter 2 focuses on the results of the Panel's review of high-price and low-price hours, as well as other anomalous market outcomes that transpired in the six months from November 1, 2013 to April 30, 2014, or the "Winter 2014 Period" following the period covered in the Panel's last semi-annual Monitoring Report. Chapter 3 discusses developments that affect the efficient operation of the IESO-administered markets, and contains the Panel's only recommendation in this report. Chapter 4 contains the Panel's annual general assessment of the state of the IESO-administered markets, summarizes future market developments of interest and discusses the status of recommendations made in the Panel's last Monitoring Report.

1 *Matters to Report in the Ontario Electricity Marketplace*

Export Nodal Price Chasing on Ontario Interties

The Panel's sole recommendation in this report is made to the Independent Electricity System Operator ("IESO") and relates to Congestion Management Settlement Credit ("CMSC") payments for constrained-off transactions across Ontario's interties. The Panel frequently noted concerns with, and made recommendations related to, constrained-off CMSC payments, most recently in its January 2014 Monitoring Report where it recommended that the IESO eliminate constrained-off CMSC payments to intertie traders.

In the context of intertie transactions, constrained-off CMSC payments are essentially payments to exporters for not exporting power from Ontario, or payments to importers for not importing power into Ontario. The Panel observes that these CMSC payments do not provide commensurate value to the market, are susceptible to gaming, increase wholesale market uplift charges and incent inefficient behavior. Since market opening, Ontario exporters have received $162.9 million in CMSC payments for not exporting power and importers have received $94.3 million in CMSC payments for not importing power; payments that are ultimately recovered from Ontario consumers. Other concerns aside, CMSC payments for intertie transactions allows a market participant to predictably profit through strategic bidding or offering behaviour.

One such behaviour, discussed in Chapter 3 of this report, is bidding by exporters in a manner that is designed to result in their exports being constrained-off. Underlying this behaviour is the powerful incentive created by constrained-off CMSC payments, which can have the effect of making profits associated with not exporting power much higher than the potential profits associated with actually exporting power.

The Panel refers to bidding or offering behaviour that appears to target CMSC payments as 'nodal price chasing'. Simply stated, nodal price chasing is the placement of offers or bids at prices that appear to have the predominant purpose of targeting CMSC payments, as opposed to purchasing or selling power from or to Ontario. The Panel estimates that of the $31.6 million in constrained-off CMSC paid to exporters from January 2013 to April 2014, upwards of $21.8 million (69%) appears to be associated with nodal price chasing.

The Panel's analysis of a number of examples of nodal price chasing reinforces the importance of expeditiously addressing this issue, and the Panel therefore re-iterates the recommendation made in its January 2014 Monitoring Report that the IESO eliminate constrained-off CMSC payments for all intertie transactions.

<u>Recommendation 3-1</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.

Data on Embedded Generation, Embedded Consumption, and Behind-the-Meter Generation

There is currently a lack of data related to certain significant changes in the energy sector; namely, the growth of generation that is connected at the distribution level (and not directly to the IESO-controlled grid) and the revised allocation of the Global Adjustment. This lack of data makes tracking changes in certain aspects of the market—and assessing outcomes in the market—more difficult. The Panel has identified three main categories of missing data: embedded generation, consumption by large industrial loads that are connected at the distribution level, and behind-the-meter generation. Chapter 3 identifies avenues that will be explored by the Panel for the purposes of obtaining this data, which will in turn enable the Panel to more accurately measure hourly supply and demand, as well as the response of electricity consumers to incentives such as the Industrial Conservation Initiative (or "ICI," the high-5 allocation of the Global Adjustment).

High-5 Allocation of the Global Adjustment – Industrial Conservation Initiative

Since the ICI was introduced in 2011, all loads with a peak demand of over 5 MW have qualified as Class A consumers for purposes of the allocation of the Global Adjustment ("GA"), and are treated as such unless they elect otherwise.

In its June 2013 Monitoring Report, the Panel discussed the efficiency and cost shifting effects of the high-5 allocation of the GA. In this report, the Panel observes that Class A consumers connected at the transmission level reduced their consumption in the high-5 hours of 2013 by an average of over 600 MWh.

In May 2014, the Provincial government expanded the scope of the ICI effective July 2015, such that consumers whose businesses are within certain industry specifications and whose peak demand is 3 MW or greater can elect to be Class A consumers. While it is too early for the Panel to comment on how these new Class A consumers will respond, the total demand reductions on high-5 days is expected to grow as the number of Class A consumers increases. An increase in the number of Class A consumers will likely lead to greater total Class A response to potential high-5 days, which in turn would increase the difficulty of predicting the high-5 days once the Class A response is factored in. To the extent that the result is reduced demand when the incremental cost of production is low, there would be an adverse effect on short-term efficiency.

Investigations

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

Amalgamation of the Independent Electricity System Operator and the Ontario Power Authority

As of January 1, 2015 the Independent Electricity System Operator (IESO) and the Ontario Power Authority (OPA) were amalgamated and continued under the IESO name. This report preserves references to the IESO or the OPA, since they existed as separate entities during the monitoring period covered by this report.

2 *Summary of Market Outcomes*

As noted above, the Panel's review of market outcomes spans the Current Annual Period from May 1, 2013 to April 30, 2014.

Demand and Supply Conditions

Ontario demand totalled 146.4 TWh in the Current Annual Period, up by 0.5 TWh (0.3%) from the previous annual period. Increased domestic consumption was largely driven by the extreme cold weather in the first few months of 2014, leading to January 2014 having the highest monthly demand of the past five years.

During the Current Annual Period 534 MW of new nameplate generating capacity was connected to the IESO-controlled grid, consisting primarily of new wind generation. Ontario experienced several plant retirements during the period. All remaining coal-fired plants (totalling 3,307 MW of generating capacity) were removed from service, making Ontario the first jurisdiction in North America to fully eliminate coal as a source of electricity generation.

This net loss of IESO-controlled grid-connected capacity resulted in a 2,773 MW reduction in total installed capacity to approximately 33,243 MW as of April 30, 2014. However, the Panel notes that significant generating capacity was added at the distribution level during the Current Annual Period.

Market Prices and Effective Prices

The Panel reports what it calls the "effective price" for Ontario consumers, which comprises the Hourly Ontario Energy Price ("HOEP"), the GA, and IESO uplift. In the Current Annual Period, the average effective price was $60.71/MWh for Class A consumers that are directly connected to the IESO-controlled grid, and $89.19 for all other consumers (Class B consumers and Class A consumers that are connected at the distribution level); an increase of 17.8% and 15.1%, respectively, from the previous annual period.[1] For both consumer groups, the increase in the effective price was driven by considerable increases in the average weighted HOEP, associated with the high average HOEP from January to March 2014. Since the GA is inversely related to the HOEP, it declined for both consumer groups during the Current Annual Period. The principal reason for the difference in the effective prices as between consumer classes lies in the methodology by which the GA is allocated to each class.

Operating Reserve (OR) prices were much higher in the Current Annual Period relative to the previous annual period, with 10-minute spinning and 10-minute non-spinning OR prices in May 2013 reaching the highest monthly average price in the history of the Ontario market. High OR prices were a result of reduced OR supply due to fewer OR offers from hydroelectric facilities by reason of high water conditions, and to reductions in the amount of Control Action Operating Reserve available to be scheduled, particularly in May 2013.

3 *Analysis of Anomalous Market Outcomes*

While the Panel's review of market outcomes covers a 12-month period, the Panel's analysis of anomalous market outcomes spans a six-month period, in this case the Winter 2014 Period from November 1, 2013 to April 30, 2014.

The Winter 2014 Period had an unprecedented number of hours in which the HOEP exceeded $200/MWh ("high-price hours"). The 133 high-price hours experienced in the Winter 2014 Period not only far exceeded the number of hours experienced in recent winter periods, but is almost double the next highest number of high-price hours experienced during any reporting period since market opening.

The vast majority of the high-price hours occurred between January and March 2014, when Ontario was experiencing extreme cold weather. The impacts of the sustained cold weather on the electricity market was threefold: (i) electricity demand increased as temperatures decreased; (ii) natural gas demand spiked across much of North America, leading to higher natural gas prices; and (iii) cold temperatures led to more forced nuclear generator outages. The high prices

[1] The "Class A" and "Class B" distinction stems from the classification of consumers into different classes for purposes of the allocation of the GA, Class A consumers being those whose average peak demand exceeds 5 MW and Class B consumers being all other consumers. As noted above, effective July 1, 2015 Class A is expanded to also include consumers in specified industries with peak demand of 3 MW or more.

in January were coincident with the highest average electricity demand of the Winter 2014 Period, while high prices in February and March were coincident with high prices in the natural gas market, which in turn increased the HOEP when gas-fired generators were setting the price. While typically a net exporter, Ontario relied on net imports during many hours in February and March, 2014.

In addition to the record number of high-price hours, the Winter 2014 Period also experienced 120 hours in which the HOEP was below $0/MWh ("negative-price hours"), mostly in November 2013, when high-levels of negative-priced offers from nuclear and wind generators coincided with below average demand.

There were 48 instances in which the Panel's anomalous uplift screening thresholds were met in the Winter 2014 Period, compared to 9 such instances in the previous annual period. The notable increase in anomalous events largely corresponds with the extreme cold weather during the Winter 2014 Period and the associated high levels of demand and high average HOEP. Many of the anomalous events were attributable to factors that have been extensively analyzed in previous Monitoring Reports; however, a small number of events of particular interest were selected for more in-depth review. Specifically, in Chapter 2 the Panel examines CMSC payments associated with nodal price chasing, CMSC payments made to constrained-on gas-fired generation facilities as a result of day-ahead commitments and day-ahead Intertie Offer Guarantee payments made in relation to import transactions that failed to flow in real-time.

4 *Overall Assessment*

The focus of the Panel's overall assessment of the state of the IESO-administered markets has been on the fairness and efficiency of the markets when considered in the context of design elements and policy decisions that affect market efficiency but with which the Panel recognizes as features of the current hybrid design.

Given this scope, the Panel has concluded that the IESO-administered markets operated in a reasonably satisfactory manner for the year ended April 2014. In particular, during the severe Winter 2014 Period, the markets generally provided appropriate signals to wholesale market participants. Nevertheless, areas for improvement in the design of and rules associated with the markets have been highlighted by the Panel through its observations and recommendations, made with a view to improving efficiency and eliminating inappropriate payments.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period May 1, 2013 to April 30, 2014 (the "Current Annual Period"), with comparisons to the same period one year earlier (the "Previous Annual Period"), as well as other periods where relevant.

1 *Pricing*

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price ("HOEP"), the effective commodity price (including the Global Adjustment and uplift), operating reserve prices, and transmission rights auction prices.

Table 1-1: Average Effective Commodity Price by Consumer Class
May – April 2012/13 & May – April 2013/14
($/MWh)

Description:

Table 1-1 summarizes the average effective commodity price[2] in dollars per megawatt hour by consumer class, for the Current and Previous Annual Periods. The average effective electricity commodity price is the summation of the average weighted HOEP, the average Global Adjustment ("GA") and average uplift. The results are reported for three consumer classes: Direct Class A consumers, Class B & Embedded Class A consumers, and for all consumers.[3]

Customer Class	Average Weighted HOEP	Average Global Adjustment	Average Uplift	Average Effective Price
Direct Class A - 2013/2014	36.03	21.39	3.29	60.71
Direct Class A - 2012/2013	25.54	23.58	2.41	51.53
Class B & Embedded Class A - 2013/2014	39.20	46.49	3.49	89.19
Class B & Embedded Class A - 2012/2013	27.18	47.86	2.47	77.50
All Consumers - 2013/2014*	38.85	43.55	3.47	85.87
All Consumers - 2012/2013*	27.00	45.14	2.46	74.60

*The average effective price for "All Consumers" is calculated using the previous GA allocation methodology in which all consumers were charged the GA based on their pro rata share of total consumption during the period.

[2] This price does not include delivery, some regulatory charges, or the Debt Retirement Charge.
[3] Direct Class A consumers are Class A consumers that are directly connected to the IESO-controlled grid, and Embedded Class A consumers are Class A consumers that are connected at the distribution level. Information regarding hourly consumption by Embedded Class A consumers is not readily available. As a result, information pertaining to pricing for Embedded Class A consumers is aggregated with information pertaining to Class B customers. Chapter 3 discusses the need for additional data on consumption by Embedded Class A consumers.

Relevance:

In Ontario the effective price a consumer pays for electricity depends on which consumer class they fall into. Consumers are divided into two groups: Class A, being consumers whose average peak hourly demand exceeds 5 MW (these customers – typically factories or other large industrial consumers – can be directly connected to the IESO-controlled grid or connected at the distribution level); and Class B, being all other consumers (including all residential consumers).[4]

Commentary and Market Considerations:

The average effective commodity price increased dramatically for both Direct Class A and Class B & Embedded Class A consumers during the Current Annual Period, when compared to the Previous Annual Period. For both consumer groups the increase in the average effective price was driven by considerable increases in the average weighted HOEP and average uplift. As can be seen in Figures 1-2A and 1-2B below, increases in the HOEP and uplift occurred largely in the winter months from January to March 2014. The GA primarily recovers the costs of payments to contracted and regulated generating resources when market revenues are insufficient to cover their contracted or regulated rates.[5] Accordingly, the HOEP and the GA exhibit an inverse relationship, leading to a modest decrease in the average GA in the Current Annual Period.

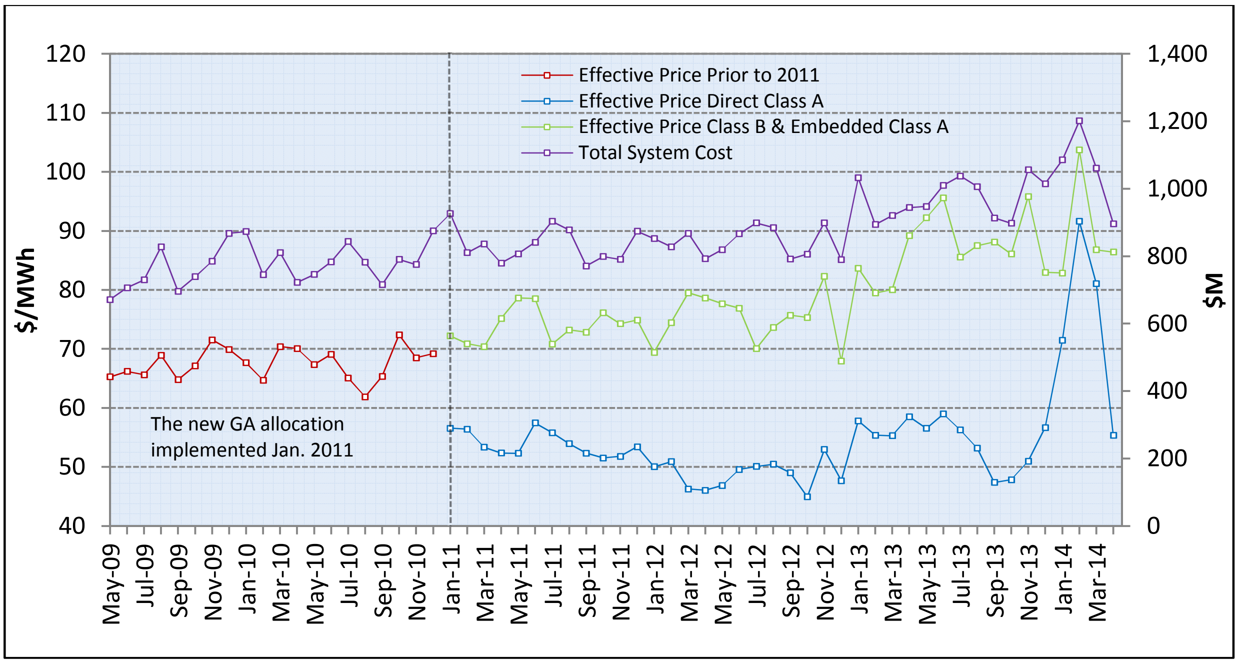
[4] See Ontario Regulation 398/10 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998,* available at http://www.e-laws.gov.on.ca/html/source/regs/english/2010/elaws_src_regs_r10398_e.htm. Starting July 1, 2015 Class A will also include consumers whose businesses are within certain industry specifications and whose average peak hourly demand exceeds 3 MW.

[5] The costs associated with compensating loads under the Ontario Power Authority's three demand response programs are also recovered through the GA charge.

Figure 1-1: Monthly Average Effective Commodity Price and Total System Cost
May 2009 – April 2014
($/MWh & $ millions)

Description:

Figure 1-1 plots the average effective electricity commodity price for Direct Class A and Class B & Embedded Class A consumers, from May 2009 to April 2014, as well as the monthly total system cost over the same period.[6] Prior to the change in the allocation of the GA in 2011, all consumers were charged GA based on their pro rata share of total consumption during the period.



Relevance:

Figure 1-1 highlights how the change in the GA allocation methodology has affected the effective commodity price paid by each consumer group.

Commentary and Market Considerations:

Relative to previous periods, monthly total system costs from late 2012 onwards have exceeded historic levels. The increase has been largely driven by the return to service of two Bruce Power nuclear units in the fall of 2012 following refurbishment, which has considerably increased the

[6] Total monthly system cost is the sum of the HOEPs, Global Adjustment and uplift charges for a given month.

province's contracted obligations and thus the payments to be recovered through the GA (the contribution of different types of generation to the GA is shown in Figure 1-10 below). In addition, a pronounced spike in the HOEP (see Figure 1-3 below) triggered a spike in monthly total system costs between January and March 2014. As a result, non-regulated generating assets and those with energy market revenue retention clauses in their contracts[7] received market revenues that generally exceeded recent levels.

The effective commodity price payable by different consumer groups diverged significantly at the beginning of the Current Annual Period, continuing the trend observed since the GA allocation methodology changed in January 2011. Since the current GA allocation methodology results in Class B consumers paying more GA than they would have based on the former methodology (where all consumers were charged GA based on their share of total consumption), the average effective commodity price paid by Class B consumers increases more significantly than that paid by Class A consumers when the GA makes up an increasing portion of the total system cost. Conversely, due to the inverse relationship between the HOEP and the GA, when the HOEP makes up proportionally more of the total system cost, the average effective commodity price paid by Class B consumers increases less than that paid by Class A consumers. The total monthly GA rose in late 2013, widening the gap between the average effective commodity price paid by Class A consumers and that paid by Class B consumers. In contrast, the considerable increase in the average HOEP in early 2014 caused a significant convergence in the average effective commodity price payable by each of the two consumer classes.

Figures 1-2A & 1-2B: Average Effective Electricity Commodity Price by Consumer Class

Description:

Figures 1-2A and 1-2B divide the monthly average effective electricity commodity price into its three components (average load-weighted HOEP, average GA, and average uplift) for Direct Class A and for Class B & Embedded Class A consumers, respectively, for the Current and Previous Annual Periods.

[7] Generally, contracts in Ontario guarantee a fixed compensation level. Where that is the case, the total compensation to these generation facilities (and thus the cost to consumers) is largely unaffected by the HOEP. However, some contracted resources, such as those with Clean Energy Supply contracts from the Ontario Power Authority, are allowed to retain a certain percentage of revenue earned above their contracted level.

Figure 1-2A: Average Effective Electricity Commodity Price for Direct Class A Consumers by Component May 2012 – April 2014 ($/MWh)

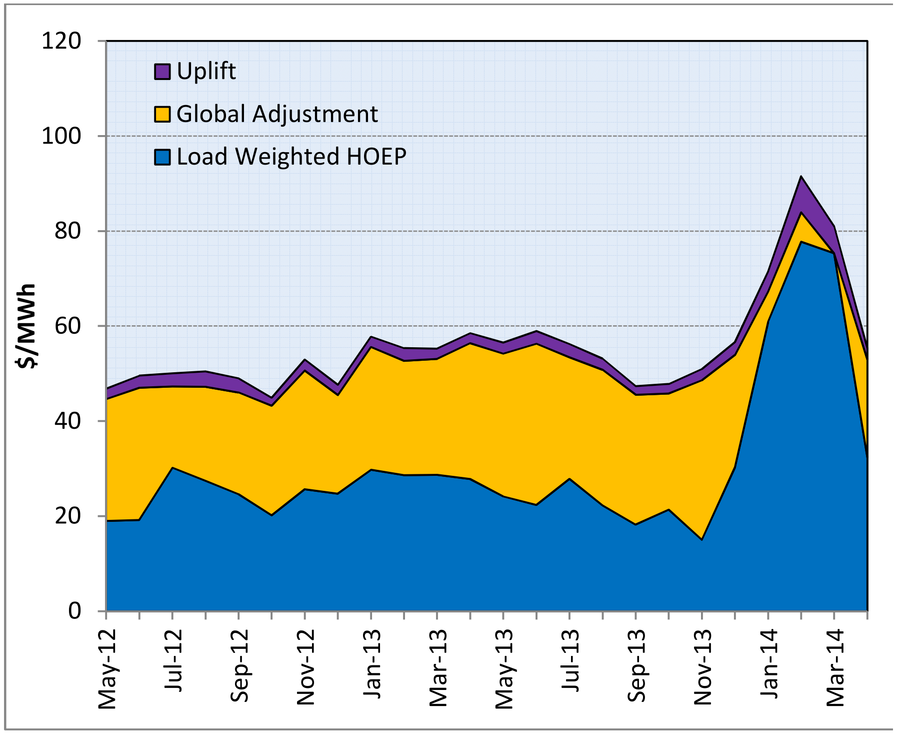
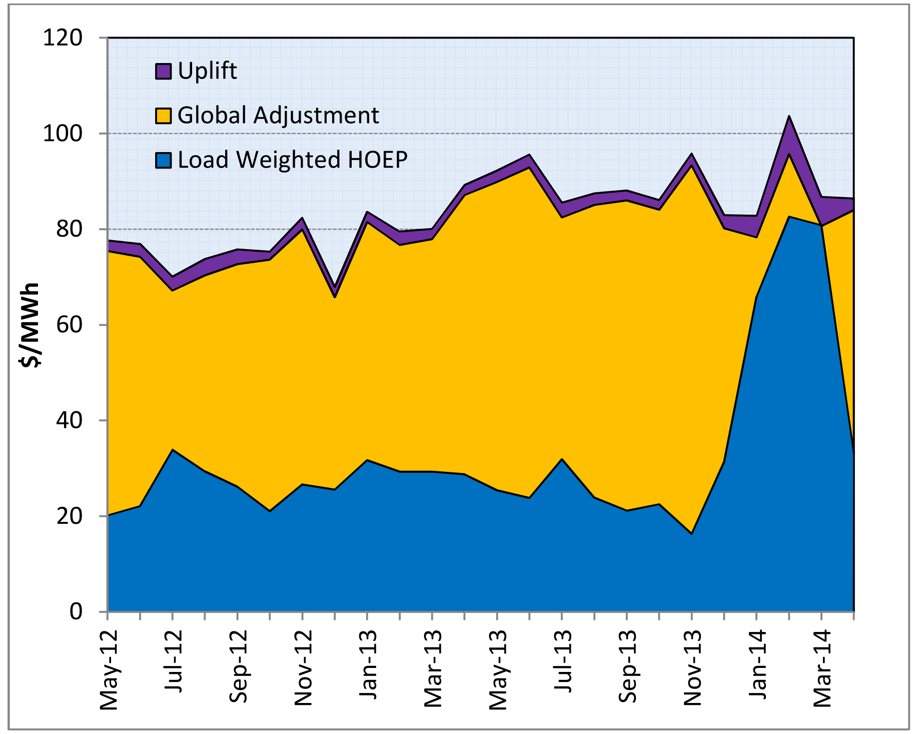


Figure 1-2B: Average Effective Electricity Commodity Price for Class B & Embedded Class A Consumers by Component May 2012 – April 2014 ($/MWh)



Relevance:

These figures illustrate how changes in the individual components of the effective commodity price affect the average effective commodity price paid by each consumer group.

Commentary and Market Considerations:

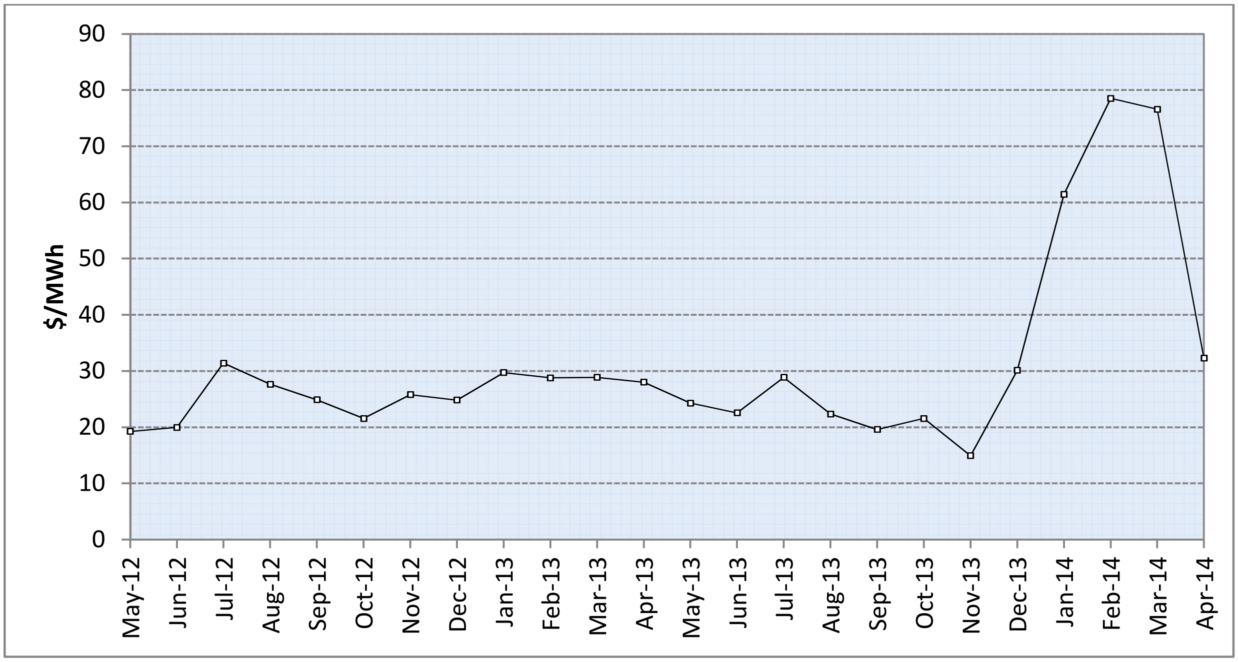
As discussed in the Commentary section associated with Figure 1-1, as a result of the revised GA allocation methodology, the two consumer groups are affected differently by changes in the three components of the average effective commodity price. For instance, in January through March 2014, both consumer groups saw an increase in the average weighted HOEP from $60/MWh to $80MWh. While the increase in the weighted HOEP was similar for both, the effect on the average effective commodity price over the same three-month period was not: Class A consumers' effective commodity price increased by between $10/MWh and $30/MWh, while Class B consumers' effective commodity price increased by between $0/MWh and $20/MWh. The result was a convergence of the average effective commodity price paid by each consumer group during these months. Conversely, in November 2013 when the total monthly GA increased due to a decrease in the weighted HOEP, the average effective commodity price for Class A consumers remained relatively constant while the effective commodity price for Class B consumers increased by approximately $10/MWh.

In March 2014, the GA allocation methodology benefited Class B consumers as the HOEP rose high enough that, for the first time since June 2008, the average GA for the month was a credit ($0.16/MWh).

Figure 1-3: Monthly Average HOEP
May 2012 – April 2014
($/MWh)

Description:

Figure 1-3 displays the average HOEP by month from May 2012 to April 2014.



Relevance:

The HOEP is the average market price for a given hour and is one component of the all-in effective price paid by consumers. The HOEP is calculated as the average of the 12 real-time market clearing prices ("MCP") set every 5 minutes by balancing supply and demand in the Ontario electricity market. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by other consumers through the Ontario Energy Board's Regulated Price Plan.

Commentary and Market Considerations:

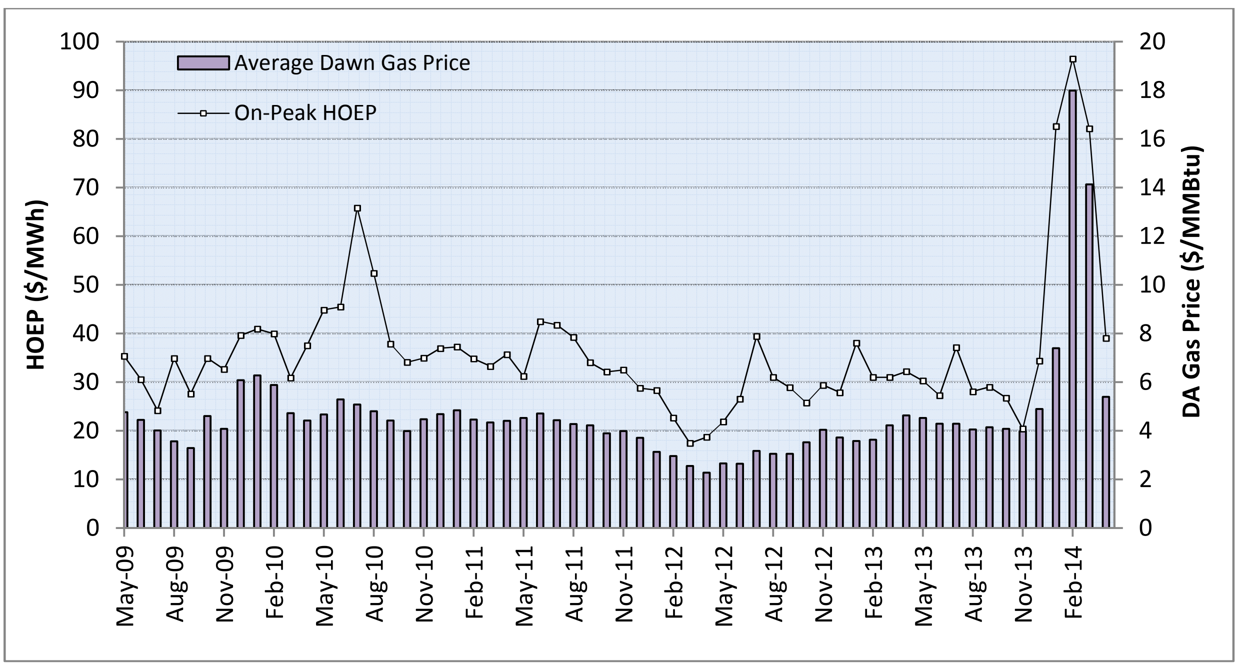
The monthly average HOEP reached an eight year high in February 2014, averaging $78.53/MWh. The sustained high average HOEP began in January 2014 and continued through March. High prices during those months were primarily driven by sustained extreme cold temperatures, which served to increase demand, and tight natural gas supply conditions. The constrained supply and transportation conditions in the natural gas market led to increased natural gas prices (see Figure 1-4), which in turn increased the marginal cost of gas-fired units; these units had a strong influence on the HOEP as they set the MCP an average of 35.3% of the time during January to March 2014 (see Figure 1-6).

For a detailed analysis of the conditions that led to high electricity market prices during the period, see Chapter 2.

Figure 1-4: Average Monthly Dawn Hub Day-Ahead Gas Price and the On-Peak HOEP May 2009 – April 2014 ($/MWh & $/MMBtu)

Description:

Figure 1-4 plots the monthly average day-ahead gas prices at the Dawn Hub and the average monthly HOEP during peak hours since May 2009.



Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario, with the largest storage facility in the province. Gas-fired generators typically purchase gas day-ahead; for that reason, the Dawn day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the on-peak HOEP, as gas-fired generators frequently set the price during these hours.

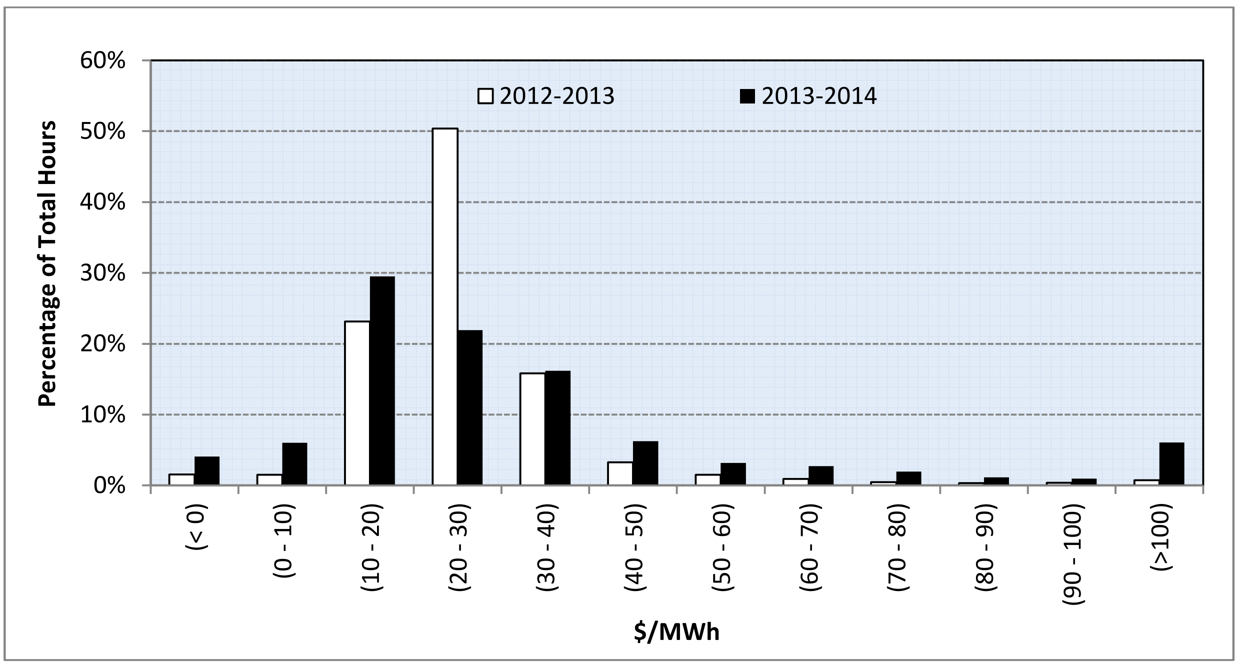
Commentary and Market Considerations:

Movements in the on-peak HOEP are highly correlated with movements in the spot market gas price, with a simple correlation coefficient between the two variables of 0.85; this relationship is particularly observable from November 2013 to April 2014. Greater demand for natural gas and a constrained transportation network contributed to increasing natural gas prices, which in turn increased the average on-peak HOEP.

Figure 1-5: Frequency Distribution of the HOEP
May – April 2012/13 & May – April 2013/14
(% of total hours)

Description:

Figure 1-5 displays the frequency distribution of the HOEP for the Current Annual Period and the Previous Annual Period, as a percentage of total hours.



Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the average HOEP falls in a given price range. This provides information that the average HOEP does not, such as the frequency of occurrence of extremely high or low prices.

Commentary and Market Considerations:

The distribution of prices was much broader in the Current Annual Period (more instances of hours with high and low prices), relative to the Previous Annual Period. The frequency of a negative HOEP increased from 1.5% of total hours during the Previous Annual Period, to 4% during the Current Annual Period, while instances when the HOEP was greater than $100/MWh increased from 0.7% to 6.0%. In the Current Annual Period, more hours had prices in each range from $30/MWh and higher.

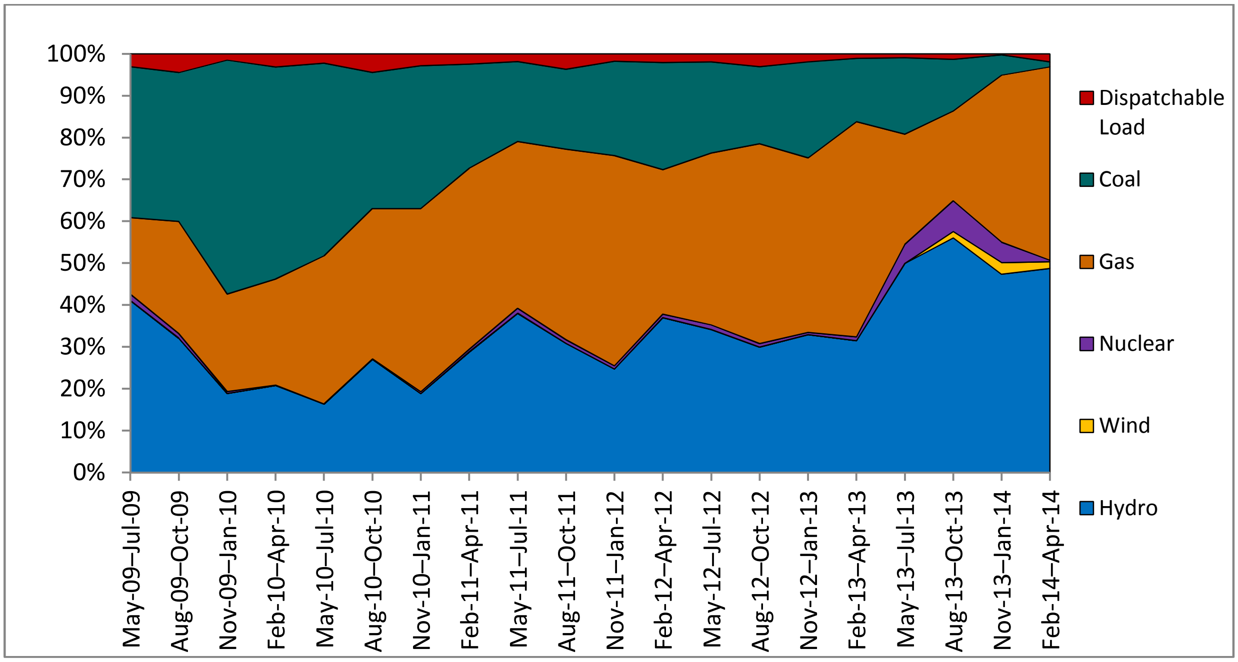
The greater number of hours with higher prices to the right of the distribution occurred primarily during the winter months when extreme cold weather was experienced.

The increase in the frequency of hours with a negative HOEP was largely driven by: (i) two Bruce Nuclear units returning to service in the fall of 2012, providing an additional 1,552 MW of negative-priced capacity in half of the Previous Annual Period but all of the Current Annual Period; (ii) a significant increase in negative-priced offers from must-run hydroelectric facilities during the Current Annual Period (13% increase from the Previous Annual Period); and (iii) increased installed capacity and generation from wind resources, which typically offer at negative prices. The downward effect on prices was most prominent during the shoulder seasons.

Figure 1-6: Share of Resource Type Setting Real-Time MCP
May 2009 – April 2014
(% of intervals)

Description:

Figure 1-6 presents the quarterly share of intervals in which each resource type set the real-time MCP as the marginal resource, from May 2009 to April 2014.



Relevance:

The relative frequency of each resource type setting the real-time MCP provides insight into Ontario's changing supply mix as well as factors such as seasonal demand and the changing costs of certain fuel sources.

Commentary and Market Considerations:

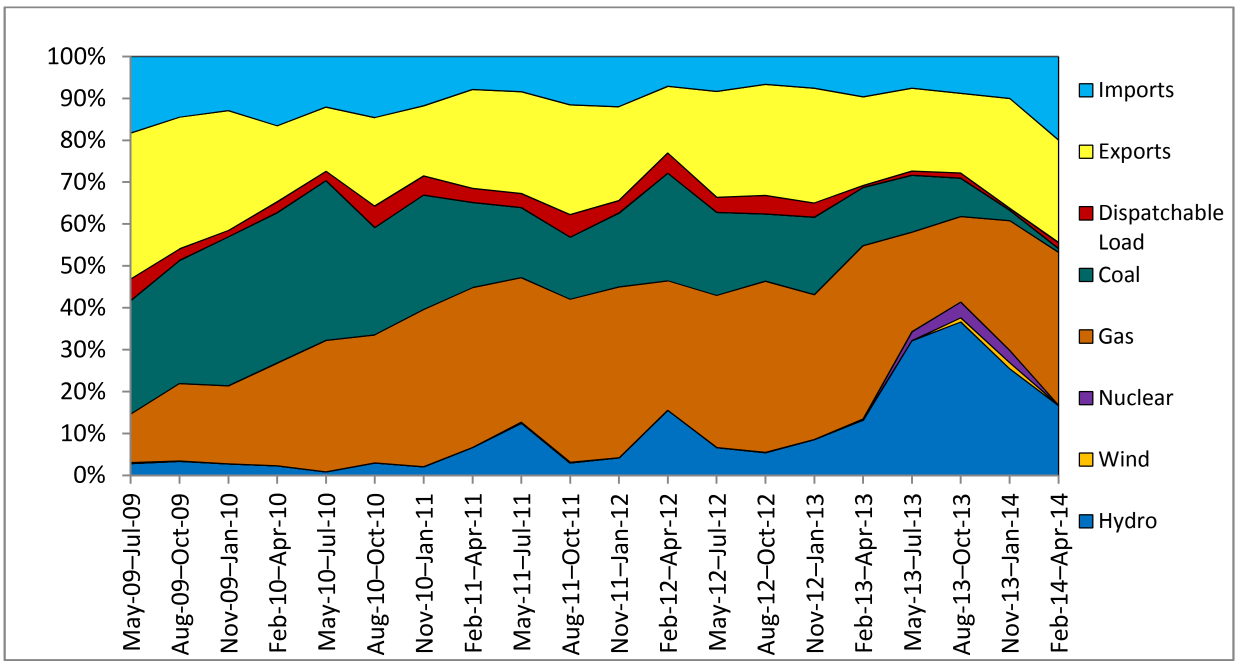
Several changes occurred during the Current Annual Period. The retirement of coal-fired resources was completed by January 2014, after which no coal resources could set the MCP. In September 2013, wind resources transitioned from being intermittent facilities incapable of setting the MCP to dispatchable facilities that set the MCP less than 3% of the time.

The share of nuclear resources setting the MCP also increased in the Current Annual Period. The return of two Bruce Nuclear units in late 2012, the increased installed capacity of renewable generation, and the establishment of a price floor for flexible nuclear generation all bumped nuclear generation up the supply stack towards the margin and contributed to the increase in the percentage of time that nuclear units set the MCP. A 13% increase in the quantity of must-run hydroelectric generation in the Current Annual Period relative to the Previous Annual Period contributed to a considerable increase in the frequency with which hydroelectric units set the real-time MCP. Nuclear, wind, and must-run hydroelectric resources typically offer at negative prices, and the increase in the frequency with which these resources set the MCP contributed to the increase in negative-price hours seen in Figure 1-5.

Figure 1-7: Share of Resource Type Setting Pre-Dispatch MCP
May 2009 – April 2014
(% of hours)

Description:

Figure 1-7 presents the quarterly share of hours in which each resource type set the pre-dispatch MCP as the marginal resource, from May 2009 to April 2014.



Relevance:

When compared with Figure 1-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the pre-dispatch MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the pre-dispatch MCP; as these transactions are unable to set the real-time price, another resource will set the real-time MCP. When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and real-time MCPs will occur.

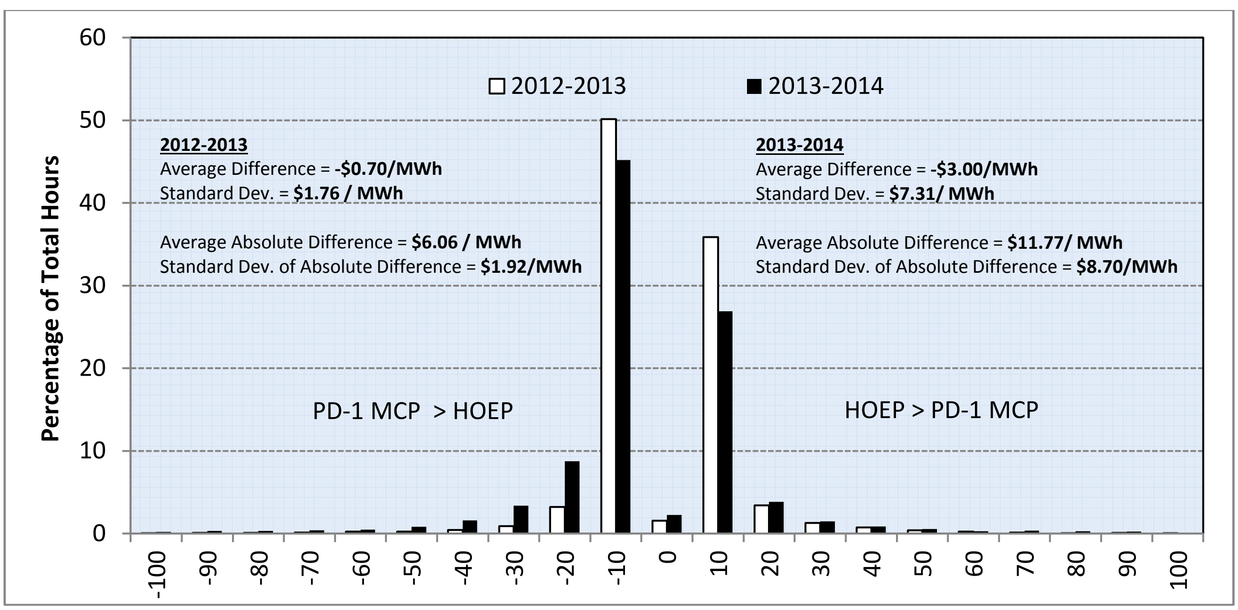
Commentary and Market Considerations:

Imports and exports set the price in 34% of the pre-dispatch hours in the Current Annual Period. In February and March 2014, imports and exports set the pre-dispatch price 46% of the time, the highest monthly total since October 2009. These two months contributed to a greater overall price discrepancy between pre-dispatch and real-time market prices, as seen in Figure 1-8.

Figure 1-8: Difference between the HOEP and the One-Hour Ahead Pre-Dispatch MCP May – April 2012/13 & May – April 2013/14 (% of total hours)

Description:

Figure 1-8 presents the frequency distribution of the $/MWh difference between the HOEP and the one-hour ahead pre-dispatch ("PD-1") MCP for the Current and Previous Annual Periods. The price differences are bucketed in $10 increments (with the bucket "10" on the x-axis representing price difference between $0.01 and $10, and so forth), save for the $0/MWh bucket which represents no change between the PD-1 MCP and the HOEP. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-1 MCP determines the schedules for import and export transactions, which are then carried over to real-time. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree supply and demand conditions change between PD-1 and real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it increases in real-time (due to, for instance, a generator outage between PD-1 and real-time), as paying the higher HOEP could result in a loss on the export transaction. Alternatively, prices could fall between PD-1 and real-time, increasing an exporter's profit, but potentially leaving it purchasing less than they would optimally purchase.

Commentary and Market Considerations:

In the Current Annual Period, the thicker tail on the left-hand side of the distribution relative to the right-hand side indicates that the HOEP decreased relative to the PD-1 MCP more frequently and by a greater degree than it increased.

Relative to the Previous Annual Period, overall fidelity of the PD-1 MCP relative to the HOEP decreased, while volatility increased on an absolute basis (a larger standard deviation in the Current Annual Period). The increase in the frequency of price divergences greater than +/- $10 was in large part due to the higher average HOEP observed during the Current Annual Period, as the average absolute standard deviation tends to increase proportionally as the average price increases. The larger price divergences increased the likelihood of intertie transactions being scheduled when uneconomic on the basis of the HOEP.

Table 1-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch MCPs and Real-Time Prices May - April 2012/13 & May - April 2013/14 (MW per hour and % of Ontario demand)

Description:

The Panel has identified six main factors that contribute to differences between the price in PD-1 and the price in real-time in any given hour. These factors are categorized as follows:

Supply

- Self-scheduling and intermittent forecast deviation (other than wind)
- Wind forecast deviation
- Generator outages
- Import failures/curtailments

Demand

- Pre-dispatch to real-time demand forecast deviation
- Export failures/curtailments

For all but one of these factors, Table 1-2 presents the average absolute difference in megawatts per hour, including as a percentage of Ontario demand, for the Current and Previous Annual Periods. The effect of generator outages is not measured in this table; these events tend to be infrequent but have significant price effects in the given hour. Generator outages are discussed in greater detail in Chapter 2.

Factor	2012/2013		2013/2014	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)
Average Ontario Demand	16,223		16,195	
Pre-dispatch to Real-time Demand Forecast Deviation	190	1.17%	208	1.29%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	27	0.17%	37	0.23%
Wind Forecast Deviation	84	0.52%	99	0.61%
Net Export Failures/Curtailments	70	0.43%	100	0.62%

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides some insight into the root causes of price risks that participants, particularly importers and exporters, will face as they enter offers and bids into the market.

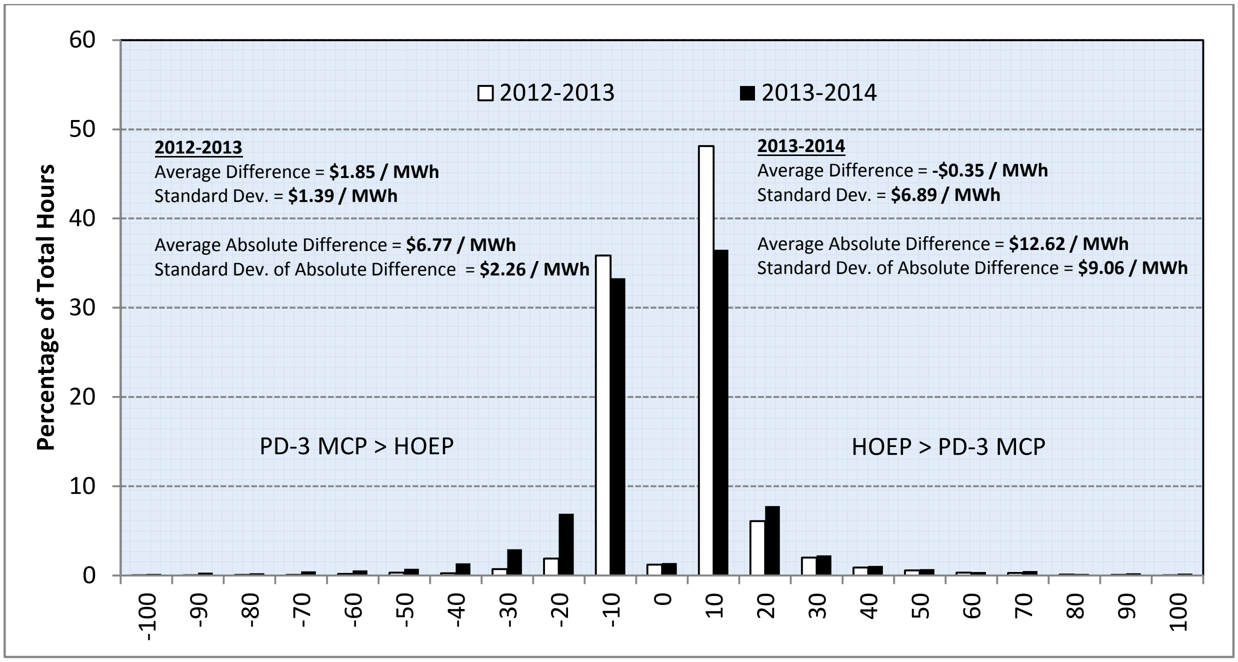
Commentary & Market Considerations:

Consistent with the decreased fidelity and increased volatility of the PD-1 MCP relative to the HOEP, all sources of potential difference increased in absolute terms and as a percentage of Ontario demand. While on an absolute basis wind forecast deviation increased, this was a result of greater installed capacity of wind in the Current Annual Period. The implementation of centralized wind forecasting in October 2012 contributed to a decrease in wind forecast error, from 15.6% in the Previous Annual Period to 14.3% in the Current Annual Period. Net export failures/curtailments increased, in part due to transient supply adequacy concerns in Ontario during the 2014 winter months that led to increased export curtailments (see Table 1-5).

Figure 1-9: Difference between the HOEP and the Three-Hour Ahead Pre-Dispatch MCP May – April 2012/13 & May – April 2013/14 (% of total hours)

Description:

Figure 1-9 presents the frequency distribution of the $/MWh difference between the HOEP and the three-hour ahead pre-dispatch ("PD-3") MCP for the Current and Previous Annual Periods. The price differences are bucketed in $10 increments (with the bucket "10" on the x-axis representing price difference between $0.01 and $10, and so forth), save for the $0/MWh bucket which represents no change between the PD-3 MCP and the HOEP. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed with consent from IESO's control room. Differences between the HOEP and the PD-3 MCP indicate changes to the supply and demand conditions between these two time periods. The resultant changes in price are particularly important for non-quick start facilities and energy limited resources, both of which rely on pre-dispatch prices to make operational decisions. Additionally, price changes are particularly important to intertie traders whose marginal benefit or cost, and therefore bids and offers in other jurisdictions, are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

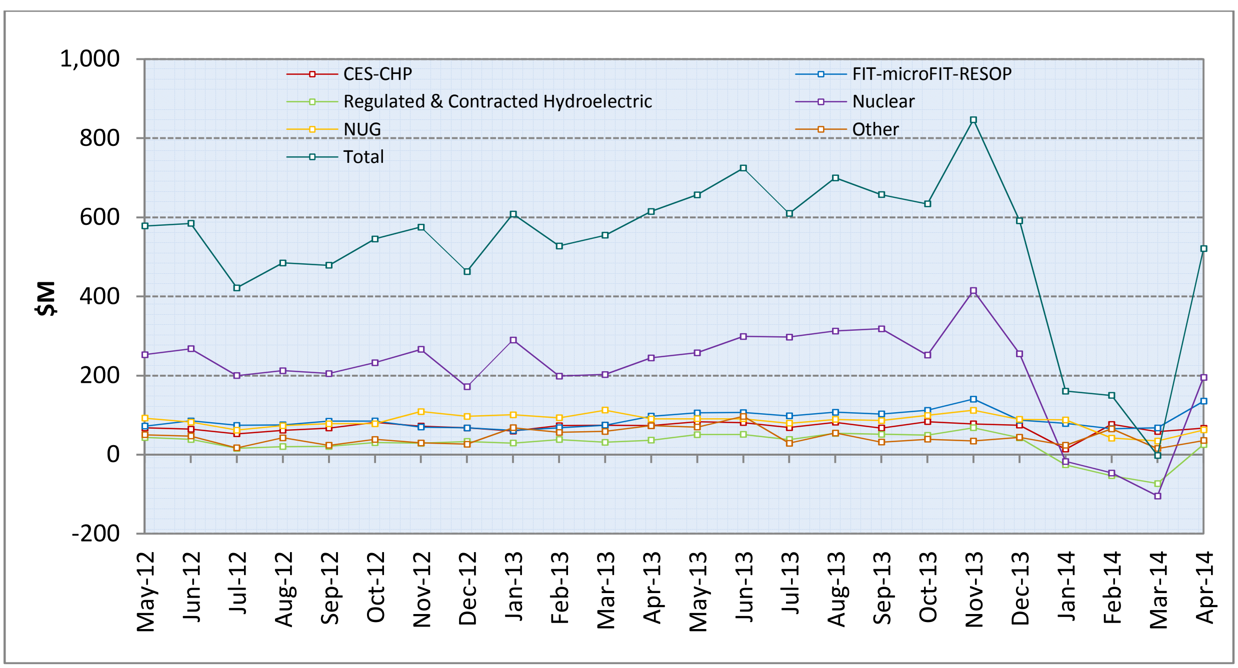
Volatility increased in the Current Annual Period as there were far fewer price differences within $10/MWh on either side of $0/MWh. As was the case with the PD-1 MCP (Figure 1-8), both the decrease in price fidelity between PD-3 and real-time and the increase in absolute volatility was largely due to the higher average HOEP observed during the Current Annual Period. The increased price volatility made it more difficult for market participants to forecast the HOEP in the three-hour-ahead timeframe.

Figure 1-10: Monthly Global Adjustment by Source
May - April 2012/13 & May- April 2013/14
($ millions)

Description:

Figure 1-10 plots the costs recovered through the GA each month, by component, for the Current and Previous Annual Periods. The total GA is divided into six components:

- Payments to nuclear facilities (Bruce Nuclear and Ontario Power Generation nuclear assets)
- Payments to holders of Clean Energy Supply ("CES") (including early-mover and accelerated gas-fired generation contracts), as well as Combined Heat and Power ("CHP") generation contracts
- Payments to holders of Ontario Electricity Financial Corporation non-utility generator ("NUG") contracts
- Payments to regulated or contracted hydroelectric generation
- Payments to holders of contracts for renewable power (Feed-in Tariff ("FIT"), microFIT, Renewable Energy Supply ("RESOP")), and
- Payments to others (including, the Ontario Power Authority's ("OPA") demand response programs, conservation programs, and the contract with OPG's Lennox generating station).



Relevance:

The GA by source helps identify the driving forces behind the total GA. High GA totals for a particular source may be the result of higher contracted rates or lower market revenues, more megawatts of production or capacity, or a combination of these factors.

Commentary and Market Considerations:

The GA exhibited an upward trend for most of 2013. Month to month changes in the GA can be primarily attributed to changes in payments to nuclear units, which are largely driven by unit availability, production and the HOEP. With respect to unit availability and production, two Bruce Nuclear units returned to service in September 2012 following an extended refurbishment period; increased compensation to the nuclear fleet can be expected to continue. Due to the contracted or regulated compensation framework for nuclear units, the HOEP also affects total monthly compensation to be recovered through the GA. Generally, nuclear units receive a flat rate per MWh of production, and receive a top-up payment when the HOEP is below the contracted or regulated rate, or rebate the market when the HOEP is above that rate. Payments are therefore inversely related to the HOEP, so as the average HOEP declined from early 2013 to a two-year low in November 2013, GA payments to nuclear facilities increased.

Hydroelectric facilities have a similar compensation structure to that of the nuclear units, so compensation to hydroelectric facilities to be recovered through the GA also experiences the same inverse relationship with the HOEP. With the higher average HOEP in December 2013, both nuclear and hydroelectric facilities received less compensation through payments to be recovered through the GA, to the point where the HOEP regularly exceeded their contracted or regulated rate, and both were essentially making payments toward the GA from January through March 2014.

The same was not the case for other resources. These resources tended to have higher contracted rates or contract structures that lead to reduced GA compensation, not necessarily when the HOEP is high but when operating profits are being made.[8] GA recovered for the "Other"

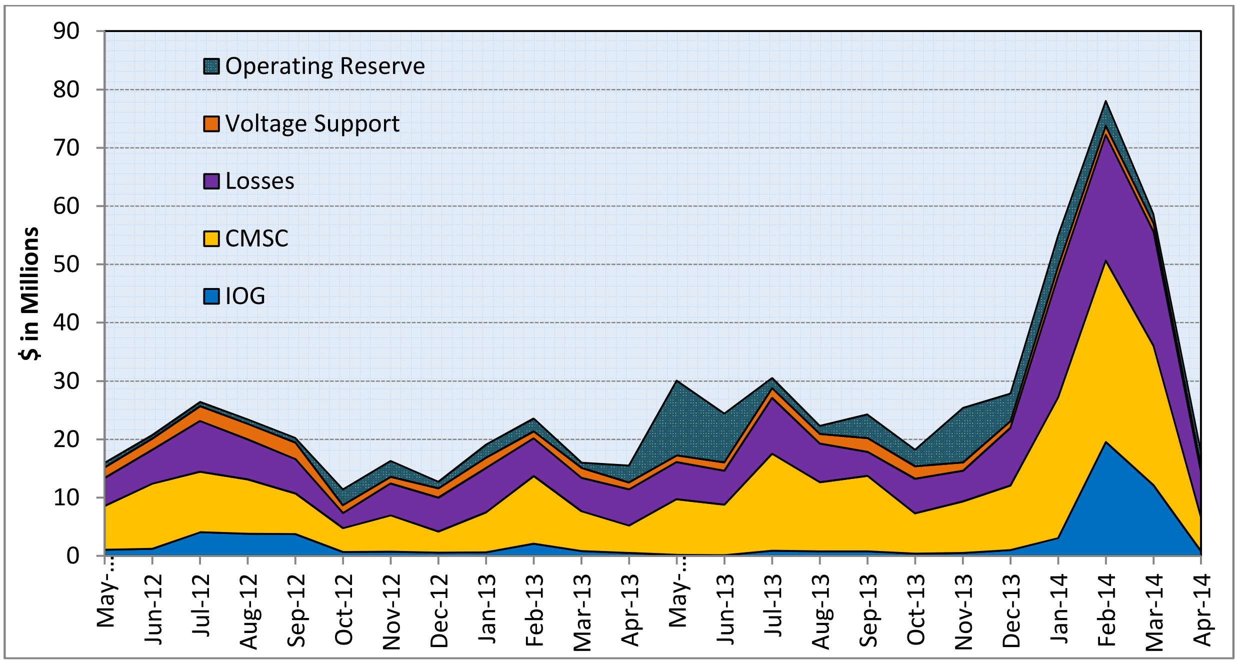
[8] For instance, CES contracted gas-fired generators are guaranteed a monthly payment under their contracts. This payment is reduced by profits made in the electricity market. In the winter 2014 months when the HOEP was high, so too was the price of gas, meaning gas-fired generators were not necessarily making as large a profit as the high HOEP would suggest. As a result their compensation recovered through the GA dropped, but not to the point of going negative.

category did not decrease as much as the other sources due the recovery of costs under the OPA's demand response programs, which is not affected by the level of the HOEP.

Figure 1-11: Total Hourly Uplift Charge by Component and Month
May 2012 – April 2014
($ millions)

Description:

Figure 1-11 presents the total hourly uplift charges by component and month for the Current and Previous Annual Periods. The uplift components include Congestion Management Settlement Credit ("CMSC") payments, Intertie Offer Guarantee ("IOG") payments, Operating Reserve ("OR") payments, hourly voltage support payments and line losses.



Relevance:

Hourly uplift is a component of the effective price of electricity consumption in Ontario. Hourly uplift is charged to consumers based on their pro rata share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

All components of hourly uplift are either directly or indirectly linked to the HOEP. For instance, total line losses are a function of the HOEP and loss factors, while OR prices tend to follow changes in the HOEP as the energy and OR markets are co-optimized.

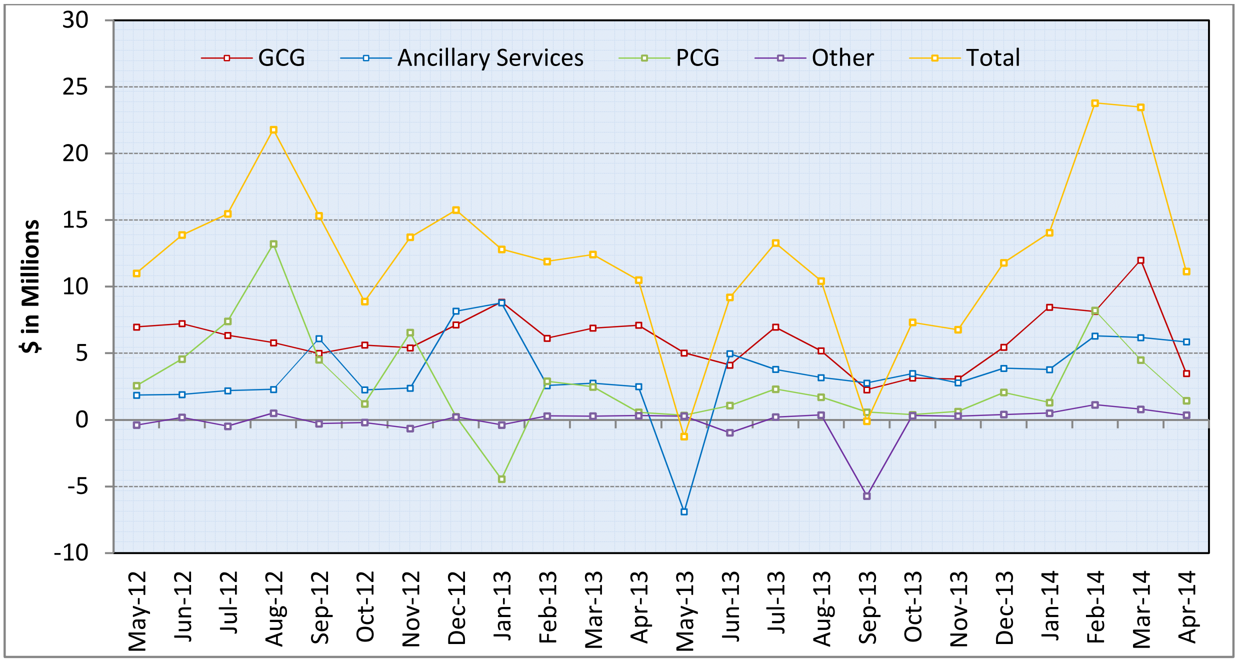
Changes in total hourly uplift costs were therefore similar to changes in the HOEP over the two year period. This is particularly evident between January and March 2014 as total hourly uplift charges surged along with the average HOEP. Of further interest is the spike in total OR costs in May 2013, without a corresponding spike in the average HOEP (see Figure 1-13 for further detail).

Figure 1-12: Total Non-Hourly Uplift Charge by Component and Month
May 2012 – April 2014
($ millions)

Description:

Figure 1-12 presents total non-hourly uplift by component and month for the Current and Previous Annual Periods. The uplift components include three main categories:

- Payments for ancillary services (i.e. regulation service, black start capability, monthly voltage support);
- Guarantee payments to generators, including Day-Ahead Production Cost Guarantee ("PCG") payments and Real-Time Generator Cost Guarantee ("GCG") payments; and
- Other, which aggregates charges and rebates such as the administrative pricing charge and Local Market Power rebate, among others.



Relevance:

Non-hourly uplift is a component of the effective price of electricity consumption in Ontario. Non-hourly uplift is charged to consumers based on their pro rata share of total demand during the relevant billing period (typically daily or monthly) in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

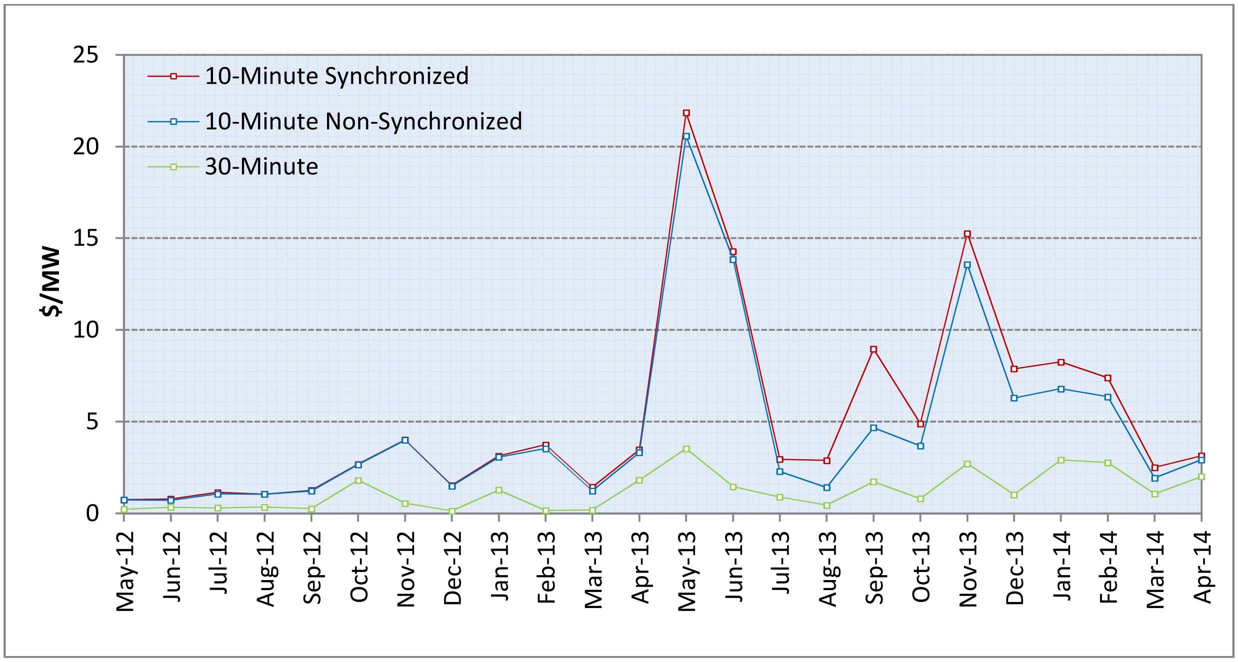
Several features stand out from the graph:

- A large payment adjustment occurred in January 2013 under the PCG program, leading to a net PCG rebate for the month.
- In September 2013 a similar adjustment was made under the IESO's Local Market Power framework, in which an approximate total of $6 million was recovered from various market participants and redistributed to consumers.
- Another substantial rebate occurred in May 2013 when an adjustment to a regulation service contract led to a net ancillary service rebate to consumers.
- Monthly ancillary service costs were elevated from July 2013 to January 2014 as a result of payments under a reliability must-run contract negotiated by the IESO with a facility that would otherwise be decommissioned.

Figure 1-13: Average Monthly Operating Reserve Prices, by Category
May 2012 – April 2014
($/MW per hour)

Description:

Figure 1-13 plots the monthly average OR price in the three OR markets: 10 minute synchronized (“10S”), 10 minute non-synchronized (“10N”), and 30 minute reserve (“30R”).



Relevance:

The three OR markets are co-optimized with the energy market, meaning resources are scheduled across all markets to minimize total cost, so price levels in these markets tend to move in similar directions.

While resources offer supply into OR markets, just as they offer into the energy market, OR “demand” is set by the IESO’s total OR requirement. The total OR requirement is specified in the reliability standards set forth by North American Electric Reliability Corporation and Northeast Power Coordinating Council to be sufficient megawatts to allow the grid to recover from the single largest grid contingency within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. This requirement ensures that the grid can operate reliably even in the event of large contingencies.

Commentary and Market Considerations:

OR prices were higher in the Current Annual Period compared to the Previous Annual Period, especially in the 10S and 10N markets. High OR prices during the spring and fall of 2013 were in part a result of reduced OR offered by hydro units (due to reduced operating flexibility during freshet conditions). Specifically, freshet contributes to an increase in the amount of hydroelectric lockouts experienced (primarily in the Northeast and Northwest). Hydroelectric lockouts limit the amount of times a unit can maneuver within a reduced megawatt range; these lockouts can last for several intervals up to several hours. There were a total of 148 hydroelectric lockouts in May 2012, in May 2013 that increased to 584, in November 2013 there were a total of 984 hydroelectric lockouts, all of which contributed to higher OR prices during those months. The price impact of reduced supply was more profound in the 10S and 10N markets where hydroelectric resources most commonly offer OR.[9]

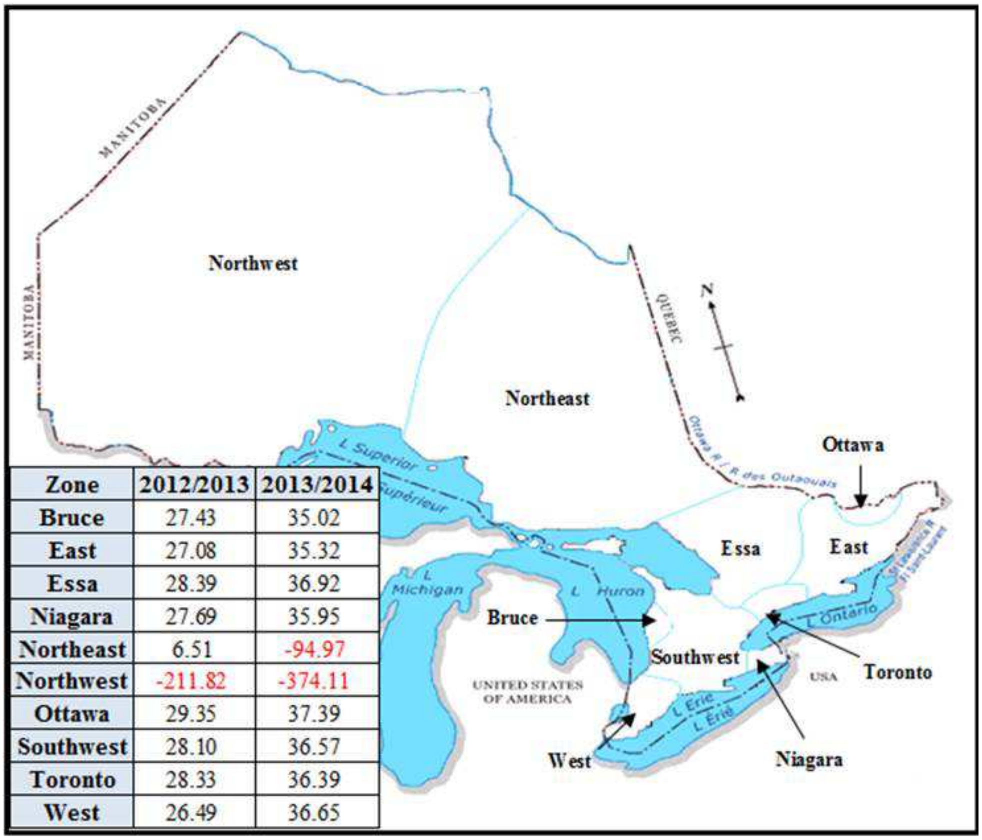
In addition to the reduction in OR available from hydroelectric facilities, there were regular reductions in the amount of Control Action Operating Reserve (“CAOR”) available to be scheduled in the OR markets, particularly in May 2013.[10] The reasons for and the effects of the May 2013 CAOR reductions were discussed in greater detail in the Panel’s September 2014 Monitoring Report.[11]

[9] To mitigate concerns over insufficient competition in the OR markets at market opening, the IESO and Ontario Power Generation (OPG) negotiated an agreement that obligated OPG to offer the maximum available amount of OR, consistent with good utility practices, at each one of their OR capable facilities, all subject to a hard offer price cap. In 2013 the IESO determined the OR markets were sufficiently competitive to justify the removal of OPG’s offer obligations, beginning in January 2014. As more data becomes available, the Panel will continue to monitor the effect on outcomes in the OR market associated with removing the obligation.
[10] When available supply is insufficient to meet demand and reserve requirements, the IESO may take out-of-market actions to maintain reliability. The Market Rules allow the IESO to include two such out-of-market actions, voltage reductions and reductions in the thirty-minute OR requirement, as a substitute for OR offered by market participants. The megawatts of reserve afforded by these out-of-market actions are known as Control Action Operating Reserve.
[11] For more information see Section 3.1 of Chapter 3 of the Panel’s September 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf

Figure 1-14: Average Internal Nodal Prices by Zone
May 2013 – April 2014
($/MWh)

Description:

Figure 1-14 illustrates the average nodal price of Ontario's ten internal zones for the Current and Previous Annual Periods. In theory, nodal prices represent the cost of supplying the next megawatt of non-dispatchable consumption at a given location.



Zone	2012/2013	2013/2014
Bruce	27.43	35.02
East	27.08	35.32
Essa	28.39	36.92
Niagara	27.69	35.95
Northeast	6.51	-94.97
Northwest	-211.82	-374.11
Ottawa	29.35	37.39
Southwest	28.10	36.57
Toronto	28.33	36.39
West	26.49	36.65

Relevance

While the HOEP is the uniform wholesale market price across Ontario, the cost of generating electricity may differ across the province due to limits on the transmission system and the cost of generators in different regions. Nodal prices approximate the regional value of electricity when respecting the internal transmission constraints of Ontario. Differences in average nodal prices across zones illustrate the discrepancy between supply and demand between different transmission constrained geographic regions of Ontario.

Commentary and Market Considerations:

In the absence of major transmission outages most average zonal prices tend to move together, aside from the Northwest and Northeast.[12] The divergence between prices in the northern zones and prices in the rest of the province is due to the availability of low-cost generation in excess of demand in the areas, and insufficient transmission to transfer power to the southern part of the province.

Relative to the Previous Annual Period, average nodal prices in southern zones increased along with the average HOEP in the Current Annual Period. Conversely, the Northeast and Northwest zones both experienced large decreases in average nodal prices. The decline in average nodal prices in the Northwest and Northeast compared to the Previous Annual Period can be attributed to an increase in the number of "must-run" hours for hydroelectric units. Hydroelectric units experience "must-run" conditions when safety, environmental or regulatory concerns dictate the units must generate at a certain output; these megawatts are offered into the market at extremely negative prices to ensure they are scheduled.

Figures 1-15 & 1-16: Import and Export Congestion by Interface Group

Description:

Figures 1-15 and 1-16 report the number of hours per month of import and export congestion respectively, by interface during the Current and Previous Annual Periods.

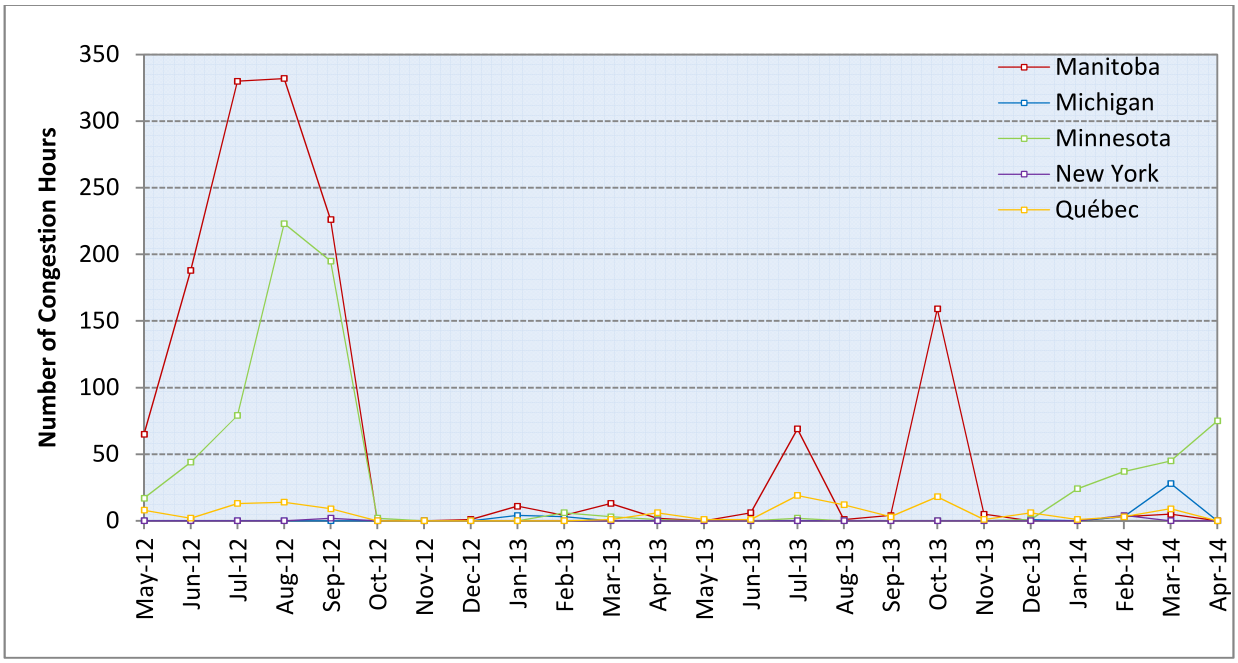
The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. When an intertie has a greater amount of economic net import offers (or export bids) than its one-hour ahead pre-dispatch transfer capability, this intertie is considered to be import (export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions. The supply of intertie transfer capability is dictated by the physical capacity at each interface, though it may be affected by line outages and de-ratings.

[12] While average nodal prices outside the Northeast and Northwest are similar, transmission outages can result in significant temporary differences in nodal prices.

Relevance

While the HOEP is the wholesale market price for domestic consumers and producers, the price for import and export transactions can differ from the HOEP when there is congestion on the intertie. When there is import congestion, importers receive less for the energy they supply while exporters pay less for the energy they purchase (the intertie zonal price decreases relative to the HOEP). When there is export congestion importers receive more for the energy they supply while exporters pay more for the energy they purchase (the intertie zonal price increases relative to the HOEP).

Figure 1-15: Import Congestion by Interface May 2012 – April 2014 (number of hours in the unconstrained schedule)



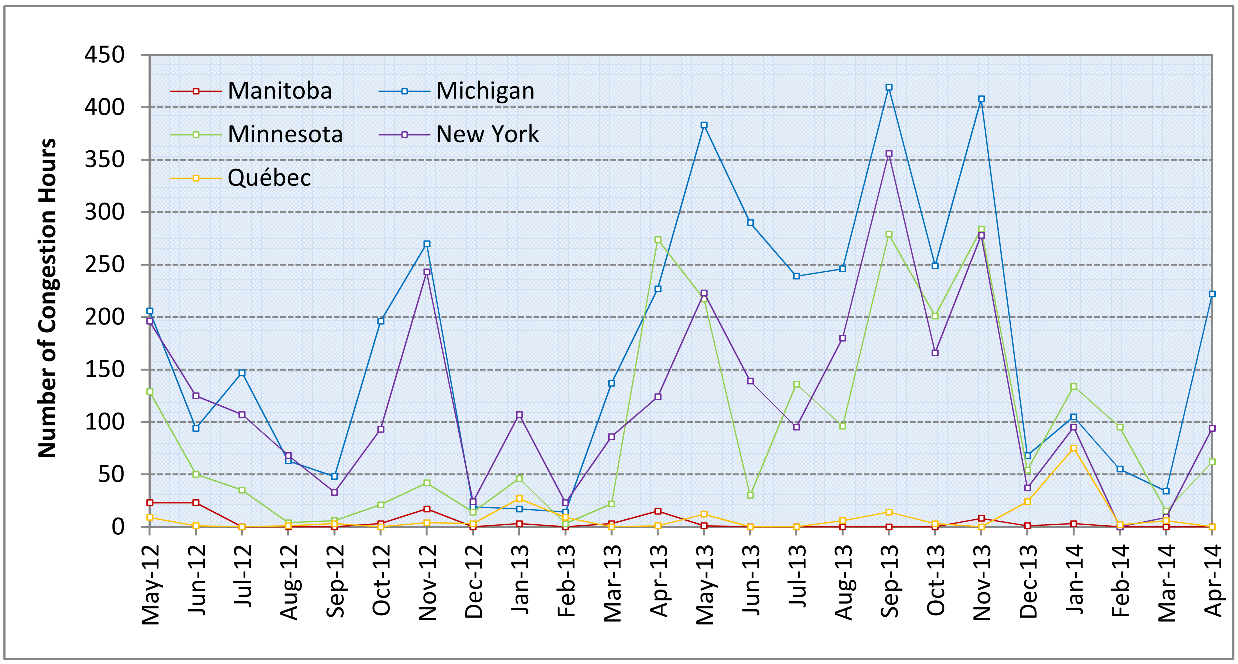
Commentary and Market Consideration:

The dramatic reduction in import congestion since October 2012 on the Manitoba and Minnesota interfaces is due to a change in the demand for transfer capability on those interfaces (modest de-ratings of each interface also contributed to frequent congestion in the Previous Annual Period).

As noted in the Panel's January 2014 Monitoring Report[13] the elimination of constrained-off CMSC paid to market participants importing into a Chronically Congested Area significantly reduced import activity at the Manitoba and Minnesota interties. Reductions in offered import megawatts and increases in the average offer price, coupled with a decrease in the average nodal price in the Northwest, have decreased the quantity of imports scheduled on these interties. The reduced need for import transfer capability has in turn significantly decreased the amount of import congestion.

Line outages have led to reduced transfer capacity at the Minnesota intertie, contributing to increased import congestion in 2014. No other interties experienced regular import congestion during the Current Annual Period.

Figure 1-16: Export Congestion by Interface Group May 2012 – April 2014 (number of hours in the unconstrained schedule)



Commentary and Market Consideration:

Export congestion on the New York, Michigan and Minnesota interties occurred far more frequently in the Current Annual Period relative to the Previous Annual Period, with that

[13] For more information see Chapter 3, Section 3.1 of the Panel's January 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

congestion concentrated in the first half of the period. With reduced and negative net exports in the Winter of 2014, export congestion was much lower. While all interties experienced transmission de-ratings, only New York, Michigan and Minnesota experienced prolonged periods when the number of outstanding transmission rights ("TR") exceeded the intertie transfer capability (see the Description section of Figure 1-17 for more information on why this can lead to greater congestion). When coupled with net export flows to New York and Michigan in every month of the Current Annual Period, as well as in most months to Minnesota, the interties experienced increased export congestion.

Figure 1-17: Import Congestion Rent & TR Payouts by Interface Group
May 2013 – April 2014
($ millions)

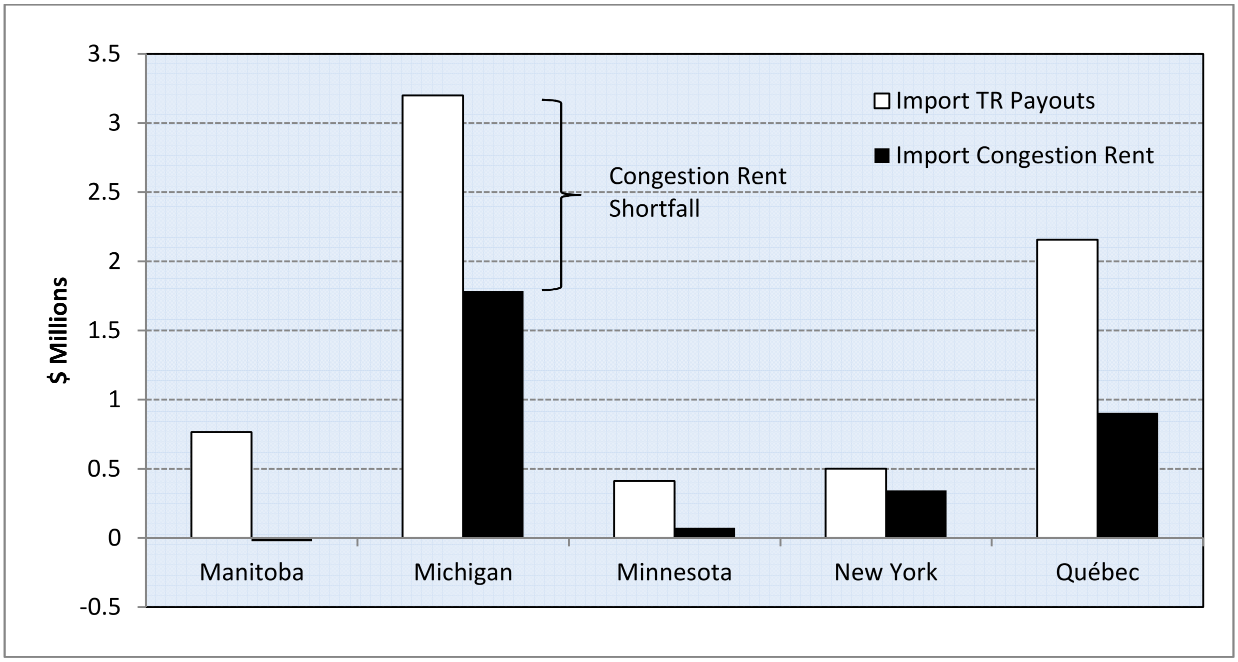
Description:

As discussed in the Relevance section associated with Figures 1-15 and 1-16, the intertie zonal price differs from the HOEP when the intertie is congested; the difference in prices is referred to as the Intertie Congestion Price ("ICP"). When an intertie is import congested the intertie zonal price is less than the HOEP, while the reverse is true when the intertie is export congested. When an intertie is congested the importer or exporter is paid or pays the intertie zonal price, while the domestic buyer or seller pays or is paid the HOEP. The difference between the amounts collected from and paid to market participants is known as "congestion rent". Congestion rent accrues in the IESO's transmission right clearing account.

To enable intertie traders to hedge against the risk of congestion-related pricing, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie and direction for which they own a TR. This product allows an intertie trader to hedge against congestion related pricing, ensuring they are settled on the HOEP and not the zonal price; this increased certainty can lead to greater intertie activity. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion as TR payments exactly offset price differences between the HOEP and the relevant intertie zone. Payments to TR holders are disbursed from the TR clearing account.

While TR payouts are theoretically offset by congestion rent collected, over the course of an annual period this is never the case. When TR payouts exceed congestion rent collected the TR clearing account is drawn down; the opposite is true when congestion rents exceed TR payouts.

Figure 1-17 compares the total collection of import congestion rent to the total payment of TRs by interface group for the Current Annual Period.



Relevance:

In addition to congestion rent collected and TR payouts, there is a third component of the TR clearing account: auction revenues. Auction revenues are the proceeds from selling TRs (a payment into the TR clearing account). In the Panel's view, TR auction revenues ought to be paid to consumers as an offset in transmission charges. If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for the scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents.[14]

Due to the two schedule system,[15] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent shortfall arises; instead of remaining revenue neutral, these events drain the TR clearing account. These shortfalls are covered by the account's other revenue streams: primarily auction revenues. To this end, every dollar of congestion rent shortfall represents a dollar not disbursed to consumers.

Commentary and Market Consideration:

All interties experienced import congestion rent shortfalls in the Current Annual Period. The Michigan intertie had the greatest shortfall with $1.4 M more import TR payouts than congestion rent collected. New York had the smallest discrepancy with a $0.2 M congestion rent shortfall. In total, the shortfall totaled $3.9M; money that, in the Panel's view ought to have been paid to consumers but that was paid to TR holders.

Manitoba experienced negative import congestion rent collected, which occurs when an intertie is import congested in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has scheduled net exports.[16]

The interties with a high frequency of congestion hours (see Figure 1-15) did not necessarily correlate with high import transmission right payouts and import congestion rent, primarily because of differences in intertie capacity (and thus TRs sold) at each intertie.

The IESO has implemented a more conservative approach to TR auctions that should reduce the frequency with which the quantity of outstanding TRs exceeds the eventual intertie transfer capability.[17] Given the year-long period in which long-term TRs are valid, this change will not

[14] For more information on the TR market and the basis for disbursing funds from the TR clearing account to offset transmission service charges, see Section 4.2 of Chapter 3 of the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

[15] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (say import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has scheduled net transactions in the opposite direction (say export). In this case negative congestion rents are collected.

[16] *Ibid*

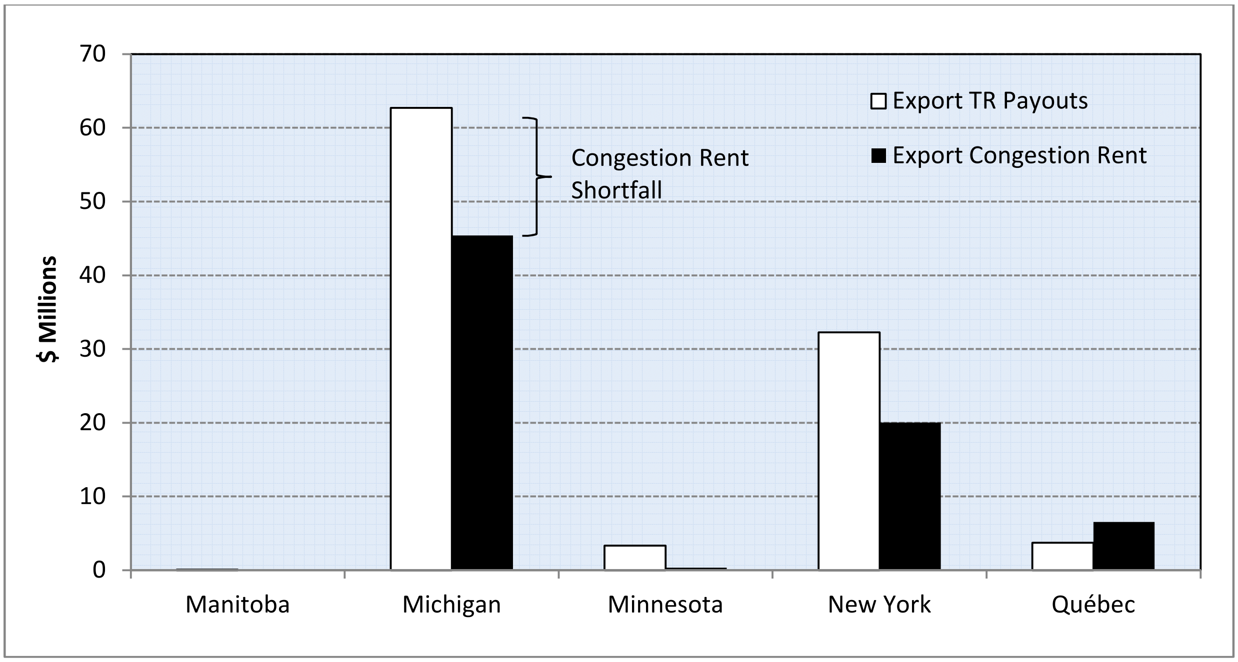
[17] For more information on the TR auction policy changes implemented by the IESO, see the Stakeholder Engagement 110 webpage, available at http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-110.aspx

fully rectify the extent to which TRs have been oversold until the remaining outstanding TRs have expired.

Figure 1-18: Export Congestion Rent & TR Payouts by Interface Group
May 2013 – April 2014
($ millions)

Description:

Figure 1-18 compares the total collection of export congestion rent to the total payment of TRs by interface group for the Current Annual Period. For a detailed explanation of TRs and congestion rent, see Figure 1-17.



Relevance:

As discussed in the Relevance section of Figure 1-17, every dollar of congestion rent shortfall represents a dollar not disbursed to consumers.

Commentary and Market Consideration:

In the Current Annual Period, export congestion rent shortfall far exceeded the import congestion rent shortfall. The total export congestion rent shortfall was $29.5M, compared to $3.9M of import congestion rent shortfall.

There was considerable congestion rent shortfall at each of the New York, Michigan and Minnesota interties. These interties regularly had TRs sold in excess of their eventual transfer capability. Congestion rent shortfalls at the Michigan and New York interties were greater due to their relatively large transfer capability and high frequency of export congestion hours (see Figure 1-16). Québec rarely had outstanding TRs in excess of the intertie transfer capability and was the only intertie that experienced an export congestion rent surplus.

Table 1-3: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction May 2013 – April 2014 ($/MW)

Description:

Table 1-3 lists the average auction prices for one megawatt of long-term (year-long) TRs sold at each interface, in either direction, during the four months in the Current Annual Period in which auctions were held (the periods covered by the TRs extend beyond the Current Annual Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec*
Import	May-13	Jul-13 to Jun-14	-	841	-	798	253
	Aug-13	Oct-13 to Sep-14	6,769	1,016	5,239	905	431
	Nov-13	Jan-14 to Dec-14	5,334	809	2,715	758	637
	Feb-14	Apr-14 to Mar-15	-	716	3,766	780	725
Export	May-13	Jul-13 to Jun-14	2,053	15,595	-	16,066	2,569
	Aug-13	Oct-13 to Sep-14	-	21,081	-	18,729	2,509
	Nov-13	Jan-14 to Dec-14	2,521	31,170	30,200	25,819	3,530
	Feb-14	Apr-14 to Mar-15	-	34,217	-	30,043	4,281

*Unless otherwise stated, all references to the Québec intertie refer to the Outaouais transmission interface.

Relevance:

In an efficient auction the price paid for one megawatt of TRs should reflect the expected payout of owning that TR for the period. This would be the equivalent of the expected sum of all Intertie Congestion Prices in the direction of the TR purchased during the valid period. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal the market's expectation of intertie congestion conditions for the forward period; these auction revenues also form the basis for what consumers should be reimbursed to them through offsets to transmission service charges.

Commentary and Market Consideration:

While the value of long-term TRs in the import direction remained largely unchanged over the course of the Current Annual Period, the price paid for export TRs across all interties increased considerably. The increase in the value placed on long-term export TRs is consistent with the increased export congestion observed (see Figure 1-16) on most interties around the time of the first long-term auction (May 2013) of the Current Annual Period.

Table 1-4: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction May 2013 – April 2014 ($/MW)

Description:

Table 1-4 lists the auction prices for one megawatt of short-term (month-long) TRs sold at each interface, in either direction, during the Current Annual Period.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	May-13	333	34	-	29	39
	Jun-13	302	47	-	49	45
	Jul-13	454	52	475	30	82
	Aug-13	415	12	-	53	75
	Sep-13	498	22	455	18	221
	Oct-13	-	29	160	43	83
	Nov-13	376	37	104	16	160
	Dec-13	263	57	125	42	160
	Jan-14	229	67	197	6	81
	Feb-14	264	62	349	31	170
	Mar-14	291	301	332	83	202
	Apr-14	451	190	354	60	744
Export	May-13	-	1,498	-	1,205	152
	Jun-13	-	2,738	-	1,510	186
	Jul-13	28	2,887	670	1,510	201
	Aug-13	-	2,002	-	1,836	157
	Sep-13	-	2,265	-	1,682	210
	Oct-13	-	2,265	-	1,682	121
	Nov-13	165	3,000	-	2,053	201
	Dec-13	194	2,894	1,501	1,450	400
	Jan-14	210	2,620	-	1,885	746
	Feb-14	232	2,801	-	2,463	577

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Export	Mar-14	157	1,455	-	1,613	525
	Apr-14	123	2,662	901	1,674	525

Relevance:

As discussed in the Relevance section of Table 1-3, auction revenues signal the market's expectation of intertie congestion conditions for the forward period; these auction revenues also form the basis for what consumers should be reimbursed to them through offsets to transmission service charges.

Commentary and Market Consideration:

There were no obvious trends in the price of short-term TRs over the course of the Current Annual Period, although the price of both import and export TRs at various interties spiked modestly during the colder winter months.

Figure 1-19: Transmission Rights Clearing Account
May 2009 – April 2014
($ millions)

Description:

The TR clearing account is administered by the IESO, the balance of which is affected by 5 transactions:

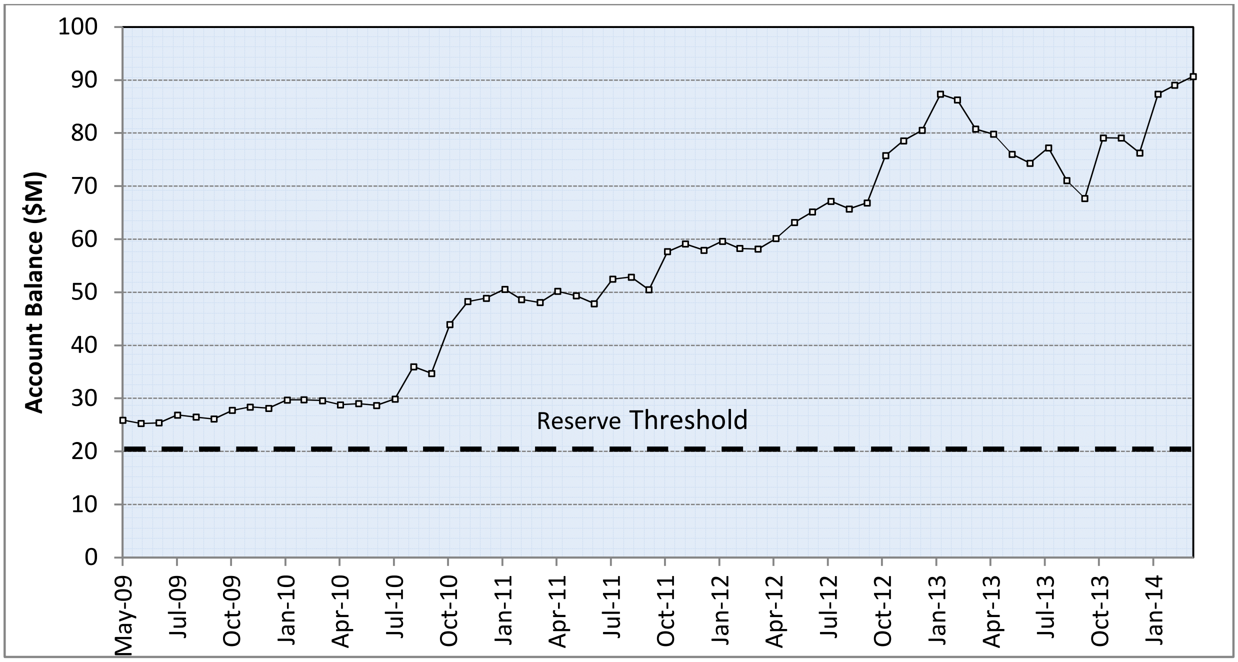
<u>Credits</u>

- Congestion rent
- TR auction revenues
- Interest earned on TR clearing account balance

<u>Debits</u>

- TR payments to TR holders
- Disbursements to offset transmission charges to Ontario consumers

Figure 1-19 shows the estimated balance of the TR clearing account at the end of each month for the previous five years.



Relevance:

Tracking the transactions of the TR clearing account over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million; the funds in excess of this threshold can be disbursed to Ontario loads at the discretion of the IESO Board.

Commentary & Market Considerations

Over the Current Annual Period, the balance in the TR clearing account increased by $9.9 million (from $80.8 to $90.7 million).[18] This change can be broken down into:

- $154.1 million in sources of inflow
    - $75.5M in congestion rent collected
    - $77.4M in auction revenues
    - $1.2M in interest
- $144.1 million in disbursements
    - $109.1M in TR payments to rights holders

[18] The TR clearing account balance presented in this report diverges significantly from the total reported on the IESO website. The Panel accounts for auction revenues as they are paid by the market participant to the IESO (prior to the start of the period covered by the TR), while the IESO allocates auction revenues over the relevant period of the TR (12 months in the case of long-term TRs), and only accounts for those revenues in the TR clearing account as each trade month occurs. Consequently, the IESO methodology understates the auction revenues received to date.

- $35M in disbursements to offset transmission charges to Ontario consumers

Overall, the TR clearing account is approximately $70 million above the $20 million reserve threshold set by the IESO board.

The Panel understands that the IESO is in the process of developing a proposal to the IESO Board to authorize a disbursement of the TR clearing account. At the same time the IESO will recommend a process for continued review of the account. The Panel is supportive of the IESO's efforts in these regards, and encourages it to take action on an expeditious basis. [19]

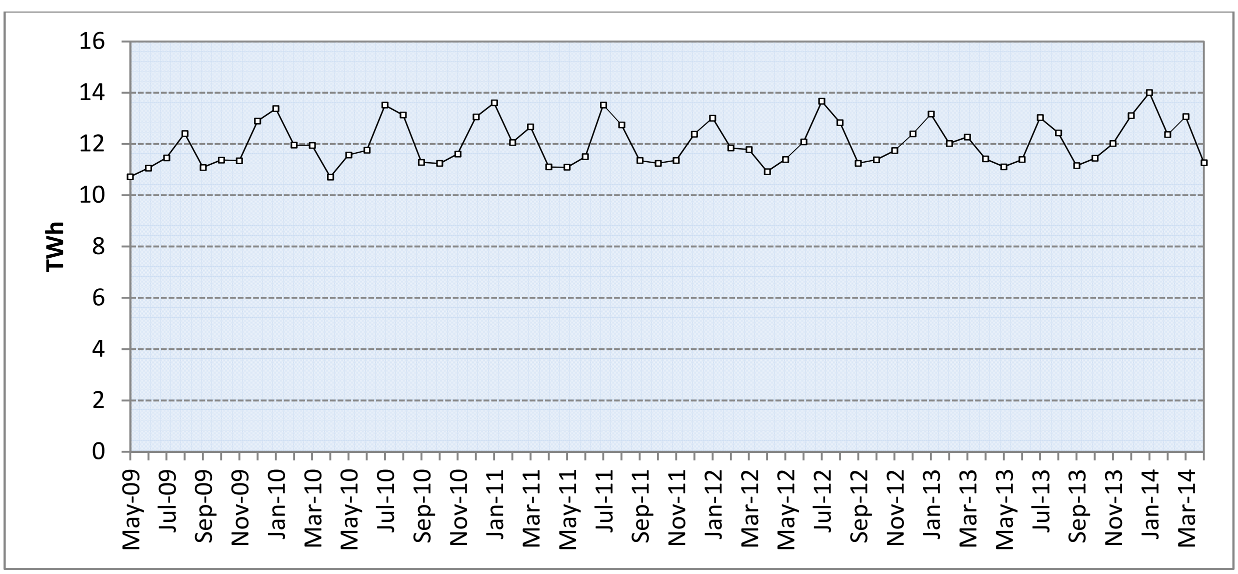
2 *Demand*

This section discusses Ontario energy demand on the IESO-controlled grid for the Current Annual Period in relation to previous years.

Figure 1-20: Monthly Domestic Energy Demand
May 2009 - April 2014
(TWh)

Description:

Figure 1-20 presents the total scheduled energy consumption of Ontario consumers in each month in the past 5 years.



[19] In response to the IESO's January 2013 recommendation, the IESO Board authorized the disbursement of $42 million from the TR clearing account to offset transmission service charges to Ontario consumers.

Relevance:

Ontario monthly consumption shows the seasonal variations in consumption and the year-to-year changes in consumption patterns.

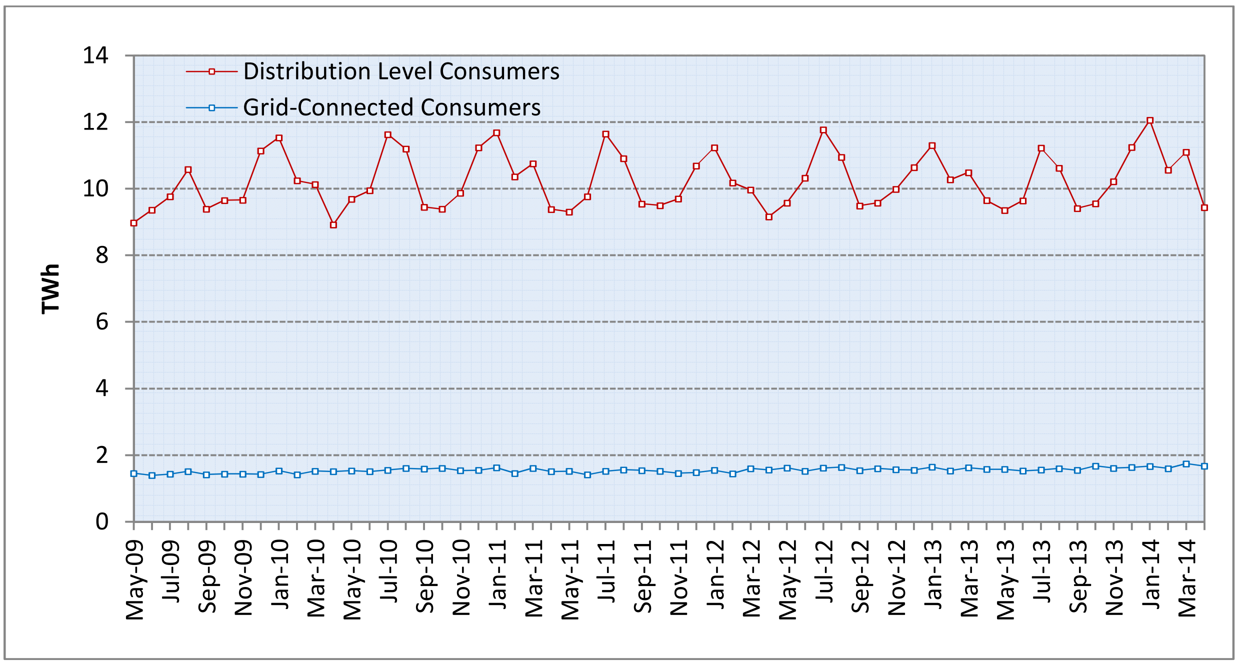
Commentary and Market Consideration:

The 2014 winter months experienced the highest monthly demand (January 2014) of the past five years. Additionally, the harsh winter and the mild fall combined for the largest difference between the fall demand trough and the winter peak over the past five years.

Figure 1-21: Monthly Total Energy Withdrawals, Distributors and Wholesale Loads May 2009 – April 2014 (TWh)

Description:

Figure 1-21 charts the demand of two categories of consumers: directly connected consumers that are billed the wholesale price (wholesale consumers), and consumers located within local distribution companies (distribution level consumers).



Relevance:

The breakdown of consumers into these two categories helps identify their monthly demand profiles. From this, their seasonal behaviors can be observed.

Commentary and Market Consideration:

Seasonal spikes in Ontario demand can almost entirely be attributed to distribution level consumers.[20] These include medium-to-small commercial, residential and smaller industrial loads. Meanwhile, demand from wholesale consumers, a group that is primarily comprised of industrial loads and large commercial consumers, has gradually increased over the past five years, but exhibited little of the seasonality of distribution level consumers.

3 *Supply*

During the Current Annual Period 534 MW of nameplate generating capacity was added to the IESO-controlled grid:[21]

- The Thunder Bay Turbine Project added an additional 40 MW of generating capacity
- A third hydro unit at Little Long with a generating capacity of 67 MW
- East Lake St. Clair Wind Farm with a nameplate capacity of 99 MW
- Summerhaven Wind Energy Centre with a nameplate capacity of 125 MW
- Erieau Wind with a nameplate capacity of 99 MW
- Port Dover and Nanticoke Wind Project with a nameplate capacity of 104 MW

During the Current Annual Period Ontario retired the remaining coal-fired plants in the province, making Ontario the first jurisdiction in North America to fully eliminate coal as a source of electricity generation. Ontario Power Generation removed three coal fired generating stations from service; the Lambton generating station (1,016 MW), the Nanticoke coal generating station (1,985 MW), and Thunder Bay units 2 and 3 (306 MW). The Thunder Bay facility is being converted to biomass, while the Lambton and Nanticoke plants are being preserved so that they can be converted to alternate fuels in the future, if needed.

The retirement of coal-fired capacity, when combined with the 534 MW of new directly-connected capacity referred to above, yields a net decrease in directly connected generating

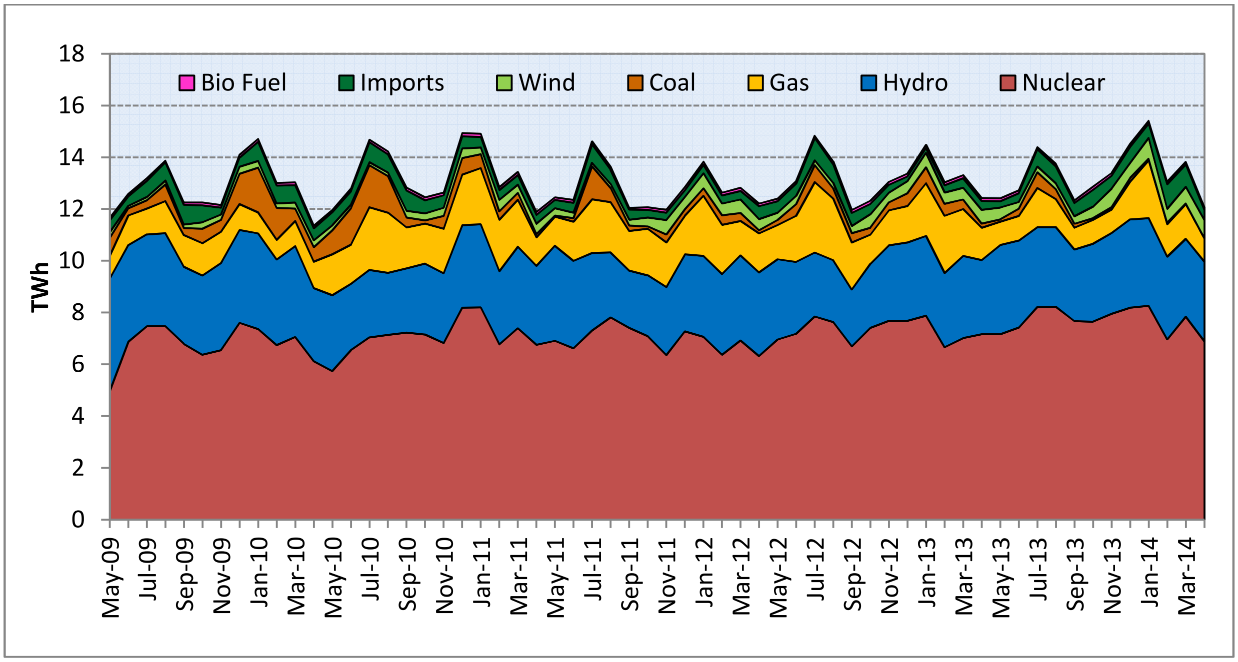
[20] Distribution level consumers are represented in the electricity market by local distribution companies.
[21] Many more megawatts of generating capacity were added at the distribution level.

capacity of 2,773 MW. For a more detailed examination of the medium term supply capacity in Ontario, see the IESO's latest 18-Month Outlook.[22]

Figure 1-22: Resources Scheduled in the Real-Time Market Schedule May 2009 – April 2014 (TWh)

Description:

Figure 1-22 illustrates the cumulative share of energy scheduled in the real-time market in TWh by fuel source each month from May 2009 to April 2014.[23]



Relevance:

This figure displays the evolution of Ontario's changing supply mix of real-time energy. These changes may be the result of a number of factors, such as recent changes in energy policy or environmental changes attributed to seasonality.

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[22] The IESO's most recent 18-Month Outlook is available at: http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-%26-18-Month-Outlooks.aspx

[23] Bio-fuel energy is generated from different types of biological processes. A prime example is biomass which is a renewable form of energy that uses organic materials to produce heat, including residual materials from forestry operations, waste matter from agricultural production and animal livestock activities, and by-products of food-processing operations.

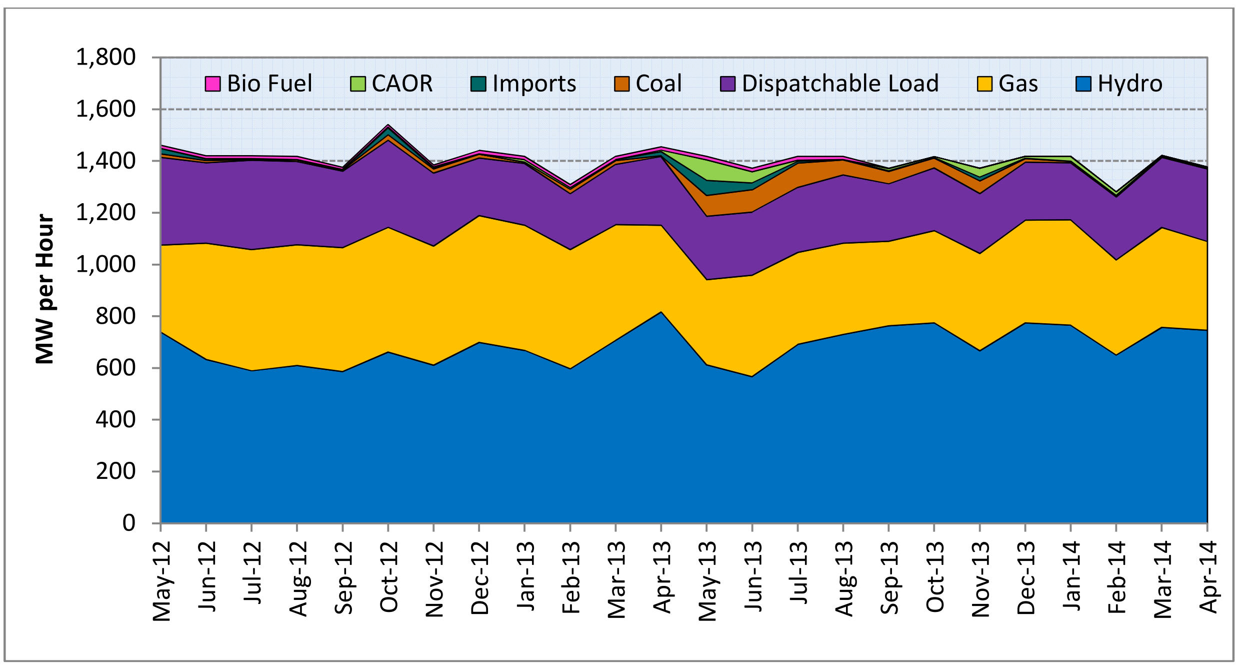
Commentary and Market Considerations:

In the Current Annual Period nuclear power continued to be the predominant resource scheduled, comprising on average 57.6% of all resources scheduled. Hydroelectric generation was the second largest producer at 23.6%, followed by gas, wind, imports and then coal, all less than 10%. The total energy scheduled was 160.7 TWh. Of note over the 5 year period is the increased production from wind generation due to the increase in installed capacity. The role of the coal-fired generating fleet diminished over the period until its eventual retirement.

Figure 1-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type May 2012 – April 2014 (MW)

Description:

Figure 1-23 plots the average hourly share of operating reserve scheduled for each resource or transaction type, including hydroelectric, gas, coal, imports, dispatchable loads, and CAOR. As OR quantity requirements can vary from hour to hour, scheduled OR is reported as an average of all hours in each month to show changes in the average OR requirement.



Relevance:

This figure reflects the evolution in Ontario's changing supply mix for OR as well as changes in the OR requirement over time. These changes may result from a variety of factors such as recent changes in energy policy or environmental changes attributed to seasonality.

Commentary and Market Considerations:

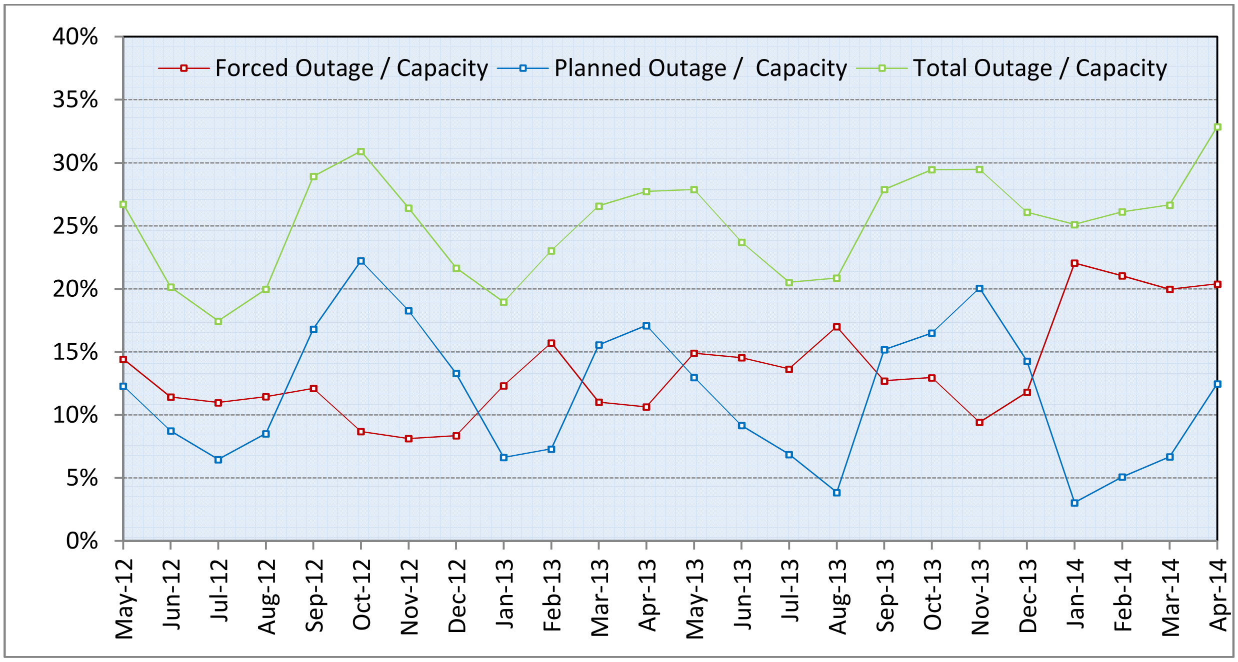
Hydroelectric resources accounted for 50.9% of scheduled OR, with gas-fired generators and dispatchable loads supplying approximately 32.2% and 20%, respectively. In the Current Annual Period approximately 12.4 TWh of OR was scheduled. Of note during the Current Annual Period was the retirement of coal-fired generation and the subsequent elimination of coal-fired resources in the OR markets. The increased frequency with which CAOR was scheduled was also a notable occurrence during the spring and early summer of 2013; this was a result of decreased supply in the OR market, a topic that was examined in greater detail in the Panel's September 2014 Monitoring Report.[24]

[24] For more information see Section 3.1 of Chapter 3 of the Panel's September 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf

Figure 1-24: Planned & Forced Outages Relative to Capacity May 2012 – April 2014 (% of capacity)*

Description:

Figure 1-24 plots planned and forced (i.e. unforeseen) outages as a percentage of total capacity for the Current and Previous Annual Periods.



Relevance:

Planned and forced outages provide an overview of the availability of supply in the province, a key factor in the determination of market prices. Forced outage rates also inform how the supply fleet handles external factors, such as extreme weather conditions.

Commentary and Market Considerations:

Planned outages followed a seasonal pattern in which the majority of planned outages occurred during the shoulder periods when demand and the HOEP tended to be lower. There was a significant increase in the percentage of total capacity on forced outage during the first four months of 2014. Extremely cold temperatures and icing played a large role in the increased occurrence of forced outages, particularly at nuclear and wind facilities. For a detailed explanation of outages during these months see Chapter 2.

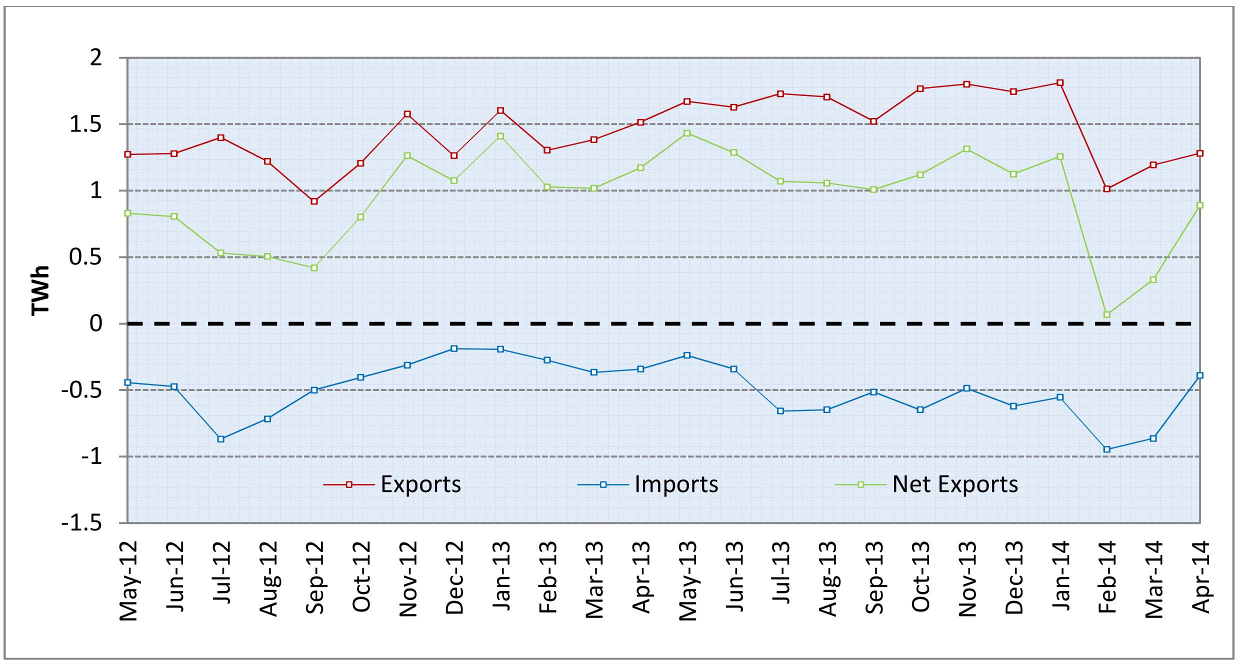
4 *Imports, Exports and Net Exports*

This section reports on intertie trading activity, using data that is based on the unconstrained schedules as these directly affect market prices; the unconstrained schedule does not necessarily reflect actual power flows.[25]

Figure 1-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) May 2012 – April 2014 (TWh)

Description:

Figure 1-25 plots total monthly imports, exports, and net exports in TWh for the Current and Previous Annual Periods. As the figure is expressed in terms of net exports, exports are represented by positive values while imports are represented by negative values.



Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus the market price. Tracking net export transactions over time informs of the supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Current Annual Period, indicate times of relative domestic

[25] Although the constrained schedules provide a better sense of actual flows of power on the interties, they are not related to intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).

energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative domestic scarcity.

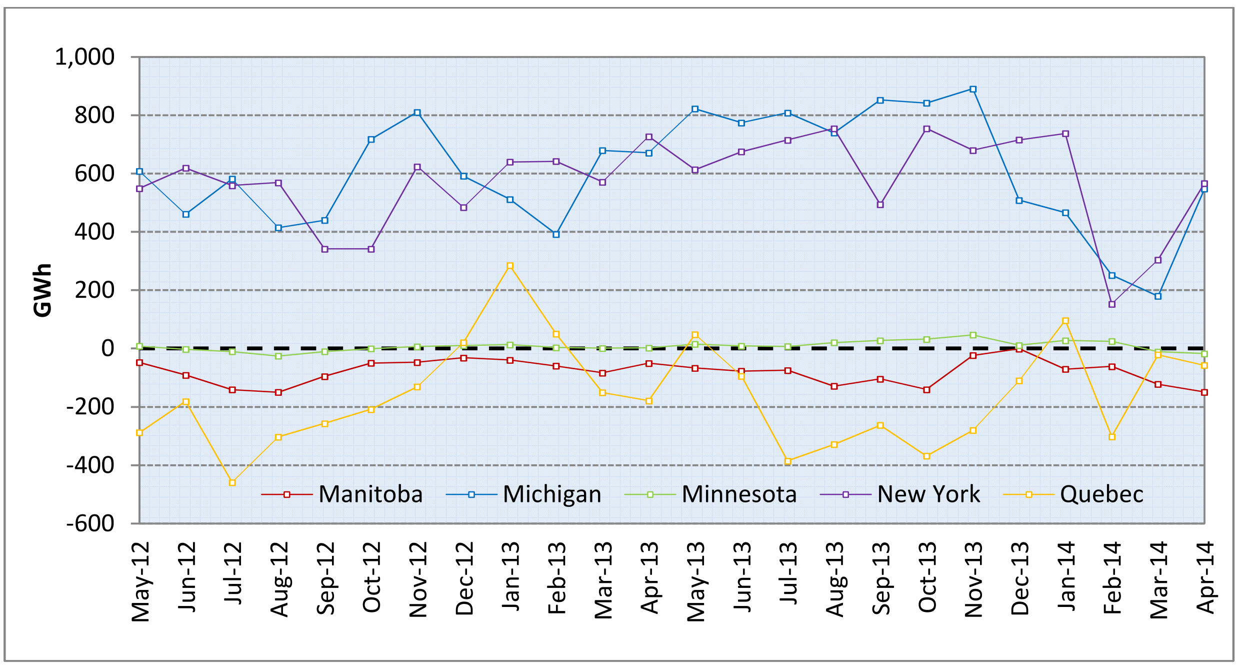
Commentary and Market Considerations:

Ontario was a net exporter during all months from May 2012 to April 2014. Net electricity exports totaled 11.96 TWh during the Current Annual Period, an increase of 1.10 TWh (10%) from the Previous Annual Period. During February 2014 when Ontario was experiencing high demand and constrained supply conditions at times, exports were curtailed at a relatively high rate for reliability reasons, this contributed to net exports of only 0.07 TWh during the month.

Figure 1-26: Net Exports by Interface Group
May 2012 – April 2014
(GWh)

Description:

Figure 1-26 presents a breakdown of net exports to the five neighboring jurisdictions of the IESO-controlled grid: Manitoba, Michigan, Minnesota, New York, and Québec from May 2012 to April 2014. As the figure is expressed in terms of net exports, net exports are represented by positive values while net imports are represented by negative values.



Relevance:

Similar to Figure 1-25, this figure allows us to better understand how Ontario's trade relationship evolves over time with each external jurisdiction.

Commentary and Market Considerations:

Across the Michigan and New York interties Ontario was a net exporter for all months during the Current and Previous Annual Periods, but experienced a significant drop in net exports during the months of February and March 2014 due to higher domestic prices and curtailed export transactions.

Ontario alternated between being a net importer from Québec during the summer months, to being a net exporter during the winter months. Ontario typically experiences peak load during the summer, while Québec experiences peak load during the winter, making such trade patterns common. Ontario continued to be a near net zero trader with Minnesota, while Manitoba remained a consistent, modestly-sized net importer into Ontario.

Table 1-5: Average Monthly Export Failures by Interface Group and Cause May – April 2012/13 & May – April 2013/14 (GWh and %)

Description:

Table 1-5 reports average monthly export curtailment/failures over the Current and Previous Annual Periods by interface group and cause. Exports are curtailed by an Independent System Operator (either Ontario or an external jurisdiction), typically for reliability reasons. Exports are considered to have failed when there is a failure on the part of the market participant (such as an inability to obtain transmission service). The failure/curtailment rate is displayed as a percentage of total exports in GWh per month over each interface, excluding linked-wheeling transactions.

Interface Group	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14
New York	545.0	568.6	2.2	2.4	21.7	26.6	0.4	0.4	4.0	4.7
Michigan	540.6	534.5	4.7	10.7	2.8	4.2	0.9	2.0	0.5	0.8
Manitoba	10.5	14.9	1.1	1.0	1.3	0.4	10.5	6.6	12.1	2.9
Minnesota	19.3	27.0	2.3	1.3	0.6	1.7	12.1	4.8	2.9	6.3
Québec	141.2	251.3	9.2	15.7	1.2	8.3	6.5	6.3	0.8	3.3

Relevance:

Export failures/curtailments represent a reduction in demand between the hour-ahead pre-dispatch schedule and the real-time schedule. This change in exports can lead to a sub-optimal level of intertie transactions in real-time given the market price, which may contribute to surplus baseload generation conditions. The IESO may dispatch off domestic generation or curtail imports to compensate for the failures/curtailments. Elevated failure/curtailment levels may arise from seams issues between jurisdictions or from market participant behaviour.

Commentary and Market Considerations:

During the Current Annual Period ISO curtailment of exports increased for all interties not located in the Northwest of the province (Manitoba and Minnesota interties). The increase in ISO export curtailments was in part due to reliability needs during the winter 2014 months (from which the Northwest was largely insulated), and from the increase in total exports over the Current Annual Period (especially to Québec).

The MP failure rate at the Manitoba intertie was materially lower during the Current Annual Period, while the all other interties saw increases in the MP failure rate.

Table 1-6: Average Monthly Import Failures by Interface Group and Cause May – April 2012/13 & May – April 2013/14 (GWh and %)

Description:

Table 1-6 reports average monthly import failures/curtailments over the Current Annual Period by interface group and cause. Imports are curtailed by an Independent System Operator (either

Ontario or an external jurisdiction), typically for reliability reasons. Imports are considered to have failed when there is a failure on the part of the market participant (such as an inability to obtain transmission service). The failure/curtailment rate is determined as a percentage of total imports in GWh per month, excluding linked-wheeling transactions.

Interface Group	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14
New York	25.8	45.4	0.2	0.7	0.7	1.6	0.8	1.5	2.5	3.6
Michigan	34.6	37.9	2.1	3.2	3.2	5.4	6.0	8.4	9.3	14.3
Manitoba	31.7	33.0	3.6	5.6	0.8	0.2	11.5	17.1	2.5	0.7
Minnesota	2.1	5.9	0.1	0.6	1.2	0.7	5.4	10.0	56.0	11.6
Québec	240.6	257.7	3.1	6.7	1.5	1.4	1.3	2.6	0.6	0.5

Relevance:

Import failures/curtailments represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This unforeseen change in imports can lead to a suboptimal level of intertie transactions in real-time given the market price, which may contribute to supply adequacy concerns and increases in price. The IESO may dispatch on domestic generation or curtail exports to compensate for the failures/curtailments. Elevated curtailment levels may arise from seams issues between jurisdictions or market participant behaviour.

Commentary and Market Considerations:

During the Current Annual Period ISO curtailment of imports increased for all interties. This was primarily a result of neighbouring jurisdictions experiencing similar supply adequacy issues to Ontario during the 2014 winter months. The MP failure rate of 56% on the Minnesota intertie in the Previous Annual Period occurred over a relatively low volume of transactions; the rate decreased to 11.6% in the Current Annual Period.

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 IESO's Market Assessment Unit (which supports the Panel), 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, enhances understanding of the market for market participants and other interested stakeholders, 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 involve 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 referred to as negative-price hours.

The Panel also reports on high uplift events associated with the various IESO-administered markets and programs. The Panel has set payment thresholds to identify uplift events in which anomalous market outcomes, or market participant behaviour, generated uplift payments that exceed normally-observed levels. Uplift payments include payments such as Congestion Management Settlement Credit ("CMSC") payments, Intertie Offer Guarantee ("IOG") payments and operating reserve ("OR") payments.

This chapter reports on anomalous price and uplift events from the November 2013 to April 2014 period (the "Winter 2014 Period"), with comparisons to preceding Winter Periods where relevant. References in this chapter to a "Winter Period" are to the period running from November to April, inclusive.

Table 2-1 sets out a summary of anomalous price and uplift events for the Winter 2013 and Winter 2014 Periods. During the Winter 2014 Period there was a notable increase in the number of anomalous events compared to the previous Winter Period.

Table 2-1: Anomalous Price and Uplift Events
November 2012 – April 2013 & November 2013 – April 2014
(Number of Hours and Days)

Anomalous Event	Winter 2013 Events	Winter 2014 Events
HOEP > $200/hour	5	133
CMSC > $1 million/day	7	30
CMSC > $500,000/hour	2	1
IOG > $1 million/day	0	12
IOG > $500,000/hour	0	0
OR Payments >$100,000/hour	0	5
HOEP < $0/hour	43	120

The notable increase in anomalous events corresponds with the extreme cold weather during the Winter 2014 Period. The significant effect the winter weather had on prices and uplift payments has prompted the Panel to report on these outcomes as a general matter, in addition to the Panel's regular and more detailed reporting of specific anomalous events.

2 *Winter 2014 Period Review*

This section sets out the Panel's review of market outcomes in the Winter 2014 Period in relation to the following: weather and temperatures in Ontario, the relationship between temperature and demand, inter-jurisdictional trade, outages at generation facilities, natural gas supply and implied gas generation costs, and the experiences of other Northeast jurisdictions.

2.1 *Weather and Temperature*

The Winter 2014 Period was characterized by consistently cold temperatures. Environment Canada ranked the winter of 2014 as the 8th coldest for Southern Ontario, 6th coldest for Northern Ontario and 10th coldest for all of Canada (all of these comparisons are since the base year of 1948, when nationwide recording of temperature began).[26]

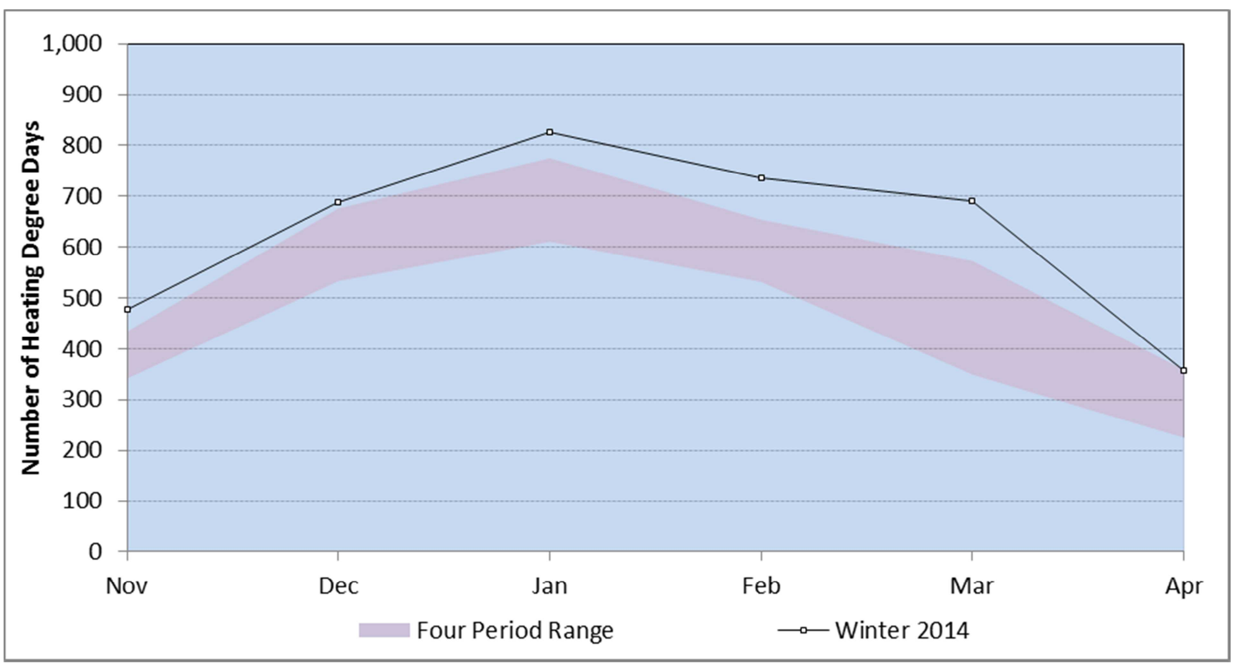
[26] For more information see the Environment Canada webpage entitled, "Climate Trends and Variations Bulletin – Winter 2013-2014", available at: http://www.ec.gc.ca/adsc-cmda/default.asp?lang=En&n=383F5EFA-1

These temperatures were the result of cold air from the polar vortex that extended into unusually low latitudes of North America. Beginning in early January, the polar vortex pushed artic air south causing well below normal temperatures across the Great Lakes region and eastern U.S.[27]

One measure of the extreme cold used by Environment Canada is heating degree-days. Per Environment Canada, "Heating degree days for a given day are the number of degrees Celsius that the mean temperature is below 18°C. Heating degree-days are primarily used to estimate the heating requirements of buildings." [28] For clarity, when the temperature is 0°C, this constitutes 18 degree-days.

Figure 2-1, from the Canadian Gas Association, sets out heating degree-days as measured at Pearson International Airport for the Winter 2014 Period as well as the range for the Winter 2009 to Winter 2013 Period (the "Four Period Range"). During the Winter 2014 Period there were more heating degree-days than had been experienced in the Four Period Range.

Figure 2-1: Heating Degree-days at Pearson International Airport
November 2013 – April 2014
(Daily °C)

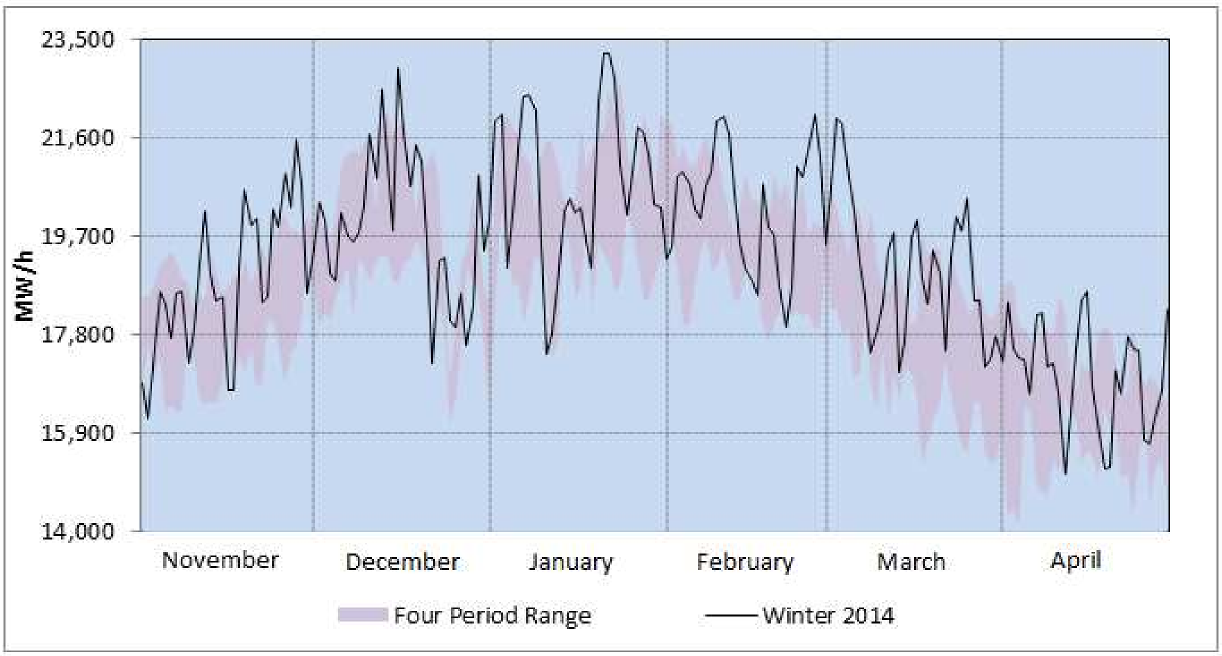


[27] For more information see the Environment Canada report entitled, "Quarterly Climate Impacts and Outlook, Great Lakes Region, March 2014", available at: http://www.ec.gc.ca/eau-water/B6344EC5-5EDA-4158-89CB-6AD45A1693B9/GL-Winter-2013-14-FINAL_E.pdf
[28] Source: http://climate.weather.gc.ca/glossary_e.html.

2.2 *Ontario Demand and Temperature*

Coinciding with extreme cold temperatures was higher Ontario demand relative to recent Winter Periods. Figure 2-2 sets out the highest hourly Ontario demand for each day[29] in the Winter 2014 Period as well as the range for the highest hourly Ontario demand for each day in the Four Period Range.

Figure 2-2: Highest Hourly Average Ontario Demand per Day November 2013 – April 2014 (MW per hour)



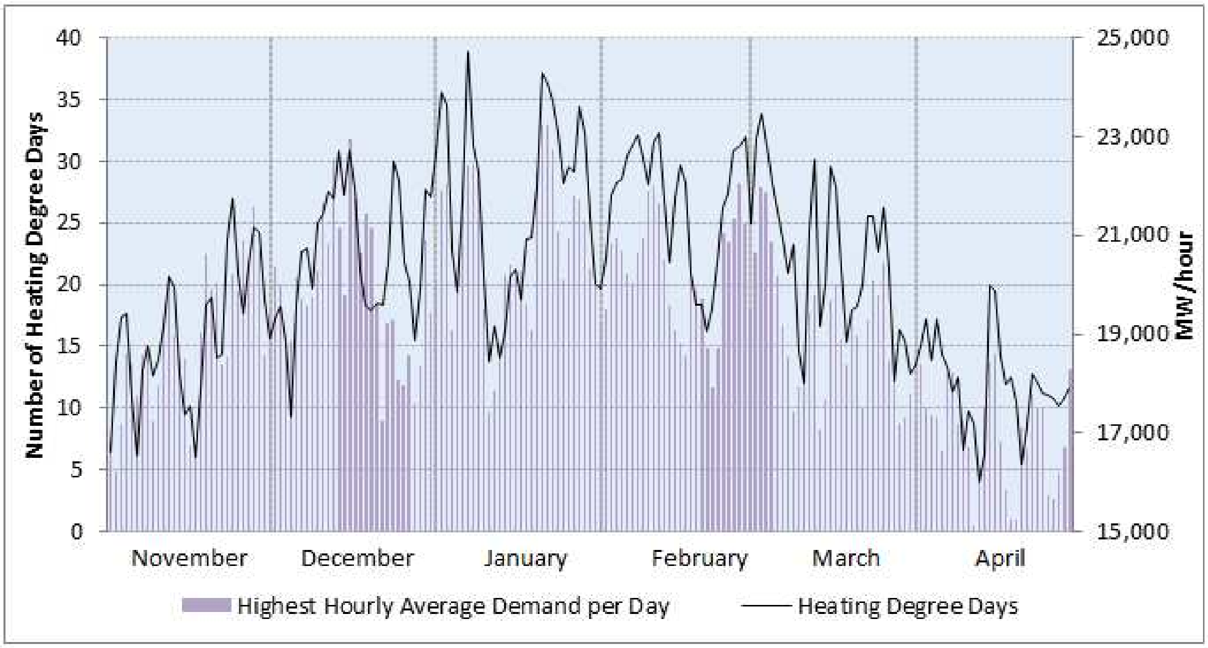
During the Winter 2014 Period, Ontario demand often exceeded the upper bound of the Four Period Range. On more than 33% of the days during the Winter 2014 Period, demand exceeded the upper bound of the Four Period Range and was only below the Four Period Range on approximately 12.5% of days.

Cold temperatures during the Winter 2014 Period contributed to the higher demand for electricity relative to previous Winter Periods. This conclusion is consistent with the data in Figure 2-3, which shows for each day the highest hourly average Ontario demand for the Winter

[29] This was calculated by taking the average Ontario demand across the 12 5-minute intervals of an hour, then selecting the highest average hourly demand of the 24 hourly averages per day.

2014 Period charted against the number of heating degree-days over the same period. High electricity demand days coincide with higher heating degree-days.

Figure 2-3: Highest Hourly Average Ontario Demand per Day & Heating Degree-days November 2013 – April 2014 (MW per hour / °C per day)

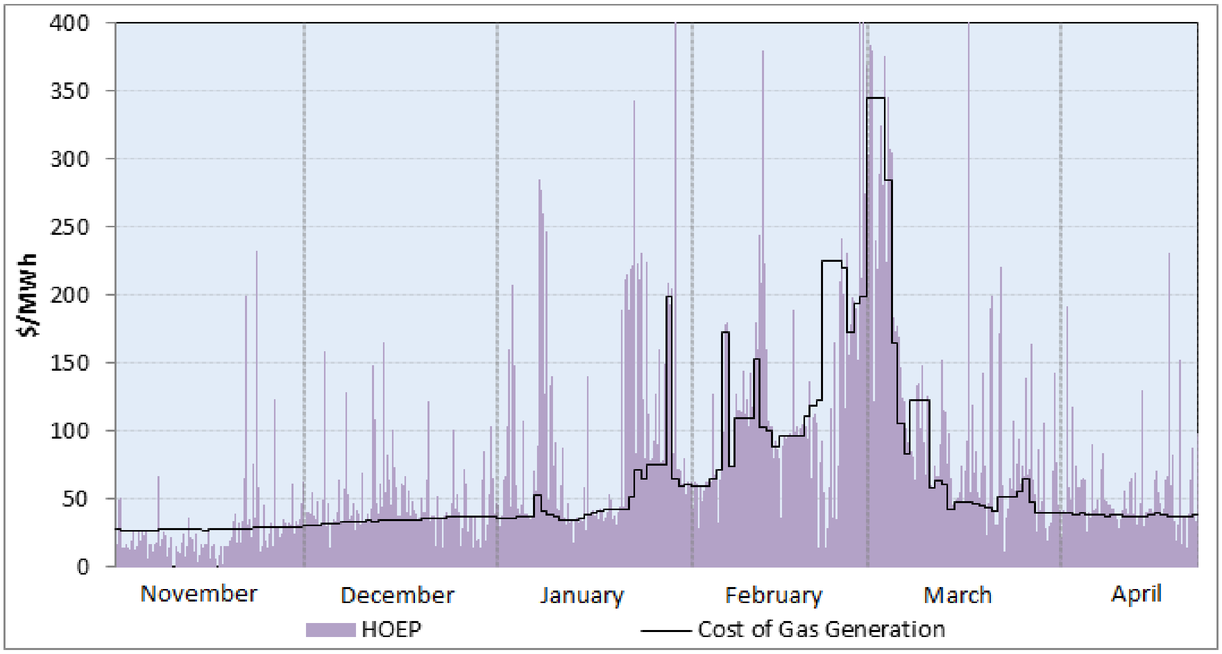


2.3 *The HOEP*

Figure 2-4 sets out the HOEP during the Winter 2014 Period and the $/MWh implied energy cost of a combined cycle gas plant for the same period.[30]

[30] This metric uses the Dawn Hub Daily Future Gas Price and a benchmark heat rate of 7000 Btu/kWh to derive the implied energy cost. This implied energy cost is the cost of gas times a benchmark heat rate – 7000Btu/kWh. The use of 7000 Btu/kWh as the benchmark heat rate for a combined cycle gas generator is consistent with industry standards. For more information see: http://www.eia.gov/todayinenergy/detail.cfm?id=9911

Figure 2-4: The HOEP & Implied Cost of Combined-Cycle Gas Generation November 2013 – April 2014 ($/MWh)

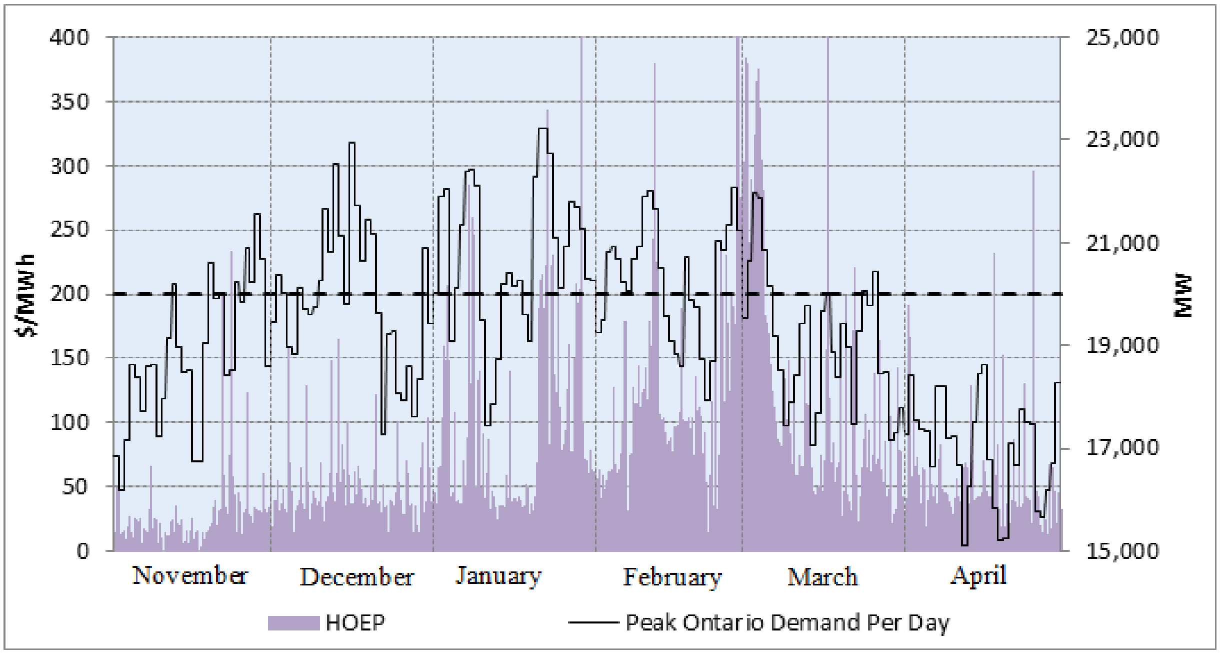


From a market price perspective the Winter 2014 Period can be divided into high prices that coincide with high gas prices and high prices that do not coincide with high gas prices. January high prices arose during periods of relatively lower gas prices, whereas prices in February and March tended to increase with rising gas prices.

2.3.1 The HOEP and Ontario Demand

Figure 2-5 shows the HOEP during the Winter 2014 Period as well as the highest hourly average Ontario demand per day (the same value as is shown in Figure 2-2, above). The area under the dashed line shows the range of prices which do not meet the Panel's $200/MWh threshold for a high-price hour.

Figure 2-5: The HOEP & Highest Hourly Average Ontario Demand per Day November 2013 – April 2014 ($/MWh, MW)



High prices tend to coincide with a day during which Ontario demand was high. That being said, during November and December of 2013, high Ontario demand did not tend to result in prices that were as high as those in the months of January through March of 2014. The extremely high prices during January through March of 2014 are not sufficiently explained solely by high Ontario demand.

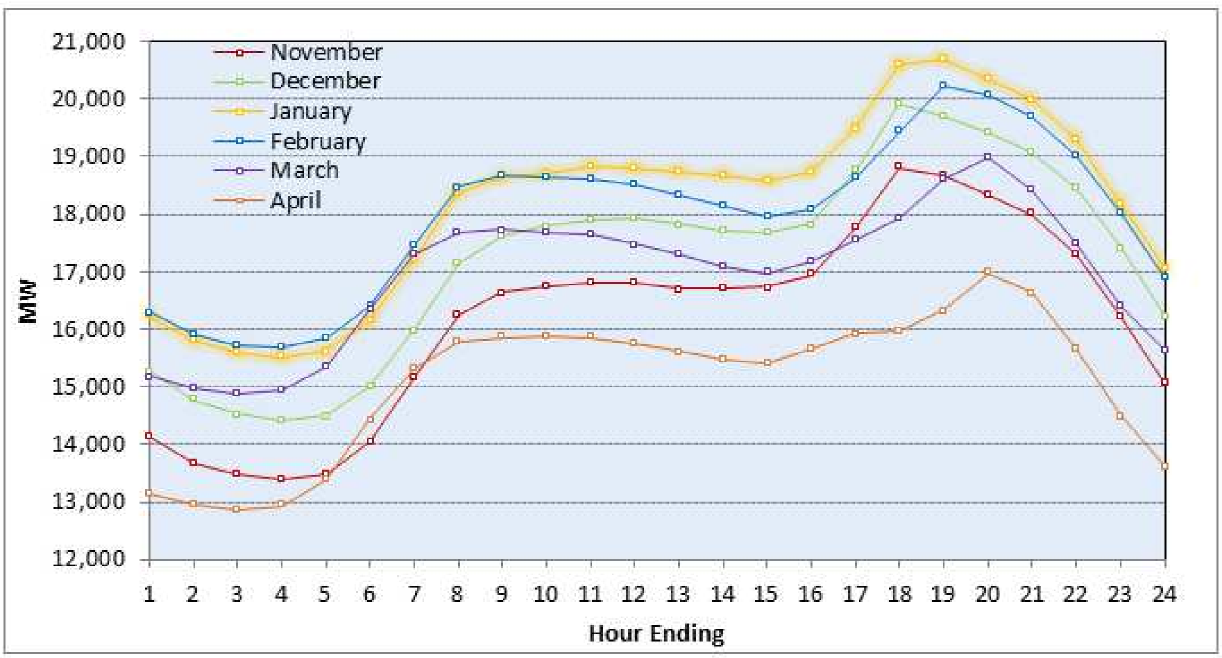
2.3.1.1 Ramp Constraints in January and February

Electricity market supply curves are generally characterized as a ‘hockey stick’ – that is, a relatively large amount of supply which is low-priced followed by a relatively small portion of supply which is priced much higher. As a result, depending on the level of demand (and consequent level of supply required to serve this demand) equivalent changes to either supply or demand can have disproportionate impacts on price. During periods of relatively low demand, changes in supply or demand can be accommodated without resulting in large price changes. During periods of high demand however, accommodating relatively small supply or demand changes can have material impacts on price.

Further, during the morning ramp-up hours and the evening ramp-down hours, resources are ramped to respond to changing demand. During this period ramp constraints limit the amount that resources can increase or decrease their production from hour to hour. If the system operator needs to accommodate a sudden change in supply or demand during these periods, low-cost ramping resources may not be able to further increase the rate at which they produce, requiring higher-cost resources to meet the ramp requirement. To the degree these constraints are present during a period of ramp, changes in price may be greater than otherwise expected.

Figure 2-6 sets out the average hourly demand for each month during the Winter 2014 Period. The morning peak was highest in January and February and the evening peak demand was highest during January 2014.

Figure 2-6: Daily Demand Curve
November 2013 – April 2014
(MW)



As a result of the higher demand peaks in these months (compared to other months during the Winter 2014 Period), equivalent changes of supply or demand had a greater impact on price than they did during other months. This may be a function to varying degrees of both ramp constraints during the ramp periods and the relatively higher demand during the same ramp period.

During the high demand months of January and February, hours where the HOEP was greater than $200/MWh occurred more frequently during ramp hours relative to the frequency of their occurrence during ramp hours outside these high demand months. During the lower demand months, the distribution of high-price hours was more evenly distributed across all hours of the day.

While the confluence of high demand and ramp constraints likely contributed to the number of high-price hours during January and February 2014, other factors (including natural gas prices and facility outages) contributed as well.

1.1.1.1 Gas Prices in February and March 2014

The higher HOEP in the months of February and March tended to coincide with higher gas prices. As cold temperatures persisted into the months of February and March, and as gas generators competed with home heating for fuel, gas in storage decreased and gas prices rose. Higher gas prices put upward pressure on Ontario's wholesale electricity price when gas generators are on the margin or are infra marginal.

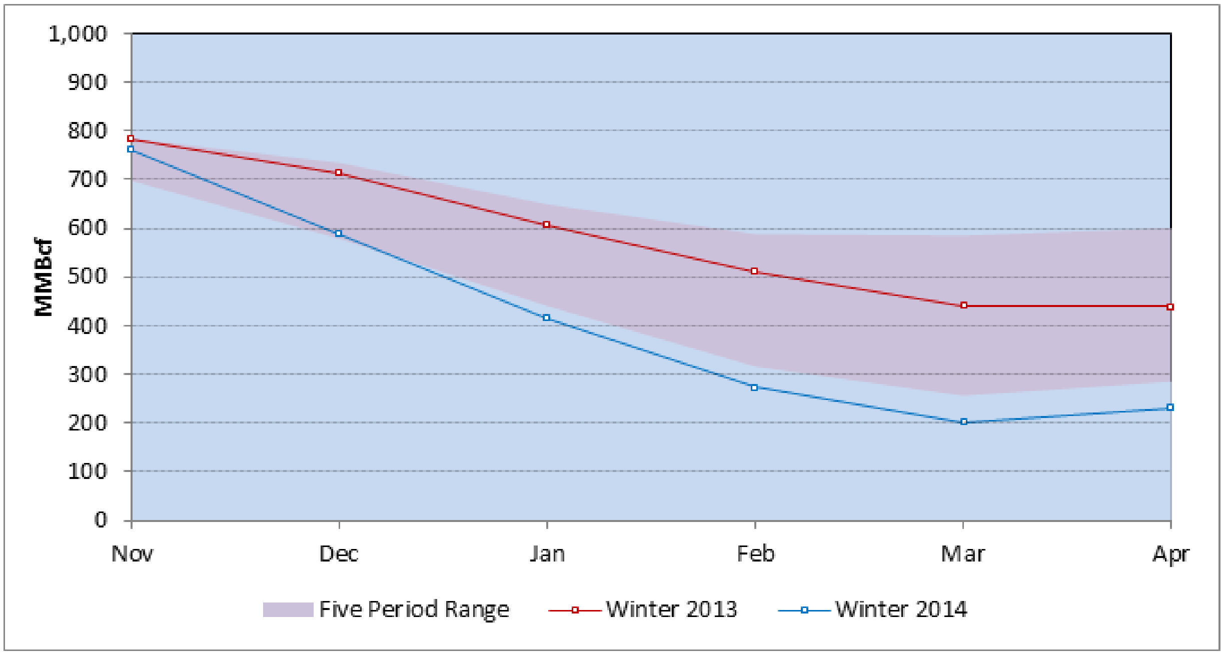
2.4 *Natural Gas Supply and Implied Cost of Gas Generation*

Ontario's supply mix has shifted in composition in recent years with the decommissioning of coal plants and the completion of numerous gas facilities (Ontario had almost 10,000 MW of installed gas capacity as of April 30, 2014). As a result, natural gas markets are affected by, and have an effect on, the Ontario wholesale electricity market.

Gas generators are commonly marginal in Ontario and as such their fuel cost is pertinent. The supply of natural gas is affected by overall demand for natural gas in Ontario and elsewhere. The extreme cold temperatures during the Winter 2014 Period had a significant impact on natural gas demand.

Figure 2-7 sets out the volume of natural gas in underground storage in billions of cubic feet (bcf) in Canada for 2013 and 2014 as well as the level of gas in storage in the five Winter Periods previous to the Winter 2014 Period (the "Five Period Range"). The Five Period Range of gas in storage is shown by the red-shaded area.

Figure 2-7: Natural Gas Storage in Canada[31]
November 2013 – April 2014
(bcf)



Storage levels in late 2013 were declining, and starting in January 2014 storage levels were lower than they had been in any of the prior 5 years. Storage levels throughout 2014 remained below 5-year historical norms.

In general, large increases in gas prices in February and March were mirrored by the HOEP. As shown in Figure 2-4 above, in January there were a number of times where the HOEP spiked above gas prices, suggesting that typical combined cycle gas-fired plants were infra-marginal during those periods and the units setting the Ontario price were more expensive peaking hydro, dispatchable load resources or less efficient gas-fired resources. This is consistent with Figure 2-5, which showed that demand during January was on average higher than other months during the Winter 2014 period.

There was also one period during February when gas prices increased at the same time that the HOEP decreased dramatically – suggesting that gas-fired generation was not economic during this period.

[31] For more information see the Canadian Gas Association storage report, available at: http://www.cga.ca/wp-content/uploads/2011/02/Chart-1-Natural-Gas-Storage37.pdf.

2.5 *Other Market Outcomes*

The extreme weather conditions during the Winter 2014 Period affected market outcomes in ways other than demand, price and natural gas storage. They had various impacts on inter-jurisdictional trade and the operation of facilities. In order to analyze the effects of these extreme weather conditions the Panel considered impacts in these two broad areas as well.

2.6 *Inter-jurisdictional Trade*[32]

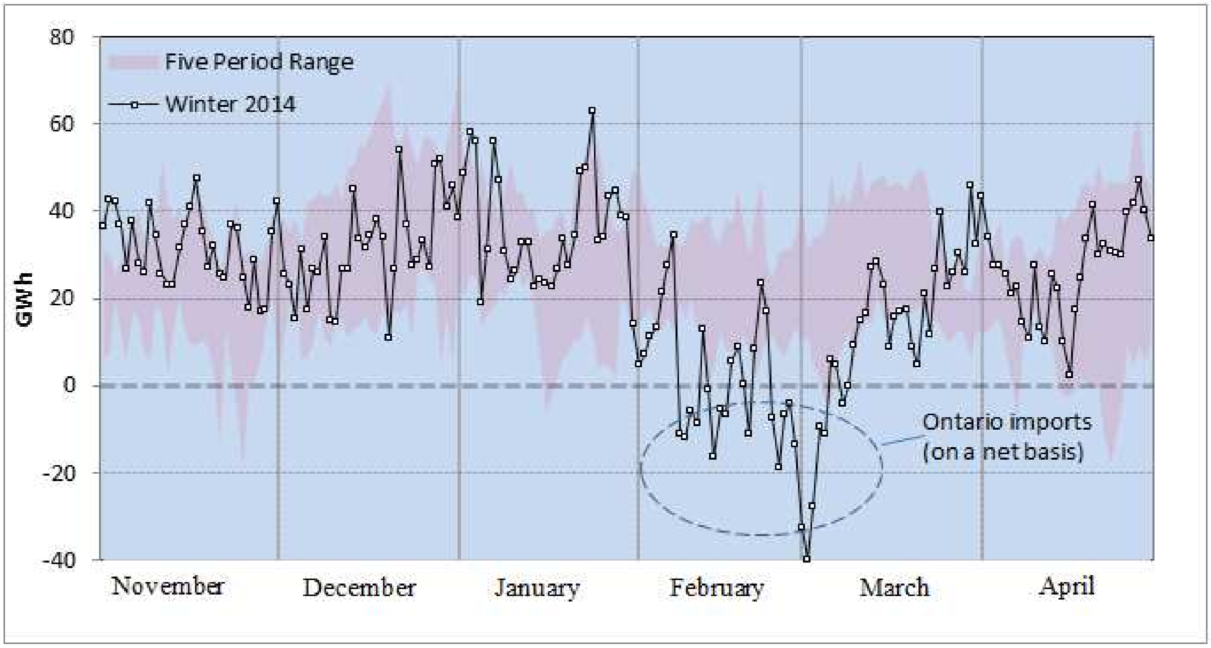
While, in recent years, Ontario has commonly been a net exporter, during the Winter 2014 Period there were hours during February and March where Ontario was a net importer.

Figure 2-8 sets out the maximum and minimum daily net exports from Ontario (total constrained GWh scheduled to export minus total GWh scheduled to import for each day) for the Winter 2014 Period and the Five Period Range.

During the Winter 2014 Period Ontario was a net exporter until February, when after the first few days of the month, Ontario became a net importer intermittently for almost a month. The volume of net imports that occurred during February and March regularly exceeded the amount of net imports that were observed during the Five Period Range.

[32] For further discussion and data around inter-jurisdictional trade during the Winter 2014 Period see Chapter 1 of this report.

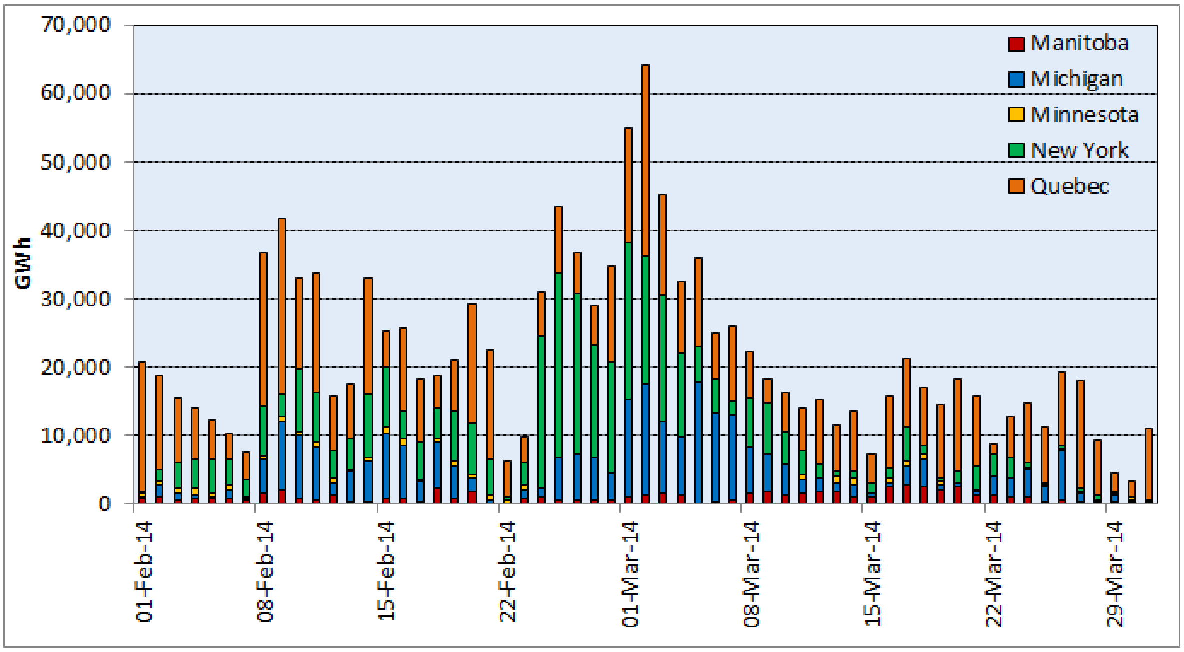
Figure 2-8: Daily Net Exports
November 2013 – April 2014
(GWh)



This move to net importing is a significant departure from the trade patterns over the Five Period Range (during which time Ontario was rarely a net importer). The period in the beginning of March when net imports reached their highest level corresponds with a period when the HOEP was frequently greater than $200/MWh. Some importers were likely responding to this price signal by importing power from a lower price jurisdiction to higher price Ontario.

Figure 2-9 shows the interties on which the net imports were scheduled, as well as the volume of net imports scheduled in real-time on each of these interties, from February 1 to March 31, 2014.

Figure 2-9: Imports by Intertie
February – April 2014
(GWh)



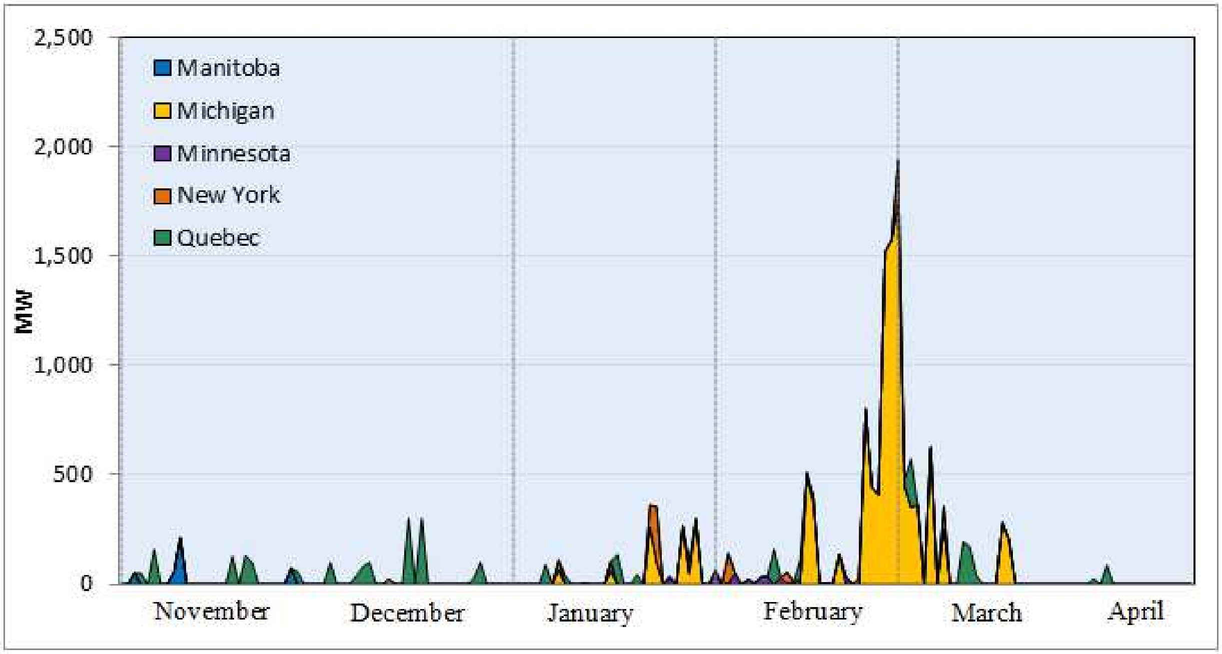
During February and March, 2014, Ontario was generally a net importer, with the New York, Michigan and Québec interties providing the majority of the imports into Ontario.

The extreme weather conditions during the Winter 2014 Period were experienced across North America, with impacts on many neighbouring jurisdictions. Other system operators dealt with conditions brought on by these extreme conditions which resulted in actions being taken which the IESO had to account for in the course of directing the operation of the Ontario system.

One example of the actions taken by other system operators was preventing otherwise-scheduled imports into Ontario from flowing. These transactions were necessarily curtailed by the IESO control room as a result of these external actions. These import curtailments forced the IESO to replace the curtailed MWs of imports with other – more expensive – supply.

Figure 2-10 shows the number of MWs of import transactions which were scheduled to be delivered but were curtailed in response to an external security, adequacy or transmission loading relief issue during the Winter 2014 Period.

***Figure 2-10: Import Transactions Curtailed for External Security or Adequacy Reasons[33]
November 2013 – April 2014
(MW)***



The quantity of imports curtailed as a result of external security or adequacy concerns peaked in late-February, early-March. On February 27, 2014, the Midcontinent Independent System Operator ("MISO") lost a Belle River generation unit with 679.5 MW of capacity[34] which resulted in imports from MISO being curtailed on the Michigan interface. These curtailments continued through February 28 and into the first few days of March and contributed to high prices, most notably in Hour Ending ("HE") 20 on February 27. During this hour, the IESO also implemented a 5% voltage reduction across Ontario (excluding the Northwest) as is described in more detail later in this chapter. During March 4, 2014, MISO experienced significant forced generation outages which resulted in a Step 1 Maximum Generation Emergency Event.[35] According to MISO documentation, the significance of a Maximum Generation Emergency Event is that all available resources are in use and MISO generators are instructed to start off-line resources (Steps 2 through 4 result in public appeals, use of emergency energy and contingency

[33] For more information on these events and how the IESO treats curtailments in response to them see page 14 of IESO Market Manual "4.3: Real-Time Scheduling of the Physical Markets", available at: http://www.ieso.ca/Documents/marketOps/mo_RealTimeScheduling.pdf.
[34] The Belle River generation facility is located just south of Sarnia in the East China Township, Michigan.
[35] For more information see: http://www.oasis.oati.com/MISO/

reserves).[36] The HOEP was higher than $200/MWh for the entirety of March 4, in part due to the import curtailments from the MISO.

2.7 *Ontario Facilities Outages*

Generator outages can have significant impact on both the system and the market.[37]

During the Winter 2014 Period, gas and hydro facility outages generally decreased until the middle of the Period and then increased toward the latter half of the Period. This pattern is similar to previous Winter Periods. Nuclear outages were relatively common throughout the Winter 2014 Period. The reasons underlying these nuclear outages are discussed below.

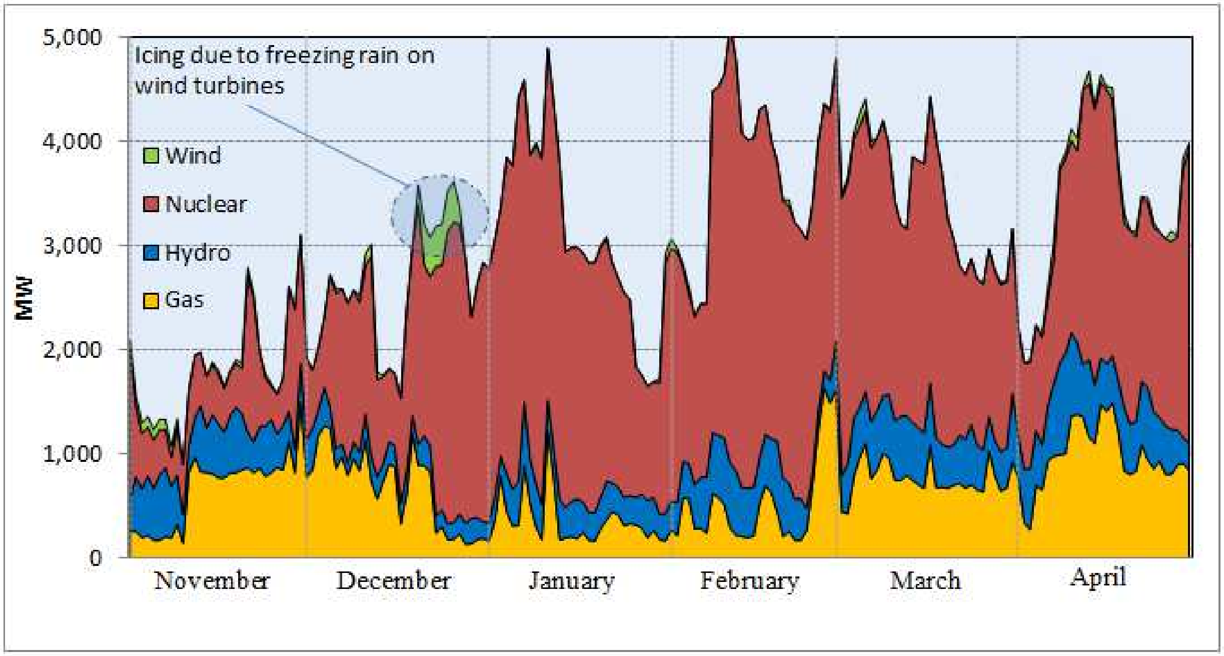
While total outages are potentially informative, the frequency and magnitude of forced outages can be said to describe the extent to which unforeseen events affected generator performance. Responding to short-notice or unexpected constraints on the IESO-controlled grid generally results in more severe system and market impacts than would likely result from expected constraints.

Figure 2-11 shows the magnitude of forced outages at generators by fuel type during the Winter 2014 Period.

[36] For more information see the MISO communication entitled, "Understanding Emergency Operations", available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/Emergency%20Operations%20Process.pdf.

[37] For the purposes of the following discussion regarding unit availability, unit de-ratings are considered part of total outages.

Figure 2-11: Generator Capacity on Forced Outage by Fuel Type
November 2013 – April 2014
(MW)

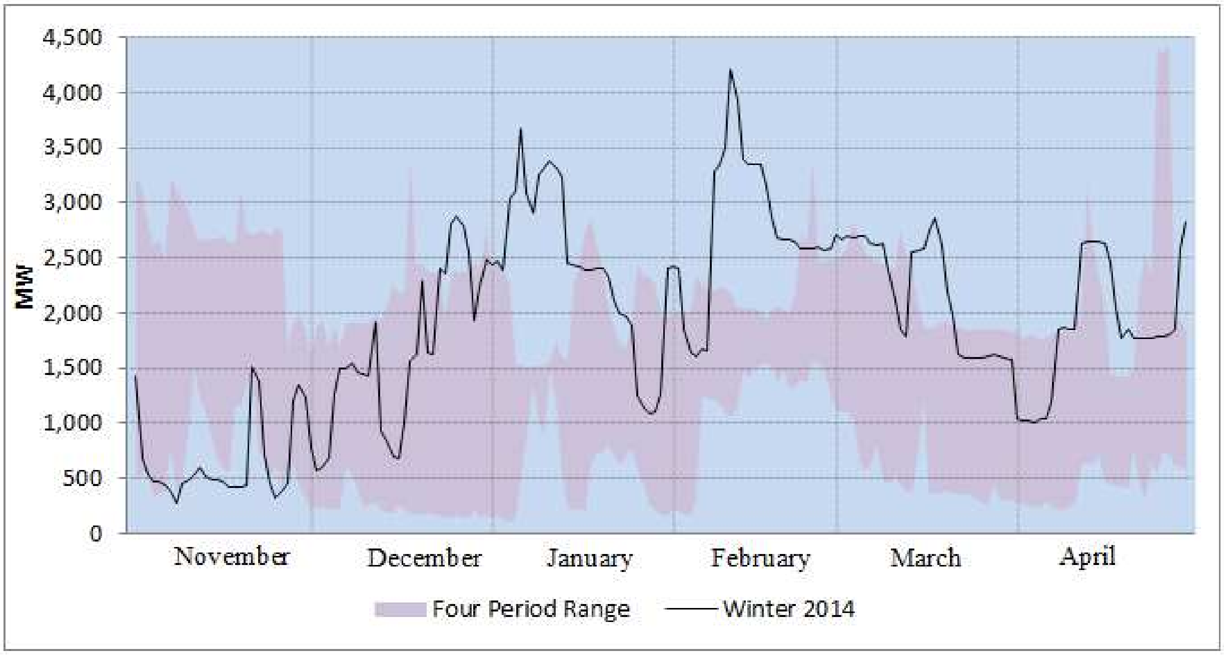


The fuel type of a particular facility has an impact on the types of occurrences which result in forced outages. Nuclear units experienced relatively persistent and significant levels of forced outages during the Winter 2014 Period, which had the effect of reducing the amount of baseload generation available to the system.

2.7.1 Forced Outages at Nuclear Facilities

Figure 2-12, shows the number of MWs of nuclear capacity on forced outage during Winter 2014 Period and during the Four Period Range.

Figure 2-12: Winter 2014 Period (and Four Period Range) Nuclear Capacity on Forced Outage
November 2013 – April 2014
(MW)



As can be seen in the above figure, the high quantity of nuclear MWs on forced outage during the Winter 2014 Period was only uncharacteristically high during limited periods. During these periods when forced outages were higher than normal, there were a number of reasons for the outages, two of these reasons were explicitly temperature-related (other reasons were equipment-related outages):

- Frazil[38] ice building up on the bodies of water which provide cooling water for the nuclear facilities; and
- Lake temperatures forcing units to be de-rated.[39]

While the majority of the forced nuclear outages during the Winter 2014 Period were marginal de-rates brought on by the cold weather, there were a few occasions when forced outages affected an entire nuclear unit – removing a significant amount of generating capacity.

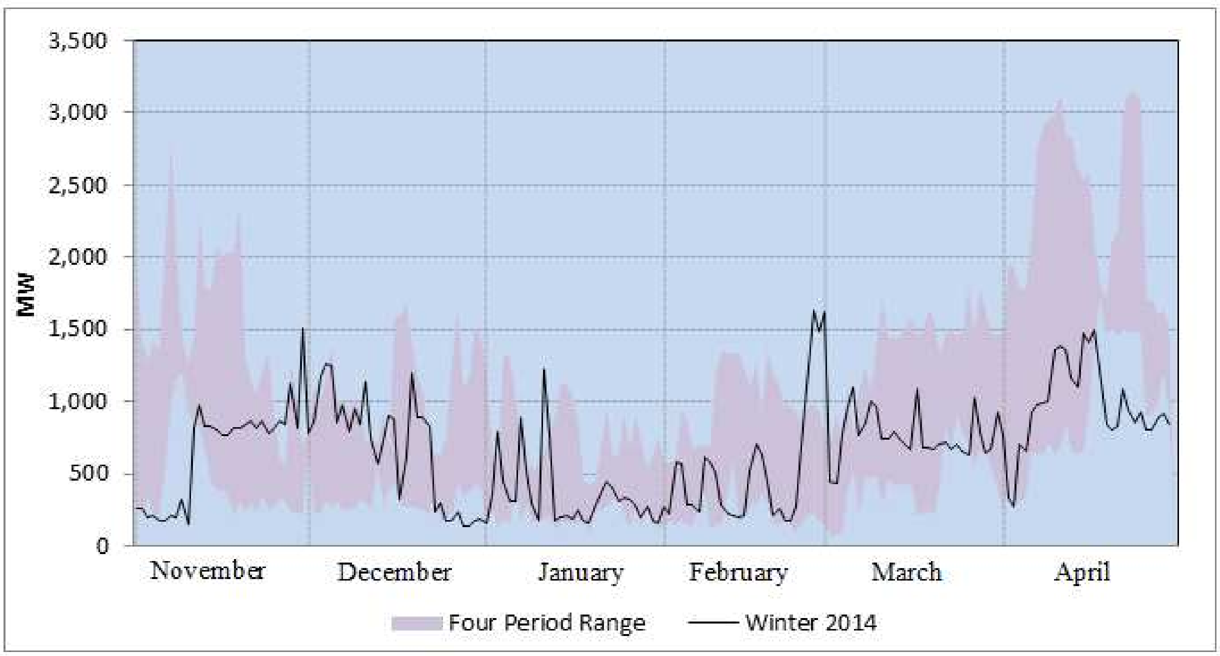
[38] Frazil is soft or amorphous ice formed by the accumulation of ice crystals in water that is too turbulent to freeze solid. Frazil ice resembles slush and will adhere to objects in the water (such as trash racks at hydro facilities).

[39] The Panel understands that these de-rates can be brought on because of ice forming on the surface of the lake water close to the nuclear plant. This ice surface reduces water circulation around the plant. As a result, in order to avoid overheating, the plant is not able to run at its nameplate capacity and must produce energy at a lower rate.

2.7.2 Forced Outages at Gas Facilities

Given the changing supply mix and the construction and entry into the market of numerous natural gas facilities, the performance of gas generators during the Winter 2014 Period relative to their performance during other milder winters is of particular interest to the Panel. Data from the Winter 2014 Period may be helpful in identifying issues related to Ontario's increased reliance on natural gas generation. Figure 2-13 is a comparison of forced outages experienced by gas generators during the Winter 2014 period as compared to the Four Period Range.

Figure 2-13: Winter 2014 (and Four Period Range) Gas Capacity on Forced Outage November 2013 – April 2014 (MW)



Gas generators generally did not experience historically high levels of forced outages during the Winter 2014 Period relative to the Four Period Range. Some exceptions to this include the period from February 24 to March 1, 2014. During this period there were a number of natural gas facilities which experienced forced outages. Reasons for these outages include general equipment concerns, ice buildup on condensers, forced shutdowns, vibration issues, and icing.

2.8 *Other Jurisdictions*

During the Winter 2014 Period, new winter peak demands for electricity were set in MISO, the Southwest Power Pool ("SPP"), PJM Interconnection ("PJM") and the New York ISO ("NYISO"). The cold temperatures and high demand for energy extended into the Southeastern United States. Prices for both electricity and natural gas were higher than previous Winter Periods. During the coldest weather events, the historically high peak demand combined with high levels of generation outages placed these regions near their capacity in meeting system demand. The real-time operators and independent system operators declared emergency conditions on several occasions and some implemented emergency procedures, including emergency demand response, voltage reduction, emergency energy purchases, and public appeals for conservation. Mechanical failures in generator systems, fuel deliverability and fuel handling problems in the extreme low temperatures experienced during the Winter 2014 Period led to high levels of forced generation outages. These levels contributed to the stressed conditions in the markets that lead to emergency actions and higher prices.[40]

Due to the elevated levels of demand and higher than expected outage rates, most of the Eastern United States. Regions were operating at the high-cost levels of their supply stacks and in many cases this meant oil units that are not often used were dispatched to maintain adequacy. Some dual-fuel generators in those regions were forced to use oil when non-firm transportation of natural gas became unavailable. And on some days, high natural gas prices made oil-fired generation more economical to dispatch than natural gas generation. Head-to-head price competition between oil and gas for power production is not something that has frequently occurred in recent years.[41]

On January 7, 2014, prices in PJM spiked as a result of forced outages and de-rates combined with the extreme cold temperatures. During the same day, MISO issued a Maximum Generation Event Warning (which signals that system operations will be altered to ensure reliability and non-firm exports are curtailed). PJM estimates that about one quarter of the 41,336MW of forced outages on January 7 were fuel related with issues such as gas curtailments, lack of fuel, oil delivery issues and frozen coal. During the cold snaps in late January, PJM's failures-to-start

[40] For more information see pages 7-8 of the April 2014 FERC presentation entitled "Winter 2013-2014 Operations and Market Performance in RTOs and ISOs", available at: http://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf
[41] *Ibid* page 10

for combustion engines and gas curtailments were less frequent than in early January. The New England system operator ("ISONE") experienced a low level of forced generation outages on January 7 relative to other jurisdictions, however all of the outages were attributed to intraday natural gas procurement issues.[42]

ISONE relied heavily on their oil-burning generators during the Winter 2014 Period. By the beginning of February, these facilities had burned much of their reserve fuel and this constraint put further upward pressure on price. Further, gas facilities in ISONE experienced significant outages during the Winter 2014 Period. One example of this is during the peak hour of January 28, 2014; during this hour gas facilities produced only about 3,000 MW from a total capacity of more than 11,000 MW. Gas prices were also significantly higher in ISONE than other jurisdictions, with the price for gas[43] from December 2013 through February 2014 averaging $19.33/MMBtu (Dawn Hub Futures prices during the same period averaged $8.97/MMBtu).[44]

2.9 *OEB 2014 Gas Electric Initiative*

As a result of the increasing role that natural gas-fired generation plays in the supply mix in North America and also in response to the Winter 2014 Period, jurisdictions across North America are in the process of carrying out a number of gas-electric co-ordination initiatives.[45] These initiatives are currently at various stages of development.

The Ontario Energy Board initiated a consultative process (the "2014 Natural Gas Market Review")[46] to examine recent developments in the North American natural gas market to better understand any potential implications for Ontario's natural gas sector. Specifically, the consultation process endeavored to identify and explain key influences on the Ontario natural gas sector over the next 3 to 5 years.

[42] *Ibid* page 8
[43] As calculated at the Algonquin Citygate in the Northeast U.S.A.
[44] For more information see the April 2014 ISO New England presentation to the FERC entitled, "Cold Weather Operations", available at: http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2014/winter_operations_technical_conference_april_2014.pdf.
[45] For a description of U.S. initiatives, see FERC's Gas Electric Coordination Quarterly Report to the Commission which describes various initiatives and communicates status updates on their development, available at: https://www.ferc.gov/legal/staff-reports/2014/12-18-14-gas-electric-cord-quarterly.pdf.
[46] For more information see the OEB's gas market review webpage, available at: http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/2014%20Natural%20Gas%20Market%20Review%20(EB-2014-0289).

Both the Panel and the IESO participated in the 2014 Natural Gas Market Review. The Panel presented preliminary analysis of the events in the Winter 2014 Period[47] and the IESO discussed initiatives related to gas-electric co-ordination which would, in the view of the IESO, promote reliable service or operational planning.[48] Where these initiatives will promote efficient market outcomes through enhanced reliability or operational planning, the Panel is fully in support of them.

3 *Anomalous HOEPs*

The number of anomalous price and uplift events identified in the Winter 2014 Period was significantly higher than in the previous Winter Period. The majority of the anomalous events occurred between January 20th and March 5th, during the extended cold weather. For this reporting period, many anomalous uplift events were coincident with high prices.

3.1 *Analysis of High-price Hours*

High-price hours in the Winter 2014 Period are mainly attributed to two factors, high demand due to cold temperatures and the high commodity price of gas. High demand is relative to supply conditions in the province and high prices can 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 of the following (among others): planned or unplanned generator outages; import failures; and ramping limitations. High gas prices influence the HOEP when generators burning gas are called on to produce electricity. The cost of burning high-price gas is passed through to the wholesale market through higher offer prices. When these gas generators are on the margin, and therefore setting the HOEP, electricity prices rise with the cost of gas.

[47] The Panel's presentation is available at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/457421/view/OEB_MSP_2014%20NGMR%20Conference_Presentation_20141127.PDF.
[48] The IESO's presentation is available at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/456953/view/IESO_2014%20NGMR%20Conference_presentation_20141126.PDF.

Table 2-2 displays the number of hours per month in which the HOEP exceeded $200/MWh in the Winter 2014 Period and the preceding five Winter Periods.

Table 2-2: Number of High-price Hours
November – April, 2009/2010 to November – April 2013/2014

Month	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014
November	0	0	0	3	1
December	0	0	0	0	0
January	1	0	0	0	34
February	0	0	1	0	32
March	0	0	2	0	63
April	0	1	0	2	3
Total	**1**	**1**	**3**	**5**	**133**

During the Winter 2014 Period there were 133 high-price hours. This number is unprecedented, and almost double the next highest number of high-price hours in a reporting period, which was 71 events during the period from May 2005 – November 2005 (the "Summer 2005 Period").

The Panel identified two hours with anomalous price outcomes for which the primary causes were not high demand and/or high gas prices and have discussed these events below. These events were chosen for further discussion in this report due to the particular conditions that precipitated them. Factors which contributed to the high-price hours which are not analyzed include those common to the hours described below, as well as factors which the Panel has previously identified as being frequently responsible for high prices (day of the week, seasonal effects, planned or unplanned generator outages, import failures and ramping limitations are some of these factors).

3.1.1 January 29, 2014 Hour Ending 8

On Wednesday, January 29, 2014 the HOEP reached $611.38/MWh in HE 8. The one hour-ahead dispatch price was $275.00/MWh. Temperatures at Toronto's Pearson International Airport were cold, with a low of -18.5°C and a high of -10.1°C, contributing to high demand throughout the day, with real time system demand averaging 23,048 MW in HE 8. Notably, this real-time demand was almost 400 MW lower than any of the prior five forecasts for demand for HE 8, which would typically lead to a lower real-time price as compared to pre-dispatch prices.

Table 2-3 displays the real-time market clearing price ("MCP"), Ontario demand and net exports for HE 8.

Table 2-3: Real-time MCP, Ontario Demand and Net Exports
January 29, 2014 HE 8
(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)
8	**1**	93.81	20,037	2,479	22,516	-	-96
8	**2**	88.69	20,276	2,479	22,755	239	-96
8	**3**	97.93	20,405	2,479	22,884	129	-96
8	**4**	105.16	20,570	2,479	23,049	165	-96
8	**5**	172.13	20,681	2,479	23,160	111	-96
8	**6**	172.13	20,697	2,479	23,176	16	-96
8	**7**	179.60	20,707	2,479	23,186	10	-96
8	**8**	179.59	20,684	2,479	23,163	-23	-96
8	**9**	250.53	20,772	2,479	23,251	88	-96
8	**10**	1999.00	20,698	2,479	23,177	-74	-96
8	**11**	1999.00	20,668	2,479	23,147	-30	-96
8	**12**	1999.00	20,632	2,479	23,111	-36	-96
Average		**611.38**	**20,569**	**2479**	**23,048**	**54**	**-96**

In HE 8 interval 10, when the MCP spiked to$1,999/MWh, Ontario demand dropped by more than 70 MWs. The price remained at $1,999/MWh despite decreasing demand during the last two intervals of the hour. As explained below, the price spike was a result of a shortage of offers for 30 minute operating reserves.

The hour-ahead pre-dispatch forecast for price for this hour was $250/MWh. As shown in Table 2-3, this $250/MWh forecast for price did not under-forecast price for first nine intervals of the hour, in fact it over-forecast price. The prices during intervals 1-9 were consistent with pre-dispatch supply and demand conditions.

From intervals 10 through 12, there was an energy market shortage which had not materialized in the hour-ahead pre-dispatch forecast price. This energy market shortage was the result of resources being dispatched down in the energy market and being scheduled to provide OR in order to remedy the OR market shortage.

Pre-dispatch supply conditions in the OR markets were tight in the hours leading up to real-time,[49] and real-time reductions in OR offers resulted in upward pressure (on the already high prices) in the energy and OR markets.

Impact of Joint Optimization on Price and Schedules

Energy and OR prices are based on the total cost of satisfying the next MW of demand. This process is fairly straightforward when only one of these markets has to be considered. However, the dispatch algorithm uses joint optimization whereby resources are traded-off between the two markets to find the optimal combination of resources that satisfies energy and OR demand at the lowest total cost. Therefore, satisfying one additional MW of demand in one market can have a price effect in the other market. This is the case because satisfying one more MW of demand in one market makes that same MW unavailable to the other market. More specifically, scheduling one additional MW in the energy market removes that MW for scheduling in the OR market (assuming that the resource offered into both markets) and vice versa.

This implies, and it is the case, that a resource with an available capacity of 500 MW could offer 500 MW into the energy market and the OR market. The dispatch algorithm would then determine the least cost way of dispatching the total capacity of 500 MW, for example, 250 MW of energy and 250 MW of OR. The resource would not receive a combined dispatch that exceeds its available capacity.

The joint optimization process leads to the scheduling of resources across the energy and operating reserve markets that maximizes the economic gain from trade across all markets. Maximizing the economic gain from trade results in scheduling the offered resources in such a way that demand can be satisfied at the lowest possible cost of production. A result of trading off resources between the energy and OR markets can be market clearing prices that do not correspond to any single offer submitted.

[49] 30 minute OR prices were forecast to be $70.01/MWh, $175.75/MWh and $186.42/MWh at the 3, 2 and 1 hour-ahead time horizons respectively.

Table 2-4 shows the real time MCPs for energy and OR (10-minute synchronized "10S", 10-minute non-synchronized "10N" and 30-minute "30R") as well as the fuel type of the marginal resource(s).

Table 2-4: Real-time MCP and Marginal Resources
January 29, 2014 HE 8
(MW & $/MWh)

HE	Interval	Real-time Energy MCP ($/MWh)	Real-Time 10S OR MCP ($/MWh)	Real-Time 10N OR MCP ($/MWh)	Real-Time 30R OR MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
Prior to HE 8							Facility scheduled for 300 MW of energy and for 161 MW of OR in PD-1. Offers were removed between 06:36 and 6:38 due to equipment concerns.
8	1	93.81	30.10	30.10	11.59	Water	Unit was scheduled for 150 MW of energy and for 60 MW of OR in PD-1 but was forced out of service (failed to start) at the beginning of HE 8. MWs removed from the unconstrained schedule after interval 4.
8	2	88.69	30.10	30.10	25.00	Water	
8	3	97.93	30.10	30.10	30.00	Water	
8	4	105.16	30.10	30.10	30.00	Water	
8	5	172.13	87.03	75.00	74.90	Water	
8	6	172.13	87.03	75.00	74.90	Water	
8	7	179.60	87.03	75.00	74.90	Water	
8	8	179.59	87.03	75.00	74.90	Water	
8	9	250.53	121.71	100.00	99.90	Water	
8	10	1,999.00	1,999.00	1,999.00	1,999.00	Load,	CAOR de-rated. 30 minute OR shortfall from interval 10 to interval 12.
8	11	1,999.00	1,999.00	1,999.00	1,999.00	Load,	
8	12	1,999.00	1,999.00	1,999.00	1,999.00	Load,	
Average		**611.38**	**548.94**	**543.12**	**541.09**		

Energy and OR prices increase in response to removal of the previously scheduled resource.

Energy and OR prices increase in response to de-rating of CAOR and the corresponding operating reserve shortage.

For intervals 1 through 9, there were sufficient offers from online resources to satisfy operating reserve requirements. However, during these intervals, resources which had been scheduled to provide energy in pre-dispatch were instead scheduled to provide OR. The dispatch algorithm's joint optimization was rebalancing energy and OR market dispatches, but each market was tight and prices in all markets were steadily on the rise over the first 9 intervals of the hour.

By interval 10 a total cumulative reduction in OR offers of 321 MW meant there were insufficient offers to meet the 30R OR requirement.

The price for OR is normally equal to the cost of satisfying the next MW of demand for OR; however, in time of supply shortfall, the OR price is the greater of the highest priced reserve offer or the energy price for the interval.[50] During intervals 10 to 12, the OR price was set by the price of energy at $1,999/MWh. The OR shortfall did not carry into HE 9 and prices dropped starting in interval 1 of HE 9.

3.1.2 February 27, 2014, Hour Ending 20

On Thursday, February 27, 2014 the HOEP reached $964/MWh in HE 20. The one hour ahead pre-dispatch price was $199.42/MWh (set by a gas facility). The pre-dispatch price is primarily explained in large part by gas prices. Gas futures prices were high at $24.844/MMBtu on this day, implying a cost of gas generation of $173.91/MWh (using the same methodology as is used in the Introduction section of this chapter).

Temperatures at Toronto's Pearson International Airport were cold, with a low of -17.2°C and a high of -10.0°C contributing to high demand throughout the day, with real time Ontario demand averaging 21,800 MW in HE 20. This demand is significantly above the IESO's forecast peak demand under normal weather conditions for the week ending March 2 of 20,886 MW and approaching the IESO's extreme weather forecast weekly peak of 21,842 MW.[51]

Production from self-scheduling, intermittent and wind resources were over-forecasted, resulting in 443 MW of generation which needed to be replaced over the hour. Net exports were 690 MW higher in real-time than was forecasted in pre-dispatch due to MISO preventing previously-scheduled imports from MISO to Ontario from flowing at the Michigan interface.

[50] For more information see page 6 of the IESO training guide entitled, "Guide to Operating Reserve", available at: http://www.ieso.ca/Documents/training/ORGuide.pdf.
[51] For more information see page 2 of the December 2013 IESO report entitled, "18-Month Outlook – Ontario Demand Forecast, available at: http://www.ieso.ca/Documents/marketReports/18Month_ODF_2013dec.pdf.

The net result of these forecasting discrepancies was that there were significantly fewer resources available to meet demand in real-time than had been predicted in the hour-ahead pre-dispatch forecast.

Table 2-5 identifies events that occurred in HE 19 and HE 20.

Table 2-5: Real-time MCP and Marginal Resources
February 27, 2014 HE 19 and 20
($/MWh & Fuel Type)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
19	**1**	196.27	Gas	
19	**2**	196.29	Gas	
19	**3**	196.31	Gas	
19	**4**	197.05	Gas	
19	**5**	199.37	Gas	
19	**6**	199.38	Gas	
19	**7**	200.16	Water	MISO curtailed 315 MW of imports from Michigan to Ontario for HE 20.
19	**8**	201.40	Gas	MISO increased their import curtailments to 698 MW for HE 20. IESO curtails 300 MW of exports for HE 20.
19	**9**	201.40	Gas	
19	**10**	219.03	Water	Gas unit de-rated from 400 MW to 250 MW. With no available generators and more MWs of CAOR scheduled than would have been achieved as a result of a voltage reduction, the IESO curtailed 304 MW of exports to MISO starting in HE 20.
19	**11**	500.00	Water	The same gas unit forced out of service. 650 MW of OR activated.
19	**12**	491.89	Water	5% voltage reduction implemented (all areas except NW) resulting in 384 MW of relief. 150 MW of OR activated. IESO requests that a gas facility synch and ramp to its minimum stable production level (Minimum Loading Point or "MLP").
Average		**249.88**		
20	**1**	392.00	Gas	
20	**2**	230.59	Gas	
20	**3**	2000.00	Load, CAOR	Voltage reduction begins to be phased out.
20	**4**	2000.00	Load, CAOR	

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource	Notable Events
20	5	466.90	Water	419 MW of exports curtailed, 280 MW of reserved deactivated.
20	6	491.90	Water	300 MW of OR deactivated.
20	7	500.00	Water	IESO curtails 444 MW of exports for HE 21.
20	8	1995.00	Load	220 MW of OR deactivated.
20	9	1995.00	Load	
20	10	500.00	Water	ON demand falls 41 MW.
20	11	500.00	Water	ON demand falls 70 MW.
20	12	500.00	Water	
Average		964.28		

The high prices experienced in HE 20 can be explained by four events which put upward pressure on prices as a result of either supply or demand effects:

- high demand conditions (which contributed to the large increase in price relative to the hour-ahead pre-dispatch price due to demand clearing on the steep portion of the supply stack);
- imports cut from MISO (which forced the IESO to replace MWs of supply with more expensive sources);
- the loss of a large natural gas unit (which forced the IESO to replace MWs of supply with more expensive sources); and
- the over-forecasting of wind and self-scheduling units (which forced the IESO to replace MWs of supply with more expensive sources).

MISO curtailed 700 MW of imports scheduled across the Michigan interface and Ontario had a 400 MW generating unit forced out of service leading up to the beginning of HE 20. The combined supply loss from these two events was 1100 MW; this loss forced the IESO to activate operating reserve for HE 20.

Following the activation of these operating reserves, the IESO had no further generation resources available which could respond to meet demand. The previously-mentioned loss of the large natural gas unit resulted in an imbalance of supply and demand, with demand outstripping supply; Ontario was withdrawing more energy from the grid than they were injecting into it. As a result, the inter-jurisdictional power flow shifted such that the shortfall in Ontario injections was made up for with energy flowing across the interties and into the province.

The IESO monitors this power balance and the net value of the flow at any given time is the Area Control Error (“ACE”) (which reflects the system balance of supply and demand). Following the loss of the natural gas unit, the ACE was outside acceptable boundaries, and the response of the IESO was to implement a 5% voltage reduction across Ontario (except for in the oversupplied Northwest, where reducing voltage would not have provided significant relief).

By interval 3 of HE 20 the voltage reduction and operating reserve activations were resulting in Ontario oversupply. The IESO began phasing out the voltage reduction and deactivating operating reserve, bringing supply and demand back into balance.

Demand increased in interval 3, causing a price spike. During intervals 8 and 9, while resources which had been called upon to provide reserve energy were deactivated, prices spiked again. Following interval 9, a decline in Ontario demand resulted in a reduction of the MCP from $1,999/MWh to $500/MWh.

3.2 *Analysis of Negative-price Hours*

Negative-price hours signal the availability of abundant baseload supply relative to demand. Low demand hours occur most frequently during overnight hours, weekends, and mild shoulder seasons (spring and fall).

The amount of baseload supply is a function of available nuclear, hydroelectric and wind generation. Generation from nuclear facilities remains fairly constant over time, with units on or returning from outage as the main influence of available generation. Baseload hydroelectric facilities and wind generators have seasonal patterns to their production. Baseload hydro tends to be highest during freshet in the spring time, and wind generation tends to be highest during the cold winter months. As installed wind generation capacity grows, windy periods will have greater influence on the number of negative price hours.

Imports are scheduled in the pre-dispatch market and are assigned real-time offer prices of -$2,000/MWh. As a result, imports tend to put downward pressure on price in real-time. As such, the quantity of imports is also relevant for analyzing the frequency of negative-price hours.

Table 2-6 displays the number of hours per month in which the HOEP was below $0/MWh in the Winter 2014 Period and the preceding four Winter Periods.

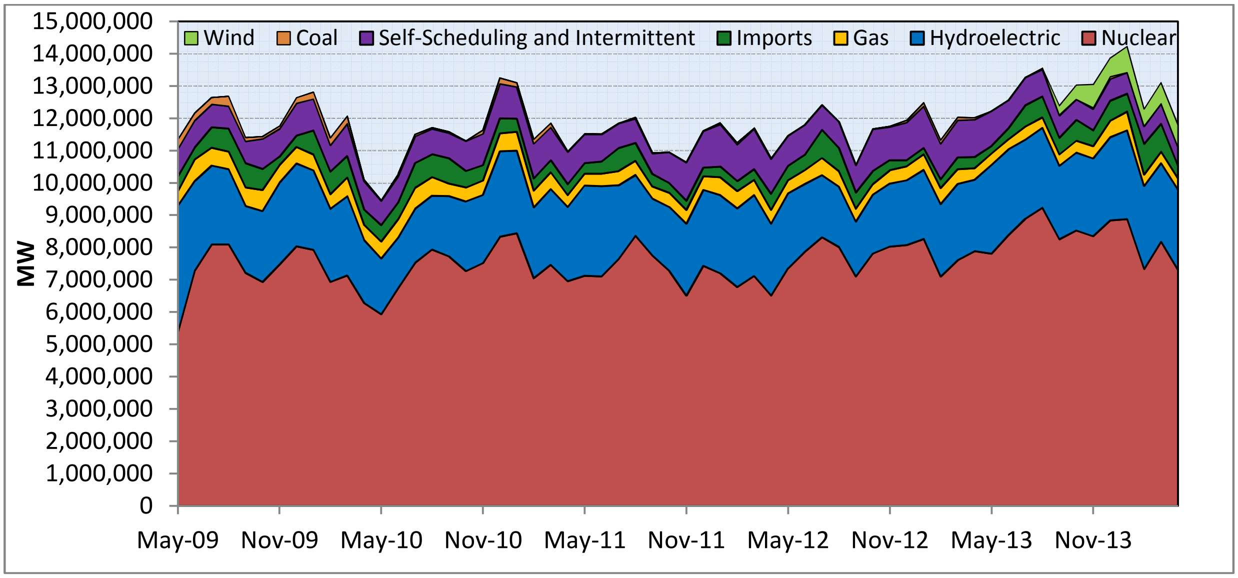
Table 2-6: Number of Hours with a Negative HOEP
November – April 2009/2010 to November – April 2013/2014

Month	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014
November	16	3	13	11	111
December	0	9	14	4	3
January	1	11	9	13	3
February	0	0	2	0	1
March	0	3	44	3	2
April	9	27	5	12	0
Total	**26**	**53**	**87**	**43**	**120**

There were 120 negative-price hours in the Winter 2014 Period. This represents a significant increase in the number of negative-price hours relative to the previous four Winter Periods. The negative-price hours occurred almost entirely within the month of November (111 of 120) and most of these hours (79) occurred from November 1 to 18.

Figure 2-14 displays the total monthly supply offered at negative prices by resource type.

Figure 2-14: Negative-priced Offers by Month and Resource Type[52,53]
May 2009 – April 2014
(MW)



There has been a step change (increase) in negative-price offers since the end of 2012 which can be attributed to the return to service of Bruce units 1 and 2 in October of 2012. Together those units offer approximately 1,500 MW of low-price baseload supply.

The spike in the frequency of negative-price hours from November 1 to November 18 can be attributed to three factors:

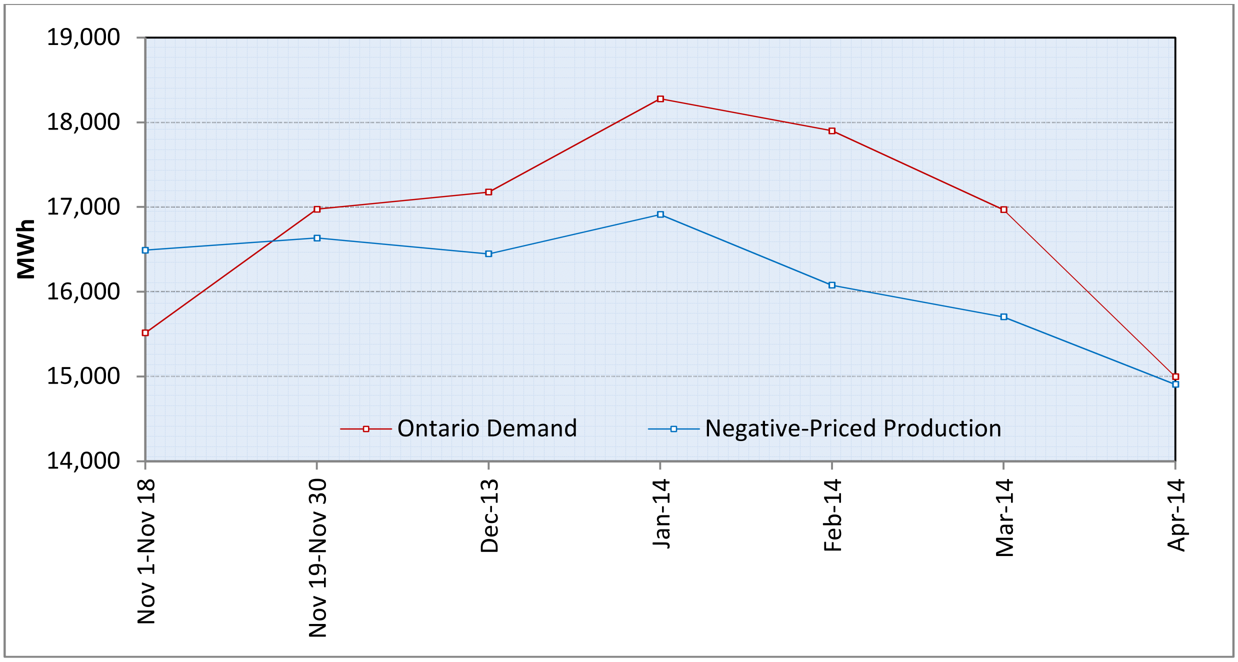
1. Increased electricity production from nuclear resources
2. Increased electricity production from wind resources
3. Relatively low electricity demand

Figure 2-15 shows the average Ontario hourly demand and the average negative-priced production during the Winter 2014 Period. Hourly negative-priced production in this figure

[52] For imports, the quantities reported are scheduled quantities, not offered quantities. Imports scheduled in pre-dispatch are priced at -$2,000/MWh in real-time to ensure their pre-dispatch schedules are respected. While priced at -$2,000/MWh for price setting purposes in real-time, these imports may have been originally offered at positive prices.
[53] As at September 2013, as a result of an IESO stakeholder engagement (SE-91), wind generators have become dispatchable resources. For wind generators, the quantities reported are scheduled quantities, not offered quantities. Quantities offered by these facilities are generally not accurate predictors of attainable delivered quantities; measuring delivered quantities instead provides a more useful estimate of the extent to which these resource types contributed to the occurrence of negative-price hours.

represents the hourly average sum of unconstrained schedules of units that offered into the market at negative prices.

Figure 2-15: Average Hourly Ontario Demand and Hourly Negative-Priced Production November 2013 – April 2014 (MWh)



As seen above, during the period November 1 to November 18, 2013, average hourly negative-priced production in the market was greater than average hourly Ontario demand.

Following this 18-day period, this relationship was reversed, with average hourly Ontario demand outstripping the average total negative-priced production offered into the market.

4 *Anomalous Uplift Payments*

4.1 *Congestion Management Settlement Credits*

The Panel considers hours in which CMSC payments exceed $500,000 to be anomalous. There was one such hour in the Winter 2014 Period.

The Panel considers CMSC payments in excess of $1,000,000 on a given day to be anomalous. There were 30 such days in the Winter 2014 Period.

By contrast, during the Winter 2013 Period, there were seven such days and two such hours.

There were 31 events during the Winter 2014 Period that met the Panel's thresholds for anomalous CMSC payments; four of which are discussed below. CMSC payments during other events involved conditions frequently observed during anomalous CMSC events; these conditions have been extensively analyzed in previous Panel reports.

The total CMSC paid and the average HOEP on each of these four days is shown in Table 2-7.

Table 2-7: CMSC & the HOEP on Analyzed Days ($ thousands and $/MWh)

Date	CMSC	Average HOEP
December 11, 2013	2,534	24.02
January 22, 2014[54]	3,175	173.81
February 27, 2014	2,595	150.23
March 4, 2014	3,476	275.09

Table 2-8 shows CMSC paid to resources to increase supply (constrained on generators and imports as well as constrained off dispatchable loads) and to increase demand (constrained off generators and imports as well as constrained on dispatchable loads and exports).

Table 2-8: CMSC for Increased Supply or Increased Demand ($ thousands)

Date	Constrained On Supply/ Constrained Off Demand		Constrained Off Supply/ Constrained On Demand	
	Domestic	Intertie Trader	Domestic	Intertie Trader
December 11, 2013	292	2,156	102	(17)
January 22, 2014	235	1,056	1,770	114
February 27, 2014	1,466	66	1,088	(26)
March 4, 2014	817	246	1,590	823

As discussed earlier in this chapter, the Winter 2014 Period was characterized by prolonged cold temperatures. Demand for energy as well as the price of energy in Ontario was very high during

[54] HE 19 of January 22, 2014 was the single hour during which the $500,000/hour anomalous CMSC threshold was met during the Winter 2014 Period.

this period. CMSC payments are in part determined by the difference between a participant's offer price and the price of energy (HOEP), so these high prices contributed directly to the amount of constrained-off CMSC paid to supply resources. The high prices also contributed to the unusually high number of days during which the total CMSC payments met the Panel's criteria for anomalous CMSC payments per day.

4.1.1 December 11, 2013

While high prices contributed to both the high number of anomalous CMSC days and to the amount of constrained-off CMSC paid to supply resources in the Winter 2014 Period, there were other circumstances under which anomalous CMSC payments arose. One example of this was on December 11, 2013, when the average HOEP was $24.02 and approximately $2.5 million of CMSC was paid. $2.2 million was paid to two intertie traders and over one third of the remainder was paid to a domestic dispatchable load.

4.1.1.1 Intertie Traders

There was a constraint within the Northwest region of Ontario near the Manitoba interface that prevented power from flowing into Manitoba at the line's full capacity. An exporter bid to export 256 MWs, some of which were bid at price of $2,000/MWh, the maximum allowable bid price. The participant was only scheduled to flow a portion of its total quantity bid and was constrained off for the remainder. As a result of being constrained off and its very high bid price, from HE 11 to HE 23 the participant received approximately $2 million in constrained-off CMSC payments. This was the most CMSC paid to a market participant on any day in the Winter 2014 Period.

Another intertie trader bid to export 18 MW of power on the Manitoba interface from HE 14 to HE 23 at prices as high as $987/MWh. This intertie trader received nearly $150,000 in constrained-off export CMSC payments by behaving in a manner consistent with nodal price chasing, as described in Chapter 3.

4.1.1.2 Domestic Resources

A dispatchable load earned just over $100,000 in constrained-off CMSC payments during HE 4 and HE 5. The load was constrained off as a result of an IESO technical issue which prevented the IESO from sending dispatch instructions beginning in HE 3. Facilities were instructed by the IESO to maintain their respective HE 3 schedules. The dispatchable load received an unconstrained schedule of 100 MW during HE 4 and HE 5; however, due to the technical issue, its constrained schedule was held constant at 55 MW. This disparity coupled with a high bid price resulted in the significant CMSC payment.

4.1.2 January 22, 2014

On January 22, 2014, CMSC payments totaled approximately $3.2 million with the highest hour being HE 19 with $560,895.31 (17.7% of daily total). As such, not only did this day meet the Panel's thresholds for an anomalously high amount of CMSC paid within a day, HE 19 met the Panel's threshold for an anomalously high amount of CMSC paid within an hour. The average HOEP was $173.81 for the day due to high Ontario demand (22,810 MW peak),[55] associated with low temperatures.

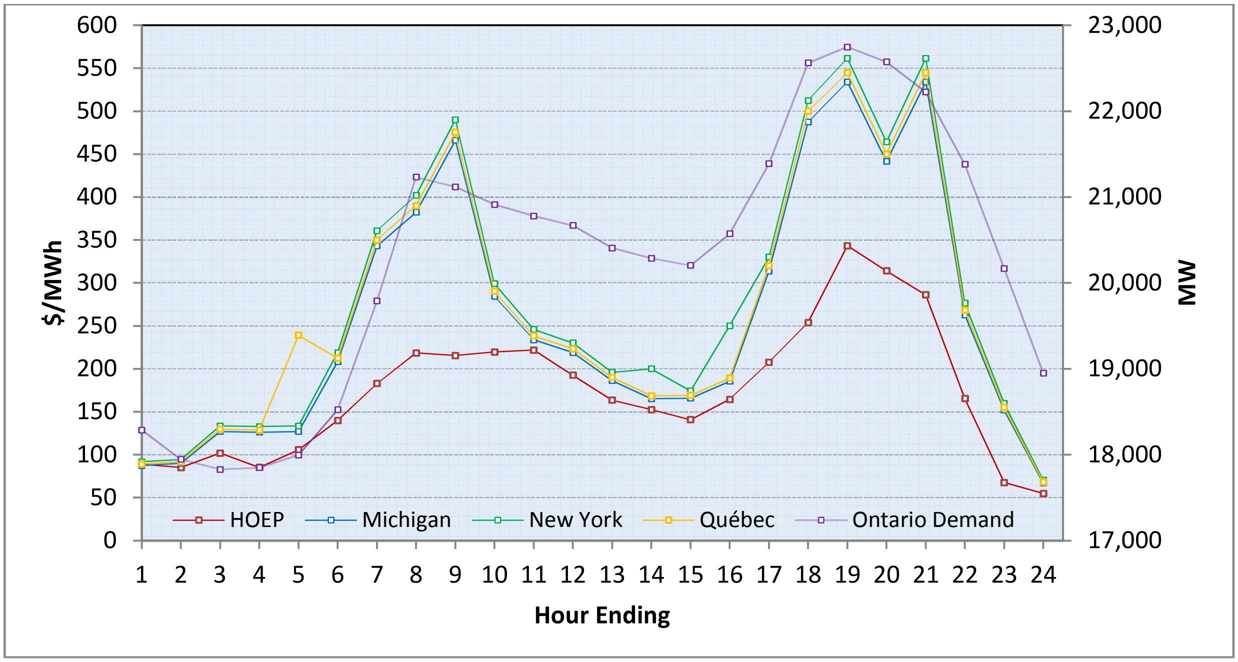
The majority of CMSC payments occurred during two distinct periods of the day. The first period, during HE 8 and HE 9, had CMSC payments of approximately 15% of the daily total. The second period was between the hours of HE 18 to HE 22 (59% of the daily total) with CMSC payments split between resources located in Ontario and energy intertie traders.

4.1.2.1 Intertie Traders

Throughout the day, intertie nodal prices, with the exception of in the Northwest, were above the Ontario price (HOEP).This is shown in Figure 2-16.

[55] Peak hourly demand during the Winter 2014 Period was 23,240, during HE 19 of January 21, 2014.

Figure 2-16: Average Hourly Ontario Demand, the HOEP & One-Hour Ahead Pre-Dispatch Intertie Nodal Prices
January 22, 2014
($/MWh & MW)



During the evening peak there was an internal transmission line forced out of service from HE 18 to HE 22 which contributed to increased nodal prices.[56]

Of the approximately $1.2 million total CMSC paid to intertie transactions, more than half was paid to two participants for constrained-off exports on the New York and Québec interties, while the rest was paid to various other intertie traders.

4.1.2.2 Domestic Resources

Throughout January 22 2014, two facilities in the Northwest region of Ontario earned CMSC payments in all hours of the day (combined CMSC payments to these facilities was approximately $560,000). The Northwest suffers from bottled supply due to transmission constraints which commonly results in low nodal prices throughout the Northwest. These low nodal prices often lead to resources being constrained off and being paid CMSC, this day was no different. The relatively high average HOEP for the day ($173.81/MWh) resulted in CMSC

[56] This transmission constraint likely increased CMSC but would not have had any impact on the HOEP.

payments that were greater than they would have been in the case where the HOEP was lower.[57] In general, a high HOEP results in larger CMSC payments for constrained-off generators and importers.

The above-mentioned transmission constraint during the evening ramp resulted in a nuclear facility being constrained down, resulting in more than $1,000,000 in CMSC being paid to that facility.

4.1.3 February 27, 2014

On February 27, 2014, approximately $2.6 million in total CMSC was paid. The average HOEP was approximately $150/MWh for the day due to a combination of high demand and supply interruptions.[58]

The primary driver of these CMSC payments was high nodal prices (both day-ahead and real-time) for the morning and evening peak hours relative to the other hours in the day. This resulted in gas facilities being issued guarantees in order to ensure that there was sufficient supply to meet peak demands. These guarantees were at prices which were only sustained during peak periods, so CMSC was paid to these resources during the non-peak hours for their production based on the difference in their real-time offer price and the prevailing market price.

4.1.3.1 Intertie Traders

While intertie traders were paid a negative total net CMSC, there was a material positive CMSC payment made to one participant. This participant received over $170,000 in CMSC payments as a result of a 100 MW export bid at $2,000/MWh on a Québec intertie that was constrained-off as a result of security or adequacy concerns internal to Ontario. This participant bid to export 100 MW of power at $2,000/MWh during all hours of this day.

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[57] Significantly higher than the average HOEP during the Winter 2014 Period of $48.78/MWh.
[58] On this day, the HOEP reached the maximum value for the Winter 2014 Period at $964/MWh during HE 20. This hour is discussed in detail above. During this hour Ontario carried out a voltage reduction due to a combination of high demand conditions, short-notice domestic outages, curtailed imports and over-forecasting of wind and self-scheduling resources.

4.1.3.2 Domestic Resources

Domestic resources received $2.5 million in CMSC payments, accounting for approximately 95% of the day's total.

Numerous gas-fired generators received a total of $1,395,314 in constrained-on CMSC. These units received either day-ahead or real-time cost guarantees which resulted in them being constrained-on.

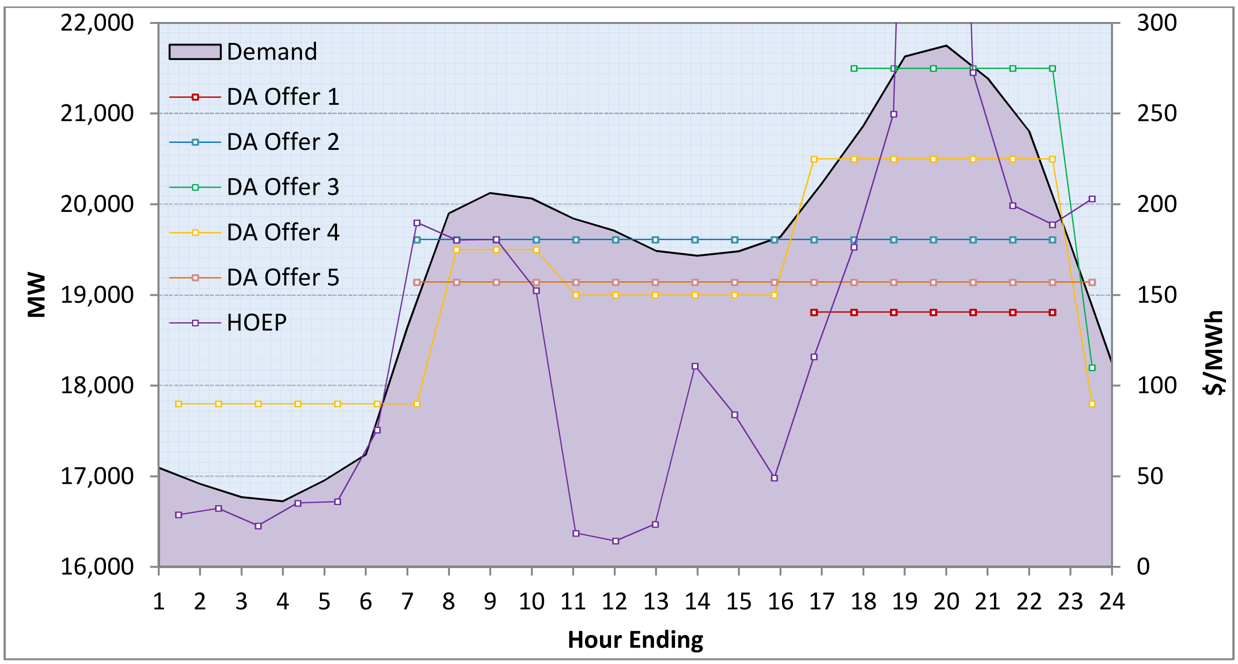
Guarantees (day-ahead or real-time) issued to gas generators can result in incremental CMSC. If a generator receives a guarantee, the IESO constrains the unit on at its MLP for the duration of the guarantee. This constraint ensures that the unit remains online over the course of the entire guarantee. This constraint only results in incremental CMSC payments if market prices are below the resource's offer prices. In this case, the resource is not economic, but is constrained on nonetheless as a result of the constraint implemented by the IESO (further to the cost guarantee). The resulting CMSC payment is equal to the difference between the market price and the offer price times the MW quantity constrained-on.

These guarantee programs ensure that facilities are made whole according to their submitted costs (of which their energy bids make up a component). As such, if the energy market revenues (including energy payments and CMSC) fall short of their submitted costs, a top-up payment is made. It is important to note that in the case of CMSC payments made to gas-fired generators who qualified for guarantees, these CMSC payments were likely not incremental costs to the system as they would have been paid through the top-up mechanism were they not paid through either energy revenues or CSMC payments.

Units that received a day-ahead guarantee were committed based on nodal prices in the $150 - $250/MW range. There were multiple gas-fired facilities that offered into the day-ahead process (but were not scheduled) at extremely high offer prices (these facilities effectively priced themselves out of the day-ahead commitment process and pursued real-time cost guarantees instead). As a result, there was less economic supply available for the day-ahead commitment process. Resources scheduled day-ahead were guaranteed to receive their submitted costs either through market revenues (energy, operating reserve or CMSC) or production cost guarantee ("PCG") payments.

Gas-fired generators were committed day-ahead in order to ensure that expected peak demands were satisfied. This is illustrated in Figure 2-17, which shows gas-fired facility day-ahead offer prices, the day-ahead demand forecast and the HOEP on this day. In order to avoid starting more expensive units, some gas-fired facilities were committed to run across the entire peak period. For these resources, market prices between peaks were too low to cover their submitted costs.

***Figure 2-17: Day-Ahead Offer Price, Demand Forecast and the HOEP
February 27, 2014
(MW and $/MWh)***



Units that received a real-time guarantee were committed based on being economic for at least half of their minimum run-time at the time that the commitment was made. Resources in real-time were guaranteed to receive their submitted costs either through market revenues (energy, OR or CMSC) or top-up payments (real-time or day-ahead cost guarantee payments).

Constrained-on payments to gas units were concentrated from HE 11 to HE 17, after the morning peak and prior to the evening peak. Prices during these hours were significantly lower than during the peak hours. These generators received material constrained-on CMSC payments during these hours as a result of market prices being lower than their offer prices for the quantities which they were constrained-on to produce.

One hydro facility was paid just over $300,000 in CMSC throughout the day, of which almost $250,000 was constrained-off CMSC payments which were the by-product of gas facilities with cost guarantees being constrained-on (some of which are discussed above).

Gas facilities who receive day-ahead guarantees are incented (but not obligated) to reduce their offer price in real-time. If they do not reduce their offer price in real-time, as was the case in this example, they risk receiving an unconstrained schedule of 0 MW and being replaced in the unconstrained scheduled by a facility with a lower offer price (in this case a hydro facility). Due to the day-ahead guarantee, even though this gas facility is not economic, it will be constrained-on and the hydro facility will be constrained-off. If the gas facility instead reduced its offer price in real-time, then it would receive a positive unconstrained and constrained schedule, and the hydro facility would not be economic. If the gas facilities had reduced its real-time offer prices, these CMSC payments would have been avoided.

Absent the constraints on these gas facilities, the production from this hydro facility would have been higher. The units at this facility tend to offer energy in the range of $15/MWh; given that the HOEP was above $100/MWh during 13 hours on this day, the resulting CMSC was significant.

4.1.4 March 4, 2014

On this day there was a total of $3,476,254.19 paid in CMSC. The average HOEP was $275.09/MWh for the day due to moderately high Ontario demand (21,468 MW peak) from low temperatures and very high gas prices ($36.60/MMBtu).

4.1.4.1 Intertie Traders

Of the just over $1 million of CMSC paid to intertie traders, $420 thousand was paid for constrained-off exports and imports on the Manitoba intertie,[59] with various other intertie traders earning the remainder.

When an export bid price is below the unconstrained price but above the nodal price at the intertie, this transaction will likely be constrained on. The transaction will flow, and the intertie trader be compensated for the difference between the MCP and bid price, effectively capping the cost of the export transaction to the intertie traders' bid price.

One intertie trader was constrained-on to export while bidding less than $1 over the pre-dispatch nodal price at the intertie throughout this day. This intertie trader received $223,003 in constrained-on export CMSC.

Another intertie trader had imports and exports on the Manitoba intertie constrained off during HE 11 and HE 12. Its exports were constrained off at bid prices of $2,000/MWh due to transmission constraints/security concerns domestic to Ontario. These constrained-off exports resulted in $196,378 in CMSC.

The same intertie trader had imports on the Manitoba intertie constrained-off in HE 1, HE 2, HE 3 and HE 7 due to transmission constraints/security concerns domestic to Ontario. The combination of two transmission outages near the intertie was the cause of these concerns.

4.1.4.2 Domestic Resources

Of the CMSC paid to domestic resources, gas facilities received approximately $1.1 million. Of this, the bulk ($932,587) was paid to gas facilities which received a cost guarantee during this day.

A hydroelectric generation facility was constrained off due to an outage on a piece of transmission equipment which resulted in part of the facility being isolated from the grid. The

[59] While MR-395 eliminated the payment of constrained-off CMSC for import transactions constrained-off in pre-dispatch and destined for a chronically congested area, transactions which are curtailed following the final pre-dispatch sequence are still eligible to receive CMSC.

total constrained-off CMSC that this resource was paid on this day was approximately $1.1 million. The amount of CMSC was primarily the result of high prevailing market prices and the extreme negative offer prices used by the facility for a portion of its output (it is common practice for hydro facilities to offer baseload capacity at negative prices). Absent these factors, the CMSC payments would have been smaller.

4.2 *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. During the Winter 2014 Period there were no such hours and twelve such days. By contrast, in the Winter 2013 Period there were no such days or hours.

While twelve days met the Panel's threshold for anomalous IOG payments, analysis of two notable days during the Winter 2014 Period is presented below. On February 20 and March 4, 2014, almost $4 million in IOG payments were made to various importers across the province.

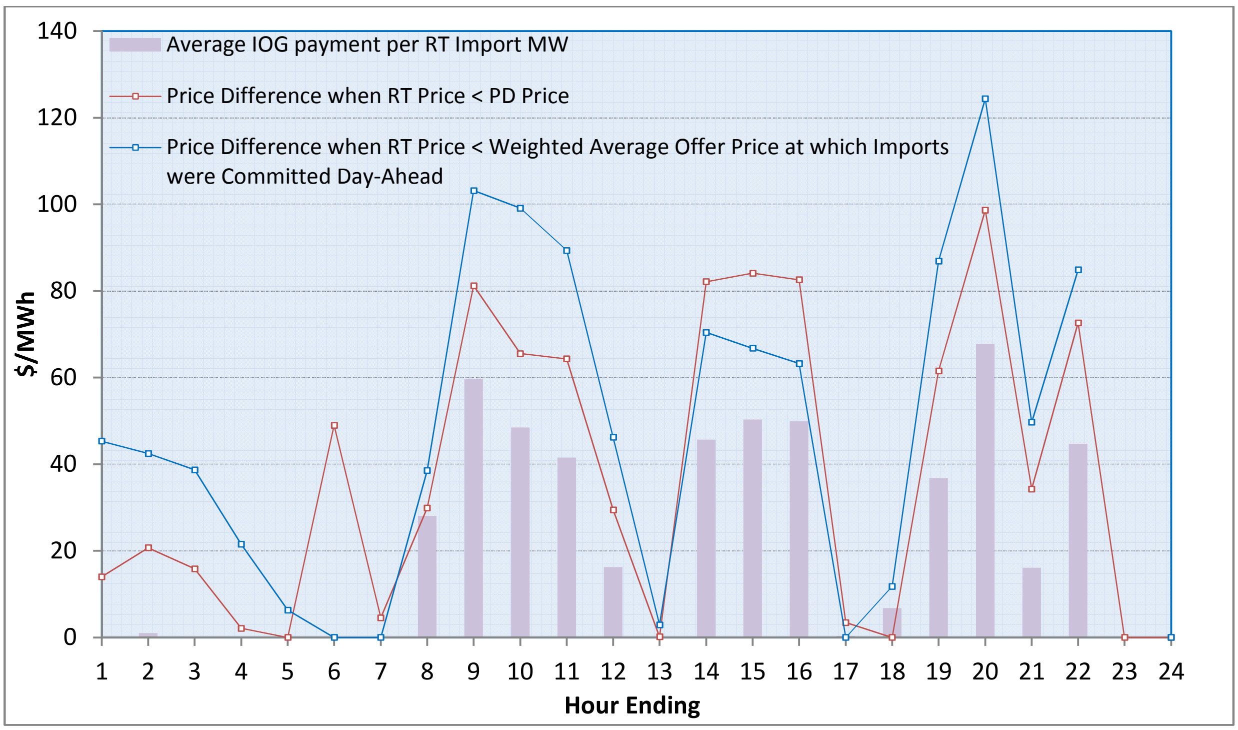
Intertie transactions are scheduled in the day-ahead or final pre-dispatch timeframes (collectively the "scheduling timeframes"), but are settled on the basis of the real-time price; this introduces price risk to intertie transactions. To incent import participation and improve supply adequacy, IOGs eliminate this price risk by guaranteeing that the importer will, at a minimum, recover their costs (as scheduled in day-ahead or pre-dispatch). By reducing exposure to price movements that work against the importer, while allowing them to keep the upside opportunity associated with the price moving in their favour, IOGs increase the incentives for importers to participate in the market and to deliver the energy scheduled day-ahead or in the final pre-dispatch run.

The following examines the factors that lead to two of the twelve anomalous IOG events; these factors are present in isolation or combination for all of the remaining ten events during the period. The first (February 20, 2014) exemplifies instances where the IOG payments are primarily the result of price differences between the scheduling timeframes and real-time; the second (March 4, 2014) exemplifies instances where import curtailments lead to the anomalous IOG payments.

4.2.1 February 20, 2014

Figure 2-18 graphs the price differences between the import scheduling timeframes and real-time. The differences are limited to instances where the real-time price was lower than the price in the relevant scheduling timeframe (i.e. there was the prospect of an IOG payment; all other hours are represented by a zero price difference). Additionally, IOG payments per MWh of imports are presented.

Figure 2-18: Average IOG Payment per Real-Time Import, Real-Time Price Difference & Day-Ahead Price Difference
February 20, 2014
($/MWh)

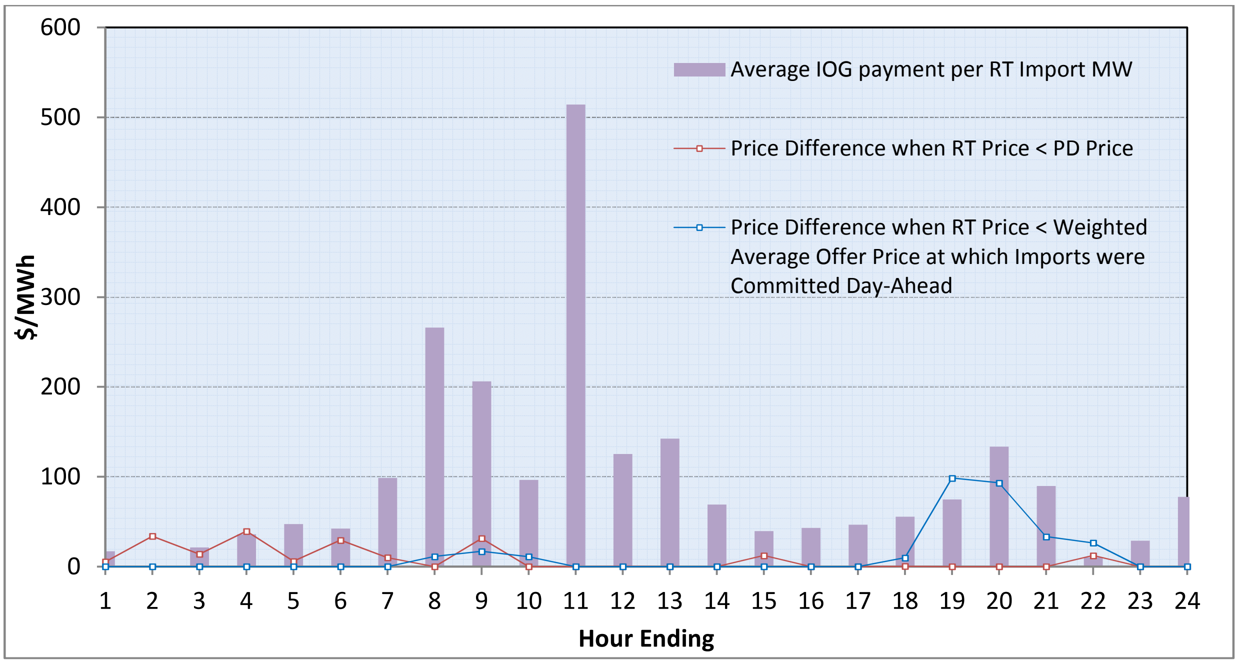


Positive values associated with the red line indicate instances where the real-time price was lower than the pre-dispatch price, presenting one of the conditions which are likely to result in an IOG payment. The blue line indicates the same for day-ahead and real-time price differences. In all hours the actual IOG payments per MWh of imports (purple bars) were lower than either the day-ahead or pre-dispatch price difference lines, indicating that these payments can be explained by price differences between the scheduling timeframes and real-time. The significant drop in prices between the scheduling timeframes and real-time was largely a result of an over forecasting of demand, nearly 1,200 MW in some hours.

4.2.2 March 4, 2014

Figure 2-19 replicates the previous price differential and IOG payment graph, but for the anomalous IOG event on March 4, 2014.

***Figure 2-19: Average IOG Payment per Real-Time Import, Real-Time Price Difference & Day-Ahead Price Difference
March 4, 2014
($/MWh)***



Unlike in the previous example, IOG payments per MWh of imports regularly exceeded the price differences between the import scheduling timeframes and real-time. The primary cause of these IOG payments was import curtailments from MISO on the Michigan interface.

Whether scheduled day-ahead or in pre-dispatch, importers are only paid the market price for the quantity of energy delivered in real-time. In instances where importers receive a day-ahead or pre-dispatch import schedule, but are curtailed by the IESO before real-time, the importer receives no energy revenue. However, these imports are guaranteed to recover their as-offered costs through the IOG program, and if energy revenue and CMSC compensation fails to compensate the importer up to their as-offered cost, an IOG payment will be made.

On March 4, 2014 the MISO market was experiencing a Maximum Generation Emergency Event and was not releasing any transmission capacity for intertie traders to purchase and complete import transactions to Ontario. Additionally, PJM was experiencing conditions which necessitated curtailing transactions scheduled to flow from the PJM market through MISO to Ontario (on the Michigan interface). These conditions were responsible for numerous curtailed imports throughout the day and led to considerable IOG payments.

4.2.3 Day-Ahead IOG: Component 2

The day-ahead and pre-dispatch import scheduling timeframes differ in that there are subsequent scheduling timeframes following day-ahead, whereas pre-dispatch is the final scheduling timeframe for importers. Imports scheduled in pre-dispatch are locked in and carried over to real-time (unless they are curtailed), however imports scheduled day-ahead may become uneconomic in subsequent scheduling timeframes, specifically the pre-dispatch timeframe.

An importer is entitled to receive an IOG Component 2 payment if it receives a day-ahead schedule but is not scheduled in pre-dispatch as a result of economic selection by the IESO.[60] In other words, if an importer fails to flow in real-time, it is considered that it should only receive a Component 2 payment if its failure to deliver is as a result of "economic selection" by the IESO.[61]

To date, the IESO has not paid Component 2 IOG payments in a manner consistent with the above methodology, and has instead paid Component 2 for imports which fail for *any* reason. Of the almost $2.8 million paid in IOG payments on March 4, 2014, approximately $2 million were Component 2 payments paid to importers that failed to deliver in real-time due to either conditions in external jurisdictions or circumstances under the market participants' control.

[60] See the Market Rules, Chapter 9, Section 3.8A.2 and Market Manual 9.5, Section 8.2
[61] To be eligible for a Component 2 IOG payment the importer must have also lowered their import offer price following receipt of their day-ahead import schedule.

Paying importers Component 2 IOG payments for transactions whose failures result from (i) actions or issues arising from external jurisdictions; or (ii) actions of the intertie trader themselves, is entirely inappropriate.

Making IOG payments for issues arising in external jurisdictions inappropriately shifts the risk of external transmission or security concerns from the intertie trader to Ontario ratepayers. Making IOG payments as a result of intertie trader actions allows an intertie trader to schedule an import, unilaterally fail it, and receive a Component 2 payment. Under these circumstances the intertie trader has a significant incentive to schedule imports for the express purpose of failing, thus receiving the Component 2 IOG payment. While an intertie trader may be exposed to failure charges under those circumstances, failure charges in Ontario have typically been low relative to the value of the Component 2 IOG payment. Allowing these distorted incentives to continue will be detrimental to the efficiency and reliability of the Ontario market as it will make the day-ahead schedules of imports less reflective of what will be realized in real-time.

The Panel understands that the IESO is in the process of updating the relevant Market Manuals to reflect the fact that Component 2 payments are paid to transactions curtailed as a result of economic selection by the IESO, and not for transaction failures resulting from actions or issues arising from external jurisdictions, or actions of the intertie traders themselves. The Panel also understands that the IESO is in the process of recovering Component 2 payments from two market participants that received these payments for circumstances other than economic selection by the IESO.

4.3 Operating Reserve Payments

The IESO administers two types of real-time markets, the energy market and the OR market. OR is standby power that can be called upon to re-establish the balance between supply and demand in the event of a contingency such as a sudden or unexpected increase in demand or a decrease in generation or transmission service.

OR payments in excess of $100,000 for a given hour are considered anomalous by the Panel. There were seven such hours during the Winter 2014 Period (the “Anomalous OR Events”).

Table 2-9 lists the relevant OR hours in chronological order and shows how much was paid to settle the OR markets during these hours.

Table 2-9: OR Market Settlement during Anomalous OR Events
($ thousands)

Date	Hour Ending	Total OR Settlement
November 21, 2013	**18**	141
January 29, 2014	**8**	521
February 27, 2014	**20**	382
February 28, 2014	**8**	285
March 17, 2014	**7**	399
April 25, 2014	**12**	121
April 25, 2014	**13**	284

There are three classes of standby power in the OR market: 10S, 10N and 30R. The IESO procures OR as a function of its role as the system operator. The cost of procuring OR is charged to consumers as part of the hourly uplift charge.

The determination of the quantity of OR that is required at any given time as per the IESO procedures is specified in reliability standards set by the North American Electric Reliability Corporation ("NERC") and the Northeast Power Coordinating Council ("NPCC").[62] The OR requirements are noted in Chapter 1 of this report, and frequently result in a total OR requirement of 1,418 MWs.

When available supply is insufficient to meet demand and reserve requirements, the IESO may take out-of-market actions to maintain reliability, these actions are offered into the OR market as Control Action Operating Reserve ("CAOR").[63] The megawatts of reserve afforded by CAOR are placed into the OR market as standing offers.[64] In Ontario, a total of 800 MW of CAOR can be offered into the OR market at fixed (pre-determined) price and quantity pairs.

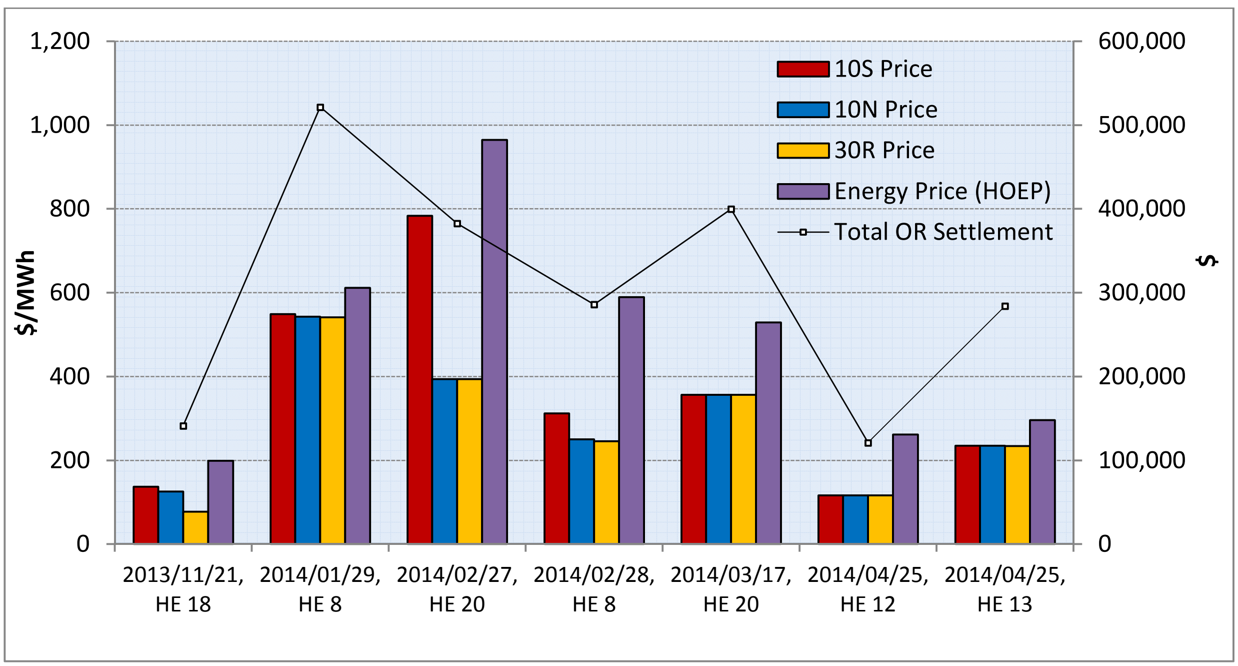
[62] NERC and NPCC set reliability standards that include operating reserve requirements. These standards describe the amounts of operating reserve required, performance obligations, and the reserve sharing program. For more information see page 2 of the IESO document entitled, "Guide to Operating Reserve", available at: http://www.ieso.ca/Documents/training/ORGuide.pdf.
[63] Additional information about the introduction of control action sources of OR can be found in the Panel's June 2004 Monitoring Report, available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_140604.pdf
[64] When the market first opened, the IESO did not price out-of-market actions in the OR market, which led to counter-intuitive pricing. As the market approached shortfall conditions, the IESO used out-of-market sources of OR which led to a lowering of reserve prices rather than a rise in the price to scarcity levels, which would have provided a proper price signal for the market.

The total OR settlement is determined by the product of the quantity of OR scheduled times the price of OR for that hour. Factors that affect demand and supply will affect the price and, in turn, the settlement totals for the OR markets.

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. High energy prices do not, however, always result in high OR prices. Energy prices can be high without OR prices also being high.

This relationship (with high OR prices coincident with high energy prices) is consistent with the data presented on Figure 2-20, which shows OR and energy prices during the Anomalous OR Events.

Figure 2-20: OR and Energy Prices and OR Settlement during the Anomalous OR Events ($/MWh, $)



Amongst the observations which can be made based on the above:

- During each of the Anomalous OR Events, the energy price was relatively high.
- In these cases, as the energy price increases, so too does at least one of the OR prices.

- The total OR markets' settlement moves with OR prices.

While the OR prices tend to move together most of the time in the figure above, there are exceptions to this tendency. For example, on February 27, 2014 during HE 20, the 10S price was significantly higher than the 10N and 30R OR prices. This price difference resulted from a shortage in the market for 10S reserves, and the fact that fewer resources are eligible to provide 10S OR than are eligible to provide 10N or 30R.

During this hour the IESO implemented a 5% voltage reduction in response to a number of factors discussed in the section above on high-price hours. The IESO also activated a number of resources to provide reserve energy, resulting in a reduced reserve requirement (any time the IESO activates operating reserves for a contingency the reserve requirement is reduced by the amount activated).[65] Supply conditions were exceedingly tight during this hour and the energy price reached $2000/MWh for a portion of the hour.

During the hour with the highest OR markets' settlement (January 29, 2014, HE 8), there was a shortfall in 30R OR which was caused by a combination of factors including forced outages, increases in real-time demand and the de-rating of CAOR. The de-rating of the CAOR results in shortening the offer stack in real-time which contributes to a steepening of the OR offer curve, leading to higher OR clearing prices.[66]

[65] For more information see page 11 of the IESO document entitled, "Operating Reserve Training Guide", available at: http://www.ieso.ca/Documents/training/ORGuide.pdf.
[66] For further details on the causes of high OR prices, see the Panel's September 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf.

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 three matters: the availability of data pertaining to embedded generation, embedded consumption, and behind-the-meter generation, as well as the high-5 Global Adjustment allocation, and nodal price chasing by exporters on Ontario's interties.

2 *Panel Investigations*

The Panel currently has investigations under way in relation to three market participants (one generator and two dispatchable loads), all of which relate to gaming. 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.[67]

3 *New Matters*

3.1 *Data on Embedded Generation, Embedded Consumption, and Behind-the-Meter Generation*

Several shifts in the electricity industry in Ontario have highlighted to the Panel that data in certain important categories is not readily available. The lack of data has made tracking changes to certain aspects of the market—and assessing outcomes in the market—more difficult. The Panel has identified three main categories of unavailable data that affect the accuracy of metrics that are important to understand several aspects of the industry. These categories are embedded generation, Embedded Class A consumption, and behind-the-meter generation.

[67] 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

The Panel intends to work with Provincial agencies (the OEB, the IESO, and the appropriate government ministries) to assess what data might be available. The Panel describes each data category below, and provides a brief explanation of why it is important.

3.1.1 Embedded Generation

Generation that is located at the distribution level has expanded rapidly since the Province introduced the Green Energy and Green Economy Act, 2009. Through the OPA's feed-in-tariff ("FIT") program many small-scale renewable generation systems have been located and built within and connected to distribution networks. These facilities produce energy that feeds into the distributor's network, reducing the amount of electricity withdrawn from the high-voltage transmission system.

The OPA's FIT and microFIT programs have contributed substantially to the growth of renewable energy projects in the province. The Ontario Power Authority ("OPA") has awarded contracts for the development of approximately 775 MW of additional solar projects and 2,631 MW of additional wind capacity for total contracted capacity of 2,171 MW of solar capacity and 5,696 MW of wind capacity, the vast majority of which will be operational by the end of 2018.[68] A large percentage of the total solar capacity (as well as some portion of wind) will be connected at the distribution level.

The Panel currently reports data on demand in the province, but importantly this hourly data understates both supply and demand because it does not include hourly production from embedded generation. The hourly demand data available to the Panel therefore reflects the underlying demand for electricity less and less, as a larger share of distribution-level demand is being met through production from embedded generation. This may lead to a situation where overall demand from the high-voltage system appears to decline, when in reality demand for electricity may be constant or increasing.

For this reason the Panel would like access to hourly production data from embedded generators and integrate this data into its regular monitoring reports. Currently the data on embedded generation resides with each distributor. The Panel expects that data on embedded generation

[68] See the OPA's Progress Reports on Electricity supply for the third quarter of 2014, available at: http://www.powerauthority.on.ca/sites/default/files/news/Q3-2014-Electricity-Supply-Report-OPA.pdf

can be made available on an hourly basis by each metered facility.[69] The Panel will work with the IESO to assess what data is available, at an hourly level, and to assess how best to obtain this information to potentially include in future monitoring reports.

3.1.2 Embedded Class A Consumption

There is a subset of large consumers that are located within and connected to distributor's networks. Some of these consumers have peak demand above 3 MW, which is large enough for them to be billed as Class A consumers, and therefore pay the Global Adjustment ("GA") based on their consumption during the high-5 hours as part of the Industrial Conservation Initiative ("ICI").

The Panel currently has no data on the hourly consumption of Embedded Class A consumers, and therefore these consumers are included with Class B when calculating the effective prices for each class of consumer. This grouping of consumers means the true effective prices for Class B consumers are understated and the true effective prices for Embedded Class A consumers are overstated. Obtaining data on Embedded Class A consumption will therefore make effective price calculations more accurate.

Also, the Panel has reported on the response of Direct Class A consumers to the high-5 allocation of the Global Adjustment, some additional discussion on this topic is included in this report. Importantly, the analysis considers only the behaviour of Direct Class A consumers and fails to consider how the response of Embedded Class A consumers may differ.

In light of the expansion of the high-5 allocation of the GA to consumers with demand of 3 MW or higher, it is likely that the pool of Embedded Class A consumers will expand considerably.[70] This expansion will make it even more important for the industry as a whole to have access to Embedded Class A consumption data in order to understand how the expansion contributes to changes in demand in the province.

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[69] The OPA has stated that annual embedded generation data will be produced as part of LTEP "Ontario Energy Reporting," see: http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013/ontario-energy-reporting#Supply. Although an important first step, the Panel sees more value in obtaining hourly production data.

[70] For more information see the June 2014 IESO document entitled, "Industrial Conservation Initiative Backgrounder", available at: http://www.ieso.ca/Documents/Expansion%20of%20the%20ICI%20Backgrounder%20-%20June%202014%20(2).pdf

The data on Embedded Class A consumption resides with each distributor and is collected by the OPA. The IESO currently collects data from distributors on embedded generation during the high-5 hours only. In line with the proposal to work with the IESO to assess what embedded generation data is available, the Panel also intends to assess what data on Embedded Class A consumption is currently available and how that data might be obtained and presented in future monitoring reports.

3.1.3 Behind-the-Meter Generation

Some large consumers have chosen to construct generation onsite in "behind-the-meter" or self-generating facilities. These consist of small generators located next to consumers that serve to meet only that consumer's demand for electricity (they do not inject energy into the grid). These facilities generate energy that can supplement or replace consumption from the grid and operate at the discretion of the consumer instead of being dispatched by the IESO.[71]

In the same way that ignoring embedded generation may lead to misperceptions about changes in the underlying demand for electricity, ignoring behind-the-meter generation may lead to conclusions about demand which, being based only on demand for energy from the high-voltage network, do not tell the full story. Specifically, the Panel is very interested in the extent to which apparent reductions in demand during the high-5 hours of the year are offset by increased behind-the-meter production. Such production would offset the reduction in demand due to the ICI, and likely contribute to inefficient outcomes if more expensive onsite generation is being used in place of lower-cost energy from the grid.

The government of Ontario currently collects data on behind-the-meter generation, as consumers are billed for the provincial Debt Retirement Charge based on their total consumption—including behind-the-meter generation (or "self-generating user," the language used in the Electricity Act, 1998). The Panel proposes to discuss with the appropriate Ministry the option of providing the Panel with aggregated data on behind-the-meter generation from across the

[71] Behind-the-meter generation is different from embedded generation in that behind-the-meter generators (i) may be located at sites connected to the high voltage transmission network, and (ii) do not inject electricity out of the site and into the grid (hence the term "behind-the-meter").

province.[72] The Panel understands that this data is currently reported as total consumption over a given period (monthly, quarterly or yearly depending on the amount of generation at each facility), rather than hourly. Nevertheless, the Panel believes this data would be informative in considering the extent of changes in demand in the province. The Panel would, if available, include aggregated data on behind-the-meter generation in the demand statistics published in its reports.

Table 3-1 summarizes the three categories of data and provides some information on why that data is especially relevant. The Panel is of the view that aggregated data will be useful to other government agencies and market participants because the aggregated data will assist with understanding the current state— and evolution—of the electricity industry in Ontario.[73]

Table 3-1: Summary of Data Categories

Category	Description	Relevance
Embedded Generation	Hourly production data from generation facilities connected to distribution networks.	Demand that is satisfied by embedded production is not currently evident in demand statistics; hourly supply from these producers is not reflected in provincial supply data.
Embedded Class A consumption	Consumption data from large (Class A) consumers located within distributor networks.	Required to report on the consumption of all Class A consumers in the high-5 hours and to understand the response to the Industrial Conservation Initiative by those consumers.
Behind-the-Meter Generation	Production data from facilities that are located next to and serve one consumer with no production going into the grid.	Generation may offset apparent load reductions during high-5 hours, which may be an important side effect of the total impact of the Industrial Conservation Initiative.

3.2 *High-5 Allocation of the GA—Industrial Conservation Initiative*

Earlier this year the provincial government expanded the conservation and peak-reduction program provided through the high-5 allocation of the GA, referred to as the Industrial Conservation Initiative (“ICI”).[74] The Panel published a review of the efficiency and cost shifting effects of the high-5 allocation of the GA in its June 2013 Monitoring Report.[75] In light of the expansion of the policy from loads of 5 MW to 3 MW, the Panel has reviewed the

[72] The Panel understands that information collected by the Province for the purposes of administering the debt retirement charge is subject to confidentiality requirements under the *Electricity Act, 1998*.
[73] The current collection of information on behind-the-meter generation is expected to last only as long as the Debt-Retirement Charge continues to be charged on some consumer’s electricity bills. In order to continue reporting on behind-the-meter generation The Panel will need to have an alternative source for this data at that time.
[74] Refer to Chapter 1 in this report for a breakdown of the cost components of the Global Adjustment.
[75] See Section 4 of Chapter 3 of the Panel’s June 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

behaviour of Direct Class A consumers in 2013 and 2014 to assess how an expanded set of Class A consumers responding to the high-5 incentives is likely to impact efficiency.

3.2.1 Expansion of High-5 Allocation of Global Adjustment to Consumers with Demand over 3 MW

When the high-5 allocation of the GA was introduced in 2011 all loads over 5 MW qualified as Class A consumers, although they had the option to be billed as Class B consumers. In May 2014 the Provincial government introduced a regulation expanding the group of consumers who can be billed as Class A consumers. To qualify as Class A these consumers must be among a specified set of industry classifications[76] and have demand of 3 MW or greater. Qualifying consumers must elect to be billed as Class A in advance of the start of each billing period (beginning in July of each year). Their share of the GA will then be determined based on their consumption during the high-5 hours from May of the previous year to April 30 of the year in which they make the election.

In the Panel's view it is very likely that only those consumers who are able to reduce their demand at peak times will choose to be billed as Class A, and to the extent they are successful in predicting and reducing consumption on the high-5 days they will contribute to reducing peak demand (and shift additional GA costs onto Class B consumers). Given the size of the financial incentive to reduce peak demand and GA costs, it is likely that some consumers will make investments that enhance their ability to predict and reduce consumption during the high five hours.

Given the Panel's past findings on the high-5 allocation of the GA, this change could exacerbate the adverse impact on efficiency the program creates during peak demand. The Panel previously found that reductions in consumption in response to the high-5 incentive reduced efficiency by a larger amount than higher off-peak consumption increased efficiency. At the time the Panel recommended that this topic should be studied in more detail.[77]

[76] The industries are the manufacturing, mining, quarrying, oil/gas extraction, greenhouse, refrigerated warehousing and data processing sectors. See Ontario Regulation 126/14, amending O. Reg. 429/04.
[77] See Section 3.1 of Chapter 3 of the Panel's September 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

Prior to the expansion of the ICI to consumers with demand of 3 MW or more, the IESO completed a stakeholder engagement on changes to the allocation of GA costs.[78] Navigant Consulting prepared a report for this stakeholder engagement to examine how changes in the allocation of the GA would affect efficiency, equity and fairness.[79] In its report Navigant concluded that significantly increasing the number of Class A consumers (to all consumers with demand greater than 50kW) would increase short-term efficiency and would improve equity and fairness (compared to the then-current high- five allocation of the GA for consumers with demand above 5 MW). Navigant's position was that by expanding the number of consumers who are exposed to the market price of electricity, more efficient consumption decisions would be made. Several months after the IESO's stakeholder engagement had been completed the government announced the expansion of the ICI program to consumers with demand exceeding 3 MW.

The first billing period for new Class A consumers will not begin until July 2015 (based on consumption from May 1, 2014 to April 30, 2015), which means it is too early for the Panel to comment on how new Class A consumers will respond to the incentives under the ICI. However, some observations can be made based on the response of current Direct Class As in 2013-2014.

3.2.2 Highest Demand Hours of 2013-2014

Table 3-2 shows the top ten demand hours on separate days from May 1, 2013 to April 30, 2014. Consumption during the top five peak hours is used to allocate GA charges to Class A consumers for the period from July 1, 2014 to June 30, 2015. The table also displays the level of the HOEP in each of the top ten demand hours.

[78] For more information see IESO Stakeholder Engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-106.aspx
[79] The report is available at: http://www.ieso.ca/documents/consult/se106/se106-20140128-Global_Adjustment_Review_Report.pdf

Table 3-2: Highest Demand Days
May 2013 – April 2014
(MW & $/MWh)

Rank	Date	Hour Ending	Ontario Demand (MW)	HOEP ($/MWh)
1	**17-Jul-13**	17	24,689	169.94
2	**16-Jul-13**	17	24,008	158.04
3	**18-Jul-13**	17	24,070	133.82
4	**19-Jul-13**	14	24,207	41.69
5	**15-Jul-13**	17	23,595	40.66
6	**29-Aug-13**	16	22,834	37.71
7	**07-Jan-14**	19	22,774	278.93
8	**22-Jan-14**	19	22,737	314.05
9	**10-Sep-13**	20	22,682	330.05
10	**10-Sep-13**	16	22,670	142.25

Two features stand out from the information in Table 3-2: (i) For the first time since the change in the allocation of the GA in 2011, two of the top ten demand hours occurred on days in the winter (January 7 and 22, 2014), and (ii) the highest prices (HOEP) do not coincide with the highest levels of demand, as prices in the six to ten highest demand hours were in some cases well above prices in the five highest demand hours.

The three high-5 hours with prices greater than $100 exhibited steeper supply curves, meaning that demand was sufficiently high that more consumption would have pushed the clearing price into a more inelastic section of the supply curve. Demand reductions from Class A consumers are therefore likely to have reduced prices on the three highest demand days (a steeper supply stack means that small changes in demand can lead to relatively large changes in price). The supply stack on the remaining two high-5 days, in contrast, was relatively flat. In consequence, the few hundred MWs of demand reductions from Class A consumers on these days likely did not affect the HOEP to a significant degree (a relatively flat supply stack means that a large change in demand creates a relatively small change in price). Overall, the Panel notes that an incentive to reduce peak demand when supply is relatively plentiful is very likely to reduce short-term efficiency, as it encourages buyers to reduce demand when suppliers are willing to produce at a relatively low cost.

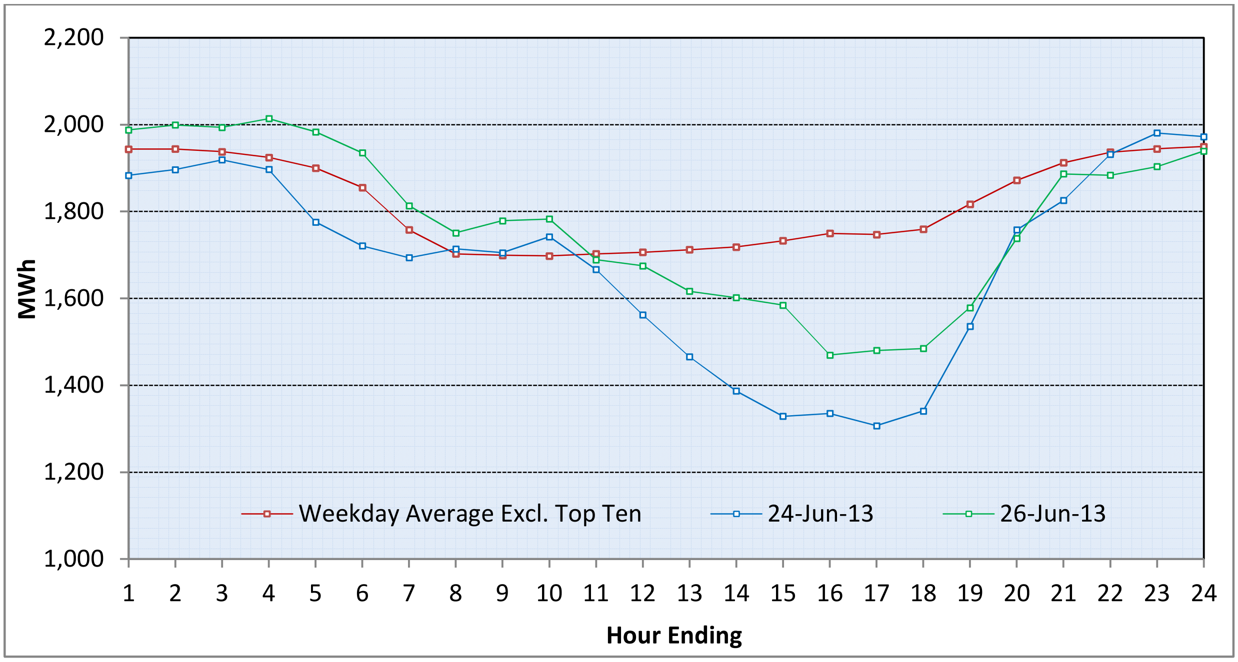
The likely effect of the expansion of the high-5 allocation of the GA to include loads above 3 MW will be to increase the amount of peak reduction in hours that are likely to be high-5. One consequence of such an uptick in demand reductions could be that an otherwise high demand hour exhibits enough demand reduction that it drops out of the set of high-5 hours. The more consumers respond to likely high-5 hours, the greater the chance that the large response moves the hour out of the high-5 category. Currently the difference in demand between the first and the tenth highest demand hour is over 2000 MWs, with an average high-5 hour demand reduction of just over 600 MWh (compared to the average—see Table 3-3). As the total demand reductions in high-5 hours grows, the possibility of large demand reductions shifting the order of high demand hours can only increase.

3.2.3 Response to Potential Peak Days in June

An example of demand reductions on days that later turn out not to include high-5 hours occurred over two days in June 2013. The IESO posts the most current high-5 demand hours on its "Peak-Tracker" website,[80] and before the actual high-5 hours for the adjustment period were set in July 2014 both June 24 and 26, 2014 were posted on the website as days with high-5 demand hours. These two days would later prove not to include even the ten highest demand hours, but on these two days some Class A consumers nevertheless reduced their consumption in anticipation that these days may contain the high-5 hours. Consumption by Direct Class A consumers on June 24 and 26 is plotted in Figure 3-1.

[80] The IESO Peak-Tracker webpage is available at: http://www.ieso.ca/Pages/Peak-Tracker-Standalone.aspx

Figure 3-1: Direct Class A Average Weekday Consumption Excluding Ten Highest Days vs. Consumption on June 24 and 26 2013-2014 (MW)



The red line in Figure 3-1 plots the average consumption by Direct Class A consumers from June 1, 2013 to May 31, 2014, excluding weekends, holidays and the top ten peak demand days. It is apparent that some Direct Class A consumers reduced consumption during the afternoon hours of June 24th and 26th relative to the average. As these days turned out not to include any of the high-5 hours, reductions in consumption in response to the incentive under the GA allocation was inefficient in the short term (the HOEP in these hours was $34 and $42 on June 24th and 26th, respectively). As the number of Class A consumers grows under the expanded ICI program, so will the number of participants forgoing consumption at times that later turn out not to be among the high-5 hours. When consumers are incentivized to reduce demand when the cost of production is low, the Panel views this response as inefficient in the short-term, although not an unexpected consequence of the ICI.

3.2.4 High-5 Response in July

The consumption by Direct Class A's on the days when the high five hours occurred in 2013 is plotted in Figure 3-2. Consumption by each Class A consumer during the peak hours on each of these days will determine their portion of the GA charges for the billing period from July 1, 2014 to June 30, 2015. The five days occurred consecutively during one week in July during which much of southern Ontario was in the midst of a heat wave. (The red line in Figure 3-2 is the average consumption by Direct Class A consumers from June 1, 2013 to May 31, 2014, excluding weekends and holidays and the top ten peak demand days.)

Figure 3-2: Direct Class A Average Weekday Consumption Excluding Ten Highest Days vs. Consumption on High-5 Days
2013-2014
(MW)

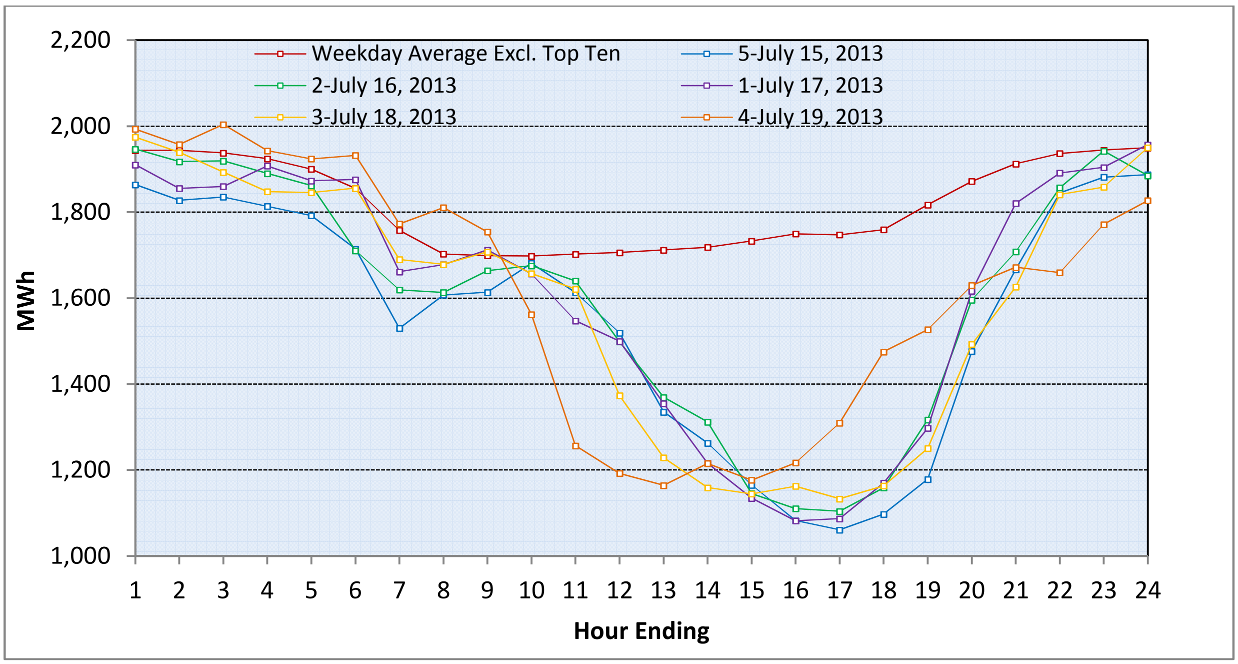


Table 3-3 presents the data behind Figure 3-2 on an average basis. The average total demand reduction compared to the weekday average amounts to just over 600 MWs in HE 16. The largest reduction on any single day was approximately 660 MWs during HE17 on July 15.

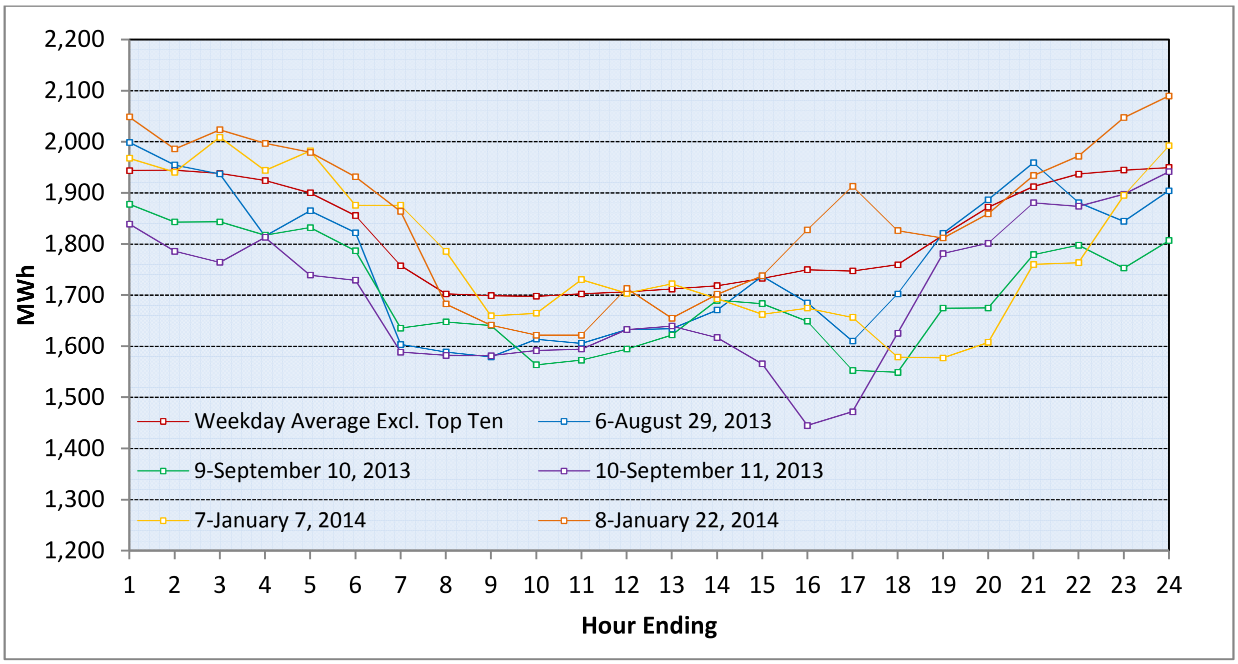
Table 3-3: Direct Class A Average Weekday Consumption Excluding Ten Highest Days vs. Average Consumption on High-5 Days
2013-2014
(MWh)

Hour Ending	Weekday Average Consumption Excl. Top Ten Days (MWh)	Average High-5 day Consumption (MWh)	Difference (MWh)
1	1,944	1,938	6
2	1,944	1,899	45
3	1,938	1,902	36
4	1,924	1,880	44
5	1,900	1,859	41
6	1,855	1,818	38
7	1,758	1,655	103
8	1,703	1,678	25
9	1,699	1,690	9
10	1,698	1,646	51
11	1,702	1,536	167
12	1,706	1,417	290
13	1,712	1,290	422
14	1,718	1,233	485
15	1,733	1,153	580
16	1,750	1,131	619
17	1,747	1,139	608
18	1,759	1,213	547
19	1,817	1,314	503
20	1,872	1,562	310
21	1,912	1,698	214
22	1,937	1,819	118
23	1,944	1,871	73
24	1,950	1,901	48

3.2.5 No Demand Reduction on Six to Ten Highest Demand Days

As shown in Figure 3-3 Direct Class A consumption in the sixth to tenth highest demand hours was little changed (compared to the weekday average), in contrast to the response on the days which contained the high-5 hours. This lack of response suggests that once the high-5 hours had been set in July Class A consumers did not believe that demand on the next highest demand days would reach similar levels, and so chose not to reduce their consumption. (The red line again represents the Direct Class A consumers' weekday average consumption excluding weekends, holiday, and the top ten demand days from June 1, 2013 to May 31, 2014). As noted earlier, for the first time since the introduction of the high-5 allocation of the GA two out of the ten highest demand hours occurred in January (in the past several years the ten highest demand hours have all occurred on summer days). Although these winter peaks did not affect Class A consumption, it is possible that such winter peaks (driven by extreme cold weather and increases in embedded generation) could enter into the high-5 hours in the future.[81]

Figure 3-3: Direct Class A Average Weekday Consumption Excluding Ten Highest Days vs. Consumption on Top 6-10 Highest Demand Days 2013-2014 (MW)



3.2.6 Negative Global Adjustment in Early 2014

For the first time since June 2008 the amount of the GA charged to loads was negative in March 2014—that is, the GA was a credit to loads (refer to Chapter 1 of this report for statistics on monthly GA amounts). As discussed in Chapter 2 of this report, high gas prices led to

[81] Although the GA allocation factors are determined for each Class A consumer based on Ontario demand, which includes embedded generation, the five peaks are set based on AQEW (Allocated Quantity of Energy Withdrawn), which measures demand on the high-voltage system and does not include production from embedded generation. The more demand that is met by production from embedded generation, the less likely demand from the high-voltage system (AQEW) is to peak. For this reason higher production from embedded generation during summer will reduce the likelihood of the high-5 hours occurring in the summer. Similarly, when embedded production is lower (during winter evenings), demand from the high-voltage system is more likely to peak. As this report went to press the 2014-2015 high-5 days included hours on two days in January 2015.

consistently high HOEPs in the first few months of 2014. High HOEPs in turn meant that many generators earned most or all of the revenue required to cover their contracted or regulated rates. Because the Global Adjustment makes up any difference between energy market revenue and the revenues required by contracted and regulated generators, higher energy market revenues turned the GA into a credit to loads in the month of March—effectively a rebate for some of the difference between energy market revenues and contracted or regulated rates.

3.2.7 Shifting Costs from Class A Consumers to Class B Consumers

Chapter 1 of this report presents the effective prices paid by Class A and Class B consumers. The main reason these prices differ is the result of different allocations of the GA to each consumer group. Because of peak reduction (and differing load profiles among Class A consumers), some GA costs that would previously have been paid by Class A consumers are now paid by Class B consumers. In 2013 this amounted to approximately $519 M in GA costs that would have been paid by Class A consumers under the old allocation of the GA but which are now paid by Class B consumers. Since the change in allocation of the GA Class B consumers have paid over $1.2 billion of GA costs that would have been paid by Class A consumers under the old allocation of the GA.[82] The Panel notes that this is one of the contributors to higher rates for residential and commercial consumers in Ontario.

[82] $1.2 billion is calculated as the difference between the total amount of the GA that was paid by Class A consumers and the total GA that would have been paid by Class A consumers if the total GA had been charged on the per-MWh basis that was in place before the introduction of the high-5 allocation of the GA.

3.3 *Export Nodal Price Chasing on Ontario Interties*

Ontario is electrically interconnected with two neighbouring provinces: Québec and Manitoba. It is also electrically interconnected with three neighbouring states: Minnesota, Michigan and New York. Ontario imports and exports electricity with these jurisdictions through transmission lines called interties, which connect Ontario's power grid to the power grids of its neighbours.

One would expect Ontario to be a net importer in hours where the electricity prices in neighbouring jurisdictions are lower than the electricity price in Ontario. Conversely, one would expect Ontario to be a net exporter whenever the electricity price in Ontario is lower than the prices in the neighbouring states and provinces. This ability to flow power from a low-price jurisdiction to high-price jurisdictions increases overall market efficiency. Producers in the lower-price jurisdictions are able to produce more energy and increase their profits. At the same time, consumers in the higher-price jurisdiction gain access to lower-price power.

There is also an expectation for intertie traders to buy at a low price and sell at a higher price, in Ontario theory and practice have not always converged. The Panel has observed many instances when an exporter who is able to export power from Ontario and sell it to a neighbouring jurisdiction for a profit bids in a manner that results in that transaction not occurring. The reason for this behaviour is a powerful incentive created by a type of side-payment called constrained-off Congestion Management Settlement Credits ("CMSC"). Simply put, constrained-off CMSC is a payment made to prospective exporters for *not* buying power from Ontario. Profits associated with not exporting power are, in many instances, higher than the profits associated with actually exporting power.

While intertie traders who are the recipients of these payments are referred to as exporters, their bids are often crafted in such a manner as to preclude an export while at the same time maximizing constrained-off CMSC payments. The Panel refers to this behaviour as "nodal price chasing". Simply stated, nodal price chasing is the submission of offers or bids at prices that have the predominant purpose of targeting CMSC payments, as opposed to purchasing or selling power from the Ontario wholesale electricity market. The opportunity to nodal price chase presents itself in situations where transmissions constraints, be they transient or associated with chronically congested areas, cause a divergence between the uniform Ontario price and nodal prices. Nodal price chasing behavior is detrimental to Ontario consumers who cover the costs of the constrained-off CMSC payments through uplift charges.

The concept of nodal price chasing is by no means a new phenomenon. In its January 1999 report, the Market Design Committee ("MDC"), which was tasked with designing Ontario's electricity market, made the following observation: "…there is a particular risk that market participants outside Ontario could submit phantom or unrealistic bids and offers, anticipating [congestion management settlement credit payments]…".[83] This report was published nearly three and half years before Ontario's electricity market opened in May of 2002.

From market opening on May 1, 2002 to April 2014, exporters have received $162.9 million in constrained-off CMSC, which are effectively payments made to exporters for not exporting power. Over the same period importers were paid $94.3 million in constrained-off CMSC, which are effectively payments for not importing power into Ontario. As recently as its January 2014 Monitoring Report, the Panel recommended the elimination of constrained-off CMSC payments for all intertie transactions. The Panel has observed that these CMSC payments: (i) do not provide commensurate value to the market; (ii) are susceptible to gaming; (iii) increase consumer uplift charges; and (iv) incent inefficient behavior.[84] In response to the Panel's recommendation, the IESO observed that constrained-off intertie CMSC payments "continue to play an important role in the existing Ontario market structure."[85] The Panel fails to see how this is the case, and this section provides further indication that significant CMSC payments are made to exporters for no credible reason. Accordingly, the Panel reiterates the recommendation that it made in January 2014 that the IESO eliminate constrained-off CMSC payments for all intertie transactions.

While the Panel disagrees with the IESO's assessment that constrained-off CMSC payments to intertie traders play an important role in Ontario's market structure, the Panel is supportive of the IESO's commitment to review the energy market pricing system under Stakeholder Engagement 114. According to the IESO this review "could result in changes to, or potentially elimination of

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[83] See pages 3-8 of the Market Design Committee's January 1999 Final Report, available at : http://www.ieso.ca/Documents/mdc/Reports/FinalReport/Volume-1.pdf
[84] See page 128 of the Panels' January 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf.
[85] See: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_Letter_MSP_Report_20140131.pdf

all CMSC payments."[86] While a broad review of the energy market pricing system is certainly laudable, it is sufficiently distinct from the Panel's specific observations relating to intertie transactions. The Panel does not believe that this long-term initiative, which may or may not result in the elimination of all CMSC payments in Ontario, should preclude the IESO from taking immediate steps to eliminate constrained-off CMSC payments for all intertie transactions, noting that in 2014, over $20 million in constrained-off CMSC was paid to intertie traders. [87]

The balance of this section provides several detailed examples of nodal price chasing behaviour, and includes analysis by the Panel indicating that from January 2013 through April 2014 ("the Analysis Period") the IESO overcompensated exporters by approximately $21.8 million in constrained-off CMSC.

3.3.1 What is Constrained-Off CMSC?

CMSC payments are a result of Ontario's decision to adopt a province-wide uniform market price using a two-schedule system. The two schedules in question are referred to as the unconstrained and constrained schedules. The unconstrained schedule assumes no internal system constraints, and is used to calculate the Hourly Ontario Energy Price ("HOEP"). In Ontario's uniform market price system, all participants are settled on the HOEP. The constrained schedule does account for system constraints and determines the dispatch schedule for market participants. When these schedules diverge, market participants receive a CMSC payment, the intent of which is to return the market participant to the operating profit it would have made according to its unconstrained schedule. These payments can be a result of being dispatched to a level greater (constrained on) or less (constrained off) than the participant's unconstrained schedule. In other words, constrained-off CMSC payments are intended to compensate dispatchable market participants for reductions in their implied operating profits that result from responding to system operator instructions to alter their output or consumption in order to relieve transmission constraints.[88]

[86] *Ibid*
[87] For more information see the IESO's energy market pricing system review stakeholder engagement webpage, available at:: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-114.aspx
[88] For more information see Volume 1, Chapter 3, page 8 of the Market Design Committee's January 1999 Final Repot, available at: http://www.ieso.ca/Documents/mdc/Reports/FinalReport/Volume-1.pdf.

In the case of intertie traders, constrained-off export CMSC is paid to exporters who are scheduled in the pre-dispatch (“one hour ahead”, or “PD-1”) unconstrained sequence, but who are then subsequently not scheduled in the PD-1 constrained sequence (the mechanics of this are explained in Section 3.3.2 below). In effect, exporters, whose role as market participants is to purchase power from Ontario for sale into neighbouring jurisdictions, are able to receive remuneration for power that they were not able to export.

The constrained-off CMSC payment is calculated as the difference between the exporter’s bid price and the HOEP, multiplied by the difference between its unconstrained schedule and constrained schedule quantities. For intertie transactions, this value is also subject to intertie congestion, making the calculation; the HOEP + the intertie congestion price (“ICP”). For simplicity, the explanatory examples in this report have assumed ICP = $0/MWh. As the spread between the HOEP and the exporter’s bid price increases so too does the implied operating profit and the resultant CMSC payment.

Implicit in the IESO’s payment of constrained-off CMSC is the assumption that buyers of Ontario electricity bid for power at their marginal benefit of consumption. It will be shown in this section that constrained-off export CMSC payments are seldom paid on this basis.

3.3.2 How Does an Exporter Receive Constrained-Off CMSC?

Understanding constrained-off CMSC payments resulting from nodal price chasing requires some commentary on the mechanics of how exporters come to be constrained off in the first place. Such occurrences are more complicated than for domestic resources due to the way in which intertie transactions are scheduled and settled in the wholesale market. For this reason, the Panel provides descriptive examples of the necessary conditions for constrained-off CMSC payments to arise.

Consider the following exporter bid and relevant Ontario prices:

Exporter's Bid Price = $40/MWh

Exporter's Bid Quantity = 100 MW

External Jurisdiction Price = $40/MWh

PD-1 Zonal Price[89] = $30/MWh

HOEP = $30/MWh

PD-1 Nodal Price[90] = $60/MWh

Where;

PD-1 Zonal Price is the price at which a given intertie is scheduled in the unconstrained sequence. If an exporter's bid is greater than the PD-1 Zonal Price, it will receive an unconstrained schedule.

HOEP is the uniform market price paid to generators and importers and paid by domestic wholesale loads and exporters. Importers and exporters may be settled at price that differs from the HOEP when the intertie becomes congested.

PD-1 Nodal Price is the price at which a given intertie is scheduled in the constrained sequence. If an exporter's bid is greater than the PD-1 Nodal Price it will receive a constrained schedule. If its bid is below PD-1 Nodal but above PD-1 Zonal, the exporter will be constrained off and receive a CMSC payment or charge.

[89] The pre-dispatch zonal price is equivalent to the pre-dispatch HOEP plus or minus the intertie congestion price at the intertie in question.

[90] A nodal price includes the incremental cost of generation (based on offers and bids) plus the cost of delivery to that node (i.e., losses and internal transmission congestion). Nodal prices in the province can differ for two reasons: losses and transmission congestion or outages. First, due to the physical characteristics of the transmission system, energy is lost as it is transmitted from generators to loads. Additional generation must be dispatched to provide energy in excess of that consumed by the load. Second, transmission congestion prevents lower cost generation from supplying the load; higher cost generation must be dispatched in its place.

How Exports are Scheduled in the IESO-Administered Energy Market:

In Ontario, because of the time required to coordinate intertie transactions between the IESO and neighbouring jurisdictions, exports are scheduled one hour in advance of the dispatch hour. If an exporter's bid price is greater than the pre-dispatch market clearing price* it receives a pre-dispatch unconstrained schedule.

So long as the exporter's bid price is also greater than the pre-dispatch nodal price+ at the specific intertie, the exporter also receives a pre-dispatch constrained schedule. The IESO control room will confirm the flow of all energy in the constrained schedule with the relevant neighbouring jurisdiction.

In real-time, the exporter is charged for purchasing the amount of power it was scheduled to export according to its pre-dispatch constrained schedule. The price that the exporter pays for the power is equal to the HOEP plus congestion and any applicable transaction costs. The exporter would have a corresponding import in the external jurisdiction, and would be paid the external price for the delivery of the energy.

* The IESO schedules intertie transactions based on the pre-dispatch zonal price for each particular intertie. Zonal prices will vary from the pre-dispatch market clearing price only due to congestion at any particular intertie.

\+ If PD-1 Zonal price at the intertie differs from the PD-1 HOEP for the province as a whole, that difference, called the intertie congestion price (ICP) is added to price paid by the exporter such that the exporter pays HOEP+ICP. ICP can be positive or negative.

In this particular case, the exporter has bid at a price of $40/MWh, which is equal to the price it is able to sell power in the external jurisdiction. The exporter's bid is economic in the unconstrained pre-dispatch sequence since its bid price of $40/MWh is greater than the PD-1 Zonal price of $30/MWh. However, in the constrained pre-dispatch sequence, its bid is not economic, as the PD-1 Nodal price at the intertie is greater than the exporter's bid price ($60>$40).[91] This situation results in the exporter being constrained off and receiving a constrained-off export CMSC payment of (bid price – HOEP) * (unconstrained schedule – constrained schedule), or numerically, ($40/MWh - $30/MWh) * (100 MW - 0 MW) = $1,000.

The intent of CMSC is to return market participants to the level of operating profit they would have realized had the transaction not been constrained on or off.[92] Additionally, Appendix 7.5, Section 2.3.1of the Market Rules, which describes the optimization objective of the dispatch scheduling process, states that, "…offer prices shall be assumed to represent the actual costs of

[91] To be scheduled to actually export power in the example above, the exporter's bid price would have needed to be $60/MWh or higher.

[92] See Chapter 9, Section 3.5 of the Market Rules, available at: http://www.ieso.ca/imoweb/pubs/marketRules/mr_marketRules.pdf

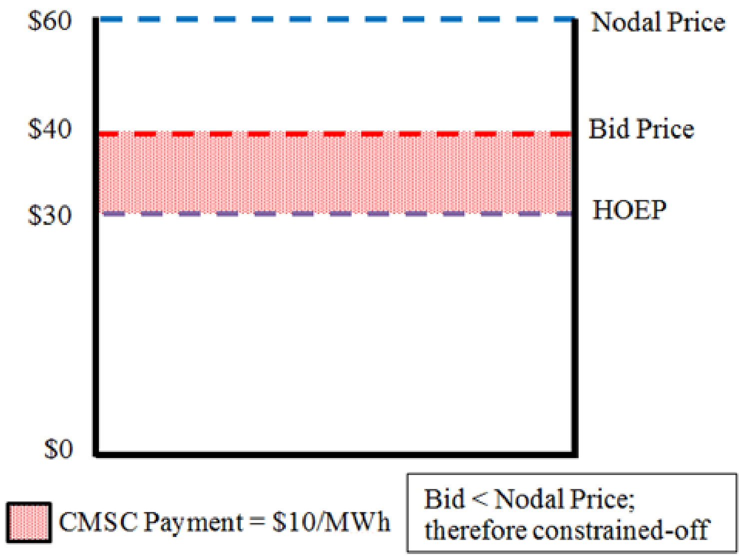
suppliers and bid prices shall be assumed to represent the actual benefits of consumption by dispatchable load facilities." While the market rule quoted here does not explicitly mention exporters, other sections of the Market Rules, such as that discussing hourly CMSC settlements,[93] group together the bids of dispatchable loads and exporters. The Panel considers that, similar to other dispatchable resources, in the calculation of CMSC exporters' bids are assumed to represent their marginal benefit.

Under the Market Rules governing CMSC payments and charges, the determination of a constrained-off export's foregone operating profit is not based on the sale price in the external jurisdiction that the intertie trader would have received had the export actually flowed. Instead, the Market Rules require the IESO to assume the exporter's bid price is reflective of the marginal benefit of the power to the exporter and therefore representative of its operating profit. If an export is constrained off, the Market Rules require the IESO to determine that the trade would have been profitable whenever the HOEP in the delivery hour turns out to be lower than exporter's bid price.

That the CMSC formula ignores the actual operating profit that an export would have generated had it not been constrained off has important implications for the nodal price chasing behavior described in this section. Figure 3-4 illustrates a simple example of constrained-off export CMSC.

[93] See Chapter 9, Section 3.5.6A.1, available at: http://www.ieso.ca/imoweb/pubs/marketRules/mr_marketRules.pdf

Figure 3-4: Example of CMSC Calculation



As a rule, constrained-off export CMSC is paid to exporters when two conditions are met:

1. PD-1 Zonal price < **Bid price** < PD-1 Nodal price
2. HOEP < Bid price[94]

The CMSC calculation example above is based on the assumption that the exporter's $40/MWh bid accurately represents the marginal benefit that the exporter places on purchasing Ontario power. If an exporter is able to purchase power at a lower price than $40/MWh, it stands to profit and it would be unwilling to purchase power at any price higher than $40/MWh as that would result in a financial loss. Constrained-off CMSC is meant to return the exporter to the level of operating profit it would have received had it been permitted to follow its unconstrained schedule.[95]

3.3.3 CMSC Charges

Constrained-off export CMSC to exporters will not always be payments. They can be, and occasionally are, charges.

[94] Intertie transactions are scheduled on the basis of PD-1 prices, but are settled on the HOEP.
[95] See Chapter 9, Section 3.5.1 of the Market Rules, available at:
http://www.ieso.ca/imoweb/pubs/marketRules/mr_marketRules.pdf

Consider the following exporter bid and relevant Ontario prices:

Bid Price = $40/MWh

Bid Quantity = 100 MW

External Jurisdiction Price = $40/MWh

PD-1 Zonal Price = $30/MWh

HOEP = $50/MWh

PD-1 Nodal Price = $60/MWh

As in the example presented in Section 3.3.2, the exporter's bid is economic in the unconstrained pre-dispatch sequence and is uneconomic in the constrained pre-dispatch sequence.
The important distinction in this example is the value of the HOEP. During the hour that elapses between PD-1 and real-time, prices in Ontario have risen from $30/MWh to $50/MWh. The calculation for CMSC remains the same; however, the HOEP settles at a price greater than what the exporter indicated it was willing to pay for the power. In being constrained off the exporter has avoided purchasing the power at a price greater than its bid price. In this example, the CMSC calculation results in a negative amount, returning the exporter to the apparent financial loss, based on its bid price and the HOEP, it would have incurred had it been permitted to follow its unconstrained schedule.

($40/MWh - $50/MWh) * (100 MW - 0 MW) = ($1,000)

During the Analysis Period there was a total of $10.4 million in constrained-off export CMSC charges, compared to $42.0 million in constrained-off export CMSC payments resulting in a net payment of $31.6 million.

3.3.4 CMSC Payments to Intertie Transactions

During the Analysis Period, $31.6 million[96] of constrained-off export CMSC was paid to intertie traders. Total CMSC payments made at interties during the same period totalled $45.4 million. This means that payments to constrained-off exports represented nearly 70% of all CMSC

[96] This value includes approximately $3.5 million in constrained-off export CMSC that was due to manual control room actions (TLRi) not PD-1 nodal prices.

payments at interties during that period. Table 3-4 provides a breakdown of CMSC paid, by type, at each of Ontario's interties.

Table 3-4: Net CMSC Payments for Intertie Transactions
January 2013 – April 2014
($ millions)

Interface	Constrained-Off Exports	Constrained-On Exports	Constrained-Off Imports	Constrained-On Imports
Michigan (Ludington)	0.44	0.11	0.05	0.34
Michigan (Calvert Cliff)	6.97	(0.10)	(0.05)	1.49
New York	11.47	0.12	(0.21)	1.99
Minnesota	4.29	2.11	0.12	0.89
Manitoba	2.74	4.58	0	0.08
Québec	5.67	(0.08)	0.24	2.11
Total	**31.58**	**6.74**	**0.15**	**6.91**

Table 3-5 shows the annual amount of total constrained-off intertie CMSC payments since January 2004.

Table 3-5: Net Constrained-Off CMSC Payments
January 2004 – April 2014
($ millions)

Year	Imports	Exports	Total
2004	(0.8)	15.4	14.6
2005	16.9	26.4	43.3
2006	7.2	15.4	22.6
2007	12.3	14.7	27.0
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	17.0
2012[97]	6.5	5.9	12.4
2013	0.8	19.3	20.1
2014 thru April	(0.7)	12.3	11.6
Total	**113.2**	**163.6**	**276.8**

[97] 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" (currently, only NW Ontario), if the import transaction was constrained off in the final pre-dispatch run. This effectively eliminated constrained-off import CMSC payments in the NW region of Ontario.

Since January 1, 2004 a total of $163.6 million has been paid to intertie traders for not exporting power from Ontario.

3.3.5 Incentives Resulting from Constrained-Off Export CMSC

This section analyzes the incentives that result from the two-schedule system and how the associated CMSC payments can distort bidding behaviour. It will be shown that, due to the incentive of constrained-off CMSC, in each situation the intertie trader is better off chasing the nodal price as opposed to bidding at the expected price in the external jurisdiction or bidding as a price taker.[98] This is not to say that the exporter must or should chase the nodal price, only that it would find it profitable to do so. What may be profitable for an intertie trader may not be beneficial to Ontario as an exporter could bid to export energy from high price Ontario to the lower price external jurisdiction confident that the export will be constrained off and the import leg of the transaction in the external jurisdiction will never be consummated. Even were it the case that the transaction was in the direction of low price to high price, it is unnecessary to have Ontario consumers pay for a constrained-off export that was bid with the intention of never flowing. Ultimately, constrained-off CMSC induces distortive bidding on the interties which in turn distort market outcomes away from the competitive outcome where exporters bid their expected marginal benefit.

The incentive of CMSC on bidding behaviour can be illustrated with two examples, first, a hypothetically profitable transaction *without* the CMSC incentive (Example A), and second, the same hypothetically profitable transaction examined *with* the CMSC incentive (Example B).

Example A:
PD-1 Zonal Price = $30/MWh
HOEP = $30/MWh
PD-1 Nodal Price = $60/MWh
Price in External Jurisdiction= $40/MWh

[98] For the purposes of this report, price taker bids are assumed to be $2,000/MWh. Price taker bids ensure that, in nearly all circumstances, the export is economic in the constrained schedule

Example A uses the assumption that CMSC payments do not exist. In this example the market participant has a clear economic incentive to transact and capture the $10/MWh profit opportunity between jurisdictions. In this situation an exporter would be prepared to bid at a price that is equal to the external jurisdiction, less any transaction costs ("TC") [99], i.e. the exporter's marginal benefit. However, bidding at the price in the external jurisdiction results in the export being constrained off because the bid price is less than the PD-1 nodal price. Numerically:

Trade Profit = External Price – HOEP – TC = ~~$40 – $30 – $5~~ = $0/MWh (constrained off)

The exporter may choose to bid at a price higher than the expected PD-1 nodal price at the interface, which is required in order to be scheduled to flow and capture the profit opportunity.

If the participant wishes to capture the $10/MWh profit opportunity, it could bid above the expected PD-1 nodal price. The expected trade profit by the market participant in this scenario is $10/MWh minus transaction costs. Numerically:

Trade Profit = External Price – HOEP – TC = $40 – $30 – $5 = +$5/MWh

At no bid price above the external price and below the PD-1 nodal price does the exporter have any greater profit opportunity. Any bid price in this range ($40/MWh to $59/MWh) will result in the export not flowing. As shown in Example B below, this is not the case once the CMSC incentive is introduced.

Bidding above the PD-1 nodal price, and therefore being scheduled to export, is a transaction with risk. It may be the case that, in real-time, the HOEP may climb to a price greater than the external price, say, $60/MWh. The exporter must then pay $60/MWh for Ontario power, and sell it to the external jurisdiction at $40/MWh for a net loss of $20/MWh plus transaction costs. In this situation the exporter would have been better off bidding at the external price and being constrained off with a trade profit of $0/MWh. All intertie transactions are subject to the risk that price may rise between pre-dispatch and real-time.

[99] This report assumes total transaction costs of $5/MWh, which is assumed to be inclusive of external transmission reservation, uplift costs and the Ontario export tariff.

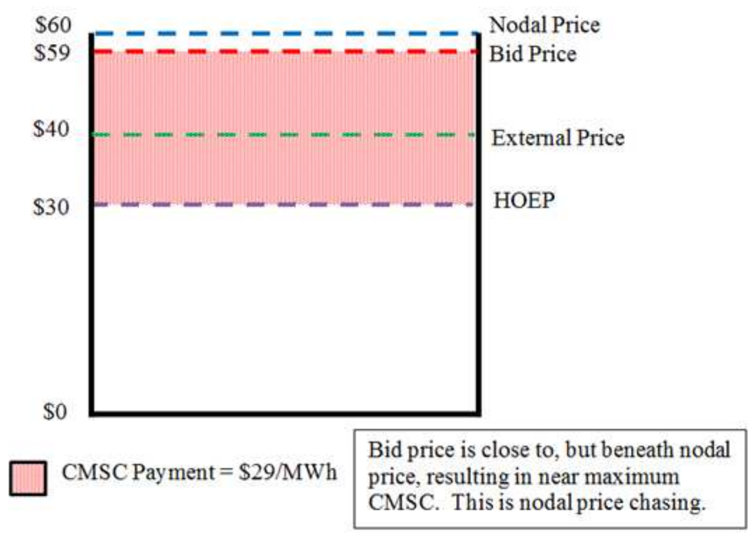
Example B:

Let's examine the same scenario, this time introducing the incentive of constrained-off export CMSC. The same $10/MWh profit opportunity between jurisdictions still exists. The exporter may again choose to bid at a price greater than PD-1 nodal price in order to be scheduled to export in order to capture the trade profit of $10/MWh less transaction costs. The exporter may also still choose to bid at the external jurisdiction price, $40/MWh, which results in the exporter being constrained-off and receiving CMSC. Numerically:

CMSC Profit = Bid Price – HOEP - TC = $40 – $30 - $0= +$10/MWh (from CMSC)

The exporter may instead choose to chase the nodal price. As discussed in the introduction to this section, 'nodal price chasing' is the placement of offers or bids at prices that appear to have a predominant purpose of targeting CMSC payments, as opposed to purchasing or selling power from or to Ontario. Figure 3-5 illuminates the CMSC incentive.

Figure 3-5: The Nodal Price Chasing Incentive



In this example, the exporter can substantially increase its expected profits from either of the above bidding scenarios by using a bid price which is close to, but beneath the nodal price, for example, $59/MWh. Assuming, as in Example A above, in real-time the HOEP is in fact $30/MWh, the constrained-off CMSC calculation will now provide the exporter with a $29/MWh payment without the additional burden of transaction costs. This is behaviour the Panel considers nodal price chasing. Numerically:

CMSC Profit = Bid Price – HOEP - TC = \$59 – \$30 - \$0= +\$29/MWh (from CMSC)

Where as in Example A the exporter had no incentive to bid in the range between the external price and the nodal price, the incentive of CMSC has now made the participant better off by chasing the nodal price with a bid price in this range.

Additionally, the exporter is better off chasing the nodal price even when price rises in real-time. If the HOEP increases to \$60/MWh and the exporter has a bid price of \$59/MWh it will now incur a CMSC charge of only \$1/MWh, compared to a charge of \$20/MWh with a bid at the external jurisdiction price of \$40/MWh or a loss of \$20/MWh plus transaction costs with a bid price above PD-1 nodal price.

The constrained-off export CMSC incentive provides the exporter with greater profits (Example B > Example A, \$29/MWh > \$5/MWh) than the market participant could have achieved by actually exporting power. The market participant has very little incentive to bid at its marginal benefit of consumption (the price it is able to sell at in the external jurisdiction) as chasing the nodal price provides it with significantly greater profit opportunities.

Constrained-off export nodal price chasing tends to occur once nodal prices rise above the price in the external jurisdiction (minus transaction costs).[100] This boundary marks the point when the opportunity presented by the constrained-off export CMSC incentive is greater than the opportunity available to exporters by actually trading power.

Example C:
This example highlights a more extreme possibility which can, and has, resulted as a consequence of the constrained-off export CMSC incentive. Consider the following exporter bid and relevant prices:

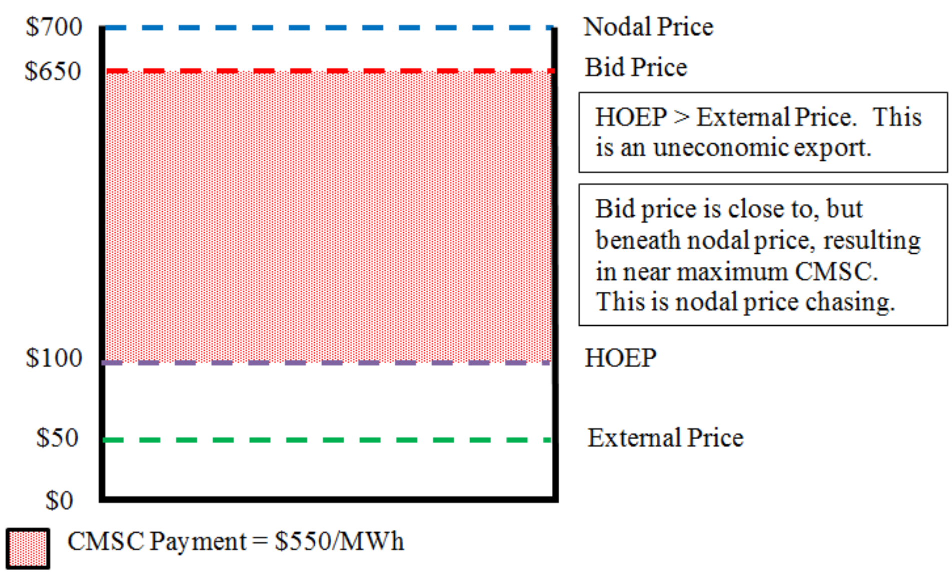
PD-1 Zonal Price = \$100/MWh
HOEP = \$100/MWh
PD-1 Nodal Price = \$700/MWh
Bid Price = \$650/MWh
External Jurisdiction Price = \$50/MWh

[100] Traders are also most likely to chase the nodal price when they can accurately predict what PD-1 nodal price will be.

CMSC Profit = Bid Price – HOEP - TC= $650 – $100 - $0 = +$550/MWh

Here, there is in fact no profitable trading opportunity, as the price in the external jurisdiction ($50/MWh) is significantly lower than the price in Ontario ($100/MWh). However, there exists a strong incentive for nodal price chasing. This situation is depicted in Figure 3-6.

Figure 3-6: Nodal Price Chasing - Under Uneconomic Trading Conditions



By placing its bid slightly below the intertie nodal price, resulting in the bid being constrained off, the exporter stands to collect **$550/MWh** ($650 - $100) in constrained-off CMSC. This is in obvious contrast with an expected *loss* of $55/MWh an intertie trader would incur from actually exporting power. Assuming that the transaction was scheduled for 100 MW, this example would see the ratepayers of Ontario pay the exporter $55,000 to not purchase power for export from Ontario.

Instead of bidding to trade power, bids such as those described in Examples B and C appear to target uplift payments and would constitute nodal price chasing. The following section will highlight and illustrate some actual examples of this conduct.

3.3.6 Nodal Price Chasing – Examples 1-2

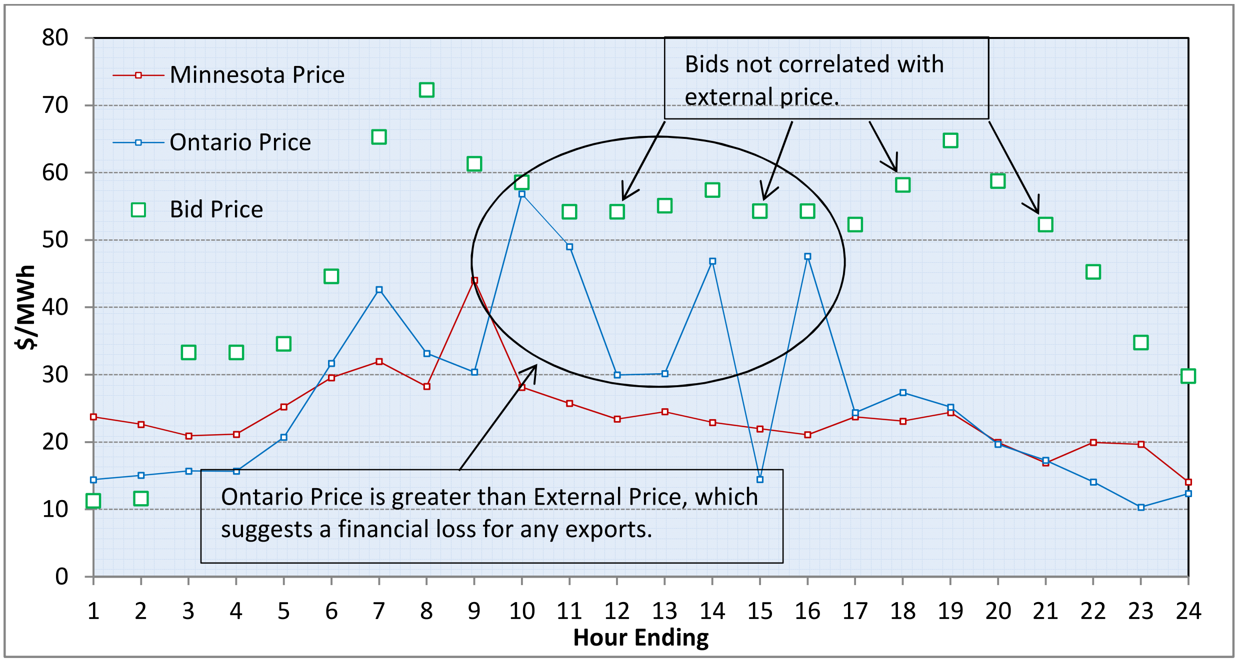
So far this section has used hypotheticals to describe the mechanics and incentives behind nodal price chasing. The following examples are intended to clarify for the reader what constitutes this conduct in practice. For these examples, the real-time external price and the HOEP are used as proxies for the prices available to market participants prior to the closure of the mandatory window (i.e. before the two hour ahead pre-dispatch run "PD-2"). The Panel understands that participants do not know the actual real-time prices in the external jurisdiction or in Ontario at the time when they must submit their bids to the IESO.

The examples below depict trading behaviour by various traders. While the situations described below offer useful examples of nodal price chasing, the chosen set of instances is by no means an exhaustive representation of nodal price chasing behaviour observed throughout the Analysis Period.

3.3.6.1 Example 1: October 25, 2013, Minnesota Intertie

Figure 3-7, shows Trader A's bids on October 25, 2013, at the Minnesota intertie. A proxy for an exporter's marginal benefit of consumption is the real-time price in the external jurisdiction minus transaction costs. This is the price at which the market participant is able to sell power in Minnesota. From Figure 3-7 it can be seen that Trader A's bid prices do not appear to correlate with the price in the external jurisdiction.

Figure 3-7: Example 1, Bids by Trader A at the Minnesota Intertie October 25, 2013 ($/MWh)



Items of interest in Figure 3-7 include the rapid rise in bid prices used by Trader A from HE 6 to HE 8 and the precipitous decline in bid price from HE 19 to HE 24, neither of which are seemingly related to the price in the external jurisdiction. Also, it is counterintuitive that Trader A would consistently bid to purchase power from HE 7 to HE 18 when the purchase price, the HOEP, is greater than the possible sale price in the external jurisdiction. Figure 3-8 will help to explain the situation, as an extremely important piece of information is added to the picture; pre-dispatch Nodal prices.

Pre-Dispatch Nodal Prices

In the IESO-administered markets all market participants, including intertie transactions, must have their bids/offers submitted to the IESO prior to the closing of a mandatory window, which occurs two hours before real-time.

For example, if an exporter wishes to purchase power for export in HE 12 (the hour running from 11:00 AM to 11:59 AM), that exporter must have its bids submitted to the IESO no later than the start of HE 10, or 8:59.

Each hour, the IESO publishes projected nodal prices for any given hour. These publications occur upwards of a day in advance of real-time. The IESO is, in effect, foreshadowing where the nodal price is likely to settle. Given the deadline to insert bids and offers, the final piece of information available to exporters regarding Ontario market prices, for any given trading hour, is the three hour ahead pre-dispatch (PD-3) Zonal and Nodal prices. In the simple example below, it can be seen that for HE 12, market participants see a change in PD-3 Nodal price prior to the close of the mandatory window for trading for HE 12. Note that in addition to PD-3 for HE 12, participants also gain information on the PD-2 Nodal prices for HE 11 and PD-1 Nodal price for HE 10. This will become important in later examples.

Intertie Nodal Prices

	PD-3	PD-2	PD-1
HE 10	$20	$20	$20
HE 11	$20	$20	
HE 12	***$100***		

Figure 3-8: Example 1, Bids by Trader A at the Minnesota Intertie with the PD-3 Nodal Price October 25, 2013 ($/MWh)

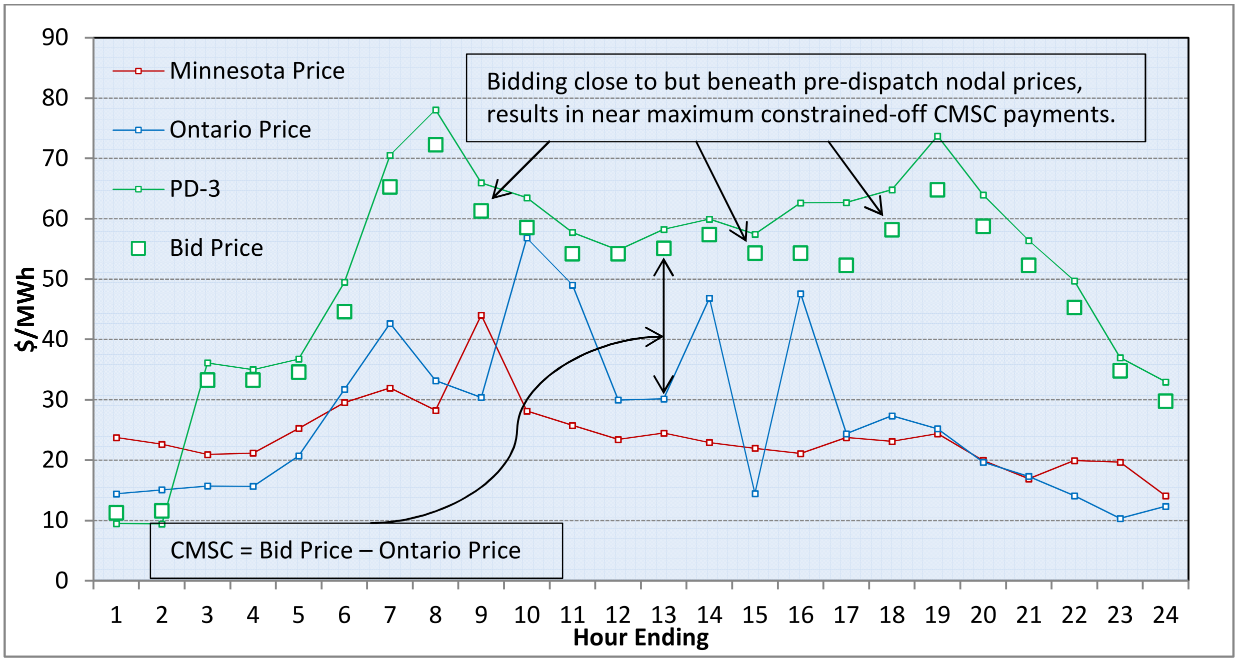


Figure 3-8 above helps to clarify Trader A's seemingly randomly priced bids. The green line in Figure 3-8 represents the PD-3 nodal price, which is the final PD nodal price that intertie traders have access to before their bids/offers must be submitted to the IESO. As articulated in Examples A-C above regarding the incentives to chase the nodal price, when the nodal price is greater than the external price, there exists a strong incentive for market participants to bid close to, but beneath, pre-dispatch nodal prices. Recall, bids which are above the pre-dispatch nodal price will actually export power and the intertie trader will realize the profit or loss from the price differential in the direction of the transaction. Also, actual exports of power are subject to transaction costs from Ontario while constrained off transactions are not.

From Figure 3-8 it can be seen that Trader A's bids were placed close to, but beneath the PD-3 nodal price and thus nearly maximize the exporters' constrained-off export CMSC payments. Table 3-6 provides a summary of the relevant data for this example.

Table 3-6: Example 1, Relevant Data from the Trading of Trader A at the Minnesota Intertie October 25, 2013 (MW, %, $)

Schedules	Total Unconstrained Schedule	1,180 MW
	Total Constrained Schedule	193 MW
	% of Schedule Constrained Off	84%
	Constrained-Off Export CMSC	$23,043
Profit (Loss)	Unconstrained Schedule Purchases[101]	$34,241
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)[102]	**($6,690)**
	Constrained Schedule Purchases[103]	$4,332
	Profit(Loss) When Constrained Off (External Sales[104] – Domestic Purchase – TC + CMSC)	*($404) + $23,043 =* **$22,639**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	0.38
	vs. PD-3 Nodal Price	0.99

Trader A's bids are nearly perfectly correlated with PD-3 nodal prices; a correlation coefficient of 0.99. This suggests that its bids were intended to target CMSC payments by consistently offering marginally below the nodal price.

According to its unconstrained schedule, Trader A would have purchased $34,241 worth of power from Ontario. However, as a result of its constrained schedule, Trader A actually purchased $4,332[105] worth of power for export which it sold in the external jurisdiction resulting in a loss of $404.

On this day, Trader A received $23,043 in constrained-off export CMSC at the Minnesota intertie, representing only the 39th highest grossing constrained-off export CMSC day for Trader A at the Minnesota intertie over the Analysis Period. This payment was for power that it was not able to export and, apparently, did not intend to purchase.

Since Trader A in the example above earned roughly $23,000 in constrained-off export CMSC for not exporting power, one would expect to find that it could have earned a profit of at least

[101] These are purchases that the exporter was scheduled to make, based on the pre-dispatch unconstrained schedule.
[102] In this report, all sale prices in external jurisdictions are converted from USD to CAD using the Bank of Canada U.S. Dollar Noon conversion rate.
[103] These are purchases that the exporter actually made.
[104] This value refers to the profit (loss) as a result of power sales from the constrained schedule.
[105] This value includes the $2/MWh Ontario export tariff.

that much by exporting to the external jurisdiction. That result would be consistent with Trader A's bids reflecting its marginal benefit. In actuality, had Trader A sold its entire unconstrained schedule into the external jurisdiction, it stood to *lose $6,690* because the Ontario price (the HOEP) regularly exceeded the price in the external jurisdiction.

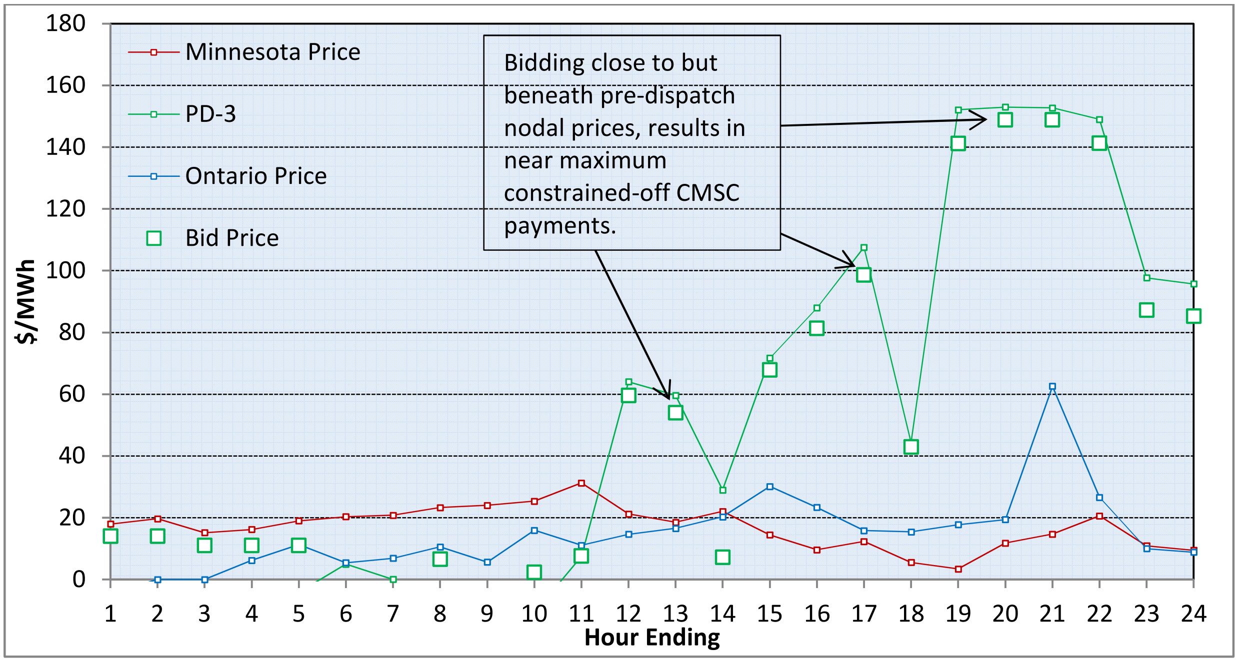
To recap, it appears that Trader A's bids were placed with the predominant purpose of being constrained off. This results graphically from Figure 3-8, and numerically through the correlation coefficients in Table 3-6. The vast majority (84%) of the participant's unconstrained schedule was constrained off, resulting in the participant not exporting power, instead the ratepayers of Ontario paid the participant $23,043 in constrained-off CMSC to not purchase power for export from Ontario. Had the participant actually sold the power it bid for in the external jurisdiction, it would have suffered a loss on the transaction. This scenario is neither special nor uncommon and is in fact the least striking example of nodal price chasing discussed in this report.

3.3.6.2 Example 2: June 3, 2013, Minnesota Intertie

The next example resulted in the largest constrained-off export CMSC payments received by Trader A at the Minnesota intertie during the Analysis Period.

Figure 3-9, shows Trader A's bids on June 3, 2013 at the Minnesota intertie. Similarly to the trading pattern in the Example 1, Trader A's bid prices do not appear correlated with the price in the external jurisdiction; instead, they tightly follow the PD-3 nodal price at the Minnesota intertie. Again, the actual real-time price in the external jurisdiction (minus transaction costs) is treated as the best proxy for an exporter's marginal benefit of consumption. This is the price at which the market participant is able to sell power exported from Ontario. Once again, the incentives provided by the CMSC regime have distorted the market participant's perception of its own marginal benefit for the transaction. Its bids do not correlate with the marginal benefit of actually trading power; instead it appears to be trading with the intention of obtaining constrained-off CMSC.

Figure 3-9: Example 2, Bids by Trader A at the Minnesota Intertie with PD-3 Nodal Price June 3, 2013 ($/MWh)



Trader A's bids have again been placed close to, but beneath the PD-3 nodal price. As previously described, such bids can result in near-maximum constrained-off CMSC payments. From HE 12 to HE 24 the nodal price chasing in this example is striking: Trader A lowers its bid price in HE 18 as PD-3 prices momentarily decrease from \$100/MWh to just above \$40/MWh and then increase once again to over \$140/MWh from HE 19 to HE 22. As illustrated by the opening examples regarding incentives, nodal price chasing tends to occur once nodal prices rise above the price in the external jurisdiction (minus transaction costs). Table 3-7 provides a summary of the data for Example 2.

Table 3-7: Example 2, Relevant Data from the Trading of Trader A at the Minnesota Intertie June 3, 2013 (MW, %, $)

Schedules	Total Unconstrained Schedule	1,888 MW
	Total Constrained Schedule	366 MW
	% of Schedule Constrained Off	81%
	Constrained-Off Export CMSC	$114,130
Profit (Loss)	Unconstrained Schedule Purchases	$37,657
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**($17,101)**
	Constrained Schedule Purchases	$1,424
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*$4,028** + *$114,130* = **$118,158**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	-0.56
	vs. PD-3 Nodal Price	0.99

* External sales from the constrained schedule resulted in a profit; however, the sales from the unconstrained schedule would have resulted in a loss.

Trader A's bids on this day are not correlated with the price in the external jurisdiction. Similarly to the previous example, Trader A's bids have a very high correlation with PD-3 nodal prices.[106] Absent the incentive of constrained-off CMSC payments, there is no apparent rationale for this trading behaviour; with the CMSC incentive, it is clear the rationale is nodal price chasing and the targeting of constrained-off CMSC payments.

By targeting constrained-off export CMSC through nodal price chasing, Trader A's actions resulted in a further distortion to the market. Trader A's phantom load[107] was used in the unconstrained schedule, therefore putting upward pressure on real-time prices (the HOEP). However, as Trader A's exports were constrained off, the IESO has to constrain off a corresponding amount of supply. Each time this situation arises the result will be constrained-off CMSC paid to generators or importers. In summary, Trader A's phantom load resulted in constrained-off export CMSC payments to Trader A for not exporting power *and* also constrained-off CMSC payments to Ontario suppliers (generators or imports) for not supplying Trader A's phantom load.

[106] This does not include the PD-3 nodal price of -$1,796.91/MWh in HE 9

[107] Phantom load refers to market demand which is present in the unconstrained schedule, therefore contributing to higher prices, but which is then subsequently constrained off in the real-time constrained sequence. Bids by exporters which appear to be predominantly for the purpose of obtained constrained-off CMSC payments therefore have an inflationary effect on the HOEP.

According to its unconstrained schedule, Trader A was scheduled to purchase $37,657 worth of power from Ontario. However, as a result of its constrained schedule, Trader A only actually purchased $1,424[108] worth of power.

On this day, Trader A received $114,130 in constrained-off export CMSC at the Minnesota intertie. Had Trader A purchased its entire unconstrained schedule for sale in the external jurisdiction, it would have incurred a loss of $17,101.

3.3.7 Examples 3 & 4

The next two examples of nodal price chasing behaviour are the most extreme examples of this type of conduct described in this report based on three factors: the uneconomic nature of the trading, the magnitude and timing of the participants' bid prices and the effectiveness of the strategy in terms of the amount of the CMSC payments.

Example 3 occurred at the Minnesota intertie on January 7, 2014. On this day the Minnesota intertie nodal price spiked to $2,715/MWh in HE 19 and remained at over $1,700/MWh until HE 23. Two market participants, Trader B and Trader C, were quick to take advantage.

Before examining the trading behaviour for Example 3, an interesting point to note is that PD-3 nodal prices, in this case, did not ever increase to anywhere close to $2,000/MWh.[109] In the previous examples, the Panel has relied on the use of PD-3 nodal prices to illustrate nodal price chasing. This is not the case in every instance. Earlier, the Panel described the information available to exporters prior to the closing of the mandatory window for intertie transactions. In general, PD-3 prices are the final piece of information that a market participant has for a given trading hour. However, participants are also provided with PD-2 and PD-1 price information for the hours *previous* to the trading hour in question. Again, the use of a simple example is illustrative:

[108] This value includes the $2/MWh Ontario export tariff.
[109] Maximum PD-3 nodal price at Minnesota on this day was $201.22/MWh in HE 22.

Intertie Nodal Prices (A)

	PD-3	PD-2	PD-1
HE 18	$20	$20	$20
HE 19	$20	***$500***	
HE 20	$20		

Example A above shows a sudden change in PD-2 nodal price for HE 19, before any change is recognized in the PD-3 nodal price for HE 20. Indeed, PD-3 prices may not ever increase. Another example is again helpful:

Intertie Nodal Prices (B)

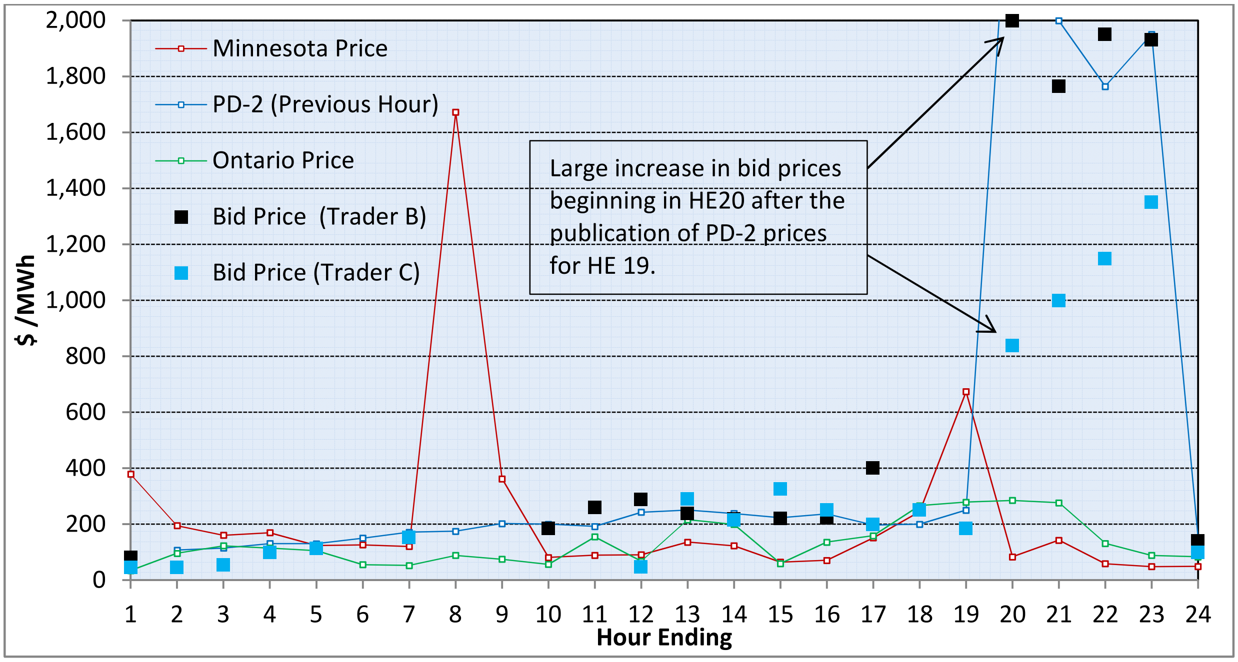
	PD-3	PD-2	PD-1
HE 18	$20	$20	$20
HE 19	$20	***$500***	***$500***
HE 20	$20	***$500***	
HE 21	$20		

In Example B, PD-3 nodal prices do not rise in any hour, however, PD-1 for HE 19 and PD-2 for HE 20 have increased to $500/MWh. This is powerful information and drives the situation observed in Example 3 as it appears that both market participants were using the previous hour's PD-2 nodal price when determining where and when, to place their bids.

3.3.7.1 Example 3, January 7, 2014, Minnesota Intertie

Figure 3-10 shows the weighted average bid prices for Trader B and Trader C on January 7, 2014 as well as external price and PD-2 (previous hour) nodal price.

Figure 3-10: Example 3, Bids by Trader B and Trader C at the Minnesota Intertie with PD-2 (previous hour) Nodal Price
January 7, 2014
($/MWh)



Of particular interest from Figure 3-10 is the extreme increase in bid prices exhibited by both Trader B and Trader C in HE 20. Interestingly, Trader B had actually stopped trading at the Minnesota intertie for HE 18 and 19. When Trader B returned to the market in HE 20, its bid was placed at $1,999/MWh, marginally below the maximum allowable bid price $2,000/MWh. Trader B continued to bid at very high prices for HE 21 to HE 23, reducing its bid price only once the PD-2 price for HE 22 showed nodal prices falling from $1,950 to $151/MWh. Trader C followed a more cautious approach, increasing its bid price from $838/MWh in HE 20 to $1,350 in HE 23. Of course neither Trader B's or Trader C's bids actually reflected their respective marginal benefit of consumption at the Minnesota intertie. Instead, the participant's high bid prices depict nodal price chasing behaviour for the purpose of obtaining large constrained-off CMSC payments.

Table 3-8: Example 3, Relevant Data from the Trading of Trader B and Trader C at the Minnesota Intertie
January 7, 2014
(MW, %, $)

Participant		Trader B	Trader C
Schedules	Total Unconstrained Schedule	655 MW	307 MW
	Total Constrained Schedule	433 MW	180 MW
	% of Schedule Constrained Off	34%	41%
	Constrained-Off Export CMSC	$152,899	$64,069
Profit (Loss)	Unconstrained Schedule Purchases	$100,459	$43,198
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**($34,298)**	**$15,611**
	Constrained Schedule Purchases	$63,154	$24,806
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*($19,252) + $152,899* = **$133,647**	*($2,880) + $64,069* = **$61,189**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	-0.26	-0.31
	vs. PD-2 (previous hour) Nodal Price	0.98	0.90

Neither Trader B's nor Trader C's average weighted bid prices on this day are positively correlated with the price in the external jurisdiction. However, both participants' bids are strongly correlated with PD-2 (of the previous hour) nodal prices as correlation coefficients for each are at or above 0.90.

On this day, Trader B and Trader C received $152,899 and $64,069 respectively in constrained-off CMSC at the Minnesota intertie. These values represented the most constrained-off CMSC that either participant received in any one day at the Minnesota intertie during the Analysis Period. Over 90% of the CMSC paid to each of the market participants in this instance occurred in three hours: HE 20, HE 21 and HE 22.

According to their unconstrained schedule, Trader B and Trader C would have purchased $100,459 and $43,198 of power to export from Ontario. However, following their respective constrained schedules, Trader B and Trader C bought $63,154[110] and $24,806 worth of power.

Had Trader B purchased its entire unconstrained schedule for sale to Minnesota, it would have incurred a loss of $34,298. Instead, through its constrained schedule, its export losses were

[110] Both unconstrained and constrained values includes the $2/MWh Ontario export tariff

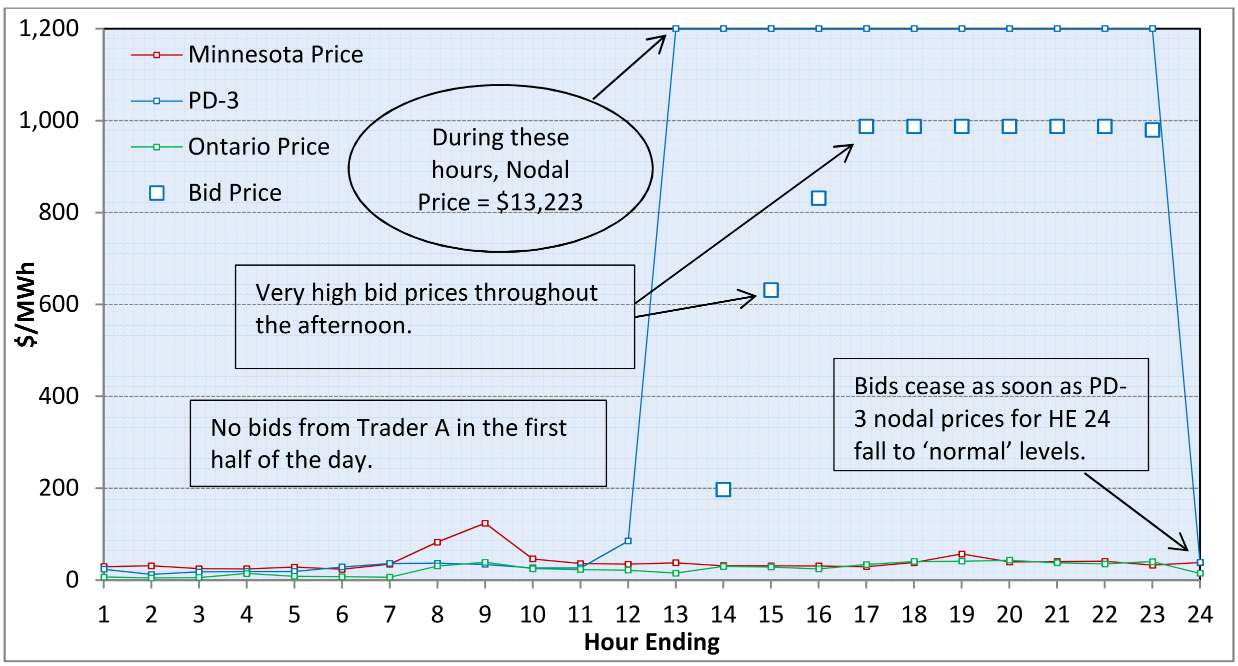
$19,252. When the $152,899 in constrained-off export CMSC is added to the losses from its exports, the result is a profit for Trader B of $133,647.

Similarly, Trader C saw its expected profits rise from $15,611 in the unconstrained schedule, to $61,189 in the constrained schedule, including CMSC.

3.3.7.2 Example 4, December 11, 2013, Manitoba Intertie

The final example of nodal price chasing presented in this section occurred at the Manitoba intertie on December 11, 2013. The participant in question is Trader A. The defining feature on this day was a dramatic increase in nodal prices at the Manitoba intertie from HE 12 to HE 23 with nodal prices rising to $13,223/MWh.[111] Figure 3-11 shows Trader A's bids for the afternoon and evening hours.

Figure 3-11: Example 4, Bids by Trader A at the Manitoba Intertie with PD-3 Nodal Price December 11, 2013 ($/MWh)



[111] The nodal price at the Manitoba intertie rose to over $13,000/MWh as a result of a binding Operating Security Limit (OSL) in the region which limited the capacity of a critical NW flow gate. From HE 12 to HE 23 export demand to Manitoba exceeded the OSL, causing penalty factors to be applied to the Manitoba intertie nodal price calculation, producing the anomalously high nodal price.

Trader A was not an active participant at the Manitoba intertie until HE 14, which coincided with the first time that nodal prices at the Manitoba intertie reached over $13,000/MWh in PD-1 (for HE 12)[112], the final run of pre-dispatch and the sequence by which intertie transactions are scheduled. Trader A placed bids for HE 14 to HE 23 at prices that began at $197/MWh, eventually reaching $987/MWh. Interestingly, once PD-3 nodal prices fell to $29/MWh in HE 24, Trader A ceased bidding. This conduct constitutes blatant nodal price chasing, and is evidently solely directed at exploiting the IESO-administered CMSC payment program. Table 3-9 presents important statistics regarding Trader A's trading on this day.

Table 3-9: Example 4, Relevant Data from the Trading of Trader A at the Manitoba Intertie December 11, 2013 (MW, %, $)

Schedules	Total Unconstrained Schedule	180 MW
	Total Constrained Schedule	0 MW
	% of Schedule Constrained Off	100%
	Constrained-Off Export CMSC	$147,708
Profit (Loss)	Unconstrained Schedule Purchases	$6,733
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**($227)**
	Constrained Schedule Purchases	$0.00
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*$0.00 + $147,708 =* **$147,708**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	0.40
	vs. PD-3 Nodal Price	N/A[113]

Trader A was constrained off for 100% of its unconstrained schedule, resulting in $147,708 of constrained-off CMSC payments. Had Trader A actually exported power according to its unconstrained schedule, it would have suffered a loss of $227. Had Trader A actually paid the *price* in each hour that it suggested it was willing to pay, i.e. its bid price, it stood to lose $147,574.

[112] HE 14 was the earliest hour that Trader A could submit bids at the Manitoba intertie once it had confirmation that PD-1 nodal price at the Manitoba intertie had cleared at over $13,000/MWh in HE 12. This is because of the 2-hour mandatory window for intertie scheduling in the IESO-administered markets.
[113] PD-3 nodal prices never varied while Trader A was bidding, therefore, this calculation is not available.

For additional examples of nodal price chasing during the Analysis Period, see Appendix A of this report.

3.3.8 CMSC Overcompensation for Constrained-off Exports

The calculation for constrained-off CMSC payments is based on the assumption that the bid/offer price used by the market participant reflects the marginal benefit/cost of selling/purchasing power. This assumption is difficult to test in practice as generators and consumers of electricity have private knowledge of their actual marginal cost of production or marginal benefit of consumption of power. On the other hand, there is greater visibility around the marginal cost and benefit of buying and selling power for intertie traders.

An exporter's operating profit is equal to the difference between the price it buys power in Ontario (the HOEP plus congestion fees) and the prevailing real-time price it is able to sell power at in the external jurisdiction, minus transaction costs. Such prices are public and offer an objective measure of the marginal benefit of consumption for exporters. However, the calculation used by the IESO for CMSC paid to intertie transactions instead uses the participant's bid/offer price, not the price in the external jurisdiction. This allows intertie traders who chase the nodal price to be paid as bid, or in other words, to 'name their profit'.

Recall that constrained-off CMSC is intended to compensate market participants for any implied change in their operating profits as a result of differences between their unconstrained (market) and constrained (dispatch) schedules. An exporter's implied operating profits are known and transparent based on their purchase price and their sale price.

As stated in previous reports, the Panel is of the view that constrained-off CMSC payments to intertie traders provide little to no commensurate value. Overcompensating exporters under the existing CMSC regime is not only unnecessary but inconsistent with the existing market design. Mindful of the intent of CMSC, the Panel has calculated the following:

- The estimated profits which would have been attainable by exporters based on their unconstrained schedules.
    - (External Price – HOEP) * Unconstrained Schedule (Table 3-10, Row D)

- The estimated profits attained by exporters based on their constrained schedules, by interface.
  - (External Price – HOEP) * Constrained Schedule (Table 3-10, Row E)

Therefore, given that the intent of CMSC payments is to compensate intertie traders for foregone operating profits, the amount of constrained-off CMSC that would be paid, based on the Market Rules description of CMSC payments[114], is the difference between the estimated profits from the unconstrained and constrained schedules.[115] The Panel has characterized the difference between the amount of CMSC that would have been paid, and the amount of CMSC that was paid, as the 'CMSC overcompensation'. During the Analysis Period this amount was $21.8 million. Table 3-10 provides the details of the analysis.

Table 3-10: Estimated Profits from Exports and CMSC Overcompensation
January 2013 – April 2014
(MW, %, $)

Intertie	Minnesota	New York	Calvert Cliff	Ludington	Manitoba[116]	Québec	Total
[A] Unconstrained Schedule (MW)	279,502	9,421,657	8,080,130	1,018,845	102,626	3,441,338	**22,344,099**
[B] Constrained Schedule (MW)	132,942	8,689,625	7,377,094	898,782	49,078	3,367,665	**20,515,187**
[C] % of Exports Constrained Off (%)	52.44	7.77	8.70	0.12	52.18	2.14	**8.19**
[D] Estimated Profit(Loss) [UC] ($MM)	(0.88)	45.46	42.42	(1.15)	(0.09)	150.56	**236.32**
[E] Actual Profit(Loss) [C] ($MM)	(0.01)	38.50	41.87	(1.02)	(0.13)	147.33	**226.53**
[F] Constrained-Off Export CMSC ($MM)	4.31	11.46	6.97	0.44	2.74	5.67	**31.60**
[G] = [F] – ([D]-[E]) CMSC Overcompensation ($MM)	5.17	4.51	6.42	0.58	2.69	2.44	**21.81**

As discussed above, the final line of Table 3-10 presents the CMSC overcompensation as $21.8 million during the Analysis Period. The Panel has calculated that had exporters' constrained-off CMSC payments been based on the operating profit they would have actually achieved by exporting power from Ontario they would have received $9.8 million in constrained-off CMSC.

[114] See Chapter 9, Section 3.5.1 of the Market Rules; available at: http://www.ieso.ca/imoweb/pubs/marketRules/mr_marketRules.pdf
[115] The Panel examined only situations where exporters were constrained off.
[116] For exports which settle in the provinces of Manitoba and Québec, neither of which have wholesale markets, the Panel has assumed a sale price (or opportunity cost) equal to the highest price available to Manitoba or Québec in any adjacent external jurisdiction.

Also of interest from Table 3-10 is the apparent misalignment of trading fundamentals at the Minnesota intertie during the Analysis Period. Consider the following; 52.4% of all exports scheduled in the unconstrained sequence at the Minnesota intertie were constrained off, leading to $4.3 million in constrained-off export CMSC being paid to market participants.

The estimated profit from unconstrained schedules at the Minnesota intertie is actually a loss of $0.9 million. This means that, as a group, market participants were willing to trade at a loss throughout the Analysis Period at the Minnesota intertie. Unsurprisingly, participants in fact did not lose money, as estimated losses at the Minnesota intertie from the constrained schedule were only $10,000 and, as mentioned above, exporters were paid $4.3 million in constrained-off CMSC. Given the frequency and volume of constrained-off exports at the Minnesota intertie, and the large amount of CMSC paid in relation to the capability of the intertie[117], it is clear that constrained-off CMSC was the main driver behind this otherwise loss incurring trading behaviour at the Minnesota intertie during the Analysis Period.

Irrespective of the amount of CMSC overcompensation, the mere presence of constrained-off export CMSC payments is unnecessary, as is paying a market participant for not purchasing a product and allowing that participant to ‘name its profit’ through its bidding behaviour in many circumstances.

Additionally, during the Analysis Period, there was a total of $10.4 million in constrained-off CMSC charges to exporters. These charges are in fact costs levied on would-be exporters of Ontario power for not being able to export power from Ontario. The Panel is of the opinion that it is as unnecessary to charge a market participant for its inability to purchase something, as it is to remunerate a participant for not purchasing it.

To recap, this section has described the incentives behind nodal price chasing, provided examples of nodal price chasing behaviour, quantified the ‘CMSC overcompensation’ and has shown that the presence of constrained-off export CMSC has incentivized trading for a loss at the Minnesota intertie.

[117] The Minnesota intertie has an export capacity of 150 MW compared to an average export capacity at New York of 1,750 MW.

The Panel notes that settling intertie transactions based on the intertie nodal price, in effect using locational marginal pricing for intertie transactions, would eliminate the incentive market participants have to chase the nodal price, as uneconomic intertie transactions would no longer be constrained off, they would merely go unscheduled in the first place. The Panel understands that through its stakeholder initiative SE-114, the IESO may be looking at alternatives to the two-schedule system which could include locational marginal pricing and the Panel is supportive of those efforts. In the interim the IESO should take immediate steps to eliminate constrained-off CMSC payments for all intertie transactions and the Panel therefore reiterates the recommendation it made in its January 2014 Monitoring Report.

Recommendation 3-1

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.

APPENDIX 3A

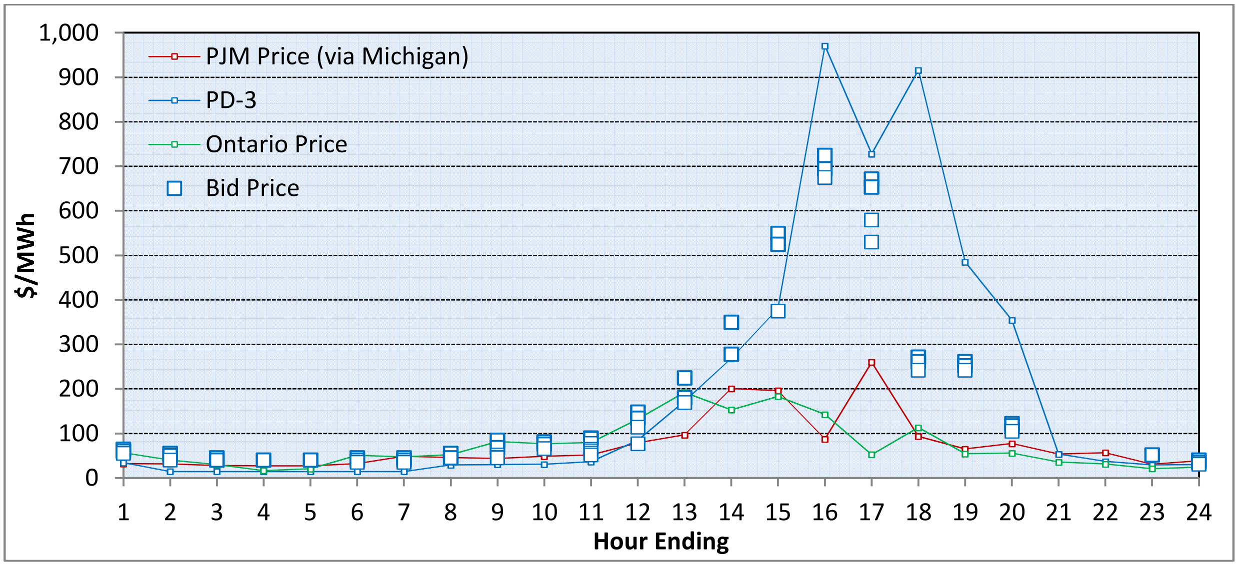
Additional Nodal Price Chasing Examples

3A.1 Example A1: September 11, 2013, Michigan (Calvert Cliff) Intertie

Example A1 focusses on behaviour at the Michigan Intertie, specifically the Calvert Cliff interface, which is used to import/export power between Ontario and Pennsylvania New Jersey Maryland ("PJM"). The example described below shows trading behaviour by Trader B on September 11, 2013. This day was characterized by challenging conditions in the IESO-administered market and the IESO-controlled grid. High Ontario demand resulting from higher than expected temperatures, and limited import capacity on the Québec interface contributed to real-time prices in excess of $100/MWh during the afternoon. In total there was $1,178,463 in CMSC payments made to generators and $1,721,145 to intertie transactions, including $907,195 for constrained-off exports.[118]

Figure 3A-1, shows Trader B's bid behaviour on September 11, 2013, at the Michigan (Calvert Cliff) intertie.

Figure 3A-1: Example A1, Bids by Trader B at the Michigan (Calvert Cliff) Intertie with PD-3 Nodal Price September 11, 2013 ($/MWh)



[118] See page 53 of the Panel's September 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf.

What is most notable from Figure 3A-1 is the rapid and substantial increase in bid prices submitted by Trader B from HE 14 to HE 21. Trader B's bids became completely disassociated from the price in the external jurisdiction and began to closely track PD-3 nodal price at the Michigan (Calvert Cliff) intertie. Table 3A-1 provides the important statistics regarding Trader B's trading at the Michigan (Calvert Cliff) intertie on this day.

Table 3A-1: Example A1, Relevant Data from the Trading of Trader B at the Michigan (Calvert Cliff) Intertie
September 11, 2013
(MW, %, $)

Schedules	Total Unconstrained Schedule	2,758 MW
	Total Constrained Schedule	1,450 MW
	% of Schedule Constrained Off	47%
	Constrained-Off Export CMSC	$288,743
Profit (Loss)	Unconstrained Schedule Purchases	$219,517
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**$20,330**
	Constrained Schedule Purchases	$81,753
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*1,819* + $288,743 =* **$290,562**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	0.77
	vs. PD-3 Nodal Price	0.86

* External sales from the constrained schedule resulted in a loss; however, the sales from the unconstrained schedule would have resulted in a profit.

Unlike previous examples, it cannot be stated that Trader B's bidding behaviour is uncorrelated with the price in the external jurisdiction. Trader B's bids have a 0.77 correlation coefficient with the real-time price in the external jurisdiction and a 0.86 correlation coefficient with PD-3 nodal price.

According to its unconstrained schedule, Trader B would have paid $219,517 to purchase power from Ontario. However, following its constrained schedule, Trader B was scheduled to purchase only $81,753worth of exports.[119]

[119] Both unconstrained and constrained values includes the $2/MWh Ontario export tariff

Trader B received $288,743 in constrained-off export CMSC representing the most in constrained-off export CMSC received by Trader B at the Michigan (Calvert Cliff) intertie over the Analysis Period.

Also of interest on this day is that Trader B received $190,757 in constrained-on import CMSC payments from HE 16 to HE 20, also at the Michigan (Calvert Cliff) intertie.

To repeat, on this day Trader B received $288,743 in constrained-off export CMSC at the Michigan (Calvert Cliff) intertie for not purchasing $137,764 worth of Ontario power. Trader B earned $270,232 more in net revenue after being constrained-off than it could have by actually exporting power according to its unconstrained schedule. Had Trader B actually exported its entire unconstrained schedule, and sold it in the external jurisdiction, it stood to earn a profit of $20,330, 7% of what it received in constrained-off CMSC.

3A.2 Examples A2 – A4

From February 4 to February 8, 2013, Ontario was experiencing an internal transmission flow constraint which had the effect of bottling substantial amounts of supply (imports and generation) in the Western zone of the province resulting in a supply shortage for the load centres in the eastern zones.[120] As a consequence, nodal prices at the New York and Québec interties increased substantially in relation to the HOEP, resulting in constrained on imports and, as will discussed, significant payments for constrained off exports. In total, from February 4-8, 2013, there was $5.5 million in constrained-off export CMSC paid to market participants ($4.1 million at New York and $1.4 million at Québec). The next three examples focus on trading that took place on February 5, 2013 at both the Québec and New York intertie.

3A.2.1 Example A2: February 5, 2013, New York Intertie

Figure 3A-2, shows Trader D's bids on Tuesday, February 5, 2013, at the New York intertie.

[120] See pages 115-120 of the Panel's January 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

Figure 3A-2: Example A2, Bids by Trader D at the New York Intertie with PD-3 Nodal Price February 5, 2013 ($/MWh)

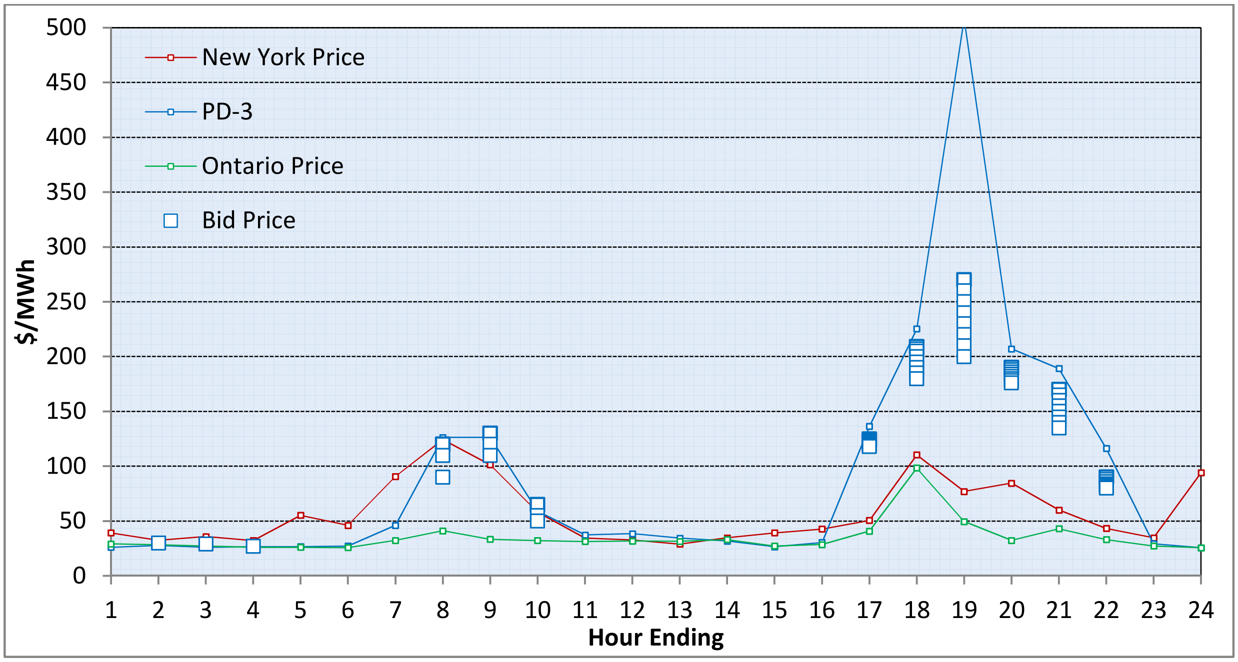


Figure 3A-2 has two distinct characteristics: a rise in Trader D's bid prices in HE 8 and HE 9 and another rise in bid prices from HE 17 to HE 22. The first rise occurs much as one would expect; as external prices rise, the participant's bid prices also rise corresponding to their opportunity for profit.[121] The second rise in prices does not correlate nearly as well with the price in the external jurisdiction, and instead closely follows the pattern of PD-3 nodal prices. Trader D's bids rise and subsequently fall from HE 17 to HE 22 in tandem with PD-3 nodal prices, and the pattern of bidding close to, but beneath PD-3 nodal prices is consistent with nodal price chasing. Table 3A-2 provides the important statistics regarding Trader D's trading at the New York intertie on this day.

[121] Trader D's bid prices also closely track PD-3 nodal prices from HE 8 to 10.

Table 3A-2: Example A2, Relevant Data from the Trading of Trader D at the New York Intertie
February 5, 2013
(MW, %, $)

Schedules	Total Unconstrained Schedule	1,500 MW
	Total Constrained Schedule	330 MW
	% of Schedule Constrained Off	78%
	Constrained-Off Export CMSC	$122,760
Profit (Loss)	Unconstrained Schedule Purchases	$72,519
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**$32,086**
	Constrained Schedule Purchases	$12,792
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*$4,247 + $122,760 =* **$127,007**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	0.62
	vs. PD-3 Nodal Price	0.90

Trader D's [average weighted] bid prices on this day are not well correlated with the price in the external jurisdiction. However, Trader D's bids are strongly correlated to PD-3 nodal prices (a 0.90 correlation coefficient).

According to its unconstrained schedule, Trader D would have paid $72,519 to export power from Ontario. However, following its constrained schedule, it purchased $12,792 worth of power for export.[122]

On this day, Trader D received $122,760 in constrained-off export CMSC at the New York intertie. This payment was for power that it was not able to export. Had Trader D purchased its entire unconstrained schedule for sale in the external jurisdiction, its profits would have been $32,086.[123]

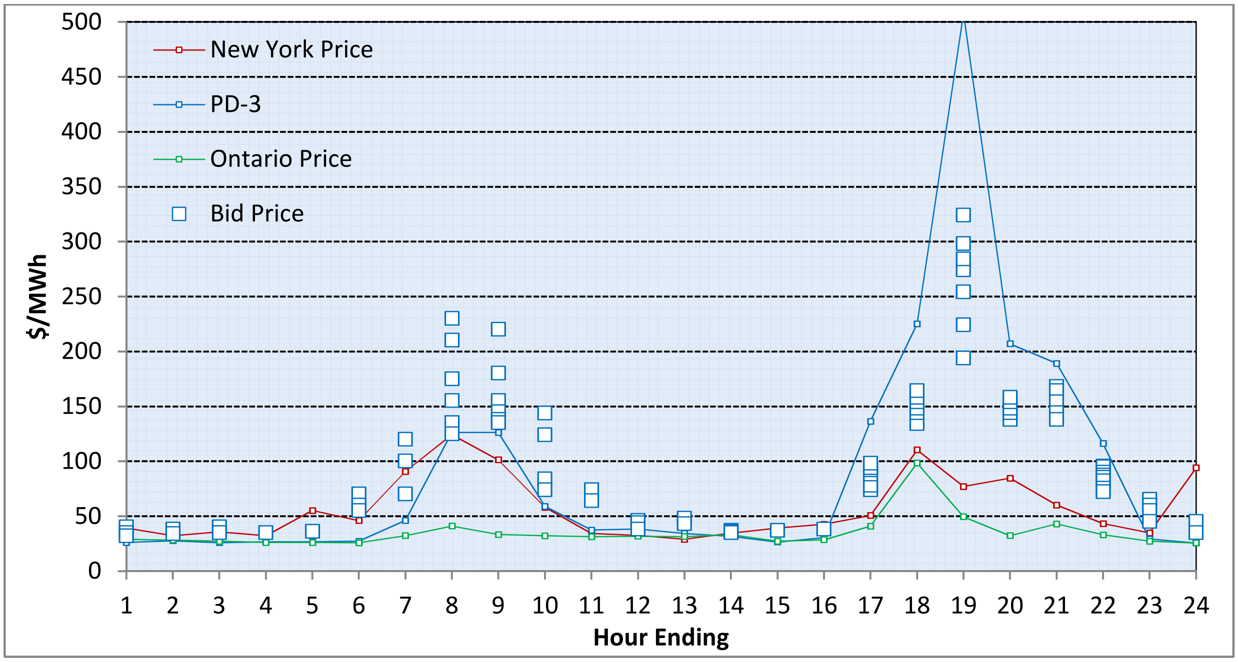
During the Analysis Period Trader D received $531,219 in constrained-off export CMSC, 23% of which occurred on this day. Trader D does not consistently exhibit nodal price chasing behaviour, however, this day offers an example of situations that arise which provide market participants significant incentive to participate in nodal price chasing behaviour.

[122] Both unconstrained and constrained values includes the $2/MWh Ontario export tariff
[123] Assuming $5/MWh of Transaction Costs

3A.2.2 Example A3: February 5, 2013, New York Intertie

Figure 3A-3 shows Trader B's bids on February 5, 2013, at the New York intertie.

Figure 3A-3: Example 5, Bids by Trader B at the New York Intertie with PD-3 Nodal Price February 5, 2013 ($/MWh)



Comparing Figure 3A-3 with Figure 3A-2 from Example A2 above, it can be seen that generally, Trader B was more aggressive in its pricing than Trader D, especially during the high PD-3 nodal prices from HE 17 to HE 22. On this day, Trader B received $279,980 in constrained-off export CMSC. There were several market participants who took advantage of the opportunity for constrained-off export CMSC on this day. Total constrained-off export CMSC payments were $781,711 paid to 13 different market participants. Table 3A-3 provides the pertinent statistics regarding Trader B trading on this day.

Table 3A-3: Example A3, Relevant Data from the Trading of Trader B at the New York Intertie February 5, 2013 (MW, %, $)

Schedules	Total Unconstrained Schedule	5,549 MW
	Total Constrained Schedule	2,713 MW
	% of Schedule Constrained Off	51%
	Constrained-Off Export CMSC	$279,980
Profit (Loss)	Unconstrained Schedule Purchases	$225,458
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**$123,464**
	Constrained Schedule Purchases	$89,089
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*($54,356 + $279,980)* = **$334,336**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	0.69
	vs. PD-3 Nodal Price	0.90

Overall, Trader B's bids are not well correlated with the price in the external jurisdiction. However, with a 0.90 correlation coefficient, Trader B's bids are well correlated with PD-3 nodal prices.

According to its unconstrained schedule, Trader B would have paid $225,458 to export power from Ontario; however, following its constrained schedule Trader B only bought $89,089 worth of power for export.[124]

On this day, Trader B received $279,980 in constrained-off export CMSC at the New York intertie. Had Trader B purchased its entire unconstrained schedule for sale into New York, its profits would have been $123,464.[125] Instead, through its constrained schedule, its profits were $54,356 plus $279,980 in CMSC = $334,336

Of importance from Examples 4 and 5 is that both Trader D and Trader B stood to earn considerable profits by actually exporting power from Ontario to New York. However, as a result of Ontario's CMSC regime, they each were presented with an opportunity to earn more net

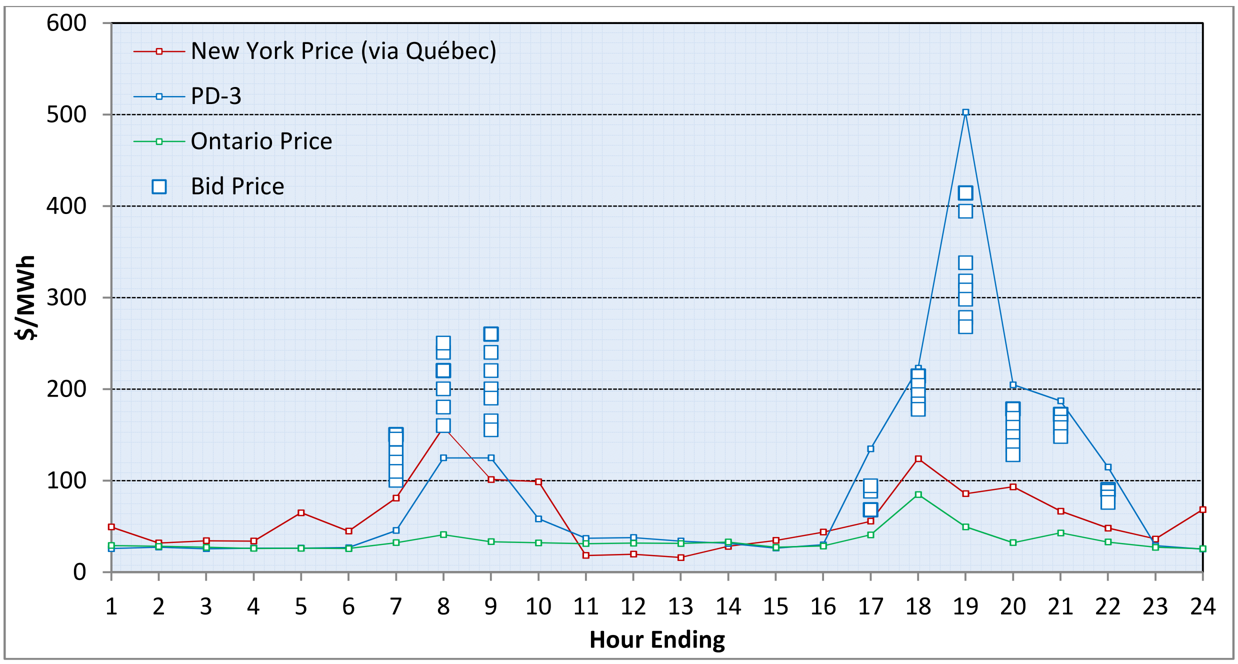
[124] Both unconstrained and constrained values includes the $2/MWh Ontario export tariff
[125] Assuming $5/MWh of Transaction Costs

revenue through nodal price chasing while incurring the opportunity cost of otherwise profitably exporting power.

3A.2.3 Example A4: February 5, 2013, Québec Intertie

Trader B also exhibited similar nodal price chasing behaviour on February 5, 2013 at the Québec (Outaouais) intertie. Figure 3A-4 illustrates their bid prices, the external price, the HOEP and the PD-3 nodal price.

Figure 3A-4: Example A4, Bids by Trader B at the Québec Intertie with PD-3 Nodal Price February 5, 2013 ($/MWh)



Once again, it can be seen that Trader B used very high bid prices especially during the high PD-3 nodal prices from HE 17 to HE 22. On this day, Trader B received $209,695 in constrained-off export CMSC at the Québec intertie. Table 3A-4 shows the relevant statistics.

Table 3A-4: Example A4, Relevant Data from the Trading of Trader B at the Québec Intertie February 5, 2013 (MW, %, $)

Schedules	Total Unconstrained Schedule	3,038 MW
	Total Constrained Schedule	1,412 MW
	% of Schedule Constrained Off	54%
	Constrained-Off Export CMSC	$209,695
Profit (Loss)	Unconstrained Schedule Purchases	$136,059
	Profit(Loss) if Trade Occurs (External Sales – Ontario Purchases – TC)	**$144,635**
	Constrained Schedule Purchases	$56,730
	Profit(Loss) When Constrained Off (External Sales – Domestic Purchase – TC + CMSC)	*($91,325 + $209,695)* = **$301,020**
Correlation Coefficient (Average Weighted Bid Price vs…)	vs. External Jurisdiction Price	0.50
	vs. PD-3 Nodal Price	0.80

Overall, Trader B's bid prices on this day are not well correlated with the price in the external jurisdiction. However, Trader B's bids are reasonably well correlated with PD-3 nodal prices (a correlation coefficient of 0.80).

On this day, Trader B received $209,695 in constrained-off export CMSC at the Québec intertie. This payment was for power that it was not able to purchase for export. According to its unconstrained schedule, Trader B would have paid $136,059 to export power from Ontario. However, following its constrained schedule, Trader B only bought $56,730 worth of power.[126] Had Trader B purchased its entire unconstrained schedule for sale into the external jurisdiction, its profits would have been $144,635.[127] Instead, through its constrained schedule, its profits were $91,325 plus $209,695 in CMSC or $301,020.

[126] Both unconstrained and constrained values includes the $2/MWh Ontario export tariff
[127] Assuming $5/MWh of Transaction Costs

Chapter 4: Panel Recommendations

This chapter contains the Panel's general assessment of the state of the IESO-administered markets. In addition, future developments in the market are briefly summarized, and the IESO's responses to recommendations made by the Panel in its September 2014 Monitoring Report are discussed. The chapter concludes with a restatement of the recommendation contained within this report.

1 *General Market Assessment*

The Panel is required to provide at least annually a general assessment of the state of the IESO-administered markets.

Since market opening in 2002, and particularly since the advent of the hybrid market in 2005, the Panel has assessed the state of the markets with due regard to several design features and policy decisions that affect market participant behaviour and market outcomes. As noted frequently in past Panel reports, these factors include:

- A uniform Ontario price for energy, which gives rise to the two-schedule system. This means that prices faced by wholesale market participants can diverge (sometimes significantly) from the incremental cost of supplying another MW of energy at a particular location.
- Virtually all generation in Ontario is now subject to long-term contracts with government agencies or price regulation by the Ontario Energy Board. These contracts and regulated prices can result in offer prices from generators that deviate from the generators' short-run marginal cost.
- The use of the 3 times ramp rate multiplier in the calculation of the unconstrained market clearing price, which distorts the Hourly Ontario Energy Price.

The Panel acknowledges the effects of these policy decisions on market efficiency, but recognizes them as features of the current hybrid design. Accordingly, the focus of the Panel's assessment has been on the fairness and efficiency of the IESO-administered markets within the current hybrid design. Given this scope, the Panel has concluded that the IESO-administered markets operated in a reasonably satisfactory manner for the year ended April 2014. In particular, during the severe winter of 2013/14, the markets generally provided appropriate signals to active wholesale market participants. Having said that, the Panel has made recommendations in this and prior reports aimed at improving efficiency and eliminating inappropriate payments. Among other things, the Panel continues to be concerned about excessive Congestion Management Settlement Credit (“CMSC”) payments, how the existence and scope of CMSC payments can affect the bidding/offering behavior of market participants and the resulting impacts on the efficiency and fairness of the market for all participants. For example, Chapter 3 of this report shows how strategies to maximize CMSC payments have affected the bidding behavior of some exporters.

2 *Future Development of the Market*

A significant initiative currently undertaken by the IESO is the development of a capacity auction through the stakeholder engagement process.[128] Generally, the IESO is looking to design a capacity auction that will introduce a market-based mechanism for new and existing technologies to compete to meet Ontario’s future resource needs. As the IESO has noted, despite best intentions, experience shows us that locking in the future through centralized procurement and long-term contracts can result in challenges for the near term if demand and supply differ from forecasts. Those risks, as well the costs of inefficient allocation of resources, are currently borne and paid for by Ontario consumers. A properly designed capacity auction could provide a more efficient, market-based alternative.

The Panel supports the IESO’s efforts to explore competitive market-based alternatives to the centralized procurement model, and will monitor the developments throughout the stakeholder engagement process.

[128] For more information see the IESO’s Capacity Auction stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Capacity-Auction.aspx

The IESO has also commenced a stakeholder engagement on demand response auctions.[129] This initiative will precede the capacity auction and is viewed by the IESO as an interim step at developing the province's demand response capabilities in advance of a full capacity auction.

At the request of the Minister of Energy, the Ontario Power Authority and the IESO launched a stakeholder engagement to identify any opportunities that might exist at Ontario interties to support the supply and reliability requirements of the power system. More specifically, possibilities such as firm capacity and energy import contracts are being considered[130], as well as improved coordination between jurisdictions, including more frequent intertie scheduling and the provision of ancillary services through intertie transactions. Given the impact of intertie transactions on pricing, operability and total system costs in Ontario, the Panel is keenly interested in this topic and will continue to monitor the developments throughout the stakeholder engagement process.

In January 2014 the IESO concluded their stakeholder engagement on the Global Adjustment (SE-106).[131] The consultation culminated with the publication of a report entitled, "Global Adjustment Review", which was produced for the IESO by Navigant Consulting. The report reviews the current allocation of Global Adjustment costs and identifies options that may allow for greater responsiveness from customers. One alternative considered was the expansion of the current high-5 methodology for allocating Global Adjustment costs. The Navigant report concluded this would increase short-term efficiency and would improve equity and fairness (compared to the then-current high-5 allocation methodology limited to consumers with demand above 5 MW).

Since that report was published, the high-5 allocation of the Global Adjustment has been expanded to include some consumers with demand over 3 MW who choose to opt-in to the program. In Chapter 3 of this report the Panel reviews the response of Direct Class A

[129] For more information see the IESO's demand response auction stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Demand-Response-Auction.aspx

[130] The IESO has recently reached a 10-year agreement with Hydro Québec that will see Québec reserve 500 MW of firm capacity for export to Ontario during the summer months, and Ontario reserve 500 MW worth of firm capacity for export to Québec during the winter months. For more information see the "Backgrounder" provided on the Province of Ontario website, available at: http://news.ontario.ca/opo/en/2014/11/joint-memorandum-seasonal-exchange-of-electricity-capacity-between-ontario-and-quebec.html

[131] For more information see the IESO's Global Adjustment stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-106.aspx

consumers to the high-5 allocation of the Global Adjustment, and will continue to monitor participants' responses in the future.

In the course of SE-111, the IESO's ongoing review of generation cost guarantee programs,[132] the Panel submitted written comments regarding the proposed options for addressing self-induced ramp down CMSC payments.[133] The Panel's submissions addressed the IESO's proposed rule-based solutions, some of which continued to use participant offers and CMSC (or a like payment) as a mechanism to compensate generators for the costs associated with ramping down. In response to the IESO's proposed solution the Panel noted its view that any offer-based compensation mechanism that is not subject to competitive forces, could be gamed, and adds further complexity to an already complicated set of market rules. The IESO indicated that it will go forward with its proposed offer-based solution, while committing to modify the Market Rules to address some of the Panel's gaming concerns. The proposed Market Rule amendment associated with the IESO's solution was presented to the Technical Panel on February 24, 2014, which voted that the amendment warrants further consideration. The Panel will continue to monitor the developments throughout the Market Rule making process.

3 *Panel Commentary on Responses to Prior Reports*

Following the release of each of the Panel's semi-annual monitoring reports, the Ontario Energy Board posts on its website the IESO's responses to any Panel recommendations that have been directed to it.[134]

The Panel's September 2014 Monitoring Report[135] contained two recommendations, one related to transparency of the basis for IESO decisions to de-rate Control Action Operating Reserve

[132] For more information see the IESO's generation cost guarantee programs stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-111.aspx

[133] The Panel's submissions are available at: http://www.ieso.ca/Documents/consult/se111/SE111-20141010-MSP.pdf and http://www.ieso.ca/Documents/consult/se111/SE111-20141212-MSP.pdf

[134] The IESO's response to the recommendations in the Panel's September 2014 Monitoring Report are set out in a letter on the Ontario Energy Board's website, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_Letter_MSP_Report_20141015.pdf The IESO historically maintained an updated listing of its responses to Panel recommendations. This has been integrated into the annual update that the IESO is now required, as a condition of licence, to provide the Ontario Energy Board. The annual update describes the status of the IESO's work on Panel recommendations made within the past five years. The first such annual update was filed with the Ontario Energy Board in December 2013, and on the IESO's website, available at http://ieso-public.sharepoint.com/Pages/Participate/Market-Oversight/Monitoring.aspx.

("CAOR") and the other related to exports and the allocation of uplift associated with recovering the costs of the IESO's generator cost guarantee programs. The IESO's responses to those recommendations are set out in Table 4-1.

Table 4-1: IESO Responses to Recommendations in the Panel's September 2014 Monitoring Report

Recommendation	IESO Response
Recommendation 3-1 *The Panel recommends that the IESO make more information available to market participants about its practices of de-rating Control Action Operating Reserve, including the criteria used to determine the amount and duration of such de-ratings.*	"The IESO agrees with the Panel's recommendation that more information should be made available to market participants with respect to CAOR de-ratings. The IESO is currently developing a proposal for communicating these de-ratings to the market. The proposal will be available for stakeholder input through the change management/baseline process. Changes will be incorporated into applicable IESO reports and market manuals by the end of 2014."
Recommendation 3-2 *The Panel recommends that the IESO revise the way it allocates uplift charges associated with top-up payments under the real-time generation cost guarantee and day-ahead production cost guarantee programs so that the charges to Ontario consumers and to exporters better reflect the extent to which each group causes those payments to be incurred.*	"The IESO agrees that the current allocation of uplift charges associated with top-up payments under the RT-GCG and DA-PCG programs can result in cross subsidization between exports and Ontario consumers. The IESO intends to assess the net benefit to the Ontario market of allocating charges to exports in a way that would better reflect the extent to which exports cause those charges to be incurred. The assessment is expected to be completed by the end of Q2 2015. The IESO previously agreed to assess the feasibility of recommendation 3-3 (b) from the Panel's January 2014 report/ which recommends that the IESO "include a forecast of exports when commitments are made under EDAC." The IESO will conduct this assessment in coordination with the assessment for recommendation 3-2, as the outcome and/or potential implementation of recommendation 3-2 would impact the need to develop a forecast of exports for integration into the day-ahead commitment process. As such, a response to recommendation 3-3(b) from January 2014 will now be provided upon the completion of the IESO'S assessment of recommendation 3-2 and its dynamic impact on exports."

[135] See the Panel's September 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf

4 *Panel Commentary on IESO Responses*

Recommendation 3-1

The Panel understands that the IESO has responded to this recommendation by formalizing the process by which it communicates de-ratings of CAOR. The new process can be found in Section 1.4.1 and 1.4.2 of Market Manual 7.2: Near-Term Assessments and Reports.

Recommendation 3-2

The Panel supports the IESO's efforts to assess the net benefit to the Ontario market of allocating charges to exports in a way that would better reflect the extent to which exports cause those charges to be incurred.

In the Panel's September 2014 Monitoring Report it recognized the interplay between recommendation 3-2 of that report and recommendation 3-3(b) from the Panel's January 2014 Monitoring Report. The Panel agrees that the recommendations should be addressed with due consideration to one another, not in isolation.

5 *Recommendations in this Report*

Recommendation 3-1

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.