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



Monitoring Report on the IESO-Administered Electricity Markets

for the period from May 2015 – October 2015

November 2016

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Executive Summary

Matters to Report in the Ontario Electricity Marketplace Review of Generation Cost Guarantee Program

In this report the Panel provides a more comprehensive overview of issues associated with the Independent Electricity System Operator's (the IESO) Real-Time Generation Cost Guarantee (RT-GCG) program under which guarantees are paid to certain gas-fired generators for start-up and operations costs. This program has been the subject of long-standing interest and past Panel commentary, and has recently been under review in an IESO stakeholder engagement. The Panel actively participated in that stakeholder engagement.

At the most fundamental level, the Panel questions the extent to which the RT-GCG program is truly necessary to serve a reliability purpose. The Panel's analysis suggests that starts under the program support reliability in only a small number of hours each year. The IESO has not provided any analysis of the continued need for the program, although the Panel has recommended on more than one occasion that such an analysis be done.

The Panel acknowledges that the IESO has to manage changing conditions between day-ahead and real-time. The Panel also acknowledges that the IESO is deferring a comprehensive overhaul of the RT-GCG program in favour of a longer-term solution in the form of an enhanced intra-day unit commitment program. However, by the IESO's own admission that solution is several years away. While the Panel is supportive of a comprehensive overhaul of the program, it is unclear to the Panel why changes to the program that have the potential to save millions in costs should not be made now pending the implementation of the more enduring solution.

Two changes in particular appear to the Panel to be desirable in the near term. First, the Panel believes that there is no demonstrable need for the RT-GCG program to guarantee start-up operations and maintenance costs in order to achieve the objective of incenting generators to come online to support reliability. Second, in the Panel's view it is similarly unnecessary for a generator to recover all of its costs through revenues earned in the market and yet still receive a guarantee payment under the RT-GCG program. Changes to these two elements of the RT-GCG program alone would, by the Panel's estimation, reduce RT-GCG payments to generators by

approximately \$40 million per year in the aggregate. These savings would ultimately avail to the benefit of Ontario ratepayers.

Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.

Recommendation 3-2

The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all congestion management settlement credit payments received, on:

(a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and

(b) output generated after the end of the facility's MGBRT.

Review of the Efficiency of Intertie Trading given Ontario's Two-Schedule System

This report contains the Panel's analysis of how Ontario's two-schedule, single price system is contributing to the inefficiency of intertie trading with Ontario's neighbours. Since the two-schedule system (prices and schedules are determined by two different algorithms) can create a difference between the price paid for energy and the cost of producing it, exports of power are inefficient when the price exporters pay is less than the cost of producing power.

The Panel has assessed the extent to which inefficient trades are created as a by-product of the two-schedule system, finding that there are opportunities to reduce inefficient trade by, for example, pricing intertie transactions at the cost of production at the intertie. The IESO has initiated work on a Market Renewal stakeholder engagement, in which it plans to examine opportunities to improve efficiency by replacing the two-schedule system, including through the introduction of locational marginal pricing. The Panel strongly supports this work.

Market Outcomes

The Panel's review and analysis of market outcomes covers the period from May 1, 2015 to October 31, 2015 (the Current Reporting Period).

High HOEPs and Uplift Payments

In the Current Reporting Period there were nine instances where the Hourly Ontario Energy Price (HOEP) was above \$200/MWh and 15 instances where Operating Reserve (OR) payments in an hour were above \$100,000. All but one of the high OR payments, and all of the high HOEP events, were associated with shortages of dispatchable capacity resulting from errors in the forecast of production from renewable resources.

The forecast errors associated with these events arose when production from renewable resources was less than forecast, a situation which requires other resources to respond on short notice to provide additional energy. Since these forecast errors only emerge in real-time, the IESO must often dispatch higher cost, fast responding resources to make up the shortfall. Frequently the resources which are available to respond are those which have been scheduled to provide operating reserve (that is, capacity that is held on standby to ensure reliability in the event of a large generator or transmission line going offline). When the resources scheduled for OR are dispatched to provide energy in response to forecast errors, there may not be enough other capacity online to meet both the energy demand and the OR requirement. In some cases the IESO has experienced an OR shortfall, in which case both energy and OR prices increase to reflect the scarcity of dispatchable capacity.

The IESO has launched a stakeholder engagement to develop solutions that will provide additional real-time flexibility when forecast errors require a response within one hour or less. The IESO has articulated principles by which it will evaluate proposed solutions, including transparency, cost-effectiveness, and creating an enduring solution. One option that would help to mitigate the impact of forecast errors is more frequent intertie scheduling. Currently, intertie schedules are fixed for one hour. Allowing intertie schedules to adjust within the hour would give the IESO greater dispatch flexibility to manage forecast errors. As Ontario is frequently a net exporter, reducing exports when the IESO experiences a scarcity of dispatchable capacity would help the IESO respond to forecast errors that otherwise require the dispatch of more expensive resources.

An additional issue the Panel has identified is the real-time pricing of operating reserve, which the Panel believes could be improved to more transparently reflect the increasing value of operating reserve as more OR resources are needed. The IESO offers Control Action Operating Reserve (CAOR) into the OR market in large blocks, which can mask the increasing value of OR as more CAOR is scheduled. The Panel has made one recommendation to the IESO to consider whether the transparency and effectiveness of OR price signals could be enhanced.

Recommendation 2-1

Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.

Demand and Supply Conditions

In 2015 Ontario electricity demand peaked for the third consecutive year in the winter, reaching total consumption of over 13.5 TWh over the month of January. In the Current Reporting Period, the peak in monthly demand occurred in July at 12.6 TWh.

408.5 MW of nameplate generating capacity was added to the grid over the Current Reporting Period, consisting of wind (308.5 MW) and solar (100 MW) resources. In addition, 237 MW of nameplate generating capacity was connected at the distribution level.

Market Prices and Effective Prices

In the Current Reporting Period, the average effective price increased to \$60.00/MWh for Direct Class A consumers and to \$104.93/MW for Class B & Embedded Class A consumers. The primary factor behind the higher average effective prices was an increase in the Global Adjustment (GA). Direct Class A consumers saw the average GA increase by over \$8.00/MWh

while Class B & Embedded Class A consumers experienced an average GA increase of over \$14.00/MWh.

The Current Reporting Period saw two of the three highest monthly effective electricity prices for Class B & Embedded Class A consumers since market opening, reaching \$111.77/MWh in May and \$110.19/MWh in June.

The Panel has previously identified a need to obtain more data on the consumption of Class A consumers embedded within distribution systems. This data is not currently in the hands of the Panel, the IESO or the Ontario Energy Board. Without this data, the Panel cannot accurately track the effective price paid by Class A consumers as whole, as a number of Class A consumers are embedded within distribution systems.

Generation connected at the distribution level is an increasingly important component of Ontario's power supply, yet there is little real-time data regarding supply from these facilities. The Panel has identified a similar need to obtain data on production from embedded generation resources. Embedded resources include variable generators (primarily wind and solar powered generators) that feed into the distribution system and behind-the-meter generators that satisfy on-site demand. These resources reduce the level of demand on the IESO-controlled grid, and without data on their production it is challenging to accurately track changes in demand for electricity. In addition, Class A consumers connected at either the transmission or distribution level have a strong incentive to reduce their peak demand by reducing consumption or through self-generation. The Panel will continue to explore options that may be available to enable the collection and analysis of real-time data on embedded Class A consumption and embedded generation.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between May 1, 2015 and October 31, 2015 (the Current Reporting Period), with comparisons to the period between November 1, 2014 and April 30, 2015 (the Previous Reporting Period) and other periods where relevant.

1 Pricing

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

Table 1-1: Average Effective Price by Consumer Class November 2014- April 2015 & May 2015 – October 2015 (\$/MWh)

Description:

Table 1-1 summarizes the average effective price¹ by consumer class for the Current Reporting Period and the Previous Reporting Period. The average effective price is the sum of the average HOEP, the average Global Adjustment (GA), and average uplift charges. Results are reported for three consumer groups: Class A consumers that are directly connected to the IESO-controlled grid (Direct Class A); Class A consumers that are connected at the distribution level (Embedded Class A) and Class B consumers (Class B & Embedded Class A);² and "All Consumers", which is provided for reference purposes and represents what the effective price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. Information pertaining to Embedded Class A consumers is aggregated with information pertaining to Class B consumers because information regarding hourly consumption by Embedded Class A consumers relates only to Direct Class A consumers.

¹ This price does not include delivery, regulatory or debt retirement charges.

² Aggregating Class B consumers with embedded Class A consumers has the effect of under-representing the average effective price paid by Class B consumers, as the lower prices paid by Embedded Class A consumers reduces the average.

Customer Class	Average HOEP (\$/MWh)	Average Global Adjustment (\$/MWh)	Average Uplift (\$/MWh)	Average Effective Price (\$/MWh)
Direct Class A – Current*	21.07	36.53	2.40	60.00
Direct Class A - Previous	25.96	28.17	2.54	56.68
Class B & Embedded Class A - Current	22.76	79.53	2.64	104.93
Class B & Embedded Class A - Previous	28.19	65.11	2.78	96.07
All Consumers - Current	22.56	74.38	2.61	99.56
All Consumers - Previous	27.94	60.97	2.74	91.66

*Current means the Current Reporting Period and Previous means the Previous Reporting Period.

Relevance:

In Ontario, the effective price a consumer pays for electricity depends on its consumer class. Consumers are divided into two groups for purposes of the allocation of the GA: Class A— consumers with an average peak demand between 3 MW and 5 MW³ that fall within certain industrial classifications and consumers with consumption greater than 5 MW (these consumers, 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—all other consumers (including, for example, all small commercial and residential consumers).⁴ Since January 2011, the GA payable by a Class A consumer is determined based on their peak demand factor, which is the ratio of the consumer's electricity consumption during the five peak hours in a year relative to total consumption by all consumers in each of those hours. The GA payable by a Class B consumer is, and has always been, based on the consumer's consumption during the period.⁵

Many Class B consumers—those that use less than 250,000 kWh of electricity per year and some others—are eligible for the Regulated Price Plan (RPP) prices set by the Ontario Energy Board (OEB). They pay those prices unless they choose to enter into a contract with an electricity retailer (in which case they pay the contract price) or they opt out of the RPP. The commodity

³ Effective July 1, 2015, Class A was expanded to include certain consumers with a peak demand greater than 3 MW but less than or equal to 5 MW. As this expansion occurred mid-reporting period, a weighted average of the calculation was used for the Current Reporting Period results.

⁴ See Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*, available at: <u>http://www.ontario.ca/laws/regulation/040429</u>.

⁵ For more information on the GA allocation methodology and its effect on each consumer class see the Panel's June 2013 Monitoring Report, pages 69-92, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2012-Oct2012_20130621.pdf</u>

price payable by Class B consumers that are not eligible for the RPP or that opt out of the RPP depends on their meter. If they have an interval meter, they pay the HOEP. If they do not have an interval meter, they pay a weighted average HOEP based on the net system load profile in their distributor's service area. For consumers that are not on the RPP, the GA appears as a separate line item on their electricity bill. Since RPP prices include a forecast of the GA, the GA is not a separate item on RPP consumer bills.

The GA primarily recovers the cost of payments to contracted and regulated generating resources when market revenues are insufficient to cover their contracted or regulated rates.⁶ The HOEP and the GA are inversely proportional, as the recovery of contract and regulated payments through the GA to generators generally increases if market revenues decrease. When market prices rise, the amount of the contract or regulated payments to be recovered through the GA declines.

In the Panel's April 2015 Monitoring Report,⁷ the need to obtain hourly generation and consumption data was discussed, specifically pertaining to embedded generation, behind-themeter generation and consumption by Embedded Class A consumers. This data is not currently in the hands of the Panel, the IESO or the OEB. The Panel noted that assessing the impacts of certain market changes is difficult, if not impossible, without this hourly generation and consumption data.

Specifically, without this data, the Panel cannot accurately track the effective price paid by Class A consumers as whole, as a number of Class A consumers are embedded within distribution systems. In addition, Class A consumers connected at either the transmission or distribution level have a strong incentive to reduce their peak demand by reducing consumption or through self-generation. The Panel is therefore also interested in ascertaining the impacts of the GA allocation methodology on Class A consumption patterns. Access to hourly data for embedded Class A consumers and behind-the-meter generation is required for these purposes.

⁶ The costs associated with compensating loads under the IESO's demand response programs and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: <u>http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx</u>

⁷ For more information on this topic see pages 105-109 of the Panel's April 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf</u>

Generation connected at the distribution level is an increasingly important component of Ontario's power supply, yet there is little real-time data regarding supply from these facilities. The Panel has identified a need to obtain data on production from embedded generation resources. Embedded resources include variable generators (primarily wind and solar powered generators) that feed into the distribution system, and behind-the-meter generators that satisfy on-site demand. These resources reduce the level of demand on the IESO- controlled gird, and without data on their production it is challenging to accurately track changes in demand for electricity.

The Panel will continue to explore options that may be available to enable the collection and analysis of real-time data on embedded Class A consumption and embedded generation.

Commentary and Market Considerations:

The average effective price increased for both Direct Class A consumers and Class B & Embedded Class A consumers during the Current Reporting Period relative to the Previous Reporting Period and to the May to October period in 2014 (the Summer 2014 Period).⁸ The average effective price for both consumer classes was approximately \$11.00/MWh greater in the Current Reporting Period than in the Summer 2014 Period.⁹

The GA was the primary driver behind the increase in the effective price for both consumer classes; reductions in the average HOEP and the average uplift relative to the Previous Reporting Period were more than offset by increases in the average GA as also shown in Figures 1-2A and 1-2B.

Relative to the Previous Reporting Period, Direct Class A consumers saw the average GA increase by over \$8.00/MWh while Class B & Embedded Class A consumers experienced an average GA increase of over \$14.00/MWh. As illustrated in Figure 1-10 below, this increase is primarily attributable to increased payments to prescribed or contracted hydroelectric generators

⁸ The expansion of Class A as noted in the Description section above affects the comparability of prices between the Current and Previous Reporting Periods as some consumers that were formerly included in Class B price calculations have been included in the Class A price calculations as of July 1, 2015.

⁹ For more information on the effective price in the Summer 2014 Period see pages 6-8 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf</u>

and renewable power contract holders, as well as increased payments under the IESO's conservation programs.

Figure 1-1: Monthly Average Effective Price and System Cost November 2010 – October 2015 (\$/MWh & \$)

Description:

Figure 1-1 plots the monthly average effective price for Direct Class A and Class B & Embedded Class A consumers, as well as the monthly average system cost¹⁰ (System Cost), for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This Figure highlights the changes in the effective price paid by each consumer class over the past five years, as well as the changes in System Cost.

Commentary and Market Considerations:

¹⁰ The System Cost is the sum of the HOEP, the GA and the uplift charges paid by consumers in a given month. It does not account for any amounts paid by exporters.

The Current Reporting Period saw two of the three highest average monthly effective prices for Class B & Embedded Class A consumers (May at \$111.77/ MWh and June at \$110.19/ MWh), as well as two of the three highest average monthly System Cost (July at \$1.189 billion and August at \$1.175 billion), since market opening.

Within the Current Reporting Period, the two highest monthly effective prices for Class B & Embedded Class A consumers corresponded with the two lowest monthly effective prices for Direct Class A consumers. This highlights the continued trend that has been observed since January, 2011 when the GA allocation methodology was changed, shifting a greater portion of the GA to Class B consumers.

A lower HOEP results in the GA accounting for a greater portion of total System Cost. Class B consumers bear a greater portion of that total as Class A consumers are incented to reduce consumption during hours of peak system demand to minimize the amount of the GA they are charged. The GA avoided by Class A consumers is allocated to Class B consumers.

The HOEP was lowest during the first two months of the Current Reporting Period (see Figure 1-3 below). As the HOEP increased through the summer and into the fall, the Class B & Embedded Class A effective price decreased and the Direct Class A effective price increased. For Direct Class A consumers, September was the highest-priced month of the Current Reporting Period at an effective price of \$66.92/MWh. This represents the fifth highest-priced month since the change in the GA allocation methodology in January 2011.

Total System Cost in the Current Reporting Period peaked in July and declined for three consecutive months beginning in August, most notably in September and October. The primary driver for the decline was a reduction in nuclear output relative to the Summer 2014 Period due to long term planned outages taken at one of Ontario's nuclear facilities beginning in early September and lasting through the end of October (see Figure 1-10 below). The contribution of nuclear facilities to the GA began to rise again in October. The resulting increase in the GA was offset by lower uplift and a lower HOEP in October (see Figure 1-2A and 1-2B below).

Figures 1-2A & 1-2B: Average Effective Price by Consumer Class and by Component

Description:

Figures 1-2A and 1-2B divide the monthly average effective price into its three components (average HOEP, average GA, and average uplift charges) for Direct Class A and Class B & Embedded Class A consumers for the previous two years.

As noted previously, the GA and the HOEP typically have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A consumers respond to that methodology are responsible for the significant difference in the average effective price paid by each consumer group. As the GA is charged to Class A consumers based on their share of peak load during the five hours with the highest total demand in a 12-month base period,¹¹ Class A consumers can substantially reduce their GA by reducing their consumption during these hours. When the average GA makes up an increasing portion of System Cost the average effective price paid by Class B consumers increases proportionately more than that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

¹¹ Each base period runs from May 1 in one year to April 30 in the following year. The GA allocation for the Current Reporting Period is based on the base period from May 2014 to April 2015.





*PRP: Previous Reporting Period. CRP: Current Reporting Period.



Figure 1-2B: Average Effective Price for Class B & Embedded Class A Consumers by Component November 2013 – October 2015 (\$/MWh)

*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

Commentary and Market Considerations:

The impact of the change in the GA allocation methodology introduced in 2011 is evident in the Current Reporting Period; while the GA was the predominant component of the effective price paid by each consumer class, the average effective price for Class B and Embedded Class A consumers was nearly 75% higher than that of Class A consumers. As the HOEP rose from June through September, the effective price for Class B & Embedded Class A consumers exhibited a general downward trend, while the effective price for Direct Class A consumers exhibited an upward trend, save for October.

The Current Reporting Period marked the first time since market opening that the effective price for Class B & Embedded Class A consumers exceeded \$100/MWh throughout the entire period. Class B & Embedded Class A consumers experienced the highest average effective price for a reporting period since market opening, while Direct Class A consumers experienced the second highest average effective price in any reporting period.

Figure 1-3: Monthly (Simple) Average HOEP November 2013 – October 2015 (\$/MWh)

Description:



Figure 1-3 displays the simple monthly average HOEP for the previous two years.

*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The HOEP is the market price for a given hour and is one component of the effective price paid by consumers. The HOEP is the simple average of the twelve Market Clearing Prices (MCPs) within the hour that are set every five minutes by balancing supply and demand. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's RPP.

Commentary and Market Considerations:

The average HOEP in the Current Reporting Period was \$20.75/MWh; nearly \$5.00/MWh lower than in the Previous Reporting Period and almost \$3.00/MWh greater than in the Summer 2014 Period.¹² Relative to the Previous Reporting Period, the lower average HOEP is to be expected given the lower demand in the Current Reporting Period (70.24 TWh vs 74.34 TWh in the Previous Reporting Period). This outcome can largely be attributed to higher demand associated with the extreme cold weather experienced in the Previous Reporting Period.

Relative to the Summer 2014 Period, demand in the Current Reporting Period was only slightly higher (< 1 TWh) but a difference in the available supply mix between the two Periods contributed to a notable difference in monthly average outcomes relative to the Summer 2014 Period. Planned outages of number of Ontario's nuclear generators removed a significant portion of baseload supply from the supply mix in the Current Reporting Period. September and October were the two lowest-priced months of the Summer 2014 Period, but represented the two highest-priced months in the Current Reporting Period.

Figure 1-4: Average Monthly Dawn Hub Day-Ahead Natural Gas Price and Average Monthly On-peak HOEP November 2010 – October 2015 (\$/MWh & \$/MMBtu)

Description:

Figure 1-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours, for the previous five years.

¹² For more information regarding the monthly average HOEP in the Summer 2014 Period, see pages 12 – 14 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

Commentary and Market Considerations:

In the four years prior to the Current Reporting Period, movements in the average Dawn Hub gas price and the average on-peak HOEP have been highly correlated; the correlation coefficient between the two variables was 0.71. The average day-ahead gas price decreased in the Current Reporting Period to \$3.72/MMBtu relative to the Previous Reporting Period (\$4.46/MMBtu). The HOEP experienced a similar decline in the Current Reporting Period (see Figure 1-3). The higher average on-peak HOEP in the Previous Reporting Period is attributable to higher electricity demand due to extreme cold temperatures and, in turn, greater demand for gas.

The correlation coefficient between the HOEP and the day-ahead gas price in the Current Reporting Period was 0.20. The two variables were weakly correlated in the Current Reporting Period, relative to the trend of the four years prior, despite gas-fired generators setting the real-time MCP in over 40% of all intervals (see Figure 1-6 below). This may be most attributable to the lack of volatility in the average Dawn Hub gas price relative to the average on-peak HOEP during the Current Reporting Period.¹³ The average Dawn Hub gas price exhibited far less volatility than did the average on-peak HOEP, resulting in a weak correlation between the two variables.

Figure 1-5: Frequency Distribution of HOEP November 2014 – April 2015 & May 2015 – October 2015 (% of hours, \$/MWh)

Description:

Figure 1-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Current Reporting Period and the Previous Reporting Period. The HOEP is grouped in \$10/MWh increments (for example, the \$30/MWh group includes all HOEPs between \$20/MWh and \$30/MWh), save for all negative HOEPs which are grouped together with all \$0/MWh values in the category <=\$0/MWh.

¹³ The coefficients of variation for the average Dawn Hub gas price and average on-peak HOEP in the Current Reporting Period were 0.16 and 0.50, respectively. In the Previous Reporting Period the coefficients of variation were 0.51 and 0.86, respectively, and in the four years prior to the Current Reporting period they were 0.71 and 0.74, respectively. These results are consistent with the correlation coefficients of the respective time periods; the two variables are more strongly correlated when they exhibit similar levels of variation and are more weakly correlated when one of the variables exhibits greater variation than the other.



*Current means the Current Reporting Period and Previous means the Previous Reporting Period.

Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, and provides information regarding the frequency of extremely high or low prices.

Commentary and Market Considerations:

The distribution of the HOEP in the Current Reporting Period was broader than in the Summer 2014 Period, but narrower than in the Previous Reporting Period. The standard deviation of the HOEP in each period is as follows: \$20.89/MWh (Summer 2014 Period), \$42.14/MWh (Previous Reporting Period), and \$31.35/MWh (Current Reporting Period). These standard deviations indicate that the HOEP was more volatile in the Current Reporting Period than in the Summer 2014 Period, but less so than in the Previous Reporting Period. The decrease in volatility relative to the Previous Reporting Period can largely be attributed to the wide range of weather Ontario experienced in the Previous Reporting Period; in particular, Southern Ontario experienced stretches of unseasonably mild temperatures as well as periods of extreme cold temperatures in the Previous Reporting Period.

The increase in the volatility of the HOEP relative to the Summer 2014 Period is in large part attributable to the reduction in baseload supply in the last two months of the Current Reporting Period. The reduction in nuclear supply due to planned outages decreased the number of hours of negative HOEPs in the Current Reporting Period relative to the Summer 2014 Period, and put upward pressure on the HOEP in the later months of the Current Reporting Period.¹⁴

Figure 1-6: Share of Resource Type setting Real-Time Market Clearing Price November 2013 - October 2015 (% of intervals)

Description:

Figure 1-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

¹⁴ For more information regarding the frequency distribution of the HOEP in the Summer 2014 Period, see page 16 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Commentary and Market Considerations:

The previously mentioned long-term nuclear outages affected the frequency with which each fuel type set the MCP in the Current Reporting Period. Nuclear, wind and hydroelectric resources are most likely to set the MCP during the shoulder seasons when demand is low and Ontario often experiences surplus baseload generation (SBG) conditions.¹⁵ However, in the Current Reporting Period, gas-fired resources set the MCP most often in September and October as gas-fired units were more frequently needed to compensate for the reduction in Ontario's baseload supply.

During September and October of the Summer 2014 Period, gas-fired units set the MCP in 9.7% of all intervals.¹⁶ In September and October of the Current Reporting Period, gas-fired units set the MCP in 62.6% of all intervals. For the entire Current Reporting Period, gas-fired units set the MCP in 42.6% of all intervals, hydroelectric resources set the MCP in 42.2% of all intervals, and nuclear units set the MCP in 6.9% of all intervals. In the remaining intervals, bio-fuel or dispatchable wind and solar resources were setting the MCP.

Figure 1-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price November 2013 - October 2015 (% of hours)

Description:

Figure 1-7 presents the monthly share of hours in which each resource type set the hour-ahead pre-dispatch (PD-1) MCP, for the previous two years.

¹⁵ SBG conditions arise when baseload generation (comprised of combined heat and power, embedded generation, non-utulity generators, nuclear, must-run hydroelectric, solar, wind, and commissioning units) is greater than Ontario demand and forecasted exports. For a description of facilities that are classified as baseload, see: <u>http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20120808-SBG_Explanation_FPFG.pdf</u>.

¹⁶ For more information on resources setting the real-time MCP in the Summer 2014 Period see pages 16 - 18 of the Panel's October 2015 Monitoring Report, available at:

http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

When compared with Figure 1-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 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 PD-1 MCP, as these transactions are unable to set the real-time MCP.¹⁷ When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Similar to the situation described in the Commentary section associated with Figure 1-6, the reduction in baseload supply in September and October of the Current Reporting Period led to an increase in high-priced resources setting the PD-1 MCP in those months. The most notable result, relative to the Summer 2014 Period, is the frequency with which gas-fired generators set

¹⁷ Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour and their prices are adjusted in real-time to -\$2,000 and \$2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time.

Figure 1-8: Difference between the HOEP and the One-Hour Ahead Pre-Dispatch Price November 2014 – April 2015 & May 2015 – October 2015 (% of hours)

Description:

Figure 1-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Current and Previous Reporting Periods. The price differences are grouped in \$10/MWh increments, save for the \$0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded \$50/MWh is negligible and so is not included in Figure 1-8, and the same is true of Figure 1-9 in relation to the absolute difference between the three-hour ahead 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.

¹⁸ For more information on resources setting the one-hour ahead MCP in the Summer 2014 Period see pages 18 – 19 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf</u>



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. 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 that supply and demand conditions change from PD-1 to 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 is higher (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

Relative to the Previous Reporting Period, differences between the HOEP and the PD-1 MCP were narrower in the Current Reporting Period as the HOEP was within +/- \$20/MWh of the PD-1 MCP in 95.4% of all hours, compared to 89.4% in the Previous Reporting Period. This decrease in price volatility between the PD-1 MCP and the HOEP is confirmed by the Current Reporting Period's lower standard deviation (\$1.55/MWh) relative to the Previous Reporting Period (\$2.66/MWh). The distribution of differences between the HOEP and the PD-1 MCP in

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the Current Reporting Period was comparable to that in the Summer 2014 Period¹⁹, and the average absolute difference for the two periods was also similar (\$6.58/MWh in the Current Reporting Period and \$6.02/MWh in the Summer 2014 Period).

Table 1-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices May 2014 – October 2014, November 2014– April 2015 & May 2015 – October 2015 (MWh & % of Ontario Demand)

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

<u>Supply</u>

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

Demand

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

Metrics for all but one of these factors are presented in Table 1-2 as the average absolute difference between PD-1 and real-time. The effect of generator outages is not shown in this table as they tend to be infrequent, although short-notice outages can have significant price effects.

¹⁹ For more information regarding the difference between the HOEP and the PD-1 MCP in the Summer 2014 Period, see pages 19 – 21 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf

	Cur	rent	Previous		Summer 2014	
Factor	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	15,205		16,461		15,118	
Pre-dispatch to Real-time Demand Forecast Deviation	211	1.39	213	1.29	213	1.41
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	81	0.53	55	0.33	51	0.33
Wind Deviation	112	0.74	126	0.77	97	0.64
Net Export Failures/Curtailments	82	0.54	101	0.61	76	0.50

Relevance:

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

Commentary & Market Considerations:

The average absolute difference in demand forecast deviation has remained relatively constant throughout the last three reporting periods. In the Previous Reporting Period, demand forecast deviation represented a smaller portion of Ontario demand due to the higher average demand totals. The average absolute difference of wind deviation as a percentage of Ontario demand in the Current Reporting Period has increased relative to the Summer 2014 Period²⁰, and is likely to continue increasing as additional wind capacity continues to be added to Ontario's generation fleet.

²⁰ For more information regarding wind deviation in the Summer 2014 Period, see page 22 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014_20151008.pdf</u>

Figure 1-9: Difference between the HOEP and the Three-Hour Ahead Pre-Dispatch Price November 2014 – April 2015 & May 2015 – October 2015 (% of hours)

Description:

Figure 1-9 presents the frequency distribution of differences between the HOEP and the threehour ahead pre-dispatch (PD-3) MCP for the Current and Previous Reporting Periods. The price differences are grouped in \$10/MWh increments, save for the \$0/MWh category 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 the approval of the IESO.

Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick

start facilities and energy limited resources,²¹ both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

Similar to the results shown in Figure 1-8, the Current Reporting Period demonstrated a greater concentration of price differences within +/- \$20/MWh relative to the Previous Reporting Period. As evidenced by the lower standard deviation of price differences in the Current Reporting Period, less volatility existed between PD-3 and real-time than in the Previous Reporting Period.

As should be expected, differences between the PD-3 MCP and the HOEP were broader than differences between the PD-1 MCP and the HOEP in the Current Reporting Period; in approximately 82% of all hours the PD-3 MCP was within +/- \$10/MWh of the HOEP, while the PD-1 MCP was within the same range of the HOEP in approximately 86% of all hours. The PD-1 MCP and the PD-3 MCP both most commonly over-forecasted the real-time price. The most frequent occurrence in the Current Reporting Period was for the HOEP to clear between \$0.01/MWh and \$10/MWh less than the pre-dispatch forecasted MCP; this occurred in 49% of hours with respect to the PD-1 MCP and in 42% of hours with respect to the PD-3 MCP.

Figure 1-10: Monthly Global Adjustment by Component November 2013 – October 2015 (\$)

Description:

Figure 1-10 plots the revenue recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG's) nuclear assets);
- Payments to holders of Clean Energy Supply (CES) contracts and Combined Heat and Power (CHP) contracts;
- Payments to prescribed or contracted hydroelectric generation;

²¹ Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

- Payments to holders of contracts for renewable power (Feed-in Tariff (FIT), microFIT and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including under the IESO's demand response programs, to holders of non-utility generator contracts and under the contract with OPG's Lennox Generating Station)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

Commentary and Market Considerations:

Four of the five highest monthly GA totals since market opening occurred at the end of the Previous Reporting Period and the beginning of the Current Reporting Period (April through July), with June representing the second highest monthly GA total on record. FIT, micro-FIT and RESOP contributions to the GA continued to rise, as they surpassed \$200 million/month for the first time in April of 2015 and remained above that monthly level throughout the Current Reporting Period. As total renewable capacity in Ontario continues to grow, its proportional contribution to the GA is expected to continue increasing.

As noted in the Commentary associated with for Table 1-1, relative to the Summer 2014 Period increases in payments to hydroelectric and renewable generators and increases in conservation program payments were the primary factors leading to the higher GA in the Current Reporting Period. Relative to the Summer 2014 Period, these payments increased by the following amounts: \$243 million for hydroelectric generation; \$440 million for FIT, micro-FIT and RESOP generation; and \$86 million for conservation programs. This is the first reporting period in which total payments to holders of contracts under the FIT, micro-FIT and RESOP programs exceeded \$1 billion (\$1.4 billion), which is a product of the aforementioned increase in renewable power capacity in Ontario.²²

The decline in the GA at the end of the Current Reporting Period corresponds with the decrease in available nuclear supply due to the planned outages noted earlier. This decline in the GA also corresponds with an increase in the HOEP in September and October, which is consistent with the inverse relationship that typically exists between the HOEP and the GA. The HOEP was higher in those months and a greater portion of the compensation payable to generators was recovered through the market. In the Current Reporting Period, September saw the lowest total GA payments to most contracted or regulated generators and the highest monthly average HOEP.

Figure 1-11: Total Hourly Uplift By Component and Month November 2013 – October 2015 (\$)

Description:

Figure 1-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement

²² For more information regarding the monthly GA by component in the Summer 2014 Period, see page 25 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014_20151008.pdf</u>

Credit (CMSC) payments, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, Operating Reserve (OR) payments, voltage support payments, and losses.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Hourly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

Hourly Uplift attributable to OR declined throughout the Current Reporting Period, as was the case in the Summer 2014 Period, and was significantly lower than in the Previous Reporting Period. Demand in the Current Reporting Period was lower than in the Previous Reporting Period, which in general results in an increase in available OR supply. When less generation capacity is required to meet demand, more capacity is made available as OR supply, placing downward pressure on OR prices. Despite the decline in average OR prices, both OR prices and the HOEP have risen during times of operating reserve scarcity, a pattern which the Panel examines in greater detail in Chapter 2 of this report.
Similar to the HOEP, Hourly Uplift peaked in September during the Current Reporting Period, primarily driven by an increase in CMSC (\$11.8 million) and IOG (\$4.4 million) payments. In September, IOGs were the highest since the period between November 2013 – April 2014 (the Winter 2014 Period). Ontario was a net importer in 235 hours in September and repeatedly committed upwards of 1,500 MWh of imports, per hour, over evening peak periods through the Day-Ahead Commitment Process. By comparison, Ontario was a net importer in a total of 27 hours in the first four months of the Current Reporting Period and was not a net importer for any hour in September of the Summer 2014 Period.²³

Figure 1-12: Total Monthly Uplift by Component and Month November 2013 – October 2015 (\$)²⁴

Description:

Figure 1-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:²⁵

- Payments for ancillary services (i.e., regulation service, black start capability, monthly voltage support);
- Guarantee payments to generators —payments under the Day-Ahead Production Cost Guarantee (DA-PCG) and Real-Time Generation Cost Guarantee (RT-GCG) programs; and
- Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.

²³ Net import figures noted in this paragraph are based on unconstrained schedules.

²⁴ The Panel has changed the manner in which it allocates Monthly Uplift charges to more closely align reported costs with the month in which they were incurred rather than the month in which they were settled. This primarily impacts the monthly reported totals for payments under the Real-time Generation Cost Guarantee program. For example, in Figure 1-12 all costs submissions for that program for starts occurring between August 11 and September 9, 2015 were settled at the end of September. However, the bulk of the settlements pertain to starts that occurred in August 2015. The Panel now reports these costs to have occurred in August 2015 rather than September 2015. As a result of this change, monthly totals reported in this report will not be directly comparable to those previously reported by the Panel.

²⁵ The Monthly Uplifts in this figure are all uplifts that are charged other than on an hourly basis.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Monthly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

Monthly Uplift charges rose gradually through the first three months of the Current Reporting Period as demand increased with rising temperatures from spring to summer, and then more than doubled from July to August. The Monthly Uplift total of \$25.1 million in August was the highest since the Winter 2014 Period and was primarily driven by increases in RT-GCG payments (\$17.6 million).

This outcome is attributable to three cost submissions that occurred at the beginning of September. One submission associated with a single RT-GCG start represented 50% of all cost submissions for the settlement period. Two other individual submissions each represented 9.5% of total cost submissions. Chapter 2 provides additional information regarding RT-GCG submissions in the Current Reporting Period.

Figure 1-13: Average Monthly Operating Reserve Prices by Category November 2013 – October 2015 (\$/MW)

Description:

Figure 1-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30 minute (30R).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The total OR requirement, as specified in the reliability standards adopted by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council, is sufficient megawatts to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. These requirements ensure that the IESO- controlled grid can operate reliably.

Commentary and Market Considerations:

Average OR prices in the Current Reporting Period were less than half those in the Previous Reporting Period for each class of reserve. Average OR prices for the Current Reporting Period were \$5.53/MW, \$4.62/MW and \$2.79/MW for 10S, 10N and 30R respectively, compared to \$11.81/MW, \$10.71/MW and \$5.65/MW in the Previous Reporting Period. This outcome can be attributed in part to lower demand in the Current Reporting Period, increasing available supply in the OR markets in the vast majority of hours. Despite the decline in average prices, OR prices reached high levels in a few hours when the IESO ran short of OR in order to cover shortfalls in the energy market. This topic is covered in greater detail in Chapter 2.

Average OR prices were slightly lower in the Current Reporting Period relative to the Summer 2014 Period in both of the 10-minute reserve markets, and slightly higher in the 30-minute market. Similar to the Summer 2014 Period, 10-minute prices were highest in May. As reported in Chapter 2, nine of the fifteen anomalous OR payments in the Current Reporting Period occurred during the month of May.

In May of the Summer 2014 Period, voltage reduction was scheduled for a total of 40.4 GWh of OR, while hydroelectric generators were scheduled for a total of 455.4 GWh (representing hydroelectric's lowest monthly total for that period). In May of the Current Reporting Period, voltage reduction was scheduled for a total of 6.6 GWh while hydroelectric generators were scheduled for a total of 662 GWh (hydroelectric's highest monthly total of the Current Reporting Period), indicating less reliance on voltage reductions for OR relative to the same time in the previous year. Despite the increase in available OR supply from hydroelectric resources relative to the Summer 2014 period, the price for each class of OR peaked in May. This topic is also discussed in more detail in Chapter 2.

Contrary to the Summer 2014 Period, OR prices did not increase at the end of the Current Reporting Period. Gas-fired generation was online during the fall shoulder season more frequently than in years past (see Figure 1-6 and associated commentary), increasing the available OR supply and, in turn, placing downward pressure on average OR prices.²⁶

Figure 1-14: Average Internal Nodal Prices by Zone November 2014– April 2015 & May 2015 – October 2015 (\$/MWh)

Description:

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



²⁶ For more information regarding OR prices in the Summer 2014 Period, see pages 28 – 30 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014_20151008.pdf</u>

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal value of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, the supply conditions are relatively tight; in zones in which average nodal prices are low, the supply conditions are relatively more abundant.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is surplus low-cost generation (in excess of demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Other than in the Northeast zone, nodal prices predictably decreased in the Current Reporting Period as a result of lower demand relative to the Previous Reporting Period. Except for the Northeast and Northwest zones, nodal prices across the province tend to closely resemble each other and trend in the same direction, as was again the case in the Current Reporting Period.

The Northeast and Northwest zones often exhibit markedly different nodal price outcomes than the rest of the province for the reasons noted in the Relevance section above. The Northwest zone is a good example of this situation in the Current Reporting Period as its average nodal price trended in the same direction as the rest of the province, but was approximately \$125/MWh and \$140/MWh lower in the Previous and Current Reporting Periods, respectively. In the Current Reporting Period, and unlike the rest of the province, the nodal price in the Northeast zone increased relative to the Previous Reporting Period. One factor contributing to this outcome was a reduction in available supply due to increased levels of generator outages during the Current Reporting Period. The total installed generation capacity of dispatchable resources in the Northeast zone is approximately 3,460 MW. During the Current Reporting Period, an average of 701 MW of capacity per month was unavailable due to outages, compared to an average of 591 MW per month in the Previous Reporting Period. September and October had the two highest monthly totals of unavailable supply in the Northeast as a result of generator outages, which corresponded with the two highest monthly average nodal prices in the zone.

Figures 1-15 & 1-16: 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 for the previous two years.

Relevance:

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

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. 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 is lower than the MCP. 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 is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has

more energy transactions than available intertie transmission line capacity. The ICP is positive when there is export congestion and negative when there is import congestion. This is discussed in more detail in the Relevance section associated with Figure 1-17.

Figure 1-15: Import Congestion by Interface Group November 2013 – October 2015 (number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Québec²⁷ was the only interface to experience more than twenty hours of import congestion in any month in the Current Reporting Period, and did so in May and October. The number of import congested hours in those two months alone (113 hours) exceeded the total congested hours at the Québec interface in all months of the Previous Reporting Period and Summer 2014 Period combined (55 hours).²⁸

²⁷ Figures reported in Chapter 1 for Québec pertain exclusively to the Outaouais intertie, which is the largest commercial intertie, by capacity, between Ontario and Québec.

²⁸ For more information on import congestion in the Summer 2014 Period, see pages 33 – 34 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf</u>

Capacity on the Québec interface was restricted to half of its normal limit for much of May due to an extended outage, which led to an increase in congested hours without any material change in the level of import activity at that interface.

In October, Québec experienced more import congested hours than any other interface over the past three reporting periods. The increased frequency of import congestion in October was primarily driven by an increase in import activity. Both the total quantity of import offers and the average hourly quantity to be scheduled in the unconstrained sequence peaked in October. From May to August, the hourly average import quantity in the unconstrained sequence was less than 520 MW; in October the hourly average was 972 MW. With a large portion of Ontario's baseload supply unavailable due to outages, increased import activity was one means by which Ontario demand was met by alternative sources of supply.

Figure 1-16: Export Congestion by Interface Group November 2013 – October 2015 (number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Increased export congestion at the Manitoba interface is a trend that began occurring with increased regularity in September 2014²⁹ and that persisted through the Previous Reporting Period and the Current Reporting Period, relative to November 2013 through August 2014. Of the three most recent reporting periods, Manitoba experienced its highest number of congested hours in the Current Reporting Period.

Across all interfaces, export congestion sharply declined in September except at Québec which experienced only four export congested hours between July and October of the Current Reporting Period. The frequency of congested hours increased again in October at all interfaces except Québec, but remained below levels experienced in the earlier months of the Current Reporting Period. Historically, export congestion tends to increase as Ontario enters the fall shoulder season, but this trend was not observed in September and October of the Current Reporting Period; the three major interfaces by capacity - New York, Michigan and Québec – all experienced higher levels of export congestion during the same months of the Summer 2014 Period.

While the HOEP increased throughout the Current Reporting Period and peaked in September, it remained lower than prices in external jurisdictions to which Ontario power is typically exported. Comparing to prices in the three main external destinations for Ontario power (Midcontinent Independent System Operator at Michigan, New York Independent System Operator and PJM Interconnection LLC), the HOEP was still at least CAD\$7/MWh less expensive than in any of these other jurisdictions in September (see Table 1-3 below).³⁰ Lower export congestion in September and October of the Current Reporting Period corresponded with a decrease in the price difference between Ontario and those neighbouring jurisdictions in those two months.

²⁹ For more information regarding export congestion in the Summer 2014 Period, see pages 34 – 35 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014_20151008.pdf</u>

³⁰ For five days in September, export capacity at the New York interface was reduced by approximately 40%, but there were no other significant transmission limitations.

Table 1-3: Monthly Average Hourly Electricity Prices – Ontario and Neighbouring Jurisdictions May 2015 – October 2015 (\$/MWh)

Description:

Table 1-3 lists the average hourly real-time spot prices for electricity, by month, in Ontario and neighbouring jurisdictions that are the most active in terms of intertie trading.

The Ontario price reported is the HOEP. Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario. The external prices reported are the real-time Locational Marginal Prices (LMPs) that correspond with the node on the other side of Ontario's interface with each jurisdiction.

Month	Ontario	Manitoba ³¹	Michigan (MISO) ³²	Minnesota (MISO) ³³	New York (NYISO) ³⁴	PJM (PJM Interconnection LLC) ³⁵
May	14.22	20.93	34.45	25.36	26.48	35.24
June	14.20	24.67	33.54	26.91	19.61	31.39
July	20.25	29.30	36.20	32.52	27.03	36.61
August	21.87	29.11	35.74	31.71	30.00	34.29
September	29.86	28.26	36.92	31.09	37.78	38.18
October	24.11	20.44	33.47	24.67	27.53	31.56

Relevance:

One objective of intertie trading is to take advantage of arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.³⁶

³¹ The Panel assumed that the real-time LMPs at the 'MHEB' node published by MISO are representative of the external prices at the Manitoba interface.

³² The Panel assumed that the real-time LMPs at the 'ONT_DECO_PSOUT' node published by MISO are representative of the external prices at the Michigan interface.

³³ The Panel assumed that the real-time LMPs at the 'ONT_W' node published by MISO are representative of the external prices at the Minnesota interface.

³⁴ The Panel assumed that the real-time LMPs at the 'OH' node published by NYISO are representative of the external prices at the New York interface.

³⁵ The Panel assumed that the real-time LMPs at the 'IMO' node published by PJM are representative of the external prices in PJM that exporters can capture by wheeling through New York or Michigan.

³⁶ Differences exist in terms of the specific costs that are reflected in the spot price of electricity between jurisdictions. For example, in Ontario the HOEP is not reflective of a gas-fired generation unit's start-up costs, as these costs are settled through uplift. The specific components that comprise the spot price will vary from jurisdiction to jurisdiction, but they are still the most accurate and readily available indicators of economic decision-making in real-time for intertie traders.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will affect the direction of trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions, among other factors, can lead to intertie trades that appeared efficient ex-ante but appear inefficient or unprofitable ex-post. However, average prices over longer time horizons should be informative about trends in the direction of trade between jurisdictions. Over the course of a month, if the average electricity price in Ontario is lower than in another jurisdiction, trade should flow from Ontario to that jurisdiction in that month on a net basis.

As discussed in the Relevance section associated with Figures 1-15 and 1-16, importers and exporters in Ontario do not receive or pay the HOEP if congestion exists at an interface in a given hour. Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction. Nevertheless, the HOEP and the spot price in the external jurisdiction are two key pieces of information in determining whether to import or export from Ontario.

Commentary and Market Considerations:

As discussed above in the Commentary associated with Figure 1-16 and in the Commentary associated with Table 1-5 and Figures 1-25 and 1-26, Ontario experienced a significant reduction in net exports and a corresponding decrease in export congestion beginning in September of the Current Reporting Period relative to earlier months. Typically, as Ontario enters the fall shoulder season, domestic demand declines and prices decrease, which often leads to an increase in export activity, as was the case in the Summer 2014 Period.³⁷

The monthly average HOEPs in September and October were the highest of the Current Reporting Period. While those monthly average HOEPs were lower than in most neighbouring

³⁷ For more information regarding demand and export activity in the Summer 2014 Period, see pages 34-35, 44-46 and 50-51 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

jurisdictions³⁸ - suggesting the existence of arbitrage opportunities - net exports declined. This outcome can be attributed to a decline in the price differential between Ontario and its neighbouring jurisdictions in the same months, relative to months earlier in the Current Reporting Period; as the price differentials narrowed, arbitrage opportunities became less attractive, contributing to an overall decline in net exports and export congestion.

Figure 1-17: Import Congestion Rent & Transmission Rights Payouts by Interface Group May 2015 – October 2015 (\$)

Description:

Figure 1-17 compares the total collection of import congestion rent to total payouts under transmission rights (TRs) by interface group for the Current Reporting Period.



Relevance:

As discussed in the Relevance section associated with Figures 1-15 and 1-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1

³⁸ The average HOEP in September and October was greater than the external price at the Manitoba interface but lower than the external prices in all other neighbouring jurisdictions.

intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import congestion rent. Congestion rent accrues to the IESO's Transmission Rights clearing account (TR clearing account). This account is discussed in greater detail in the Relevance section associated with Figure 1-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or payout) equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. 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 payouts will exactly offset price differences between the Ontario price and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,³⁹ transaction failures and intertie de-ratings, there are congestion events in which a congestion rent shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing

 $^{^{39}}$ 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 that 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 (*e.g.*, import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.*, export). In this case, import TR payouts are made and negative import congestion rents are "collected".

Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.⁴⁰ In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers. In recent years, the IESO has taken to making more frequent disbursements from the TR Clearing Account.

Note that interties with a high frequency of import congestion hours (see Figure 1-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

Commentary and Market Consideration:

An excess of \$198,000 in import congestion rents, relative to TR payouts, was collected in relation to the Québec interface in the Current Reporting Period. This outcome was the product of the increase in import activity at the Québec interface in the last two months of the Period, primarily in October (see the Commentary associated with Figure 1-15). The quantity of TRs sold for the Québec interface's constant throughout the Current Reporting Period at 615 MW – half of the Québec interface's full capacity - while the level of import activity increased significantly at the end of the Current Reporting Period. Owning short-term TRs in October for the Québec interface was a profitable position as the relatively high rate of import congestion was coupled with the second lowest cost for a short-term TR in the Current and Previous Reporting Periods, at \$5/MW (see Table 1-5 below); a single MW of an import TR for the Québec interface yielded a return on investment of 15,090% in October.

⁴⁰ 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 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. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see pages 146-160 of the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report Nov2011-Apr2012_20130114.pdf

Description:

Figure 1-18 compares the total collection of export congestion rent to total TR payouts by interface group for the Current Reporting Period.



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 1-17, which describes the relationship between congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR clearing account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

Across all interfaces, export congestion rents collected were in excess of TR payouts by just over \$10 million, with the primary contributor being the Michigan interface which was the most

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heavily export congested interface in the Current Reporting Period (see Figure 1-16). The average export capacity of the Michigan interface exceeded average export TR ownership over the Current Reporting Period by 387 MW. This means that, on average, in hours where congestion existed, congestion rent was being collected on a greater quantity of MWs than those receiving TR payouts, resulting in a net surplus of export congestion rent over the Current Reporting Period.

Only the Manitoba interface experienced a shortfall in congestion rents in excess of \$100,000 during the Current Reporting Period (\$900,000). Manitoba experienced the highest rate of export failures in the Current Reporting Period (see Table 1-6), which contributed to the under-collection of congestion rents. If a scheduled export transaction fails in an hour where congestion existed, congestion rent goes uncollected as no energy is purchased, though the transaction contributed to congestion at the interface in pre-dispatch.

Table 1-4: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction November 2014 – October 2015 (\$/MW)

Description:

Table 1-4 lists the average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since November 2014 (these TRs would have been valid during the Current Reporting Period).

			Average Auction Price (\$/MW)							
Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec			
Import	Nov-14	Jan-15 to Dec-15	3,788	-	-	2,480	-			
	Feb-15	Apr-15 to Mar-16	2,847	1,172	4,525	767	1,367			
	May-15	Jul-15 to May-16	3,294	511	5,306	456	2,454			
	Aug-15	Oct-15 to Aug-16	2,844	505	4,445	404	1,106			
Export	Nov-14	Jan-15 to Dec-15	5,695	-	33,518	61,225	-			
	Feb-15	Apr-15 to Mar-16	7,293	43,370	28,558	36,741	4,176			
	May-15	Jul-15 to May-16	15,883	62,961	26,374	42,910	6,745			
	Aug-15	Oct-15 to Aug-16	12,605	72,534	21,850	51,193	9,865			

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. 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.

Commentary and Market Consideration:

With certain exceptions, long-term export TR prices increased in each successive auction, an indication that the expectation of the market is that export congestion on the interties would persist through the summer of 2016. Auction prices for Manitoba, Michigan and New York increased significantly relative to auctions held the previous year: in November of 2013, export TRs for Manitoba were sold at \$2,521/MW, while the lowest price for auctions held from November 2014 to August 2015 was \$5,695/MW. In the auctions held from November 2014 to August 2015 was \$5,695/MW. In the auctions held from November 2014 to August 2015, the highest export TR prices for Michigan and New York reached \$72,534/MW and \$61,225/MW, respectively. This compares with prices of \$38,836/MW and \$32,216/MW in the auctions for long term export TR's in the period November 2013 to August 2014.⁴¹

Table 1-5: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction November 2014 – October 2015 (\$/MW)

Description:

Table 1-5 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during the Previous and Current Reporting Periods.

⁴¹ For more information regarding long-term TR auction prices in November 2013 - August 2014, see page 40 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf

		Average Auction Price (\$/MW)						
Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec		
	Nov-14	506	134	251	129	118		
	Dec-14	380	119	351	136	131		
	Jan-15	328	136	317	160	19		
	Feb-15	306	45	268	171	32		
	Mar-15	259	99	376	79	152		
Import	Apr-15	310	55	418	90	135		
Import	May-15	317	16	-	16	90		
	Jun-15	387	12	-	11	81		
	Jul-15	417	30	201	7	79		
	Aug-15	202	12	164	7	0		
	Sep-15	135	19	290	15	118		
	Oct-15	165	15	122	15	5		
	Nov-14	329	7,626	-	5,022	2,000		
	Dec-14	701	6,245	1,674	6,049	3,169		
	Jan-15	692	6,176	2,001	2,500	2,070		
	Feb-15	410	3,678	1,868	2,500	300		
	Mar-15	511	4,221	2,074	2,689	158		
Ernort	Apr-15	810	4,494	1,735	2,262	179		
Export	May-15	1,300	5,575	-	2,520	27		
	Jun-15	751	6,897	-	2,645	82		
	Jul-15	459	7,462	-	930	37		
	Aug-15	580	5,947	-	1,125	6		
	Sep-15	393	2,701	-	671	123		
	Oct-15	310	4,009	-	2,297	72		

As discussed in the Relevance section associated with Table 1-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

Short-term auction prices in the Current Reporting Period were reflective of the relative frequency of congestion experienced at each interface. TRs for the Michigan and New York interfaces were the most expensive; these and were also the most frequently congested interfaces throughout the Current Reporting Period (see Figure 1-16). Short-term auction prices were also consistent with the general trends seen for the long-term auctions (see Table 1-4).

Looking at the average of Manitoba's short-term auction prices in the Current Reporting Period, there was an increase of 625% (average cost of a TR: \$632/MW) relative to the Summer 2014 Period (average cost of a TR: \$101/MW)⁴²; no monthly price in the Current Reporting Period was below \$310/MW, while only one monthly price in the Summer 2014 Period exceeded \$60/MW. The rising cost of export TRs was also reflected in the long-term auctions and speaks to the increased frequency of export congestion at the Manitoba interface discussed in the Commentary associated with Figure 1-16.

Short-term auction prices for the Michigan interface were higher the first four months of the Current Reporting Period relative to the Summer 2014 Period by an average of \$2,964/MW. This outcome is likely attributable to the reduced quantity of TRs sold, as the monthly average of TRs held for the Michigan interface was 192 MW lower in the Current Reporting Period (899 MW) than it was in the Summer 2014 Period (1091 MW).

For the Michigan and New York interfaces, short-term TRs were most expensive in September and October in the Summer 2014 Period. The same did not hold true in the Current Reporting Period, as September was the least expensive month for both interfaces and October was the second least expensive for the Michigan interface. The reduction in TR auction prices for the Michigan and New York interfaces indicates that exporters anticipated less favorable export conditions in Ontario during the 2015 fall shoulder season relative to the Summer 2014 Period and prior months of the Current Reporting Period. At least in part, this expectation could have been founded on publicly available information about the reduction in Ontario's baseload supply resulting from nuclear outages in September and October.⁴³

⁴² For more detailed information regarding Manitoba's short term auction prices in the Summer 2014 Period see pages 41 – 42 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

⁴³ For more information regarding short-term TR auction prices in the Summer 2014 Period, see pages 41-42 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf</u>

Figure 1-19: Transmission Rights Clearing Account Balance November 2010 – October 2015 (\$)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 1-19 shows the estimated balance in this account at the end of each month for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The TR Clearing Account balance is affected by five types of transactions:

Credits

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

<u>Debits</u>

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions 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 set by the IESO Board of Directors; funds in excess of this threshold can be disbursed to wholesale loads and exporters at the discretion of the IESO Board of Directors.

Commentary & Market Considerations:

In the Current Reporting Period, the balance in the TR Clearing Account increased by \$1.46 million; from \$135.95 million at the end of the Previous Reporting Period to \$137.41 million at the end of the Current Reporting Period. This change was composed of:

- \$113.23 million in revenue
 - o \$55.48 million in congestion rent collected
 - \$57.15 million in auction revenues
 - \$0.60 million in interest
- \$111.76 million in disbursements
 - \$44.96 million in TR payments to rights holders
 - \$66.80 million in disbursement to Ontario consumers

In the Current Reporting Period the TR clearing account ended approximately \$117 million above the Reserve Threshold. In December 2015, the IESO announced a lump sum disbursement from the TR Clearing Account of \$100 million, to occur during the November 2015 billing cycle. ⁴⁴

2 Demand

This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

⁴⁴ For details see: <u>http://www.ieso.ca/Pages/News/NewsItem.aspx?newsID=7268</u>

Figure 1-20: Monthly Ontario Energy Demand November 2010 – October 2015 (TWh)

Description:

Figure 1-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-themeter (embedded) generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and yearto-year changes in consumption patterns.

Commentary and Market Consideration:

Historically, Ontario has been a summer peaking jurisdiction, but 2015 marked the third consecutive year in which Ontario's peak monthly demand occurred in the winter, at 13.58 TWh in January. Peak monthly demand in the Current Reporting Period occurred in July at 12.62

TWh. Both July and August (12.25 TWh) exceeded the Summer 2014 Period's peak monthly demand of 12.02 TWh which occurred in July 2014.⁴⁵

Figure 1-21: Monthly Total Energy Withdrawals – Distributors and Wholesale Loads November 2010 – October 2015 (TWh)

Description:

Figure 1-21 charts the demand of two categories of consumers: market participants that are directly connected to the IESO-controlled grid other than distributors (Grid-Connected Consumers), and consumers connected to distribution systems (Distribution Level Consumers).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The breakdown of consumers into these two categories helps identify their respective monthly demand profiles.

⁴⁵ For more information regarding monthly Ontario demand in the Summer 2014 Period, see pages 44 – 46 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014_20151008.pdf</u>

Commentary and Market Consideration:

Seasonal change in Ontario demand is attributed almost entirely to Distribution Level Consumers. These include residential, small and medium commercial, and small industrial loads. The primary driver of demand for this consumer group is weather. Mild temperatures result in a reduced need for heating or cooling. April – May and September – October are typically the periods of lowest distribution-level demand. In the Current Reporting Period, however, demand in June (9.52 TWh) was very similar to demand in October (9.38 TWh) and was exceeded by demand in September (10.13 TWh), as June proved to be milder than September in 2015 in Ontario's most densely populated regions.

Meanwhile, demand from Grid-Connected Consumers, a group that is primarily comprised of industrial loads and large commercial consumers, which had been increasing slightly over the past five years, was down in the Current Reporting Period relative to the Summer 2014 Period.⁴⁶ Demand from Grid-Connected Consumers exhibits little of the seasonality seen with Distribution Level Consumers.

3 Supply⁴⁷

During the second and third quarters of 2015, 408.5 MW of nameplate generating capacity completed commissioning and was added to the total installed generation capacity connected to the IESO-controlled grid. This new grid-connected capacity consists of wind (308.5 MW) and solar (100 MW) generation. At the end of the third quarter of 2015, grid connected generation capacity totalled 35,203 MW, consisting of nuclear (12,978 MW), gas-fired (9,934 MW), hydroelectric (8,462 MW), wind (3,234 MW), biofuel (455 MW) and solar (140 MW) generation.

During the second and third quarters of 2015, 237 MW of nameplate generation capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity)

⁴⁶ For more information regarding monthly Ontario demand in the Summer 2014 Period, see pages 44 – 46 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-</u>Oct2014_20151008.pdf

⁴⁷ For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in September 2016 and available at: <u>http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-%26-18-Month-Outlooks.aspx</u>

⁴⁸ Capacity totals were obtained from the Quarterly Ontario Energy Report as reported by the IESO. Added capacity totals were calculated from the 2015 Q1, Q2 and Q3 reports, available at: <u>http://www.ontarioenergyreport.ca/index.php</u>

consists of solar (132 MW), wind (59 MW), biofuel (19 MW), hydroelectric (16 MW), energy from waste (10 MW) and gas-fired and combined heat and power (1 MW). At the end of the third quarter of 2015, embedded capacity totalled 2,840 MW, consisting of solar (1,766 MW), wind (484 MW), hydroelectric (264 MW), gas-fired and combined heat and power (209 MW), biofuel (107 MW) and energy from waste (10 MW).⁴⁹

Figure 1-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule November 2010 – October 2015 (TWh)

Description:

Figure 1-22 illustrates the cumulative share of energy in the real-time unconstrained schedule from November 2010 to October 2015 by resource or transaction type: wind, coal-fired, gas-fired, hydroelectric, nuclear, and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

⁴⁹ Embedded capacity totals were obtained from the Quarterly Ontario Energy Reports as reported by the IESO. Added embedded capacity totals were calculated from the 2015 Q1, Q2 and Q3 reports, available at: <u>http://www.ontarioenergyreport.ca/index.php</u>.

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

Commentary and Market Considerations:

As previously noted throughout this chapter, there was a significant drop in nuclear output in the last two months of the Current Reporting Period due to planned outages. Nuclear production dropped from a high of 8.46 TWh in August to 5.76 TWh in October. Hydroelectric output also decreased over the course of the Current Reporting Period from a high of 3.42 TWh in May to a low of 2.63 TWh in October.

The remaining supply types combined to compensate for the decreased production from nuclear and hydroelectric resources in September and October: gas-fired generation produced 3.13 TWh– an increase of 1.71 TWh relative to the same two-month period in 2014 – and dispatchable wind and solar resources produced 1.7 TWh – an increase of 0.71 TWh relative to the same two-month period in 2014. Wind resources produced 1.07 TWh in October alone, the highest monthly output for those resources on record and the first time Ontario's wind fleet exceeded 1 TWh of production in a single month.

In September and October 2015, imports provided 1.89 TWh – an increase of 1.25 TWh relative to September and October of 2014 – and export demand was 1.54 TWh lower in September and October of 2015 relative to those months in 2014.⁵⁰

⁵⁰ For more information on real-time scheduling by resource in the unconstrained sequence in the Summer 2014 Period, see pages 46 – 47 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf

Figure 1-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type November 2013- October 2015 (MW per hour)

Description:

Figure 1-23 plots the average hourly amount of OR in the unconstrained schedule from November 2013 to October 2015 by resource or transaction type: hydroelectric, gas-fired, coal-fired, imports, dispatchable loads and Control Action Operating Reserve (CAOR).⁵¹ Changes in the total average hourly OR scheduled reflects changes in the OR quantity requirements.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors

⁵¹ CAOR is an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements. The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only used in real-time, never in pre-dispatch.

such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors.⁵²

Commentary and Market Considerations:

The quantity of OR scheduled in the unconstrained sequence increased in the Current Reporting Period relative to the Summer 2014 Period,⁵³ from approximately 6.29 TWh to 6.68 TWh. In the Current Reporting Period it became increasingly common for the power flow on a major 500kV circuit connecting supply in Northern Ontario to demand in the South to exceed the capacity of Ontario's largest generation unit. In such instances, the circuit became Ontario's single largest contingency and increased the minimum OR requirement that the province was required to maintain. This situation tends to occur when demand in the province is higher and increasing quantities of supply in the North are required to meet demand in the South of the province. The increased frequency of a higher OR requirement corresponded with higher demand in the Current Reporting Period relative to the Summer 2014 Period (see the Commentary associated with Figure 1-20) and resulted in an overall increase in OR scheduled in the unconstrained sequence.

56.7% of all OR was supplied by hydroelectric resources, followed by gas-fired resources and dispatchable loads at 28.1% and 13.6%, respectively. Imports, biofuel and voltage reduction comprised the remainder of the OR supply mix, each contributing less than 6% of total supply.

⁵² The total energy available from the 10-minute OR market must be enough to cover the single largest contingency in Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.

 $^{^{53}}$ For more information regarding the average hourly OR schedule in the Summer 2014 Period, see pages 48 – 49 of the Panel's October 2015 Monitoring Report, available at:

http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014 20151008.pdf

Figure 1-24: Unavailable Generation Relative to Capacity November 2013 – October 2015 (% of capacity)⁵⁴

Description:

Figure 1-24 plots the monthly averages of the hourly sums of unavailable generation capacity as a percentage of total grid-connected installed generation capacity from November 2013 to October 2015.⁵⁵ Unavailable generation capacity is comprised of capacity that s unavailable due to planned and forced (i.e. unforeseen) outages, derates, and operating security limits, as well as unscheduled capacity from intermittent, self-scheduling and transitional generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

⁵⁴ In previous reports, the Panel reported planned and forced outages and derates relative to capacity. The Panel has decided to report on all unavailable generation capacity, which is consistent with the IESO's method for calculating unavailable capacity. The Panel is therefore now also including unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid. As a result, the data reported in Figure 1-24 is not directly comparable with similar data published in previous Panel reports.
⁵⁵ Unavailable generation capacity data was obtained from System Status Reports published daily by the IESO. A simple monthly

⁵⁵ Unavailable generation capacity data was obtained from System Status Reports published daily by the IESO. A simple monthly average was calculated using the most recently reported totals for each hour of each trade date. Daily, weekly and monthly market summaries published by the IESO are available at: <u>http://www.ieso.ca/Pages/Power-Data/Market-Summaries-Archive.aspx</u>.

Statistics regarding unavailable generation capacity provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices.

Commentary and Market Considerations:

There was a notable increase in unavailable generation capacity in the final two months of the Current Reporting Period, with total unavailable capacity reaching its highest totals of the period between November 2013 and October 2015. This was primarily attributable to the planned nuclear outages that occurred in the fall of 2015. September and October had the lowest monthly total outputs from Ontario's nuclear fleet in the Current Reporting Period at 6.52 TWh and 5.76 TWh, respectively, and had the highest totals of unavailable nuclear capacity (either planned or forced outages) at 2.93 TWh and 3.94 TWh, respectively.

4 Imports, Exports and Net Exports

The data used in this section is based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.⁵⁶

Figure 1-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) November 2013 – October 2015 (TWh)

Description:

Figure 1-25 plots total monthly energy imports, exports and net exports from November 2013 to October 2015. Exports are represented by positive values while imports are represented by negative values.

⁵⁶ Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Current Reporting Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

Commentary and Market Considerations:

Ontario was a net energy exporter in each month of the Current Reporting Period, totalling 6.797 TWh. September and October were the second and fourth lowest net export totals of the two year period from November 2013 through October 2015 at 302 GWh and 380 GWh, respectively; two of only five months between November 2013 and October 2015 with monthly net export totals below 1.1 TWh, the others being February – April of 2014.⁵⁷

⁵⁷ For more information regarding monthly net exports in the Winter 2014 Period see pages 51-53 of the Panel's April 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf</u>

Total imports increased from 773 GWh in September to 1.151 TWh in October and total exports increased from 1.075 TWh in September to 1.531 TWh in October. Québec was the primary source of the increase in imports, while export demand increased at almost every interface relative to September (Minnesota being the sole exception). The largest change in net exports occurred at the New York interface, which went from 201 GWh of net exports in September to 553 GWh of net exports in October. Québec was a net importer in both months (401 GWh in September and 586 GWh in October).

Figure 1-26: Net Exports by Interface Group (Unconstrained Schedule) November 2013 – October 2015 (GWh)

Description:

Figure 1-26 presents a breakdown of net energy exports from November 2013 to October 2015 to each of Ontario's five neighbouring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. Net exports are represented by positive values while net imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

This figure shows how Ontario's intertie trade evolves over time with each external jurisdiction.

Commentary and Market Considerations:

Ontario continued its historical trend as a net exporter to New York and Michigan throughout the Current Reporting Period and Minnesota maintained its position as a near net zero trader with Ontario.

Relative to the Summer 2014 Period, the most notable changes occurred in relation to Québec and Manitoba. Ontario was a net exporter to Manitoba in three of six months during the Current Reporting Period. Though Manitoba remained a net importer to Ontario, the total was down from 510 GWh in the Summer 2014 Period⁵⁸ to 8 GWh in the Current Reporting Period. Québec went from being a net exporter from Ontario of 0.153 TWh in the Summer 2014 Period⁵⁹ to a net importer to Ontario of 1.805 TWh in the Current Reporting Period.

Table 1-6: Average Monthly Export Failures by Interface Group and Cause (Constrained Schedule) November 2014 – April 2015 & May 2015 – October 2015 (GWh and %)

Description:

Table 1-6 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.⁶⁰

⁵⁸For more information regarding net exports in the Summer 2014 Period, see pages 50-53 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014</u>_ Oct2014_20151008.pdf

⁵⁹ For more information regarding net exports in the Summer 2014 Period, see pages 50-53 of the Panel's October 2015 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2014-Oct2014_20151008.pdf</u>

⁶⁰ A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

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	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	289.1	387.6	1.5	1.0	5.9	5.1	0.5	0.3	2.0	1.3
Michigan	333.8	410.8	1.2	3.7	4.7	4.9	0.4	0.9	1.4	1.2
Manitoba	37.4	40.8	3.2	3.3	11.7	4.8	8.5	8.2	31.1	11.7
Minnesota	8.2	9.1	0.4	0.4	0.2	0.3	5.0	4.4	2.9	2.8
Québec	92.5	187.2	1.4	13.3	0.4	1.9	1.5	7.1	0.4	1.0

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails due to a failure on the part of a market participant (such as an inability to obtain transmission service).

MP Failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a suboptimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to SBG conditions. The IESO may be required to take mitigating control actions, such as dispatching down domestic generation or curtailing imports, to compensate for MP Failures or ISO Curtailments.

Commentary and Market Considerations:

Similar to both the Previous Reporting Period and the Summer 2014 Period, the Manitoba interface continues to be an outlier with respect to the percentage and absolute volume of ISO Curtailments and MP Failures. Manitoba continues to experience an increasingly higher percentage of MP Failures: 31.1% in the Current Reporting Period vs. 11.7% in the Previous Reporting Period, 28.3% in the Summer 2014 Period and 3.9% in the Winter 2014 Period.⁶¹

In absolute terms, MP failures at the Manitoba interface were more than double that at any other interface in the Current Reporting Period, despite the fact that Manitoba had the second lowest

⁶¹ For more information regarding the export failures and curtailments in the Summer 2014 Period and the Winter 2014 Period see pages 53 – 54 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

average monthly export total. In terms of the percentage of MP Failures, exports failed at the Manitoba interface at a rate more than ten times greater than any other interface in the Current Reporting Period. The Manitoba interface also experienced the highest percentage and absolute volume of ISO Curtailments in the Current Reporting Period.

Table 1-7: Average Monthly Import Failures by Interface Group and Cause (Constrained Schedule November 2014 – April 2015 & May 2015 – October 2015 (GWh and %)

Description:

Table 1-7 reports average monthly import failures and curtailments over the Current and Previous Reporting Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel 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	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	13.1	11.3	0.1	0.1	0.4	0.3	0.6	0.8	3.0	2.7
Michigan	5.4	14.5	0.1	1.9	0.6	0.9	1.6	13.1	10.4	6.1
Manitoba	21.0	20.7	3.5	2.9	0.1	0.2	16.8	14.0	0.5	0.8
Minnesota	1.4	1.1	0.1	0.2	0.1	0.1	4.9	21.0	4.2	9.0
Québec	136.1	123.7	5.9	4.0	0.5	0.4	4.3	3.3	0.3	0.3

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This change in supply can lead to a suboptimal level of intertie transactions and may contribute to increases in price. The IESO may be required to take mitigating control actions, such as dispatching up domestic generation or curtailing exports, to compensate for MP Failures and ISO Curtailments.
Commentary and Market Considerations:

Relative to the Previous Reporting Period, the percentage of ISO Curtailments of imports decreased at all interfaces except for Manitoba and Québec in the Current Reporting Period. The most significant decreases occurred at the Minnesota and Michigan interfaces. The percentage of ISO Curtailments and MP Failures at the Minnesota interface both reduced significantly despite an increase in average monthly imports; in absolute terms, however, only the ISO Curtailments were reduced. At the Michigan interface, the percentage of MP Failures increased despite a decrease in the absolute number of imports failed, as the average quantity of monthly imports experienced a greater decrease relative to the Previous Reporting Period. The absolute number of imports curtailed and percentage of ISO Curtailments increased at both the Manitoba and Québec interfaces in the Current Reporting Period.

Chapter 2: Analysis of Anomalous Market Outcomes

1 Introduction

This chapter examines market outcomes that fell outside of predicted patterns or norms during the period from May 1, 2015 to October 31, 2015 (the Current Reporting Period), with comparisons to the period from November 1, 2014 to April 30, 2015 (the Previous Reporting Period) and other periods as relevant. A reference to a "Summer Period" is to the period running from May 1 to October 31.

The Panel has established thresholds to signal an anomalous outcome for the Hourly Ontario Energy Price (HOEP), Operating Reserve (OR) payments, Congestion Management Settlement Credit (CMSC) payments, and Intertie Offer Guarantee (IOG) payments. Table 2-1 shows the number of anomalous price and uplift events that occurred in the Current Reporting Period and the preceding two Summer Periods.

Anomalous Event	May – October 2013	May – October 2014	May – October 2015
High HOEPs (above \$200/MWh)	8	3	9
Negative HOEPs	224	656	371
OR Payments above \$100,000/hour	6	0	15
CMSC above \$1 million/day	8	1	0
CMSC above \$500,000/hour	2	0	0
IOG above \$1 million/day	0	0	0
IOG above \$500,000/hour	0	0	0

Table 2-1: Summary of Anomalous Events during the 2013, 2014 and 2015 Summer Periods (Number of Occurrences)

Additionally, the Panel reports the five highest payments made under the IESO's Real-Time Generation Cost Guarantee (RT-GCG) and Day-Ahead Production Cost Guarantee (DA-PCG) programs. Payments made under these programs are recovered from consumers through uplift charges.

In the Previous Reporting Period there were 32 instances of anomalous OR payments, and the Panel reported on the increasing trend in OR prices.⁶² In the Current Reporting Period there were 15 anomalous OR payments, well above the levels seen in previous Summer Reporting periods. One of those payments set a new record for the highest total hourly OR payments ever, with payments in that hour of over \$1.7 million.

Section 2 describes how supply shortfalls in the energy market, which have increasingly occurred because of variable generation forecast errors, can lead to shortfalls in the OR market. High OR payments are a product of these shortfalls and signal the growing challenge of managing the system in the face of higher penetration of variable (wind and solar) generation. The Panel concludes that an increase in the frequency of anomalous OR payment events is an expected outcome given larger forecast errors and a decrease in OR offers.

The IESO has recognized that forecast errors create new challenges for system operations. Several of the anomalous payment events occurred when the IESO was unable to schedule sufficient OR to meet its OR requirement. The Panel is supportive of the IESO's efforts in the Enhancing System Flexibility stakeholder engagement to investigate options to address forecast errors associated with wind and solar generation.⁶³. The Panel notes initiatives that are underway in other jurisdictions to address issues similar to those described in this chapter, which could help the IESO manage the impact of forecast errors on the energy and OR markets. A by-product of the forecast errors and the decrease in OR offers is the more frequent scheduling of Control Action Operating Reserve (CAOR) in the OR market. The Panel is recommending that the IESO review prices and offer quantities for CAOR to consider whether changes should be made to enhance efficiency of the OR market.

The remainder of the chapter discusses other anomalous events in the Current Reporting Period, as well as high RT-GCG and DA-PCG payments.

⁶² See the Panel's May 2016 Monitoring Report, available at:

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2014-Apr2015_20160512.pdf ⁶³For more information on this stakeholder engagement, see: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx

2 Anomalous OR and HOEP Events

Table 2-2 lists the high HOEPs and anomalous OR payments during the Current Reporting Period, as well as the price for 10-minute spinning (10S) reserve in all of those hours. The two highest of such HOEP and OR payment events (the first and last events listed in Table 2-2) are described in greater detail in the next section.

Table 2-2: High HOEP and Anomalous OR Payment Events
May 1, 2015 to October 31, 2015
(\$)

Delivery	HOEP	10S OR Price	OR Payments	Threshold Exceeded		
Date	Hour	(\$/ NIW h)	(\$/MW)	(\$)	HOEP	OR
05/05/2015	16	\$1,255.89	\$1,231.36	\$1,736,895.51	✓	\checkmark
05/05/2015	21		\$149.91	\$176,079.68		\checkmark
05/05/2015	22		\$94.51	\$133,315.59		\checkmark
06/05/2015	20		\$162.48	\$146,930.24		\checkmark
08/05/2015	20	\$243.80	\$247.43	\$294,190.06	\checkmark	\checkmark
09/05/2015	17		\$92.04	\$118,520.78		\checkmark
11/05/2015	13		\$169.34	\$219,576.56		\checkmark
30/05/2015	11		\$120.71	\$126,688.95		\checkmark
30/05/2015	16	\$211.93	\$201.29	\$219,785.13	\checkmark	\checkmark
12/06/2015	8	\$200.08	\$86.29		\checkmark	
14/06/2015	17	\$321.48	\$237.45	\$217,646.34	\checkmark	\checkmark
15/06/2015	22		\$65.21	\$107,917.63		\checkmark
15/06/2015	23		\$69.19	\$122,212.86		\checkmark
02/08/2015	16	\$371.76	\$256.34	\$284,112.31	\checkmark	\checkmark
02/08/2015	17	\$254.27	\$187.20	\$225,183.38	\checkmark	\checkmark
07/09/2015	20	\$251.73	\$81.43		\checkmark	
02/10/2015	9	\$1,053.11	\$961.18	\$1,047,728.54	\checkmark	\checkmark
Total				\$5,176,783,90	9	15

The high HOEPs and anomalous OR payments in the Current Reporting Period are associated with short-lived scarcity events during which the IESO dispatched more expensive energy to deal with differences between actual and forecast supply and demand.

Operating Reserve (OR) Requirement

All electricity system operators are required to maintain sufficient operating reserves to respond to contingencies on the grid: if the largest generator or heaviest-loaded transmission line trips, the operator must have enough operating reserve to ensure that the system remains stable.

OR is categorized according to the time it takes for generators to provide the required energy. Ten minute reserves can provide the required energy within ten minutes of receiving a dispatch. These reserves are of two types: spinning (synchronized with the grid) (10S) and non-spinning (not synchronized with the grid (10N). Thirty minute reserves (30R) can provide energy within 30 minutes of receiving a dispatch (and are not synchronized).

The IESO must operate with sufficient 10-minute OR to cover the single largest contingency (transmission line or generator) at any time. A portion of this requirement is met through 10S (typically 25% or more), and the remainder is met through 10N. The IESO must also procure sufficient 30R to cover half of the second largest contingency (or the largest commissioning generator, as a commissioning generator has a higher risk of tripping offline).*

When OR is dispatched to provide energy, reliability standards require ISOs to schedule additional OR to meet the standard and recover from any shortage within 90 minutes (105 minutes if OR was activated to respond to a contingency). In certain cases ISOs are permitted to operate without sufficient 30R for up to 4 hours.

The IESO's Market Rules define the circumstances under which the IESO can deploy OR (see section 4.5 of Chapter 5 of the Market Rules):

- Cover or offset unanticipated increases in load during a dispatch day or dispatch hour;
- Replace or offset capacity lost due to the forced outage of generation or transmission equipment; or
- Cover uncertainty associated with the performance of generation facilities or dispatchable loads in responding to the IESO's dispatch instructions.

*The IESO's OR requirement is determined in accordance with standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

As levels of variable generation capacity increase, greater differences between forecast and actual supply can arise than has occurred historically. These differences arise when variable generation connected to the IESO-controlled grid is more or less than forecast, contributing to supply forecast errors, or when variable generation connected at the distribution level (embedded) is more or less than forecast, contributing to forecast errors in demand on the IESO-controlled grid.

Although other factors also contribute to supply and demand forecast errors (for example, forced outages), the growth in variable generation capacity is a major factor contributing to the

increasing magnitude of these forecast errors. Table 2-3 reports wind production and shortfalls (the average and maximum amounts by which wind production is less than forecast). The largest wind shortfall has increased from 581 MW in 2012 to over 1,000 MW in 2015.

Production		Shortfall		
Year	Average (MWh)	Maximum (MWh)	Average (MW)	Maximum (MW)
2012	522.94	1627.60	104.08	581.60
2013	588.18	1967.70	85.92	518.90
2014	755.18	2687.80	105.96	713.10
2015	1007.94	3475.00	123.81	1032.40

Table 2-3: Hourly Average and Maximum Wind Production and Shortfalls January 1, 2012–December 31, 2015 (MW and MWh)

The purpose of OR is to ensure that sufficient capacity is available to respond to differences between forecast and actual supply and demand, including shortfalls caused by contingencies, but the OR requirement is based only on the size of potential contingencies (see the text box above). The increase in variable generation has added to the magnitude of the difference between forecast and actual supply and demand, which in turn has increased the number of hours in which less OR can be scheduled than is called for by the OR requirement (an OR shortfall). An OR shortfall often produces anomalous OR payments. ⁶⁴

OR shortfalls have occurred with increasing frequency. Table 2-4 shows the number of intervals (one interval is 5 minutes) in which the IESO has scheduled at least 5 MW less than the tenminute OR requirement. These occurrences have increased from fewer than 100 in 2012 to 525 in 2015. While OR shortfalls still occur relatively infrequently, it seems prudent to review whether the increasing trend in OR shortfalls poses a risk to reliability.

⁶⁴ Reliability standards permit the IESO to operate with less OR scheduled than the OR requirement, as long as OR schedules are returned to the OR requirement within certain timeframes (which are defined in the reliability standards--see text box above).

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Year	Ten minute OR shortfalls larger than 5 MW	
2012	90	
2013	92	
2014	179	
2015	525	

Table 2-4: OR Requirement Shortfalls
January 1, 2012–December 31, 2015
(Number of intervals)

The increase in forecast errors, coupled with a relative decrease in the total quantity of OR offers have both contributed to higher OR prices (and, in some cases, to OR shortfalls).

2.1 Examples of Large Variations Leading to Scarcity of Dispatchable Capacity

This section illustrates how supply and demand forecast errors in the energy market can lead to shortfalls and high prices in the OR market, using two examples from the Current Reporting Period. In both examples, additional energy needed to be dispatched in real-time when variable supply was less than forecast or real-time demand was higher than forecast. In the first example, wind generation produced less than forecast; in the second example, actual demand was higher than forecast and the IESO experienced a contingency event that required the activation of OR. In both cases, the dispatch of additional energy to make up for the supply shortfall led to insufficient OR remaining to meet the OR requirement and resulted in an OR shortfall and high OR prices. During the OR shortfall events, the price in the energy and OR markets cleared just under the maximum market clearing price of \$2000.

2.2 Highest HOEP and OR payments When Wind Production Shortfall Leads to OR Requirement Shortfall

On Tuesday, May 5, 2015, a storm front moving across Ontario led to wind production being 490 MW less than forecast in pre-dispatch in hour ending (HE) 16, which in turn led to a 73 MW OR shortfall and energy and OR prices of over \$1,200/MWh for the hour. Table 2-5 presents market data for this event.

Table 2-5: Market Data Tuesday May 5, 2015, HE 16 (MW and \$)

HE 16 on Tuesday May 5, 2015		
Wind Shortfall490 MW		
Total OR Payments\$1,736,895.51		
НОЕР	\$1,255.89 / MWh	
10S OR Price	\$1231.40 / MW	
30R OR Price	\$1206.10 / MW	
OR Shortfall 73 MW		

The IESO noticed early in the day that wind forecast information was not being updated accurately due to an IT issue. The IESO noted that the forecast for HE 16 was 600 MW, but that wind production had been decreasing since its peak of 400 MW at 12:30. In HE 16, wind production was 490 MW less than pre-dispatch forecasts. This wind shortfall required that additional energy be dispatched in real-time.

In addition, a change in transmission line flows increased the size of the largest contingency on the system by 150 MW, which increased the OR requirement to 1,650 MW.⁶⁵ Both the wind forecast error and the increase in the OR requirement required the IESO to dispatch more resources to meet energy demand and the OR requirement; however, there were insufficient OR offers available to meet the OR requirement, resulting in an OR shortfall of 73 MW from interval 5 to interval 11 of HE 16.

⁶⁵ Such an increase in the OR requirement occurs often during the afternoon.



Figure 2-1: OR Schedules and 10S Price Tuesday May 5, 2015, HE 16 (MW and \$/MW)

Figure 2-1 illustrates the OR schedules for this hour, beginning in the day-ahead, through predispatch and then every five minutes (interval-by-interval) throughout the hour (OR schedules illustrated represent the total 10S, 10N and 30R schedules). The reduction in the OR scheduled from hydroelectric and gas resources in Figure 2-1 reflect how these resources were dispatched to provide energy in response to the 490 MW wind shortfall. In order to meet energy demand, the IESO scheduled a dispatchable load that offered at \$1,999/MWh. To replace these resources and maintain OR at prescribed levels, the IESO had called on all available OR offers as well as relying on CAOR, but this was not enough to avoid an OR shortfall. When there is an OR shortfall, the OR price for all three categories of OR is equal to the energy market price, in this case \$1,999/MWh.

2.3 High HOEP and OR Payments When a Contingency Coincided With Demand Forecast Error

The second highest HOEP and OR payments in the Current Reporting Period occurred in HE 9 on October 2, 2015, when there was a loss of 800 MW of generation capacity just prior to the

Chapter 2

hour. In addition to the sudden supply loss, actual demand in HE 9 was approximately 600 MW higher than was forecast in pre-dispatch. Table 2-6 presents market data for this event.

Table 2-6: Market Data Friday October 2, 2015, HE 9 (MW, \$/MW, \$/MWh and \$)

HE 9 on Friday October 2, 2015		
Loss of Generation Capacity	800 MW	
Demand Forecast Error	600 MW	
OR Activated (SAR) ⁶⁷	600 MW (425 MW)	
10S OR Price	\$961.2/MW	
30R OR Price	\$961.1/MW	
OR Shortfall	61 MW	
Total OR Payments	\$1,047,728.54	
НОЕР	\$1,053.11/MWh	

In response to the loss of generation the IESO activated⁶⁶ 600 MW of OR and 425 MW of Simultaneous Activation Reserve .⁶⁷ Between the end of HE 8 and the beginning of HE 9, approximately 500 MW of OR from hydroelectric facilities and 100 MW of OR from gas-fired facilities were activated to provide energy. Figure 2-2 illustrates the OR schedules for HE 9.

⁶⁶ When OR is used to respond to a contingency, OR is "activated" to provide replacement energy (as compared to OR resources being economically dispatched in response to shortfalls from forecast errors). When OR is activated, the OR requirement is temporarily reduced by the size of the activation; when OR resources are economically dispatched to provide energy, the OR requirement does not change.

⁶⁷ Simultaneous Activation Reserve is an arrangement that allows some members of the eastern interconnection to share in the activation of operating reserves in the event of a significant loss of generation.



Figure 2-2: OR Schedules and 10S Prices Friday October 2, 2015, HE 9 (MW and \$/MW)

When OR was activated just prior to HE 9, the OR requirement was temporarily adjusted down from 1500 MW to 900 MW and was restored to 1500MW once the IESO recovered from the contingency (in interval 2 of HE 9). The OR requirement was then further increased to 1600 MW in interval 6, when changes in transmission line flows increased the size of the largest contingency.

Following the OR activation, the IESO called on additional resources to provide OR and energy, but there were not enough OR offers to meet the OR requirement. This led to an OR shortfall of approximately 61 MW from interval 4 to interval 8. As noted earlier, when there is an OR shortfall the OR price for all three categories of OR is equal to the energy market price. The energy price during these intervals was set by a dispatchable load at \$1999/MWh, as was the case on May 5, 2015.

2.4 Differences Between Forecast and Actual Supply and Demand can Lead to Scarcity

As shown in Figure 2-3, all but one of the High HOEP and anomalous OR payment events in the Current Reporting Period occurred when the IESO experienced a supply shortfall. Specifically,

the IESO experienced a scarcity of dispatchable capacity in the energy and OR markets in realtime. Since forecast errors only emerge in real-time, the IESO is forced to call on more expensive resources. In some cases there is insufficient dispatchable capacity online and there are shortfalls in the OR market. There were many other instances in the Current Reporting Period when the IESO experienced a shortfall in forecast supply, but there was sufficient dispatchable capacity available to avoid High HOEPs or anomalous OR payments.



Figure 2-3: High HOEPs and Anomalous OR Payment Events May 1, 2015 to October 31, 2015 (MW)

High prices provide a signal of scarcity that should generally encourage a market response, but since the high resulting from forecast errors do not emerge until real-time there is limited ability for most participants to respond. The next section examines the supply of OR to assess the market response and options for enhancing the market response.

2.5 Forecast errors put more strain on OR supply

The IESO dispatches more expensive resources to provide energy and OR in response to differences between forecast and actual supply and demand. Changes on the supply side of the OR market have contributed to a more frequent incidence of higher prices and more frequent scheduling of CAOR.

The IESO operates the OR market by dispatching offers from market participants that offer OR. Twenty-five market participants have consistently offered into the OR market between January 1, 2012 to December 31, 2015, with the three largest scheduled to provide an average of more than 65% of OR supply. In some months, these three suppliers have been scheduled for as much as 80% of OR supply.

Figure 2-4 displays the share of all OR suppliers from January 2012 to December 2015, by scheduled MWs. Aside from the three largest suppliers, the next three OR suppliers (all dispatchable loads) have supplied an average of 10% of OR supply over this time period. The "other" category includes all other resources, which individually each contribute less than 5% of OR supply.





2.6 Reduction in Total Offers of OR

In general, OR offers are informed by the opportunity cost of not supplying energy. Physical limitations may affect the ability of some generators to supply OR in some cases. For example, limits on river systems may affect the ability of some hydro units to change their production on short notice. Moreover, the largest OR supplier (OPG) is indifferent to the amount of OR revenues that it receives from the market because OR revenue has been subtracted from its revenue requirement when the OEB sets payment amounts for its hydroelectric facilities. Other resources that offer into the OR market are able to profit from OR prices, and offer into the OR market accordingly.⁶⁸

Total offers into the OR market have decreased relative to historic levels. Figure 2-5 shows the average hourly OR offers into all three categories of OR, from January 1, 2012 to December 31, 2015.

⁶⁸ In contrast to OPG's regulated hydro resources, generators who are eligible for the IESO's RT-GCG program currently do not have their guaranteed costs offset by OR revenue at all. See Chapter 3 in this report for more detail.





2.7 Control Action Operating Reserves are Scheduled More Frequently

The reduced volume of OR offers, combined with larger magnitude and frequency of forecast errors, has resulted in more frequent scheduling of Control Action Operating Reserves (CAOR) in the OR market. This is a sign of stress on the OR market.

CAOR is always offered in the OR market and when scheduled it replaces more expensive OR offers. CAOR is offered into the OR market like other energy-producing (or load-reducing) resource, but "control actions" involve the IESO reducing voltage (thereby reducing demand) or scheduling less 30-minute OR than is required for up to four hours. When CAOR is scheduled for OR, it does not mean the IESO will necessarily take those actions; ⁶⁹ scheduling CAOR allows the IESO to schedule less OR from other resources, enabling the IESO to dispatch those resources into the energy market.

⁶⁹ CAOR is offered into the energy market at \$2000, so in the event energy is required the IESO will dispatch energy from other resources before taking control actions.

Two categories of CAOR resources are offered into the OR market, 3VR and 5VR:

- 3VR offer: 400 MW at \$30.10/MW
- 5VR offer: 200 MW at \$75/MW and 200 MW at \$100/MW

Table 2-7 shows the number of intervals in which 3VR and 5VR CAOR resources have been scheduled over the past 5 years. The number of intervals in which CAOR is scheduled has increased in frequency in recent years, from less than 200 intervals to over 5000 intervals in 2015 for the 3VR resource, and over 400 intervals in 2015 for the 5VR CAOR resource.

Table 2-7: Number of Intervals with CAOR Schedules January 1, 2012 – December 31, 2015 (Number of intervals in unconstrained schedule)

Year	3VR	5VR
2010	154	115
2011	2,419	261
2012	1,285	96
2013	9,860	413
2014	9,449	397
2015	5,879	406

In 2011 the IESO reviewed its CAOR offers in stakeholder engagement 72 (SE-72).⁷⁰ The IESO launched this engagement to review the impact of CAOR offers in the OR market, stating that:

"To establish CAOR prices, the historical frequency of control actions was used as an initial reference. As time progressed and market conditions changed the historical frequency reference point for setting the price for CAOR should be reconsidered. As such, the IESO in consultation with stakeholders is proposing to define a set of principles to re-evaluate the pricing for CAOR."⁷¹

The IESO closed SE-72 without changing the pricing of CAOR offers, stating that that the "efficiencies identified in the review did not warrant implementing changes to the CAOR standing offers."⁷² At that time CAOR was scheduled less than half as often as it is today: given the more frequent scheduling of CAOR, the IESO may come to a different conclusion about the

⁷⁰ http://iesoqa-public.sharepoint.com/Pages/Participate/Stakeholder-Engagement/SE-72.aspx

⁷¹ For more information, see <u>http://iesoqa-public.sharepoint.com/Documents/consult/se72/se72-20110505-position_paper.pdf</u>.

⁷² For more information, see http://iesoqa-public.sharepoint.com/Pages/Participate/Stakeholder-Engagement/SE-72.aspx

efficiency gains available from making changes to CAOR offer prices. It might be beneficial to offer CAOR at escalating prices (comparable to an OR demand curve) rather than in large blocks in order to signal a need for additional OR offers as CAOR capacity is exhausted. Changes to CAOR offers could be used to set an OR demand curve (as initially considered in SE-72), which would help send a signal of increasing scarcity as more of this resource is scheduled.

Furthermore, the IESO's standing offers for CAOR may offer more capacity into the market than is actually available. The IESO subsequently reduces this quantity (or derates this capacity) in either day-ahead (3VR) or real time (5VR). Since the 5VR CAOR offers are derated only once they are scheduled, this change in availability is only reflected in the market when this capacity is actually needed. The Panel recommends that the IESO revisit the standing CAOR offer quantities.

Recommendation 2-1

Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.

2.8 Other North American ISOs are Facing Similar Challenges Managing Forecast Errors

The issue of greater variability between forecast and actual supply and demand driven by increasing production from wind and solar generators is one that other jurisdictions are also experiencing.

For example, similar to the analysis for Ontario presented in this chapter, situations have occurred in California where the ISO lacks sufficient dispatchable capacity to deal with supply and demand forecast errors. The California Independent System Operator (CAISO) has experienced:

"...numerous instances in which ... commitments are rendered infeasible due to load forecast error, generation variability, intertie changes. <u>These instances pose reliability</u>

concerns because to the degree the ISO must re-dispatch resources in real-time and there is insufficient committed resource flexibility the ISO may be drawing on operating reserves, regulation or on the interconnection.⁷⁷³ (Emphasis added)

The Midcontinent Independent System Operator (MISO) has also experienced scheduling shortfalls in their OR market similar to those examined in this chapter:

"Deviations from expected net load or high rates of change ... can leave dispatchable resources ... without ramp capability to respond, <u>which can lead to short-term scarcity</u> <u>events</u>. The [proposed] approach manages the ramp capability from controllable resources ... <u>in a way that better positions them to be able to respond to variations and</u> <u>uncertainty in the forecasts from the various non-controllable assets in the system such as</u> <u>the load, intermittent generators,</u> and net scheduled interchange."⁷⁴ (Emphasis added)

This issue is sufficiently common among ISOs that the North American Electric Reliability Corporation (NERC) has remarked:

"... the Operating Reserve practices of the Balancing Authorities in the United States and Canada enable them to accommodate the current amounts of variable generation penetration. However, many Balancing Authorities may need to change their practices to increase amounts of Operating Reserves to match anticipated increases in variable generation integration. For example, this may include adding additional Ancillary Service products."⁷⁵

Although Ontario will require its own solution, it is instructive to observe that the additional ancillary service products referred to in the quote are currently under development in some other North American jurisdictions. For example, CAISO is in the process of revising their scheduling algorithms to schedule more capacity when the conventional dispatch mechanisms do not schedule sufficient capacity to manage the uncertainty associated with production from variable

⁷³ For more information, see: http://www.caiso.com/Documents/TechnicalBulletin-

FlexibleRampingConstraint_UpdatedApr19_2011.pdf

⁷⁴ See

https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ra mp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf at page 2. ⁷⁵ For more information, see: http://www.nerc.com/files/ivgtf2-3.pdf at page 10.

generators. Similar to OR, the ISO schedules standby capacity, but that capacity is scheduled based on the uncertainty of output from variable generators (whereas OR is scheduled based on the size of potential contingencies). This change provides the ISO with additional means to manage variability in supply and demand, without relying solely on resources scheduled to deal with contingencies.

Although each jurisdiction is unique, the issue of managing the increasing unreliability of supply associated with variable generation is one that is having an impact on operating reserve markets across North America. Other ISO's have adopted changes to their market and scheduling systems to deal with the impact.

2.9 Market Design Changes are needed to Keep Pace with Ontario's Evolving Resource Mix

Given the recent and planned increases in variable generation capacity in Ontario, it is likely that forecast errors will continue to increase in size. Not only is this likely to lead to a higher frequency of unforeseen high prices in real-time, but it also creates new risks for the system operator to manage to maintain reliability. The IESO has recognized that forecast errors from variable generation have created new challenges for system operations. The IESO recently completed an operability assessment and identified that there is a need for "additional response capability to manage potential over-forecast of wind/solar output."⁷⁶ This conclusion is consistent with the Panel's observations and analysis.

As a result of the operability study, the IESO has launched a stakeholder initiative to identify potential options for acquiring additional response capability.⁷⁷ The IESO has indicated that the development of these options is to be coordinated with the IESO's Market Renewal stakeholder engagement. In the Panel's view this is appropriate: how to acquire the most cost-effective response capability is precisely the type of question the Market Renewal initiative should be addressing.

⁷⁶ For more information, see: <u>http://www.ieso.ca/Documents/consult/sac/SAC-20160511-Operations-Update.pdf</u> at slide 6.

⁷⁷ For more information, see: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx.

A properly functioning market should signal a need and enable market participants to respond. In the circumstances described in this chapter, the IESO-administered markets are indicating scarcity conditions in real-time and signalling a need for flexible resources. Responses to this need could range from grid energy storage, demand response, enabling simple cycle operation at combined cycle plants, or adding additional flexible generation, among others. In the Panel's view, the more the IESO-administered markets enable participants to compete to provide the appropriate response the less need there is for the IESO to direct solutions.

Market design changes will be needed to support the appropriate market response. In the Market Renewal stakeholder engagement the IESO has argued that now is the time to modernize because "market mechanisms with transparent price signals have proven critical in effectively bringing suppliers and consumers together, allocating risk, and supporting efficient decision making."⁷⁸ The Enabling System Flexibility stakeholder engagement has identified the need to develop a comprehensive solution, in line with the principles of maintaining reliability, being cost-effective, competitive, transparent, stable, sending efficient price signals, scalable to system needs and technology neutral.

More frequent intertie scheduling is one example of a market design change that would help meet this need and satisfy the IESO's stated principles. Allowing intertie schedules to adjust during the hour (currently, intertie schedules are fixed for an hour) would allow traders to respond to changing conditions and provide the IESO with additional dispatch flexibility. Since Ontario is often a net exporter, if supply shortfalls emerge when Ontario is exporting, higher prices would cause export demand to fall within the hour, helping to reduce or eliminate the shortfall. The Panel encourages the IESO to include more frequent intertie scheduling as an option in allowing a market response to variable generation forecast errors, and assess how additional market design changes can meet the identified need at the lowest cost.

The proposed changes being considered in the IESO's Enabling System Flexibility initiative are needed in advance of the planned growth in variable generation. In light of the fact that operating reserves are required to maintain system reliability, and that variable generation forecast errors

⁷⁸ For more information, see <u>http://www.ieso.ca/Documents/consult/ME/ME-20160419-Market-Design-Considerations.pdf</u> at slide 2.

are contributing to instances where less OR is scheduled than the OR requirement, the Panel believes that the IESO should place a high priority on developing solutions to mitigate the impact of forecast errors on the energy and OR market. The Panel will actively monitor this engagement.

3 Negative HOEPs

Typically, negative energy prices signal an abundance of supply relative to demand. There are many events that contribute to the occurrence of negative HOEPs such as low Ontario demand, failed export transactions or an abundance of supply offered at negative prices. Generators ordinarily offer energy at negative prices either to avoid getting dispatched off where such an event would be economically undesirable, or to ensure their participation in the market where contracted rates have desensitized them from variations in the market price.

During the Current Reporting Period there were 371 negative HOEPs. Due to the large numbers of negative HOEPs because of consistent surplus baseload generation (SBG), the Panel will not report on the causes of negative HOEPs in individual hours. SBG hours have increased in line with expectations given the changes in Ontario's underlying supply mix and relatively stable demand.

4 Anomalous CMSC Payments

An anomalous hourly CMSC event is defined as an hour where total CMSC payments exceeded \$500,000. An anomalous daily CMSC event is defined as a day where the total CMSC payments exceeded \$1,000,000. There were no such days in the Current Reporting Period.

5 Anomalous IOG Payments

An anomalous IOG event is defined as either a day where the total payments made through the IOG program exceeded \$1,000,000 or an hour where the total payments made through the IOG program exceeded \$500,000.

Neither of these thresholds was met during the Current Reporting Period.

6 Five Highest Daily DA-PCG Payment Totals

Day Ahead-Production Cost Guarantee (DA-PCG) payments are made to ensure that generators scheduled through the Day-Ahead Commitment Process (DACP) are guaranteed to recover certain eligible day-ahead costs. These costs are:

- Speed No Load Costs
- Start-Up Costs
- Incremental Energy Costs

Table 2-8 below shows the top five highest DA-PCG payments made to generators during the Current Reporting Period.

Table 2-8: Anomalous DA-PCG Payments (daily) Five Highest Daily DA-PCG Payments May – October 2015 (\$)

Delivery Date	Facility Name	PCG Payment
17/08/2015	Facility A	158,868
29/07/2015	Facility A	148,856
16/09/2015	Facility A	141,754
17/09/2015	Facility A	130,797
18/10/2015	Facility B	116,429

7 High RT-GCG Payments

The Generator Cost Guarantee (RT-GCG) program ensures that eligible generators who are scheduled in real time are guaranteed to recover certain eligible costs relating to start-up and the facilities Minimum Generation Block Run Time (MGBRT) and Minimum Loading Point (MLP). The top five RT-GCG runs with the highest RT-GCG payments during the Current Reporting Period are shown in Table 2-9 below with their corresponding dates.

Date	Facility Name	Payment
06/09/2015	Facility C	9,520,769
06/09/2015	Facility C	1,835,499
06/09/2015	Facility C	1,834,541
04/10/2015	Facility D	299,750
04/10/2015	Facility D	273,755

Table 2-9: Highest RT-GCG Payments May – October 2015 (\$)

The combined payments of over \$13 million to Facility C on September 6, 2015 are associated with a cost submission for maintenance costs incurred over multiple starts in the previous several years. The IESO has stated that it will be auditing the payment against revenues earned over those historical starts.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel presents its analysis of two aspects of the IESO-administered markets. The Panel's analysis considers the inefficiency on Ontario's interties induced by the two-schedule system, as well as several issues relating to the IESO's Real-time Generation Cost Guarantee program.

2 Panel Investigations

The Panel may conduct an investigation into the conduct of market participants, including in relation to inappropriate or anomalous market conduct, when it considers such an investigation is warranted. The Panel currently has one gaming investigation under way in relation to a generator.

3 New Matters

3.1 Inefficiency on Ontario's Interties Induced by the Two-Schedule System

In past Monitoring Reports the Panel has commented on the efficiency of electricity flows on the interties that connect Ontario to neighbouring jurisdictions.⁷⁹ The Panel found that, among other issues, the two-schedule price setting system (two-schedule system) has had a considerable impact on incenting inefficiency on the interties. In its August 2007 Monitoring Report the Panel estimated this inefficiency to be \$50 million per year on the New York intertie alone.⁸⁰ With the IESO currently considering the merits of alternate market design options as part of its Market Renewal stakeholder engagement,⁸¹ including the potential adoption of locational marginal pricing, the Panel revisits the issue of inefficiency on Ontario's interties to help inform the engagement. Specifically, the Panel has reviewed recent market outcomes in order to demonstrate how the current two-schedule system contributes to inefficiency on Ontario's interties.

⁷⁹ For references to past Panel commentary on the issue see the section below entitled "History of Panel Commentary regarding Inefficiency on the Interties".

⁸⁰ Ibid.

⁸¹ For more information see the IESO's Market Renewal stakeholder engagement webpage, available at: <u>http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Market-Renewal.aspx</u>

3.1.1 Defining Efficiency on the Interties and the Wedge Created by the Two-Schedule System

Electricity trade between jurisdictions increases productive efficiency when electricity flows from a lower cost jurisdiction to a higher cost jurisdiction, allowing for electricity demand to be met at a lower total cost.⁸² Trade from the lower cost jurisdiction to the higher cost jurisdiction increases productive efficiency until the costs equalize across jurisdictions. At this point total production costs have been minimized, gains from trade have been fully exploited and any divergence from this outcome would only increase total production costs.

Productive efficiency is dependent on the marginal cost of supplying electricity, which is not necessarily the same as the price at which electricity is sold. The distinction between price and cost is particularly important in the context of the Ontario wholesale electricity market due to the two-schedule system. The two-schedule system, and the accompanying uniform price regime, separates the price at which electricity is bought and sold from the cost of supplying it.

The two schedules of Ontario's two-schedule system refer to the "unconstrained sequence" and the "constrained sequence". The determination of price and cost are split between these two sequences, with the price determined in the unconstrained sequence and the cost determined in the constrained sequence. The divergence of price and cost is the result of differing assumptions amongst the unconstrained and constrained sequences.

For the purpose of achieving a uniform "market clearing price" for the entire province, the unconstrained sequence optimizes supply and demand whilst ignoring many of the operational constraints of the transmission grid and individual facilities.⁸³ Conversely, the constrained sequence optimizes supply and demand bound by those same operational constraints, producing the lowest cost solution which can be accommodated by the configuration of the electricity grid. Outputs of the constrained sequence include the production and consumption schedules to be

⁸² In this context, the term "cost" refers to the change in total system costs associated with serving the next megawatt of nondispatchable demand. When there is no transmission congestion this cost is notionally equal to the marginal cost of the supplying resource (typically a generator) plus the cost of transmission losses. In the presence of transmission congestion, this cost is notionally equal to the change in total system costs associated with dispatching resources to respect the transmission constraint while meeting the incremental demand. The dispatch solution could involve increasing the schedule of some resources, while decreasing the schedule of others, plus the cost of transmission losses.

⁸³ For instance, the unconstrained sequence ignores transmission constraints within Ontario. Additionally, it treats dispatchable generators and loads as if they can change production or consumption at their facilities three times faster than they are capable of.

followed by each resource, as well as measures of the cost of satisfying additional demand at each location on the grid. Put simply, the constrained sequence provides the most realistic representation of the conditions on the power system, the unconstrained sequence does not.

When the price of electricity (determined in the unconstrained sequence) is the same as the cost (determined in the constrained sequence), profit seeking behaviour induces efficient outcomes; what is privately profitable is also productively efficient. When price and cost diverge, as they often do in Ontario, what is privately profitable may not be productively efficient, and vice versa. Intertie traders are motivated by private incentives not social efficiencies; when these two things diverge, inefficiency is bound to occur.

3.1.2 How the Wedge Created by the Two-Schedule System Induces Inefficiency on the Interties

In the context of electricity trading, the wedge between price and cost can lead to inefficiency by either incenting too much, or too little trade in a given direction. For ease and consistency of reference the following analysis will consider trade from an Ontario net export perspective. The optimal (i.e. efficient) quantity of net exports occurs where total production costs are minimized: the point at which the costs equalize across jurisdictions. If the net export quantity is not optimal, say if efficiency could be improved by decreasing net exports, there are "excessive net exports". Alternatively, if efficiency could be improved by increasing net exports, there are "insufficient net exports".⁸⁴

Consider the following simplified example of trade between Ontario and New York (illustrated in Figure 3-1). The optimal net export quantity (Q*) is the quantity corresponding to the intersection of the cost curves for New York and Ontario (Cost^{ONT} and Cost^{NY}), at which quantity the cost in Ontario and New York are equal (C*).⁸⁵ The New York cost curve is inverted

⁸⁴ Note that negative net exports are positive net imports. It follows that "excessive net exports" is equivalent to "insufficient net imports", and vice versa.

⁸⁵ These simplified cost curves represent the residual supply curves at either side of the intertie. The supply curves are affected by the physical limitations of the grid (for example, supply offered in the Northwest is unlikely to factor heavily into the supply curves in southern Ontario) as well as domestic demand.



Figure 3-1: Example of Trade between Ontario and New York

The intersection of the two cost curves determines the optimal net export quantity (Q*). If there is no wedge between price and cost, as is the case in this example, one would expect the actual net export quantity to approximately equal the optimal net export quantity.⁸⁷ In jurisdictions that employ some form of locational marginal pricing, such as New York, price and cost are equal, at least in terms of eliminating the wedge created by Ontario's two-schedule system.⁸⁸ As such, in our example the New York cost curve also represents the New York price curve. In Ontario, the two-schedule system creates a wedge between price and cost, and is thus represented as two separate curves in the examples to follow.

⁸⁶ For example, starting at the optimal net export quantity (Q^*), increasing net exports to New York by 1 MW increases total production in Ontario by 1 MW (a move up the Ontario cost curve, $Cost^{ONT}$) and decreases production in New York by 1 MW (a move down the inverted New York cost curve, $Cost^{NY}$).

⁸⁷ For illustrative purposes, Figure 3-1 represents a simplified model of electricity trading between jurisdictions. This simplified example assumes perfect competition and information, among other assumptions that do not necessarily hold in reality. As discussed later in the chapter, even absent a wedge between price and cost, seams issues can contribute to a divergence between the actual net export quantity and the optimal net export quantity.

⁸⁸ New York employs a hybrid locational marginal pricing system whereby generators and intertie traders are settled based on locational marginal prices at individual nodes, while loads are settled based on zonal prices. Zonal prices are calculated as the load weighted average price of all nodes within a zone. Under such a system, a wedge can exist between the price charged to domestic loads and the cost of supplying that electricity; such a wedge does not exist for generators and intertie traders.

Consider the example illustrated in Figure 3-2, when the price of electricity in Ontario is lower than the cost.⁸⁹ This lower price is represented by a rightward shift of the Ontario price curve (Price^{ONT}) relative to the Ontario cost curve. Theoretically, intertie traders, who buy and sell at the price of electricity, will arbitrage price differences between Ontario and New York until the prices are equal (P^A) and no further arbitrage opportunities exist. Given that the Ontario price is less than the Ontario cost at all net export quantities, the actual quantity of net exports (Q^A) will exceed the optimal quantity of net exports (Q^{*}). The difference in quantity between the two outcomes is referred to as the excessive net export quantity. In effect, the lower price has induced excess demand for Ontario electricity.





Given the actual net export quantity (Q^A) , the efficiency loss associated with excessive net exports to New York is measured by the degree to which higher-cost Ontario supply replaced lower-cost New York supply (equal to the area of the red triangle). That is to say, for each megawatt of net exports between Q* and Q^A, the cost of producing electricity in Ontario and exporting it to New York was higher than the cost of producing the electricity in New York.

⁸⁹ As noted earlier, this could be the result of a number of things, including the unconstrained sequence ignoring internal transmission constraints, and/or the treatment of generators as if they can ramp three times faster than they are capable of.

However, due to the wedge between price and cost, these inefficient transactions were profitable for intertie traders and were thus consummated (there were excessive net exports).

The opposite case is that of insufficient net exports. Consider the example illustrated in Figure 3-3, where the price of electricity in Ontario is higher than the cost. Given cost curves identical to those in Figures 3-1 and 3-2, the optimal net export quantity (Q^*) is positive (Ontario exports to New York on a net basis). As the Ontario price curve is to the left of the Ontario cost curve, the Ontario price is greater than the Ontario cost at all net export quantities. The fact that the price is higher than the cost in Ontario will result in fewer net exports (Q^A) relative to the optimal net export quantity (Q^*). The difference in quantity between the two outcomes is referred to as the insufficient net export quantity. In effect, the higher price has induced insufficient demand for Ontario electricity.





Given the actual net export quantity (Q^A), the efficiency loss associated with insufficient net exports to New York is equal to the degree to which higher-cost New York supply *could have been* replaced with lower-cost Ontario supply *but was not* (equal to the area of the blue triangle). That is to say, for each megawatt of net exports between Q^A and Q^{*}, the cost of producing electricity in Ontario and exporting it to New York was lower than the cost of producing the electricity in New York. However, due to the wedge between price and cost, these efficient transactions were unprofitable for intertie traders and thus went unconsummated (there were insufficient net exports).

The example above illustrates an important concept, while the cost curves may be such that the optimal net trade quantity be in one direction (in this case the export direction), the position of the price curves may result in actual net trade in the opposite direction (imports in this case).

From an efficiency standpoint, the inefficiency associated with insufficient net exports (Figure 3-3) is just as undesirable as the inefficiency associated with excessive net exports (Figure 3-2), as both have the effect of increasing total production costs.

3.1.3 History of Panel Commentary Regarding Inefficiency on the Interties

The Panel discussed inefficiency on Ontario's interties in three successive semi-annual monitoring reports from June 2006 to August 2007.

In its June 2006 Monitoring Report the Panel reported on inefficiency on the Ontario to New York intertie, observing that excessive net exports occurred in approximately 25% to 30% of all hours over a two-year period. The report included a theoretical example which demonstrated how the two-schedule system can create a wedge between price and cost and incent excessive net exports to New York. The Panel concluded its analysis by noting that the two-schedule system also leads to domestic inefficiency, and that the adoption of locational marginal pricing would reduce these inefficiencies.⁹⁰

In its December 2006 Monitoring Report the Panel examined the factors that influence the size of the wedge between price and cost. The Panel noted that the average wedge had been decreasing over time, resulting in a reduction in the frequency of excessive net exports to New York. However, it determined that this was related to other changes in the market rather than as a result of an improvement to the two-schedule system market design. Again, the Panel concluded

⁹⁰ For more information see pages 68-79 of the Panel's June 2006 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf</u>

its analysis by noting that the solution to this problem was to adopt some form of locational marginal pricing.⁹¹

Having established that the wedge between price and cost had led to inefficiency on the interties, and examined the sources of the wedge, the Panel estimated the efficiency gains that could be realised if exports to New York were charged the marginal cost of production (as calculated in the constrained sequence) and not the price (as calculated in the unconstrained sequence) in its August 2007 Monitoring Report. Using historic costs and estimates of export elasticity the Panel estimated that this change would have resulted in efficiency gains of approximately \$50 million in 2006 alone. While recognizing the limitations of its study, the Panel felt the results were directionally correct and provided sufficient evidence for it to recommend that the IESO assess the efficiency benefits and costs of moving to a locational marginal pricing market design.⁹²

3.1.4 Inefficiency on the Interties Induced by the Two-Schedule System

In the sections that follow the Panel examines recent market outcomes and concludes that the current two-schedule system continues to contribute to inefficiency on Ontario's interties. The analysis focusses on the New York intertie, though the Panel found similar results at other Ontario interties.⁹³

Variables used to Identify Inefficiency on the Interties

In order to consider how the two-schedule system has contributed to inefficiency on the interties, reasonable measures of cost and price are needed for both sides of each transaction. The Panel chose the following variables as measures for cost and price in the importing and exporting jurisdictions:

⁹¹ For more information see pages 104-110 of the Panel's December 2006 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf</u>

⁹² For more information see pages 145-153 of the Panel's August 2007 Monitoring Report, available at: <u>http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf</u>

⁹³ As part of its analysis the Panel also examined the interties connecting Ontario with Michigan, Minnesota and the Pennsylvania-Jersey-Maryland Interconnection in the manner in which the New York intertie was examined. The Panel found similar results across all interties. The Panel did not examine the Manitoba and Québec interties as these jurisdictions do not have wholesale electricity markets, and therefore do not have explicit and public measures of price and cost, this makes it difficult to observe inefficiency.

Ontario, Price – the real-time unconstrained zonal price in the respective intertie zone in Ontario. This price is what intertie traders pay in Ontario when exporting, or are paid when importing.

Ontario, Cost – the average hourly real-time constrained nodal price at the generator located nearest the relevant intertie.⁹⁴

External Jurisdiction, Price and Cost – all interties examined in this study connect to jurisdictions with wholesale electricity markets that employ some form of locational marginal pricing. Under these pricing systems, price and cost are equal, at least in terms of eliminating the wedge created by Ontario's two-schedule system. The locational marginal price is the price intertie traders pay in the external jurisdiction when exporting from that market to Ontario, or are paid when importing to that market from Ontario.

Actual Net Exports – net exports in Ontario's real-time constrained sequence.

Instances of Inefficiency on the Interties

To start, the Panel reviewed recent market outcomes at the New York intertie to identify hours in which inefficiency occurred. Figure 3-4 plots net exports and the cost spread between New York and Ontario over a two-year period. The cost spread, plotted against the Y-axis, is positive when New York's cost is higher than that of Ontario and negative when the reverse is true. Recall that gains from trade are maximized at the optimal net export quantity, where the costs between jurisdictions are equal.⁹⁵

• Hours with optimal net exports (yellow dots) are identified by instances where the costs between jurisdictions are approximately equal.⁹⁶

⁹⁴ There is no real-time nodal price at the intertie itself. Consequently, the Panel believes that the real-time nodal price of the nearest generator provides the best representation of the real-time marginal cost of supplying the next megawatt of nondispatchable demand at the intertie. The real-time price at the nearest generator does not include the cost of congestion at the intertie itself. Accordingly, hours with intertie congestion in pre-dispatch (the best indicator of whether there would be intertie congestion in real-time) have been removed from the analysis that follows so as to avoid misrepresenting the cost during those hours.

⁹⁵ Per the previous footnote, hours in which trade in the efficient direction was limited by the intertie capacity (as represented by congestion in pre-dispatch) have been removed from Figure 3-4 and subsequent figures; this occurred in approximately 21% of all hours. Net export flows during these hours are optimal given the limited capacity of the intertie. This also suggests that efficiency could be improved during those hours if the intertie capacity was increased.

⁹⁶ Because supply curves are non-linear and step-like, one would not expect a cost difference of exactly \$0/MWh between jurisdictions, even when price and cost are equal.

- Hours with excessive net exports (red dots) are identified by instances where the Ontario cost is higher than that of New York (bottom half).⁹⁷
- Hours with insufficient net exports (blue dots) are identified by instances where the New York cost is higher than that of Ontario (top half).





In the vast majority of hours, the actual net export quantity on the New York intertie did not equal the optimal net export quantity, as evidenced by the number of hours with excessive or insufficient net exports (red and blue dots).

While the actual net export quantity was not optimal in most hours, only limited conclusions can be drawn about the magnitude of inefficiency in any given hour. This limitation arises due to the fact that, despite being able to observe the actual net export quantity (Q^A from Figures 3-2 and 3-

⁹⁷ Note that "excessive net exports" does not necessarily mean that Ontario was a net exporter (see the red dots in the lower-left quadrant), it means there should have been fewer net exports (i.e. greater net imports). The same logic applies for "insufficient net exports".

3), the optimal outcome (Q*) did not occur and thus cannot be observed. As a result the quantity of the excessive or insufficient net exports is unknown.⁹⁸

What can be said is that, all else being equal, the larger the spread between the cost in Ontario and the cost in New York, the larger the difference between the actual net export quantity and the optimal net export quantity, and thus the greater the inefficiency. While all else is not equal from hour to hour in reality, this relationship likely holds across a large sample of hours.

While it is unsurprising that the combination of profit-seeking behaviour by intertie traders and Ontario's two-schedule system did not lead to cost convergence between jurisdictions very often, did their trading behaviour lead to price convergence?

Over the two-year period the price spread between Ontario and New York was much narrower than the cost spread. The average absolute **price spread** per hour was \$20/MWh with a standard deviation of \$44/MWh, while the average absolute **cost spread** per hour was \$28/MWh with a standard deviation of \$85/MWh. This data supports the idea that electricity trade is driven by the price spread between jurisdictions, and not the cost spread; intertie traders are motivated by private incentives not social efficiencies.

Frequency of a Wedge between Price and Cost in Ontario

Having observed that inefficiency on the interties does occur, the Panel considered whether the two-schedule system and the wedge between price and cost could be driving these outcomes.

The larger and the more frequent the wedge between the price of electricity in Ontario and the cost, the greater the likelihood of inefficiency on the intertie. Figure 3-5 displays the monthly distribution of the hourly difference between price and cost in Ontario at the New York intertie. For example, in the first month of the series (May 2013), the price in Ontario was within +/- \$20/MWh of the cost in Ontario during 90% of hours. The wider the spread of the distribution band, the more significant the wedge between price and cost during that month and thus the greater the likelihood of inducing inefficiency on the intertie.

⁹⁸ It is possible to estimate what the optimal net export quantity would have been, however doing so accurately is challenging. Accurate estimation would require a simulator with detailed constrained models of both jurisdictions, something the Panel does not have access to, as well as detailed information on the supply and demand curves prevailing in each jurisdiction at the time.



Figure 3-5: Wedge between Price and Cost in Ontario at the New York Intertie May 2013 – April 2015 (\$/MWh)

Significant divergences between price and cost occurred regularly over the two-year period. The price in Ontario was higher than the cost in 65% of hours, often by a significant margin. For instance, in November 2014 the price was higher than the cost in 80% of hours, with the average difference exceeding \$14/MWh during those hours.

Differences between price and cost were positively correlated with the price: during months when average price was relatively high, the distribution of the difference between price and cost was wider. For example, the monthly average price during February 2014 was the highest of the period (\$78/MWh), the distribution of the difference between price and cost was also the widest during this month (90% of hours had a difference between -\$35/MWh and \$90/MWh).

Identifying Inefficiency on the Interties Induced by the Two-Schedule System

While the Panel has identified 1) many hours with insufficient or excessive net exports (see Figure 3-4), and 2) a frequent wedge between price and cost in Ontario (see Figure 3-5), inefficiency on the interties occurs in all electricity markets to some degree, even those with locational marginal pricing systems. Issues that cause insufficient or excessive electricity trade in

all electricity markets include: offer and bid timing, intertie schedule timing, transaction charges and reliability curtailments, among other issues.⁹⁹

Figure 3-6 integrates the information of Figures 3-4 and 3-5 to help demonstrate how the twoschedule system contributed to inefficiency on the intertie. Specifically, Figure 3-6 plots net exports and the cost spread between New York and Ontario over a two-year period, just as was done in Figure 3-4. Recall from Figure 3-4 that hours when the New York cost was higher than that of Ontario (upper half) there were insufficient net exports, while when the Ontario cost was higher than that of New York (lower half) there were excessive net exports. In addition to this information the hourly difference between price and cost in Ontario from Figure 3-5 has been incorporated into the data points using a colour scale. The blue dots indicate hours when the price in Ontario exceeded the cost, while the red dots indicate hours when the opposite is true. The larger the difference between price and cost the darker the colour, with hours when price and cost are approximately equal appearing as grey dots.

⁹⁹ These issues are often referred to as "seams issues" when discussing intertie transactions. The IESO is already exploring more frequent intertie scheduling in order to mitigate schedule timing induced inefficiency. In its stakeholder engagement "Review of Ontario Interties", the IESO indicated that it will include more frequent intertie scheduling in its broader market development plan to improve the efficiency and the effectiveness of Ontario's wholesale electricity market.




While the above analysis may not allow definitive conclusions to be drawn about the source of inefficiency in any one specific hour,¹⁰⁰ the patterns that emerge over the larger sample of hours allow us to infer several key findings:

- In hours when the price in Ontario was less than the cost (red dots), it was more frequently observed that the Ontario cost was higher than the New York cost (lower half).
 In other words, when Ontario sold electricity below cost, there were excessive net exports.
- Conversely, in hours when the price in Ontario was higher than the cost (blue dots), it was more frequently observed that the New York cost was higher than the Ontario cost (upper half). In other words, when Ontario sold electricity above cost, there were insufficient net exports.

¹⁰⁰ To determine with certainty the source of inefficiency in a given hour, one would need to carefully consider all market conditions at the time of the transactions, as well as leading up to it. The unavailability of certain data, such as pre-dispatch prices in neighbouring jurisdictions, precludes such analysis.

- When the price and cost in Ontario were approximately equal (grey dots), convergence between the cost in Ontario and the cost in New York was observed (the closer to the x-axis). In other words, when Ontario sold electricity at cost, efficiency was approximately maximized.¹⁰¹
- The larger the difference between the price in Ontario and the cost (dark red and dark blue dots), the larger the cost spread between Ontario and New York (the further from the x-axis). In other words, the larger the wedge between the price of electricity in Ontario and the cost, the greater the inefficiency.

All of these findings support the view that the wedge between the price and the cost in Ontario created by the two-schedule system incents inefficiency on the New York intertie. The persistent and significant spread between the cost in Ontario and the cost in New York strongly suggests that actual net export quantities are often far from optimal net export quantities, and that the inefficiency associated with insufficient and excessive trade is large. These findings are consistent with the Panel's August 2007 findings regarding inefficiency on the New York intertie: charging intertie traders the cost of electricity (as opposed to the prevailing price) would have resulted in efficiency gains of approximately \$50 million in 2006 alone.¹⁰²

3.1.5 Conclusions

The Panel's analysis suggests that there continues to be significant inefficiencies associated with electricity trade between Ontario and its neighbouring jurisdictions. Some causes of inefficiency affect all electricity markets, such as schedule timing and transaction charges, while other causes of inefficiency affect only Ontario, such as the two-schedule system. This source of inefficiency is significant, and can be eliminated if a locational marginal pricing market design were adopted. The IESO has launched a stakeholder engagement that will consider fundamental market design

¹⁰¹ When the price and cost in Ontario align (grey dots), and Ontario is a net exporter (right half), cost convergence at a \$0/MWh spread was not frequently observed, but instead a persistent spread where the New York cost is higher than the Ontario cost by \$10/MWh to \$15/MWh (i.e. there are insufficient net exports). This persistent spread is likely the result of transaction charges, specifically uplift and the export tariff in Ontario. Neither uplift nor the export tariff are captured in the measure of price used in this section, but both increase the price of buying Ontario electricity, but not the cost. Similar to the wedge between price and cost created by the two-schedule system, transaction charges levied on exporters can lead to insufficient net exports.

¹⁰² For more information on the Panel's August 2007 study, see section 3.1.2 History of Panel Commentary regarding Inefficiency on the Interties.

issues and changes, which may include consideration of a locational marginal pricing system.¹⁰³ The Panel strongly encourages the IESO to continue work towards implementing such a pricing system.

3.2 A Review of the IESO's Real-Time Cost Guarantee Program

3.2.1 Introduction

In the course of the Panel's regular monitoring of the IESO-administered markets, few topics have appeared more often in its bi-annual monitoring reports than the IESO's real-time generation cost guarantee (RT-GCG) program. The program has been a fixture in Ontario's wholesale electricity market since 2003, shortly after market opening. While the program has evolved over the years, the Panel continues to find reasons to be concerned with it.

The Panel has previously commented on the RT-GCG program, highlighting and recommending changes to specific aspects. In this report, the Panel provides a more comprehensive summary of its concerns with the cost of the program and makes two recommendations to address those concerns.

At the most fundamental level, the Panel questions the extent to which the RT-GCG program is truly necessary to serve a reliability purpose. The Panel's analysis found that, in 2014, commitments through the RT-GCG program were needed to meet real-time domestic demand and operating reserve requirements in less than 1% of the hours in which a commitment actually occurred. These needs were met at a cost of \$61 million. The IESO has not provided any analysis of the continued need for the program, although the Panel has recommended on more than one occasion that such an analysis be done.

The Panel acknowledges that the IESO has to manage changing conditions between day-ahead and real-time. The Panel also acknowledges that the IESO is considering a longer-term solution in the form of an enhanced intra-day unit commitment program. However, by the IESO's own admission that solution is many years away and it is unclear to the Panel why changes to the program that have the potential to save millions in costs should not be made now. The Panel

¹⁰³ For more information see the IESO's Market Renewal stakeholder engagement webpage, available at: <u>http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Market-Renewal.aspx</u>

believes that the RT-GCG program pays generators in excess of what is required to achieve the program's objective of incenting generators to come online in real-time in support of reliability. These unnecessary payments total approximately \$40 million per year; the cost of which are ultimately borne by Ontario ratepayers.

The Panel does not believe that there is a demonstrable need for the RT-GCG program to guarantee start-up operations and maintenance (O&M) costs. Since 2010, the RT-GCG program has paid out \$280 million for such costs. The Panel finds it instructive that the program served its intended function for over six years and more than 6,000 unit commitments without guaranteeing O&M cost recovery. Accordingly, the Panel is not convinced that the current guarantee (and associated payouts) of O&M costs has provided Ontarians with commensurate value in terms of an incremental reliability benefit. The Panel recommends that the IESO eliminate the guarantee of start-up O&M costs from the RT-GCG program, a change which is expected to reduce the cost of the program by approximately \$30 million annually.

The RT-GCG program also allows resources to operate profitably, on an all in basis, and still receive a guarantee payment. The Panel does not consider this a reasonable outcome. Accordingly, the Panel recommends that the revenues used to offset the guaranteed costs be expanded to include all net energy and operating reserve as well as all CMSC revenues received while the unit is online. The Panel has calculated that implementing such a change will further reduce the cost of the program by approximately \$10 million per year while reducing the incentive for generators to inefficiently schedule their guarantee hours.

3.2.2 History of Guarantee Programs

Electricity is a product that most consumers expect to be delivered immediately and at any quantity demanded. The IESO takes the necessary steps to procure and deliver the required amount of electricity at every second of every day. It uses programs like the RT-GCG in order to incent domestic generators to offer their supply to the market in real-time to meet demand. This section provides a brief history of the IESO's activities in this regard, specifically, the types of costs that the IESO has guaranteed throughout the years, with an emphasis on the evolution of the RT-GCG program.

In September 2003 the IESO introduced the RT-GCG, then named the spare generation online (SGOL) program. Material posted on the IESO's Technical Panel (TP) webpage articulated the need for the program which was to reduce the need for the IESO to take out-of-market control actions in response to real-time changes in market and system conditions.¹⁰⁴

The 2003 SGOL program provided a guarantee for fuel costs. Generators would submit their fuel costs several days after the day of operation, what the Panels refers to as 'after-the-fact' submissions, and if their energy market revenues were not sufficient to cover those fuel costs, the IESO would make a payment for the difference.

The TP material that described the RT-GCG program explicitly excluded other incremental costs from the guarantee and such costs remained out of the RT-GCG's scope until 2009. According to the IESO's TP material, O&M costs were not included in the 2003 RT-GCG for three reasons:

- Limit the advantage that the cost guarantee would provide non-quick start facilities over quick-start facilities;
- Simplify for participants the determination of applicable guaranteed costs; and
- Reduce the need for the IESO to audit the RT-GCG.¹⁰⁵

The TP meeting minutes at the time of SGOL rule amendment show that there was discussion amongst the TP members that more than just fuel costs should be included as part of the guarantee. However, a counter argument was made that guarantee of too many costs would risk losing the support of the loads on the TP and the guaranteed costs remained restricted to fuel only.¹⁰⁶

¹⁰⁴"It is expected this initiative will reduce the frequency of the need for the IMO to use out of market control actions in response to market and system changes in real-time."

Expected benefits of the program were listed as, "[the SGOL is] expected to assist in the maintenance of the reliable operation of the IMO controlled grid, through the additional resources being available to address reliability concerns as well through improved and rational pricing signals and outcomes at times of market need." For more information on the IESO's rationale for implementing the SGOL program, see the IESO's Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr/mr_00235-R00-R05.pdf

¹⁰⁵ For more information on the IESO rationale for guaranteeing only fuel costs in the SGOL program, see the IESO Board's Decision, page 20, available at: http://www.ieso.ca/Documents/Amend/mr/mr_00235-R00-R05_BA.pdf ¹⁰⁶ For more information on discussion from the TP meeting, see the final meeting minutes, available at: http://www.ieso.ca/Documents/tp/tp_min_2003Jun24.pdf

In the summer of 2005 Ontario experienced tight supply conditions, with demand at times exceeding Ontario's own generation capacity. As a result, the IESO relied on imports to service domestic demand and, at times, was forced to take emergency control actions to support reliability.

In September 2005 the IESO began a stakeholder engagement (SE) to create a day-ahead commitment process (DACP) that would provide a day-ahead intertie offer guarantee for importers as well as a day-ahead cost guarantee (DA-GCG) for domestic generators. An IESO presentation highlighted the difficult conditions in the summer of 2005 and explained the factors that contributed to the need for emergency control actions; such factors included the failure of import transactions.¹⁰⁷ According to the IESO, import failures were precipitated by the lack of a financially firm day-ahead import offer guarantee.¹⁰⁸ Lack of availability/reliability from nonquick start domestic generation was not listed as a factor contributing to the need for emergency actions.

Throughout the stakeholder sessions, the IESO proposed that the DA-GCG would include only a guarantee for fuel costs, which was consistent with the existing SGOL program. Generator representatives argued for O&M costs to be included in the day-ahead guarantee. In November 2005 the Association of Power Producers of Ontario sent the IESO's CEO a letter suggesting that the proposed DACP favoured importers at the expense of domestic generation and informed the IESO it would not be able to support the DACP initiative unless the real-time and day-ahead programs include a guarantee for incremental O&M and profit.¹⁰⁹ The IESO included O&M in the DA-GCG guarantee soon after.

Initially, the IESO's rationale for guaranteeing O&M costs was that the additional guarantee was a response to stakeholder concerns that the DACP process benefitted importers over domestic

¹⁰⁷ Other reasons listed included: load growth, extended periods of hot weather, low hydro-electric energy available, environmental limitations to production due to heat and transmission system at its limit due to heat

¹⁰⁸ The IESO presentation noted that "New York will curtail Ontario's hourly transactions to protect their day-ahead transaction." At the time, New York had a full day-ahead market, while Ontario did not yet have any processes in place to commitment resources day-ahead. ¹⁰⁹ For more information on the Association of Power Producers of Ontario's letter regarding the proposed DACP,

see the letter itself, available at: http://www.ieso.ca/Documents/consult/dayAhead/da 20051111-APPrO.pdf

generators.¹¹⁰ That reason was amended in subsequent documentation to instead read as a response to stakeholder concerns that generators may be disincented to accept a day-ahead commitment because generators who accept day-ahead starts may incur greater costs compared to costs incurred in real-time.¹¹¹ Although the IESO did eventually provide a guarantee for O&M in the DACP, it refused further requests to include such costs in the RT-GCG.¹¹²

In 2009, responding to a January 2009 Panel recommendation¹¹³, the IESO began a stakeholder initiative intended to increase the efficiency of the RT and DA-GCG programs by introducing competition for guarantees and strengthening the eligibility criteria required for obtaining IESO commitments. In similar fashion to the 2005 engagement, the IESO's initial position was to guarantee only fuel costs (i.e. start-up fuel) through the RT-GCG guarantee, only the DA-GCG would allow for start-up O&M costs. The IESO held to this position for several months.

In an echo of the result of the 2005 engagement, generator representatives continually requested that O&M be included in the RT-GCG until finally the IESO relented.¹¹⁴ The IESO's rationale for implementing this guaranteed cost was to provide parity between the DA and RT programs.¹¹⁵ Not unexpectedly, this decision to include O&M in the RT-GCG led to a surge in the cost of the RT-GCG program, see Figure 3-1 below.

¹¹⁰ For more information on the IESO's initial rationalization for including O&M costs in the DA-GCG, see the IESO's Market Rule Amendment Proposal, page 8, available at: http://www.ieso.ca/Documents/tp/tp 174-3-MR-00303-R00-R05-AP-v1 0.pdf

¹¹¹ For more information on the IESO's final rationale for including O&M costs in the DA-GCG, see the IESO Board's decision, page 7, available at: http://www.ieso.ca/Documents/Amend/mr2006/MR 00303-R00-R05-BA.pdf ¹¹² For more information on the IESO's response to OPG's comments, see the IESO's response document prepared for the TP, page 2, available at: http://www.ieso.ca/Documents/tp2006/tp177-5a-DACP-Response-to-OPG-WS-

Cover-Memo.pdf ¹¹³ For more information on this recommendation, see the Panel's January 2009 Monitoring Report, pages 217-220, ¹¹⁴ For more information on this recommendation, see the Panel's January 2009 Monitoring Report, pages 217-220, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/msp report 200901.pdf

¹¹⁴ "It is noted that generators continue to request a guarantee of incremental operating and maintenance costs for start up and ramp to minimum loading point (non-minimum generation block period) for the real-time guarantee program. The IESO agreed to review this request and get back to generators.

Follow-up: The IESO has updated the amendment to include incremental operating and maintenance costs incurred during start up and ramp to MLP for the real-time guarantee program can be submitted on form 1551 creating parity between the guarantee programs."

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¹¹⁵ For more information on the IESO's rationale for guaranteeing start-up O&M costs through the RT-GCG, see the IESO Board's decision, page 4, available at:

The cost of the RT-GCG program spiked sharply in 2010, and in late 2011 the IESO began to audit generator cost submissions. Nine years after the introduction of the RT-GCG, the IESO exercised its authority under the Market Rules to review generator cost submissions. The IESO has stated that it has recovered \$150 million in overpayments from generators. This figure accounts for overpayments through the former DA-GCG program as well as the RT-GCG program. The IESO did not provide a breakdown of recoupments by program.

In October 2011 the DA-GCG program was eliminated when it was replaced by the Enhanced Day-Ahead Commitment process (EDAC).¹¹⁶ EDAC significantly changed the way generators offer and receive guarantees: all costs are offered in advance, with no after-the fact submissions. Generator's offers would be made in three 'parts' which included start-up cost, speed no-load cost,¹¹⁷ and incremental energy cost. Successful generators would then receive a day-ahead guarantee for the total production cost of the commitment, based on that three-part offer. The program continued making financial guarantees to generators (and importers) to ensure that the costs they offered would be covered if they received insufficient revenue through the energy market. Notably, this program did not distinguish between fuel and O&M costs, but instead between energy, start-up, and speed no-load costs.

http://www.ieso.ca/Documents/icms/tp/2009/06/IESOTP_226_3b_MR_00356_R00_R02_Amendment_Proposal_v1_0.pdf

¹¹⁶ For more information on the Panel's assessment of EDAC, see the Panel's January 2014 Monitoring Report, pages 154-174, available at: <u>http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf</u> ¹¹⁷ The IESO Market Manual for the enhanced DACP defines Speed no-load costs as "The cost to maintain a

¹¹⁷ The IESO Market Manual for the enhanced DACP defines Speed no-load costs as "The cost to maintain a generation unit synchronized with zero net energy injected into the system for an hour." For more information on speed-no-load costs, see the IESO DACP training guide, page 14, available at: <u>http://www.ieso.ca/Documents/training/DACPguide.pdf</u>

3.2.3 The Cost of the RT-GCG Program

From 2003 through 2009 the RT-GCG program provided generators with guarantees for fuel costs only. Over that time average cost submissions per start were approximately \$25,600 and payments were \$4,600 per start. Since the introduction of guarantees for O&M costs in December 2009, the average cost guarantee per start has increased to over \$47,000 and average payments per start increased to \$22,400.

The guarantee of O&M costs represented a significant addition to the guarantee for fuel costs, especially when considering that the IESO instructs generators to start without knowing the startup costs those generators later submit.

In total, the IESO has made RT-GCG payments to generators of over \$400 million since January 2010, of which \$280 million was to cover guaranteed start-up O&M costs.¹¹⁸

Figure 3-1 shows the average payouts per run through the RT-GCG program since 2006. It is easy to see the increase in average per run payouts associated with the O&M guarantee post 2010. The Panel has provided Dawn Daily Index gas prices as well. The gas price index demonstrates that the increase in payouts is not a consequence of increasing gas prices. The price spike in winter 2014 aside, natural gas prices have been decreasing since 2008 and are currently at very low levels.

¹¹⁸ These figures do not reflect the \$150 million in recoveries that the IESO has made through its audit of the dayahead and real-time guarantee programs. Details regarding those recoveries (year, day-ahead vs. real-time program or cost type (fuel vs. O&M)) have not been made available.



Figure 3-1: Average RT-GCG Payments and Dawn Daily Gas Price January 1, 2006 – December 31, 2015 (\$, \$CAD/GJ)

3.2.4 Panel's Past Commentary on RT-GCG Programs

The Panel's previous commentary on the RT-GCG program has spanned a broad range of aspects of the program, from the technical parameters generators provide to the IESO to the inefficiency associated with after the fact cost submissions. The program is a regular topic of interest, and the Panel has commented on the program in 14 of its 27 semi-annual monitoring reports and made seven recommendations related to the program. In a number of instances the IESO made changes to the program in response to Panel recommendations.

Below is a brief summary of the various current features of the program that have been the subject of Panel recommendations:

• After-the-fact cost submissions mean the IESO starts generators knowing only their energy offers, and generators submit start-up costs after-the-fact.¹¹⁹

¹¹⁹ For more information on this topic, see the Panel's January 2014 Monitoring Report, page 167, available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report Nov2012-Apr2013 20140106.pdf</u>

- The RT GCG program can provide more generous guarantee payments compared to the IESO's day-ahead guarantee program (the payments are more attractive because less revenue is counted against costs).¹²⁰
- More generous real-time payments can lead some generators to avoid competing in the day ahead commitment program, potentially weakening competition in that program.¹²¹
- The cost allocation of the RT-GCG program has subsidized export uplifts. Although the majority of RT-GCG commitments occur in order to meet export demand, 40% of RT-GCG uplift costs caused by exporters have been allocated to Ontario consumers.¹²²

While the Panel is of the view that the IESO's longer term solution would go a long way towards addressing the various issues with the program, the cost of the program remains too high to not address existing shortcomings in the interim. As the rest of this report will show, the cost of inaction is high, and the time to the enduring fix too far, not to move expeditiously to address the Panel's recommended changes.

3.2.5 The Need to Guarantee Costs

As part of a stakeholder engagement concerning the RT-GCG (SE-GCG) launched in October 2015, the IESO provided the following explanation regarding why the IESO has generation cost guarantees:

"The IESO-administered markets schedule resources to ensure energy and operating reserve demands are met at any given time. If there is a disturbance on the electricity system or market demand increases, resources need to be ready to dispatch to meet system conditions. Not having enough resources online to meet changing conditions can have significant impacts on reliability.

Some resources can take several hours to reach the point at which they are available for dispatch, called the minimum loading point (MLP). During the period between initiating

¹²⁰ Ibid, p. 168.

¹²¹ Ibid, p. 171.

¹²² For more information on how the cost allocation of the RT-GCG subsidizes export transactions, see the Panel's September 2014 Monitoring Report, pages 71-88, available at: http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report May2013-Oct2013 20140924.pdf

a start to reaching MLP, a resource will incur costs as a result of starting up. Without assurance that the resource will be dispatched in real-time, a generator faces uncertainty that the resource will be able to recover the incremental costs of starting and ramping to MLP. As a result, some resources may be less likely to be offered when the IESO may need them to be available.

To address this concern, the IESO introduced the Spare Generation On-Line (SGOL) program in 2003, now called the Real-Time Generation Cost Guarantee (RT-GCG) program. The IESO relies on this and other mechanisms such as the Day-Ahead Production Cost Guarantee (DA-PCG) program to incent participants to offer generation facility resources to the market in real-time."¹²³

The IESO has also stated that the rules governing start-up O&M cost submissions have been administratively burdensome for both market participants (who, according to the IESO, are unclear at times what costs are recoverable and how to allocate them within the program) and the IESO.¹²⁴ The Panel observes that the IESO has undertaken a number of activities to clarify eligible costs, including: audits of market participant cost submissions, the issuance of an interpretation bulletin detailing eligible costs and the opening of SE-GCG which is meant, "…to develop a clearly defined and transparent cost recovery mechanism that reduces the scope and frequency of audits related to the RT-GCG program."¹²⁵

The Panel has been an active participant throughout SE-GCG making three submissions to the IESO, the content of which is described in more detail below. The Panel believes that the IESO has not adequately articulated why the guaranteed recovery of certain costs, specifically, start-up O&M, is necessary in order to achieve the objectives of the program.

Given the above explanation regarding the need for the program and the Panel's concern regarding the extent of guaranteed costs, the Panel has examined two questions associated with the use of the RT-GCG program.

¹²³ For more information on the RT-GCG Cost Recovery Framework, see the IESO's framework document, available at: <u>http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151203-Design-Document.pdf</u>

¹²⁴ Ibid, page 6

¹²⁵ Ibid, page 6

- 1. How often are RT-GCG committed units actually required in order to satisfy domestic energy demand and OR?
- 2. Is the guarantee of start-up O&M required to incent participants to offer into the market in real-time?

The Panel has found that the RT-GCG program is needed to satisfy domestic energy demand and OR in fewer than 1% of hours in which it was used to incent participants to offer in real-time, and that the current incentive is approximately \$40 million per year larger than it needs to be. These findings are discussed in more detail in the following sections.

3.2.6 How often are RT-GCG Committed Units Required?

In the IESO's view, incenting participants to offer generation facility resources to the market in real-time is necessary for maintaining system reliability. The Panel has on more than one occasion asked the IESO to provide a detailed analysis supporting this statement.¹²⁶ No such study has been provided.

As part of the Panel's first submission to SE-GCG,¹²⁷ the Panel conducted its own reliability study. The Panel examined GCG commitments throughout 2014 to determine whether or not the IESO could meet domestic demand and OR requirements in real-time absent units committed under the RT-GCG program. EDAC satisfies forecasted Ontario demand and OR in the day-ahead timeframe, therefore any unit with incremental schedules to day-ahead, which includes all RT-GCG units, are scheduled to meet changes in supply and demand conditions from day-ahead to real-time.

The Panel's analysis found the following:

• In 2014, there was at least one unit committed through the RT-GCG program during 3,638 hours (42% of all hours in the year)

¹²⁶ For more information on these previous Panel recommendations, see the Panel's February 2011 and January 2014 Monitoring Reports, pages 86-96 and 154-174 respectively, available at: <u>http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf</u> and <u>http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf</u>

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf ¹²⁷ For more information on this topic, see the Panel's official submission, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-Market-Surveillance-Panel.pdf

- In 2014, absent units committed through the RT-GCG program, there were insufficient domestic resources available in real-time to meet supply and domestic demand changes from day-ahead in only 19 hours (0.5% of the hours in which there was a RT-GCG commitment), 10 of the 19 hours occurred on the same day
- During the 3,638 hours in which there was a RT-GCG commitment, the IESO committed an average of 412 MW, and a maximum of 1,377 MW
- During the 19 hours in which, absent units committed through the RT-GCG program, there were insufficient resources available in real-time to meet supply and domestic demand change from day-ahead, the average insufficiency was 177 MW, and never exceeded 495 MW.

In summary, the Panel found that in 2014, commitments through the GCG program were needed to meet domestic demand and OR needs in real-time in less than 1% of the hours in which a commitment actually occurred. In 2014, these needs were met at a cost to Ontario consumers of \$61 million.

3.2.7 Is the Guarantee of Start-up O&M Necessary?

As discussed in section 3.2, start-up O&M was not a cost that was guaranteed in the RT-GCG program from 2003 through 2009. When the original RT-GCG program was implemented in 2003 (known then as the spare generation on-line program) the IESO made the decision to guarantee only the fuel costs of generators. All other costs associated with start-up and operation at a facility's Minimum Loading Point (MLP) were excluded from the guarantee.¹²⁸ The IESO's position and its supporting arguments for not guaranteeing O&M costs were included in material prepared for the Technical Panel in 2003:

"Only fuel costs are proposed to [be] eligible for the [RT-GCG] guarantee for the following reasons, even though there may be other incremental costs associated with the start-up and operation of a generation facility at its minimum load point.

¹²⁸ For more information on past IESO decisions and rationale regarding O&M cost eligibility through the IESO's GCG programs, see the above section 3.2 "History of Guarantee Programs"

- Facilities eligible for this program will, by the nature of the guarantee of cost recovery, have an advantage over non-eligible facilities that can be available in real-time i.e. this program, to some extent, reduces the market value of quick-start facilities. Restricting the cost guarantee to fuel costs limits this advantage.
- Fuel costs are readily verifiable on the basis of public information e.g. natural gas, oil, coal prices and historical cost submissions. This facility of verification is expected to reduce the market participant effort required to determine the applicable costs and the need for IMO auditing of submitted costs, both of which should improve the administrative efficiency of the program.¹²⁹

Six years later, the guarantee of start-up O&M was first introduced in an IESO submission to the TP on June 23, 2009. In that document, the IESO provides the following rationale for the inclusion of start-up O&M as a guaranteed cost,

"This change [the inclusion of start-up O&M] would create parity between the real-time and day-ahead guarantee program since the day-ahead guarantee program already allows market participants to claim those [start-up O&M] costs."¹³⁰

The Panel is not satisfied that "parity" alone is reason enough to justify the added cost of O&M. Moreover, this contradicts the IESO's earlier position in 2006, when it purposefully resisted creating parity between the two programs by refusing to add O&M to the RT-GCG.

Start-up O&M costs have accounted for 70% of the cost of the RT-GCG program since January 2010 (\$280MM out of \$405MM).

SE-GCG, launched by the IESO in late 2015, has been described by the IESO to be a discussion about how to guarantee start-up O&M costs in a defined and transparent manner that reduces the administrative burden of audits on participants and the IESO. To that end the IESO published a proposed RT-GCG cost recovery framework. While the Panel does not dispute that the many

¹²⁹ For more information see the IESO Board's decision, page 20, available at: <u>http://www.ieso.ca/Documents/Amend/mr/mr_00235-R00-R05_BA.pdf</u>

¹³⁰For more information see the IESO Board's decision, page 4, available at: <u>http://www.ieso.ca/Documents/Amend/mr2009/MR-00356-R00-R02-BA.pdf</u>

costs which make up the IESO's proposed cost recovery framework are bona fide, it is not convinced that all of these are actually incremental to start-up and ramping to MLP.¹³¹ What the Panel believes is critically missing from the discussion is any analysis or explanation as to whether the guaranteed recovery of start-up O&M costs is necessary to incent generators to come online in real-time to ensure that Ontario's reliability needs are met.

The Panel finds it illustrative that from 2003 through 2009, a time when O&M was explicitly excluded from the RT-GCG, there were over 6,000 RT-GCG unit commitments, including many by generators who participate in the RT-GCG program today. Clearly, the guarantee of O&M costs was not required to incent these generators to start in real-time from 2003 through 2009; the Panel suggests that it is also not required in 2016.

The RT-GCG program exists to support the reliable operation of the IESO-controlled grid; it does not exist to ensure that all of a generator's actual costs are recovered.¹³² In the Panel's view, costs should only be guaranteed to the extent necessary to ensure that the ultimate reliability objective is achieved and no more.

¹³¹ Examples of proposed eligible costs include: contracted labour, cost of permit fees, crane rentals, disposal of waste and temporary office trailers. For more information regarding O&M costs the IESO has determined are eligible for recovery see the IESO's presentation slides of May 26, 2016, slide 8-36, available at: <u>http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160526-Presentation.pdf</u>

¹³² Through written submissions to the IESO's RT-GCG SE, some participants have provided their own thoughts on the purpose/goal/objective of the RT-GCG program:

 [&]quot;...the current goal of the program, which is to recover actual incurred costs." TransAlta submission, Nov. 20, 2015, page 1, available at: <u>http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-TransAlta.pdf</u>

 [&]quot;The framework document moves away from a main objective of the RT-GCG program – recovery of actual costs." Goreway submission, Nov. 20, 2015, page 1, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-Goreway.pdf

^{• &}quot;OPG believes employing such a method undermines the purpose of the RT-GCG program to reimburse participants for their actual incremental costs incurred during start-up." OPG Submission, Nov. 20, 2015, page 1, available at: <u>http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-OPG.pdf</u>

 [&]quot;This [IESO proposed framework] is moving away from the original intent of the program which sought to allow generators to recover their actual costs incurred associated with starting that plant which were not able to be recovered elsewhere, do to other contracts / obligations, and to ensure that generators would be held whole." Northland Power Submission, April 15, 2016), page 1, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-Northland-Power.pdf

3.2.8 The IESO's Proposed RT-GCG Market Rules Changes

The significant cost of the RT-GCG program has not gone unnoticed by the IESO. Indeed, the IESO has recently conducted audits of RT-GCG (and the former Day Ahead-GCG) participants, exercising its authority to do so under the Market Rules.¹³³ The audits resulted in the recovery of \$150 million in ineligible costs that were initially paid by the IESO through both programs and then subsequently recovered during the audit. The results of the audits precipitated the launch of SE-GCG in October 2015. SE-GCG's objective was to "develop a clearly defined and transparent cost recovery mechanism that reduces the scope and frequency of audits related to the RT-GCG program."¹³⁴ The IESO proposed to change the rules governing the RT-GCG program because the audit results showed that participants were unclear at times what costs were recoverable under the RT-GCG program and the IESO views the current audit process as too burdensome for both participants and the IESO.

The Panel was an active participant throughout the stakeholder initiative making three submissions to the IESO. The Panel and/or its representatives also attended numerous SE-GCG meetings and webinars, and notes that generator representatives were the large majority of attendees at the meetings.

In its submissions the Panel made several requests and recommendations, including that the IESO should expand the scope of the SE to allow for the consideration of better aligning whether a cost is recoverable, with the stated reliability objective of the program, and whether lower cost alternatives to the current RT-GCG are available.¹³⁵ The IESO elected not to expand the scope of the SE, stating that exploring lower cost alternatives did not align with the objective of the initiative, which was to develop a clearly-defined and transparent cost recovery mechanism that reduces the scope and frequency of audits related to the RT-GCG program.¹³⁶

¹³³ The audits covered submissions from January 1, 2006 through December 31, 2016. For more information on the IESO's audit results, see the IESO's response to stakeholder feedback, page 8, available at:

http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-IESO-Response-to-Stakeholder-Feedback.pdf ¹³⁴ For more information, see the IESO's framework document, available at:

http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151203-Design-Document.pdf ¹³⁵ For more information, see the Panel's submissions, available at: thttp://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415_Market_Surveillence_Parents/

thttp://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-Market-Surveillance-Panel.pdf ¹³⁶ For more information, see the IESO's response to stakeholder feedback, page 4, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-IESO-Response.pdf

The IESO has proposed to prescribe dollar amounts (\$/GJ, \$/start, \$/MWh or \$) for specific costs that the IESO has determined are eligible for recovery and has provided a long list of recoverable costs available to eligible market participants.¹³⁷

Despite this extensive list of recoverable items, participants have expressed their concern on several aspects of the IESO proposed framework. These concerns include:

- Eligible fuel costs should account for distance from source
- The program should compensate generators for the fixed costs of gas storage and transportation because it is necessary for generators to secure storage and transportation services to start the facility
- The cost of full time staff performing planned maintenance work should be eligible for cost recovery through the GCG program. Not allowing reimbursement of internal labour costs may encourage participants to hire more expensive contracted labour in order to ensure recovery under the program. The program should not bias generators towards hiring contract staff for planned maintenance
- The program should allow for recovery of actual costs, not pre-approved universal costs

The message from generators is clear, their business is complicated and costly, and there seems to be no end to the number of costs that generator's believe should be covered by the IESO's RT-GCG. Additionally, each generator has its own method for managing the operation, maintenance and fuel costs of its facility.

The IESO's proposed solution would result in 97.5% of eligible start-up O&M costs being preapproved through bilateral conversations with the IESO. These discussions would determine each facility's start-up O&M revenue for the ensuing three years.¹³⁸ It is unknown at this time when these discussions will be completed, or whether the results of those discussions will be made publically available.

¹³⁷ For more information regarding O&M costs the IESO has determined are eligible for recovery see the IESO's presentation slides of May 26, 2016, slides 8-36, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160526-Presentation.pdf

¹³⁸ The IESO has committed to reviewing the program at least once every three years.

Bilateral discussions aside, the Panel believes that each market participant is in the best position to manage and minimize its own costs, and does not need an explicit IESO guarantee to do so. Without an IESO guarantee, generators have a clear incentive to procure all of their fuel and O&M needs at the lowest cost reasonably possible. A blanket IESO guarantee risks numbing this incentive, as costs become a pass-through to ratepayers.

The Panel suggests that instead of risking introducing a bias into participants' business decisions, the IESO should simplify the suite of costs that it is prepared to guarantee. The Panel believes that the IESO should guarantee only those costs that can be demonstrated to support the reliable operation of the IESO-controlled grid. Based on experience from 2003 to 2009 inclusive,¹³⁹ the critical portion of the start-up guarantee is likely to include the fuel commodity cost and little else.

The Panel finds it instructive that the IESO's decision to not include O&M costs in the original set of guarantee payments (from 2003) was supported by a desire to limit the need for auditing submitted costs and to improve the administrative efficiency of the program. By reducing the scope of the current cost guarantee the IESO would succeed in achieving the objectives of SE-GCG: (1) increasing transparency of guaranteed costs; (2); further diminish the need for, and complexity of, audits; and (3) significantly reduce the administrative burden of the RT-GCG program both for participants and the IESO.

The IESO has stated that in the longer-term it will explore a transition from the RT-GCG to an optimized program similar to the Day Ahead Production Cost Guarantee (DA-PCG) program (which currently schedules non-quick start units based on their three-part offers).¹⁴⁰ The Panel supports that initiative, as it will result in more efficient unit commitment through a more refined scheduling process and a further emphasis on competition¹⁴¹, however, as acknowledged by the IESO, this initiative will take many years to develop and implement.

¹³⁹ The original 2003 RT-GCG program guaranteed fuel costs required for start-up and minimum run-time operation, up to a unit's MLP.

¹⁴⁰ Three part offers refer to the start-up, speed-no-load and incremental energy costs that the IESO currently uses to schedule non-quick start generators in the day-ahead timeframe. Currently, only incremental energy offers are used when scheduling non-quick start units in real-time.

¹⁴¹ In 2015, competitively offered start-up costs through EDAC averaged \$14,607 per committed resource compared to \$27,825 per resource through the RT-GCG's after-the-fact submissions.

In the interim, given that continuing to guarantee start-up O&M costs in the RT-GCG results in significant costs and administrative burden for little discernable benefit to the reliable operation of the grid, the Panel recommends that the IESO eliminate the guarantee for start-up O&M from the RT-GCG program. This action is expected to reduce the cost of the RT-GCG by approximately \$30 million per year.

Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.

Reducing the suite of costs guaranteed by the RT-GCG may have the positive side-effect of driving increased competition day-ahead. The EDAC accounts for generators' start-up, speed no-load and incremental energy costs when it schedules non quick-start generators day-ahead; only the lowest cost facilities, on an all-in cost basis, earn commitments. So long as the RT-GCG program exists in its current form generators have little incentive to vigorously compete in the EDAC¹⁴² as they still have the chance to be committed in real-time without having to compete on start-up costs. Another reason for generators to prefer the current RT-GCG over the EDAC is the comparatively narrow set of revenues that are used to offset the real-time guaranteed costs¹⁴³ which is the subject of the next section.

3.2.9 Revenues Off-setting Guaranteed Costs

In its January 2014 monitoring report the Panel recommended that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program include any profit earned on output above a generation facility's MLP during its Minimum

¹⁴² Participation in the EDAC is mandatory, however, three of the 10 largest gas-fired generation facilities in Ontario appear to offer in a manner that purposely avoids them being scheduled day-ahead; instead they only participate in the IESO markets through the RT-GCG.

¹⁴³ The Panel has previously reported on the competing incentives between the IESO's day-ahead and real-time guarantee programs. For more information, see the Panel's January 2014 Monitoring Report, pages 154-175 available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Report Nov2012-Apr2013_20140106.pdf</u>

Generation Block Run-Time (MGBRT) and profit on output generated after the end of the facility's MGBRT.¹⁴⁴ The Panel continues to support this recommendation.

The current treatment of revenues allows GCG payments to be made even when a generator recovers all its costs with market revenues. The Panel considers it appropriate to utilize a more comprehensive approach which would base the offsetting net revenues on the *entirety* of that unit's production.

The guarantee currently offered by the IESO includes the unit's offer price for operation at MLP for its MGBRT as well as eligible start-up costs. The Panel's proposed comprehensive offset methodology does not interfere with this guarantee; it simply provides that the payments under the guarantee will not exceed what was necessary to cover the guaranteed costs. The Panel does not consider it a reasonable outcome when a generator can operate profitably, on an all-in basis, and still receive a guarantee payment under the RT-GCG program.

For example, if during the course of a day's operation a generator earns net revenues in excess of its guaranteed costs, then it logically follows that no guarantee payment needs to be made; the unit has covered its costs through its market operations. However, if a generator profitably operates for some time after its MGBRT period but still does not earn sufficient net revenues to cover its guaranteed costs, then it is sensible to provide that unit with a guarantee payment based on the totality of its net revenues, not just those earned during its MGBRT.

The current revenue offset calculation ignores this logic, and allows generators to operate profitably over the course of the day and still receive a RT-GCG payment. The Panel's comprehensive offset methodology would eliminate such a result while still providing generators assurance that they will recover their eligible costs. Utilizing this comprehensive offset

The revenues used to offset these guaranteed costs include the following:

• energy revenue earned and CMSC received from synchronization and ramp to MLP

¹⁴⁴ Currently, the RT-GCG program guarantees the following costs of market participants:

[•] start-up fuel and O&M (submitted after-the-fact)

[•] the offer cost for the unit's energy up to its MLP, over its MGBRT

[•] energy revenue earned and CMSC received during MGBRT, up to the unit's MLP

methodology is expected to reduce the cost of the program by approximately \$10 million annually.

3.2.10 Off-Setting Revenues – Incentives of the IESO's Current Methodology

The RT-GCG program provides an incentive, in the form of a cost guarantee, for generators to start in real time, whereby if the generator does not receive sufficient revenue to cover its costs of start-up and minimum operation, the IESO makes a payment for the difference. While conceptually straightforward, the specific Market Rules are far more nuanced. RT-GCG payments are made if revenues earned over the guarantee run for output up to MLP are less than the costs for the same period, including an after-the-fact submission of the generator's start-up costs, which may include fuel and O&M costs. To become eligible for the guarantee the generator must be economic in pre-dispatch for half of its MGBRT. This design is flawed, and exposes Ontario consumers to unnecessary guarantee costs.

One flaw is that the revenue calculation used to offset costs provides generators with an incentive to choose to offer their MGBRT hours in a way that both minimizes their offsetting revenues (thereby increasing their guarantee payment) and increases their opportunity to earn profit above MLP and post MGBRT (profits which are not used to offset the guarantee payment). This incentive increases the likelihood that generators operate profitably on an all in basis and still receive a guarantee payment on a given day. A more comprehensive revenue offset envelope would resolve this situation.

Increasing the revenue offset envelope for the RT-GCG will also help alleviate an undesirable and inefficient situation/opportunity that results from the current RT-GCG program.

This situation is best illustrated with an example. Consider a generator that is economically scheduled in HE 7, 8, 9 (half of its six hour MGBRT). The generator is now afforded the opportunity to select its RT-GCG hours to include either HE 7, 8, 9, 10, 11, 12 or HE 4, 5, 6, 7, 8, 9 (or some other six continuous hour period therein). In general, HOEP is lower for hours early in the morning than it is at mid-day.¹⁴⁵ The implication is that generators have an incentive

 $^{^{145}}$ In 2015, the average HOEP for HE 4-6 was \$10.62/MWh and for HE 10-12 was \$26.30/MWh, a difference of \$15.67/MWh.

to set their MGBRT period to encompass the lowest priced hours (HE 4, 5, 6, 7, 8, 9). By doing so, generators are able to 'use up' their minimum generation period on very low priced hours (even if market prices are \$0/MWh the IESO will guarantee cost recovery) and, thanks to the current revenue offset, retain the upside potential of earning profits (above MLP and post-MGBRT) during hours when prices are, in general, higher.

The early morning hours in which generators are selecting to generate are also the same hours in which RT-GCG eligible generators are least needed and risk exacerbating surplus baseload generation (SBG) conditions.

The example described above occurred on August 10, 2015. Generator A (Gen A) selected to begin ramping at 1:00 a.m. for a guarantee run that started at 3:00 a.m. and ended at 9:00 a.m. Gen A earned a guarantee payment for this run of \$65,255. However, the facility went on to generate continuously until 11:00 p.m.; no portion of the approximately \$153,000 that Gen A earned after 9:00 a.m. was used to offset its RT-GCG payment. A more detailed description of the day's events can be found in Appendix A.

Operationally, the choice by Gen A to begin ramping at 1:00 AM has the effect of exacerbating SBG conditions which Ontario regularly experiences overnight. Often, the IESO control-room utilizes nuclear 'maneuvers', which involve dispatching blocks of nuclear capacity, to address the potential reliability concerns associated with over-generation. In general, the IESO is able to dispatch down nuclear generation whenever it is economic to do so, typically when Ontario prices are negative. On this day, nuclear maneuvers were used at 1:15 AM, 15 minutes after Gen A began ramping its units online. While the Panel cannot definitively state that Gen A's choice to begin ramping at 1:00 AM caused the nuclear maneuver, the Panel can say with confidence that Gen A's decision exacerbated SBG conditions in Ontario and made nuclear maneuvers more likely.

In 2015 there were 25 days when a RT-GCG eligible generation unit was online in the early morning hours at the same time a nuclear unit was dispatched down to help alleviate SBG conditions. The generation units were not online in those hours solely because they were economically scheduled, they were online because of how they chose to structure their offers. In

such instances it seems that the RT-GCG program is undermining reliability as much as it is supporting it.

Incenting a generator to begin its MGBRT period in the early morning hours exacerbates the inefficiencies inherent in the RT-GCG program. Since a generation unit needs only half of its MGBRT to be scheduled, it does not matter to the participant how inefficient the 'other' half happens to be, however, it can significantly affect the total cost of its commitment which are borne by Ontario consumers.

Table 3-1 shows the cost of the guarantee payment under two scenarios. The scenario where the generator chose its MGBRT hours and the scenario that is least cost. The generator's choice increased the system cost of the real-time commitment by over \$20,000.

Hour Ending	Generator Choice (MGBRT HE 4-9)	Least Cost (MGBRT HE 7-12)	
4	(11,160)	-	
5	(11,160)	-	
6	(5,065)	-	
7	88	88	
8	115	115	
9	119	119	
10	-	(3765)	
11	-	178	
12	-	(3,392)	
Total	(27,305)	(6,656)	

Table 3-1: Profit (Loss) During MGBRT HoursAugust 10, 2015

(\$)

Where an operating loss is a pass through to Ontario consumers, there is no incentive for generators to choose the least cost alternative. Indeed, the current design incents them to do just the opposite.

This incentive can be reversed by adopting the Panel's proposed comprehensive offset methodology. This is illustrated in the example¹⁴⁶ below.

Table 3-2 presents the two different choice options described above (Generator Choice and Least Cost) under two different guarantee calculations (the current and MSP comprehensive). What the table shows is that presently generators are better off choosing to start at 3:00 a.m. (\$9,750 profit versus \$8,250) under the current calculation, but that preference switches to 6:00 a.m. under the comprehensive calculation (\$1,250 profit versus \$0). Today, generators are privately better off beginning their GCG commitment as early as possible; however, that private profitability comes at the expense of social efficiency.

Methodology	Option	MGBRT Start Time	Total Revenues^ (\$)	Total Costs* (\$)	GCG Payment (\$)	Net Revenue (\$)
Current IESO GCG Offset	1. Current Participant Choice	3:00AM	70,750	61,000	13,000	9,750
	2. Least Cost Choice	6:00AM	63,250	55,000	7,000	8,250
MSP Comprehensive GCG Offset	3. Current Participant Choice	3:00AM	61,000	61,000	3,250	0
	4. New Participant Choice = Least Cost Choice	6:00AM	56,250	55,000	0	1,250

Table 3-2: Comparison of Revenue Offset Methodology(\$)

^Includes GCG payments

*Includes start-up costs

By considering all revenues earned during the unit's operation, the IESO can reduce the system costs related to many RT-GCG commitments, decrease the overall cost to ratepayers and significantly reduce the risk of exacerbating SBG conditions while still preserving the guarantee that participants will recoup their eligible start-up and minimum costs. Importantly, this scenario allows the generator to operate profitably, which will remain the ultimate pursuit of generators.

¹⁴⁶ The example assumes the following: HOEP from HE 1- 6 =\$5/MWh and from HE 7- 21 = \$25; marginal costs of generation = \$20/MWh; MLP = 100 MW; MGBRT = 6 hrs; MGBRT production is 100 MW for HE 4,5,6 and 150 MW for HE 7, 8, 9; output post-MGBRT is 150 MW from HE 10-21; start-up costs = \$10,000; no operating reserve revenues or CMSC payments are earned or received.

The ability to begin MLP operation during inefficient, low-priced hours would not be eliminated entirely as generators will still, in some situations, be able to strategically offer their MGBRT hours, however, the benefit for doing so will be significantly reduced. Of course, the cost guarantee available to generators; the as-offered MGBRT costs and whatever start-up costs are available to them, would be unaffected by such a change.

3.2.11 OR Revenue

The Panel has also reviewed the RT-GCG program from the perspective of offset revenues. As noted above and in previous monitoring reports, the Panel has recommended that additional energy market revenues be used to offset generator costs. In this section, the Panel goes further to recommend that OR net revenues also be used to offset costs. The Panel's view can summarized as, any net revenues generated based on a guaranteed run that was backed by Ontario consumers should go to offsetting costs and any guarantee payment before they go to the generator. Generators remain incented to generate profits, the Panel's recommendations simply raise the threshold where profits begin and guarantee payments end to a level that is fair to Ontario consumers who assume any downside risk that generators run at a loss.

OR revenues were used to offset guarantee costs when the program operated between 2003 and 2009. It was removed from the offset calculation in an attempt to encourage gas-fired generation facilities to offer more OR to the market.¹⁴⁷

Ostensibly, the concern with including offsetting RT-GCG guarantees with OR net revenue is that generators may reduce the frequency and/or quantity of their OR offers if those net revenues counted against their RT-GCG payment.

In a competitive market generators are motivated to earn as much revenue above their guaranteed costs as possible, since this profit is theirs to keep. In general, generators who earn as much revenue as possible from all sources while online regardless of the guarantee they have started under (day-ahead or real-time) have a better chance of earning revenues in excess of their

¹⁴⁷ For more information on the decision to remove OR revenue from the RT-GCG offset calculation, see the IESO's Market Rule Amendment Proposal, page 12, available at: http://www.ieso.ca/Documents/icms/tp/2009/06/IESOTP_226_3b_MR_00356_R00_R02_Amendment_Proposal_v1_0.pdf

guaranteed costs. A generator whose unused capacity sits idle and is paid to provide operating reserve is better off than the same generator who sits idle and is not paid to do so.

The incentive to offer OR is in the OR price, not in a subsidy from consumers to generators via the guarantee payment. The incentive for generators to offer OR exists absent the IESO's guarantee program. If OR prices are under signalling the need for OR, then the appropriate course of action, as the Panel recommends in Chapter 2 of this report, is to review the pricing methodology in the OR market, not to subsidize generators via the guarantee program.

Furthermore, the Panel makes the observation that net OR revenues are an offset for Day-Ahead Production Cost Guarantee payments. If OR as an offsetting revenue was discouraging OR offers, we would expect to see this in generator day-ahead offers. The Panel has analyzed units who, on a given day, had a DA-PCG schedule and were also scheduled for OR day-ahead and found on average in 2015, 86% of the OR MW's scheduled day-ahead were also scheduled in real-time. This is important in the context of adding OR net revenue when offsetting RT-GCG payments, as currently, DA-PCG payments are also offset by OR net revenues. The fact that OR MW's scheduled for generators in the day-ahead are also scheduled in real-time, shows that offsetting guarantee payments with OR net revenues does not significantly affect generators' OR offer decisions in real-time. Using net OR revenues to offset the guaranteed costs of the RT-GCG is expected to reduce the cost of the program by more than \$2 million annually.

The Panel recommends that the revenues used to offset the guaranteed costs be expanded to include all net energy and OR revenues as well as all CMSC revenues received from the start of a RT-GCG commitment until the unit either begins a Day-Ahead commitment or de-synchs from the grid. The Panel has calculated that implementing such a change will reduce the cost of the program by nearly \$10MM annually while incenting efficient offers from generators and reducing the incentive for generators to inefficiently schedule their guarantee hours.

Recommendation 3-2

The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all congestion management settlement credit payments received, on:

(a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and

(b) output generated after the end of the facility's MGBRT.

3.2.12 Materiality of Implementing the Panel's Recommended Changes

The Panel has calculated that by adopting the Panel's proposed comprehensive offset methodology, including net OR revenue in the offset calculation and removing the guarantee of start-up O&M, the IESO would reduce the annual costs related to the RT-GCG program by approximately \$40 million per year. Table 3.2 shows the average annual effect each recommended change would have had since 2010. In total, the Panel's recommended changes would have reduced the cost of the RT-GCG program by just under \$300 million over the past six years.

Table 3-3: Annual RT-GCG Savings			
2010-2015			
(\$ millions)			

Year	Actual RT- GCG Payments	Savings from Including OR	Savings from Comprehensive Offset Methodology	Savings from Removing O&M from the Guarantee	Total Savings ¹⁴⁸
2010	72.8	0.5	18.8	55.5	60.2
2011	71.7	1.2	12.9	55.6	59.6
2012	78.4	0.8	18.3	61.1	66.1
2013	63.5	2.4	11.1	38.3	43.2
2014	61.5	1.9	4.5	27.9	30.6
2015	57.1	2.1	7.3	35.1	39.0
Total	405.0	8.8	72.8	273.5	298.6

3.2.13 Concluding Observations

On September 13, 2016, a majority of the IESO's Technical Panel members voted against (six Panel members voted against and four Panel members in favour of) recommending the IESO's proposed RT-GCG market rule amendments to the IESO Board for approval. A key concern among those voting against recommending the market rule amendments was the limited level of detail in the market rule amendments relative to detail expected to be included in a market manual. On October 13, 2016, a stakeholder meeting was held to discuss the IESO's proposed approach for allocating planned maintenance costs to the RT-GCG program for the purpose of determining pre-approved, resource-specific costs under the framework and to discuss and seek feedback on a draft market manual.

The history of the RT-GCG program and its evolution, in particular in more recent years, highlights an area of concern regarding the IESO's stakeholder engagement processes. Those processes appear on paper to be quite robust and make provision for participation by stakeholders representing a broad spectrum of interests. However, in the Panel's experience the IESO's stakeholdering processes tend to be dominated by those with a direct and substantial financial interest in the outcome. The relative absence of other stakeholders has been

¹⁴⁸ Since RT-GCG payments cannot be negative values, the Total Savings reported in Table 3-2 are less than the sum of savings from OR, comprehensive offset methodology and the removal of O&M. The savings from incorporating all changes at once is bounded at a \$0 RT-GCG payment.

acknowledged by the IESO through its articulation of the need to encourage "effective representation of the public in each engagement, especially those groups that have a tendency to remain silent or are reluctant to engage".¹⁴⁹ The Panel has voiced its support for this principle in the context of the Market Renewal initiative.¹⁵⁰

The Panel also notes that through the flexibility stakeholder engagement described in Chapter 4, the IESO has identified a number of criteria by which it intends to assess potential options to meet its flexibility needs: technology neutrality, competitiveness, transparency, enduring solution and cost effectiveness. The Panel believes these are useful criteria and that they could equally be applied to assess and improve the RT-GCG program. Table 3.4 below offers a preliminary assessment of the RT-GCG program using these criteria.

¹⁴⁹ For more information see the IESO's Engagement Principles document, available at: <u>http://www.ieso.ca/Documents/consult/IESO-Engagement-Principles.pdf</u>

¹⁵⁰ For more information see the Panel's submission to the Market Renewal stakeholder engagement, available at: http://www.ieso.ca/Documents/consult/ME/ME-20160506-Market-Surveillance-Panel.pdf

Criteria	Assessment	Implications
	Costs have increased over 400%	Costs are in excess of
	per start since the guarantee of	requirements to meet domestic
Cost	start-up O&M despite decreasing	reliability, yet the IESO has
Effectiveness	fuel prices. MSP analysis shows	decided to defer cost reductions
	minimal need for program to meet	for several years
	domestic reliability needs	
	Start-up O&M costs are recovered	Dispatch order distorted
Competitiveness	via after-the-fact cost submissions	No competitive incentive to
Competitiveness	and are not subject to competitive	manage costs
	discipline	
	97.5% of start-up O&M costs to be	Lack of transparency impedes
Transparency	determined through closed door	assessment and improvement
	bi-lateral discussions	
	RT-GCG widely recognized as	Current design ensures ongoing
Enduring	sub-optimum solution in need of	inefficiency and unnecessary
	replacement as part of broader	costs. Panel recommendations
	market reform, but entrenched for	offer short-term mitigation.
	at least next three years	
	Extending the guarantee of start-up	Absence of technology neutrality
Technology	O&M further entrenches the	discourages the development and
Neutrality	subsidy paid to non-quick start	provision of other potential
	fossil-fuelled generation	solutions ¹⁵¹

Table 3.4: Assessing the RT-GCG Program

¹⁵¹ Other sources of reliability resources include imports, storable hydro, dispatchable wind and solar, dispatchable load, storage, etc.

3.3 Appendix A

Figure 3.A1 below depicts an example of this situation from August 10, 2015.



Figure 3-A1 : Example of 'Choosing' MGBRT Period August 10, 2015

In this example, the Gen A's MGBRT offers were economic for HE 7, 8, 9, and uneconomic for HE 4, 5, 6. The generator began ramping online at 1:00 AM in order to be at its MLP by 3:00 AM, thus beginning its six hour MGBRT period. By starting its MGBRT period at 3:00 AM, the generator was able to 'use up' its guarantee hours from 1:00 AM to 8:59 AM, and then operate as a merchant facility from 9:00 AM until it desynchronized from the grid at nearly 11:00 PM. Revenues earned over these 14 hours, approximately \$153,000 on this day, are not currently factored into the generator's cost guarantee.

Chapter 4: Future Market Developments and Panel Recommendations

This chapter contains an update on future developments in the market and lists the recommendations contained in this report.

1 Future Development of the Market

There are a number of significant initiatives which are currently being undertaken by the IESO which are discussed in the sections that follow.

1.1 Market Renewal

In response to the operational challenges that had arisen under the existing market design, the IESO established the Electricity Market Forum (EMF) in March 2011. The EMF found that there was considerable scope for improvement.

Following on from the work of the EMF, the IESO undertook a series of reviews to investigate possible areas of improvements, which confirmed many of the findings of the EMF. These reviews included issues related to:

- Energy: The IESO reviewed intertie scheduling frequency, generator guarantee programs, the two schedule-system and HOEP.
- Capacity: The IESO established the demand response auction and is currently working with stakeholders on enabling capacity exports as a precursor to the development of broader incremental capacity auctions in the province.

The IESO is planning on evolving Ontario's electricity market to address known market inefficiencies and to develop a more dynamic marketplace in the future. The Market Renewal stakeholder engagement, which began in March 2016, is intended to set out specific market design changes to be implemented in the coming years and will define target timelines and work plans for completing these projects.

IESO materials published in April 2016 identify a number of projects that the IESO proposes to include in the work plan:¹⁵²

- Two schedule replacement moving to a pricing approach based on congestion pricing;
- Day-ahead market introducing a day-ahead market to provide greater certainty to market participants and the IESO;
- Real-time unit commitment improving real-time unit commitment to optimize over multiple hours with known costs;
- Interties enhancing intertie scheduling to improve efficiency and flexibility;
- Demand response auction evolving the demand response auction;
- Capacity trade develop a system to enable capacity exports; and
- Incremental capacity auction develop capacity auction for incremental capacity needs.

The IESO has since published more materials regarding the stakeholder engagement¹⁵³ and established the Market Renewal Working Group (MRWG).¹⁵⁴

The MRWG consists of 13 market participants (and an additional 2 alternates) whose roles include assisting the IESO by providing valuable insight, technical expertise and advice to support the development and implementation of the Market Renewal initiatives as well as playing an active role in reviewing the preliminary analyses related to qualitative and quantitative aspects of the work plan.¹⁵⁵ The MRWG met in August and October of 2016 and has been solicited to provide input into the analysis regarding the potential benefits of carrying out the Market Renewal initiatives.

 ¹⁵² For more information on the IESO materials regarding these proposed projects, see the IESO presentation
 "Future Market Design Considerations", available at: <u>http://www.ieso.ca/Documents/consult/ME/ME-20160419-Market-Design-Considerations.pdf</u>.
 ¹⁵³ For more information, see the IESO's Market Renewal stakeholder engagement webpage at:

 ¹⁵³ For more information, see the IESO's Market Renewal stakeholder engagement webpage at: http://ieso.ca/Pages/Participate/Stakeholder-Engagement/Market-Renewal.aspx.
 ¹⁵⁴ For the IESO's Terms of Reference for the Market Renewal Working Group, see:

¹⁵⁴ For the IESO's Terms of Reference for the Market Renewal Working Group, see: http://ieso.ca/Documents/consult/ME/ME-20160624-Terms-of-Reference-Draft.pdf.

¹⁵⁵ For more information on the Market Renewal Working Group, see the IESO web page at: <u>http://ieso.ca/Pages/Participate/Stakeholder-Engagement/Working-Groups/Market-Renewal-Working-Group.aspx</u>.

The IESO proposes to finalize the report analyzing the estimated benefits from carrying out Market Renewal in the first quarter of 2017.¹⁵⁶

This stakeholder engagement is in its early stages; April 2016 IESO materials state that the target date for finalization of the work plan is "Late 2016/Early 2017".¹⁵⁷ The Panel is very supportive of the proposed reforms and encourages the IESO to make developing and implementing these reforms on a timely basis a high priority.

1.2 Enabling System Flexibility

The IESO has launched a stakeholder engagement in parallel with the Market Renewal initiative to explore the range of options that can be used to provide greater flexibility to the IESO to manage the growing fleet of variable (primarily wind and solar) generating resources.¹⁵⁸ Similar to the Panel's findings in Chapter 2 of this report, the IESO has recognized the challenge that forecast errors pose to operations, and is soliciting options from stakeholders to help meet this need.

The IESO has asked market participants to identify potential solutions to the issue of greater required flexibility and will present a list of options for evaluation in the fourth quarter of 2016.¹⁵⁹ The Panel is supportive of the IESO's efforts to pursue market-based solutions to meet this identified need, and will be tracking this engagement with interest.

2 Update on Past Panel Recommendations and Investigations

2.1 Limiting CMSC Payments During Ramp-Down

In its June 2013 Monitoring Report, the Panel recommended that the IESO implement a permanent, rule-based solution to eliminate self-induced Congestion Management Settlement

¹⁵⁶ For more information, see the IESO presentation on the Proposed Approach to the Benefits Case Analysis available at: http://ieso.ca/Documents/consult/MRWG/MRWG-20160824-Presentation.pdf.

¹⁵⁷ For more information on the IESO's proposed timelines, see page 15 of the IESO's presentation "Developing a Market Renewal Workplan", available at: <u>http://www.ieso.ca/Documents/consult/ME/ME-20160419-Developing-a-Workplan.pdf</u>.

¹⁵⁸ For more information, see the Stakeholder Engagement webpage, available at:

http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx ¹⁵⁹ For more information on the flexibility products which have been discussed by the IESO in the context of the stakeholder engagement, see the IESO's August 16, 2016 presentation at: http://ieso.ca/Documents/consult/ESF/ESF-20160816-Presentation.pdf.

Credit (CMSC) payments to ramping down generators. On June 24, 2015, the IESO approved a Market Rule amendment that would mitigate, but not eliminate such payments. However, the effective date of that Market Rule has been tied to the implementation of the required IT system changes at the IESO.¹⁶⁰ As such, the effective date of the market rule has been postponed several times, most recently on September 6, 2016.¹⁶¹ As of the publication of this report, there is no publically available estimate of the effective date of the rule. The Panel estimates that this postponement has resulted in approximately \$1.5 million in CMSC payments during ramp-down that would have been mitigated by the new market rule. The Panel will continue to monitor both the implementation of the rule and the payments accruing to generators as a result of the postponement.

2.2 IESO Concludes its Investigation into Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.

In August 2015, the Panel published a report on its investigation into the conduct of Abitibi-Consolidated Company of Canada (Abitibi) and its affiliate Bowater Canadian Forest Products Inc. (Bowater) (Resolute FP Canada Inc. (Resolute) had become the successor in interest to Abitibi and Bowater when the Panel's report was published), which concluded that the market participants engaged in gaming while operating as dispatchable loads. The public version of the investigation report, redacted to address confidentiality considerations, is available on the Ontario Energy Board's website.¹⁶²

The Panel's gaming investigation related to CMSC payments received by the two market participants from January to August 2010 when their facilities were operating as dispatchable loads. The Panel found that both market participants engaged in gaming, and in doing so received \$20.4 million in unwarranted CMSC payments over the eight-month period in question.

¹⁶⁰ For more information on Market Rule amendment 414, see the IESO's Market Rule Amendment Proposal, available at:

http://www.ieso.ca/Documents/Amend/mr2015/MR 00414 R00 Amendment Proposal Ramp Down CMSC v5. 0.pdf

^{0.}pdf ¹⁶¹ For more information see the SE-111 stakeholder engagement webpage, available at: <u>http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-111.aspx</u>

¹⁶² See the Panel's "Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.", available at: <u>http://www.ontarioenergyboard.ca/oeb/ Documents/MSP/MSP Investigation Report CMSC Abitibi Bowater 2015.pdf</u>
These CMSC payments were recovered through uplift and ultimately paid by Ontario consumers. In its report, the Panel encouraged the IESO to take whatever action may be open to it to recover the amounts paid to Abitibi and Bowater as a result of their gaming behaviour.

As a result of the IESO's own investigation into whether the two dispatchable loads breached the Market Rules, a non-compliance letter was issued to Resolute by the IESO in August 2016 for breach of the requirements of certain provisions of the Market Rules during the period October, 2004 to September, 2013. The non-compliance letter was issued as part of a settlement between the IESO and Resolute.

Without acknowledging or admitting any breach of the Market Rules, Resolute accepted, without contest, the IESO's determinations and agreed to repay \$8,750,000. This payment is in addition to an earlier voluntary repayment of \$1,825,010. Resolute also agreed to develop and implement an Internal Compliance Program in order to ensure that potential breaches of the Market Rules are detected and corrected.¹⁶³

3 Recommendations in this Report

In chapter 2 the Panel reported on outcomes in the OR market and identified the need to consider more transparent real-time OR price signals. In particular, the IESO currently offers Control Action Operating Reserve in large blocks, which can mask the increasing value of OR as more Control Action Operating Reserve is scheduled.

Recommendation 2-1

Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.

¹⁶³ For more information on this and other enforcement sanctions, see the IESO's enforcement sanctions webpage, available at: <u>http://www.ieso.ca/Pages/Participate/Market-Oversight/Sanctions.aspx</u>

In chapter 3 the Panel reviewed the history of the IESO's RT-GCG program and commented on a number of significant concerns with that program. The Panel has made two recommendations that, together, would result in savings of approximately \$40 million per year.

Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.

Recommendation 3-2

The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all congestion management settlement credit payments received, on:

(a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and
(b) output generated after the end of the facility's MGBRT.