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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2010 – October 2010

Ontario Energy Commission de l'énergie

February 2011

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Ontario

February 28, 2011

Ms. Cynthia Chaplin
Chair
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Chaplin:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Roger Ware and Bill Rupert, I am pleased to provide you with the Panel's 17th semi-annual Monitoring Report on the IESO-administered wholesale electricity markets.

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

As you know, Tom Rusnov's term on the Panel came to an end on January 1st, 2011. Tom was appointed to the Panel at its inception in 2002. I would like to recognize and thank him for his enormous contributions to the Panel's work and to each of its reports over the past eight years.

Best Regards,

Neil Campbell
Chair, Market Surveillance Panel

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Executive Summary

This summer 2010 report represents an abbreviated report and does not include the detailed overview of market outcomes historically published in Chapter 1 or a Statistical Appendix. A detailed Chapter 1 and a Statistical Appendix will be published in the comprehensive winter 2010/2011 report.

Overall Assessment

Ontario's IESO-administered wholesale electricity market has operated reasonably well according to the hybrid design set for it over the summer period, May 2010 to October 2010, although there were occasions where actions by market participants or the IESO led to inefficient outcomes. In addition, the Panel continues to identify areas for improvement in the market design. In particular, the Panel has observed numerous complications associated with the two-sequence market structure that have undermined efficiency or increased costs to load with little or no apparent benefit. To this end, the Panel has recommended that the IESO work with stakeholders to examine the feasibility of evolving beyond the two-sequence market structure.

The Market Surveillance Panel (MSP or Panel) did not find an abuse of market power to have occurred in this period. However, an investigation undertaken at the request of a market participant is proceeding and the Panel will report on the outcome of this investigation when it is completed.

The MSP initiated a formal gaming investigation in this period associated with congestion management settlement credit (CMSC) payments. This investigation is ongoing and the Panel will report on the outcome of this enquiry when it is completed.

Demand and Supply Conditions

Ontario Demand totalled 71.5 TWh this summer, up by 4.3 TWh (6.4 percent) compared to the same period last summer. There were increases in demand in every month, relative to the prior year, with the exception of October where there was a small decline of 1.8 percent. Warm weather was an important factor leading to higher demand this summer.

During the period May to October 2010 there was one significant addition to Ontario's generation supply as well as a reduction in coal-fired generation. The Halton Hills generating station, a 632 MW combined-cycle facility located in Halton Hills, Ontario, became dispatchable beginning September 1, 2010 after commissioning since late April 2010. In response to the Ontario Government's requirement that coal-fired generation be phased out by 2014, Ontario Power Generation (OPG) closed down four coal-fired units totalling approximately 2,000 MW of generation capacity in October 2010. These four units represented a reduction to Ontario's supply capacity of approximately 5 percent and a 31 percent reduction in the coal-fired generating capacity in Ontario.

Market Prices and the Global Adjustment

The average Hourly Ontario Energy Price (HOEP) was $39.45/MWh during the recent summer period, representing an increase of 62.5 percent from $24.28/MWh last summer. The higher HOEP was primarily attributable to higher Ontario demand and lower hydroelectric supply during the recent summer period. The highest monthly average HOEP occurred in July 2010 at $50.83/MWh representing the first time the average HOEP exceeded $50.00/MWh since January 2009 ($53.22/MWh).

Although the HOEP increased significantly during this period, the price including the Global Adjustment increased only slightly from $63.05/MWh last summer to $63.98/MWh (1.5 percent) this summer. The Global Adjustment, which averaged $24.53/MWh, exceeded the average HOEP in only one month during this sixth month, summer reporting period (October).

Market Outcomes

There were seven hours in the summer period in which the HOEP exceeded $200/MWh. All instances were consistent with normal supply/demand variation when at least one of the following occurred:

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

Over the current reporting period, there were 22 five-minute intervals when the market clearing price (MCP) was set by hydroelectric units at offer prices above $500/MWh, which is approximately the same as the same period last year. However, there was a noticeable increase in the proportion of energy offers above $500/MWh relative to total offers from peaking hydro resources since May 2008 as well as an increase in submitted offers between $400/MWh and $500/MWh from these same facilities. The Panel has asked the MAU to continue to monitor and report on trends in the frequency of high-priced hydro offers that set the real-time MCP.

The number of hours when the HOEP was negative decreased substantially this summer. There were 19 negative-priced hours this summer, which is down from 121 hours last summer (an 84 percent decline). All negative-priced hours this period occurred in September and October.

In the last report, the Panel reported that a change in offer strategy at a nuclear facility led to the lower observed MCPs in April 2010. The impact of the change continued to result in some intervals with MCPs below - $100/MWh over the recent summer period although the frequency of these low MCPs was small. Over the six-month period, there were 28 intervals when the MCP fell below -$100/MWh where nuclear resources were most often marginal. Individual interval MCP reached a record low of -$128.30/MWh in HE 7 on June 9, 2010, which surpassed the previous record low MCP by $0.15/MWh.

Matters to Report in the Ontario Electricity Marketplace

Market Rule Changes

The IESO implemented an urgent rule amendment on August 27, 2010, temporarily suspending all constrained-off CMSC payments to dispatchable loads in order to address a problem identified by the Panel and discussed in its August 2010 report. On December 3, 2010, the IESO replaced the urgent rule amendment with a new rule amendment, which was designed to eliminate CMSC payments to dispatchable-loads for self-induced ramping. Contrary to the Panel's recommendation, the IESO did not implement a rule change to eliminate CMSC payments to dispatchable loads that were induced by consumption deviation. The IESO believed these payments could largely be recovered through existing authorized processes or would otherwise be significantly limited by a separate rule change implemented on December 3, 2010 that limited the magnitude of constrained on CMSC payments to exports and dispatchable loads.
The Panel has requested that the MAU assess and report on the efficacy of the rules in achieving their intended function.

Surplus Baseload Generation (SBG)

Surplus baseload generation is a condition where market actions, or actions that are required for reliability, regulatory, safety or equipment concerns, require the reduction of imports and/or generation that results in the manoeuvre of nuclear units or the loss of fuel for a generator that is reduced (e.g. hydroelectric spill). In Ontario an SBG event refers to the supply and demand situation in the constrained sequence only. The constrained sequence reflects the actual system conditions and takes into account various transmission limitations within the province and at the interties. In Ontario, an SBG event may not necessarily translate into a low or negative market price. That is because the market price is calculated using the unconstrained sequence, which ignores internal and to a large extent actual intertie transmission capabilities. In fact, the market price during many SBG hours is often much greater than $0/MWh. This counter-intuitive pricing is caused primarily by fundamental differences between the two sequences as well as by IESO control actions taken to manage SBG conditions.

One action frequently taken to address SBG conditions is to curtail imports. The Panel believes that this control action should be reflected in the constrained sequence only but not in the unconstrained sequence. Curtailing imports is an out-of-market action and removing the imports from the unconstrained sequence tends to increase the market price during the SBG events. This is counter-intuitive, sends an incorrect signal to the marketplace and may increase the IESO's need to resort to additional out-of-market mechanisms to deal with SBG in future hours. The Panel therefore recommends that the IESO eliminate the impact of import curtailments on the unconstrained market schedule.

New Procedure Relating to the Release of Transmission Service

All intertie transactions require obtaining transmission service in both or multiple markets associated with the transaction. A failure to obtain transmission service in one jurisdiction results in intertie transaction failure on the side where the trader has obtained the transmission service.

One reason for intertie transaction failures has been that market scheduling occurred too late in Ontario to allow traders to obtain necessary transmission service in MISO (including Manitoba). To address the issue, the IESO implemented a new procedure on September 8, 2009, providing traders with additional time to arrange transmission service outside of Ontario. Since the implementation of the new procedure, exports by market participants other than Manitoba Hydro have increased significantly, from almost no exports historically to 150 GWh (approximately 68% of all exports on the Manitoba intertie) for the period September 2009 to August 2010. The Panel believes that this is a positive development.

Treatment of Transfer Capability Reductions outside of Ontario

On July 13-15, 2010 there was a transfer capability reduction[1] in Manitoba, which prevented any power from flowing between Ontario and MISO on the Ontario-Manitoba intertie. However, two market participants still offered or bid at the Manitoba interface, as permitted under the current market rules. In two days, Ontario loads paid $163,000 in uplift to two traders for constrained-off imports at the Manitoba interface even though the imports could not possibly have flowed. The Panel is currently assessing the behaviour of these market participants.

The Panel recognizes there are challenges in dealing with external transmission outages/deratings under the current market design. A locational pricing system could be very useful in addressing such issues. In the absence of such a market design, the Panel recommends that the IESO should not make CMSC payments where there are transmission capability reduction outside Ontario that prohibits power flow out of or into Ontario.

Unintended Consequences Caused by the Two-Sequence Market Structure in Ontario

In this report the Panel continues its investigation of market operation in the Ontario Northwest.

The Panel has repeatedly noted the large CMSC payments made to the region, amounts that are far out of proportion for an area which accounts for only a small portion of Ontario generation and load. Cumulative net CMSC payments to dispatchable resources (excluding dispatchable loads) since the start of the market amount to approximately $1.1 billion, of which roughly one-third (or $360 million) was paid to generators and intertie traders in the Northwest area. Of the $360 million in CMSC payments:

- $161 million were paid for not producing,

[1] An outage could result because the transmission line is totally out of service. On other occasions the transfer limit may be reduced to 0 MW because of system reliability.

- $146 million were paid for not importing, and
- $53 million were paid for constrained-on exports / imports / generation.

Many of the outcomes in the Northwest are associated with the two-sequence market design. This design has fundamental defects which are exacerbated by the nature of the surplus supply in the Ontario Northwest area and its limited connections to other areas. Based on additional investigation in this report, the Panel again concludes that Ontario loads receive little or no benefit for the constrained-off payments that they fund through uplift charges. These constrained-off payments neither help to relieve transmission congestion, nor provide accurate price signals to the marketplace.

In this report, as with previous reports, the Panel has recommended that CMSC payments be reduced or eliminated where they do not contribute to market efficiency. Stepping back and looking at the two-sequence structure in Ontario, it is clear that the majority of issues identified by the Panel since the market was established have dealt with inefficiencies introduced by the two-sequence market structure. In addition, the existing two-sequence structure is a barrier to allowing market participants' access to increased efficiencies available to other markets. For example, it causes complications in relation to potential movement to a day-ahead market, broader regional market initiatives being undertaken by neighbouring areas, and efficient management of Ontario's changing supply mix as well as implications for SBG and efficient imports and exports.

The Panel believes that, with the IESO embarking on a "market road map" process, now is the appropriate time to consider replacing the existing two-sequence market structure.

Inefficient Stops and Starts Under the IESO's Generation Cost Guarantee Program

During the most recent monitoring period, the MAU observed that some generation facilities synchronize and operate for their minimum run time, shut down for a short period of time (at times for as little as half an hour), and then resynchronize for another run. This creates higher costs to Ontario loads because the cost of shutting down a generation facility only to restart that facility several intervals later typically exceeds what it would have cost to keep that same facility online. During the summer period, the MAU observed 426 instances where generators operating under a guarantee went offline, only to restart again within two hours. For the summer 2010 period, the total efficiency loss due to these multiple re-starts was estimated to be $19 million. Nearly all of the efficiency loss was borne by consumers through uplift charges. The Panel also found that approximately 98% of the efficiency loss was associated with two market participants.

The Panel recommends that the IESO amend the Generation Cost Guarantee program to limit generators to one start-up cost guarantee submission per day unless the IESO requests a second start during a day, and re-examine whether the real-time GCG program continues to provide a net benefit to the Ontario market once the Enhanced Day-Ahead Commitment (EDAC) process is implemented.

Ontario's Long-Term Energy Plan

On November 23, 2010 the Ontario Government released its long term energy plan *Building our Clean Energy Future* (the Energy Plan). The Energy Plan represented the first significant update to the Province's long-term energy policy since the release of the OPA's 2007 Integrated Power System Plan. Under the Energy Plan the government has detailed at a high level its investment plans over the next 20 years.

The Plan reflects the changing demand and supply picture of the province anticipated over the next 20 years, change that is significantly influenced by policy initiatives. Demand is anticipated to recover from recessionary levels and be supplied by a fuel mix made up of refurbished nuclear, new nuclear, gas-fired supply and large investments in renewable energy dominated by increased wind, solar and biomass supply as well as increasing combined heat and power developments.

Prices for industrial consumers are forecast to rise by 2.7 percent per year, or 70 percent cumulatively (on a nominal basis) over the next 20 years. Prices for residential consumers, small businesses and farms are expected to double over the next 20 years (a growth rate of 3.5 percent per year), although almost half of this price increase is expected to be fully realized within the first 5 years (a growth rate of 7.9 percent per year). To reduce the impact of these price increases, the government has introduced a 10 percent rebate for Ontario residential, small business and farm consumers paid for outside of electricity rates.

The electricity consumers in Ontario must pay for these changes in electricity infrastructure and so must also benefit from these investments. In order to achieve long term benefit, the market structure and underlying contracts or rate regulation mechanisms are of paramount importance. The Panel believes that price fidelity of the market can be improved through fundamental redesign and that all contracts or rate regulation structures should include price responsiveness measures to efficiently operate within the planned marketplace.

Recommendations

The Panel has made four recommendations: one related to price fidelity, one related to dispatch and two related to hourly uplift payments. All recommendations are addressed to the IESO.

Price Fidelity

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

> **Recommendation 3-1 (Chapter 3, Section 2.2.6)**
>
> ***The IESO should not remove imports curtailed to address SBG conditions from the unconstrained market schedule. This could be accomplished by changing how the ADQh code operates with respect to the market schedule.***

Hourly Uplift Payments

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

Recommendation 3-2 (Chapter 3, Section 3.1)

Where there are transfer capability reductions outside Ontario that prohibit power flow out of or into Ontario, the IESO should not make CMSC payments. Possible methods might include but not limited to: removing the related offers/bids, reducing intertie transfer capability to zero, or establishing a mechanism for clawback of the CMSC payments.

Recommendation 3-3 (Chapter 3, Section 3.2.5)

As part of its "market road map" process, the IESO should work with stakeholders to examine the feasibility of replacing the two-sequence design with locational pricing, variable pricing for dispatchable resources or other alternatives.

Dispatch

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

Recommendation 3-4 (Chapter 3, Section 3.3)

(i) ***The IESO should resume work on Stakeholder Engagement 84 regarding elimination of self-induced CMSC payments for ramping down generators and should amend the Generation Cost Guarantee program to ensure that all guaranteed costs are considered as part of the dispatch optimization.***

(ii) ***On an interim basis until after-the-fact start-up cost submissions are capped by generator offer prices and CMSC payments to ramping down generators are eliminated, the IESO should amend the Generation Cost Guarantee***

program to limit generators to one start-up cost guarantee submission per day unless the IESO requests a second start during a day.

(iii) ***The IESO should re-examine whether the GCG program continues to provide a net benefit to the Ontario market once the Enhanced Day-Ahead Commitment (EDAC) process is implemented or as part of its "Market Roadmap" process.***

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Chapter 1: Market Outcomes May - October 2010

1. Highlights of Market Indicators

This Chapter provides a brief summary of the results for the IESO-administered markets over the period May 1, 2010 to October 31, 2010, with comparisons to the same period one year earlier. For ease of reference, the May to October period is referred to as the 'summer period'.[2]

1.1 Pricing

The average Hourly Ontario Energy Price (HOEP) was $39.45/MWh during the recent summer period, representing an increase of 62.5 percent from $24.28/MWh last summer. The lowest monthly average HOEP occurred in October 2010 at $29.39/MWh. With the exception of October 2010, the average monthly HOEP did not fall below $30.00/MWh in any month this summer while never exceeding that price in any month last summer. The highest monthly average HOEP occurred in July 2010 at $50.83/MWh representing the first time the average HOEP exceeded $50.00/MWh since January 2009 ($53.22/MWh).

Although the HOEP increased significantly during this period, the effective prices, which include the Global Adjustment (GA), increased only slightly to $63.98/MWh this summer from $63.05/MWh last summer (or a 1.5 percent increase). The GA, which averaged $24.53/MWh, exceeded the average HOEP in only one month this summer (October) and accounted for 38 percent of total effective price.

[2] Beginning in 2009, the Panel adopted a streamlined format for its summer semi-annual report. More detailed analysis of market outcomes will be provided in the report for the period ending October, 2011.

1.2 Demand

Ontario Demand totalled 71.5 TWh this summer, up by 4.3 TWh (6.4 percent) compared to the same period last summer. There were increases in demand in every month, relative to the prior year, with the exception of October where there was a small decline of 1.8 percent. The largest monthly percentage increases occurred in July and May 2010 at 17.8 and 8.6 percent above the prior year, respectively. Warm weather was an important factor leading to higher demand this summer.

1.3 Supply

There was one significant addition to Ontario's generation supply as well as a reduction in coal-fired generation between May and October 2010. The Halton Hills generating station, a 632 MW combined-cycle facility located in Halton Hills, Ontario, became dispatchable beginning September 1, 2010 after commissioning since late April 2010. In response to the Ontario Government's requirement that coal-fired generation be phased out by 2014, Ontario Power Generation (OPG) closed down four coal-fired units (two Nanticoke and two Lambton units), totalling approximately 2,000 MW of generation capacity in October 2010. These four units represented a reduction to Ontario's supply capacity of approximately 5 percent and a 31 percent reduction in the coal-fired generating capacity in Ontario.

1.4 Imports and Exports

Net exports totalled 3.6 TWh this summer, which is 1.4 TWh (28 percent) lower than last summer.

Exports (excluding linked wheel transactions) declined by 1.0 TWh (11.9 percent) to 7.4 TWh. The largest monthly declines in exports occurred in May and June as exports fell 49.8 percent and 32.1 percent respectively. Approximately 40 percent of exports occurred at the Quebec interties followed closely by the Michigan interties at 37 percent.

Imports (excluding linked wheel transactions) increased slightly from 3.4 TWh last summer to 3.7 TWh this summer, an increase of 0.3 TWh (8.8 percent). Off-peak hours accounted for 54 percent of the total flows, with 50 percent of total import volumes occurring at the Michigan intertie.

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Chapter 2: Analysis of Market Outcomes

1. Introduction

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

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

The MAU reviews the previous day's operation and market outcomes on a daily basis, not only to discern anomalous events but also to review:

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

The daily review process is an important part of market monitoring. Identification of anomalous events may lead to discussion with the relevant market participants and/or the IESO. Certain events may trigger more detailed examinations or formal investigations if the event pertains to potential abuse of market power, gaming or efficiency issues, The Panel defines high-priced hours as all hours in which the HOEP is greater than $200/MWh and low-priced hours as all hours in which the HOEP is less than $20/MWh,[3] including negative-priced hours.

There were seven hours during the latest six-month review period, May through October 2010, where the HOEP was greater than $200/MWh. Section 2.1 of this Chapter summarizes these events and factors contributing to the relatively high HOEPs.

Between May and October 2010, there were 361 hours in which the HOEP was less than $20/MWh, including 19 hours where the HOEP was negative. Section 2.2 of this Chapter reviews the factors typically driving prices to low levels in these hours.

In the January 2009 Monitoring Report, the Panel refined the indicators of anomalous uplift as payments in excess of $500,000/hour for Congestion Management Settlement Credits (CMSC) or Intertie Offer Guarantees (IOG) and $100,000/hour for OR payments. Daily payments of $1,000,000 for CMSC or IOG in the intertie zones are also considered anomalous.[4] During May to October 2010, there were no hours meeting the above criteria related to anomalous uplift events.

2. Anomalous HOEP

2.1 Analysis of High Price Hours

The MAU reviews all hours where the HOEP exceeds $200/MWh. The objective of this review is to understand the underlying causes that led to these high prices. More importantly, it serves the purpose of determining whether further analysis of the design or operation of the market or market participant conduct is warranted.

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

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

Table 2-1: Number of Hours with a High HOEP May to October 2007-2010, (Number of Hours)

	Number of Hours with HOEP >$200/MWh			
	2007	**2008**	**2009**	**2010**
May	0	0	0	0
June	2	4	0	1
July	1	3	0	4
August	0	2	4	0
September	0	5	0	1
October	1	3	2	1
Total	4	17	6	7

In previous reports, the Panel has noted that a HOEP greater than $200/MWh typically occurs during hours when at least one of the following occurs:

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

In addition, a significant increase in net exports in the unconstrained sequence from one hour to the next can place additional upward pressure on the market clearing price (MCP) in the first few intervals, thereby increasing the HOEP for that hour. Spikes in the MCP in the first few intervals of an hour in which net exports increase became more pronounced after the assumed ramp rate in the unconstrained sequence was reduced from 12 to three in September 2007. The change in the assumed ramp rate removed some of the fictitious energy supply that the unconstrained sequence had perceived to be ‘available’ to meet increased export demand at the beginning of the hour. This led to higher MCPs in the first intervals of hours in which net exports were increasing.[5]

[5] For more details, see the Panel’s July 2008 Monitoring Report, pp. 134-140.

Each of the factors discussed above has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. Spikes in the HOEP above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[6]

June 28, 2010 HE 11

On June 28, 2010 HE 11, the HOEP was $314.84/MWh. Factors that contributed to the price spike included demand under-forecast, wind output less than forecast, and numerous generator outages leading to relatively tight real-time supply conditions.

Prices and Demand

Table 2-2 lists the real-time and pre-dispatch information for HE 11 on June 28, 2010. The MCP reached a high of $509.17/MWh in intervals 10 and 11 and was above $400/MWh in five other intervals. On average, real-time demand came in 444 MW heavier than the forecast in pre-dispatch while there was 100 MW of import failure in HE 11.

[6] The Panel's March 2003 Monitoring Report, pp. 11-16 noted that a supply cushion lower than 10 percent was more likely to be associated with a price spike. The Panel began reporting a revised supply cushion calculation in its July 2007 Monitoring Report, pp. 79-81. It remains the case that when the supply cushion is below 10 percent, a price spike becomes increasingly likely.

Table 2-2: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports June 28, 2010, HE 11 ($/MWh and MW)

Delivery Hour	Int	PD MCP	RT MCP	MCP Difference	PD ONT Demand	RT ONT Demand	ONT Demand Difference	PD Net Exports	RT Net Exports	Net Exports Difference
11	**1**	53.37	117.12	63.75	19,954	20,114	160	1,564	1,664	100
11	**2**	53.37	119.36	65.99	19,954	20,171	217	1,564	1,664	100
11	**3**	53.37	140.00	86.63	19,954	20,176	222	1,564	1,664	100
11	**4**	53.37	415.13	361.76	19,954	20,327	373	1,564	1,664	100
11	**5**	53.37	174.34	120.97	19,954	20,366	412	1,564	1,664	100
11	**6**	53.37	415.13	361.76	19,954	20,441	487	1,564	1,664	100
11	**7**	53.37	415.13	361.76	19,954	20,503	549	1,564	1,664	100
11	**8**	53.37	415.13	361.76	19,954	20,555	601	1,564	1,664	100
11	**9**	53.37	415.13	361.76	19,954	20,553	599	1,564	1,664	100
11	**10**	53.37	509.17	455.8	19,954	20,588	634	1,564	1,664	100
11	**11**	53.37	509.17	455.8	19,954	20,606	652	1,564	1,664	100
11	**12**	53.37	133.32	79.95	19,954	20,379	425	1,564	1,664	100
Average		**53.37**	**314.84**	**261.47**	**19,954**	**20,398**	**444**	**1,564**	**1,664**	**100**

Assessment

The main factor leading to the high prices in HE 11 was the inaccuracy of the pre-dispatch demand forecast. The pre-dispatch forecast was 19,954 MW while the real-time average forecast was 444 MW (2.2 percent) higher at 20,398 MW. The largest pre-dispatch to real-time demand differences occurred in intervals 11 and 12 of HE 11 at 634 MW (3.2 percent) and 652 MW (3.3 percent) respectively, which coincided with the highest interval MCPs.

Self-scheduling generators produced 189 MW (12 percent) less than forecast in pre-dispatch with approximately half of the shortfall attributable to wind generators. In the one-hour ahead pre-dispatch run for HE 11, wind generators were scheduled to produce 267 MW. In real-time, these generators produced 180 MW, which is 87 MW (33 percent) less than anticipated.

Going into June 28, 2010, there were numerous generator outages including four fossil-fired units and three nuclear units either on planned or forced outage resulting in tight supply conditions. An additional fossil-fired unit was derated by 200 MW. In total there was approximately 4,700 MW of unavailable generation capacity in HE 11 (13 percent of total domestic generation capacity). Figure 2-1 below illustrates the real-time generation supply curve in HE 11 on June 28, 2010 above 10,000 MW.[7]

Figure 2-1 – Real-time Energy Offer Curve
June 28, 2010, HE 11
($/MWh)

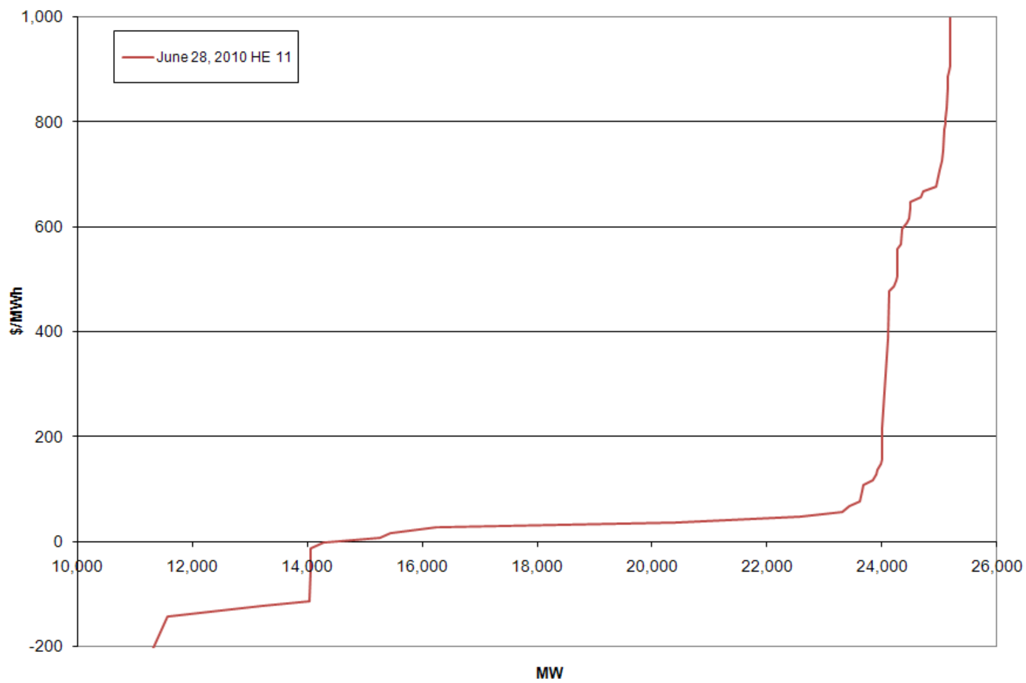

Table 2-3 shows that the real-time MCP was set by hydroelectric resources in all intervals of HE 11 on June 28, 2010, with 7 intervals being set at prices above $400/MWh.

[7] The energy offer curve includes all energy offers from generators, including those that provided operating reserve in HE 11.

Table 2-3: Real-time MCP and Fuel Type of Price Setting Resource June 28, 2010, HE 11 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Marginal Resource (Fuel Type)
11	1	117.12	Hydroelectric
11	2	119.36	Hydroelectric
11	3	140.00	Hydroelectric
11	4	415.13	Hydroelectric
11	5	174.34	Hydroelectric
11	6	415.13	Hydroelectric
11	7	415.13	Hydroelectric
11	8	415.13	Hydroelectric
11	9	415.13	Hydroelectric
11	10	509.17	Hydroelectric
11	11	509.17	Hydroelectric
11	12	133.32	Hydroelectric
Average		**314.84**	

The pricing of hydroelectric units is discussed in more detail in Section 2.1.7 below.

July 7, 2010 HE 10

On July 7, 2010 HE 10, the HOEP was $272.47/MWh. Higher than projected demand, failed imports, and slightly less wind production in real-time all contributed to the price spike.

Prices and Demand

Table 2-4 lists the real-time and pre-dispatch information for HE 10 on July 7, 2010. The MCP in HE 10 gradually increased from $105.21/MWh in the first interval to $167.51/MWh in interval seven before noticeably increasing above $400/MWh in the remaining intervals of the hour. The peak MCP occurred during the final two intervals of HE 10 at $501.87/MWh.

Average Ontario Demand came in at 23,157 MW, which was 490 MW (2.2 percent) higher than the pre-dispatch forecast. The largest interval discrepancies occurred at the end of HE 10 when the MCPs were highest. Ontario demand was 840 MW (3.7 percent) higher than pre-dispatch demand in the final interval of HE 10.

An increase of 311 MW (75 percent) in net exports during the hour placed additional pressure on the real-time HOEP. The increase in net exports was attributable to 311 MW of failed imports at the Michigan interface. The 311 MW of failed imports resulted from a 200 MW transaction that failed due to inability of a participant to acquire transmission service in the external jurisdiction and a 111 MW transaction that was curtailed due to external conditions in MISO.

Table 2-4: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports July 7, 2010, HE 10 ($/MWh and MW)

Delivery Hour	Int	PD MCP	RT MCP	MCP Difference	PD ONT Demand	RT ONT Demand	ONT Demand Difference	PD Net Exports	RT Net Exports	Net Exports Difference
10	1	64.33	105.21	40.88	22,667	22,699	32	415	726	311
10	2	64.33	111.64	47.31	22,667	22,780	113	415	726	311
10	3	64.33	121.54	57.21	22,667	22,850	183	415	726	311
10	4	64.33	135.05	70.72	22,667	22,987	320	415	726	311
10	5	64.33	135.05	70.72	22,667	23,012	345	415	726	311
10	6	64.33	161.27	96.94	22,667	23,098	431	415	726	311
10	7	64.33	167.51	103.18	22,667	23,233	566	415	726	311
10	8	64.33	415.13	350.80	22,667	23,386	719	415	726	311
10	9	64.33	415.13	350.80	22,667	23,404	737	415	726	311
10	10	64.33	498.42	434.09	22,667	23,430	763	415	726	311
10	11	64.33	501.87	437.54	22,667	23,497	830	415	726	311
10	12	64.33	501.87	437.54	22,667	23,507	840	415	726	311
Average		**64.33**	**272.47**	**208.14**	**22,667**	**23,157**	**490**	**415**	**726**	**311**

Although less significant in magnitude, lower real-time wind and self-schedule production relative to submitted forecasts also placed additional upward pressure on the HOEP. Self-scheduling and intermittent generators produced 94 MW (6.5 percent) less than the pre-dispatch forecast, of which wind generators produced 67 MW (82.7 percent) less in real-time relative to the pre-dispatch projections.

Assessment

The spike in HOEP in HE 10 on July 7, 2010 was largely a consequence of real-time demand exceeding the pre-dispatch forecast (490 MW) as well as 311 MW of failed imports. Table 2-5 below illustrates the successive changes in forecast demand and scheduled intertie transactions from the final Day-Ahead Commitment Process (DACP) run (19-hours ahead of real-time) up to the one-hour ahead pre-dispatch run. Pre-dispatch prices fluctuated between $47.48/MWh in the final DACP run and $64.33/MWh in the two hours prior to real-time.

Ontario Demand projections fluctuated between 22,603 MW (in the final DACP run) and 22,721 MW (5 hours ahead pre-dispatch run) and were all much less than real-time Ontario Demand of 23,157 MW. As mentioned above, the change in net exports was attributable to a decline in imports from 2,230 MW scheduled in the one-hour ahead pre-dispatch run to 1,919 MW in real-time.

Table 2-5: Prices, Ontario Demand and Imports / Exports
July 7, 2010, HE 10
($/MWh and MW)

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
DACP (19)	47.48	22,603	0	n/a	0
10	57.45	22,694	1,883	1,470	(413)
5	50.00	22,721	1276	1,470	194
4	49.56	22,704	1350	1,170	(180)
3	52.02	22,712	1378	1,495	117
2	64.33	22,662	2230	2,645	415
1	64.33	22,667	2230	2,645	415
Real-Time Average	272.47	23,157	1,919	2,645	726

Table 2-6 shows that the real-time MCP was set by hydroelectric resources in nine of the 12 intervals in HE 10 on July 7, 2010 while a gas-fired generator set the MCP in one interval and a dispatchable load set the MCP in two intervals.

Table 2-6: Real-time MCP and Fuel Type of Price Setting Resource July 7, 2010, HE 10 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Marginal Resource (Fuel Type)
10	1	105.21	Gas
10	2	111.64	Hydroelectric
10	3	121.54	Hydroelectric
10	4	135.05	Hydroelectric
10	5	135.05	Hydroelectric
10	6	161.27	Hydroelectric
10	7	167.51	Hydroelectric
10	8	415.13	Dispatchable Load
10	9	415.13	Dispatchable Load
10	10	498.42	Hydroelectric
10	11	501.87	Hydroelectric
10	12	501.87	Hydroelectric
Average		**272.47**	

The pricing of hydroelectric units is discussed in more detail in Section 2.1.7 below.

July 19, 2010 HE 15

On July 19, 2010 HE 15, the HOEP was $218.74/MWh. Import curtailments at the beginning of the hour, demand under-forecast, and a number of deratings at fossil-fired generators all contributed to the high price in HE 15.

Prices and Demand

Table 2-7 presents pre-dispatch and real-time price and demand information for July 19, 2010, HE 15. The MCP spiked up to $485.13/MWh in the first two intervals of the hour before fluctuating between $236.47/MWh and $118.60/MWh for the remaining 10 intervals of the hour.

Real-time demand was higher in all intervals of HE 15 relative to the pre-dispatch forecast of 20,591 MW with the largest demand differences occurring in the last three intervals of the hour (peak difference of 619 MW or 3 percent in interval 11). .

The difference in net exports between pre-dispatch and real-time varied throughout the hour, which is a consequence of the 15-minute scheduling and evaluation of intertie transactions in the external markets.[8] Net exports increased by 132 MW in intervals one to three relative to the pre-dispatch schedule, which placed additional upward pressure on real-time prices. The increase in net exports was due to some import transactions scheduled at the Michigan and Minnesota interfaces that failed due to ramp limitations in the external market and was reflected in all intervals in HE 15. After interval three, net exports declined in real-time relative to pre-dispatch as 225 MW of exports scheduled at the New York interface were failed by the external ISO for security reasons. The quantity of the export failures to New York subsequently increased in intervals 10 to 12 by an additional 163 MW leading to overall declines in net exports of 256 MW occurring in the last quarter of the hour.

[8] The Panel previously recommended that a 15-minute dispatch algorithm would provide efficiency benefits to the Ontario market. See the Panel's December 2007 Monitoring Report, p. 160.

***Table 2-7: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports
July 19, 2010, HE 15
($/MWh and MW)***

Delivery Hour	Int	PD MCP	RT MCP	MCP Difference	PD ONT Demand	RT ONT Demand	ONT Demand Difference	PD Net Exports	RT Net Exports	Net Exports Difference
15	**1**	52.19	485.13	432.94	20,591	20,942	351	1,791	1,923	132
15	**2**	52.19	485.13	432.94	20,591	20,951	360	1,791	1,923	132
15	**3**	52.19	236.47	184.28	20,591	20,860	269	1,791	1,923	132
15	**4**	52.19	178.85	126.66	20,591	21,005	414	1,791	1,698	-93
15	**5**	52.19	224.56	172.37	20,591	21,069	478	1,791	1,698	-93
15	**6**	52.19	184.13	131.94	20,591	21,041	450	1,791	1,698	-93
15	**7**	52.19	125.35	73.16	20,591	21,009	418	1,791	1,698	-93
15	**8**	52.19	157.11	104.92	20,591	21,044	453	1,791	1,698	-93
15	**9**	52.19	125.34	73.15	20,591	21,010	419	1,791	1,698	-93
15	**10**	52.19	125.34	73.15	20,591	21,156	565	1,791	1,535	-256
15	**11**	52.19	178.85	126.66	20,591	21,210	619	1,791	1,535	-256
15	**12**	52.19	118.60	66.41	20,591	21,137	546	1,791	1,535	-256
Average		**52.19**	**218.74**	**166.55**	**20,591**	**21,036**	**445**	**1,791**	**1,714**	**-77**

Assessment

A series of forced deratings prior to real-time placed additional upward pressure on prices in HE 15. Three units at a fossil-fired generating station were in service commissioning over the afternoon hours of July 19, 2010. In real-time, the facility produced a combined 219 MW less than what was anticipated in pre-dispatch for HE 15, largely due to an outage of one of the gas-fired units and consequently the loss of output from the facility's steam unit due to the outage. Two additional fossil-fired generators were forced derated by a combined 195 MW over the hour due to fuel source issues. These deratings contributed to a real-time production loss of over 400 MW (1.9 percent of total Ontario Demand forecast in pre-dispatch) relative to the pre-dispatch schedule and were important factors leading to the high HOEP of $218.74/MWh in HE 15.

Table 2-8 shows that the real-time MCP was set by hydroelectric resources in all intervals of HE 15 on July 19, 2010 with the exception of interval 12, which was set by a gas-fired unit.

Table 2-8: Real-time MCP and Fuel Type of Price Setting Resource July 19 2010, HE 15 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Marginal Resource (Fuel Type)
15	1	485.13	Hydroelectric
15	2	485.13	Hydroelectric
15	3	236.47	Hydroelectric
15	4	178.85	Hydroelectric
15	5	224.56	Hydroelectric
15	6	184.13	Hydroelectric
15	7	125.35	Hydroelectric
15	8	157.11	Hydroelectric
15	9	125.34	Hydroelectric
15	10	125.34	Hydroelectric
15	11	178.85	Hydroelectric
15	12	118.60	Gas
Average		**218.74**	

The pricing of hydroelectric units is discussed in more detail in Section 2.1.7 below.

July 27, 2010 HE 16 and HE 18

On July 27, 2010, the HOEP reached $492.89/MWh in HE 16 and $316.46/MWh in HE 18. Tight supply conditions were prevalent as numerous fossil and nuclear units were on forced outage. Ontario Demand was heavier in real-time than in pre-dispatch leading to the high prices in HE 16 while a forced outage to a fossil-fired unit late in HE 17 led to high prices in HE 18. Wind forecast error, especially in HE 18, also contributed to the high real-time prices.

Prices and Demand

Table 2-9 presents pre-dispatch and real-time price and demand information for July 27, 2010, HE 16 to HE 18. Although the HOEP in HE 17 did not exceed $200/MWh, it came close at $194.88/MWh.

The HOEP in HE 16 was $492.89/MWh. The MCPs in the hour fluctuated between $479.13/MWh and $571.80/MWh. The HOEP in HE 17 was $194.88/MWh and was above $200/MWh in seven of the 12 intervals, with the highest MCP occurring in interval 12 at $315.14/MWh. Finally, the HOEP in HE 18 was $316.46/MWh. MCPs in the hour were above $400/MWh during the first seven intervals of HE 18 before gradually declining to less than $110/MWh in the final three intervals.

Demand forecast error was a factor for the high prices in HE 16 and to a lesser extent in HE 17, but was not a factor for the high prices in HE 18. Real-time demand was higher than pre-dispatch demand in HE 16 by 515 MW (2.3 percent) with the highest interval demand difference of 577 MW (2.6 percent) in interval eight, which also coincided with the highest MCP in the hour at $571.80/MWh. Real-time Ontario Demand was between 443 MW and 577 MW higher than in pre-dispatch for all intervals of HE16.

At the beginning of HE 16, the demand forecast was increased for HE 17 to HE 22 by 300 MW as temperatures were higher than anticipated. Ontario demand was 126 MW (0.6 percent) higher in real-time compared to pre-dispatch for HE 17 with the largest interval difference of 198 MW (0.9 percent) in interval seven. By HE 18, real-time demand was lower than the pre-dispatch forecast by 75 MW (0.3 percent) at 22,052 MW.

Table 2-9: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports July 27, 2010, HE 16–18 ($/MWh and MW)

Delivery Hour	Int	PD MCP	RT MCP	MCP Difference	PD ONT Demand	RT ONT Demand	ONT Demand Difference	PD Net Exports	RT Net Exports	Net Exports Difference
16	**1**	73.00	479.13	406.13	22,002	22,461	459	833	883	50
16	**2**	73.00	479.13	406.13	22,002	22,445	443	833	883	50
16	**3**	73.00	479.13	406.13	22,002	22,481	479	833	883	50
16	**4**	73.00	479.13	406.13	22,002	22,512	510	833	883	50
16	**5**	73.00	498.00	425.00	22,002	22,536	534	833	883	50
16	**6**	73.00	479.13	406.13	22,002	22,468	466	833	883	50
16	**7**	73.00	479.13	406.13	22,002	22,509	507	833	883	50
16	**8**	73.00	571.80	498.80	22,002	22,579	577	833	883	50
16	**9**	73.00	497.00	424.00	22,002	22,554	552	833	883	50
16	**10**	73.00	497.00	424.00	22,002	22,561	559	833	883	50
16	**11**	73.00	497.00	424.00	22,002	22,566	564	833	883	50
16	**12**	73.00	479.13	406.13	22,002	22,537	535	833	883	50
Average		**73.00**	**492.89**	**419.89**	**22,002**	**22,517**	**515**	**833**	**883**	**50**
17	**1**	80.01	157.43	77.42	22,360	22,489	129	426	376	-50
17	**2**	80.01	187.13	107.12	22,360	22,500	140	426	376	-50
17	**3**	80.01	200.70	120.69	22,360	22,518	158	426	376	-50
17	**4**	80.01	157.43	77.42	22,360	22,441	81	426	376	-50
17	**5**	80.01	200.70	120.69	22,360	22,550	190	426	376	-50
17	**6**	80.01	200.70	120.69	22,360	22,513	153	426	376	-50
17	**7**	80.01	200.70	120.69	22,360	22,558	198	426	376	-50
17	**8**	80.01	200.70	120.69	22,360	22,511	151	426	376	-50
17	**9**	80.01	157.43	77.42	22,360	22,447	87	426	376	-50
17	**10**	80.01	200.70	120.69	22,360	22,503	143	426	376	-50
17	**11**	80.01	157.43	77.42	22,360	22,449	89	426	376	-50
17	**12**	80.01	315.14	235.13	22,360	22,351	-9	426	376	-50
Average		**80.01**	**194.68**	**114.67**	**22,360**	**22,486**	**126**	**426**	**376**	**-50**
18	**1**	75.31	501.80	426.49	22,127	22,261	134	486	286	-200
18	**2**	75.31	409.13	333.82	22,127	22,164	37	486	286	-200
18	**3**	75.31	497.31	422.00	22,127	22,178	51	486	286	-200
18	**4**	75.31	409.14	333.83	22,127	22,162	35	486	286	-200
18	**5**	75.31	409.13	333.82	22,127	22,070	-57	486	286	-200
18	**6**	75.31	409.13	333.82	22,127	22,100	-27	486	286	-200
18	**7**	75.31	409.13	333.82	22,127	22,089	-38	486	286	-200
18	**8**	75.31	315.13	239.82	22,127	22,049	-78	486	286	-200
18	**9**	75.31	125.46	50.15	22,127	21,927	-200	486	286	-200
18	**10**	75.31	110.00	34.69	22,127	21,905	-222	486	286	-200
18	**11**	75.31	101.09	25.78	22,127	21,834	-293	486	286	-200
18	**12**	75.31	101.09	25.78	22,127	21,879	-248	486	286	-200
Average		**75.31**	**316.46**	**241.15**	**22,127**	**22,052**	**-75**	**486**	**286**	**-200**

Assessment

One-hour ahead pre-dispatch prices were above $70/MWh for HE 16 to HE 18 on July 27, 2010 as supply conditions were relatively tight. Three nuclear units and four fossil units were forced out of service for a combined 3,700 MW of unavailable capacity (10 percent of total domestic generation capacity).

To further aggravate the tight supply situation, a gas-fired unit was forced out of service in interval 12 of HE 17 with a derate of the associated steam unit, leading to a loss of 350 MW in the unconstrained schedule in the final interval of HE 17 and all of HE 18. The immediate jump in MCP from $157.43/MWh in interval 11 to $315.14/MWh in interval 12 of HE 17 and the sustained high prices in HE 18 were in large part a result of this forced outage event.

Production of self-scheduling and intermittent (including wind) generators was also lower in real-time relative to pre-dispatch from HE 16 to HE 18. Real-time production was 105 MW (10.3 percent) lower in real-time in HE 16. The shortfall was more significant in HE 17 at 130 MW (12.7 percent) and 164 MW (15.4 percent) in HE 18, leading to additional upward pressure on real-time prices.

As shown in Table 2-10 below, the real-time MCP was set by hydroelectric resources in all intervals in HE 16, HE 17, and the first eight intervals of HE 18. Gas-fired units set the price in the remaining four intervals.

Table 2-10: Real-time MCP and Fuel Type of Price Setting Resource July 27, 2010, HE 16–18 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Marginal Resource (Fuel Type)
16	1	479.13	Hydroelectric
16	2	479.13	Hydroelectric
16	3	479.13	Hydroelectric
16	4	479.13	Hydroelectric
16	5	498.00	Hydroelectric
16	6	479.13	Hydroelectric
16	7	479.13	Hydroelectric
16	8	571.80	Hydroelectric
16	9	497.00	Hydroelectric
16	10	497.00	Hydroelectric
16	11	497.00	Hydroelectric
16	12	479.13	Hydroelectric
17	1	157.43	Hydroelectric
17	2	187.13	Hydroelectric
17	3	200.70	Hydroelectric
17	4	157.43	Hydroelectric
17	5	200.70	Hydroelectric
17	6	200.70	Hydroelectric
17	7	200.70	Hydroelectric
17	8	200.70	Hydroelectric
17	9	157.43	Hydroelectric
17	10	200.70	Hydroelectric
17	11	157.43	Hydroelectric
17	12	315.14	Hydroelectric
18	1	501.80	Hydroelectric
18	2	409.13	Hydroelectric
18	3	497.31	Hydroelectric
18	4	409.14	Hydroelectric
18	5	409.13	Hydroelectric
18	6	409.13	Hydroelectric
18	7	409.13	Hydroelectric
18	8	315.13	Hydroelectric
18	9	125.46	Gas
18	10	110.00	Gas
18	11	101.09	Gas
18	12	101.09	Gas

The pricing of hydroelectric units is discussed in more detail in Section 2.1.7 below.

September 26, 2010, HE 11

On September 26, 2010 HE 11, the HOEP was $319.34/MWh. Factors contributing to the price spike include real-time demand greater than the pre-dispatch forecast, the forced derating of a fossil-fired unit during HE 11, and significantly lower wind generation in real-time relative to pre-dispatch.

Prices and Demand

Table 2-11 presents pre-dispatch and real-time price and demand information for September 26, 2010, HE 11. The MCPs successively increased between intervals one to six beginning at $71.86/MWh in interval one. MCPs climbed above $500/MWh in four intervals in the hour and peaked at $547.74/MWh (interval six).

The 243 MW (1.7 percent) average difference between the pre-dispatch and real-time Ontario Demand forecast was one reason for the higher real-time prices. Real-time Ontario Demand was higher than the pre-dispatch forecast in all intervals of HE 11 and the difference exceeded 200 MW in 11 of the 12 intervals in the hour. Ontario Demand differences peaked at slightly above 300 MW in intervals 6 and 11, which is consistent with the highest observed MCPs in the hour of $547.74/MWh and $544.83/MWh respectively.

Table 2-11: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports September 26, 2010, HE 11 ($/MWh and MW)

Delivery Hour	Int	PD MCP	RT MCP	MCP Difference	PD ONT Demand	RT ONT Demand	ONT Demand Difference	PD Net Exports	RT Net Exports	Net Exports Difference
11	1	34.00	71.86	37.86	14,228	14,272	44	1,412	1,393	-19
11	2	34.00	99.00	65.00	14,228	14,439	211	1,412	1,393	-19
11	3	34.00	99.00	65.00	14,228	14,435	207	1,412	1,393	-19
11	4	34.00	128.78	94.78	14,228	14,527	299	1,412	1,393	-19
11	5	34.00	283.67	249.67	14,228	14,475	247	1,412	1,393	-19
11	6	34.00	547.74	513.74	14,228	14,534	306	1,412	1,393	-19
11	7	34.00	543.07	509.07	14,228	14,519	291	1,412	1,393	-19
11	8	34.00	227.01	193.01	14,228	14,448	220	1,412	1,393	-19
11	9	34.00	272.00	238.00	14,228	14,452	224	1,412	1,393	-19
11	10	34.00	472.00	438.00	14,228	14,495	267	1,412	1,393	-19
11	11	34.00	544.83	510.83	14,228	14,531	303	1,412	1,393	-19
11	12	34.00	543.07	509.07	14,228	14,524	296	1,412	1,393	-19
Average		**34.00**	**319.34**	**285.34**	**14,228**	**14,471**	**243**	**1,412**	**1,393**	**-19**

Assessment

There was little indication from the one-hour ahead pre-dispatch price that real-time prices would be high, as the one-hour ahead pre-dispatch price was $34.00/MWh for HE 11. However, numerous units were on long-term planned outages which are typically observed in the September/October shoulder load period heading into the winter season. There were two nuclear units and seven fossil-fired units on planned outages totally slightly over 4,000 MW of unavailable generation capacity (representing 11 percent of total domestic generation capacity).

Along with the observed demand forecast error, there were two additional factors that contributed to a high real-time HOEP in HE 11. First, a 300 MW forced derating of a fossil-fired unit beginning in interval 5 of HE 11 placed additional pressure on the MCPs for the remainder of the hour. Secondly, wind generators produced much less in real-time than was forecasted in pre-dispatch. Real-time wind generation output was only 5 MW across all units but pre-dispatch projections totaled 115 MW, representing a 110 MW (96 percent) discrepancy. As discussed in previous Panel reports and similar to demand forecast error, wind forecast error is a factor that can contribute to significant differences between pre-dispatch and real-time prices. Over the last six-month period, pre-dispatch forecasts were on average 19 MW higher than real-time wind production. Although the average difference does not appear large, wind forecast error can have a significant impact on prices in a given hour as shown on September 26, HE 11. Centralized wind forecasting is expected to help reduce hourly wind forecast errors and is due to begin in mid-2012.[9]

Table 2-12 shows that the real-time MCP was set by hydroelectric resources in 10 intervals of HE 11 on September 26, 2010 with the exception of intervals 1 and 4, which were set by gas-fired unit generators.

Table 2-12: Real-time MCP and Fuel Type of Price Setting Resource September 26, 2010, HE 11 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Marginal Resource (Fuel Type)
11	1	71.86	Gas
11	2	99.00	Hydroelectric
11	3	99.00	Hydroelectric
11	4	128.78	Gas
11	5	283.67	Hydroelectric
11	6	547.74	Hydroelectric
11	7	543.07	Hydroelectric
11	8	227.01	Hydroelectric
11	9	272.00	Hydroelectric
11	10	472.00	Hydroelectric
11	11	544.83	Hydroelectric
11	12	543.07	Hydroelectric
Average		**319.34**	

[9] http://www.ieso.ca/imoweb/marketdata/windpower.asp

The pricing of hydroelectric units is discussed in more detail in Section 2.1.7 below.

October 15, 2010, HE 19

On October 15, 2010 HE 19, the HOEP was $544.87/MWh, which was the highest HOEP in the latest six-month period.

Prices and Demand

Table 2-13 presents pre-dispatch and real-time price and demand information for October 15, 2010, HE 19. The one-hour ahead pre-dispatch price for HE 19 was $39.00/MWh, which was $505.87/MWh lower than the HOEP in the hour. The real-time MCP rose above $500/MWh in all intervals with the exception of interval 12 ($92.15/MWh) and peaked at $600.78/MWh between intervals two and eight. Pre-dispatch and real-time net exports were identical at 1,390 MW indicating that intertie transactions did not contribute to higher real-time prices.

Similar to some of the high-priced events summarized previously in this chapter, Ontario Demand forecast error contributed significantly to the high real-time MCPs in HE 19. Real-time Ontario Demand was higher than the pre-dispatch forecast by an average of 376 MW (2.3 percent) in HE 19 and higher over all intervals in the hour. Aside from interval 12, Ontario Demand was at least 324 MW higher in real-time relative to the pre-dispatch projection and climbed above 400 MW in four intervals with a peak of 456 MW in interval seven. The highest Ontario Demand differences occurred in intervals with the highest real-time MCPs of $600.78/MWh in HE 19.

Table 2-13: One-hour Ahead PD and RT MCP, Ontario Demand and Net Exports October 15, 2010, HE 19 ($/MWh and MW)

Delivery Hour	Int	PD MCP	RT MCP	MCP Difference	PD ONT Demand	RT ONT Demand	ONT Demand Difference	PD Net Exports	RT Net Exports	Net Exports Difference
19	1	39.00	505.52	466.52	16,636	16,960	324	1,390	1,390	0
19	2	39.00	600.78	561.78	16,636	17,081	445	1,390	1,390	0
19	3	39.00	600.78	561.78	16,636	17,064	428	1,390	1,390	0
19	4	39.00	600.78	561.78	16,636	17,062	426	1,390	1,390	0
19	5	39.00	600.78	561.78	16,636	17,058	422	1,390	1,390	0
19	6	39.00	600.78	561.78	16,636	17,035	399	1,390	1,390	0
19	7	39.00	600.78	561.78	16,636	17,092	456	1,390	1,390	0
19	8	39.00	600.78	561.78	16,636	17,030	394	1,390	1,390	0
19	9	39.00	578.44	539.44	16,636	17,008	372	1,390	1,390	0
19	10	39.00	578.44	539.44	16,636	17,015	379	1,390	1,390	0
19	11	39.00	578.44	539.44	16,636	17,018	382	1,390	1,390	0
19	12	39.00	92.15	53.15	16,636	16,719	83	1,390	1,390	0
Average		**39.00**	**544.87**	**505.87**	**16,636**	**17,012**	**376**	**1,390**	**1,390**	**0**

Assessment

Going into October 15, 2010, there were ten fossil-fired units and two nuclear units on planned outage representing approximately 4,900 MW of unavailable capacity (14 percent of total domestic generation capacity). Although the demand forecast error was the largest contributing factor to the high price hour in October 15, 2010, a fossil-fired facility was also scheduled to produce 74 MW in pre-dispatch but was not available in real-time.

Self-scheduling and intermittent generation forecast error was not a contributing factor to the high real-time price in HE 19. In fact, self-scheduling and intermittent generators produced 187 MW (13.3 percent) more energy in real-time compared to the pre-dispatch projection. The large discrepancy was almost all due to higher production from wind generation than was not anticipated in pre-dispatch.

Table 2-14 shows that the real-time MCP was set by hydroelectric resources in all intervals of HE 19 on October 15, 2010.

Table 2-14: Real-time MCP and Fuel Type of Price Setting Resource October 15, 2010, HE 19 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Marginal Resource (Fuel Type)
11	1	505.52	Hydroelectric
11	2	600.78	Hydroelectric
11	3	600.78	Hydroelectric
11	4	600.78	Hydroelectric
11	5	600.78	Hydroelectric
11	6	600.78	Hydroelectric
11	7	600.78	Hydroelectric
11	8	600.78	Hydroelectric
11	9	578.44	Hydroelectric
11	10	578.44	Hydroelectric
11	11	578.44	Hydroelectric
11	12	92.15	Hydroelectric
Average		**544.87**	

The pricing of hydroelectric units is discussed in more detail in Section 2.1.7 below.

Overall Assessment of High Price Hours

In the last MSP Report, the Panel noted that it did not view the negative implications to the market from high offer prices on certain hydroelectric units to be material due to limited number of intervals where the MCP was set by these resources during the reporting period. However, the Panel noted that a concern may exist if the frequency is to increase in the future.[10] Over the current reporting period, there were 22 five-minute intervals when the MCP was set by hydroelectric units at offer prices above $500/MWh, which is two intervals more than what was observed in the previous summer period.

Over the recent summer period, there was a noticeable increase in the proportion of energy offers above $500/MWh relative to total offers from peaking hydro resources since May 2008. There has also been an increase in submitted offers between $400/MWh and $500/MWh from these same facilities. The higher frequency of high

[10] See the Panel's August 2010 Monitoring Report, p. 112.

priced offers this summer can be partly attributed to poor water conditions in early 2010. However, the number of intervals in which these high-priced offers set the MCP continues to remain relatively low. The Panel has asked the MAU to continue to monitor and report on trends in the frequency of high-priced hydro offers that set the real-time MCP.

2.2 Analysis of Low Price hours

Table 2-15 below presents the number of hours when the HOEP was less than $20/MWh (low HOEP) or negative by month over the last four May-to-October periods. The total number of hours with a low HOEP declined over the latest summer period by 1,258 hours (78 percent) relative to the same months last summer. Although there was a significant drop in low price hours this summer relative to 2009, the total is similar to the number of low-priced hours observed in the 2007 summer period and almost half of the observed hours during the 2008 summer period.

The number of hours when the HOEP was negative has also decreased substantially this summer as shown in Table 2-15 below. There were 19 negative-priced hours this summer, which is down from 121 hours (an 84 percent decline) last summer. All negative-priced hours this period occurred in September and October (nine and ten hours, respectively).

Table 2-15: Number of Hours with Low and Negative HOEPs
May to October, 2007 – 2010
(Number of Hours and %)

	Hours when HOEP<$20/MWh				Hours when HOEP<$0/MWh			
	2007	**2008**	**2009**	**2010**	**2007**	**2008**	**2009**	**2010**
May	115	193	210	22	0	6	24	0
June	67	87	295	8	0	0	42	0
July	57	144	393	20	0	16	14	0
August	11	126	236	19	0	4	11	0
September	45	90	297	143	1	0	25	9
October	36	84	188	149	0	2	5	10
Total	331	724	1,619	361	1	28	121	19

As outlined in previous Panel reports, the primary factors leading to a low (or negative) HOEP are identified as:[11]

- Low market demand
- Abundant low-priced supply (i.e. nuclear, baseload hydro, self-scheduling and intermittent generation, fossil generation up to minimum loading point, and other hydro generation offering energy at prices less than $20/MWh).
- Demand deviation: the forecast demand that is used in PD is typically different from, and often greater than, the average RT demand that determines the HOEP.
- Failed export transactions: these can place downward pressure on the HOEP as failures represent a reduction in demand in RT relative to PD.

Table 2-16 shows real-time output by generation type and unscheduled generation that offered at prices less than $20/MWh (called 'low price supply') for all low price hours this period. Generation categories are segmented into nuclear, baseload hydro, self-scheduling and intermittent (including wind) resources, and other hydroelectric resources (both run-of-the river and peaking). Run-of-the-river and peaking hydro units may want to operate when market prices are low, especially when an abundant supply of water is available and spilling is the only alternative. Average hourly scheduled imports, excluding linked wheels, during low-priced hours are also included in the low price supply table.

[11] These factors were first identified in the Panel's June 2004 Monitoring Report, pp. 84-85.

Table 2-16: Low-Priced Supply During Low-Priced Hours
May to October, 2010
(MW)

Month	Low-Priced Supply						Total
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Other Unscheduled Generation (offered <$20)	Imports (excl. linked wheels)	
May	8,253	1,704	1,085	1,016	469	405	12,932
June	8,848	1,544	1,126	1,437	1,316	493	14,764
July	9,398	1,228	1,245	1,212	1,137	702	14,922
August	9,970	1,268	921	1,289	1,391	1,038	15,877
September	10,219	1,386	1,035	1,847	442	1,013	15,942
October	9,694	1,567	1,236	1,851	141	653	15,142
Average	9,794	1,469	1,129	1,724	427	800	15,342

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

Summary statistics related to the demand conditions during the low-priced hours are presented in Table 2-17. The table includes monthly average Ontario Demand, Exports, and Total Market Demand over the low-priced hours this summer. Excess low-priced supply, which is the difference between low-priced supply (see Table 2-16) and market demand over all low-priced hours is presented in the final column of Table 2-17.

Table 2-17: Demand and Excess Low-Priced Supply During Low-Priced Hours
May – October 2010
(MW)

Month	Number of Low-Priced Hours	Demand			Excess Low-Priced Supply (Supply - Demand)
		Ontario Demand	Exports	Market Demand	
May	22	12,348	641	12,989	-57
June	8	13,159	1,022	14,181	583
July	20	12,431	1,768	14,199	723
August	19	12,833	1,784	14,617	1,260
September	143	12,591	2,471	15,062	880
October	149	12,673	2,201	14,874	268
Average	361	12,626	2,141	14,767	575

On average, excess low-priced supply (including scheduled imports) was 575 MW higher than total market demand during the low price hours between May and October 2010, with a maximum monthly difference of 1,260 MW in August 2010. Excess low- priced supply was -57 MW in May 2010, indicating that the low priced supply was very close to the market demand.

Table 2-18 provides additional summary information by month for all low-priced hours between May and October 2010 including failed net exports, the difference between pre-dispatch demand and real-time average demand (referred to as 'Demand Discrepancy'), and average pre-dispatch and real-time prices. Demand discrepancy can result from demand forecast errors or simply result from differences in peak and average demand within an hour. Pre-dispatch prices during the low price hours over the recent summer period were on average $4.49/MWh higher (38.4 percent) compared to the real-time prices. Abundant baseload supply relative to total demand (575 MW surplus on average) was the most important factor leading to the low HOEP outcomes over the latest summer period, followed by failed net exports (41 MW), and finally demand deviation (36 MW).

Table 2-18: Average Monthly Summary Data for Low-Priced Hours May to October, 2010 ($/MWh and MW)

	Excess Supply	Failed Net Exports (MW)	RT Average Demand (MW)	PD Demand Forecast (MW)	PD to RT Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT - PD) ($/MWh)
May	-57	41	12,348	12,515	167	14.70	23.10	(8.40)
June	583	234	13,159	13,424	265	17.55	25.97	(8.42)
July	723	0	12,431	12,659	228	13.89	24.20	(10.31)
August	1,260	14	12,833	12,955	122	14.55	20.91	(6.36)
September	880	8	12,591	12,606	15	10.16	13.82	(3.66)
October	268	71	12,673	12,660	(13)	11.72	15.20	(3.48)
Average	575	41	12,626	12,662	36	11.68	16.17	(4.49)

In the last report, the Panel reported that a change in offer strategy at a nuclear facility led to the lower observed MCPs in April 2010.[12] The impact of the change continued to result in some intervals with MCPs below - $100/MWh over the recent summer period although the frequency of these low MCPs was small. Over the six-month period, there were 28 intervals when the MCP fell below -$100/MWh where nuclear resources were most often marginal. This figure is lower than the 32 intervals observed in April 2010 alone. The lowest HOEP over the latest summer period was -$38.01/MWh, which occurred in HE 8 on September 6, 2010. Individual interval MCP reached a record low of

[12] See the Panel's August 2010 Monitoring Report, pp. 96-97.

-$128.30/MWh in HE 7 on June 9, 2010, which surpassed the previous record low MCP by $0.15/MWh.

3. Anomalous Uplift

During the period May to October 2010, there were no hours when the anomalous uplift criteria were met. There were no hours when CMSC payments or IOG payments were greater than $500,000 in a single hour, CMSC payments at an intertie group exceeded $1 million for a day, or hourly OR payments were greater than $100,000. The Panel intends to review the criteria used to assess which events should be considered anomalous in the future MSP reports and determine whether an adjustment is appropriate based on current market conditions.

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Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

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

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

- market rule amendments relating to constrained-off CMSC payments to dispatchable loads;
- increased Surplus Baseload Generation and the IESO's coding practice when curtailing intertie transactions;
- improvements associated with the IESO's new procedure relating to the release of transmission service;
- the IESO's actions to prevent transmission lines from becoming overloaded; and
- the operational status of the phase angle regulators (PARs) at the Michigan interface.

In Section 3, the Panel comments on three new issues:

- the treatment of transfer capability reductions outside of Ontario;
- increased trading activity and CMSC payments in the Northwest region; and
- multiple starts at gas-fired generators under the Generation Cost Guarantee program.

2. Changes Related to Issues Discussed in the Panel's Previous Reports

2.1 *Market Rule Amendments Relating to Constrained-Off CMSC Payments to Dispatchable Loads*

In its previous report, the Panel identified that two dispatchable loads had received extremely large CMSC payments for self-induced ramping and consumption deviations during the period of February to May 2010. The Panel concluded that those payments were self-induced and provided no benefit to the market. The Panel recommended eliminating self-induced CMSC payments paid to dispatchable loads resulting from either a voluntary change in consumption or a consumption deviation.[13]

During the period when the Panel was drafting its last report, the IESO worked with the MAU to explore the issues related to self-induced CMSC and search for possible solutions. The IESO implemented an interim urgent rule amendment on August 27, 2010, temporarily suspending all constrained-off CMSC payments to dispatchable loads until a long term solution could be found.[14]

On December 3, 2010, the IESO replaced the interim urgent rule amendment with a new rule amendment,[15] which was designed to eliminate CMSC payments to dispatchable loads for self-induced ramping. Contrary to the Panel's recommendation, the IESO did not implement a rule change to eliminate CMSC payments to dispatchable loads that was induced by consumption deviation. The IESO believed these payments could largely be recovered through existing processes authorized by the market rules[16] or would otherwise be significantly limited by a

[13] See the Panel's August 2010 Monitoring Report, pp. 112-128.
[14] For details, see: http://ieso.ca/imoweb/pubs/mr2010/MR_00373-R00.pdf.
[15] See IESO Market Rule Amendment MR – 00374 (dated October 19, 2010), at http://ieso.ca/imoweb/amendments/mr_Amendments.asp.
[16] The deviation-induced constrained-off payments can be recovered under the provision of Market Rules Chapter 9 Section 3.5.1A. For further discussion, see the Panel's August 2010 Monitoring Report, pp. 112-123.

separate rule change implemented on December 3, 2010 that limits the magnitude of constrained-on CMSC payments to exporters and dispatchable loads.[17]

The Panel has asked the MAU to continue monitoring the CMSC payments to dispatchable loads. The Panel has also requested that the MAU assess and report on the efficacy of the rules in achieving their intended function. In addition, the Panel is investigating whether the conduct of the two dispatchable loads constitutes gaming.

2.2 Increased Surplus Baseload Generation and the IESO's Coding Practice when Curtailing Intertie Transactions

2.2.1 *Introduction*

Surplus Baseload Generation (SBG) is "a condition where market actions, or actions that are required for reliability, regulatory, safety or equipment concerns, require the reduction of generation that results in the manoeuvre of nuclear units or the loss of fuel for a generator that is reduced (e.g. hydroelectric spill)". Baseload generation is defined as the sum of the expected generation of all available: nuclear generators, must-run hydroelectric generation, self-scheduling generators (including commissioning units), intermittent generators (including wind generators), and other generators that typically offer their generation at a value lower than the highest offer for nuclear generation. [18] SBG typically occurs during periods when demand is low.

In a well-functioning market, SBG events should rarely occur. Potential SBG events would normally be signaled through low or negative pre-dispatch market prices.[19] The low or negative prices would in turn incent an increase in domestic consumption, to the degree that it is price-

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[17] The deviation-induced constrained-on payments should largely be mitigated under the new rule amendment MR – 00370**,** which uses a replacement bid price of -$50/MWh to cap the amount of the constrained-on payment. For details, see: http://ieso.ca/imoweb/pubs/mr2010/MR-00370-R00-BA.pdf.
[18] Section 1.3 of Market Manual 7.2: http://www.ieso.ca/imoweb/pubs/systemOps/so_NearTermAssessReport.pdf.
[19] The IESO also provides day ahead forecasts of potential SBG conditions. For details, see http://ieso.ca/imoweb/marketdata/sbg.asp.

responsive, and an increase in exports. Similarly, generators and imports would be incented to reduce output. The increase in demand and decrease in supply would create an upward pressure on the price, which in turn would eliminate or reduce the frequency and severity of SBG events.

There are, however, certain factors that limit such responses. To begin with, a pre-condition of price-responsiveness is the presence of an accurate forward price signal. With respect to domestic consumption, consumers (except dispatchable loads) have historically shown limited responsiveness to the real-time price, although some large consumers may be able to increase their consumption or shift their consumption from high price hours to low price hours when an accurate price signal exists. Export response can also be hindered by seams issues between the exporting and importing jurisdiction (e.g. differences in the dispatch frequency and the setting of schedules in the two jurisdictions). In addition, if neighbouring jurisdictions are also experiencing SBG conditions the price-responsiveness may be muted. On the supply side, market rules, programs or contracts may reduce generators' or importers' incentives to respond. In addition, the speed of response of dispatchable resources is limited by the "window" after which offers and bids cannot be changed, which is currently two hours, and the fact that imports and exports are dispatchable on an hourly basis. [20] However, if SBG events persist, this may be indicative of problems with market design, the price signal or operating procedures of the market.

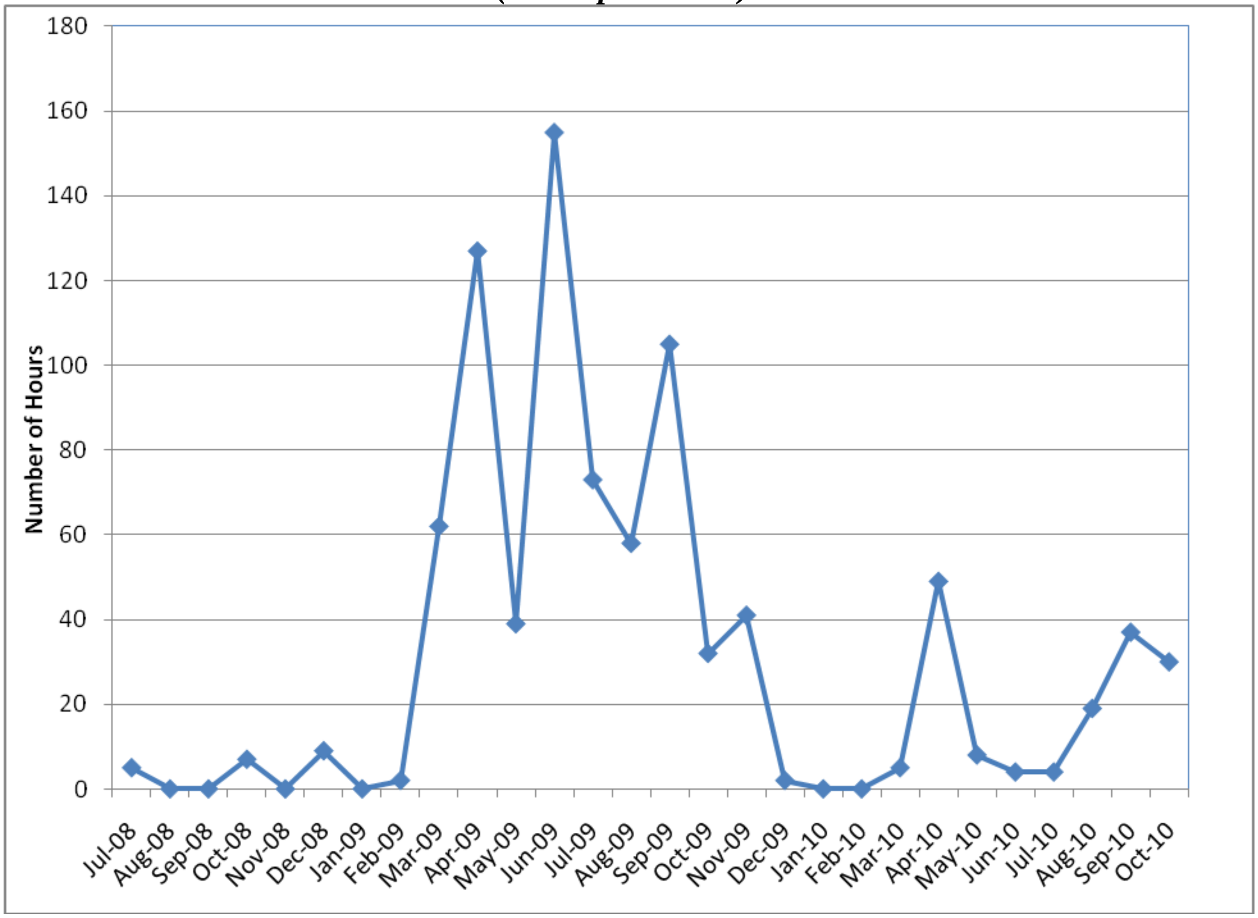
When an SBG event occurs, the market is oversupplied and the system operator has to take manual actions to reduce supply. The purpose of this section is to examine control actions taken by the IESO and their consequences to the market during SBG events.

[20] The Panel has previously recommended that the IESO examine the feasibility of 15 minute dispatch and shorter offer/bid windows, as are currently used by some US markets. See the Panel's January 2009 Monitoring Report, pp. 186-191 and the December 2007 Monitoring Report, pp. 151-160.

2.2.2 *History of SBG Events in Ontario*

In Ontario, SBG conditions used to be rare: they occurred in only 20 hours from the period of market opening in May 2002 to June 2008. The majority of these SBG events occurred during the low-demand Christmas holiday period or the spring freshet period when abundant water was available to hydroelectric generating units. From July 2008 to March 2009, the frequency of SBG events began to increase. The period April to December 2009 was marked by a dramatic increase in SBG events, including a record of 155 hours in June 2009. The frequency of SBG events in 2010 was down significantly from 2009, with the exception of April and September 2010 when there were 49 and 37 hours of SBG respectively. Figure 3-1 below depicts the total number of hours with SBG by month since July 2008. In these events, the IESO had either curtailed imports or dispatched down generation at nuclear units.

Figure 3-1: Number of Hours with Surplus Baseload Generation by Month July 2008 – October 2010 (Hours per Month)



As discussed in the Panel's July 2009 report, the increase in SBG events in 2009 was caused by several major factors:[21]

- *Lower Ontario demand*: Ontario demand has been decreasing over the last few years.[22]
- *Reduced export capability at interfaces with external jurisdictions*: The increase in SBG events in March and April 2009 were mainly induced by the outages at the New York interface. These outages reduced export capability to New York, which in turn reduced export capability at the Michigan interface (in order to deal with loop flows).

[21] See the Panel's July 2009 Monitoring Report, pp. 218-235.
[22] Ontario demand (i.e. electricity demand by all Ontario consumers) declined by 5.4 percent in May to April 2009/2010 relative to 2008/2009 and declined by 4.6 percent in May to April 2008/2009 relative to 2007/2008. See the Panel's August 2010 Monitoring Report, pp. 48-50.

During this period, total export capability at Michigan and New York was reduced to 655 MW from the usual export capability of approximately 4,000 MW. The New York interface was out of service again in November 2009.

- *Greater supply from hydro generators:* Hydro output in the spring and summer of 2009 was very high as a result of unusually high precipitation levels.
- *Increased wind generation*: Installed wind generation has increased significantly since 2008.[23] Wind is currently treated as non-dispatchable and therefore effectively forms a non-responsive component of baseload supply.
- *Commissioning of gas-fired generation:* Ontario saw a large increase in gas-fired generation capacity beginning in late 2008. Some of these units were commissioning during periods when SBG conditions were present and thus were not dispatchable.

2.2.3 *Forecasts for Ontario SBG Events*

In its 2008 submission for the Integrated Power System Plan (IPSP) review,[24] the IESO predicted an increase in SBG events over the period 2010-2020 (Figure 3-2). Two scenarios were forecast: the first scenario anticipated the continuance of the current market structure where wind generation is non-dispatchable (represented by the red bars); while the second scenario anticipated that market rules would change and that wind generation would become dispatchable (represented by the green bars). If wind generation can be dispatchable and curtailed if needed, the number of SBG hours where alternative control actions are required (e.g. dispatching down nuclear generation or curtailing imports) can be reduced significantly (by roughly 70 percent under these IESO forecast scenarios).

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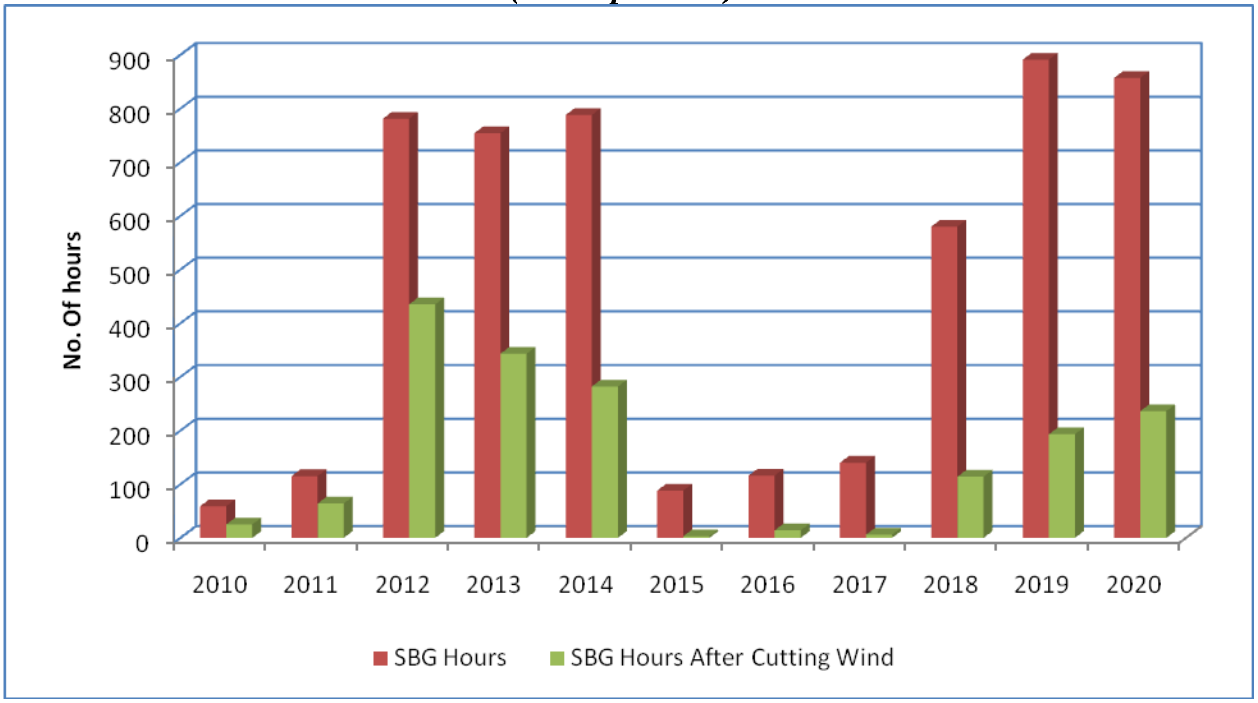
[23] The trend in average hourly wind output is plotted in Chapter 1 of the August 2010 MSP Monitoring Report, p 29.
[24] IESO, "*Operability Review of OPA's Integrated Power System Plan*", April 21, 2008, p.15. For details, see: http://www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf.

Figure 3-2: IESO Projection of Number of Hours with Surplus Baseload Generation Prepared in 2008 for the Integrated Power System Plan, 2010 to 2020 (Hours per Year)



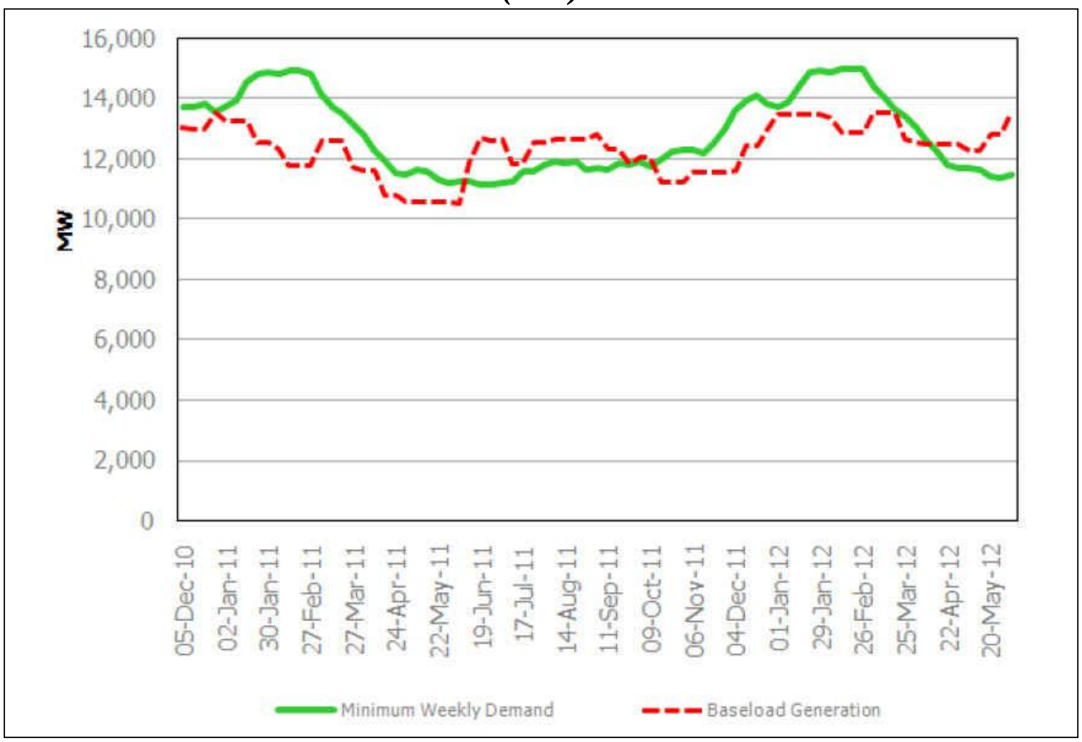
There are two reasons to expect that these 2008 forecasts may understate the frequency of SBG events if wind generation does not become dispatchable.[25] First, the introduction of the OPA's feed-in-tariff (FIT)[26], which occurred subsequent to the publication of the IPSP, has led to a significant increase in expected installed capacity of renewable resources compared to what had been originally forecast under the IPSP. Under the IPSP, the OPA forecast approximately 3,000 MW of installed wind, solar and biomass capacity.[27] In addition to the approximately 1,500 MW of wind currently under contract and operating in Ontario, the OPA is now anticipating as much as 6,600 MW of renewable resources may be contracted for under the FIT program by the end of 2013.[28] Second the vast majority of these new resources are expected to be wind generators.

[25] In fact, there were 156 hours of SBG in January - October 2010, compared to 60 hours in the IESO's 2008 forecast for this period.
[26] See: http://fit.powerauthority.on.ca/Page.asp?PageID=1115&SiteNodeID=1052.
[27] See: http://www.powerauthority.on.ca/sites/default/files/page/4875_D-9-1_corrected_071019.pdf , p.8, table 7. This is composed of 2,594 MW of wind, 88 MW of solar and 233 MW of biomass.
[28] See Ontario Power Authority, 2011-2013 Business Plan, p. 22, at: http://www.powerauthority.on.ca/sites/default/files/news/2011%20-%202013%20Business%20Plan.pdf.

Wind typically produces at higher output levels in the late evening and very early morning when the prevalence of SBG events is greatest.[29]

In 2008, the IESO began to publish SBG forecasts. These SBG forecasts compare expected minimum demand against expected baseload generation on a weekly basis.[30] Figure 3-3 below is replicated from the IESO's 18-Month Outlook for December 2010 to May 2012. The IESO predicts a significant number of SBG events during summer 2011 and winter 2012 (i.e. the period when the dotted red line is above the solid green line).[31]

Figure 3-3: IESO Forecast of Weekly Minimum Demand and Baseload Generation Prepared in November 2010 for December 2010 to May 2012 (MW)



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29 For details, see the Panel's January 2009 Monitoring Report, p. 24. In other markets (e.g. NYISO), a similar result was found: http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf

30 See https://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp.

31 See: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2010aug.pdf, p.18

2.2.4 *Control Actions During SBG Events*

It is worth clarifying that in Ontario an SBG event refers to the supply and demand situation in the constrained sequence. The constrained sequence reflects the actual system conditions and takes into account various transmission limitations within the province and at the interties. In Ontario, an SBG event may not necessarily translate into a negative market price. [32] That is because the market price is calculated using the unconstrained schedule, which ignores internal transmission capabilities and in general assumes larger intertie transmission capabilities than what the interties are capable of delivering. In fact, as will be demonstrated later in this section, the market price during many SBG hours is often much greater than $0/MWh. This counter-intuitive pricing is caused primarily by fundamental differences between the two sequences as well as by IESO control actions taken to manage SBG conditions. The balance of this section discusses the impact of IESO control actions on the market price signal.

In anticipation of, or during an SBG event, the IESO is authorized (as outlined in the Market Rules and the IESO's internal procedures under the guidelines of the Northeast Power Coordinating Council, i.e. NPCC standards) to take several control actions to ease the supply surplus.[33] Actions and the market consequences of these actions include:

- *Curtail imports*: The primary choice by the IESO to cope with SBG situations is to curtail imports if applicable and effective.[34] When an import is curtailed, the IESO applies a code of ADQh[35] to the transaction. This has the effect of removing the

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[32] Conversely, market prices may fall below $0/MWh when SBG conditions do not exist on the system.
[33] See Market Manual, Series 7: *System Operations Manual*, Part 7.2: *Near Term Assessments and Reports*, Section 1.3: *Surplus Baseload Generation*; and Internal Procedure 2.4-2 '*Responding to Market and System Events*', Section 7: *Respond to Surplus Baseload*.
[34] At times, imports may not be curtailed because of export congestion at the interface. Cutting imports would not be implemented in this situation because it would lead to the transmission line becoming overloaded.
[35] The IESO assigns a code for each intertie transaction (for details, see IESO Procedure 2.4-7, '*Interchange Operations')*. The codes include:
- AUTO: transactions that are scheduled by the DSO in the final PD and have never been revised
- NY90: transactions at the NYISO intertie that are checked at 90 minutes before RT
- TLRi: transactions that are curtailed for reliability at the intertie
- TLRe: transactions that are curtailed for external reliability
- MrNh: transactions that have failed due to a lack of ramp or transmission service in external ISOs
- ORA: transactions that are curtailed or scheduled for IESO's operating reserve activation
- OTH: transactions that have failed due to reasons under the participant's control

import transaction from both the constrained and unconstrained sequences. Removing imports from the unconstrained sequence has the effect of increasing the market price, which does not reflect the available imports and the surplus situation.[36] This price increase may in turn attract more import offers and less export bids in subsequent hours, thereby perpetuating or even escalating future SBG conditions, which may require further cutting of imports or other control actions.

- *Increase the Net Intertie Scheduling Limit (NISL)*[37] *to allow an increase in net exports*: The Panel had previously recommended that the IESO review the NISL in order to facilitate larger hourly changes in net exports, particularly during periods of low demand.[38] Assuming a higher NISL is technically feasible, it may improve both system reliability and market efficiency. The IESO implemented a procedure effective December 23, 2008 to increase the hour-to-hour NISL to 1,000 MW, if feasible, when there is an SBG event. The higher NISL affects both the unconstrained and constrained sequence and thus the greater net exports could lead to a higher HOEP. The higher HOEP in this situation, however, should not be considered distorted because it reflects the actual export bids that are available and the scheduling of the increased level of exports is efficiency enhancing. Since introducing the new procedure, the IESO has applied the 1,000 MW limit in 48 hours, of which 40 hours occurred in 2009.[39]
- *Dispatch down baseload hydro generators:* This may be ordered by the IESO even though it means spilling water. This action does not impact the market price because the output adjustment occurs in the constrained but not the unconstrained sequence.

- ADQh: transactions that are curtailed by IESO for resource adequacy (either shortage or surplus)

[36] The price increase is more pronounced when the import transaction had a smaller schedule in the constrained sequence than in the unconstrained sequence (e.g. 100 MW curtailed in the constrained sequence accompanied by 400MW of constrained off imports results in 500 MW removed in the unconstrained sequence).

[37] The NISL is a limit used by both the unconstrained and constrained schedule tools to limit the amount of changes in net exports that can be ramped in or out between two successive hours. It effectively represents a conservative estimate of the collective ramping capability of domestic generators to accommodate the changing level of imports and exports.

[38] See the Panel's July 2008 Monitoring Report, pp. 103-110. More generally, in its July 2007 Monitoring Report, pp. 97-100, the Panel recommended that IESO review whether the default 700 MW limit could be increased.

[39] However, the hour-to-hour change in net exports in the 48 hours was never actually greater than 700 MW. This could be because the net exports were already very large so that the interfaces with export potential were already at or near capacity; there were not additional arbitrage profit opportunities between Ontario and external markets, or other factors.

This has occurred on many occasions, but the magnitude and timing of spill activities is not well documented as data on these events is not readily available to the IESO or to the Panel.

- *Derate coal-fired generators to their "gas support" level*:[40] This action can be initiated by either the IESO or OPG. It is accomplished by derating coal units to an output level lower than their registered minimum loading point (MLP) and requires that the unit be fuelled by natural gas only. Because the reduction below the normal MLP is implemented as a derating, the supply is removed from the market as well as the constrained schedule. Removal from the market schedule increases the market clearing price. The Panel expressed its concerns regarding the market impact of this type of intervention in its July 2008 Monitoring Report.[41] However, this has only happened occasionally and will become less of an issue as coal-fired units produce less overnight and are gradually phased out in the coming years.
- *Shut down or reject the start-up of fossil-fired units:* Some fossil-fired generators may request synchronization even under SBG conditions because they are commissioning, they are participating in a cost-guarantee program, or they are operating as self-schedulers under fixed-price contracts (i.e. the non-utility generator contracts). The IESO can reject such synchronization requests for reliability concerns and may also order operating fossil-fired generators to fully shut down. Unlike the constraining off of output by an online generator, these actions have the effect of increasing the HOEP because offline fossil-fired generators are not considered as available by the unconstrained sequence (or the constrained sequence). Such situations have occurred infrequently and those related to commissioning are expected to occur even less frequently in the future as the vast majority of Ontario's new gas-fired generation has now been installed and commissioned.

[40] Some coal-fired generators can also use natural gas as support, which allows the generator to sustain production at a lower minimum output level, their 'gas support' level.

[41] See the Panel's July 2008 Monitoring Report, pp. 110-112. The Panel observed that the market rules allow for only a single MLP to be registered regardless of the fact that two MLPs may exist depending on the fuel type. The Panel noted that the generator could register the lower MLP and shift its output level from the coal-fired MLP to the gas-support MLP by adjusting its offers. However, a low MLP may increase the generator's risk of being constrained down below its normal MLP in non-SBG situations.

- *Dispatch down or fully shut down nuclear units*: This is generally viewed as an action of last resort because nuclear units are typically designed to produce at their maximum capacity and manoeuvring them can involve significant operational issues and costs. However, some units do have limited flexibility to ramp down when required.[42] At times, a nuclear operator, in consultation with the IESO, may choose to shut down fully even though doing so means the generator must remain offline for 48 hours or even longer for operational reasons.[43] When a nuclear unit is constrained down but not off, the HOEP is not affected because the change only occurs in the constrained sequence. However, if the unit is fully shutdown, HOEP will increase because an offline nuclear unit is regarded as unavailable in the unconstrained (and constrained) sequence.[44]

[42] For example, when performing an SBG manoeuvre Bruce Power does not change the power output of the reactor; rather it relies on redirecting some steam from the turbine generator to the steam condenser. This reduces generator output while allowing the unit to remain ready to increase production when required. For a description of Bruce unit operational flexibility and limitations, see http://ieso.ca/imoweb/pubs/consult/se57/se57-20090703-BrucePower.pdf.
[43] Nuclear unit shutdowns for SBG happened twice in 2009. There were none in 2010.
[44] In the past, the IESO derated a nuclear unit to accommodate the SBG situations in both pre-dispatch and real-time, which led to efficiency loss and an increased HOEP. The Panel, in its January 2009 Monitoring Report, reported the issues and acknowledged that the issues were solved by the IESO after discussions with the MAU. For details, see: http://www.oeb.gov.on.ca/OEB/_Documents/MSP/msp_report_200901.pdf, pp.169-171.

Table 3-1 below summarizes the IESO control actions, their associated codes, and the implications on the HOEP under SBG conditions.

Table 3-1: IESO Surplus Baseload Generation Control Actions, Applicable Codes, and Impact on the HOEP

Action	Code	Affects Constrained Schedule (CS)	Affects Unconstrained Schedule (US)	Eligibility for CMSC	Impact on HOEP
Curtail import	ADQh	yes	Yes (set US equal to CS)	no	Increased
Derate coal-fired generation	MAN or AUTO, depending on the timing	yes	yes	no	Increased
Shutdown or reject the start-up of fossil fired units	MAN or AUTO, depending on the timing	yes	yes	no	Increased
Dispatch down baseload hydro units	MAN	yes	no	yes	No impact
Dispatch down nuclear units	MAN	yes	no	yes	No impact
Shut down nuclear units	MAN or AUTO, depending on the timing	yes	yes	no	Increased
Increase the NISL	n/a	yes	yes	yes	Increased

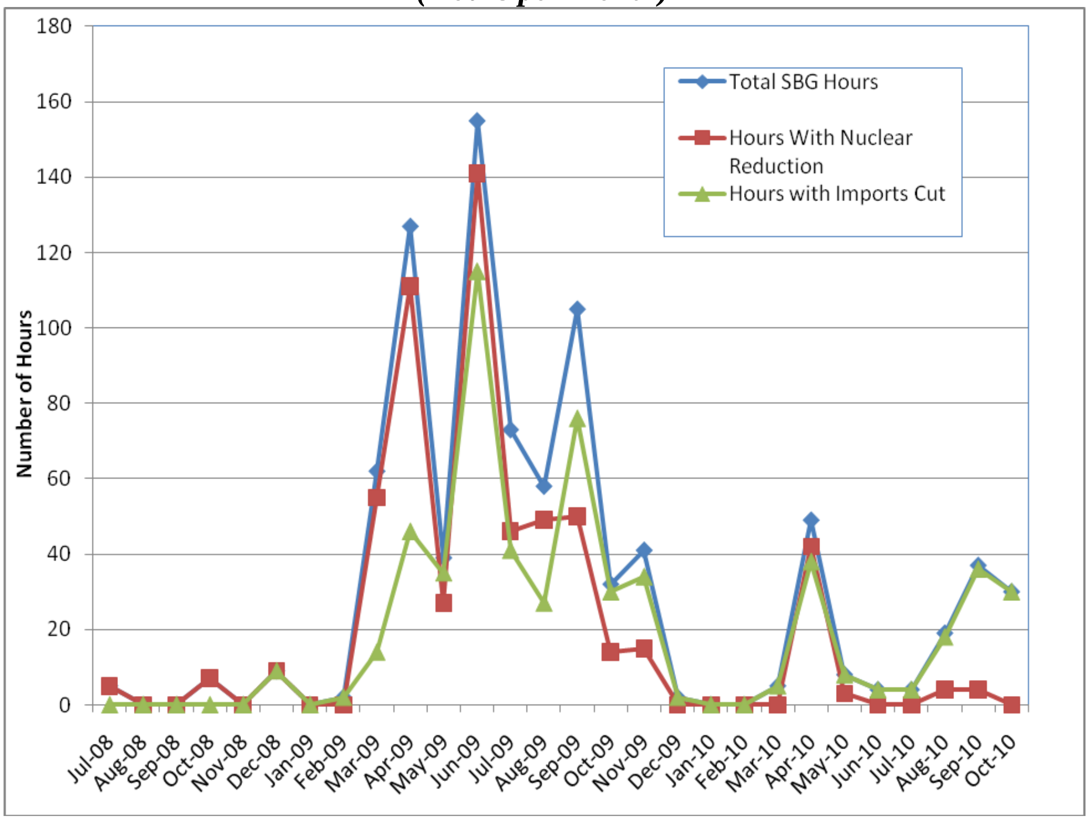
2.2.5 *Import Curtailment History*

In 2009, nuclear units were regularly instructed to reduce production during SBG hours. Since late 2009, import curtailments have replaced reductions to nuclear output as the primary mechanism for alleviating SBG.[45] In 2010 nuclear units have rarely been called upon, with the

[45] In 2009, there was typically export congestion at the Michigan interface, which meant that import curtailment was not a viable option. In 2010, the Michigan interface has rarely been export congested and substantial quantities of imports from MISO have been available for curtailment.

exception of May 2010. This can be seen from Figure 3-4 below, which illustrates on a month-by-month basis for the period July 2008 to October 2010 the total hours of SBG as well as the total hours of nuclear reductions and import curtailments during the corresponding SBG hours.[46]

Figure 3-4: Surplus Baseload Generation Events, Nuclear Reductions and Import Curtailments July 2008 to October 2010 (Hours per Month)



2.2.6 *Assessment*

In this section, the Panel focuses on the impact of the intertie transactions. While it may be necessary for the IESO to cut imports for reliability, the use of ADQh for this purpose has the counter-intuitive effect of increasing the HOEP. The higher HOEP represents a distorted price

[46]Other control actions are not shown on Figure 3-4 because they are rare or are not as readily identifiable as these two key control actions. .

signal to market participants. The higher price could attract higher power flow into Ontario in subsequent hours when in reality Ontario has adequate supply. The higher price also discourages traders from exporting from Ontario, even though Ontario has surplus supply.

To see how the higher HOEP induced by the ADQh code can impact arbitrage opportunities between markets, the Panel examined the off-peak hours when the MISO and NYISO interties were in service.[47] Over this period, HOEP has been increasing during SBG hours, from an average price of -$8/MWh in March 2009 to approximately $20/MWh during the summer of 2010. Associated with the increase in HOEP is a general increase in import curtailment in the unconstrained sequence. For example, the average import curtailment in mid-2009 was generally below 150 MW, whereas it has been above 250 MW in many months in 2010.

Import curtailment tends to increase the HOEP relative to the pre-dispatch MCP. The scatter plot in Figure 3-5 below reports the difference between HOEP and one-hour ahead pre-dispatch MCP against the unconstrained import curtailment for the period July 2008 to October 2010. The fitted line has a statistically significant upward slope of 0.0126,[48] implying that every 100 MW of import curtailment tends to increase the HOEP by roughly $1.26/MWh relative to the PD MCP, all else being equal.

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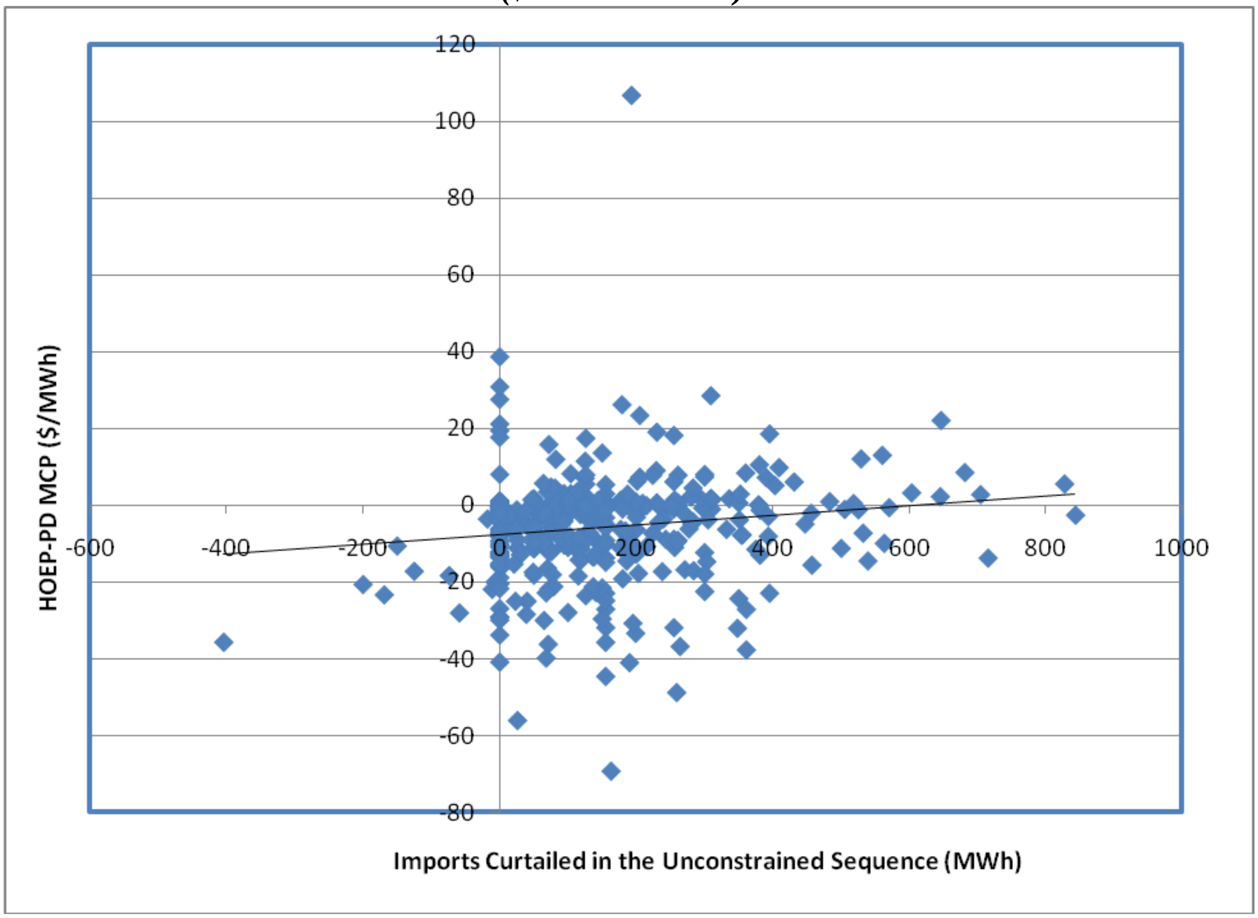
[47] On-peak hours with SBG conditions are not analyzed because an SBG at an on-peak hour was typically a result of a lack of trading opportunities between Ontario and external markets (e.g. outages/derating at interfaces) and/or involved a shutdown of a full nuclear unit in order to deal with SBG situation for a long period of time.

[48] There are other factors (e.g. steepness of the supply curve, real-time generation outages/derating, ramp rates, etc) that may affect the price difference. This simple regression against the import curtailment provides an indication of how the import curtailment may have affected the price difference. Time constraints precluded development of a more robust model that includes other major factors to isolate the impact of the import curtailment more accurately. The fitted line reported above has the following equation (T-ratios are reported in brackets):

HOEP - PD MCP = -7.6634 + 0.0126*MW curtailed
(-8.0985) (2.8942)

Figure 3-5: Import Curtailment (Unconstrained Sequence) and Differences Between HOEP and Pre-dispatch MCP during Surplus Baseload Generation Events July 2008 to October 2010 ($/MWh and MW)



Given that almost all curtailed imports in the study period were scheduled at the Michigan interface, it is relevant to examine how the import or export profitability at this interface has evolved. Ideally, when there is SBG in Ontario, exporting rather than importing activities should be incented. Table 3-2 below lists (for SBG events during HE 1-6 and 23-24) the HOEP, the MISO price for the MISO_ONT interface (which reflects the Michigan side of the intertie with Ontario), and average hourly imports from Michigan, the number of hours with SBG, and the number of hours with export congestion during hours with import curtailments resulting from SBG. Until April 2010 (with the exception of March, April, and September 2009), the HOEP was typically less than the MISO_ONT interface price during SBG hours, and thus disincented imports and incented exports. However, since May 2010, the HOEP has been approximately

$20/MWh and persistently higher than the MISO_ONT interface price during SBG hours. This has lead to more imports being attracted into Ontario and fewer exports being attracted to Michigan. Notwithstanding 83 hours of off-peak SBG in Ontario since December 2009, the MISO interfaces have not been export congested during these events.

Table 3-2: HOEP, MISO Prices, Average Imports, and Export Congestion During Surplus Baseload Generation Events in December 2008 to October 2010 For HE 1-6 and 23-24 when MISO Interties are in Service ($/MWh, MW and Number of Hours)

Month[49]	HOEP ($/MWh)	MISO's ONT Zone Price ($/MWh)	MISO Price-HOEP ($/MWh)	Average Imports from Michigan (MW)	Number of Hours with SBG	SBG Hours with Export Congestion
Dec-08	-28.99	17.86	46.85	0	4	0
Feb-09	17.49	26.19	8.70	0	2	0
Mar-09	12.10	7.55	-4.55	59	6	0
Apr-09	-6.23	-65.87	-59.64	60	3	0
May-09	-0.97	3.17	4.14	9	29	6
Jun-09	2.95	13.46	10.51	24	69	41
Jul-09	4.51	13.23	8.72	44	27	14
Aug-09	5.99	17.22	11.23	0	10	1
Sep-09	6.87	-6.26	-13.13	230	67	3
Oct-09	10.20	23.61	13.41	68	28	0
Nov-09	12.99	17.33	4.34	0	10	8
Dec-09	14.25	24.96	10.71	0	1	0
Mar-10	15.16	21.21	6.05	52	3	0
Apr-10	12.04	15.78	3.74	54	19	0
May-10	19.08	16.31	-2.77	156	5	0
Jun-10	26.13	5.47	-20.66	138	2	0
Jul-10	19.52	3.53	-15.99	621	2	0
Aug-10	19.59	11.65	-7.94	415	14	0
Sep-10	13.41	-0.12	-13.53	452	13	0
Oct-10	19.03	12.87	-6.16	252	25	0

[49] There were no SBG events during January 2009 and January/February 2010.

An Example: September 5, 2010 HE 1

September 5, 2010 HE 1 was an SBG hour but the HOEP reached $123.96/MWh, which is the highest recorded hourly price for an SBG hour in Ontario.

In the hour, the IESO took several precautionary actions to handle the potential over-supply conditions. Collectively, they resulted in an enormous discrepancy between the HOEP ($123.96/MWh) and the $17.27/MWh price projected in the final pre-dispatch run. Similarly, in the constrained sequence, the final pre-dispatch shadow price at Richview was $17.62/MWh, while in real-time the shadow price reached $137.91/MWh. Neither the PD MCP/Richview shadow price nor the HOEP/real-time Richview shadow price accurately reflected the potential for or the actual SBG conditions. In fact, the high real-time shadow price and HOEP suggested tight supply/demand conditions.

Prices and Demand

Table 3-3 below lists the summary information for September 4, 2010 HE 24 and September 5, 2010 HE 1. The MCP in HE 24 was much higher than the PD price in intervals 1 to 9 of the hour, but well below for the last three intervals. In interval 1 of HE 1, the MCP dramatically increased to $189.95/MWh, well above the projected $17.27/MWh in PD. The MCP stayed above $100/MWh in intervals 1 to 9, then decreased to $79.34/MWh in intervals 10 and 11, and finally dropped to $7.05/MWh in the last interval of the hour.

Table 3-3: MCP, Ontario Demand and Net Exports September 4 HE 24 and September 5 HE 1 ($/MWh and MW)

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($MWh)	Difference (RT-PD) ($MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Export (MW)	PD Net Export (MW)
Sep 4 HE 24	1	45.05	13.48	31.57	12,706	12,390	1,554	1,455
	2	45.05	13.48	31.57	12,706	12,390	1,554	1,455
	3	35.05	13.48	21.57	12,637	12,390	1,554	1,455
	4	35.49	13.48	22.01	12,535	12,390	1,658	1,455
	5	35.05	13.48	21.57	12,461	12,390	1,658	1,455
	6	26.63	13.48	13.15	12,379	12,390	1,658	1,455
	7	20.05	13.48	6.57	12,300	12,390	1,658	1,455
	8	20.05	13.48	6.57	12,277	12,390	1,658	1,455
	9	20.05	13.48	6.57	12,246	12,390	1,658	1,455
	10	7.60	13.48	-5.88	12,203	12,390	1,658	1,455
	11	7.20	13.48	-6.28	12,133	12,390	1,658	1,455
	12	7.60	13.48	-5.88	12,123	12,390	1,587	1,455
	Average	**25.41**	**13.48**	**11.93**	**12,392**	**12,390**	**1,626**	**1,455**
Sep 5 HE 1	1	189.95	17.27	172.68	11,997	11,672	2,082	1,940
	2	189.73	17.27	172.46	11,970	11,672	2,082	1,940
	3	166.30	17.27	149.03	11,903	11,672	2,082	1,940
	4	166.30	17.27	149.03	11,927	11,672	2,082	1,940
	5	166.30	17.27	149.03	11,912	11,672	2,082	1,940
	6	119.41	17.27	102.14	11,868	11,672	2,082	1,940
	7	113.34	17.27	96.07	11,784	11,672	2,082	1,940
	8	105.21	17.27	87.94	11,753	11,672	2,082	1,940
	9	105.21	17.27	87.94	11,748	11,672	2,082	1,940
	10	79.34	17.27	62.07	11,738	11,672	2,082	1,940
	11	79.34	17.27	62.07	11,701	11,672	2,082	1,940
	12	7.05	17.27	-10.22	11,560	11,672	1,932	1,940
	Average	**123.96**	**17.27**	**106.69**	**11,822**	**11,672**	**2,070**	**1,940**

Supply and Demand Conditions for HE 1

On September 4, HE 21, the IESO issued an SBG alert for September 5 HE 1 to 8. The alert was intended to provide market participants advance information about the expected market conditions over those hours. At the same time, MISO and PJM also issued an alert of potential SBG in their markets. The SBG situation in such a large footprint limited traders' arbitrage opportunities and the system operators' capabilities for dealing with the situation.

In advance of September 4 HE 24, the IESO observed that, in the absence of other control actions, there would be a reduction in the schedule for a nuclear unit in many intervals of the hour. In response, 104 MW of imports at the Michigan interface were curtailed in order to avoid manoeuvring the nuclear unit.

The pre-dispatch prices for September 5 HE 1 were persistently low up to three hours ahead. Prior to the two hour ahead pre-dispatch run, a generator reduced its offered quantity at a baseload hydro station by 310 MW. However, this reduction in baseload supply was almost entirely offset by a reduction of net exports by 294 MW in the next pre-dispatch run. Relevant pre-dispatch statistics are reported in Table 3-4 below.

Table 3-4: PD Price, Ontario Demand and Exports / Imports
September 5, 2010, HE 1
($/MWh and MW)

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
13	-129.00	12,026	0	0	0	
10	-128.4	12,026	0	0	0	
5	4.41	11,795	583	2,666	2,083	
4	4.85	11,795	683	2,766	2,083	
3	-1.00	11,602	558	2,756	2,198	A baseload hydro resource reduced offered quantity by 310 MW
2	17.27	11,747	1,076	2,980	1,904	
1	17.27	11,672	1,040	2,980	1,940	After final pre-dispatch, IESO curtailed 347 MW of imports which translated into a 193 MW curtailment in the unconstrained sequence.

Real-time Conditions in HE 1

Before the real-time run, there was a 50 MW export failure at the NYISO interface. In light of the SBG condition in September 4 HE 24 and a potential reduction in schedules at nuclear units, the IESO curtailed 347 MW of imports from MISO for September 5 HE 1. The 347 MW curtailment translated to only a 193 MW import curtailment in the unconstrained sequence because 154 MW were imports that were scheduled as constrained-on in final pre-dispatch.[50]

[50] The imports were offered at $17.27/MWh and both the final pre-dispatch MCP and the locational zonal price at the interface were $17.27/MWh. In other words, the imports set both the final unconstrained and constrained pre-dispatch price. However, due to the configuration difference between the unconstrained and constrained sequence,

In addition, the real-time demand in the first few intervals in HE 1 was 200 to 300 MW greater than projected in the final pre-dispatch. The higher-than-projected demand placed further upward pressure on the MCP.

Assessment

The high price in the SBG hour was a consequence of higher-than-expected Ontario demand, the baseload hydro reduction and the IESO's coding practice on import curtailments.

To isolate the impact of the coding practice, the MAU ran a simulation which examined the expected outcomes had the import curtailment been limited to the constrained sequence rather than the constrained and unconstrained sequences (i.e. revising the effect of the ADQh code). Table 3-5 reports the import curtailments in both sequences and the actual and simulated MCPs. If the curtailed import had been left as a source of available supply in the unconstrained sequence, the HOEP would have been $54.19/MWh, or $69.76/MWh (56 percent) lower than the actual HOEP.

the imports were scheduled at their full amount in the constrained sequence but not in the unconstrained sequence, leading to 154 MW being constrained on.

Table 3-5: Actual and Simulated MCP and HOEP Resulting from IESO Coding of Import Curtailments September 5, 2010 HE 1 (MW and $/MWh)

Interval	Constrained Sequence Import Curtailment (MW)	Actual Import Curtailment in Unconstrained Sequence (MW)	Actual MCP ($/MWh)	Simulated Curtailment in Unconstrained Sequence (MW)	Simulated MCP ($/MWh)	Difference (Simulated – Actual) ($/MWh)
1	347	193	189.95	0	119.42	-70.53
2	347	193	189.73	0	119.41	-70.32
3	347	193	166.30	0	105.21	-61.09
4	347	193	166.30	0	105.21	-61.09
5	347	193	166.30	0	79.34	-86.96
6	347	193	119.41	0	79.34	-40.07
7	347	193	113.34	0	7.45	-105.89
8	347	193	105.21	0	7.40	-97.81
9	347	193	105.21	0	7.40	-97.81
10	347	193	79.34	0	7.05	-72.29
11	347	193	79.34	0	7.05	-72.29
12	347	193	7.05	0	6.05	-1.00
Average	**347**	**193**	**123.96**	**0**	**54.19**	**-69.76**

One implication of using the ADQh code is that importers and generators are rewarded while exporters and loads are penalized because of a higher HOEP that does not reflect the actual market supply/demand conditions. The counter-intuitive pricing sends an incorrect signal to the marketplace and may increase the IESO's need to resort to non-market mechanisms to deal with SBG in future hours. Increasing the HOEP provides importers with a degree of assurance that an SBG event will not lead to a negative price, thus encouraging them to offer more into the market even though the market is currently oversupplied or is expected to be oversupplied. On the other hand, the increased price can undermine the profitability of exports and discourages exporters from exporting power that would help to alleviate the SBG conditions.

The Panel observed a further impact of this counter-intuitive price at OPG's Beck facility. The Beck facility has six units that can operate as either generators or as pumped storage facilities (i.e. a dispatchable load). In anticipation of low-priced hours, OPG had configured a number of these stations to operate as pumped storage facilities. During HE 1, however, the high price made these facilities uneconomic and the facilities were not dispatched. Significantly, pumped storage has been promoted as a means to manage SBG conditions, but in this particular instance the facilities were not dispatched because of the high and counter-intuitive price.

Finally, several traders failed a total of 390 MW exports in HE 2, possibly in order to avoid being charged high prices for their transactions.[51] These export failures raised the risk of an output reduction at a nuclear station during HE 2, and in response the IESO cut an additional 400 MW of imports using the ADQh code. The incident highlights the consequence of a distorted price signal on the operation of future hours due to the use of the ADQh code.

Price Impact of ADQh Curtailments

Table 3-6 reports the total number of hours with import curtailments associated with ADQh and its price impact during SBG hours for the period January to October 2010.[52] Based on simulations of the unconstrained sequence with curtailed imports restored (i.e. the import curtailment not being removed from the unconstrained sequence), the HOEP would have been on average -$9.19/MWh in those SBG hours, compared to an actual of $18.07/MWh.

[51] Intertie traders can fail the transactions without notifying the IESO the reasons. However, in a few incidents, intertie traders did call the IESO, indicating that they would fail their transactions because of a high price in Ontario.
[52] There were no SBG events in January and February 2010.

Table 3-6: Price Impact of ADQh Coding in Surplus Baseload Generation Hours January to October 2010 (MW and $/MWh)

Month	Number of SBG Hours	Average Import Curtailment (MWh)	Actual HOEP ($/MWh)	Average Simulated HOEP (MWh)	Difference (Simulated – Actual) ($/MWh)
Mar-10	5	245	11.99	-6.72	-18.71
Apr-10	39	189	9.37	-1.85	-11.22
May-10	8	354	21.74	4.43	-17.31
Jun-10	4	240	26.63	21.36	-5.27
Jul-10	4	293	22.73	9.78	-12.95
Aug-10	18	503	20.26	-10.78	-31.04
Sep-10	36	313	25.37	-28.5	-53.87
Oct-10	29	279	17.56	-5.14	-22.70
Total/Average	143	293	18.07	-9.19	-27.26

The Panel has previously observed that curtailing exports with the ADQh code during shortage conditions has artificially reduced the market price to a level that does not reflect the shortage situations. As with the import curtailments discussed above, the Panel was concerned that this approach provides distorted incentives to traders and other market participants, and may increase the need for the IESO to take further control actions in future hours. The Panel therefore recommended that exports not be removed from the unconstrained sequence when curtailed for system adequacy reasons.[53] The IESO initially determined this to be at a low priority for further

[53] For details, see the Panel's July 2008 Monitoring Report, pp. 171-180. Because curtailed exports for ADQh are also removed from the unconstrained sequence, the HOEP is decreased, which is inconsistent with the shortage situation at the time.

investigation. [54] However, it recently decided to change the coding practice for export curtailments in such situations.[55]

The IESO's initial response to the Panel's recommendation on the coding practice when exports are curtailed during shortage conditions noted that the change proposed by the Panel would result in further differences between the constrained and unconstrained sequences, which would create an additional uplift burden. The Panel agrees that not removing curtailed exports or imports from the unconstrained sequence will often result in further quantity differences between the two sequences.[56] However, a larger quantity difference does not necessarily result in a higher uplift because the HOEP is changed as well. A higher HOEP tends to increase constrained-off payments, but reduce constrained-on payments, while a lower HOEP tends to reduce constrained-off payments and increase constrained-on payments. The net effect depends on the relative magnitude of the two payments. In two sample cases (one with export curtailments during shortage conditions and the other with import curtailments during an SBG event), the

[54] The IESO's response to the Panel's recommendation was: "As stated in response to the December 2007 report, there are several issues regarding the appropriate market price during curtailment of exports (imports) due to adequacy. The IESO's current practices are based on the belief that the resultant price impacts of curtailed exports do not represent a distortion. Not removing these exports from the unconstrained algorithm would also result in further differences between the constrained and unconstrained sequences, which would create an additional uplift burden for Ontario consumers and would be opposite in direction from the IESO's goal of aligning pricing with actual dispatch. However, the IESO is sensitive to counter-intuitive prices and as stated previously will consider this within the policy review of SE-67, currently assigned a low priority." The Stakeholder Engagement Plan SE-67 is currently put on hold because of other priorities. For details, see: http://ieso.ca/imoweb/consult/active_consultations.asp

[55] Effective January 10, 2011 the IESO updated its coding practice when exports are curtailed for adequacy reasons. When the adequacy concern is due to bottled resources in real-time, the IESO will apply the TLRi code (which the curtailed transactions from the constrained sequence but leaves them in the unconstrained sequence). When there is a global adequacy concern the IESO will continue to apply the ADQh code. After-the-fact analysis will be relied upon to verify that the proper code was used. See: the IESO's Interim Market Document Change, IESO_IMDC_0160 at http://www.ieso.ca/imoweb/pubs/imdc/IESO_IMDC_0160.pdf.

[56] At times, not removing the unconstrained schedules of curtailed exports (or imports) could lead to a smaller difference between the constrained and unconstrained sequences. For example, an export is scheduled 200 MW in the constrained sequence but 50 MW in the unconstrained sequence (i.e. the export is constrained on). The Ontario demand is 20,000 MW in both sequences, and net exports are 1,000 MW in the unconstrained sequence but 2,000 MW in the constrained sequence (i.e. net exports are constrained-on). If the export is curtailed, but not removed from the unconstrained sequence, the net exports would be 1,000 MW in the unconstrained sequence and 1,800 MW in the constrained sequence. The difference of 800 MW is smaller than 850 MW (=2,000-200-1,000+50) when the 50 MW is removed from the unconstrained sequence

Panel calculated that uplift would have been lower had the curtailed intertie transactions not been removed from the unconstrained sequence.[57]

As a general rule, the Panel believes that the market price should reflect the offer/bid prices of the resources that have been dispatched. However, in certain instances, it is appropriate for the market price to deviate from the offer price of the resources that have been dispatched. Specifically, where the IESO must undertake out-of-market control actions in order to stabilize conditions, such as during shortage or SBG conditions, it is appropriate for the market price to reflect the conditions immediately prior to the out-of-market control action. The IESO's manual intervention to cut imports is an action outside of the market, and its impact on the market price should be minimized. Strictly aligning the price with the offer/bid prices of dispatched facilities during shortage or SBG conditions compromises the market signal and undermines the IESO's own efforts to manage these conditions.

The IESO, following previous Panel recommendations, has revised several of its procedures to allow for the market price to better reflect demand/supply situations following IESO interventions. These revisions include, but are not limited to:

- Removing the emergency imports from the market supply to allow the market price to reflect the tight supply/demand condition;[58]

- Increase the market demand by the estimated amount of reduced demand due to a voltage reduction to allow the price to reflect the tight supply/demand condition;[59]

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[57] The Panel assessed the incidents of January 18, 2010 HE 10 and September 5, HE 1. In the two cases, total CMSC payments would have been about $4,000 and $5,600 lower, respectively, had the curtailed exports or imports in not been removed from the unconstrained sequence. Supplementary information on CMSC during these hours is contained in Appendix 2 to this chapter.

[58] Emergency imports are an out-of-market mechanism employed by the IESO in order to increase supply. These imports increase the supply but are priced at -$2,000 in the IESO's real-time tool. In the past, this led to a suppressed HOEP, not reflecting the true shortage conditions. The IESO, following the Panel's recommendation, implemented a new procedure on August 11, 2005 of removing the emergency imports from the supply and thus eliminating the price distortion. For details, see the Panel's June 2004 Monitoring Report, p. 63 and December 2005 Monitoring Report, pp. 73-74.

[59] Voltage reduction is an out-of-market mechanism employed by the IESO in order to reduce demand during extremely tight supply situations. The reduction leads to reduced demand for energy. In the past, this led to a suppressed HOEP, not reflecting the true shortage conditions. The IESO, following the Panel's recommendation,

- Adding Control Action Operating Reserve (CAOR) as an OR source in order to avoid the reduction in OR requirements and thus a collapse in the energy price during OR shortage conditions; [60]

- Not removing reduced nuclear generation from the market schedules during SBG situations;[61] and

- Currently working towards not removing curtailed exports from the market schedule during shortage conditions.

The Panel regards the curtailment of imports during SBG conditions in the same manner as a reduction in nuclear output during SBG conditions. The Panel recommends that the IESO leave curtailed imports in the unconstrained schedule during periods of SBG. This would be consistent with the IESO's approach to reductions in nuclear output during periods of SBG. The Panel further believes that the treatment of curtailed imports during the SBG conditions should be consistent with the treatment of emergency imports during shortage conditions: the former deals with over-supply while the latter with under-supply. The Panel believes that where the IESO relies upon manual actions that are outside of the market, the impact of these interventions on the market price should be minimized.

The current analysis focuses on the implications of the ADQh code on the market price in respect of import curtailments under SBG conditions. As with its prior analysis of export curtailments, the Panel believes that the IESO should avoid distorting the market price when it intervenes with out-of-market actions. Furthermore, the distortion of the market signal in one hour tends to necessitate more intervention in subsequent hours and thus more distortion to the market. The

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implemented a new procedure on August 11, 2005 of adding the estimated reduction in demand into the total demand and thus eliminated the price distortion. For details, see the Panel's December 2005 Monitoring Report, pp. 73-74.

[60] CAOR is out-of-market action whereby the IESO provides operating reserve through a voltage reduction. Currently, 800 MW of CAOR is applied in real-time. Before the implementation of CAOR, the IESO reduced the OR requirement at times of OR shortage, leading to a suppressed HOEP due to the joint optimization of energy and OR market. The introduction of CAOR eliminated the OR shortage and thus the reduction in the OR requirement, resulting in a more intuitive HOEP. For more details on CAOR, see: http://www.ieso.ca/imoweb/marketdata/ControlActionOR.asp

[61] See footnote 44.

Panel therefore believes that impact of the ADQh code on the unconstrained market schedule should be eliminated

Recommendation 3-1:

The IESO should not remove imports curtailed to address SBG conditions from the unconstrained market schedule. This could be accomplished by changing how the ADQh code operates with respect to the market schedule.

2.3 New Procedure Relating to the Release of Transmission Service

All intertie transactions require transmission service on both sides of the border. A trader may be able to obtain transmission service on one side but unable to obtain transmission service on the other side. A failure to obtain transmission service in one jurisdiction results in a transaction failure in the jurisdiction where the trader obtained the transmission service.

In Ontario, all intertie transactions that have been scheduled in the final one-hour ahead pre-dispatch are considered firm as they are guaranteed transmission service in Ontario. Traders, however, have to subsequently arrange their own transmission service in other markets (the IESO runs its final pre-dispatch ahead of all other adjacent markets). As a result, failed transactions in Ontario at times are due to the trader being unable or unwilling to obtain transmission service in other markets, particularly Manitoba.

One well-known reason for intertie transaction failures historically was that the IESO released the transmission service too late to allow traders to obtain necessary transmission service in Manitoba and MISO.[62] To address the issue, the IESO implemented a new procedure on September 8, 2009, providing traders with sufficient time to arrange transmission service outside of Ontario.[63] Since the new procedure was implemented, several market participants have successfully acquired transmission service in Manitoba and MISO in order to export from Ontario or import from MISO. The Panel has observed that at times traders have been able to export as much as 200 MW from Ontario to Minnesota through

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[62] The transmission service in Manitoba is provided by Manitoba Hydro, which also participates in the Ontario market as an importer and exporter.

[63] Under the old procedure, ETAGs were adjusted 30 minutes before dispatch (T-30) after the 1 hour ahead pre-dispatch (PD) run is complete, with subsequent transmission release. Thus if a trader did not have a schedule in the final one hour ahead pre-dispatch run, the release of its transmission to other traders began only at T-30. Thirty minutes does not allow enough time for market participants to acquire transmission service through Manitoba as well as into or out of MISO. As a result, market participants who did not initially acquire transmission service but were scheduled during the final PD run were forced out of the market and their transactions did not flow. In order to provide market participants with the necessary time to acquire transmission, the IESO now manually adjusts ETAGs 90 minutes before the hour (T-90) to align with the associated two-hour-ahead PD constrained schedule. This should allow transmission to be released in MISO and provide sufficient time for market participants to obtain the necessary service before the final Ontario PD run.

Manitoba, which is an alternative to exports at the Ontario-Minnesota interface. Table 3-7 below reports the total imports and exports at the Manitoba intertie by participant. In the year since the implementation of the new procedure, exports by market participants other than Manitoba Hydro have increased significantly, from almost no exports historically to 150 GWh (approximately 68% of all exports on this intertie) for the period September 2009 to August 2010.

Table 3-7: Imports and Exports at Manitoba Interface September to August, 2006 - 2010 (GWh)

Period	Imports (GWh)			Exports (GWh)		
	Manitoba Hydro	Others	Total	Manitoba Hydro	Others	Total
Sep 06 –Aug 07	319	225	544	259	1	260
Sep 07 –Aug 08	251	104	355	74	0	74
Sep 08 –Aug 09	231	32	263	176	0	176
Sep 09 –Aug 10	***346***	***19***	***364***	***68***	***150***	***219***
Total	**1,147**	**380**	**1,526**	**577**	**151**	**729**

Increased exports may reduce constrained-off imports from Manitoba and constrained-off generation, and thus reduce constrained-off payments to importers and generators (see Table 3-9 below).[64] As discussed more fully in section 3.2 below, the Panel and the MAU are continuing to monitor the evolution of trading activity on the Northwest interties and its impact on CMSC payments.

[64] For example, assume the HOEP is $30/MWh and the shadow price at the Manitoba intertie is $1/MWh. An import is offered at $5/MWh. Without exports, the import will be constrained-off and Ontario consumers pay $25/MWh of CMSC to the importer for not importing. Assume an export bids in with a bid price of $6/MWh and the shadow price increases to $5/MWh. Then the export is constrained-on but the import is not constrained-off. The exporter pays $6/MWh after receiving the constrained-on CMSC ($30 – ($30-$6)), and the importer is paid $30/MWh for the import which flows. The net result is that Ontario consumers pay $24/MWh of CMSC, which is $1/MWh less than without export bidding. As a result, facilitating more exports tends to reduce total CMSC payments (as long as prices are not negative).

2.4 IESO's Actions to Prevent Transmission Lines from Becoming Overloaded

At times, an intertie may become congested or nearly congested. If a transaction that would relieve the congestion (i.e. any transaction that flows in the opposite direction of the congestion) fails, the transmission line will become overloaded unless the IESO or the counterpart system operator in the other jurisdiction responds by curtailing a transaction flowing in the opposite direction of the failed transaction.

In the Past, the IESO's practice was to attach the TLRi code[65] to the curtailed transaction(s). Because the curtailed transaction or transactions are not removed from the unconstrained sequence under this code, the IESO's manual action may lead to a greater discrepancy between the two schedules. At times the constrained-off CMSC payments may be very large when transactions were offered or bid at a high price.

Unlike the curtailments for internal adequacy discussed in section 2.2 above, these are situations where the cause of the control action is based on an external situation beyond the control of the IESO or Ontario market participants. After MAU identified the impact of this coding practice, and discussed it with IESO personnel, the IESO altered its practice and beginning November 25, 2009 has applied the TRLe code[66] to such situations. This approach reflects the principle that failures due to external causes should be removed from both the unconstrained and constrained sequence as these transactions are not feasible regardless of their bids/offers in Ontario and are not a direct result of IESO initiatives to manage the domestic resource shortage or supply conditions.[67]

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[65] TLRi means Transmission Loading Relief for intertie or internal transmission.
[66] TLRe means Transmission Loading Relief for external jurisdictions.
[67] See the Panel's July 2008 Monitoring Report, pp. 171-180. In the report, the Panel recommended that (1) For interjurisdictional transactions that fail because of market participants' ('OTH') or external system operators' actions ('TLRe' and 'MrNh'), the MSP recommends the IESO revise its procedures to avoid distorting the unconstrained schedule. This would prevent counter-intuitive pricing results (and would allow traders in those instances to receive the Congestion Management Settlement Credit payment consistent with other situations where such payments are currently available).and (2) The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy ('ADQh') should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted**.**

In addition to mitigating the distortion of the market price which occurs when externally infeasible trades are included in the market schedule, the change in coding practice has also reduced CMSC payments to traders associated with these transactions. The total estimated savings in CMSC payments due to the code change for the period November 2009 to October 2010 is $252,000.[68]

2.5 Loop Flow and the Status of the Phase Angle Regulators (PARs) at the Michigan Interface

A PAR is a special transformer that is used to control the power flowing over a transmission line. There are five PARs on four transmission lines at the Michigan interface, with a capability of controlling about 600 MW of Lake Erie Circulation (LEC). To effectively control LEC, all five PARs need to be in service. With any one of them not activated, the remaining PARs have limited capability to control LEC effectively.

- One PAR (owned by Hydro One) is installed on one transmission line in the Windsor area. It has been properly functioning since market opening, but has had minimal effect in controlling the LEC because PARs at other interties at the Michigan border are not activated.

- Two PARs (owned by Hydro One) are installed on two transmission lines in the Lambton area. Those PARs were out of service in 2003, and returned to service in March 2005. However, due to a technical issue with the PARs, the import/export capability at the Michigan interface was reduced by about 400 MW. As a result, the IESO has bypassed them under normal conditions until an agreement for

[68] It is worth noting that the potential savings could have been much higher because the change in code has eliminated an opportunity for traders to strategically bid or offer. For example, knowing that the IESO would use the TLRi code when curtailing exports/imports, an exporter might bid an extremely high price (the risk of bidding a high price is fully hedged if the exporter has sufficient TRs) and thus increase the constrained-off payment (which is calculated as the difference between the bid price and the HOEP). The change in code has eliminated the CMSC payment and correspondingly removed the potential incentive for traders to bid or offer a high price that does not reflect their actual opportunity costs.

operation between Hydro One and International Transmission Company (ITC) in Michigan can be reached.[69]

- Two new PARs, owned by ITC, have been installed at one transmission line in the Sarnia area to replace one which failed. ITC has indicated that the two PARs will not be put into service until the United States Federal Energy Regulatory Commission (FERC) approves regional sharing of the costs of the PARs.[70]

The Panel has repeatedly commented on this issue and recommended that the bypassed and non-activated PARs be brought into service as soon as possible and practicable, because of the large efficiency gains to Ontario as well as external markets.[71] It appears, however, that activation of the two ITC-owned PARs depends on resolution of U.S. regulatory matters and is outside the control of the IESO and Hydro One.[72]

3. New Matters

3.1 Treatment of Transfer Capability Reductions Outside of Ontario

In other electricity markets, if there is a known lack of transfer capability (either due to outage/derating or other reliability problems) outside the market that prevents intertie transactions from flowing, traders will typically cease offering into or bidding out of the market as they cannot profit from a transaction that cannot flow. Indeed, if they offer or bid and get scheduled, their transaction would fail and they could become subject to potential

[69] See the Panel's December 2005 Monitoring Report, pp 79-82.
[70] FERC Order on Compliance Filing, New York Independent System Operator, Inc., Docket ER08-1281-004, July 15, 2010, paragraph 32.
[71] See the Panel's December 2005 Monitoring Report, pp 79-82; July 2006 Monitoring Report, pp 100-102; January 2008 Monitoring Report, pp 146-151; July 2009 Monitoring Report, pp 164-181; and January 2010 Monitoring Report, pp 69-84.
[72] In December 2010, FERC ordered a settlement proceeding on a request by MISO and ITC that the New York ISO and PJM absorb part of the cost of the ITC-owned PARs. The New York ISO has requested a reconsideration or rehearing of the FERC order. See FERC Order Accepting and Suspending Proposed Tariff Sheets and Establishing Hearing and Settlement Judge Procedures, Midwest Independent Transmission System Operator, Inc., Docket ER11-1844-000, December 30, 2010; and, New York ISO submission on Docket ER11-1844-000, January 21, 2011.

financial penalties and compliance investigations as these failed transactions may be considered not for bona fide reasons. Avoiding offers and bids for infeasible transactions when there are external transfer problems can reduce transaction failures and thereby increase system reliability as well as market price fidelity.

However, this type of reaction by traders to external transfer problems may not occur in the Ontario market because of the two-sequence design and the IESO's coding practice.

- Constrained-off CMSC payments may incent traders to continue offering (or bidding) even though they know there is a transmission problem outside of Ontario that prevents them from importing into (or exporting out of) Ontario.
- Continuing to offer/bid is a risk free strategy because the scheduled imports/exports (in the constrained sequence) will be curtailed by the IESO with an associated code of TLRe as a result of the curtailment being made for external reliability.[73] This exempts the trader from any potential financial penalty (i.e. Intertie Failure Charge) and non-compliance investigation in Ontario.[74] They can avoid sanctions and compliance investigations in the neighbouring market by not arranging the exports (or imports) in the other jurisdictions, given that the transactions are schedule in Ontario earlier than in neighbouring jurisdictions.

July 13-15, 2010

The events of July 13-15, 2010 are an example. A part of the transmission system in Manitoba was derated to 0 MW of transfer capability, which prevented any power from flowing between Ontario and MISO on the Ontario-Manitoba intertie from July 13 HE 10 to July 15 HE 18. However, two market participants still offered or bid at the Manitoba interface. To accommodate the loss of transfer capability in Manitoba, the IESO can either preemptively curtail transactions (prior to final pre-dispatch) or curtail transactions in real-time (if they were scheduled in the constrained sequence). However, where transactions are

[73] For a general discussion of curtailments and other control actions see section 2.2.4 of this chapter.
[74] Because the IESO's pre-dispatch tool runs ahead of external jurisdictions, a failed transaction in Ontario is typically not a failed transaction in the corresponding external jurisdiction and thus there is no financial implication outside Ontario.

scheduled only in the unconstrained sequence but not in the constrained sequence, there is no manual curtailment required and, under the circumstances, this would automatically lead to constrained-off CMSC payments. In the two days (July 14 and 15), Ontario load paid $163,000 in uplift to two traders for constrained-off imports at the Manitoba interface even though the imports could not possibly have flowed.[75] The Panel is currently assessing the behaviour of these market participants.

The Panel recognizes there are challenges in dealing with external transmission problems under the current market design.[76] A locational marginal pricing (LMP) regime could be very useful in addressing such issues because the LMP regime will not provide financial incentives for traders to offer or bid transactions that could not possibly flow. In the absence of such a market design, one option is to reduce the transfer capability when there are transfer capability reductions Ontario prohibit flow over the interface. This would preclude the scheduling of intertie offers or bids in both the constrained and unconstrained sequences. It also would eliminate unnecessary CMSC payments. Alternatively, the IESO could remove all offers and bids for those transactions that are physically incapable of flowing from both the constrained and unconstrained sequence (i.e., using the TLRe code for all offers/bids– not the TLRi code, which removes transactions from the constrained schedule only).[77]

While the Panel maintains its overall views regarding CMSC and the two-sequence market structure, it feels there is a particular urgency regarding the following recommendation. This recommendation should not be interpreted to mean a tolerance for other forms of constrained-off CMSC, or even CMSC in general.

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[75] Major transmission outages/deratings or transfer capability reductions are generally made available to market participants in neighbouring US markets based on the open access tariffs or market rules in the markets.
[76] In its January 2010 Monitoring Report, pp. 77-82 and 84-86, the Panel discussed the IESO's action of pre-emptively curtailing exports (or imports) in response to external problems. The Panel concluded that although the action may be blunt to the market, the most practical and efficient way for the IESO to independently assist external ISO to manage their congestion in the short term is to curtail exports (or imports) before the final pre-dispatch run. In the long term, a more efficient way to address the congestion problem might be achieved through improved coordination among market operators. A broader regional resolution, which is under consideration before the FERC, appears to be the right approach.
[77] See section 2.2.4 of this chapter.

Recommendation 3-2:

Where there are transfer capability reductions outside Ontario that prohibit power flow out of or into Ontario, the IESO should not make CMSC payments. Possible methods might include but not limited to: removing the related offers/bids, reducing intertie transfer capability to zero, or establishing a mechanism for clawback of the CMSC payments.

3.2 Increased Trading Activity and CMSC Payments in the Northwest Region

3.2.1 Introduction

This section reports on the Panel's continuing examination of bottled supply and significant CMSC payments in the Northwest region.

The average zonal price for the Northwest region was - $553/MWh in the summer (May - October) of 2009, -$263/MWh in the winter (November - April) of 2010, and -$157/MWh in the summer of 2010. The significant increase in the zonal price in summer 2010 is likely due to lower water levels over the past summer and a corresponding lower hydroelectric capacity. The negative zonal price reflects how generators in the area are offering into the market. These negative prices would not have been sustainable had the generators actually been exposed to the resulting prices.

The Panel has repeatedly reported on large CMSC payments made to market participants in the Northwest region, even though the area accounts for only a small portion of the total Ontario generation and load (see Table 3-9 below). The CMSC payments are major contributors to zonal prices which do not reflect actual marginal or opportunity costs of production or consumption. As can be seen in Table 3-8, the CMSC payments also represent a major component of total revenues for suppliers in the region, and a major offset to the purchase costs for dispatchable loads in the region. Table 3-8 below indicates the average realized price for the various types of dispatchable resources in the Northwest region as well as in other regions.[78]

Table 3-8: Revenues, Payments and Average Realized Price by Participant Type May to October, 2009-2010 (GWh and $/MWh)

Area	Participant Type	Summer 2009					Summer 2010				
		Energy Revenue/ Payments ($M)	CMSC ($M)	Total Revenue/ Payments ($M)	Supply/ Consumption (GWh)	Average Revenue/ Payments ($/MWh)	Energy Revenue/ Payments ($M)	CMSC ($M)	Total Revenue/ Payments ($M)	Supply/ Consumption (GWh)	Average Revenue/ Payments ($/MWh)
Northwest	Generators	59.4	4.2	63.6	2,429	26.18	74.9	5.4	80.3	1,834	43.78
	Importers	4.6	12.5	17.1	176	97.16	10.6	9.6	20.2	388	52.06
	Dispatchable Loads	9.1	(4.7)	4.4	376	11.70	15.1	(15.5)	(0.4)	421	(0.95)
	Exporters	9.3	(7.2)	2.1	392	5.36	4.6	(1.6)	3.0	119	25.21
All Other Areas	Generators	1,644.5	39.1	1,683.6	64,430	26.13	2,834.9	25.4	2,860.3	67,895	42.13
	Importers	80.7	1.4	82.1	2,837	28.94	121.2	0	121.2	2,840	42.68
	Dispatchable Loads	28.8	(1.2)	27.6	1,259	21.92	35.6	(0.5)	35.1	1,099	31.94
	Exporters	186.2	(13.8)	172.4	7,173	24.03	284.2	(2.1)	282.1	7,078	39.86
Ontario	Non-dispatchable loads	1,696.1	84.1	1,780.2	65,517	27.17	2,912.8	60.1	2,972.9	69,500	42.78

There are several important observations arising from these data:

- Although the market has a uniform price design, different market participants in different locations have been paid or charged a different price (after taking into account the CMSC payment). For example, on average, in the Northwest area generators were paid $43.78/MWh in summer 2010 for every MW they produced, importers were paid $52.06/MWh for every MW they imported, dispatchable loads were paid $0.95/MWh for every MW they consumed, and exporters were charged $25.21/MWh for every MW they purchased. In contrast, in all other areas, on average, generators were paid $42.13/MWh, importers were paid $42.68/MWh, dispatchable loads were charged $31.94/MWh, and exporters were charged $39.86/MWh. As the figures above indicate, sources of supply are paid

[78] These calculations exclude Global Adjustment and other, non-CMSC uplift charges as well as contract, regulatory and generator cost guarantee payments.

more than dispatchable sources of consumption (loads and exporters). To hold the market whole, the balance is recovered from non-dispatchable loads, which paid on average $42.78/MWh in summer 2010**.**

- Importers in the Northwest received a much higher price than generators in the Northwest after taking into account CMSC payments. For example, in summer 2009, importers received on average $97.16/MWh for every MWh imported to Ontario, which is 271 percent greater than what Northwest generators received and 272 percent greater than what generators in other areas of Ontario received, on average, over the same period. On average importers in the Northwest are the biggest beneficiaries of the two-sequence market design.

- Conversely, the average actual energy purchase cost by dispatchable loads in Northwest, net of CMSC payments received, was $11.70/MWh in summer 2009 and -$0.95/MWh in summer 2010. This is 47 percent and 103 percent lower, respectively, than the price that other dispatchable loads had paid in the same periods.

- Exporters, especially in the Northwest, have also enjoyed a lower price than non-dispatchable loads. For example, in summer 2009 exporters in the Northwest paid $25.21/MWh, which is 37 percent less than what other Ontario exporters had paid and 41 percent less than what non-dispatchable loads paid.

The price differences among types of market participants indicate that, in reality, the market is not a uniform price market. Furthermore, the generators and importers in a bottled area (like the Northwest) are paid more than other generators and importers in other areas for energy that they have provided to the market. The concept that generators and importers in an area with excess supply are paid more than generators and importers in an area with lower levels of supply (and higher demand) is totally counter-intuitive and has resulted in numerous inefficient and unattended consequences.

In a previous report,[79] the Panel highlighted several issues in the Northwest area and demonstrated that many are a result of the two-sequence market design. In particular, the major findings in that report are:

- The Northwest has accounted for about 1/3 of total CMSC payments in Ontario, although both the intertie capacity and generation capability are small (roughly 10% of Ontario's total intertie capacity and approximately 4 percent of Ontario's total installed generation capability). These CMSC payments provide distorted signals to market participants that undermine market efficiency. The two-sequence design also provides market participants with opportunities to strategically target CMSC payments rather than the delivery or consumption of energy.

- Both the Manitoba and Minnesota interfaces are frequently import congested in the unconstrained sequence without any corresponding physical import of electricity (i.e. imports are constrained off). This has led to congestion rent at this interface being insufficient to cover the TR payouts on these interfaces. Constrained-on payments to exporters and dispatchable loads may at times be inflated due to negative zonal prices in the area, which do not appear to reflect generator production costs or opportunity costs.

This section discusses further developments and issues in the Northwest area, some of which were raised in the Panel's previous report. The focus is on two areas:

- Cost of congestion in the Northwest;
- Trading activity at the Manitoba interface; and
- Subsidization to various market participants and its implications on market efficiency.

[79] See the Panel's January 2010 Monitoring Report, pp. 89-105.

3.2.2 *Cost of Congestion*

There are two major congested locations in the Northwest area: one at the Northwest-to-East interface within Ontario and the other at the interfaces with Manitoba and Minnesota. The former has a transfer capability slightly above 300 MW, but this is frequently reduced due to lightning activity in the area. The latter has a total export capability of about 410 MW (140 MW at the Minnesota interface and 270 MW at the Manitoba interface) and an import capability of about 260 MW (90 MW at the Minnesota interface and 170 MW at the Manitoba interface). With abundant hydro resources in the Northwest (and Manitoba) and declining levels of load, the Northwest area is regularly characterized by supply in excess of demand.

In a well-designed market, abundant low-cost supply should translate into a low market price in the area, providing incentives for generators to reduce their output or scale down capacity, for loads and exporters to increase consumption, and for importers to reduce imports. The market forces would work towards an equilibrium at which all demand willing to pay no less than the market price is satisfied and all supply that has a generation/opportunity cost no greater than the market price is scheduled. However, Ontario continues to operate with the uniform HOEP and associated CMSC payments that were intended to be a temporary structure prior to the development of locational pricing.[80] This design has resulted in a distorted price signal, where none of the above-mentioned functions perform optimally and where market efficiency is not maximized:

- Generators are paid constrained-off payments which undermine the incentive to produce less or scale down their generation capacity in an over-supplied area.
- Loads do not benefit from the abundant supply because they pay the uniform effective price (which includes the HOEP, the Global Adjustment (GA) and uplifts). Notwithstanding the excess of local supply, loads may be incented to reduce their consumption to avoid a high all-in effective price.

[80] For discussion of the original expectation that the market would evolve towards locational pricing, see the Panel's October 2002 Monitoring Report, pp. 140-141.

- Exporters may be incented to bid at a price which does not reflect their actual arbitrage opportunities in order to realize larger constrained-on payments (because the constrained-on payment is calculated as the difference between their bid price and the HOEP).
- Importers may be incented to offer at prices below their supply costs in order to increase constrained-off payments (because the constrained-off payment is equal to the difference between the HOEP and their offer price).

Table 3-9 below reports the total annual CMSC payments for the period from May 2002 to October 2010 (excluding dispatchable loads). The total CMSC payment in Ontario was about $1.1 billion (before clawbacks),[81] of which roughly one-third (or $360 million) was paid to generators and intertie traders in the Northwest area. Of the $360 million in CMSC payments, $161 million (45 percent) was paid for not generating, $146 million (40 percent) was paid for not importing, and $53 million (15 percent) was paid for constrained-on exports /imports / generation.

[81] Approximately 3% of CMSC payments are recovered through clawback processes administered by the IESO. Statistics which net clawback against CMSC payments at the level of the individual interfaces and types of market participants are not readily available. Accordingly, unless otherwise noted, all CMSC data in this report is based on gross payments ignoring clawbacks.

Table 3-9: Annual CMSC Payments
May 2002 to October 2010
($ Millions; Excluding Dispatchable Loads)

Year	Northwest							Ontario		
	Constrained -Off			Constrained-On			Total	Constrained -Off	Constrained-On	Total
	Generators	Manitoba	Minnesota	Generators	Manitoba	Minnesota				
2002*	24	9	2	1	0	0	36	39	107	146
2003	6	9	8	3	0	0	26	68	42	110
2004	20	3	1	0	0	0	24	55	25	80
2005	48	17	6	0	0	6	77	121	81	202
2006	16	9	0	1	0	2	28	62	41	103
2007	14	13	2	2	1	4	35	68	39	107
2008	16	30	3	1	1	16	67	98	53	151
2009	9	17	4	1	4	6	41	73	52	125
2010**	9	10	2	1	2	2	26	43	30	73
Total	161	118	28	9	9	35	360	627	470	1,097
Clawback							14			34
Net CMSC							346			1,063

*From May to December 2002
**from January to October 2010

Eleven market participants have accounted for almost all the $360 million total CMSC payments in the Northwest area since market opening. The three largest recipients account for 90 percent of the total since market opening and 79 percent of the 2010 (January to October) payments. Over the past two years, new traders have become active at the Manitoba interface and are receiving significant CMSC payments. In 2009-2010, four new or smaller traders received about $14 million at the Manitoba and Minnesota interfaces, which accounted for about 20 percent of total CMSC in the Northwest area.

The CMSC payments in 2010 ($26 million) are the lowest in the past six years. This is in part a result of a smaller number of months (January to October in 2010), in part due to a relatively low HOEP[82] (although not as low as in 2009) and in part due to more active trading at the interfaces (especially the Manitoba interface) resulting in lower CMSC payments per constrained MWh.

[82] A lower energy price tends to reduce constrained–off payments, which represent more than 60% of total CMSC payments in the area.

3.2.3 *Trading Activity at the Manitoba Interface*

As noted in section 2.5 above, there has been increased activity in the Northwest area, especially at the Manitoba interface, since the IESO implemented the new transmission service procedure in September 2009 (discussed in Chapter 3 Section 2.3) . The new procedure provides traders sufficient time to obtain transmission service in MISO and Manitoba, and thus facilitates arbitraging transactions between Ontario and MISO. The possible incentives for increased involvement by traders at the interface include opportunities to obtain constrained-off payments for imports and constrained-on payments for exports.

Table 3-10 below reports constrained-off imports[83] and constrained-on exports[84] by traders at the Manitoba interface. It can be seen that in the year since the implementation of the new IESO procedure, market participants other than Participant A have obtained a significant share of constrained-off imports and the majority of constrained-on exports.

[83] A negative value means constrained-on imports.
[84] A negative value means constrained-off exports.

Table 3-10: Constrained-off Imports and Constrained-on Exports at Manitoba Interface September 2002 to August 2010 (GWh)

Period	Constrained-Off Imports (GWh)			Constrained-On Exports (GWh)		
	Participant A	Others	Total	Participant A	Others	Total
Sep 02 –Aug 03	74	20	94	-6	0	-6
Sep 03 –Aug 04	132	-4	128	-100	0	-100
Sep 04 –Aug 05	249	25	274	0	0	0
Sep 05 –Aug 06	346	10	356	3	0	3
Sep 06 –Aug 07	193	14	207	-16	0	-16
Sep 07 –Aug 08	950	57	1,007	49	0	49
Sep 08 –Aug 09	1,079	59	1,138	99	0	99
Sub -total	***3,022***	***182***	***3,204***	***29***	***0***	***28***
Sep 09 –Aug 10	***951***	***202***	***1,153***	***56***	***144***	***200***
Total	3,973	384	4,357	85	144	228

3.2.4 Subsidization to Northwest Participants and the Implications on Market Efficiency

This section examines the impact of CMSC payments on various market participants and on market efficiency. The analysis focuses on the constrained-off payments to importers and generators as well as the constrained-on payments to exporters.[85]

Constrained-off Imports

The Panel has previously observed that payments to constrained-off importers do not provide benefits to the Ontario market and has recommended that they should be eliminated.[86] Since market opening, constrained-off payments to importers in the Northwest region alone have amounted to about $146 million (or an uplift of $0.12/MWh when spread over total Ontario demand plus exports in the past 8 years).

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85 Given the regular surplus generation conditions in the Northwest area, constrained-on imports and generation and constrained-off exports are rare and typically are the result of manual actions taken by the IESO for system reliability purposes. CMSC payments to dispatchable loads, most of which are self-induced, were discussed extensively in the Panel's prior report: see the August 2010 Monitoring Report, pp.112-128.

86 See the Panel's CMSC consultation paper "Consultation on CMSC in the IMO-Administered Electricity Market - Issues Related to Constrained-off Payments to Generators and Imports" at : http://www.oeb.gov.on.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Consultation+on+CMSC, and various reports (such as the October 2002 Monitoring Report, pp. 142-144 and most recently the July 2006 Monitoring Report, p. 124)

If an importer offers at marginal cost or opportunity cost, the constrained-off payment may effectively represent a subsidy from Ontario loads to the importer without affecting dispatch or allocative efficiency. However, constrained-off payments may induce importers to offer at prices lower than opportunity cost because the magnitude of the constrained-off payment is negatively related to their offer price. This strategy may lead to imports being scheduled inefficiently, ahead of generation which could supply the same energy at a lower marginal cost.

One indicator of socially inefficient transactions at the Manitoba interface can be seen by comparing the locational price in Minnesota (MISO's "ONT_W" interface price) with the shadow price in the Northwest area when there were imports coming from Manitoba into Ontario and there was spare capacity for power to flow from Manitoba to Minnesota at the Manitoba / Minnesota interface.[87] In such a situation, the imports from Manitoba to Ontario would be expected to go to Minnesota (up to the transmission capacity at the Manitoba/Minnesota interface) when the 'ONT_W' interface price in Minnesota is greater than the shadow price in Northwest, as this would be the globally efficient outcome. It can be seen from Table 3-11 that potentially 71% of imports from Manitoba to the Ontario Northwest since January 2009 are inefficient based on this comparison. The Panel believes that the Ontario CMSC regime is the principal driver for these otherwise inefficient transactions.

[87] Only the Manitoba interface is assessed because this is the interface at which most imports are constrained-off and there are only a few market participants trading at this interface.

Table 3-11: Inefficient Imports at the Manitoba Interface
January 2009 to October 2010
(MWh and $1 000)

Month	Total Imports in Unconstrained Schedule (MWh)	Total Imports in Constrained Schedule (MWh)	Inefficient Imports (MWh)	Percentage of Imports Constrained Off (%)	Percentage of Actual Imports which are Inefficient (%)
Jan-09	62,838	14,360	11,494	82	80
Feb-09	96,624	9,401	8,411	91	89
Mar-09	69,774	499	414	99	83
Apr-09	77,336	8,840	6,608	91	75
May-09	130,752	8,180	6,102	95	75
Jun-09	133,949	19,974	18,514	86	93
Jul-09	160,672	36,750	27,425	83	75
Aug-09	169,643	22,970	14,937	91	65
Sep-09	124,785	18,865	15,267	88	81
Oct-09	164,109	33,044	22,568	86	68
Nov-09	142,095	42,015	32,432	77	77
Dec-09	105,055	4,121	2,802	97	68
Jan-10	119,424	3,911	3,370	97	86
Feb-10	69,579	2,822	2,583	96	92
Mar-10	121,988	17,400	16,007	87	92
Apr-10	119,778	61,531	49,989	58	81
May-10	94,177	1,524	1,355	99	89
Jun-10	129,430	44,117	31,022	76	70
Jul-10	156,789	47,279	30,648	80	65
Aug-10	171,934	69,436	46,361	73	67
Sep-10	156,839	82,776	58,392	63	71
Oct-10	145,366	68,558	44,463	69	65
Total	**2,722,936**	**741,535**	**528,798**	81	**71**

Table 3-11 above also reports the imports that have been constrained-off by month for the period January 2009 to October 2010. As can be seen, 81 percent of imports that were offered at the Manitoba interface were constrained off. The enormous percentage of constrained-off imports is another indicator of the incentives traders have to offer at the interface in order to receive the constrained-off payments.

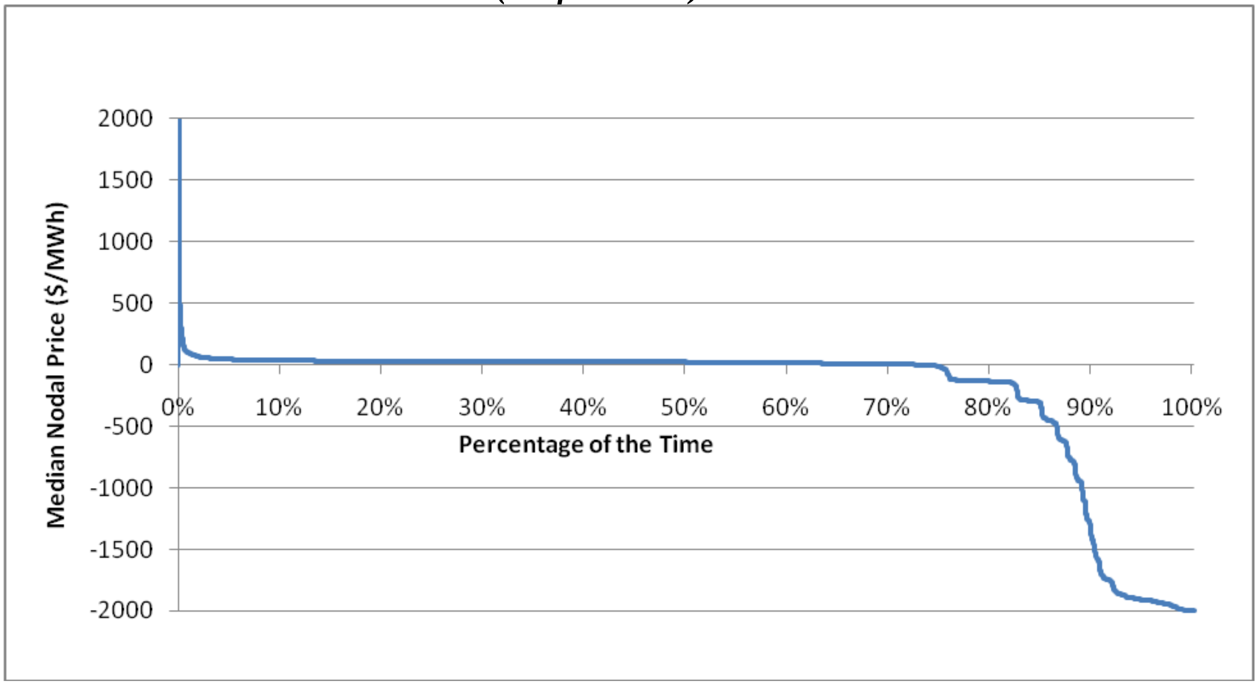
Constrained-off Generation

The Panel has previously recommended that constrained-off payments to generators be eliminated.[88] A report prepared for the IESO in 2003 agreed that constrained-off payments to internal generators may provide some reliability benefit to the market on the basis that generators might otherwise not follow dispatch instructions.[89] The Panel remains puzzled as to why market participants would need to be compensated for following dispatch instructions that the market rules require them to follow.[90] Moreover, the constrained-off payments also incent generators to offer below marginal cost (or opportunity cost), in a similar manner as discussed in the previous section with respect to importers.

Figure 3-6 below depicts the duration curve of the median location nodal price[91] in the Northwest (generators only) for the period from November 2009 to October 2010. The duration curve provides an indication about how generation units had been offered during the period.[92] It can be seen that the median offers were below -$1,500/MWh in 10% of the hours, below -$500/MWh in 13% of the hours, and below $0/MWh in 25% of the hours.

[88] See the Panel's "Consultation on CMSC in the IMO-Administered Electricity Market - Issues Related to Constrained-off Payments to Generators and Imports' at: http://www.oeb.gov.on.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Consultation+on+CMSC, and most recently the July 2008 Monitoring Report, pp. 203-205.
[89] "Congestion Management Settlement Credits in Ontario', Charles River Associates, prepared for Ontario Independent Electricity Market Operator, December 24, 2003.
[90] See the Panel's December 2007 Monitoring Report, pp. 151-160.
[91] There is no material change when average locational nodal price is used. A median has been used in order to eliminate the impact of a few very high or very low location nodal prices at specific locations.
[92] It should be noted that half of the generator offers will be below the median.

Figure 3-6: Duration Curve of Median Generator Nodal Price in the Northwest Region November 2009 to October 2010 (% of intervals)



It is understandable that at times fossil-fired generators are willing to offer at a negative price (i.e. willing to pay loads to consume) in order to avoid incremental costs associated with shutting down and restarting a unit (if they need to recover the shutdown cost directly from the market).[93] Similarly, hydroelectric units may offer at a negative price if water levels are high and the facility is unable to store or spill the water (especially during the freshet period in spring). However, it is implausible that generators in the Northwest would have been willing to pay loads to consume approximately 25% of the time for the period November 2009 to October 2010, including paying $1,500/MWh or more 10 percent of the time, as is implied by the negative portion of the nodal price duration curve in Figure 3-6. The high frequency of negative nodal prices strongly suggests that generators regularly offer below marginal or opportunity costs in order to receive constrained-off payments. To the extent that below cost offers result in changes to the merit order in the market schedule, this will also have negative effects on market efficiency.

[93] As noted in section 3.3 below, fossil-fried units often participate in the Generator Cost Guarantee program which reimburses them for operating costs that exceed their revenues.

Constrained-on Exports

A low nodal price may result in exporters being constrained-on even though they bid at a negative price. The constraining-on of exporters leads to those participants being paid to consume and at times the payment could be very large and appear to be unwarranted. The Panel previously recommended that the constrained-on payment should be capped with a replacement bid price such as $0/MWh.[94] The IESO's new rule of capping the CMSC payment, following the Panel's recommendation, will reduce these payments but will not eliminate them.[95]

If constrained-on exports are supplied by internal generators, exporters are subsidized to move power out of Ontario (because generators are effectively paid a higher price to produce the energy).

If constrained-on exports are matched by imports, exporters are effectively subsidized by Ontario loads through CMSC payments to either keep power in external markets or move power from one external jurisdiction to another. The former occurs when the source market of imports is the same as the sink market of the exports, while the latter occurs when they are different. Subsidies have occurred because constrained-on exports are charged a lower price (after netting out the constrained-on payment) while the energy is imported at a higher price. Because importers are incented to offer below cost, exporters may be subsidized to move power from high cost markets to low cost markets. Ontario loads' subsidization of these transactions is not matched by a corresponding benefit to the Ontario market.

Table 3-12 below reports the estimated subsidization by Ontario loads to intertie traders who keep power in external markets or who move power between external markets. The estimates are the constrained-on payments for exports when all the exports were met by imports, which is exactly the difference between what Ontario has paid for the same amount of imports and

[94] See the Panel's January 2010 Monitoring Report, pp. 89-105.
[95] For details, see Market rule Amendment: MR-00370 - Limiting CMSC Payments for Exporters and Dispatchable Loads at: http://ieso.ca/imoweb/amendments/mr_Amendments.asp.

what it has received from the offsetting exports. It is worth noting that the new rule amendment that uses a replacement bid of -$125/MWh will mitigate this subsidy (when exporters strategically bid a large negative price) but will not eliminate it.

Table 3-12: Subsidies to Traders Moving Power In and Out of Ontario or between External Markets At Manitoba and Minnesota Interfaces January 2009 to October 2010 ($000)

Month	Interface		Total
	Manitoba	Minnesota	
Jan-09	1	43	44
Feb-09	2	218	220
Mar-09	0	297	297
Apr-09	0	111	111
May-09	0	293	293
Jun-09	0	89	89
Jul-09	0	11	11
Aug-09	0	28	28
Sep-09	3	250	253
Oct-09	6	19	25
Nov-09	566	8	574
Dec-09	22	25	47
Jan-10	11	42	53
Feb-10	9	2	11
Mar-10	56	4	60
Apr-10	286	12	298
May-10	14	3	17
Jun-10	11	17	28
Jul-10	37	48	85
Aug-10	49	49	98
Sep-10	29	19	48
Oct-10	1	15	16
Total	**1,101**	**1,604**	**2,705**

In summary, during the period January 2009 to October 2010, it is estimated that Ontario loads provided exporters with an approximate $2.7 million subsidy for constrained-on exports that effectively moved power out of, then back into, Minnesota or for moving power from Manitoba to Minnesota through Ontario (most exports at the Manitoba interface are from Ontario to Minnesota). Ontario loads received no benefit to offset the uplift charge associated with these transactions.[96]

3.2.5 *Assessment*

As demonstrated above, there are significant problems in the Northwest associated with the two-sequence market design. This design has a few fundamental defects:

- The uniform price regime leads to (i) payments for not producing or importing (i.e. generators or importers are constrained off), or (ii) market prices that are not high enough to cover the marginal or opportunity costs (i.e. generators and importers are constrained on), thus requiring constrained-on payments to top up the costs, or (iii) market prices that are too high to loads and exporters compared to the value of consumption or opportunity costs, thus requiring constrained-on payments to offset the charges in order to induce efficient consumption and exports. These side-payments require complex calculations and are difficult to understand.

- Ontario non-dispatchable loads receive little or no benefit for the constrained-off payments that they fund through uplift charges. These constrained-off payments neither help to relieve transmission congestion, nor provide accurate signals or references for decisions relating to the construction of new transmission.

- By providing incentives for market participants to not offer/bid at marginal cost or opportunity cost, CMSC payments potentially lead to efficiency losses. For example, an efficiency loss can result when the change in offer/bid strategy may change the merit order of supply, causing more expensive generation/imports to be scheduled ahead of cheaper generation/imports.

[96] The subsidized amount varies significantly at the Manitoba interface, depending on the volume of exports that traders can move through Manitoba.

The Panel has been previously recommended that a locational pricing design or other similar designs could significantly improve market efficiency and reduce the unnecessary subsidies from Ontario loads to intertie traders as well as to generators and to dispatchable loads, particularly in the Northwest. As a whole, Ontario would benefit from such a market change, both in the short term and in the long term. The Panel understands that the IESO is drafting a "market road map",[97] which will be made available for the industry to review. As part of this process, the Panel suggests the IESO seriously consider the merits of locational pricing, or a variation where dispatchable resources receive/pay location-specific prices with non-dispatchable loads remaining subject to a uniform price.[98]

Recommendation 3-3:
As part of its "market road map" process, the IESO should work with stakeholders to examine the feasibility of replacing the two-sequence design with locational pricing, variable pricing for dispatchable resources or other alternatives.

3.3 Inefficient Stops and Starts Under the IESO's Generation Cost Guarantee Program

3.3.1 Introduction

Previous Findings

In the previous Monitoring Report,[99] the Panel discussed the impact of the December 2009 market rule amendment affecting the IESO's generation cost guarantee (GCG) program.[100] The new rules guarantee eligible fossil-fired generators their start-up costs associated with ramping up to their minimum loading point (MLP).[101] These costs are submitted several

[97] For details, see the IESO's fee submission at: http://www.ieso.ca/imoweb/pubs/corp2/IESO_SUB_2011%20FEES_20101102.pdf
[98] For further discussion of the alternative of variable pricing for dispatchable resources, see the Panel's January 2010 Monitoring Report, pp. 120-123.
[99] See the Panel's August 2010 Monitoring Report, pp. 128–140.
[100] See MR-00356 - Interim Changes to Real-Time and Day-Ahead Generation Cost Guarantee Programs, available at: http://www.ieso.ca/imoweb/pubs/mr2009/MR-00356-R00-R02-BA.pdf.
[101] The minimum loading point (MLP) is the minimum output of energy, specified by the market participant, that can be produced by a generation facility under stable conditions (i.e. the minimum output level at which the

days after the generator has produced and are not considered as part of the IESO's dispatch decision. In addition, under the new rules generators are guaranteed the incremental cost associated with operating their facility for the duration of their minimum generation block run time (MGBRT). [102] This component of the guarantee is calculated based on the generator's real-time MGBRT offer price.[103]

As part of its assessment of the rule change, the Panel observed that between December 9, 2009 and April 30, 2010, after-the-fact submitted start-up costs under the GCG program accounted for 61.8% of the total costs, while the costs associated with the MGBRT offers accounted for only 38.2% of total costs. Yet under the new rules dispatch decisions are dictated exclusively by the MBGRT offer price. The Panel concluded that the new GCG program, which continued to allow for after-the-fact cost submissions, may have contributed to inefficient dispatch, offers below the average incremental cost of starting and running fossil units, a depressed market clearing price, and an inflated global adjustment. Accordingly, the Panel recommended that, to the extent the IESO believed a reliability program such as the GCG program continued to be warranted, the IESO should base the guarantee payment on the offer submitted by the generator or should implement another solution that would require actual generation costs to be taken into account at the time of scheduling decisions. In addition, the Panel noted that the ability to submit after-the-fact costs raised the possibility of gaming opportunities if the GCG program was not regularly audited.[104]

generator can reliably and persistently operate). A generator also must produce at least at the MLP in order to supply operating reserves.

[102] The minimum generation block run-time is the number of hours, specified by the market participant, that a generation facility must be operating at its minimum loading point or above in accordance with the technical requirements of the facility (i.e. the minimum duration, in hours, that the generation facility, once online, must operate at its MLP or above).

[103] For scheduling purposes, the new GCG rules require that generators offer their MLP at a single price for the duration of their MGBRT. If a generator raises its offer price, it becomes non-compliant with the market rules. (In theory a generator could lower its offer price for certain hours during the MGBRT, but in practice generators would not do so as lowering the offer price would only serve to reduce the guarantee payment available under the GCG program.)

[104] See the Panel's August 2010 Monitoring Report, at pp. 133 and 139–140.

3.3.2 Costs to Loads

During the most recent reporting period the Panel directed the MAU to continue to monitor the impact of the GCG program. The MAU observed that some generation facilities synchronize and operate for their MGBRT, then shut for a short period of time (at times for as little as half an hour), and then re-synchronize for another run. The MAU observed that this behaviour was creating a high cost to Ontario loads because the cost of shutting down a generation facility only to restart that facility several intervals later typically exceeded what it would have cost to keep that same facility online. To illustrate, assume a facility with a 100 MW MLP shuts down only to restart two hours later. Shutting down and restarting this facility may cost consumers $50,000 in exchange for only a small amount of energy produced during the ramp-down and start-up periods. As an alternative to shutting down, the facility could have remained online. The cost to loads associated with the unit remaining online and producing energy may have been as little as $10,000.

During the summer period, the MAU observed 426 instances where GCG eligible generators came offline only to restart again[105] within two hours.[106]

The two main cost components resulting from the shutdown and restart of a GCG generator are an additional payment of constrained-off CMSC during ramp-down and an additional set of start-up costs to ramp back up.[107] Table 3-13 below reports the total submitted start-up costs, as well as CMSC payments during the ramping down period, in the events where generators were offline for two hours or less.

[105] These are situations where the generator pro-actively raised its offer price after completion of the MGBRT period in order to be dispatched off.
[106] For further discussion of the two hour time period used in this analysis, see section 3.3.3 below.
[107] Start-up costs per MWh of output are significantly higher than operating costs per MWh once a unit is at or above its MLP.

Table 3-13: Submitted Start-up Costs and CMSC Payments to Generators For Shutting Down and Restarting within Two Hours Under the Generator Cost Guarantee Program May to October 2010 (Number of Events and $ millions)

Facility	Number of Events	Submitted GCG Start-Up Costs ($ million)	CMSC Payments for Ramp-down ($ million)
A	5	0.02	0
B	2	0.04	0
C	5	0.04	0
D	1	0.04	0
E	1	0.08	0
F	10	0.17	0.07
G	66	1.38	0.27
H	336	21.69	1.19
TOTAL	426	23.46	1.53

It is important to note that the values above are not an estimate of efficiency loss to the market. However, observation of the frequent restarts led the Panel to consider the impact of this behaviour on market efficiency.

3.3.3 Short-Term Shutdowns and Restarts

Fossil-fired generators may need to be shut down for maintenance, technical difficulties, or economic reasons. If a generator is offline for maintenance or technical reasons these shutdowns are not considered inefficient and the start-up costs associated with resynchronization are a necessary aspect of the return to operation. In Ontario, fossil generators are typically economic during mid-peak and peak hours. They are typically not economic during off-peak hours. Absent the GCG program, it would generally be in the financial interest of a fossil generator to shut down during off-peak hours. Shutting down fossil units during off-peak hours is also efficient to the market because it allows demand to be supplied by other sources at lower marginal cost than fossil-fired generation.

Shutting down fossil-fired generators for a short period of time and then restarting them can lead to an efficiency loss to the market if the overall cost to the market, including the start-up cost and CMSC payments, is higher than the cost at which the system could source energy from the generator without a shutdown. Given the typical MGBRT length of six to eight hours for gas generators, a shutdown and restart typically also results in operation in some off-peak hours. The actual output over a two-day period for one of the generators included in this report is illustrated in Figure 3-7 below.

Figure 3-7: An Example of Multiple Starts at One Generation Unit (MW per interval)

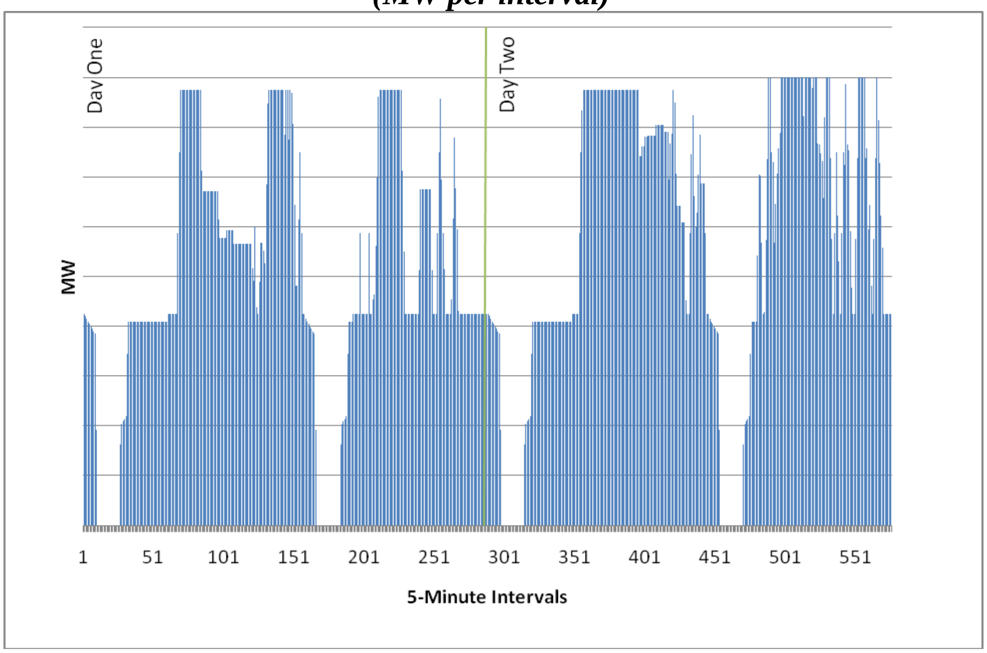
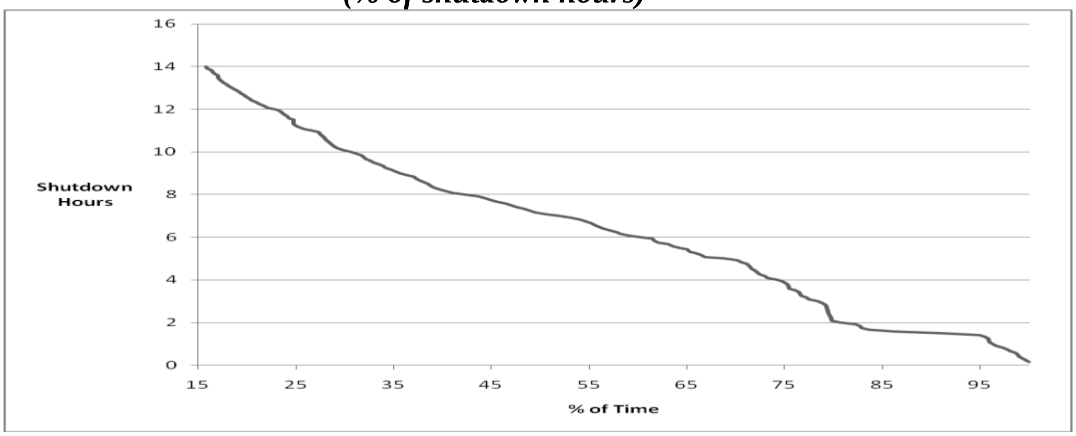


Figure 3-8 shows the duration curve of shut down hours.[108] One can see that following a shutdown, approximately 40% of the time GCG generators were offline for six hours or longer. Such units typically are only starting once per day. However, Figure 3-8 also demonstrates that the duration curve begins to decline more sharply between 5 hours and 2

[108] This does not include ramp-down or resynchronization.

hours offline. For the purpose of this analysis, the Panel has focused on the approximately 20% of events in which a unit was shut down for two or less hours. Accordingly, this analysis understates the efficiency loss whenever a unit remained shut down for a period of more than two hours and it would have been more efficient for that unit to have remained online.

Figure 3-8: Duration Curve of Shutdown Hours at All Generators Under the Generation Cost Guarantee Program May to October 2010 (% of shutdown hours)



3.3.4 Market Efficiency Losses

This section estimates the market efficiency losses associated with short-term (two hour or less) shutdowns for the period May to October, 2010.[109] The method applied to calculate the efficiency loss is described in detail in Appendix 1 to this chapter.

For calculation purposes, the Panel estimated and then compared the benefit to the market for two scenarios: (i) the actual shutdown/restart event which occurred; and (ii) the hypothetical alternative scenario in which the generator is assumed to have stayed online and continued to produce at its MLP rather than shutting down. Where the latter situation leads to a greater benefit to the market, it would be efficiency improving for the generator to stay online.

[109] There was no change to the GCG program rules or settlement methodology during this time period.

In the study period, there were 426 starts that followed a shutdown period of 2 hours or less. This represents approximately 20% of all GCG unit starts during the study period, averaging about 2 starts per day. As demonstrated in Table 3-14 below, the total efficiency loss due to these multiple starts is estimated at approximately $19 million. The Panel also found that 95% of this efficiency loss was associated with the activities of a single market participant. The high efficiency loss associated with this market participant is directly attributable to its submitted start-up costs, which are very large relative to all other market participants participating in the GCG program. The Panel is currently assessing the market participant's behaviour and has asked the MAU to continue monitoring these frequent shut down events.

Table 3-14: Estimated Efficiency Loss due to Generators Shutting Down and Restarting Within Two Hours or Less Under the Generator Cost Guarantee Program May to October 2010 (Number of Events and $ millions)

Market Participant	Number of Events	Efficiency Loss ($ Million)	Percentage of Total (%)
A	5	-0.03	-0.16
B	2	0.06	0.31
C	5	0.02	0.10
D	1	0.04	0.21
E	1	-0.03	-0.16
F	10	0.14	0.73
G	66	0.65	3.39
H	336	18.31	95.56
TOTAL	426	19.16	100.00

3.3.5 Incentives for Generators to Engage in Short-Term Shutdowns and Restarts

The Panel has identified several incentives for GCG generators to shut-down and restart on a short-term basis.

Opportunities to profit from constrained-on CMSC payments during ramp down

In Ontario's market, generators use offer prices to signal to the IESO's dispatch algorithm their desire to come offline. In order to be dispatched off, the generator must submit an offer price that exceeds the shadow price in the area. Under the current market rules, the existing facility is paid constrained-on CMSC payments based on the offer price during the ramp-down period. The Panel has previously observed that some generators use an offer price that significantly exceeds the local shadow price as a signal to the IESO that the facility wishes to come offline.

In its January 2009 Report, the Panel recommended that the IESO take "action to limit CMSC payments where the CMSC payments are induced by the generator strategically raising its offer price to signal the ramping down of its generation."[110] In its August 2010 Report, the Panel observed that CMSC payments to generators shutting down were contributing approximately $1 million per month to the uplift paid by loads (which based on an annual market demand of approximately 155 TWh translates into a consumer uplift charge of $0.08/MWh) and urged the IESO to expedite the implementation of this rule change. However, the IESO initiative to address this issue was temporarily suspended in late August 2010 to address other priority issues.[111] Between May and October 2010, a further $5.4 million in ramp-down CMSC was paid to generators. Of this, approximately 28 percent relates to the 426 shutdowns and restarts within a period of 2 hours or less.

[110] See the Panel's January 2009 Monitoring Report, pp. 216-217.
[111] The status of the initiative can be monitored on the IESO's web page. See IESO Stakeholder Engagement 84 (SE-84): http://www.ieso.ca/imoweb/consult/consult_se84.asp.

Table 3-XX: Monthly Constrained on CMSC Payments Resulting from Generator Shutdowns May 2009 – October 2010 ($1 000)

Month	CMSC for Shutting Down ($1 000)
May-09	1,126
Jun-09	1,494
Jul-09	1,168
Aug-09	1,204
Sep-09	1,111
Oct-09	829
Nov-09	943
Dec-09	700
Jan-10	771
Feb-10	1,234
Mar-10	1,061
Apr-10	1,011
May-10	1,088
Jun-10	898
Jul-10	987
Aug-10	1,104
Sep-10	599
Oct-10	772
Total	18,100

Potential opportunities to profit through GCG start-up submissions

In its previous report the Panel observed a large discrepancy in start-up cost submissions among generators that on their face appeared to be quite similar in nature (i.e. similar facility technology, vintage, MLP, and MGBRT). The Panel noted that the ability to submit after-the-fact costs raised the possibility that allocation methodologies and cost submission rules could potentially allow recovery of amounts in excess of actual incremental start-up costs, especially if the start-up cost submissions were not regularly audited.[112] Accordingly, the Panel encourages the IESO to exercise the authority granted to it under the market rules to audit the cost submissions that generators have made under the GCG program beginning with those which have received the largest payments.

[112] See the Panel's August 2010 Monitoring Report, p. 133

Risk-free participation in the market through the GCG program

In order to qualify for a successive GCG run a generator must shut down. Once the generator has shut down, it can re-qualify for the GCG program provided that its offer price for the restart is economic for at least 50% of its MGBRT based on pre-dispatch prices. Once the facility qualifies for the GCG program, the generation facility is completely insulated from any downside market exposure. That is because, at a minimum, the facility will recover its start-up costs and its MGBRT operating costs (which are assumed to reflect the generator's marginal costs). At the same time the facility has upside exposure to the market to the extent that actual market clearing prices during the GCG run may exceed the MGBRT offer price. Accordingly, generators have an incentive to come offline following one GCG run so as to re-qualify for a successive GCG run.

Hedge of revenue offsets under OPA Clean Energy Supply (CES) contracts

All recently built gas-fired generation in Ontario have OPA CES contracts. Under these contracts, the generators are paid a fixed amount per month for providing the capacity. However, the payments are reduced whenever the facility is deemed to be economic, whether or not it actually operated. By utilizing the GCG program to operate throughout large portions of the day, natural gas generators can minimize their exposure to payment reductions under the CES contracts.[113]

3.3.6 Conclusion

It is understandable that generators need to shut down for maintenance or, technical difficulties, or when they are no longer economic as a result of low demand. However,

[113] In a CES-style contract, a generator's net revenue is calculated based on the HOEP and its heat rate times the daily gas price. As a general rule, if the HOEP in an hour is greater than the heat rate times the daily gas price, the generator is deemed to produce at its deemed capacity, regardless of its actual output. The OPA then deducts the deemed amount from the monthly payment to the generator.

proactively shutting down a unit for a short period of time in order to renew eligibility for the generator cost guarantee program has lead to significant efficiency losses to the market. As demonstrated above, the estimated efficiency loss for these generators shutting down and restarting within two hours was approximately $19 million for the period May to October 2010. Most of these efficiency losses are ultimately borne by loads and exporters. Based on the 71.5 TWh of market demand during this period, this is the equivalent of an avoidable uplift charge of approximately $0.27/MWh for every MWh consumed by these participants.

Recommendation 3-4:

(i) ***The IESO should resume work on Stakeholder Engagement 84 regarding elimination of self-induced CMSC payments for ramping down generators and should amend the Generation Cost Guarantee program to ensure that all guaranteed costs are considered as part of the dispatch optimization.***

(ii) ***On an interim basis until after-the-fact start-up cost submissions are capped by generator offer prices and CMSC payments to ramping down generators are eliminated, the IESO should amend the Generation Cost Guarantee program to limit generators to one start-up cost guarantee submission per day unless the IESO requests a second start during a day.***

(iii) ***The IESO should re-examine whether the GCG program continues to provide a net benefit to the Ontario market once the Enhanced Day-Ahead Commitment (EDAC) process is implemented or as part of its "Market Roadmap" process.***

Chapter 3 Appendix 1: Efficiency Estimation of Multiple Shutdowns

The following section illustrates how the efficiency loss is calculated. There are two scenarios for comparison: 1) the actual scenario with the generator of interest having shut down for two hours or less, and 2) the counterfactual scenario with the generator producing at its MLP for the whole shutdown and ramping up period.

As such, the efficiency calculation has two components:

First, the start-up costs for the restart, less the value of energy provided by the GCG generator during ramp up, are an efficiency loss, which is associated with Scenario 1.

Second, because the GCG generator ramps down, stays offline for up to two hours, and then ramps up to its MLP again, it is necessary for other generators to supply the energy that the GCG generator would have supplied had it continued to operate at its MLP. There is an efficiency loss if the shadow price at that location exceeds the GCG generator's MGBRT offer price. This is associated with Scenario 2.

For simplicity, the shadow price at the generator's location is assumed to represent the replacement cost for the generator, or the marginal value to consumers. The Panel further assumes that the shadow price would have remained unchanged regardless of whether or not the generator of interest had stayed online. Finally, the generator of interest is assumed to produce at its MLP with an incremental cost equal to the offer price for its MGBRT period if it is assumed to have stayed online.

Scenario 1: Actual Situation with Generators Having Shut Down

Let $X1$ be the net benefit: $X1 = BENEFIT1 - COST1$, where…

*BENEFIT1 = Shadow Price * Actual Output for ramp up/down*

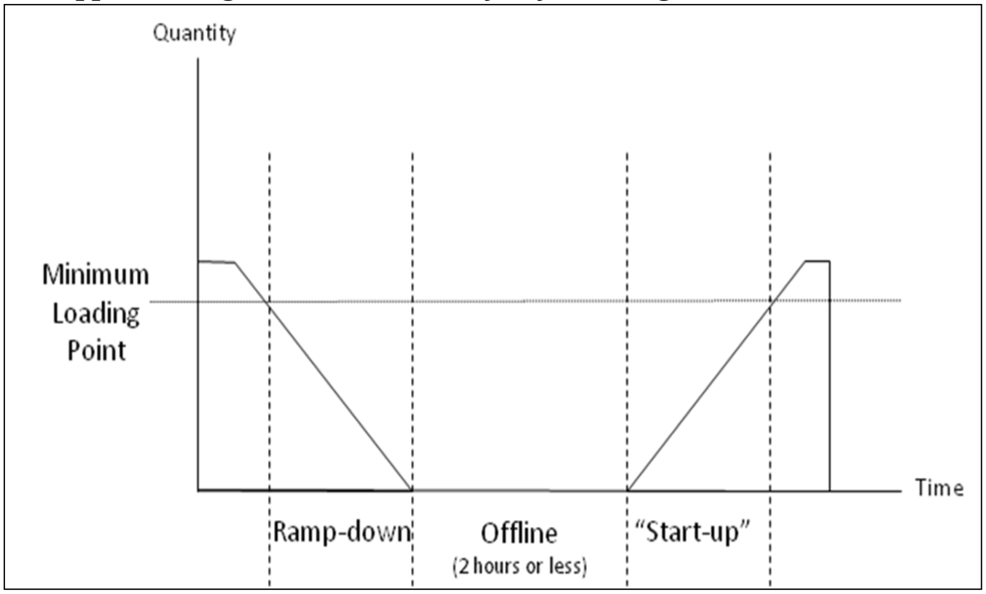
*COST1=Offer Price * Actual Output for ramping down*[114] *+ Startup Costs*

The net benefit represents the cost savings to the market due to the shutdown of the generator. A positive number indicates that the shutdown is efficient to the market, while a negative number means it is inefficient to the market.

Appendix Figure 3-1 below illustrates how the cost-benefit is calculated when a generator has shut down. The benefit is derived from the energy that it has actually provided to the market and is calculated as the marginal replacement cost multiplied by the supplied energy, up to the generation facility's MLP. The MLP is used because in the counter-factual case, i.e. where the unit stays online, the unit is assumed to stay at the MLP during the period that the facility has ramped down and then ramped up. The cost, conversely, is the production cost for ramping down (Offer Price for MGBRT* MW injected) plus the cost associated with ramping the generation facility back up to its MLP (i.e. the start-up costs submitted under the GCG program) given that the start-up has already included the cost for ramping up.

[114] The cost's ramp-up component is replaced with the participant's after-the-fact submitted costs, i.e. the start-up costs.

Appendix Figure 3-1: Cost-Benefit of Shutting Down a Generator



Scenario 2: Generators Had Stayed Online and Produced at MLP

Let $X2$ be the net benefit of staying online: $X2 = BENEFIT2 - COST2$, where…

$BENEFIT2 = Shadow\ Price * MLP$

$COST2 = Offer\ Price * MLP$ *for the period from its ramping down from MLP to ramping up to the MLP*

Again, the net benefit represents the cost savings to the market due to the generator having not been shut down. A positive number indicates that keeping the unit online is efficient to the market, while a negative number means it is inefficient to the market.

It is worth noting that the net benefit may be overstated because in the counter factual situation the Panel has assumed the shadow price would be unchanged if the facility had remained online. In reality, with more generators online, the locational shadow price tends to decrease, leading to a lower marginal value to the market.[115] However, the

[115] This is demonstrated in the following diagram, which compares two supply curves: a) the actual case, which is the thin line representing the unit dispatched off, and b) the counter-factual case with the thick line, where the unit is imagined to have staid online at MLP. The entire shaded region is the calculated

overstatement is expected to be not material because there tends to be low demand relative to available supply at the time when the generators were shutdown. For example, the market participant that contributed to the greatest amount of efficiency loss typically shuts down in the early morning when demand is low and in the early afternoon, prior to the afternoon peak. During these hours shadow prices were generally low and would not have been significantly affected by the online status of the generator of interest.

Appendix Figure 3-2 depicts the distribution curve of shadow prices during the shutdown hours (< 2) for a single resource (participant H). The horizontal flat line indicates that the shadow price is fairly consistent during these hours, which would suggest that the true (locational) shadow price for staying online would not deviate much from the actual value used in the calculation (i.e. the locational shadow price for being offline).

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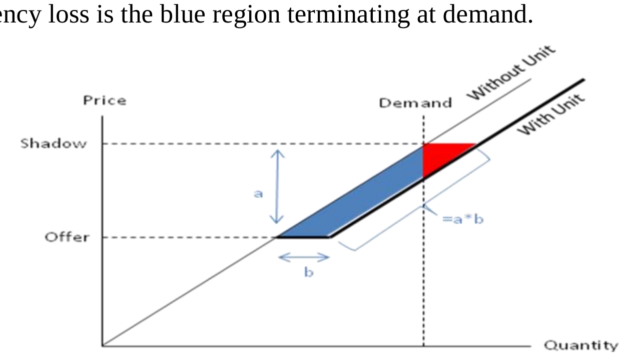
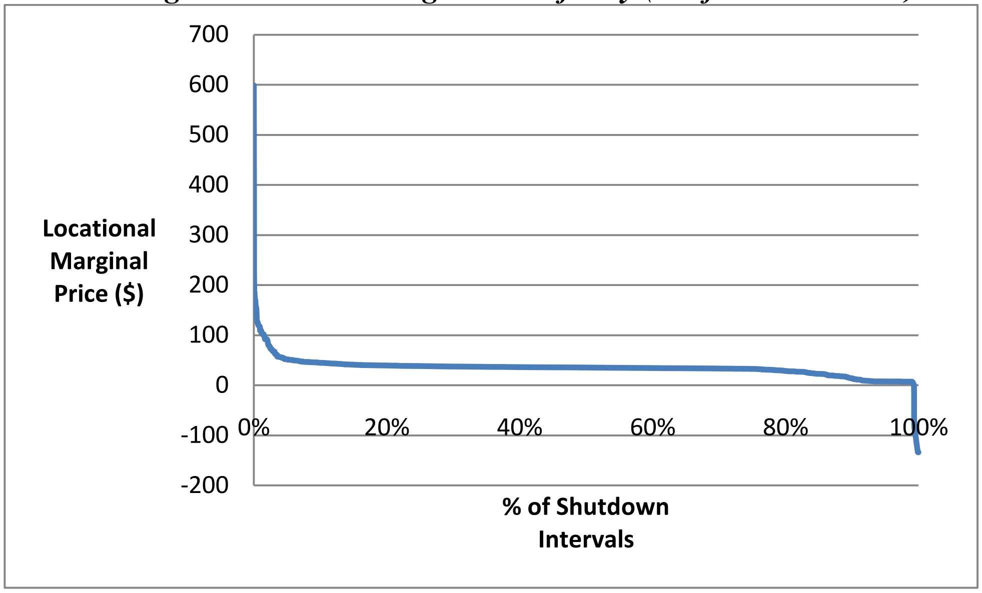
efficiency loss; the red region is an over-stated component as a result of assuming a uniform shadow price, while in actuality efficiency loss is the blue region terminating at demand.



Appendix Figure 3-2: Distribution Curve of Shadow Prices During Shutdown Hours For Single Resource During Month of July (% of Shadow Price)



Efficiency Loss due to shutting down

Efficiency loss due to shutting down is defined as the difference of the net benefit between the actual scenario and the counter-factual scenario. Given that all customers were assumed to have been satisfied, the difference between the net benefit in the two scenarios is the cost savings to meet the same demand. That is, efficiency loss is as follows:

$$\textit{Efficiency Loss} = X2 - X1 = BENEFIT2 - COST2 - BENEFIT1 + COST1$$

A positive number indicates that keeping the generator online would be efficiency improving compared to shutting it down. In contrast, a negative number indicates shutting the generator down is more efficient to the market. Consider the following example: a GCG unit's MGBRT offer and (assumed) incremental cost is $50/MW[116], while its submitted start-up costs are $10,000 (which includes the costs of starting up the unit and ramping to its MLP). The shadow price is $100/MW. Assume the ramping down

[116] To be dispatched offline the participant will have to offer much higher to be placed out of the market. As result, this offer for signalling shut down does not reflect true cost. Instead, the MGBRT offer is used for efficiency calculation.

and ramping up output is 30 MWh each, and the MLP is 300 MW. Further assume the generator stayed offline for half an hour (output 0 MWh) and it required a total of half an hour to ramp down and back up (15 minutes for each). As a result, the total energy that the unit could have provided during the one hour shutdown period was 300 MWh. In this instance, the efficiency loss would have been $20,500 (see below for detailed calculation), meaning that it would have been more efficient for the unit to have stayed online.

Net Benefit for Shutting Down:
*X1 = ($100*60MWh) – ($50*30MWh+ $10,000) = -$5,500*
Net Benefit for Staying online:
*X2 = ($100*300MWh) – ($50*300MWh) = $15,000*

Efficiency Loss = X2 – X1 = 20,500

Chapter 3 Appendix 2: Simulated CMSC Payments during Export/Import Curtailments

One IESO concern related to eliminating the price impact of a curtailed transaction is the impact on CMSC. While CMSC payments may be larger if ADQh-coded curtailments are left in the market schedule, this is not necessarily so. Below are two examples of situations where CMSC payments would have been smaller if ADQh-coded curtailments had been left in the unconstrained, market schedule.

1. ***January 18, 2010 HE 10 ('HOEP' $69.49/MWh vs. Predispatch MCP $48.73/MWh)***

The hour was not an hour with resource shortage. However, with 250 MW CAOR scheduled in HE9 and a 420 MW ramp out in HE10, the IESO felt that there would be insufficient internal resources to meet the first contingency (about 1,500 MW at the time) in a timely manner. The IESO subsequently curtailed 200 MW exports for HE10, using the ADQh code. The 200 MW curtailment resulted in a 250 MW curtailment in the unconstrained sequence because 50 MW were constrained-off.

To see the impact (both on the HOEP and the CMSC payments), the MAU ran a simulation by assuming the 250 MW export curtailment had not been removed from the unconstrained sequence. Appendix Table 3-1 below reports the actual and simulated MCP.[117]

[117] Recognizing that the MAU simulator does not have the exactly same inputs as in the DSO and thus at times may produce a different result, the Panel always compares the simulated "actual" to simulated results in order to isolate the consequences of any change that is of interest. The hour was an hour with an administered price ($70.13/MWh). The simulated "actual" price was $0.64/MWh (1%) lower than the administered HOEP.

Appendix Table 3-1: Actual and Simulated Market Clearing Price and HOEP for Export Curtailment Using ADQh January 18, 2010 HE 10

Date	Hour	Interval	Export Curtailment (MW)		'Actual' MCP ($/MWh)	Simulated MCP ($/MWh)	Difference (Simulated - Actual) ($/MWh)
			Actual	Used for Simulation			
18-Jan-10	10	1	250	0	70.13	134.13	64.00
18-Jan-10	10	2	250	0	69.36	120.13	50.77
18-Jan-10	10	3	250	0	69.36	117.08	47.72
18-Jan-10	10	4	250	0	69.36	117.08	47.72
18-Jan-10	10	5	250	0	69.36	117.08	47.72
18-Jan-10	10	6	250	0	69.36	117.08	47.72
18-Jan-10	10	7	250	0	69.36	117.08	47.72
18-Jan-10	10	8	250	0	69.36	117.08	47.72
18-Jan-10	10	9	250	0	69.36	117.08	47.72
18-Jan-10	10	10	250	0	69.36	117.08	47.72
18-Jan-10	10	11	250	0	69.36	117.08	47.72
18-Jan-10	10	12	250	0	70.13	117.90	47.77
Average (HOEP)			250	0	69.49	118.82	49.33

Because the 200 MW exports were curtailed with the ADQh code, their corresponding schedules in the unconstrained sequence were also removed. Had the exports not been removed from the unconstrained sequence, the HOEP would have been $118.82/MWh, or $49.33/MWh (71%) higher.

Appendix Table 3-2 below reports the actual and estimated CMSC based on this simulation. With a higher price (i.e. if the curtailed exports had not been removed from the unconstrained sequence), the total CMSC would have been $4,000 lower (which consists of a higher CMSC to generators but a much larger CMSC charged to traders).

Appendix Table 3-2: Actual and Simulated CMSC During an Hour with Export Curtailment
January 18, 2010 HE 10
($)

Type of CMSC Payment	'Actual' CMSC	Simulated CMSC	Difference (Simulated – Actual)
CMSC to ADQh Curtailed Exporters	0	-13,024	-13,024
CMSC to Other Traders	-9,771	-42,332	-32,561
CMSC to Generators	20,709	62,290	41,581
CMSC to Dispatchable Loads	0	0	0
Total	10,938	6,934	-4,004

1. September 5, 2010 HE 1 (HOEP $123.96/MWh vs. PD MCP $17.27 /MWh)

As discussed in Section 2.2, this was an hour with potential surplus baseload generation. The IESO curtailed 347 MW imports, using the ADQh code. The 347 MW curtailment resulted in a 193 MW curtailment in the unconstrained sequence.

To see the impact (both on the HOEP and the CMSC payments), the MAU ran a simulation by assuming the 193 MW is not removed from the unconstrained sequence. Table 3-5 reports the "actual" and simulated MCP. Had the imports not been removed from the unconstrained sequence, the HOEP would have been $54.19/MWh, or $69.76/MWh lower.

Appendix Table 3-3 below reports the actual and estimated CMSC based on the simulation. With a lower price (if the curtailed imports were not removed from the unconstrained sequence), the total CMSC would have been $5,600 lower (which consists of a higher CMSC to importers who were curtailed with ADQh but a much smaller CMSC paid to generators and other traders).

Appendix Table 3-3: Actual and Simulated CMSC During an Hour with Import Curtailment September 5, 2010 HE 1 ($)

Type of CMSC Curtailment	'Actual' CMSC	Simulated CMSC	Difference (Simulated – Actual)
CMSC to ADQh Curtailed Importers	0	6,543	6,543
CMSC to Other Traders	19,041	8,331	-10,710
CMSC to Generators	2,602	1,179	-1,423
CMSC to Dispatchable Loads	0	0	0
Total	21,643	16,053	-5,590

Net exports in the hour were 2,237 MW. With a lower HOEP (if curtailed imports not being removed from the unconstrained sequence), exporters were charged $276,132 less than they have actually paid. This lower charge would have incented exporters to export more to alleviate the SBG condition in the following hours and would have allowed exporters who helped to alleviate the SBG conditions to benefit.

2. Summary

The two examples above indicate that removing the counter-intuitive impacts of the ADQh code may not result in higher CMSC payments and may in fact reduce CMSC payments.

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Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is the Panel's 17th semi-annual Monitoring Report of the IESO-administered markets. It covers the summer period, May to October 2010. As in previous reports, the Panel has concluded that the market has operated reasonably well according to the hybrid design established for it, although there were occasions where actions by market participants or the IESO led to inefficient outcomes. In addition, the Panel continues to identify areas for improvement in the market design. In particular, the Panel has observed numerous complications associated with the two-sequence market structure that have undermined efficiency or increased consumer costs with little or no apparent benefit. To this end, the Panel has recommended that the IESO work with stakeholders to examine the feasibility of evolving beyond the two-sequence market structure as part of the IESO's new "market roadmap" process.

2. Unintended Consequences Caused by the Two-Sequence Market Structure in Ontario

In its past two reports, the Panel discussed how Ontario's two-sequence market structure compensates dispatchable resources for costs or implied losses imposed on them by transmission congestion, ramp limitations, and IESO manual actions. The Panel also reiterated that, on many occasions, significant inefficient outcomes have arisen as a result of the two-sequence system. The Panel indicated that exploring a structural change to the existing two-sequence system should be a high priority.[118]

In this report the Panel has commented further on the inefficiencies associated with the two-sequence market structure. Significantly, many of these inefficiencies have

[118] See the Panel's January 2010 Monitoring Report, pp. 120-123 and the Panel's August 2010 Monitoring Report, pp. 268-273.

translated to higher costs for Ontario consumers with little or no commensurate value received in return. For example, at Table 3-9 the Panel reports that since the market opened in May 2002, traders have received $146 million in constrained-off payments in the Northwest region of the province, the vast majority of which were for constrained off imports.[119] Importantly, the Northwest is an area of the province that is marked by an abundance of internal, low-cost supply. This abundance of supply is reflected by the extremely low zonal price in the region (- $157/MWh in summer 2010) as well as the $161 million dollars in constrained-off payments paid to generators located in that area not to produce power since May 2002. During the most recent six month period from May to October 2010, Ontario consumers paid importers $12 million dollars not to deliver power into the Northwest area of the province, while also paying local generators an additional $9 million dollars not to generate power.

A particularly notable example of unnecessary constrained-off payments is discussed in Chapter 3, section 3.1 of this report. Over a two-day period in July, Ontario load paid two traders almost $163,000 in constrained-off payments when it would have been physically impossible for the underlying transactions to flow because of a transmission derate in Manitoba.

In this report, as with previous reports, the Panel has recommended that CMSC payments be reduced or eliminated where they do not contribute to market efficiency. The large majority of issues identified by the Panel since the market was established have dealt with inefficiencies introduced by the two-sequence market structure. None of these individual recommendations, however, address the fundamental and underlying problems of the two-sequence market structure. Moreover, the Panel understands that the two-sequence design inhibits implementation of market changes which would allow for increased efficiency of dispatch with other markets to benefit Ontario consumers, and indeed was the major factor in the decision to develop only an Enhanced Day-Ahead Commitment (EDAC) process rather than a full day-ahead market. The Panel believes

[119] Of the $146 million of constrained off CMSC paid to traders in the Northwest since market opening, approximately $15.0 million was for constrained off exports and $131 for constrained off imports.

that, with the IESO embarking on a "market road map" process, now is the appropriate time to consider replacing the existing two-sequence market structure.

3. Ontario's Long-Term Energy Plan

On November 23, 2010 the Ontario Government released its long term energy plan *Building our Clean Energy Future* (the Energy Plan).[120] The Energy Plan represented the first significant update to the Province's long-term energy policy since the release of the OPA's 2007 Integrated Power System Plan.[121] Under the Energy Plan the government has detailed at a high level its investment plans over the next 20 years. The OPA will prepare an updated IPSP based on the Energy Plan for review by the OEB in 2011 or 2012. Highlights of the Energy Plan include:

- *Demand Forecast:* Demand is expected to recover from recent recessionary levels over the next 10 years. Thereafter demand is expected to remain relatively flat, reflecting conservation efforts and shifts in industrial and commercial energy needs. The bulk power system should be prepared to provide 146 TWh of generation in 2015 and 165 TWh by 2030.
- *Supply*: Coal plants will be shut down by the end of 2014. Significant portions of coal capacity have already been replaced by natural gas plant capacity. Some coal plants have also begun a conversion to biomass or natural gas and more conversions may follow. Nuclear will continue to represent a prominent component of Ontario's supply. Approximately 10,000 MW of nuclear capacity will be refurbished over the next 10 to 15 years and 2,000 MW of new supply will be added. By 2018, wind, solar and biomass is forecast to account for 10,700 MW of installed capacity, up substantially from approximately 1,500 MW today. In addition, the OPA will develop a standard offer program for combined heat and power (CHP) facilities in Ontario with the intention of adding approximately 550 MW of additional CHP capacity.[122]

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[120] See: http://www.mei.gov.on.ca/en/pdf/MEI_LTEP_en.pdf
[121] See: http://www.powerauthority.on.ca/integrated-power-system-plan/b-ipsp
[122] Including CHP capacity that has already been contracted the long-term energy is targeting 1,000 MW of CHP capacity.

- *Prices*: Prices for industrial consumers are forecast to rise by 2.7% percent per year, or 70% cumulatively (on a nominal basis) over the next 20 years. Prices for residential consumers, small businesses and farms are expected to double over the next 20 years (a growth rate of 3.5% per year), although almost half of this price increase is expected to be fully realized within the first 5 years (a growth rate of 7.9% per year). Fifty-six percent of the cost increases will be associated with investment in new, renewable energy generation and the balance will be associated with investments in nuclear and gas generation and upgrades to the transmission and distribution system. To reduce the impact of these price increases, the government has introduced a 10% rebate for Ontario residential, small business and farm consumers. Based on projected price growth rates, the rebate program will cost over $7 billion over the five years during which it will be in place.

The Panel expects that new generation built under the Energy Plan will be subject to long-term contracts. The Panel strongly encourages that the contracts include price-responsive measures.[123] In recent years, contracts have left certain generation resources indifferent or partially indifferent to market prices. For example, certain contracts for nuclear, wind and solar power entitle generators to a single fixed price per MWh of energy injected, regardless of prevailing market prices. This has contributed to SBG conditions and market price distortions. The expectation of 10,700 MW of installed renewable (wind, solar and biomass) capacity by 2018, also highlights the need that these resources be dispatchable by the marketplace. A failure to do so could lead to a significant increase in SBG conditions, as is discussed in greater detail in Chapter 3, section 2.2 of this report. The Panel is encouraged that the IESO is well along in a stakeholder process aimed, in part, at making renewable resources dispatchable.[124]

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[123] See the Panel's review of various types of contracted generation in Ontario, in the Panel's July 2009 Monitoring Report, pp. 227-235.

[124] See IESO Stakeholder Engagement 91 at http://www.ieso.ca/imoweb/consult/consult_se91.asp

4. Implementation of Panel Recommendations from Previous Report

The Panel's August 2010 report contained six recommendations, all of which were directed at the IESO.

4.1 Recommendations to IESO

The IESO formally reports on the status of actions it has taken in response to the Panel's recommendations. Following each of the Panel's Monitoring Reports the IESO posts this information on its web site and discusses the recommendations and its actions with the Stakeholder Advisory Committee to the IESO Board of Directors (SAC).

In this section we review the status of the recommendations from our last Monitoring Report, released in August 2010. The IESO responses are summarized in Table 4-1 below.

Table 4-1: Summary of IESO Responses to Recommendations in the Panel's August 2010 Monitoring Report

Recommendation Number & Status	Subject	Summary of Action
3-1 **In progress IESO to Monitor**	Hourly Uplift Payments	"An urgent market rule amendment to temporarily suspend energy-related CMSC for constrained-off dispatchable loads went into effect on August 28th, 2010. In consultation with the dispatchable load community, the IESO is exploring alternative solutions to expedite the development of market rule amendments to replace the temporary suspension - refer to stakeholder engagement initiative SE-89."
3-2 **In progress IESO to Monitor**	Hourly Uplift Payments	"The Technical Panel endorsed a market rule amendment proposal (MR-00370) to limit CMSC payments for exporters and dispatchable loads using replacement bids, as recommended in the January 2010 MSP Monitoring Report. This amendment will be proposed to the IESO Board for approval at their meeting on November 11th, 2011."
3-3 **Pending IESO to Monitor**	Price Fidelity	"The IESO agrees that the deadband should be reviewed for a number of reasons, including the impacts of the GEA and the changing composition of market participants. This is already contemplated. However, the issue identified by the MSP will accelerate the review of the sufficiency of the Interpretation Bulletin which sets out the deadband."
3-4 **Pending IESO to Monitor**	Dispatch	"In response to a recommendation from the January 2009 MSP report, the IESO initiated a market rule amendment to revise the method of calculating guarantees to improve the effectiveness of day-ahead scheduling decisions. These changes, implemented in December 2009 under MR-00356, linked the guarantee payment to the market participant's offer price and introduced more stringent eligibility requirements for the real-time GCG program. As a result of the changes implemented under MR-00356, approximately 40% of generators' costs are reflected in their offers. This is a significant improvement compared to the initial design where none of the costs were reflected in offers. The IESO continues to believe a reliability program is warranted and some changes to the day-ahead guarantee program are part of the Enhanced Day-Ahead Commitment initiative. The IESO's immediate priorities related to the [Green Energy Act], specifically the integration of renewable energy into the electricity system and market, take precedence over this MSP recommendation."

Recommendation Number & Status	Subject	Summary of Action
3-5 & 3-6 **Pending IESO to Monitor**	Price Fidelity	"The IESO agrees with these recommendations. Efforts to address them have been put on hold to enable to the IESO to address other priorities such as the [Enhanced Day-Ahead Commitment] and changes required to implement the Green Energy and Green Economy Act."

The Panel notes that on December 3, 2010 the IESO implemented rule changes that partially addressed recommendations 3-1 and 3-2 above.[125] The Panel will monitor and report on these changes in its next report.

5. Implementation of Panel Recommendations from Other Reports

In its July 2008 Report the Panel made the following recommendation:

> The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy ('ADQh') should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted.[126]

In January 2011, the IESO implemented an interim change that is directionally positive in addressing the Panel's concerns relating to the use of ADQh in circumstances where exports have been curtailed for resource adequacy reasons.[127] The Panel's concerns relating to the use of ADQh code for curtailed imports remains an area of concern for the Panel and is the basis of a recommendation in this report.

Information on other outstanding Panel recommendations can be found on the IESO's website.[128]

[125] See: http://www.ieso.ca/imoweb/pubs/mr2010/MR-00374-R00-BA.pdf and http://www.ieso.ca/imoweb/pubs/mr2010/MR-00370-R00-BA.pdf.
[126] See the Panel's July 2008 Report at p. 180.
[127] See: http://www.ieso.ca/imoweb/pubs/imdc/IESO_IMDC_0160.pdf
[128] See IESO Response to MSP Recommendations at: http://www.ieso.ca/imoweb/marketSurveil/surveil.asp

6. Summary of Recommendations

The Panel groups its recommendation thematically by category: price fidelity, dispatch, transparency and hourly uplift payments. Some recommendations could have impacts in more than one category (e.g. a scheduling change could affect prices as well as uplift). In such cases the recommendation is included in the category of its primary effect. Within each category of price fidelity, dispatch and hourly uplift payments[129], the recommendations in this report have been prioritized based on the Panel's view of their relative importance.

6.1 Price Fidelity

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

Recommendation 3-1 (Chapter 3, section 2.2)

The IESO should not remove imports curtailed to address surplus baseload generation conditions from the unconstrained market schedule. This could be accomplished by changing how the ADQh code operates with respect to the market schedule.

6.2 Dispatch

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

Recommendation 3-4 (Chapter 3, Section 3.3)

(i) The IESO should resume work on Stakeholder Engagement 84 regarding elimination of self-induced CMSC payments for ramping down generators

[129] The Panel does not have any recommendations in this report relating to transparency.

and should amend the Generation Cost Guarantee program ensure that all guaranteed costs are considered as part of the dispatch optimization.

(ii) On an interim basis until after-the-fact start-up costs submissions are capped by generator offer prices and CMSC payments to ramping down generators are eliminated, the IESO should amend the Generation Cost Guarantee program to limit generators to one start-up cost guarantee submission per day unless the IESO requests a second start during a day.

(iii) The IESO should re-examine whether the Generation Cost Guarantee program continues to provide a net benefit to the Ontario market once the Enhanced Day-Ahead Commitment (EDAC) process is implemented or as part of its "Market Roadmap" process.

6.3 Hourly Uplift Payments

The Panel examines hourly uplift payments[130] both in respect of their contribution to the effective price and also their impact on the efficient operation of the market.

Recommendation 3-3 (Chapter 3, Section 3.2)

As part of its "market road map" process, the IESO should work with stakeholders to examine the feasibility of replacing the two-sequence design with locational pricing, variable pricing for dispatchable resources or other alternatives.

Recommendation 3-2 (Chapter 3, Section 3.1)

Where there are transfer capability reductions outside Ontario that prohibit power flow out of or into Ontario, the IESO not make CMSC payments. Possible methods might include but not limited to: removing the related offers/bids, reducing intertie transfer capability to zero, or establishing a mechanism for clawback of the CMSC payments.

[130] Hourly Uplift Settlement Charges are collected from customers in the wholesale market to pay for Operating Reserve, Congestion Management Settlement Credits, Intertie Offer Guarantee payments and other incurred hourly costs such as energy losses on the IESO-controlled grid. The IESO also collects monthly uplift charges to pay for contracted services such as black start capability, voltage support, and regulation Service. There are also a few more monthly uplift charges, which occur occasionally (i.e. Emergency Energy purchase).