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 2009 – October 2009

January 2010

Ontario Energy Board

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Ontario

January 29, 2010

The Honourable Howard I. Wetston, Q.C.
Chair & Chief Executive Officer
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Mr. Wetston:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Don McFetridge and Tom Rusnov, I am pleased to provide you with the Panel's 15th semi-annual Monitoring Report of Ontario's wholesale electricity market, the IESO-administered markets.

This report, covering the period May, 2009 to October, 2009, is submitted pursuant to Article 7.1.1 of Ontario Energy Board By-law #3.

Best Regards,

Neil Campbell
Chair, Market Surveillance Panel

Enclosure

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Table of Contents

List of Tables

List of Figures

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Executive Summary

On September 24, 2009, the Market Surveillance Panel (MSP) initiated a consultation regarding proposed market Monitoring Reporting changes.[1] In an environment of decreased resources, the Panel proposed reductions to the breadth and depth of its reports. After reviewing responses to proposed changes the Panel has decided to move forward with the proposed reporting changes. This summer 2009 report represents the first 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 streamlined Statistical Appendix will be published in the comprehensive winter 2009/2010 report.

Overall Assessment

Ontario's IESO-administered wholesale electricity market has operated reasonably well according to the parameters set for it over the summer period, May to October 2009, although there were occasions where actions by market participants or the IESO led to inefficient outcomes. The Market Surveillance Panel (MSP) did not find an abuse of market power to have occurred and did not initiate a formal gaming investigation. However, we have observed an increase in frequency of behaviours associated with extraction of congestion management settlement credit (CMSC) payments that profit some participants at the expense of the market as a whole.

Market Prices, Uplifts and the Global Adjustment

The average Hourly Ontario Energy Price (HOEP) was $24.28/MWh this summer, representing a reduction in HOEP of 49.7 percent from $49.25/MWh last summer. Although the HOEP decreased significantly during this period the effective average price, which includes uplifts and the Global Adjustment, increased from $55.87/MWh last summer to $63.05/MWh this summer (a 16 percent increase). The magnitude of the

[1] For more details, see:
http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Electricity+Market+Surveillance/Consultation+on+Reporting

Global Adjustment exceeded the average HOEP in all 2009 summer months with the largest difference between the Global Adjustment and HOEP at $22.73/MWh occurring in July 2009 (the lowest HOEP month this summer and the second lowest HOEP month since market opening).

Demand and Supply Conditions

Ontario demand totalled 67.2 TWh this summer, down by 5.6 TWh (or 7.7 percent) compared to the same period in 2008.

An additional wind facility and a new intertie with Quebec became operational during the summer of 2009. The new wind facility adds an additional 198 MW of generating capacity in Ontario, while the new 1,250 MW intertie with HQ increases the total Ontario intertie capability by approximately 30 percent.

Net exports totalled 5.0 TWh this summer, which is 0.8 TWh (or 14 percent) lower than the same period last year.

Exports (excluding linked wheel transactions) declined to 8.4 TWh, a drop of 0.8 TWh (or 8.7 percent). Of the 8.4 TWh of exports this summer, 59 percent of the flows occurred during the lower price off-peak hours with the largest volumes being exported at the Michigan interties and destined for PJM.

Imports (excluding linked wheel transactions) remained at 3.4 TWh this summer, unchanged relative to the same period last year. On-peak hours accounted for 54 percent of the total flows, with 48 percent of total import volumes occurring at the Quebec interties.

Market Outcomes

There were 6 hours during the summer review period where the HOEP was greater than $200/MWh. All these events can be explained either by the underlying demand and supply forces or by the inconsistency between the constrained and unconstrained dispatch sequences. Many of the price-setting resources in intervals during these hours were hydroelectric resources. These hydroelectric resources routinely offer at prices in excess of $500/MWh as an indication that they do not want to (or cannot) run for energy but can provide operating reserves for shorter periods. The Panel will be continuing to assess this pattern of hydroelectric pricing.

In this review period, there were 1,619 hours in which the HOEP was less than $20/MWh, up from 724 hours (or 124 percent) for the same period one year earlier, including 121 hours where the HOEP was negative. The primary factors leading to a low (or negative) HOEP include low market demand (including low Ontario demand and low net exports) and abundant low price supply (including nuclear, baseload hydro, self-scheduling and intermittent generation, as well as fossil-fired generation operating at their minimum loading point).

During the study period, there were four hours with OR payments greater than $100,000, all occurring in August 2009. There were no hours with hourly CMSC payments greater than $500,000, daily CMSC payments greater than $1,000,000 at a single intertie zone, or hourly IOG payments greater than $500,000.

Two Dispatch Sequence Structure in Ontario

As discussed in Chapter 4, the Ontario market operates on a two dispatch sequence structure with an associated CMSC regime. The Panel has reported on many occasions that significant efficiency losses were resulting from this structure and that it may give rise to opportunities for market participants to receive CMSC payments without providing apparent benefit to the market.[2] The issues in the Northwest that are discussed in Chapter 3 provide further illustration of problems arising from the two schedule

[2] Multiple Panel Reports reference the inefficiencies associated with the two schedule system. All of the Panel's previous reports are available at: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Electricity+Market+Surveillance/Market+Surveillance+Panel+Reports

structure. Since market opening, this has contributed to more than $300 million in constraint payments in the Northwest area alone.[3]

Some changes have been implemented to curtail constraint payments (e.g. capping the constrained off payments to importers and generators), or to permit some 'unwarranted' CMSC payments to be recovered from participants (e.g. the Local Market Power rules and Constrained off Watch Zones). However, they do not appear to be sufficient to remedy the problems arising from the two schedule regime.

The Panel believes that it would be worthwhile to reconsider the two schedule system that was initially established as an 18-month interim approach at market opening. Although the Panel has previously recommended that the full Locational Marginal Pricing (LMP) regime originally contemplated should be pursued[4], other alternatives may exist. One such alternative could be to continue to use a uniform price for loads in the province, while exploring alternatives to directly compensate dispatchable resources at prices consistent with the constrained schedule.

In the spring of 2009 the IESO introduced a Stakeholder Engagement initiative (SE-79)[5] titled "More Efficient Uniform Pricing" with the objective to "review the current real-time uniform pricing model." However, due to other IESO priorities, work on this initiative is presently not active. The Panel believes that addressing this structural issue should be a high priority for the industry. In coming reports the Panel intends to investigate options to improve the Ontario pricing structure by replacing the two schedule approach with one that improves the fidelity of the price signal and that better incents efficient bids and offers.

The Green Energy Act

[3] See Table 3.8 in Chapter 3 of the current report.
[4] See Table 3.8 in Chapter 3 of the current report.
[5] See Table 3.8 in Chapter 3 of the current report.

As discussed in Chapter 4, Ontario's Green Energy Act (GEA)[6] came into force in May 2009. One important aspect of the GEA is the announcement of a new Feed-in-Tariff (FIT) contract for renewable generators. The FIT provides renewable generators with long-term contracts to provide energy at guaranteed rates.[7]

At present, Ontario has 1,085 MW of transmission-connected wind generation capacity. In December 2009, the Ontario Power Authority (OPA) announced that it had received FIT applications representing approximately 8,000 MW of potential electricity generation. For these FIT projects, the OPA has estimated that there is presently 2,500 MW of available transmission connection capacity. Directionally, the Panel is pleased to see that the FIT contract contains some of the price-responsiveness measures advocated in its previous report.[8]

The addition of large amounts of renewable energy will also impact HOEP and Global Adjustment. Most renewable generation has a marginal production cost near $0/MWh. Thus, whenever these generators produce energy, they displace generation offered above $0/MWh. This reduces HOEP, everything else being equal. However, the reduced HOEP is accompanied by an increased Global Adjustment associated with the contract payments to renewable facilities under FIT contracts and other contracted facilities. Historically, the Global Adjustment represented a rebate from generators to consumers, then a small payment from consumers to generators. As more contracted generators have come online and as contract prices have increased, the Global Adjustment has become a more substantial component of the total effective cost of energy. It is expected that as new generation under FIT contracts come on-line they will put further downward pressure on HOEP and upward pressure on the Global Adjustment.

[6] See: http://www.mei.gov.on.ca/en/energy/gea/
[7] For more information see the OPA's FIT webpage at: http://fit.powerauthority.on.ca/Page.asp?PageID=1115&SiteNodeID=1052
[8] See FIT contract, specifically section 1.5 to Exhibit B dealing with "IESO Instructions"

Recommendations

The Panel has five recommendations in this report:

<u>Recommendation 3-1 (Chapter 3, Section 2.1)</u>

The OPA's Demand Response Phase 3 (DR3) program, which has been in place for 15 months, could benefit from certain efficiency enhancements.

(i) ***The Panel recommends that the Ontario Power Authority (OPA) should target all Demand Response Phase 3 (DR3) activations, except those required for 'testing' purposes, based on efficiency considerations. This would involve improved identification of periods when system need is greatest and the value of foregone consumption is less than the incremental cost of providing the energy.***

(ii) ***The Panel recommends that OPA explore the feasibility of introducing a bidding process to allow demand response resources to bid the value at which they are prepared to reduce consumption and work with the IESO to align such a process with the Enhanced Day-Ahead Commitment (EDAC) process in order to avoid over-commitment of generation and/or imports.***

<u>Recommendation 3-2 (Chapter 3, Section 2.3)</u>

Bringing into service the Phase Angle Regulators (PARs) at the Michigan border would reduce inefficiencies associated with inadvertent loopflow (i.e. Lake Erie circulation). International Transmission Company (ITC), the owner of the PAR in Michigan, has indicated it will not bring the PAR into service absent a cost-sharing arrangement with neighbouring jurisdictions.

The Panel recommends that IESO and Hydro One work with their counterparts in Michigan and New York to bring the Phase Angle Regulators (PARs) into service as soon as possible. The Panel encourages the IESO and Hydro One to pursue available channels, including intra-regional discussions, to address any potential future delays

resulting from issues raised by the owner of the Michigan PAR in order that Ontario and its neighbouring markets obtain the benefits available from operation of this equipment.

Recommendation 3-3 (Chapter 3, Section 2.3)

The BP76 transmission line at the Ontario-New York Niagara interface has been out of service since January 30, 2008 due to equipment damage. The loss of this transmission capacity has resulted in market inefficiencies.

The Panel recommends that Hydro One work with its transmission counterpart in New York (National Grid) to return the BP76 transmission line at the New York/Ontario interface at Niagara into service in order to mitigate Surplus Baseload Generation (SBG) situations and realize gains from efficient trading opportunities for participants in the Ontario and New York markets.

Recommendation 3-4 (Chapter 3, Section 3.1)

Ontario's two dispatch sequence and associated CMSC payments have resulted in significant efficiency losses. As long as the two dispatch sequences continue to exist the IESO should adopt Market Rule changes that reduce the inefficiencies associated with unwarranted CMSC.

The Panel recommends that, for the purposes of calculating Congestion Management Settlement Credit (CMSC) payments, the IESO should revise its constrained on payment calculation using a replacement bid (such as $0/MWh) when market participants (both exporters and dispatchable loads) bid at a negative price. This would create more consistent treatment with generators and importers that are constrained off.

<u>**Recommendation 3-5 (Chapter 3, Section 3.3)**</u>

The Panel is concerned that generators participating in the real-time and day-ahead cost guarantee programs are providing the IESO with generation plant operating characteristics that may be motivated by financial considerations rather than genuine operating limitations. As a result generators may be extracting unwarranted CMSC payments for their own benefit and to the detriment of the market as a whole.

(i) The Panel recommends that the IESO provide market participants with specific parameters for determining operating plant characteristics, including Minimum Loading Point (MLP), Minimum Run-Time (MRT) and Minimum Generation Block Run-Time (MGBRT) in order to ensure that submitted operating characteristics, which affect market outcomes, reflect actual operating capabilities.

(ii) The Panel recommends that the IESO develop a compliance or other review mechanism for ensuring that submitted operating characteristics are appropriate having regard to the parameters specified and equipment capabilities.

In past reports we have grouped recommendations under four categories – price fidelity, dispatch, transparency, and uplift payments. The recommendations from this report are grouped in the table below. There were no recommendations to improve price fidelity or transparency.

Summary of Recommendations

CATEGORY	RECOMMENDATION	SUBJECT	RELEVANT ENTITIES
Dispatch	**3-1**	**Demand Response Phase 3 Program**	**OPA**
	3-2	**Ontario/Michigan Phase Angle Regulators**	**IESO Hydro One**
	3-3	**BP76 Transmission Line**	**Hydro One**
	3-5	**Operating Parameters**	**IESO**
Uplift Payments	**3-4**	**Congestion Management Settlement Credit**	**IESO**

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Chapter 1: Market Outcomes May-October 2009

On September 24, 2009, the Market Surveillance Panel (MSP) initiated a consultation regarding proposed market Monitoring Reporting changes. In an environment of decreased resources, the Panel proposed reductions to the breadth and depth of its reports. Interested parties were invited to review and comment on a revised report structure. [9] After reviewing the responses received from four participants, the Panel has decided to move forward with the proposed reporting changes.

Two reports will continue to be produced annually. A brief summer report covering May to October will focus on monitoring activities of the prior six months, summarizing reports provided by the MAU to MSP, and referrals of issues to other parties (primarily the IESO) in respect of both anomalous events and other emerging matters significant to the market. The more comprehensive winter report will be the required annual report on the state of the market, covering similar types of information and reporting as currently performed, although there will be less detailed statistical information and less detailed assessment in some areas. It will also include reviews of events in the six month period, like the mid-year report. The current summer report represents the first abbreviated report and does not include the detailed overview of market outcomes historically published in Chapter 1 or a Statistical Appendix. A streamlined Statistical Appendix will be published in the comprehensive winter report.

1. Highlights of Market Indicators

This Chapter provides a brief summary of the results of the IESO-administered markets over the period May 1, 2009 to October 31, 2009, with comparisons to the same period a year earlier.

[9] The proposed reporting structure and specific comments received from four participants can be found on the OEB website at: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Electricity+Market+Surveillance/Consultation+on+Reporting

1.1 Pricing

The average Hourly Ontario Energy Price (HOEP) was $24.28/MWh this summer, representing a reduction in HOEP of 49.7 percent from $49.25/MWh last summer. The average monthly HOEP did not exceed $30.00/MWh in any month this summer. The lowest monthly average HOEP occurred in July 2009 at $18.99/MWh. This is only slightly above the lowest monthly HOEP since market inception of $18.40/MWh in April 2009.

Although the HOEP decreased significantly during this period, the effective prices paid by domestic load, which include the Global Adjustment, actually increased from $55.87/MWh last summer to $63.05/MWh (16 percent) this summer. The magnitude of the Global Adjustment (GA) exceeded the average HOEP in all 2009 summer months with the largest difference between the GA and HOEP at $22.73/MWh occurring in July 2009 (the lowest monthly HOEP this summer).

1.2 Demand

Ontario Demand totalled 67.2 TWh this summer, down by 5.6 TWh (7.7 percent) compared to the same period in 2008. There were declines in every month with the largest monthly percentage declines occurring in July and June 2009 at 13.9 and 10.6 percent below the prior year, respectively. Relatively poor economic conditions together with lower than usual temperatures this summer were primary reasons for the observed decline in demand.

1.3 Supply

A new wind facility and an intertie with Quebec became operational during the summer of 2009 and an existing gas unit became dispatchable.

The Wolfe Island Wind Project, a 198 MW wind farm located a few kilometres off the shore of Kingston Ontario, on Wolfe Island in Frontenac Township began operating in

May 2009. This represents slightly less than 1 percent of total installed generating capacity in Ontario but an additional 22 percent in total wind capacity.

In addition to this new supply, a new interconnection between the Hawthorne transformer station in Ontario and the Outaouais station in Quebec became operational in July 2009. The 1,250 MW of additional intertie capability increases the total Ontario intertie capability by approximately 30 percent.

The East Windsor Cogeneration Centre (84 MW capacity) was being commissioned to become a dispatchable resource this summer. It was successful in doing so coming into service shortly after the period ended in early November 2009.

1.4 Imports and Exports

Net exports totalled 5.0 TWh this summer, which is 0.8 TWh (14 percent) lower than the same period last year.

Exports (excluding linked wheel transactions) declined by 0.8 TWh (8.7 percent) to 8.4 TWh. The largest monthly decline to exports occurred in the first and last month of the summer period as exports fell 29.6 percent in May and 30.2 percent in October due to various factors such as less baseload supply in these months relative to last year, lower demand in other jurisdictions, and the IESO curtailing exports in response to New York transmission congestion. Export flows across the new Outaouais intertie were not accounted as exports for most of this summer because the intertie was undergoing commissioning. Of the 8.4 TWh of exports this summer, 59 percent of the flows occurred during the lower price off-peak hours with the largest volumes being exported at the Michigan interties and destined for PJM.

Imports (excluding linked wheel transactions) remained unchanged this summer relative to last year at 3.4 TWh. On-peak hours accounted for 54 percent of the total flows, with 48 percent of total import volumes occurring at the Quebec interties.

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 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 tools and procedures that the IESO employs.

On a daily basis, the MAU reviews the previous day’s operation and market outcomes, 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.

This daily review often leads to identification of anomalous events that may be discussed with the relevant market participants and/or the IESO. The daily review process is an important part of market monitoring. During the current reporting period, this monitoring did not identify an abuse of market power by market participants or activities that warranted a formal gaming investigation.

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,[10] including negative-priced hours.

There were 6 hours during the summer review period, May through October 2009, where the HOEP was greater than \$200/MWh. Section 2.1 of this Chapter examines the factors contributing to the relatively high HOEP in each instance. Many of the price-setting resources in intervals during these hours were hydroelectric resources. These hydroelectric resources routinely offer at prices in excess of \$500/MWh as an indication that they do not want to (or cannot) run. A preliminary review of the offer behaviour commonly used by some hydroelectric generators is included in section 2.1.6.

In this review period, there were 1,619 hours in which the HOEP was less than \$20/MWh including 121 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.[11] During the study period, there were four hours with OR payments greater than \$100,000, all occurring in August 2009. We discuss these incidents in section 3. No other anomalous events occurred during the current reporting period.

[10] See Table 3.8 in Chapter 3 of the current report.
[11] See the Panel's January 2009 Monitoring Report, pp. 178-184.

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 and to determine whether further analysis of the design or operation of the market or of market participant conduct is warranted.

Table 2-1 depicts the total number of hours per month where HOEP exceeded $200/MWh. There were 6 hours during the 2009 summer period where HOEP exceeded $200/MWh. This was significantly lower than the 17 high HOEP hours observed one year earlier and similar to the number of high HOEP hours that occurred during the 2006 and 2007 summer months.

Table 2-1: Number of Hours with a High HOEP May - October 2006 - 2009, (Number of Hours)

	Number of Hours with HOEP >$200/MWh			
	2006	**2007**	**2008**	**2009**
May	3	0	0	0
June	0	2	4	0
July	1	1	3	0
August	2	0	2	4
September	0	0	5	0
October	0	1	3	2
Total	6	4	17	6

In previous reports, we have 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 real-time delivery; 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 lead to a sharp increase in Market Clearing Price (MCP) in the first few intervals, thereby increasing 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-times to 3-times 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.[12]

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 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.[13]

2.1.1 *August 8, 2009 HE 19*

The high HOEP of $237.76/MWh on August 8, 2009 HE 19 was a combined result of a steep offer curve, losses of expected supply sources, and inconsistencies between the constrained and unconstrained dispatch sequences.

Prices and Demand

Table 2-2 below lists the real-time and pre-dispatch MCP, Ontario demand and net exports for HE 18 and HE 19 on August 8, 2009. For most of HE 18 (the hour immediately preceding the price spike), the real-time (RT) MCP was slightly above the pre-dispatch (PD) projected MCP and Ontario demand was slightly greater than the forecast peak demand. In HE 19, the peak demand was more than 300 MW above

[12] For more details, see the Panel's July 2008 Monitoring Report, pp. 134-140.
[13] 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, however, that when the supply cushion is below 10 percent, a price spike becomes increasingly likely.

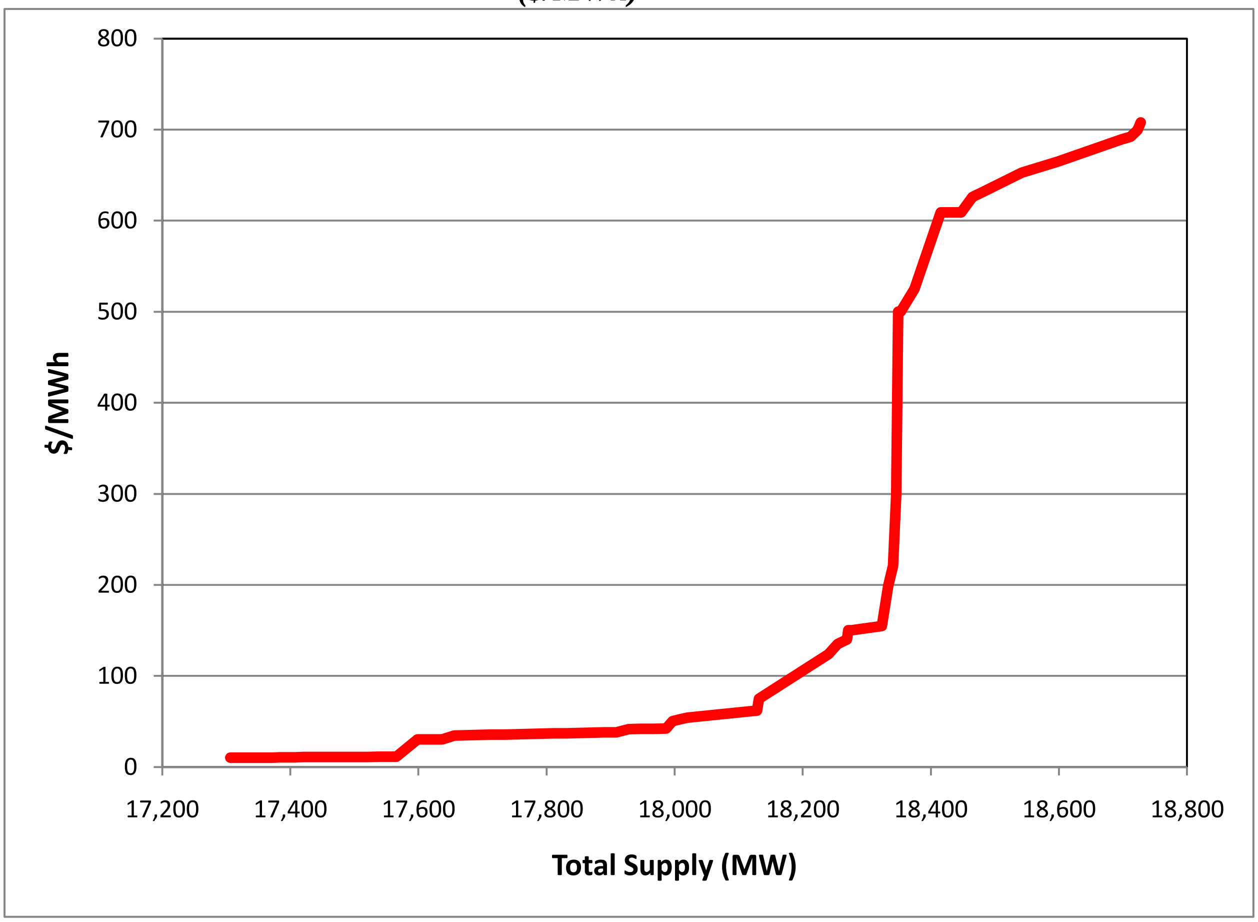
forecast and there was a 750 MW net import failure. A fossil-fired unit also shut-down based on economics in the HE 19, which led to a 433 MW discrepancy between the constrained and unconstrained sequences as explained later. The MCP ranged from $67/MWh (in interval 2) to $665/MWh (in interval 4).

Table 2-2: Pre-dispatch and Real-time Prices, Demand, and Net Exports August 8, 2009, HE 18 and 19 ($/MWh and MW)

Delivery Hour	Interval	PD MCP ($/MWh)	RT MCP ($/MWh)	Diff (RT-PD) ($/MWh)	PD Ontario Demand (MW)	RT Ontario Demand (MW)	PD Net Exports (MW)	RT Net Exports (MW)
18	**1**	29.50	31.82	2.32	15,288	15,376	2,169	2,169
18	**2**	29.50	32.09	2.59	15,288	15,403	2,169	2,169
18	**3**	29.50	31.82	2.32	15,288	15,353	2,169	2,169
18	**4**	29.50	31.94	2.44	15,288	15,361	2,169	2,169
18	**5**	29.50	32.09	2.59	15,288	15,393	2,169	2,169
18	**6**	29.50	32.36	2.86	15,288	15,419	2,169	2,169
18	**7**	29.50	32.36	2.86	15,288	15,394	2,169	2,169
18	**8**	29.50	32.49	2.99	15,288	15,383	2,169	2,169
18	**9**	29.50	32.76	3.26	15,288	15,398	2,169	2,169
18	**10**	29.50	31.94	2.44	15,288	15,305	2,169	2,169
18	**11**	29.50	31.54	2.04	15,288	15,251	2,169	2,169
18	**12**	29.50	69.96	40.46	15,288	15,273	2,169	2,169
Average		**29.50**	**35.26**	**35.26**	**15,288**	**15,359**	**2,169**	**2,169**
19	**1**	32.00	169.90	137.90	15,058	15,345	1,952	2,702
19	**2**	32.00	67.68	35.68	15,058	15,263	1,952	2,702
19	**3**	32.00	113.31	81.31	15,058	15,286	1,952	2,702
19	**4**	32.00	664.99	632.99	15,058	15,244	1,952	2,702
19	**5**	32.00	240.14	208.14	15,058	15,189	1,952	2,702
19	**6**	32.00	250.14	218.14	15,058	15,203	1,952	2,702
19	**7**	32.00	254.50	222.50	15,058	15,230	1,952	2,702
19	**8**	32.00	240.14	208.14	15,058	15,215	1,952	2,702
19	**9**	32.00	235.13	203.13	15,058	15,200	1,952	2,702
19	**10**	32.00	240.13	208.13	15,058	15,203	1,952	2,702
19	**11**	32.00	240.14	208.14	15,058	15,206	1,952	2,702
19	**12**	32.00	136.88	104.88	15,058	15,111	1,952	2,702
Average		**32.00**	**237.76**	**237.76**	**15,058**	**15,225**	**1,952**	**2,702**

August 8 was a Saturday and the demand (as well as the market price) was expected to be relatively low. As is typical, most fossil-fired generators were shutdown for the weekend. The supply curve was flat in the range of $30/MWh to $60/MWh with 530 MW of available offers and then very steep in the range of $60/MWh to $600/MWh as illustrated in Figure 2-1 below with 350 MW of available offers.

Figure 2-1: Portion of Supply Curve between $0/MWh and $700/MWh
August 8, 2009, HE 19
($/MWh)



Before RT, an 18 MW import (based on the constrained sequence) failed on the Beauharnois interface because that schedule was lower than Quebec's minimum requirement.[14] However, this import was scheduled at 750 MW in the unconstrained sequence (in other words, based on PD schedules, this was a constrained off import). Because a TLRe code is applied to the transaction failure and both schedules were set to 0 MW, the 18 MW failure and loss in the constrained sequence led to a 750 MW loss in the unconstrained sequence. This put significant upward pressure on the RT MCP (moving the price from the bottom of the flat portion of the supply curve to the lower range of the steep portion, as illustrated in Figure 2-1). In fact, the MCP in HE 19 interval 1 jumped to about $170/MWh from about $70/MWh in HE 18 interval 12, whereas it had been projected at $32/MWh in the final PD run.

In HE 19 a fossil-fired generator also completed its scheduled shutdown by interval 3. Although its constrained schedule was moving down from 90 MW in HE 18 interval 12 to 0 MW in HE 19 interval 3, its unconstrained schedule was ramping up as the market price kept increasing. When the unit's breaker was finally opened in HE 19 interval 4, the unconstrained schedule immediately removed the unit reducing its output in the schedule from 433 MW to 0 MW. This caused the MCP to jump from $113/MWh to $665/MWh. Table 2-3 below shows interval prices and schedule changes for the failed import and the fossil-fired generator that shut down.

[14] There is no pre-determined cut-off minimum requirement. The procedures allow HQ to claim that a schedule smaller than 40 to 50 MW is below the minimum output level considered to be efficient to operate one of the units at the Beauharnois station.

Table 2-3: RT MCP, Ontario Demand and the Constrained and Unconstrained Schedules of the Failed Import and the Shutting-down Generator August 8, 2009, HE 18 and 19 ($/MWh and MW)

Delivery Hour	Interval	RT MCP ($/MWh)	RT Ontario Demand (MW)	Failed Imports (MW)		Generator Shutting down (MW)	
				Constrained Schedule	Unconstrained Schedule	Constrained Schedule	Unconstrained Schedule
18	**1**	31.82	15,376	0	0	90	172
18	**2**	32.09	15,403	0	0	90	188
18	**3**	31.82	15,353	0	0	90	173
18	**4**	31.94	15,361	0	0	90	187
18	**5**	32.09	15,393	0	0	90	206
18	**6**	32.36	15,419	0	0	90	220
18	**7**	32.36	15,394	0	0	90	220
18	**8**	32.49	15,383	0	0	90	226
18	**9**	32.76	15,398	0	0	90	246
18	**10**	31.94	15,305	0	0	90	187
18	**11**	31.54	15,251	0	0	90	155
18	**12**	69.96	15,273	0	0	90	245
Average		**35.26**	**15,359**	**0**	**0**	**90**	**202**
19	**1**	169.90	15,345	18	750	60	335
19	**2**	67.68	15,263	18	750	30	413
19	**3**	113.31	15,286	18	750	0	433
19	**4**	664.99	15,244	18	750	0	0
19	**5**	240.14	15,189	18	750	0	0
19	**6**	250.14	15,203	18	750	0	0
19	**7**	254.50	15,230	18	750	0	0
19	**8**	240.14	15,215	18	750	0	0
19	**9**	235.13	15,200	18	750	0	0
19	**10**	240.13	15,203	18	750	0	0
19	**11**	240.14	15,206	18	750	0	0
19	**12**	136.88	15,111	18	750	0	0
Average		**237.76**	**15,225**	**18**	**750**	**8**	**98**

The RT MCP was set by a dispatchable load, a peaking gas generator, and several peaking hydroelectric generators as presented in Table 2-4 below.

Table 2-4: Real-time MCP and Fuel Type of Price Setting Resource August 8, 2009, HE 19 ($/MWh)

Delivery Hour	Interval	MCP Price	Fuel Type
19	**1**	169.90	Hydroelectric
19	**2**	67.68	Hydroelectric
19	**3**	113.31	Gas
19	**4**	664.99	Hydroelectric
19	**5**	240.14	Dispatchable load
19	**6**	250.14	Dispatchable load
19	**7**	254.50	Dispatchable load
19	**8**	240.14	Dispatchable load
19	**9**	235.13	Hydroelectric
19	**10**	240.13	Dispatchable load
19	**11**	240.14	Dispatchable load
19	**12**	136.88	Hydroelectric

Dispatchable loads generally have a high reservation value for load reduction, and are willing to reduce their consumption only when the market price is high. In the current case, the dispatchable load submitted a bid of approximately $250/MWh to curtail a portion of its consumption and set the RT MCP in a few intervals.

The peaking gas generator was a quick start unit and was off-line at the time. This type of generator typically has a high average incremental cost for each start and thus offers a relatively high price when it is off-line.

Peaking hydro generators are typically shut down to accumulate water during the weekend. As a result, they tend to offer a high price (often between $100/MWh and $200/MWh) in order to avoid energy production, while concurrently meeting the requirements to provide operating reserve. The $664.99/MWh was set by a peaking hydro generator who had operated for a total of 5 hours prior to HE 19 on August 8th. The generating unit and others that are located along the same river system generally offer at a binary price: a very high price when they want to stay off-line or a very low (often negative price) when they want to be in the market. However, even if this generator had offered at a significantly lower price, a dispatchable load would have set the price and the RT MCP would only have been reduced to approximately $600/MWh).

Table 2-5 below lists the HOEP, PD price as of HE 8, three-hour ahead PD price, and the generator's total output for all units on the river system. The output was well below the generator's production capability for the day. It appears that much of the water was being stored for the coming weekdays. Based on the PD price as of HE 8, the three-hour ahead price, and allowing for travel time of water on the river system, the output at these generators were generally allocated to hours with a high forecast price (i.e. within the day it was generally efficient *ex ante*). However, based on the RT HOEP, the water was used inefficiently since water was typically used in hours with a low HOEP. Of the three highest priced hours, no water was used in HE 18 or HE 19 and only 19 MW (about 4 percent of the day's output) was generated in HE 20.

Table 2-5: Hourly Output, HOEP and PD MCP
August 8, 2009,
($/MWh and MW)

Delivery Hour	Total Output (MW)	HOEP ($/MWh)	PD MCP Generated in HE 8 ($/MWh)*	3 Hr Ahead PD MCP ($/MWh)
1	0	21.15	n/a	15.92
2	0	12.19	n/a	5.60
3	0	13.27	n/a	7.08
4	0	4.99	n/a	4.80
5	0	2.40	n/a	3.90
6	0	(11.00)	n/a	4.80
7	0	(0.91)	n/a	7.90
8	0	2.91	n/a	20.05
9	0	4.78	28.01	25.27
10	19.1	3.03	30.00	31.00
11	126.8	8.54	31.00	31.00
12	126.8	9.88	31.00	31.00
13	0	12.92	30.72	29.65
14	0	19.41	31.00	31.00
15	17.7	14.35	30.73	31.00
16	36.8	7.53	31.00	31.00
17	74.7	31.56	31.00	31.10
18	0	35.26	30.85	31.00
19	0	237.76	29.88	31.00
20	19	39.19	30.85	31.10
21	56.9	8.86	30.72	29.60
22	0	8.99	27.53	27.88
23	0	5.57	21.42	6.02
24	0	6.62	2.52	4.41
Total/ Average	477.8	20.80	28.01	20.96

* The pre-dispatch market price forecast for the remainder of the day as determined in the HE 8 pre-dispatch run.

Assessment

A large part of the price spike in HE 19 was a consequence of the inconsistency of the constrained and unconstrained dispatch sequences. Although the RT demand was about 300 MW more than forecast demand, there was a greater impact on price from schedule discrepancies arising from supply failures.

- A small 18 MW actual import failure in the constrained schedule led to a much larger 750 MW apparent supply loss in the unconstrained sequence, and

- The opening of the breaker as a fossil-fired generator shut-down based on economics led to an apparent loss of 433 MW of supply in the unconstrained sequence, although the unit was scheduled to zero MW in the previous interval's constrained sequence and was actually not producing.

The seemingly anomalous result of the failed import that led to a reduction in the unconstrained sequence greater than the magnitude of the import failure is consistent with the treatment of generation outages or deratings in general (including the treatment of the specific fossil-fired unit shut-down in this same hour).[15] While import failures of this type have been historically uncommon, they have become more frequent in recent months at the radial interties with Quebec (i.e. 16 times from January to August of 2009, of which 11 were between May and August).

2.1.2 *August 14, 2009 HE 19*

The high HOEP of $272.68/MWh on August 14, 2009 HE 19 was a combined result of derating a baseload hydro unit, underforecast of peak demand, over-forecast self-scheduled and intermittent production, and the ramping of a large increase in net exports between HE 18 and HE 19.

Prices and Demand

Table 2-6 below lists the PD and RT price, demand and net exports (in the unconstrained sequence) for HE 18 and HE 19:

- In HE 18, the HOEP was $97/MWh, or $52/MWh higher than the pre-dispatch projection, with the RT MCP more than doubling the PD MCP from

[15] In the July 2008 Monitoring Report, pp. 171-180, the Panel discussed the situation where a failed import (or export) led to an increase in imports (or exports) in the unconstrained sequence. The Panel recommended (see Recommendation 3-6 on pp. 179-180) procedural changes to help deal with counter-intuitive pricing outcomes that occur as a result of trying to equate the constrained and unconstrained schedules. The current situation is different since the failed import amplified the change in the unconstrained sequence.

interval 6 to 11. The average demand in the hour was 21,579 MW, with a peak demand of 21,735MW in interval 1 (209 MW or 0.7 percent greater than the forecast). Only 50 MW of exports failed in the hour.

- In HE 19, the HOEP was $272.68/MWh. The MCP in interval 1 reached the maximum of $2,000/MWh, and then gradually decreased to $36.47/MWh in interval 12. Average demand was 20,793 MW, with a peak of 21,241 MW (317 MW or 2.2 percent greater than the forecast). There were no intertie transaction failures in the hour.

Table 2-6: Pre-dispatch and Real-time Prices, Demand, and Net Exports August 14, 2009, HE 18 and 19 ($/MWh and MW)

Delivery Hour	Interval	PD MCP ($/MWh)	RT MCP ($/MWh)	Diff (RT-PD) ($/MWh)	PD Ontario Demand (MW)	RT Ontario Demand (MW)	PD Net Exports (MW)	RT Net Exports (MW)
18	**1**	45.00	64.14	19.14	21,526	21,735	1,187	1,137
18	**2**	45.00	63.75	18.75	21,526	21,701	1,187	1,137
18	**3**	45.00	63.49	18.49	21,526	21,676	1,187	1,137
18	**4**	45.00	63.49	18.49	21,526	21,674	1,187	1,137
18	**5**	45.00	63.75	18.75	21,526	21,655	1,187	1,137
18	**6**	45.00	116.22	71.22	21,526	21,616	1,187	1,137
18	**7**	45.00	157.68	112.68	21,526	21,611	1,187	1,137
18	**8**	45.00	154.61	109.61	21,526	21,578	1,187	1,137
18	**9**	45.00	119.13	74.13	21,526	21,533	1,187	1,137
18	**10**	45.00	118.13	73.13	21,526	21,440	1,187	1,137
18	**11**	45.00	116.22	71.22	21,526	21,411	1,187	1,137
18	**12**	45.00	64.25	19.25	21,526	21,312	1,187	1,137
Average		**45.00**	**97.07**	**52.07**	**21,526**	**21,579**	**1,187**	**1,137**
19	**1**	50.00	1,999.99	1,949.99	20,924	21,241	1,686	1,686
19	**2**	50.00	240.14	190.14	20,924	21,167	1,686	1,686
19	**3**	50.00	226.43	176.43	20,924	21,064	1,686	1,686
19	**4**	50.00	169.9	119.90	20,924	20,991	1,686	1,686
19	**5**	50.00	135.04	85.04	20,924	20,922	1,686	1,686
19	**6**	50.00	129.13	79.13	20,924	20,849	1,686	1,686
19	**7**	50.00	74.23	24.23	20,924	20,797	1,686	1,686
19	**8**	50.00	70.73	20.73	20,924	20,702	1,686	1,686
19	**9**	50.00	64.12	14.12	20,924	20,657	1,686	1,686
19	**10**	50.00	63.46	13.46	20,924	20,555	1,686	1,686
19	**11**	50.00	62.49	12.49	20,924	20,489	1,686	1,686
19	**12**	50.00	36.47	-13.53	20,924	20,083	1,686	1,686
Average		**50.00**	**272.68**	**222.68**	**20,924**	**20,793**	**1,686**	**1,686**

Pre-dispatch and Real-time Conditions

Several hydro units at one generating station were derated between HE 18 interval 8 until the end of HE 23 due to a lack of stored water. At the beginning of HE 16, the hydro generator informed the IESO that it only had two hours of water remaining in storage. In such circumstances, the generator is required to either revise its submitted offers or submit an outage slip to accurately indicate availability to the market as soon as it is known by the hydro operator when the water will be used up. For example, if the hydro operator identified that its units were scheduled in all intervals in HE 16 and HE 17, the appropriate action would have been to immediately revise its offers or submit an outage slip for HE 18 onwards. Accurate availability can lead to more efficient import and export scheduling decisions in pre-dispatch. In this case however, it was not immediately clear to the operator when the units would be scheduled and therefore, when the stored water would be depleted so the hydro units were not derated by the operator until HE 18 for all subsequent hours. The total of the deratings in the unconstrained sequence was 540 MW during HE 19. The lack of an opportunity for imports and exports to respond to the reduced availability from the hydro plant placed upward pressure on the HOEP.

Self-scheduling and intermittent generators forecast 904 MW of production, but only produced 774 MW in HE 19 interval 1, which was 130 MW (14 percent) less than forecast. This put additional upward pressure on the HOEP.

In summary, the greater-than-forecast demand (317 MW), the derating of several hydro units (540 MW) and the under-performance of self-scheduling and intermittent generators (130 MW) created a need for 987 MW of additional supply relative to the level projected in pre-dispatch.

In addition, there was an increase in net exports by 549 MW from HE 18 interval 12 to HE 19 interval 1 in the unconstrained sequence despite the fact that net exports were actually decreasing by 528 MW in the constrained sequence. This placed further upward pressure on the HOEP as these net exports had to be ramped out in one interval (HE 19 interval 1) as Table 2-7 below indicates. The opposite movement of net exports in the constrained and unconstrained intertie schedules highlights how the outcomes under the two dispatch sequences can significantly deviate from each other. Table 2-7 also shows that the Richview shadow price was significantly different from the MCP in many intervals due to these differences between the constrained and unconstrained sequences.

Table 2-7: RT MCP, Richview Price, Net Exports and Deratings in the Unconstrained and Constrained Schedules
August 14, 2009, HE 18 and 19
($/MWh and MW)

Delivery Hour	Interval	Price ($/MWh)		RT Net Exports (MW)		Hydro Generator Derating (MW)	
		MCP	Richview Shadow Price	Unconstrained	Constrained	Unconstrained	Constrained
18	**1**	64.14	113.64	1,137	906	0	0
18	**2**	63.75	146.99	1,137	906	0	0
18	**3**	63.49	110.58	1,137	906	0	0
18	**4**	63.49	109.96	1,137	906	0	0
18	**5**	63.75	69.18	1,137	906	0	0
18	**6**	116.22	63.86	1,137	906	270	0
18	**7**	157.68	109.48	1,137	906	470	0
18	**8**	154.61	778.73	1,137	906	470	208
18	**9**	119.13	757.00	1,137	906	470	208
18	**10**	118.13	2,375.28	1,137	906	470	402
18	**11**	116.22	2,362.82	1,137	906	470	402
18	**12**	64.25	134.98	1,137	906	470	402
Average		**97.07**	**594.38**	**1,137**	**906**	**258**	**135**
19	**1**	1,999.99	69.19	1,686	378	540	483
19	**2**	240.14	61.40	1,686	378	540	483
19	**3**	226.43	58.34	1,686	378	540	483
19	**4**	169.90	57.20	1,686	378	540	483
19	**5**	135.04	56.46	1,686	378	540	483
19	**6**	129.13	43.83	1,686	378	540	483
19	**7**	74.23	35.02	1,686	378	540	483
19	**8**	70.73	34.70	1,686	378	540	483
19	**9**	64.12	34.43	1,686	378	540	483
19	**10**	63.46	33.71	1,686	378	540	483
19	**11**	62.49	35.02	1,686	378	540	483
19	**12**	36.47	35.56	1,686	378	540	483
Average		**272.68**	**46.24**	**1,686**	**378**	**540**	**483**

Assessment

From HE 18 to 19, there were no material changes in generator offers, only 70 MW of incremental generator deratings, and essentially no change to Ontario demand. However, the MCP increased sharply from $64.25/MWh to $2,000/MWh. The main reason was the large increase in net exports (549 MW) in the unconstrained sequence, which had to be accommodated within one interval by generators. After allowing for units to provide OR, there were approximately 400 MW of available energy offers between $64/MWh and $2,000/MWh suggesting tight supply conditions.

As the hour progressed, demand kept decreasing and the ramping up of fossil units gradually reduced the MCP to $36/MWh at the end of the hour.

In summary, the high HOEP in HE 19 was a result of high MCP at the beginning of the hour. From HE 18 to HE 19, both the actual Ontario demand and net exports (in the constrained sequence) decreased, but the MCP sharply spiked primarily because of an increase in net exports in the unconstrained sequence.

The high prices above $200/MWh in intervals 1 to 3 of HE 19 were set by two dispatchable loads as indicated in Table 2-8 below. The prices in other intervals were set by either gas-fired/combined cycle or peaking hydroelectric generators.

Table 2-8: Real-time MCP and Fuel Type of Price Setting Resource
August 14, 2009, HE 19
($/MWh)

Delivery Hour	Interval	MCP Price	Fuel Type
19	1	1999.99	Dispatchable load
19	2	240.14	Dispatchable load
19	3	226.43	Dispatchable load
19	4	169.90	Gas
19	5	135.04	Hydroelectric
19	6	129.13	Hydroelectric
19	7	74.23	Steam
19	8	70.73	Gas
19	9	64.12	Gas
19	10	63.46	Gas
19	11	62.49	Gas
19	12	36.47	Gas

2.1.3 *August 17, 2009 HE 9 and HE 10*

On August 17, 2009, HE 9 and HE 10, the HOEP was $289.11/MWh and $382.64/MWh respectively. The high HOEPs were primarily triggered by various forced outages and deratings of fossil-fired generators.

Prices and Demand

One-hour ahead pre-dispatch and real-time prices, Ontario demand, net exports, and fossil outages and deratings for August 17, 2009, HE 9 to HE 11, are reported in Table 2-9 below.

The HOEP reached $289.11/MWh in HE 9, substantially higher than the one-hour ahead pre-dispatch price of $44.00/MWh. The MCP increased from $37.90/MWh at the beginning of the hour to $530.00/MWh in interval 8, and then up to $689.14/MWh in interval 12. The average Ontario demand was 21,166 MW, with a peak of 21,727 MW in interval 12 which was 558MW (or 2.6 percent) greater than the projected demand in the final pre-dispatch. There were 888 MW of scheduled net exports in real-time, compared to 1,013 MW scheduled in pre-dispatch.

In HE 10, the HOEP was $382.64/MWh. The MCP increased rapidly from a low of $75.16/MWh in interval 1 up to a peak MCP of $1998.00/MWh in interval 12. The average Ontario demand was 22,420 MW with a peak of 23,105 MW in interval 12, which was 682 MW (or 3.0 percent) greater than the projected demand in pre-dispatch. There were 189 MW of net exports in both pre-dispatch and real-time until interval 9 when real-time net exports dropped by 300 MW (i.e. a net export of 189 MW turned into a net import of 111 MW for the remainder of HE 10 as the IESO was forced to cut 300 MW of exports destined for PJM for internal resource adequacy). The MCP dropped back to $122.08/MWh at the beginning of HE 11 and remained in that vicinity throughout HE 11.

Table 2-9: PD and RT Price, Demand, and Net Exports August 17, 2009, HE 9 to 11 ($/MWh and MW)

Delivery Hour	Interval	PD MCP ($/MWh)	RT MCP ($/MWh)	Diff (RT-PD) ($/MWh)	PD Ontario Demand (MW)	RT Ontario Demand (MW)	Diff Ontario Demand (RT-PD) (MW)	PD Net Exports (MW)	RT Net Exports (MW)	Total Fossil Unit Outages/ Derates (MW)
9	1	44.00	37.90	-6.10	21,169	20,510	-659	1,013	888	394
9	2	44.00	37.90	-6.10	21,169	20,603	-566	1,013	888	300
9	3	44.00	37.91	-6.09	21,169	20,800	-369	1,013	888	177
9	4	44.00	38.57	-5.43	21,169	20,925	-244	1,013	888	144
9	5	44.00	42.97	-1.03	21,169	21,115	-54	1,013	888	85
9	6	44.00	82.57	38.57	21,169	21,178	9	1,013	888	245
9	7	44.00	87.35	43.35	21,169	21,266	97	1,013	888	245
9	8	44.00	530.00	486.00	21,169	21,322	153	1,013	888	685
9	9	44.00	530.00	486.00	21,169	21,381	212	1,013	888	685
9	10	44.00	689.14	645.14	21,169	21,517	348	1,013	888	850
9	11	44.00	665.89	621.89	21,169	21,645	476	1,013	888	700
9	12	44.00	689.14	645.14	21,169	21,727	558	1,013	888	675
Average		**44.00**	**289.11**	**245.11**	**21,169**	**21,166**	**(3)**	**1,103**	**888**	**432**
10	1	56.33	75.16	18.83	22,423	21,893	-530	189	189	795
10	2	56.33	116.92	60.59	22,423	21,968	-455	189	189	910
10	3	56.33	106.00	49.67	22,423	22,029	-394	189	189	910
10	4	56.33	159.69	103.36	22,423	22,202	-221	189	189	910
10	5	56.33	204.59	148.26	22,423	22,272	-151	189	189	910
10	6	56.33	252.83	196.50	22,423	22,377	-46	189	189	880

10	**7**	56.33	277.83	221.50	22,423	22,464	41	189	189	850
10	**8**	56.33	301.67	245.34	22,423	22,412	-11	189	189	910
10	**9**	56.33	200.87	144.54	22,423	22,660	237	189	-111	910
10	**10**	56.33	252.84	196.51	22,423	22,783	360	189	-111	820
10	**11**	56.33	645.31	588.98	22,423	22,878	455	189	-111	910
10	**12**	56.33	1,998.00	1941.67	22,423	23,105	682	189	-111	910
Average		**56.33**	**382.64**	**326.31**	**22,423**	**22,420**	**(3)**	**189**	**89**	**885**
11	**1**	89.00	122.08	33.08	23,090	22,998	-92	512	787	760
11	**2**	89.00	140.47	51.47	23,090	23,182	92	512	787	730
11	**3**	89.00	109.98	20.98	23,090	23,163	73	512	787	610
11	**4**	89.00	98.56	9.56	23,090	23,258	168	512	787	490
11	**5**	89.00	125.00	36.00	23,090	23,446	356	512	747	370
11	**6**	89.00	117.94	28.94	23,090	23,446	356	512	747	250
11	**7**	89.00	94.00	5.00	23,090	23,482	392	512	747	158
11	**8**	89.00	121.76	32.76	23,090	23,605	515	512	747	113
11	**9**	89.00	117.94	28.94	23,090	23,607	517	512	747	80
11	**10**	89.00	119.42	30.42	23,090	23,646	556	512	747	50
11	**11**	89.00	121.99	32.99	23,090	23,795	705	512	747	20
11	**12**	89.00	122.38	33.38	23,090	23,644	554	512	747	260
Average		**89.00**	**117.63**	**28.63**	**23,090**	**23,439**	**349**	**512**	**760**	**324**

Pre-dispatch and Real-time Conditions

There were numerous forced outages or derates to fossil-fired units during the morning hours of August 17 that diminished the supply situation and increased the pressure placed on HOEP in HE 9 and HE 10. The final column of Table 2-9 above reports the total fossil outages and derates by interval in the unconstrained schedule resulting from the events outlined below. Pre-dispatch to real-time differences resulting from fossil-fired outages and deratings were largest in intervals towards the end of HE 9 and HE 10 when real-time prices were generally highest.

- A coal-fired unit was forced out of service in interval 8 of HE 9 due to boiler pressure problems, representing a loss of 440 MW in the unconstrained schedule.
- In pre-dispatch, a gas-fired unit was scheduled for 490 MW in HE 9. The unit was derated to 315 MW in intervals 6-10 of HE 9 due to duct burner problems, representing a loss in the unconstrained schedule of 175 MW.
- A coal-fired unit was scheduled in pre-dispatch for 220 MW in HE 9 and 340 MW in HE 10. The unit only reached 150 MW in HE 9 and most of HE 10. The

forced derating to 150 MW resulted from problems placing a pulverizer in service.

- Two gas-fired units encountered high drum level problems. One unit was forced out of service in HE 9, interval 10. This represented a loss of 165 MW in the unconstrained schedule for the remainder of HE 9 and all of HE 10. The second unit was derated from 225 MW to 110 MW for most of HE 10 beginning in interval 2.

Assessment

As described above, the high prices in HE 9 and HE 10 resulted from factors affecting the supply and demand conditions in the hours. Table 2-10 below shows the price-setting fuel-type by interval for HE 9 and HE 10. Hydroelectric units and dispatchable loads were the marginal resources when the MCP increased above $200/MWh.

Table 2-10: Real-time MCP and Fuel Type of Price Setting Resource August 17, 2009, HE 9 and HE 10 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Fuel Type
9	1	37.90	Gas
9	2	37.90	Gas
9	3	37.91	Gas
9	4	38.57	Coal
9	5	42.97	Gas
9	6	82.57	Hydroelectric
9	7	87.35	Hydroelectric
9	8	530.00	Dispatchable Load
9	9	530.00	Dispatchable Load
9	10	689.14	Hydroelectric
9	11	665.89	Hydroelectric
9	12	689.14	Hydroelectric
Average		**289.11**	
10	1	75.16	Gas
10	2	116.92	Oil
10	3	106.00	Hydroelectric
10	4	159.69	Hydroelectric
10	5	204.59	Hydroelectric
10	6	252.83	Hydroelectric
10	7	277.83	Dispatchable Load

10	**8**	301.67	Dispatchable Load
10	**9**	200.87	Hydroelectric
10	**10**	252.84	Hydroelectric
10	**11**	645.31	Hydroelectric
10	**12**	1,998.00	Dispatchable Load
Average		**382.64**	

2.1.4 *October 1, 2009 HE 7*

On October 1, 2009, HE 7, the HOEP reached $210.05/MWh, primarily due to heavier than expected demand and the forced derating of two fossil units.

Prices and Demand

One-hour ahead pre-dispatch and real-time prices, Ontario demand, and net exports for October 1, 2009, HE 7, are reported in Table 2-11. Over the first three intervals of HE 7, real-time MCP was slightly below the pre-dispatch projected price of $35.89/MWh. As the difference between pre-dispatch and real-time Ontario Demand increased throughout the hour, additional upward pressure was placed on real-time prices. As shown in Table 2-11 below, real-time demand came in heavier than the pre-dispatch forecast towards the end of the hour, specifically between intervals 8 to 12 in HE 7 (the peak demand difference of 277 MW or 2 percent occurred in interval 11). By early in HE 8, real-time MCPs dropped back to the vicinity of the pre-dispatch price of $35.88/MWh.

**Table 2-11: One-hour ahead Pre-dispatch and Real-time MCP, Demand, and Net Exports
October 1, 2009, HE 7 and HE 8
($/MWh and MW)**

Delivery Hour	Interval	PD MCP ($/MWh)	RT MCP ($/MWh)	Diff MCP (RT-PD) ($/MWh)	PD Ontario Demand (MW)	RT Ontario Demand (MW)	Diff Ontario Demand (RT-PD) (MW)	PD Net Exports (MW)	RT Net Exports (MW)
7	1	35.89	32.35	(3.54)	16,101	15,368	(733)	1,150	1,060
7	2	35.89	32.52	(3.37)	16,101	15,569	(532)	1,150	1,060
7	3	35.89	35.36	(0.53)	16,101	15,756	(345)	1,150	1,060
7	4	35.89	51.49	15.60	16,101	15,894	(207)	1,150	1,150
7	5	35.89	51.49	15.60	16,101	15,921	(180)	1,150	1,150
7	6	35.89	51.71	15.82	16,101	16,015	(86)	1,150	1,150
7	7	35.89	54.44	18.55	16,101	16,089	(12)	1,150	1,150
7	8	35.89	255.23	219.34	16,101	16,211	110	1,150	1,150
7	9	35.89	585.15	549.26	16,101	16,353	252	1,150	1,150
7	10	35.89	260.23	224.34	16,101	16,306	205	1,150	1,150
7	11	35.89	575.13	539.24	16,101	16,378	277	1,150	1,150
7	12	35.89	535.51	499.62	16,101	16,334	233	1,150	1,150
Average		**35.89**	**210.05**	**174.16**	**16,101**	**16,016**	**(85)**	**1,150**	**1,128**
8	1	35.88	65.98	30.10	16,510	16,329	(181)	1,204	1,204
8	2	35.88	45.61	9.73	16,510	16,372	(138)	1,204	1,204
8	3	35.88	39.26	3.38	16,510	16,388	(122)	1,204	1,204
8	4	35.88	35.13	(0.75)	16,510	16,411	(99)	1,204	1,204
8	5	35.88	35.14	(0.74)	16,510	16,468	(42)	1,204	1,204
8	6	35.88	33.41	(2.47)	16,510	16,374	(136)	1,204	1,204
8	7	35.88	34.22	(1.66)	16,510	16,437	(73)	1,204	1,204
8	8	35.88	35.14	(0.74)	16,510	16,490	(20)	1,204	1,204
8	9	35.88	34.22	(1.66)	16,510	16,440	(70)	1,204	1,204
8	10	35.88	34.36	(1.52)	16,510	16,442	(68)	1,204	1,204
8	11	35.88	34.38	(1.50)	16,510	16,458	(52)	1,204	1,204
8	12	35.88	34.13	(1.75)	16,510	16,391	(119)	1,204	1,204
Average		**35.88**	**38.42**	**2.54**	**16,510**	**16,417**	**(93)**	**1,204**	**1,204**

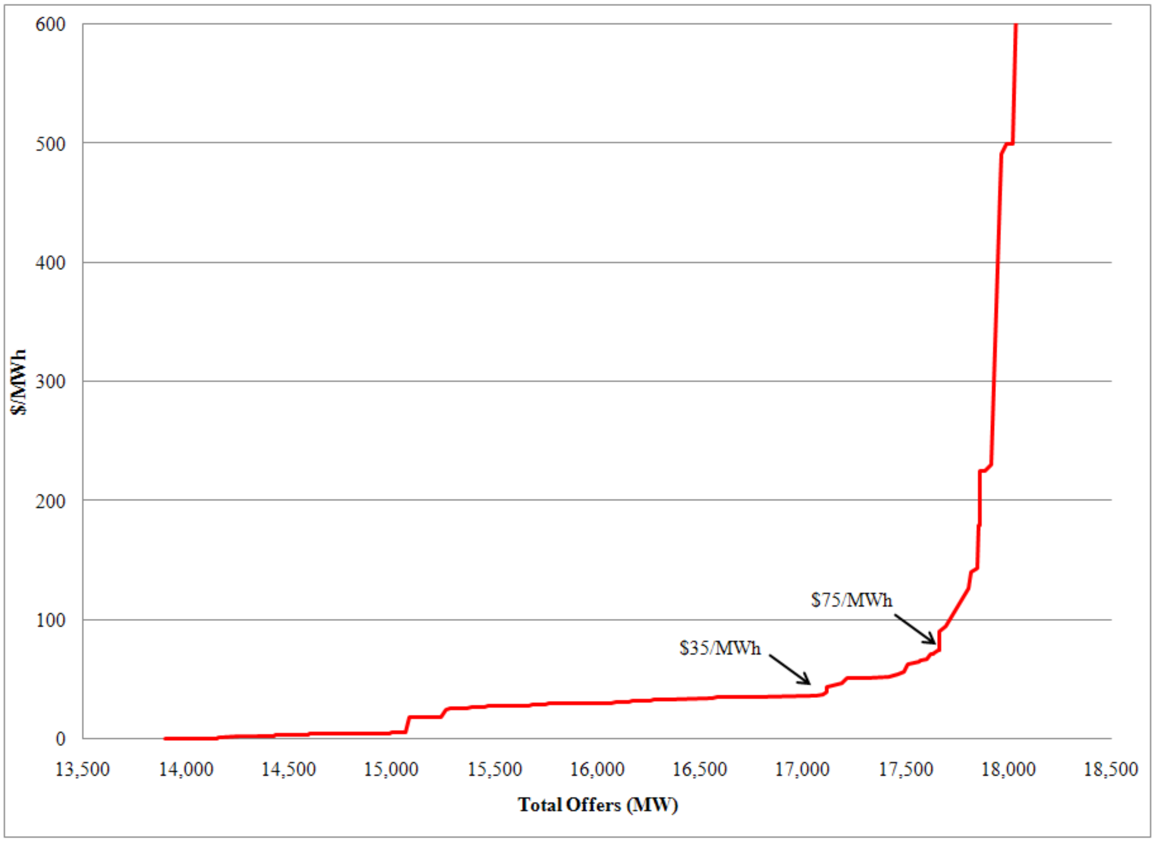
Pre-dispatch and Real-time Conditions

Going into October 1st, many generators were unavailable as they were either on planned or forced outages or were not available due to environmental reasons. Five coal-fired units were on planned outages (two of them on planned CO_2 outages) while OPG designated two additional coal units as being NOBA (Not Offered but Available) units. Both NOBA units had been off-line for more than three days prior to HE 7 and with pre-dispatch prices not exceeding $40/MWh for the on-peak hours of the day, it is unlikely that OPG would have started the units even if not on NOBA. Two nuclear units were also on planned outage, and several gas-fired units were either on planned or forced outages.

The price spike occurred in HE 7, which is typically a load pickup hour, but also an hour where some resources that are available for on-peak hours are not yet running. For example, some fossil-fired units had not come online by HE 7 or were just starting to ramp up. Similarly, some peaking hydro units with limited water were not running as they may have been saving their water for later peak hours.

Figure 2-2 below plots a portion of the supply curve that includes offers between $0/MWh and $600/MWh. The offer curve was relatively flat between $0/MWh and $35/MWh with over 2,800 MW of offered generation. As shown in Figure 2-2, the offer curve became very steep after $75/MWh with approximately 360 MW of available offers between $75/MWh and $600/MWh Furthermore, there was only 100 MW of available offers between $250/MWh and $500/MWh, and some of these generators offering high energy prices were being scheduled in the operating reserve market rather than the energy market. Given the steepness of the offer curve above $75/MWh, it is understandable that two forced deratings and the higher than expected demand led to high prices in intervals 8 to 12 of HE 7.

Figure 2-2: Portion of Supply Curve between $0/MWh and $600/MWh October 1, 2009, HE 7 ($/MWh)



Forced deratings at two coal-fired units in the hour placed additional upward pressure on real-time prices. At the beginning of HE 7, one unit was force derated to a maximum of 50 MW for the entire hour due to late synchronization in the hour. The unit was scheduled in the unconstrained sequence at 283 MW. The other unit was forced derated to 220 MW in interval 8 due to a boiler feed pump temperature mismatch and remained there for the remaining intervals in the hour. This represented a generation loss of almost 250 MW relative to the unconstrained pre-dispatch schedule. This latter derating coincided with the MCP spike to $255.23/MWh.

By the beginning of HE 8 both deratings ended, and real-time prices fell below $40/MWh by interval 3.

Assessment

The price spike in HE 7 can be explained by the supply and demand conditions. Two coal-fired units were force derated and demand came in heavier than expected leading to the high prices in HE 7.

Table 2-12 below shows the price-setting units by interval for HE 7. All interval prices above $200/MWh were set by hydroelectric resources.

Table 2-12: Real-time MCP and Fuel Type of Price Setting Resource October 1, 2009, HE 7 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Fuel Type
7	1	32.35	Coal
7	2	32.52	Coal
7	3	35.36	Gas
7	4	51.49	Hydroelectric
7	5	51.49	Hydroelectric
7	6	51.71	Hydroelectric
7	7	54.44	Hydroelectric
7	8	255.23	Hydroelectric
7	9	585.15	Hydroelectric
7	10	260.23	Hydroelectric
7	11	575.13	Hydroelectric
7	12	535.51	Hydroelectric
Average		**210.05**	

2.1.5 <u>*October 6, 2009 HE 7*</u>

On October 6, 2009, HE 7, the HOEP reached $292.81/MWh. Outages and forced deratings at a gas-fired plant as well as a coal unit, combined with heavier than forecasted demand led to the price spikes observed late in HE 6 and in HE 7.

Prices and Demand

One-hour ahead pre-dispatch and real-time prices, Ontario demand, and net exports and total fossil outages and deratings on October 6, 2009, HE 6 to HE 8 are reported in Table 2-13 below. Real-time MCP was similar to the one-hour ahead pre-dispatch projections over the first nine intervals of HE 6. However, in interval 10 of the hour, the MCP spiked up to $427.00/MWh from $41.80/MWh in the previous interval (the pre-dispatch price for the hour was $41.79/MWh). The MCP remained high the rest of the hour and reached a peak hourly MCP of $609.65/MWh in interval 12 leading to an hourly HOEP of $159.05/MWh. Real-time peak Ontario demand of 15,112 in interval 12 was only slightly (0.9 percent) above the pre-dispatch projected peak of 14,977 MW. However, real-time net exports in HE 6 were lower in real-time relative to the pre-dispatch schedule by 145 MW (8 percent) over the first six intervals and 45 MW (2 percent) over the remaining six intervals.

Table 2-13: One-hour Ahead PD and RT MCP, Demand, and Net Exports October 6, 2009, HE 6 to HE 8 ($/MWh and MW)

Delivery Hour	Interval	PD MCP ($/MWh)	RT MCP ($/MWh)	Diff MCP (RT-PD) ($/MWh)	PD Ontario Demand (MW)	RT Ontario Demand (MW)	Diff Ontario Demand (RT-PD) (MW)	PD Net Exports (MW)	RT Net Exports (MW)	Total Fossil Unit Outages/ Derates (MW)
6	1	41.79	31.93	(9.86)	14,977	13,446	(1,531)	1,856	1,711	756
6	2	41.79	32.33	(9.46)	14,977	13,627	(1,350	1,856	1,711	756
6	3	41.79	35.39	(6.40)	14,977	13,905	(1,072)	1,856	1,711	726
6	4	41.79	35.33	(6.46)	14,977	13,872	(1,105)	1,856	1,711	756
6	5	41.79	41.42	(0.37)	14,977	14,066	(911)	1,856	1,711	955
6	6	41.79	41.13	(0.66)	14,977	14,232	(745)	1,856	1,711	910
6	7	41.79	41.07	(0.72)	14,977	14,304	(673)	1,856	1,811	760
6	8	41.79	41.43	(0.36)	14,977	14,566	(411)	1,856	1,811	610
6	9	41.79	41.80	0.01	14,977	14,715	(262)	1,856	1,811	572
6	10	41.79	427.00	385.21	14,977	14,901	(76)	1,856	1,811	875
6	11	41.79	530.13	488.34	14,977	15,013	36	1,856	1,811	875
6	12	41.79	609.65	567.86	14,977	15,112	135	1,856	1,811	875
Average		**41.79**	**159.05**	**117.26**	**14,977**	**14,313**	**(664)**	**1,856**	**1,761**	**777**
7	1	45.50	63.17	17.67	16,086	15,504	(582)	1,114	1,219	654
7	2	45.50	94.81	49.31	16,086	15,716	(370)	1,114	1,219	654
7	3	45.50	125.00	79.50	16,086	15,804	(282)	1,114	1,219	654
7	4	45.50	80.17	34.67	16,086	15,914	(172)	1,114	1,219	504

7	**5**	45.50	125.00	79.50	16,086	15,950	(136)	1,114	1,219	504
7	**6**	45.50	94.81	49.31	16,086	16,012	(74)	1,114	1,219	364
7	**7**	45.50	209.13	163.63	16,086	16,118	32	1,114	1,219	364
7	**8**	45.50	609.65	564.15	16,086	16,221	135	1,114	1,219	444
7	**9**	45.50	521.96	476.46	16,086	16,252	166	1,114	1,219	314
7	**10**	45.50	530.00	484.50	16,086	16,307	221	1,114	1,219	284
7	**11**	45.50	530.00	484.50	16,086	16,370	284	1,114	1,219	254
7	**12**	45.50	530.00	484.50	16,086	16,364	278	1,114	1,219	244
Average		**45.50**	**292.81**	**247.31**	**16,086**	**16,044**	**(42)**	**1,114**	**1,219**	**437**
8	**1**	44.93	38.49	(6.44)	16,416	16,463	47	519	344	0
8	**2**	44.93	40.66	(4.27)	16,416	16,526	110	519	344	0
8	**3**	44.93	40.05	(4.88)	16,416	16,561	145	519	344	0
8	**4**	44.93	39.72	(5.21)	16,416	16,509	93	519	344	0
8	**5**	44.93	38.63	(6.30)	16,416	16,488	72	519	344	0
8	**6**	44.93	38.52	(6.41)	16,416	16,497	81	519	344	0
8	**7**	44.93	37.35	(7.58)	16,416	16,514	98	519	344	0
8	**8**	44.93	30.09	(14.84)	16,416	16,477	61	519	344	0
8	**9**	44.93	37.35	(7.58)	16,416	16,564	148	519	344	0
8	**10**	44.93	37.35	(7.58)	16,416	16,578	162	519	344	0
8	**11**	44.93	36.73	(8.20)	16,416	16,443	27	519	344	0
8	**12**	44.93	30.22	(14.71)	16,416	16,417	1	519	344	0
Average		**44.93**	**37.10**	**(7.83)**	**16,416**	**16,503**	**87**	**519**	**344**	**0**

Over the first six intervals of HE 7, the MCP was between $63.17/MWh to $125.00/MWh, well above the pre-dispatch projected price of $45.50/MWh. It then climbed above $200/MWh in interval 7 and was above $500/MWh for the remaining five intervals of the hour. The HOEP in HE 7 was $292.81/MWh. Real-time Ontario demand came in heavier than the pre-dispatch projection over the final six intervals and peaked in interval 11 at 16,370 MW, which was 284 MW (2 percent) higher than the pre-dispatch forecast of 16,086 MW. Real-time net exports (over all intervals) were 1,219 MW, 105 MW (9 percent) higher compared to pre-dispatch scheduled net exports of 1,114 MW.

In HE 8, real-time prices fell back to more normal levels. The HOEP was $37.10/MWh, which was 17 percent lower than the pre-dispatch price of $44.93/MWh.

Pre-dispatch and Real-time Conditions

Going into October 6th, five coal units were on planned outages, another was on a planned CO_2 outage, and a sixth was designated as being a NOBA unit for the day. The

NOBA unit was cold as it had been out for more than a month and pre-dispatch conditions had not indicted a need for the unit. Three nuclear units were unavailable due to planned outages as were several oil-fired and gas-fired units.

Table 2-13 provides the total amount of outages and deratings by interval to a gas-fired facility and a coal-fired facility (as described below) between HE 6 to HE 8 as reflected in the difference between the one hour-ahead pre-dispatch and real-time unconstrained schedules.

At the beginning of HE 3, a gas-fired generator notified the IESO that one of its units, which was scheduled to start in HE 4, would not be available due to a faulty start-up control card. The IESO accepted its request to start another unit instead, an outage slip was issued for the unavailable unit up to the beginning of HE 5, and offers were modified accordingly. The outage was subsequently extended to the beginning of HE 7. However, the unit was unable to produce in HE 7, despite having been scheduled for 180 MW in the final pre-dispatch run.

A steam unit at the same generating facility was expected to start-up in HE 5, but was forced out of service due to a stuck steam check valve leading to uncontrolled rising temperatures. The unit was scheduled for 220 MW in HE 5 and 290 MW in HE 6 but due to the outage, was unable to produce. The unit returned in the middle of HE 7, but was derated to 60 MW as only one gas unit was in service.

An additional gas unit started as scheduled in HE 5 but was forced out of service in interval 5 of HE 6 due to boiler problems. This represented a loss of 185 MW in the unconstrained sequence beginning in interval 5 of HE 6 for the remainder of the hour and all of HE 7. In addition, a related combined cycle unit was derated from 185 MW to 126 MW (loss of 59 MW) due to the gas unit outage.

In HE 6, interval 10, a coal unit was forced to derate to 125 MW (the unit was scheduled for 469 MW in the unconstrained sequence) due to a boiler feedpump problem. The derating lasted until the middle of HE 7. It led to a shortfall of 341 MW for intervals 10, 11, and 12 of HE 6, which corresponded with the large jump in MCP to $427.00/MWh in interval 10 from $41.80/MWh in interval 9. The derating also caused a 225 MW shortfall from the unit's 350 MW pre-dispatch schedule over the first 7 intervals of HE 7. The unit then began to ramp-up again and reached full output at 475 MW in the unconstrained schedule by the end of HE 7.

Assessment

Similar to other high price events that occurred during the recent summer period, deratings at fossil-fired units and heavier than expected demand led to the high prices in HE 7. Table 2-14 below presents the fuel type of the price-setting units by interval for HE 7. The resources setting the high prices were a combination of dispatchable load and peaking hydroelectric generators.

Table 2-14: Real-time MCP and Fuel Type of Price Setting Resource
October 6, 2009, HE 6 and HE 7
($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Fuel Type
6	1	31.93	Coal
6	2	32.33	Coal
6	3	35.39	Coal
6	4	35.33	Hydroelectric
6	5	41.42	Hydroelectric
6	6	41.13	Gas
6	7	41.07	Hydroelectric
6	8	41.43	Hydroelectric
6	9	41.80	Hydroelectric
6	10	427.00	Dispatchable Load
6	11	530.13	Hydroelectric
6	12	609.65	Hydroelectric
Average		**159.05**	
7	1	63.17	Hydroelectric
7	2	94.81	Hydroelectric
7	3	125.00	Hydroelectric
7	4	80.17	Hydroelectric
7	5	125.00	Hydroelectric
7	6	94.81	Hydroelectric
7	7	209.13	Hydroelectric

7	**8**	609.65	Hydroelectric
7	**9**	521.96	Hydroelectric
7	**10**	530.00	Hydroelectric
7	**11**	530.00	Hydroelectric
7	**12**	530.00	Hydroelectric
Average		**292.81**	

2.1.6 *Overall Assessment of High-Price Hours*

There were 6 hours with a HOEP greater than $200/MWh in this reporting period. The price movements in these hours generally were consistent with supply/demand conditions prevailing at the time or a consequence of the inconsistency of the two dispatch sequences. In some cases, the HOEP spiked notwithstanding stable supply and demand conditions. As the Panel has noted in previous reports, the two dispatch sequences provide the market with distorted signals and induce market inefficiency. As discussed more fully in Chapter 4 of this report, the Panel believes that it would be useful to explore whether the Ontario market could be modified to operate with a single schedule.

A review of the marginal resources during the high price hours in the 2009 summer months indicated a high frequency of hydro units as the marginal resources during intervals when the MCP was above $200/MWh, including many intervals with MCPs above $500/MWh.

There are numerous factors that influence the offer behavior of hydroelectric resources such as water inflow and storage limits, environmental and regulatory restrictions, the co-ordinated operation of units on a river system, and joint optimization of energy and operating reserves. Furthermore, OPG is obligated to offer operating reserves at all available capacity and is therefore required by the Market Rules to submit accompanying energy offers.[16]

[16] Section 12.2 (a.1) of the Independent Electricity System Operator Electricity Distribution Licence (EI-2008-0088) states that OPG may offer less than the maximum available amount of any category of operating reserve for its coal-fired generation stations to satisfy certain environmental obligations. The License Agreement is available at: http://www.ieso.ca/imoweb/pubs/corp/EI-2003-0088_IESO-Licence.pdf

When peaking generators want to avoid being scheduled for energy, they tend to offer a high price for energy. At times, these units may become marginal in the unconstrained sequence and the high offer price sets the MCP. The implications of the offer strategies currently used by hydroelectric generators will be examined further in the Panel's next report.[17]

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 since 2005. The total number of hours with a low HOEP has continued to increase as Ontario's supply situation has improved and Ontario demand has fallen relative to previous years. There were 1,619 hours when the HOEP was less than $20/MWh in the 2009 summer months, compared to 724 hours in 2008 – an increase of 124 percent. The highest frequency of low price hours occurred in July with 393 hours, representing 53 percent of all hours in the month.

The number of hours when the HOEP was negative has also increased in the 2009 summer months relative to previous summers as shown in Figure 2-15 below. There were 121 negative price hours this summer, which is more than four times the number of negative price hours that occurred in the 2008 summer months. In the summer months between 2005 and 2007, negative price hours were rare as there were only two occurrences (one in 2006 and one in 2007).

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[17] For a general overview of the Panel's approach to opportunity costs and offers by energy-limited resources, see the Panel's *Monitoring Document: Monitoring of Offers & Bids in the IESO-Administered Electricity Markets* (October 2009) available at: http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20091026.pdf

Table 2-15: Number of Hours with a Low and Negative HOEP
May - October, 2005 – 2009
(Number of Hours and %)

	Hours when HOEP<$20/MWh					Hours when HOEP<$0/MWh				
	2005	**2006**	**2007**	**2008**	**2009**	**2005**	**2006**	**2007**	**2008**	**2009**
May	11	17	115	193	210	0	0	0	6	24
June	25	14	67	87	295	0	0	0	0	42
July	4	30	57	144	393	0	0	0	16	14
August	3	4	11	126	236	0	0	0	4	11
September	0	63	45	90	297	0	1	1	0	25
October	9	21	36	84	188	0	0	0	2	5
Total	52	149	331	724	1,619	0	1	1	28	121
Period Over Period Change (%)	n/a	187	122	119	124	n/a	100	0	2,700	332

The primary factors leading to a low or negative HOEP are:

- Low market demand
- Abundant low price supply
    - Nuclear
    - Baseload Hydro
    - Self-scheduling and intermittent generation
    - Fossil generation up to minimum loading point
    - Other hydro generation offering energy at prices less than $20/MWh

Additional factors include:

- Demand deviation: the forecast peak demand that is used in PD is typically greater than the average RT demand that determines the HOEP. Two factors typically cause the deviation:
    - Demand over-forecast: This can lead to over-scheduling imports in pre-dispatch, placing downward pressure on the HOEP because in RT these imports are moved to the bottom of the offer stack.
    - Peak vs. average demand: Even when the peak demand is accurately forecast, a low HOEP can result because of lower RT demand in other intervals. This occurs because some imports that are scheduled based on-peak demand may be needed in other intervals.

- Failed export transactions: These can place downward pressure on the HOEP as these failures represent a reduction in demand in RT relative to PD.

2.2.1 *Low Price Hours*

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. Nuclear, self-scheduling and intermittent resources,[18] fossil units (up to their minimum loading point),[19] and baseload hydro are the types of generators that typically offer to operate at low and often negative prices. Other hydroelectric resources (both run-of-the river and peaking) may also want to operate at very low prices in some circumstances, especially when an abundant supply of water is available and spilling is the only alternative. Under these conditions, hydro resources will submit low price offers in an effort to get scheduled.

Table 2-16: Supply During Low Price (<$20/MWh) Hours
May – October 2009
(MW)

Month	Low Price Supply						
	Scheduled Nuclear	Scheduled Self-Scheduling and Intermittent	Scheduled Fossil	Scheduled Baseload Hydro*	Other Scheduled Hydro	Other Unscheduled Generation offered < $20/MWh	Total Low Price Supply
May	7,943	1,191	475	1,985	2,632	1,467	15,693
June	9,461	1,306	748	1,975	2,091	1,250	16,831
July	10,010	918	670	2,168	1,910	1,775	17,451
August	10,134	915	577	2,087	1,824	1,446	16,983

[18] Wind output is typically highest during off-peak hours. Wind generators submit very low offer prices to ensure they will be scheduled. This represents an additional source of low price supply in low price hours and will become an increasingly important issue as wind capacity grows in Ontario (see the Panel's July 2009 Monitoring Report, pp. 22-24). Increased self-scheduling output at new gas-fired generators that are commissioning also represents a source of low price supply that can contribute to low market prices.

[19] In certain circumstances, some fossil units may want to run at their minimum loading (MLP) point during low price hours and submit low price offers for the MW up to MLP in order to remain available for upcoming on-peak hours. There are also fossil units that require being online over all hours of the day as their by-product from energy production (eg. steam) is used by other industrial processes.

September	9,484	909	506	2,067	1,152	1,226	15,344
October	8,613	1,293	567	1,918	1,236	1,412	15,039
Average	9,401	1,138	591	2,050	1,807	1,236	16,223

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

The demand conditions (specifically monthly average Ontario Demand and Net Exports) over the low price hours this summer are presented in Table 2-17. The difference between low price supply and total demand (Ontario Demand plus exports) over all low price hours is shown in the final column of Table 2-17. On average, low price supply was 1,350 MW (9 percent) higher than total demand during the low price hours over the recent six month period and as high as 1,632 MW (10 percent) greater than total demand in July 2009.

Table 2-17: Demand and Excess Low Price Supply During Low Price (< $20/MWh) Hours
May – October 2009
(MW)

Month	Demand			Total Low Price Supply	Excess Supply (Low Price Supply - Demand)
	Ontario Demand	Net Exports	Total		
May	12,549	1,702	14,251	15,693	1,442
June	13,394	1,984	15,378	16,831	1,453
July	14,039	1,780	15,819	17,451	1,632
August	13,854	1,764	15,618	16,983	1,365
September	13,276	1,037	14,313	15,344	1,031
October	13,264	597	13,861	15,039	1,178
Average	13,396	1,477	14,873	16,223	1,350

Table 2-18 below presents additional monthly summary data over the low price hours for the period May to October 2009 including failed net exports, the difference between pre-dispatch demand (forecast of peak interval) and real-time average demand (referred to as 'Demand Deviation'), and average pre-dispatch and real-time prices. As discussed above, demand deviation can result from demand forecast errors or simply result from differences in peak and average demand within an hour. Based on the average magnitudes associated with the factors that contribute to a low HOEP, excess low price supply relative to total demand (Ontario Demand plus exports) was the main reason for the low HOEP outcomes over the recent six-month period, followed by demand deviation, and failed net exports.

Table 2-18: Average Monthly Summary Data for Low Price (< $20/MWh) Hours May - October 2009 ($/MWh and MW)

	Number of Low Price Hours	Excess Supply (Low Price Supply - Demand)	PD Average Demand (MW)	RT Demand (MW)	Demand Deviation (MW)	Failed Net Exports (MW)	Pre-dispatch Price ($/MWh)	HOEP ($/MWh)	Difference (RT - PD) ($/MWh)
May	210	1,442	12,827	12,549	278	101	18.74	6.16	(12.58)
June	295	1,453	13,706	13,394	312	163	19.21	5.88	(13.33)
July	393	1,632	14,371	14,039	332	235	22.98	8.08	(14.90)
August	236	1,365	14,204	13,854	350	139	19.69	8.99	(10.70)
September	297	1,031	13,589	13,276	313	106	19.55	8.88	(10.67)
October	188	1,178	13,559	13,264	295	66	26.78	11.79	(14.99)
Average	270	1,350	13,709	13,396	313	135	21.16	8.30	(12.86)

2.2.2 <u>*Negative Price Hours*</u>

Of the 1,619 low price hours (which represents 37 percent of total operating hours) between May and October 2009, the HOEP was below $0/MWh in 121 hours (7 percent of all low price hours and 3 percent of total operating hours). This is substantially higher than the 28 negative price hours observed during the 2008 summer months as presented in Table 2-15 above.

The lowest HOEP over the recent summer occurred on June 7, 2009 HE 6 at -$52.08/MWh. This was also the lowest observed HOEP since market opening surpassing a HOEP of -$51.00/MWh on March 29, 2009 (HE 2- HE 4).

At least one negative HOEP occurred in all 2009 summer months while the greatest frequency of negative price hours occurred in June (42 hours) and the lowest frequency occurred in October (5 hours). Of the 42 hours in June, 35 hours occurred during the first seven days of the month. A major factor that contributed to low and often negative

HOEPs during the first week in June 2009 was an abundance of self-scheduling and intermittent generation. Their output exceeded 1,800 MW in many hours, largely due to a gas-fired plant commissioning (the plant produced over 900 MW during 17 of the 35 negative price hours between June 1 and June 7, 2009).

Although Surplus Baseload Generation (SBG) conditions refer to the supply and demand situation in the constrained schedule, they are strongly correlated with HOEP which is typically negative during these events.[20] Tables 2-19 and 2-20 present the average supply and demand conditions respectively during the negative price hours between May and October 2009. Real-time output by generation type along with other unscheduled generation with offers less than $0/MWh is presented in Table 2-19 (called 'negative price supply'). Along with a large amount of available nuclear offers[21] (an average of 9,281 MW per month), there was significant baseload hydroelectric supply (1,591 MW), self-scheduling and intermittent generation (1,139 MW), and fossil generators at their MLP (321 MW) all offering a portion of their capacity at negative prices. Additionally, there was an average of 974 MW of other generation (MW from all unscheduled offers below $0/MWh) not selected in the unconstrained schedule due to an abundance of low price supply.

[20] The relationship between negative HOEP and SBG conditions was discussed in the Panel's July 2009 Monitoring Report, pp 218-235.
[21] Nuclear availability (MW of offers available below $0/MWh) is used rather than the scheduled MW because nuclear units are often the marginal resources during negative price hours.

Table 2-19: Supply During Negative Price Hours
May – October 2009
(MW)

Month	Negative Price Supply						
	Scheduled Nuclear	Scheduled Self-Scheduling and Intermittent	Scheduled Fossil	Scheduled Baseload Hydro*	Other Scheduled Hydro	Other Unscheduled Generation Offered < $0/MWh	Total Negative Price Supply
May	8,255	1,275	327	1,511	2,339	1,017	14,724
June	9,264	1,502	691	1,370	1,702	633	15,162
July	10,255	886	185	1,530	940	1,128	14,924
August	10,210	839	258	1,635	1,286	926	15,154
September	9,186	1,075	189	1,654	835	866	13,805
October	8,518	1,258	274	1,845	1,077	1,272	14,244
Average	9,281	1,139	321	1,591	1,363	974	14,669

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

Monthly Ontario Demand, net exports, and total demand are shown in Table 2-20. On average, the difference between low price supply (from Table 2-19) and total demand over the negative price hours was 908 MW for the six-month period (with a range between 598 MW in September 2009 and 1,024 MW in May 2009).

Table 2-20: Demand and Excess Negative Price Supply During Negative Price Hours
May – October 2009
(MW)

Month	Demand			Total Negative Price Supply	Excess Supply (Negative Price Supply - Demand)
	Ontario Demand	Net Exports	Total		
May	12,070	1,630	13,700	14,724	1,024
June	12,191	1,960	14,151	15,162	1,011
July	11,942	2,072	14,014	14,924	910
August	12,389	1,925	14,314	15,154	840
September	12,509	698	13,207	13,805	598
October	12,337	841	13,178	14,244	1,066
Average	12,240	1,521	13,761	14,669	908

Table 2-21 below lists average monthly summary data for the 121 hours negative price hours between May and October 2009. The average one-hour ahead pre-dispatch price for the negative price hours was $11.07/MWh, well above the average HOEP of -$6.70/MWh. Pre-dispatch to real-time price differences were smallest in June to August 2009 and largest during October 2009 (-$33.13/MWh), although October only contained 5 hours with a negative HOEP. Failed net exports averaging 313 MW and demand deviation averaging 238 MW both placed downward pressure on real-time prices relative to pre-dispatch projections in these hours, but were much smaller than the average excess negative price supply of 908 MW.

Table 2-21: Average Monthly Summary Data for Negative Price Hours May - October 2009 ($/MWh and MW)

	Number of Negative Price Hours	Excess Supply (Negative Price Supply - Demand)	PD Average Demand (MW)	RT Demand (MW)	Demand Deviation (MW)	Failed Net Exports (MW)	Pre-dispatch Price ($/MWh)	HOEP ($/MWh)	Difference (RT - PD) ($/MWh)
May	24	14,724	12,441	12,070	371	250	10.96	(4.67)	(15.63)
June	42	15,162	12,330	12,191	139	306	2.72	(9.59)	(12.31)
July	14	14,924	12,167	11,942	225	392	5.37	(5.24)	(10.61)
August	11	15,154	12,650	12,389	261	388	8.41	(4.88)	(13.29)
September	25	13,805	12,834	12,509	325	161	14.87	(6.77)	(21.64)
October	5	14,244	12,507	12,337	170	380	24.09	(9.04)	(33.13)
Average	20	14,669	12,488	12,240	248	313	11.07	(6.70)	(17.77)

2.2.3 *June 7, 2009 HE 6*

On June 7, 2009, HE 6, the HOEP fell to -$52.08/MWh, which represents the lowest HOEP since market opening. The previous record low HOEP was -$51.00/MWh set on March 29, 2009 in three off-peak hours (HE 2 to HE 4). Export failures due to surplus generation conditions in other jurisdictions and a significant amount of supply from a facility that was commissioning were the main contributors to the low price in HE 6.

Prices and Demand

Table 2-22 presents pre-dispatch and real-time summary statistics for HE 5 to HE 7 on June 7, 2009. Pre-dispatch prices for all three hours were negative and prices in real-time came in even lower. In HE 6, the pre-dispatch price was -$11.20/MWh but the HOEP was much lower at -$52.08/MWh, a reduction from pre-dispatch to real-time of $40.88/MWh. In HE 7, the HOEP moved up to -$35.85/MWh.

June 7th was a Sunday and Ontario Demand was relatively low at 11,086 MW in HE 6 (within the lowest 1 percent of all hours during the 2009 summer period). At 11,086 MW, average real-time Ontario demand was almost identical to the pre-dispatch projection of 11,098 MW. The difference of only 12 MW indicates that demand forecast error did not contribute significantly to the drop in HOEP relative to pre-dispatch. However, there was a large quantity of net export failures in HE 6 totaling 754 MW (7 percent of total forecast demand). In HE 7, net exports failures totaled 624 MW while the difference between real-time and pre-dispatch Ontario demand was 225 MW.

Table 2-22: One-hour Ahead PD and RT MCP, Demand, and Net Exports June 7, 2009, HE 5 to HE 7 ($/MWh and MW)

Delivery Hour	PD MCP ($/MWh)	HOEP ($/MWh)	Price Diff (HOEP-PD) ($/MWh)	PD Ontario Demand (MW)	Average Ontario Demand (MW)	Diff Ontario Demand (RT-PD) (MW)	PD Net Exports (MW)	RT Net Exports (MW)	Net Export Failure (MW)
5	-12.20	-15.22	-3.02	10,713	10,962	249	1,837	1,587	-250
6	-11.20	-52.08	-40.88	11,098	11,086	-12	1,887	1,133	-754
7	-10.00	-35.85	-25.85	11,820	11,595	-225	1,833	1,209	-624

Pre-dispatch and Real-time Conditions

On the morning of June 6, 2009, all units at a gas-fired facility were brought online to perform commissioning tests, which added to the amount of generation required to run during the low price hour on June 7 HE 6. The commissioning continued until the end of the day on June 9 representing over 900 MW of supply in all hours over the 4 days. Excluding the commissioning gas-fired unit, other self-scheduled and intermittent generation produced 719 MW in HE 6. Of this, 96 MW was produced by wind generators.

As a result of SBG conditions, nuclear units were beginning to be dispatched down by the optimization tool as early as HE 17 on June 6. To relieve the excess supply conditions projected for the remainder of June 6 and the morning hours on June 7, three nuclear units at a single facility were manoeuvred. One nuclear unit was reduced by 400 MW in HE 21 on June 6, a second was completely shut down in HE 22, and a third was reduced by 250 MW in HE 24. This represented a combined 1,475 MW of reduced nuclear capacity. An additional four nuclear units were reduced at two separate nuclear facilities for a combined 420 MW in HE 1 and HE 2 on June 7. Overnight nuclear reductions totaled over 1,900 MW across three nuclear facilities. The removal of this nuclear supply placed upward pressure on HOEP and partially counteracted the downward influences on HOEP specified above. However, even with these nuclear reductions the HOEP remained notably negative during the morning hours on June 7.

Both the MISO and PJM jurisdictions were experiencing surplus baseload generation conditions during the early morning hours of June 7, 2009. There were 450 MW of exports curtailed by the external system operator in HE 6 that were destined for PJM through Michigan. Additionally, 304 MW of exports destined for New York were cut as they were not economically selected in the New York market. These failed exports exaggerated the surplus conditions in Ontario

Many hydroelectric resources were forced to spill their water supply during the SBG conditions. The majority of hydroelectric resources were constrained-down as much as possible while still respecting environmental and regulatory obligations. By HE 6 on June 7, there was in excess of 1,300 MW of hydroelectric spill in to accommodate the excess supply.

Assessment

Table 2-23 shows that nuclear units were the price-setting resource in all intervals of HE 6 on June 7, 2009 as they typically are during hours when the MCP is negative.

Table 2-23: Real-time MCP and Fuel Type of Price Setting Resource June 7, 2009, HE 6 ($/MWh)

Delivery Hour	Interval	RT MCP ($/MWh)	Fuel Type
6	1	-53.00	Nuclear
6	2	-52.00	Nuclear
6	3	-52.00	Nuclear
6	4	-52.00	Nuclear
6	5	-52.00	Nuclear
6	6	-52.00	Nuclear
6	7	-52.00	Nuclear
6	8	-52.00	Nuclear
6	9	-52.00	Nuclear
6	10	-52.00	Nuclear
6	11	-52.00	Nuclear
6	12	-52.00	Nuclear
Average		**-52.08**	

In HE 6 on June 7, 2009, several factors contributed to the low HOEP of -$52.08/MWh including excess baseload generation, production from self-scheduling and intermittent resources (including a significant gas-fired unit that was commissioning), and a significant amount of export failures, partly due to similar excess supply conditions experienced in neighboring jurisdictions.

3. Anomalous Uplifts

During the study period May to October 2009 there were 4 hours when the payments for operating reserve exceeded $100,000. There were no hours when the three other anomalous uplift criteria were met (hourly CMSC payments greater than $500,000, daily CMSC payments greater than $1,000,000 at a single intertie zone, or hourly IOG payments greater than $500,000).

3.1 Hourly Operating Reserve Payments Greater than $100,000

Hourly operating reserve payments exceeded $100,000 in four hours in August 2009:

- August 8, 2009 (HE 19) – Total OR payment was $185,588
- August 14, 2009 (HE 19) – Total OR payment was $195,859
- August 17, 2009 (HE 10) – Total OR payment was $193,689
- August 18 (HE 16) – Total OR payment was $149,069

OR payments in these hours were largely driven by the tight supply conditions relative to prevailing demand resulting from factors such as generator deratings/outages and demand forecast errors as reflected by the high MCP and OR prices.[22] Table 2-24 below presents energy and operating reserve MCPs by interval over the four hours when OR payments exceeded $100,000. Both energy and OR prices were very high during these hours. The HOEP ranged from a low of $199.35/MWh on August 18, HE 16 to $382.64/MWh on August 8, HE 19. Average hourly OR prices were also high and exceeded $120.00/MWh for all OR categories and OR MCP reached a maximum of $1,998/MWh in the final interval on August 14, HE 19, which is identical to the energy MCP.

Table 2-24 – Energy and Operating Reserve MCPs
August 8 (HE 19), 14 (HE 19), 17 (HE 10), and 18 (HE 16), 2009
($/MWh)

Day	Hour	Interval	Energy MCP	10N MCP	10S MCP	30R MCP
08/08/2009	19	1	169.90	75.00	75.00	74.90
08/08/2009	19	2	67.68	30.10	30.10	30.00
08/08/2009	19	3	113.31	75.00	75.00	74.90
08/08/2009	19	4	664.99	510.49	510.49	510.39
08/08/2009	19	5	240.14	100.00	100.00	99.91
08/08/2009	19	6	250.14	100.00	100.00	99.91
08/08/2009	19	7	254.50	100.00	100.00	99.91
08/08/2009	19	8	240.14	100.00	100.00	99.91
08/08/2009	19	9	235.13	100.00	100.00	99.91
08/08/2009	19	10	240.13	100.00	100.00	99.91
08/08/2009	19	11	240.14	100.00	100.00	99.91
08/08/2009	19	12	136.88	75.00	75.00	74.91
Average			237.76	122.13	122.13	122.04

[22] The factors that contributed to the high prices on August 8, 14, and 17 are discussed in detail in section 2.1 of Chapter 2.

08/14/2009	19	1	1999.99	1,380.96	1,380.96	1,380.86
08/14/2009	19	2	240.14	100.00	100.00	99.90
08/14/2009	19	3	226.43	100.00	100.00	99.90
08/14/2009	19	4	169.90	75.00	75.00	74.90
08/14/2009	19	5	135.04	75.00	75.00	74.90
08/14/2009	19	6	129.13	75.00	75.00	74.90
08/14/2009	19	7	74.23	30.10	30.10	30.00
08/14/2009	19	8	70.73	30.10	30.10	30.00
08/14/2009	19	9	64.12	30.01	30.01	30.00
08/14/2009	19	10	63.46	30.00	30.00	30.00
08/14/2009	19	11	62.49	30.00	30.00	30.00
08/14/2009	19	12	36.47	4.62	4.62	4.62
Average			272.68	163.40	163.40	163.33
08/17/2009	10	1	75.16	30.00	30.00	30.00
08/17/2009	10	2	116.92	30.00	30.00	30.00
08/17/2009	10	3	106.00	30.00	30.00	30.00
08/17/2009	10	4	159.69	30.10	30.10	30.00
08/17/2009	10	5	204.59	75.00	75.00	74.90
08/17/2009	10	6	252.83	75.00	75.00	74.91
08/17/2009	10	7	277.83	100.00	100.00	99.90
08/17/2009	10	8	301.67	100.00	100.00	99.90
08/17/2009	10	9	200.87	30.10	30.10	30.00
08/17/2009	10	10	252.84	75.00	75.00	74.90
08/17/2009	10	11	645.31	100.00	100.00	99.90
08/17/2009	10	12	1,998.00	1,998.00	1,998.00	1,998.00
Average			382.64	222.77	222.77	222.70
08/18/2009	16	1	110.61	75.00	75.00	74.90
08/18/2009	16	2	123.13	75.00	75.00	75.00
08/18/2009	16	3	138.05	100.00	100.00	100.00
08/18/2009	16	4	148.13	100.00	100.00	100.00
08/18/2009	16	5	148.14	100.00	100.00	100.00
08/18/2009	16	6	138.93	100.00	100.00	100.00
08/18/2009	16	7	138.93	100.00	100.00	100.00
08/18/2009	16	8	144.74	100.00	100.00	100.00
08/18/2009	16	9	514.81	419.81	419.81	419.81
08/18/2009	16	10	501.02	406.02	406.02	406.02
08/18/2009	16	11	148.13	100.00	100.00	100.00
08/18/2009	16	12	137.57	100.00	100.00	100.00
Average			199.35	147.99	147.99	147.98

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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 includes three topics:

- The OPA's Demand Response Phase 3 (DR3) program.
- OPG's 2009 CO2 Emissions Strategy and 2010 CO2 Emissions Strategy.
- The Lake Erie Circulation (LEC) and Phase Angle Regulators (PARs) at the Michigan Intertie.

In section 3 the Panel comments on new issues arising:

- Issues associated with the interties in the Northwest area.
- The expiration of the OPG Rebate mechanism for its non-prescribed assets.
- The actions of a combined cycle market participant.
- The impact of the new Quebec DC intertie.

2. Changes to the marketplace since the Panel's last report

2.1 The OPA's Demand Response Phase 3 (DR3) program.

Introduction

The Ontario Power Authority (OPA) has been given a mandate by the Government of Ontario to take a leadership role in electricity conservation and demand management and was directed to reduce Ontario peak demand by 6,300 MW by 2025.[23] OPA set a target load reduction of 2,700 MW by 2010, and an additional 3,600 MW by 2025.[24]

To meet its target, OPA has developed 14 programs[25] ranging from increasing consumers' awareness and funding the replacement of inefficient appliances, to financing load shifting and load reduction. Demand response (DR) programs are initiatives that encourage either load shifting (from on-peak to off-peak hours) or load reduction (reducing consumption when certain criteria are met). There is no preset target for the amount of demand response to be developed.

The OPA has developed three phases of demand response programs:

- DR1: The program was initiated in 2005. Each month, a DR participant submits a strike price to the OPA which must be equal to or exceed the floor price provided by OPA. When the IESO's three-hour ahead pre-dispatch price exceeds the strike price, the participant may indicate to the OPA that it will reduce its consumption for that hour and up to two hours after the event. The participant will be paid the strike price times the estimated reduction in consumption.[26]
- DR2: The program started to operate in July 2009. A participant is contracted to shift its consumption from on-peak hours to off-peak hours. Currently there are about 130 MW of load registered in the program.[27]
- DR3: The program was initiated in August 2008. The activation of DR3 is triggered by a supply cushion threshold that is established after consultation with the IESO. The program has two types of contracts: up to 100 hours or up to 200 hours of activation annually. Each activation is for a minimum of 4 hours. OPA

[23] Ontario Ministry of Energy News Release, "Securing Reliability for Ontario's Long Term Electricity Supply", June 13, 2006.
[24] http://www.powerauthority.on.ca/Storage/75/7112_Paul_Shervill_Carbon_Offsets_Conference_Ottawa_June_17-08.pdf
[25] See OPA's "2007 Final Conservation Results", dated February 2009: http://www.powerauthority.on.ca/Storage/96/9130_2007_Conservation_final_results_report_final_March_3-09.pdf
[26] OPA has not published any information on either the registration or the activation of DR1.
[27] OPA has not published any information on either the registration or the activation of DR2.

provides each contracted resource with an upfront payment, which depends on the contract type, the location of the resource, and the length of the contract (i.e. 1, 3, or 5 years) and $200/MWh for each activation.[28]

The DR1 program was assessed in two previous Panel reports.[29] The DR2 program began operation in July 2009. The Panel will assess it in a future report once more information is available. The first eight months of DR3's operation was reviewed in the Panel's January and July 2009 Monitoring Reports.[30] In the current report, we continue our assessment of DR3.

The Panel concluded in its prior reports that the DR3 program was inefficient from a short-term perspective. This followed from an assessment of the possible efficiency gains from reducing load that is willing to pay the HOEP but is not willing to pay the higher Richview price (which reflects the marginal cost of electric power more accurately than the HOEP). The Panel found that under the DR3 program the estimated value attached by loads to foregone consumption could vastly exceed the Richview price (i.e. approximately the marginal cost of generation).

The Panel did note that the program had potential to be efficient from a long-term perspective if it avoided the cost of building a corresponding amount of new peaking generation. That assessment compared the portion of the cost of a new peaking generator that could not be recovered from the market (i.e. that OPA would likely have to compensate through procurement contracts) with the consumer surplus on foregone consumption.[31] This analysis showed that, while a perfectly targeted DR3 type program

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[28] For details, see: http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=314

[29] The Panel's December 2006 Monitoring Report, pp 135-141, and December 2007 Monitoring Report, pp 142-146.

[30] The Panel's January 2009 Monitoring Report, pp 197-213, and July 2009 Monitoring Report, pp 191-197.

[31] Essentially the comparison is between the avoided cost of a peaking generator (which is equal to the revenue from the market plus the cost unrecovered from the market) and the consumer valuation of the offsetting consumption (which is equal to the consumer surplus plus the payment to generators through the market). Because the revenue from the market and the payment to generators through the market cancel each other, only the cost unrecovered from the market and the consumer surplus need to be compared.

might theoretically increase efficiency in the long-run (i.e. the benefit of avoiding a peaking generator could be greater than the cost of reducing consumption by DR resources), it would be more efficient if payments to forego consumption were set at a lower rate so as not to attract marginal participants whose value of foregone consumption is greater than the avoided cost of building a new peaking generator. Moreover, as a practical matter, the existing methodology of targeting high-demand or high-priced hours should be significantly improved in order to achieve the purpose of reducing the need for new peaking capacity. Accordingly, the Panel recommended that OPA review the effectiveness and efficiency of the program and reduce the payment to loads to forgo consumption. The Panel also recommended that OPA and IESO work towards improving the supply cushion calculation upon which activations are based.

At a recent discussion with MAU, the OPA described the primary objective it has for the DR3 program as reducing the need for new peaking capacity. In order to achieve that objective OPA is seeking to quickly establish industry capability and awareness of the program. In OPA's view its overall priorities make it difficult to assess the success of the demand response programs on a pure efficiency basis. For example:

- They are mandated to establish DR capability,
- The DR3 participants do not inherently have the flexibility of many dispatchable generation resources,
- DR resources may have to be activated for testing purposes regardless of short-term efficiency so that they are available when needed,
- To gain longer term commitments from DR participants, the OPA has judged that it must provide participants compensation that is both predictable and sufficient, and
- Setting DR compensation at too low a level would not only see a lack of DR participation, but would also represent a payment that is insufficient to build peaking generation, since payments would not cover costs that the peaking generators would need to recover (such as fixed costs) but could not recover from the market.

In the OPA's view limitations on the ability of DR3 participants to offer demand response are not unlike some other resources in the market such as hourly imports and fossil plant cost guarantees and minimum run times, which all result in reduced market efficiency if compared on the same basis as DR.

Activation Triggers

Since January 2009, OPA has modified its day-ahead supply cushion triggers to account for differences in import offers day-ahead and day-at-hand, and included a pre-dispatch price trigger as described below.

Table 3-1 below lists the IESO supply cushion triggers since the program's inception. A supply cushion trigger is the minimum supply cushion that triggers activation. Thus, the lower the supply cushion trigger, the less likely it is that DR3 will be activated. In response to the increasingly likely situation that DR3 would be activated during SBG hours, on September 8, 2009 the OPA implemented an additional trigger before an activation is carried out: even if the supply cushion criterion is met, the pre-dispatch price[32] must also be greater than the "trigger floor price" for at least one of the upcoming hours within a potential four-hour activation period. The new trigger followed a Panel recommendation in its December 2008 Monitoring Report that "the OPA should develop other triggers such as a pre-dispatch price threshold that could be better indictors of tight supply/demand conditions."[33]

[32] The pre-dispatch price used to trigger an action is the pre-dispatch price at a point of time. For example, at HE 6, the IESO DSO produces a series of pre-dispatch prices for all hours after HE 6. DR may be activated if one among the following four hours has a pre-dispatch price that is greater than the trigger price and if the supply cushion is lower than the supply cushion trigger.
[33] The Panel's December 2008 Monitoring Report, p 213.

Table 3-1: IESO Supply Cushion and Price Triggers for Activation of DR3 Program August 2008 – October 2009 (% and $/MWh)

Effective Period	IESO Supply Cushion Trigger (%)		Pre-dispatch Trigger Floor Price (>$/MWh)
	100-Hour Contract	200-Hour Contract	
August 1 - August 26, 2008	24	25	n/a
August 27 - September 17, 2008	29	30	n/a
September 18 - December 1, 2008	18	23	n/a
December 2, 2008 – January 4, 2009	0	0	n/a
January 5 – May 7, 2009	11	12	n/a
May 8 - August 12, 2009	25	28	n/a
August 13 – September 07, 2009	42.7	44	n/a
September 8 – October 12, 2009*	32	34	29.07
October 13 – October 18, 2009	25.1	25.6	40.25
October 19 – October, 31 2009	25.1	25.6	45.41

*The program was suspended from September 18 to October 12, 2009

The Panel has previously observed that the IESO's supply cushion formula does not accurately reflect available supply because it includes all import offers even though some offers cannot be scheduled because of transmission limitations and because it does not take into account generator deratings or forced outages, both of which bias the supply cushion upwards.[34] However, even if the supply cushion triggers were revised to take into account the differences in import offers day-ahead and day-at-hand, this does not directly deal with the availability problem and thus may not help improve the accuracy of the supply cushion. The Panel continues to be concerned by the lack of progress in improving the IESO's supply cushion calculation because it is directly linked to the activation of the DR3.

[34] The Panel's January 2009 Monitoring Report, pp 197-213. On June 2, 2009, the IESO responded that "the IESO acknowledges the differences in the MSP and IESO supply cushion calculations and will consider the appropriate changes. At this time, the IESO supply cushion calculation is … consistent with the capacity calculation that is published in the System Status Report and the IESO believes that being consistent with this application is important."

Activations

Table 3-2 below shows all activations since the DR3 program's inception. In total, it has been activated on 21 occasions (or 84 hours) for 200-hour participants, and 13 occasions (or 52 hours) for 100-hour participants. The total reduction in consumption was 4,242 MWh, of which 1,667 MWh came from customers with 100-hour contracts and 2,575 MWh came from customers with 200-hour contracts. The table also provides the average HOEP (paid by load) and the real-time Richview shadow price (the approximation of incremental cost of generation to meet demand). The potential short term efficiency gain is the excess of the Richview price over the HOEP because it is efficient for a load to reduce its consumption if its value of consumption is lower than the Richview price but higher than the HOEP.

Table 3-2: DR3 Activations, HOEP and the Richview Price
August 2008 – October 2009
(MW and $/MWh)

Date	Activation Hours	100 Hr Contract Activated (MW)	200 Hr Contract Activated (MW)	Average HOEP ($/MWh)	Average Richview Price ($/MWh)	Difference (Richview - HOEP) ($/MWh)
08/18/2008	15-18	1.6	1.4	87.45	94.93	7.48
09/02/2008	14-17	14.3	1.4	136.91	180.64	43.73
09/03/2008	14-17	14.3	1.4	103.69	108.14	4.46
09/04/2008	15-18	14.3	1.4	76.99	89.52	12.54
09/12/2008	14-17	14.3	1.4	52.59	51.65	-0.95
09/17/2008	15-18	14.3	1.4	40.89	45.34	4.45
10/28/2008	17-20	0	47.6	69.26	64.33	-4.93
10/29/2008	18-21	0	47.6	72.98	68.97	-4.02
11/10/2008	18-21	0	48.4	72.26	71.94	-0.33
11/17/2008	18-21	0	48.4	75.47	83.14	7.67
11/18/2008	17-20	35.0	48.4	82.03	83.15	1.12
11/19/2008	17-20	35.0	48.4	101.04	101.89	0.85
11/24/2008	17-20	35.0	48.4	97.39	121.07	23.68
11/26/2008	18-21	0	48.4	71.66	75.87	4.21
12/01/2008	17-20	0	48.4	84.83	85.99	1.17
06/25/2009	14-17	0	9.8	46.76	45.72	-1.04
08/14/2009	13-16	36.0	12.2	48.25	57.41	9.17
08/17/2009	14-17	69.3	22.2	64.32	51.41	-12.91
09/09/2009	14-17	0	22.5	29.13	35.53	6.41
09/10/2009	13-16	61.7	67.5	31.37	36.85	5.47
09/14/2009	14-17	71.5	67.5	39.26	44.36	5.11

Total (MWh) /Average ($/MWh)		1,667	2,575	70.69	76.09	5.40

The potential short term efficiency gains (excess of the Richview price over the HOEP) varied from -$12.91/MWh to $43.73/MWh for the 21 activations, with an average of $5.40/MWh across all events. That is, if the value of consumption that was foregone under the program was the HOEP ($70.69/MWh on average), then on average, the maximum short term efficiency gain over the 13 month period was $5.40/MWh. Given that participants were paid $200/MWh to forego consumption, it is highly likely that most if not all foregone consumption was valued above the average Richview price ($76.09/MWh).[35] This implies that the program reduces short-term market efficiency. This outcome would be the same if analysis were restricted to DR activations within the 6 month scope of this report.

Targeting of Activations

OPA's stated objective for the DR3 program has been:

> "*To assist in reducing the system peak demand during pre-determined scheduled periods noted for high-demand, high prices and tight supply by contracting with a broad range of consumers to participate in managing the electricity needs of Ontario.*" [36]

If DR3 is to achieve its stated goal, the program should lead to activations in high-demand, high price or tight supply periods. It is recognized that the intent of the program is not to reduce price. One way to assess whether this goal has been achieved is to rank,

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[35] In other words, participants would forego consumption if and only if the value they received from the DR3 payment ($200) and avoided consumption charges (i.e. the HOEP, Global Adjustment, and other fees) exceeded the value of consumption.
[36] OPA: "A Progress Report on Electricity Conservation – 2008 Quarter 2", page 29, http://www.powerauthority.on.ca/Storage/82/7717_Q2_2008_Conservation_progress_report_updated_Aug._29.pdf

from highest to lowest, the Ontario demand and HOEP over a period of time and to see whether activations occurred during hours of high-demand or high HOEP. [37]

Table 3-3 shows the highest hourly Ontario demand and HOEP within each of the 21, 4-hour DR3 activation events and how that demand or HOEP ranks relative to the highest demand or HOEP over the 15-month period from August 2008 to October 2009 as well as within the month that the activation event occurred.[38]

Table 3-3: Rank of the Peak Demand and HOEP during Hours with DR3 Activations August 2008 to October 2009

Date	Activation Hours	Highest Demand During Activation (MW)	Rank of Highest Demand in each Activation During Study Period (Aug 2008 to Oct 2009*	Rank of the Highest Demand During Activation During Activation Month	Highest HOEP During Activation ($/MWh)	Rank of Highest HOEP in each Activation During Study Period (Aug 2008 to Oct 2009*	Rank of Highest HOEP in each Activation During Activation Month
08/18/2008	15-18	22,477	29	4	100.12	155	32
09/02/2008	14-17	22,643	**21**	3	214.00	**21**	5
09/03/2008	14-17	23,016	**11**	1	105.87	118	24
09/04/2008	15-18	21,606	132	15	83.25	360	58
09/12/2008	14-17	18,925	1,497	75	78.53	437	78
09/17/2008	15-18	18,793	1,641	91	41.81	3,560	400
10/28/2008	17-20	19,320	1,116	2	83.85	348	25
10/29/2008	18-21	19,322	1,113	1	87.72	281	19
11/10/2008	18-21	19,669	865	35	84.69	337	49
11/17/2008	18-21	20,267	544	17	77.60	453	72
11/18/2008	17-20	20,693	368	4	87.01	296	39
11/19/2008	17-20	21,054	257	1	114.93	81	3

[37] As the Panel observed in the past, a tight supply condition is usually reflected by a high price or price spike. See, for example, the Panel's March 2003 Monitoring Report, pp 11-16. As a result, the rank of HOEP should have provided a reasonable approximation of the rank of supply condition. Ideally, a tight supply/demand condition should be directly measured by a tight supply cushion. However, the Panel does not believe the IESO's supply cushion has accurately reflected the actual supply/demand conditions (see the Panel's January 2009 Monitoring Report, pp 197-213)..

[38] Ideally demand and HOEP would be ranked over a January to December calendar year since the 100 or 200 hour contracts apply on this basis. However, the DR3 program has not been in operation for a full calendar year. As such, the rankings are based on the 15 month period (August 2008 to October 2009) during which the program has operated. A monthly ranking is also provided in order to assess how well DR3 was activated in a specific month if the activation was deemed necessary for testing purposes

11/24/2008	17-20	21,028	263	2	104.24	127	10
11/26/2008	18-21	20,674	379	7	87.91	280	36
12/01/2008	17-20	20,892	298	43	90.34	244	30
06/25/2009	14-17	21,130	240	13	59.42	1,237	8
08/14/2009	13-16	22,041	62	25	49.62	1,980	30
08/17/2009	14-17	24,435	**1**	1	129.70	53	6
09/09/2009	14-17	19,480	989	3	30.23	6,701	135
09/10/2009	13-16	19,056	1,355	18	32.22	6,193	85
09/14/2009	14-17	18,463	1,992	51	49.75	1,969	7

*bold if ranking fell within the top 21 highest demand or highest priced hours

During its 15 months of operation the DR3 program has been activated 21 times. If targeted perfectly, one would have expected the 21 activations to occur during periods that correspond with either the 21 highest demand hours or the 21 highest priced hours (assuming high prices reflect system need). In practice, only three of the 21 activations (September 2 and 3, 2008 and August 17, 2009) fell within the top 21 high-demand hours and only one activation (September 2, 2008) occurred in the top 21 high-priced hours. Thus the targeting of the 21 activations was generally poor relative to a perfectly targeted program. With activations lasting 4 hours, there would be a maximum of 25 activations during a year for the 100-hour participants and 50 activations during a year for the 200-hour participants. In a 15-month period, without taking into account any seasonal variation, the maximum number of activations should be approximately 31 times for the 100-hour participants and 62 for the 200-hour participants. Even applying these larger bandwidths, only five of the activations to date fell within the top 62 high-demand hours or two within the top 62 high price hours.

The above analysis has shown how the DR3 program has performed against real-time outcomes. Another way to assess how the DR3 resources have been utilized is to rank activations against the three hour ahead pre-dispatch Richview shadow price. This shadow price represents a reasonable approximation of the three hour ahead supply cushion which triggers the DR3 activations. Table 3-4 below lists the highest Richview shadow price within each of the 21, 4-hour DR3 activation events and its rank over the 15-month period as well as within the month that the activation event occurred. One can see that only two out of 21 activations fell in the top 21 high-priced hours, implying that the targeting was poorly performed *ex ante* (as well as *ex post* as demonstrated above).

Table 3-4: Rank of the three Hour Ahead Richview Price during Hours with DR3 Activations
August 2008 to October 2009

Date	Contract Type	Activation Hours	Highest 3 Hour Ahead Richview price in Activation Hours ($/MWh)	Rank of the Highest 3 Hour Ahead Richview price in each Activation (Aug-2008 to Sep-2009	Rank of the Highest 3 Hour Ahead Richview Price in each Activation In Each Month
8/18/2008	100/200	15-18	123.32	26	6
9/2/2008	100/200	14-17	108.07	67	7
9/3/2008	100/200	14-17	121.38	29	4
9/4/2008	100/200	15-18	91.58	268	30
9/12/2008	100/200	14-17	65.57	918	150
9/17/2008	100/200	15-18	71.76	748	117
10/28/2008	200	17-20	92.44	253	9
10/29/2008	200	18-21	114.31	46	1
11/10/2008	200	18-21	96.30	182	42
11/17/2008	200	18-21	154.50	6	1
11/18/2008	100/200	17-20	101.79	123	27
11/19/2008	100/200	17-20	107.72	73	16
11/24/2008	100/200	17-20	133.53	16	2
11/26/2008	200	18-21	88.40	321	85
12/1/2008	200	17-20	127.11	24	3
6/25/2009	200	14-17	93.60	223	1
8/14/2009	100/200	13-16	81.26	450	8
8/17/2009	100/200	14-17	92.35	255	3
9/9/2009	200	14-17	41.11	2,124	41
9/10/2009	100/200	13-16	35.57	2,589	58
9/14/2009	100/200	14-17	59.79	1,112	4

Although OPA added a price trigger on September 8, 2009, the new trigger appears not to have helped improve the targeting of activation. Of the three activations in September 2009, two occurred in hours with a relatively low demand or low price. Based on the three hour ahead price in the period August 2008 to October 2009, the trigger should have been about $100/MWh in order for DR3 to have been activated both 31 and 62 times. It is worth noting that from an efficiency perspective a $100/MWh trigger may be still too low because the load with a high value of lost consumption (e.g. $200/MWh) may be instructed to curtail consumption even though the cost of providing the energy is projected at $100/MWh.

Assessment

In concept, the use of supply cushion to activate DR is reasonable. The supply cushion inherently recognizes constraints on the grid that would not be captured by a uniform price trigger and potentially results in activations which are much more aligned with system need than may be the case with alternative triggers. However, the results achieved with the current application of this approach are far from optimal.

The Panel concludes that the DR3 program is still very likely to induce short term inefficiency because payments to participants far exceed the small potential short-term efficiency gains available from foregone consumption. In addition, given its continued poor targeting, the program appears unlikely to achieve the desired long term efficiency benefits to reduce need for peaking generation because activation targeting is not sufficiently accurate to capture hours where peaking generators are required.

In its December 2006 Monitoring Report, the Panel observed that:

> *"If demand response programs are deemed to be required they should be designed so as to enable customers to (i) curtail their consumption of service (or have it curtailed on their behalf) when the value customers derive from the service is less than the incremental cost of providing it and; (ii) consume when the value they derive from the service exceeds the incremental cost of providing it. Incentive programs that induce customers to curtail consumption at times when the value they derive from the service*

> *is greater than the incremental cost of providing do not conserve resources in the true sense of the word."*[39]

Conservation, in the Panel's view, is the efficient use and stewardship of resources in general. Simply defining conservation as using less electricity may lead to the cost of reducing consumption being significantly higher than the benefit of doing so, an inefficient outcome as demonstrated by the past performance of the DR3 program.

The Panel understands that OPA has been mandated to meet conservation targets set by the Ontario Government. Demand response programs are deemed by OPA to be an important element to meeting such a target. However, the Panel urges the OPA to work with industry to find more efficient ways to meet the target than these programs as currently designed.

- The OPA has contracted demand resources for 100 or 200 hours of activation in a calendar year. OPA should continue to treat this as a maximum number of activation hours rather than as the target number of activation hours.
- The Panel understands that as a practical matter demand resources may have to be activated periodically to ensure continued availability, and that such 'testing' hours may not coincide with high-demand or high-priced hours in the calendar year. However, OPA should first estimate how many tests are required in each calendar year and then attempt to conduct the tests in high-demand or high-priced hours in a month or quarter, as this is most efficient. Testing in high-priced hours also allows DR resources to avoid relatively high energy prices.
- All other activations should be efficiency based, i.e. DR should be activated only when the cost of providing electricity (Richview or specific zonal constrained prices would be a good approximation) is expected to be greater than the value of foregone consumption (given the $200/MWh activation payment, it is likely the value of foregone consumption by some resources is at least $200/MWh). Where this approach conflicts with other objectives of the program, such as insufficient

[39] See the Panel's December 2006 Monitoring Report, p140.

uptake of the program, the additional costs should be clearly identified and paid in a manner which creates the least reduction in market efficiency.

- Given the intended growth in DR resources in the coming years, OPA should introduce a bidding process to allow demand resources to reveal their true preferences for consumption curtailment. That is, the program could allow demand resources to bid a price at which it is willing to reduce consumption, in a way similar to a dispatchable load or exporter. This would allow demand resources that have a lower value of consumption to reduce consumption ahead of demand resources that have a higher value of consumption. Such a process could be incorporated into the IESO's Enhanced Day-Ahead Commitment (EDAC) process in order to avoid over-commitment of generation resources and/or imports.[40]

Based on conversations between the MAU and the OPA, the Panel understands that the total DR3 capacity could reach 1,000 MW by 2010. With such growth, it will become even more important to improve the program design in order to achieve market efficiency. The OPA has regularly expressed interest in working with the MSP and industry to ensure the most efficient programs possible, and we will continue to do so. In light of the foregoing, the Panel has the following recommendations.

Recommendation 3-1

(i) ***The Panel recommends that the Ontario Power Authority (OPA) should target all Demand Response Phase 3 (DR3) activations, except those required for 'testing' purposes, based on efficiency considerations. This would involve improved identification of periods when system need is***

[40] The EDAC, which is expected to be in service in 2011, is a three-part bid and 24-hour optimization process, allowing resources (both internal and external) to be scheduled more efficiently day-ahead than the current Day-Ahead Commitment process (DACP). For more details, see: http://www.ieso.ca/imoweb/consult/stakeholder_ac_meetings.asp

greatest and the value of foregone consumption is less than the incremental cost of providing the energy.

(ii) ***The Panel recommends that OPA explore the feasibility of introducing a bidding process to allow demand response resources to bid the value at which they are prepared to reduce consumption and work with the IESO to align such a process with the Enhanced Day-Ahead Commitment (EDAC) process in order to avoid over-commitment of generation and/or imports.***

2.2 OPG's 2009 CO_2 Emissions Strategy and 2010 CO_2 Emissions Strategy

As outlined in the Panel's last report, OPG's strategy for complying with the maximum emissions limit set by the Ministry of Energy and Infrastructure for 2009 involved extended planned outages for coal units (CO_2 outages), designating one or more units as Not Offered But Available (NOBA) for particular days, and applying an emissions adder of $7.50/tonne[41] to the offers of its coal units.[42]

Figure 3-1 plots OPG's production from coal-fired generators in 2008 and 2009. Similar to what the Panel observed in their last report, total coal-fired energy production has fallen significantly this year relative to last year.[43] In 2008, OPG's coal-fired generators produced 23.2 TWh while annual CO_2 emissions totaled approximately 23.0 Mt.[44] In 2009, production from OPG's coal-fired generators totaled 9.8 TWh, representing a drop of 13.4 TWh, or 58 percent, relative to the last year. CO_2 output from coal-fired generators in 2009 was less than 10.0 Mt. OPG ended the year approximately50 percent below its 2009 limit of 19.6 Mt of CO_2 emissions.

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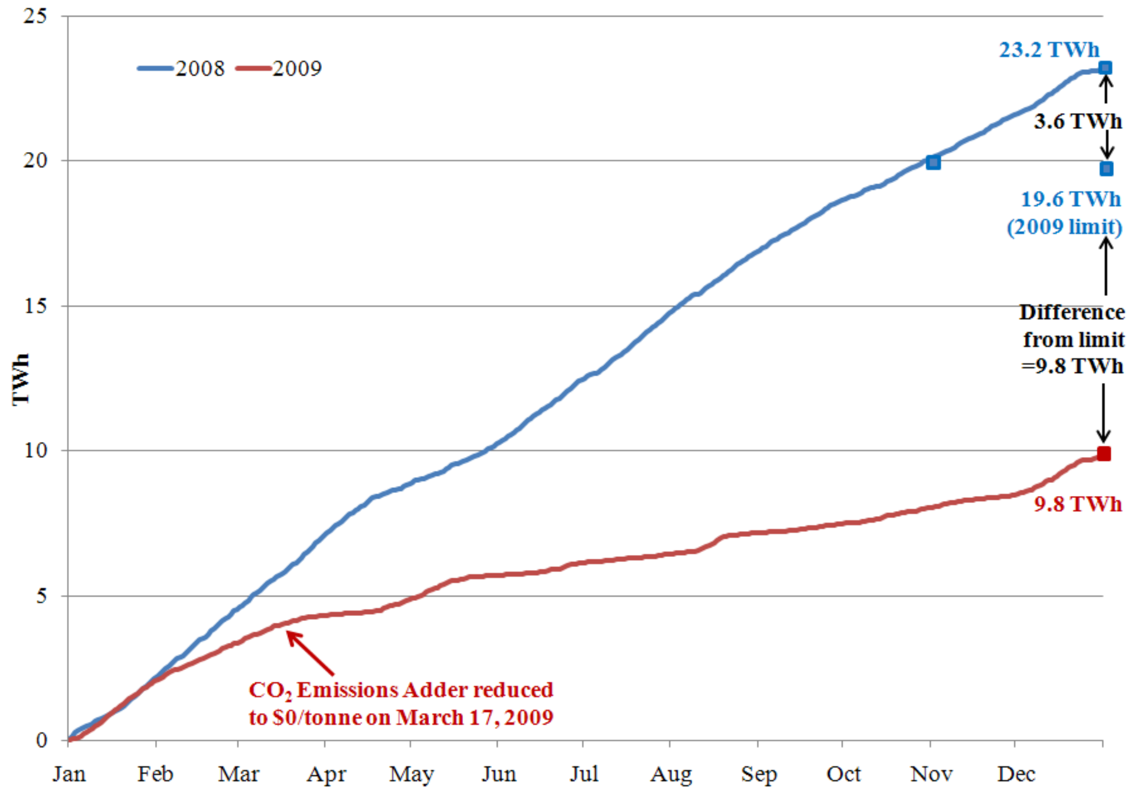
[41] The adder was reduced to $0.00/tonne of emissions on March 17, 2009.
[42] See the Panel's July 2009 Monitoring Report, pp 181-188, and OPG's "Addressing Carbon Dioxide Emissions Arising from the Use of Coal at its Coal-fired Generating Stations, May 15, 2008", http:www.opg.com/pdf/directive_co2.pdf
[43] See the Panel's July 2009 Monitoring Report, p 182.
[44] See Ontario Power Generation's "Sustainable Development Report 2008", at: http://www.opg.com/pdf/sustainable%20development%20reports/sustainable%20development%20Report%202008.pdf , p. 37.

Figure 3-1: Energy Production from Coal-Fired Generation
January – December 2008 and 2009
(TWh)



NOBA Units and CO_2 Outages

Table 3-5 presents summary statistics on the number of days in 2009 when coal units were designated as either NOBA or on a CO_2 outage. OPG designated at least one coal unit as NOBA in 139 days (cumulatively 87.2 GWh of energy), with 51 of those days falling in September and October. Of the 139 days, there were 51 days when at least two coal units were on NOBA. A larger number of NOBAs had originally been scheduled, but OPG expected to and occasionally did remove a NOBA designation from a unit if one of the other coal units was forced out-of-service or OPG did not expect the unit to have its offer accepted on a forecast basis.[45, 46]

[45] In 2009, there were 8 NOBA designations recalled by OPG resulting from forced outages to other coal units in its fleet.

In 2009, there were seven planned outages designated as CO2 outages with an average length of 62 days. There were a total of 245 days in 2009 (cumulatively 200.3 GWh of energy) when at least one coal-fired unit was on a planned CO2 outage. Of the 245 days, multiple CO2 outages were designated during 151 days with the majority of these days occurring between March and June and in November 2009.

Table 3-5: Summary Statistics for NOBA and CO_2 Outages
January – December 2009
(Number of Days and GWh)

	NOBA			CO_2 Outages		
	Days with at least 1 NOBA Unit	Days with at least 2 NOBA Units	Total Energy on NOBA (GWh)	Days with at least 1 Unit on CO_2 Outage	Days with at least 2 Units on CO_2 Outage	Total Energy on CO_2 Outage (GWh)
January	-	-	-	6	-	2.6
February	2	-	0.9	28	2	13.3
March	18	10	13.0	31	31	41.1
April	19	4	10.6	30	30	35.1
May	21	1	9.9	31	27	27.0
June	22	4	11.7	27	27	24.8
July	-	-	-	-	-	-
August	-	-	-	-	-	-
September	30	24	24.7	28	-	12.3
October	21	7	13.5	31	9	17.8
November	6	1	3.1	30	25	24.8
December	-	-	-	3	-	1.4
Total	139	51	87.2	245	151	200.3

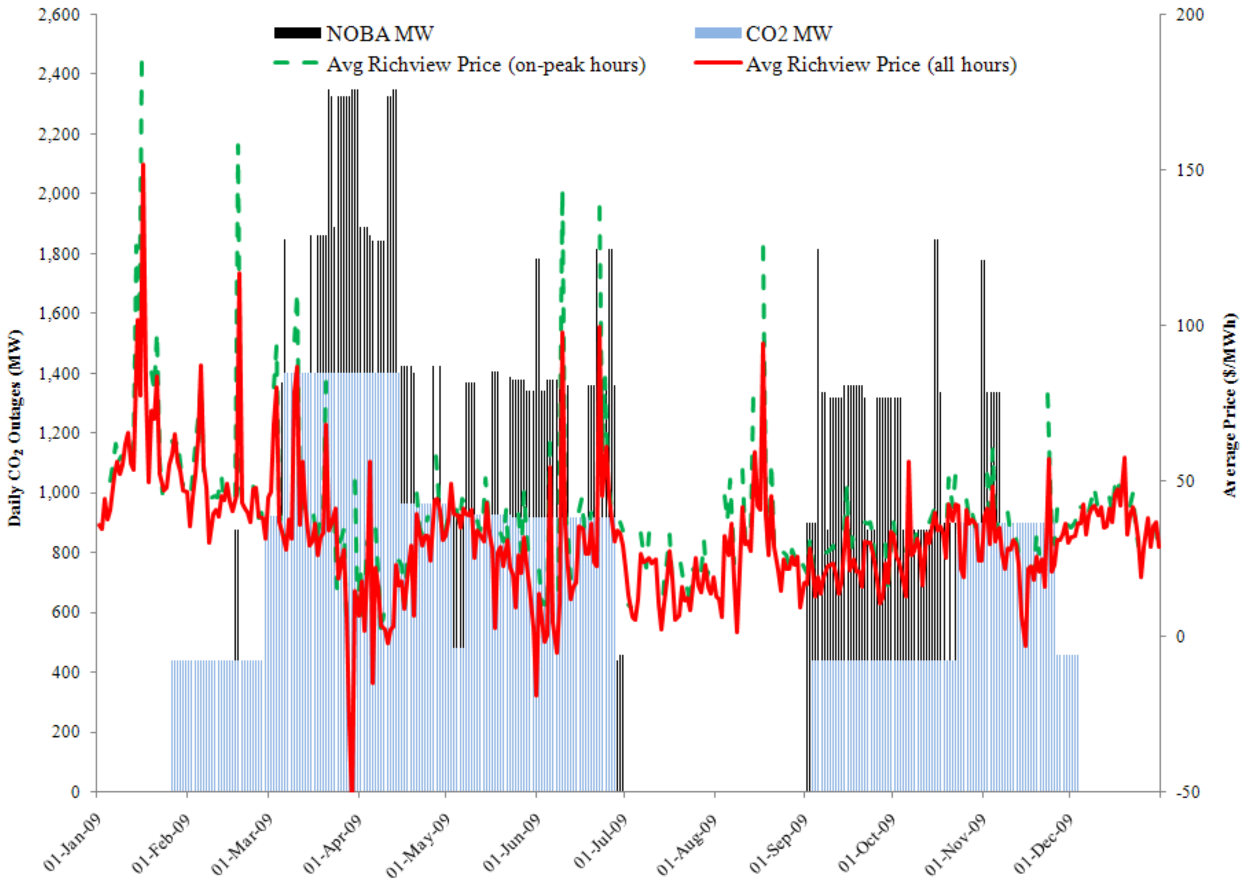
On average, OPG designated NOBA units and CO_2 outages during some of the lower priced days in 2009. The average HOEP on days with at least one NOBA was \$23.40/MWh, compared to an average price of \$33.28/MWh on days with no NOBA. The average on-peak HOEP was \$32.03/MWh on days with NOBA and \$39.70/MWh on non-NOBA days. Similarly, the HOEP on days with at least one CO_2 outage was \$28.29/MWh, \$3.72/MWh lower than on days with no units on CO_2 outage. The average

[46] See "OPG's Strategy to Meet the 2009 CO_2 Emissions Target", p. 2, available at: http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202009%20CO2%20Emission%20Targets%20Jan%2022.pdf

on-peak HOEP was \$36.14/MWh on days with a unit on CO_2 outage and \$38.54/MWh on non-CO_2 outage days.

The Richview nodal price is a better indicator of marginal costs or opportunity costs each day than the HOEP. The average Richview price on days with at least one NOBA was \$25.28/MWh (\$35.55/MWh on-peak) compared to an average price of \$35.95/MWh (\$43.69/MWh on-peak) on days with no units designated as NOBA. The average Richview price on days with at least one CO_2 outage was \$30.69/MWh (\$40.04/MWh on-peak) compared to an average price of \$34.32/MWh (\$42.18/MWh on-peak) on days with no units on CO_2 outage. Figure 3-2 plots the daily average Richview price (all hours and on-peak hours only) against the amount of MW designated by OPG as NOBA or as on CO_2 outage for each day in 2009. Notwithstanding the foregoing averages, it is apparent that some NOBA and CO_2 outages occurred on days when prices turned out to be relatively high. The MAU is examining the efficiency implications of this observation.

Figure 3-2: Daily NOBA and CO_2 Outages and Average Richview Shadow Price January – December 2009 (\$/MWh and MW)



OPG's 2010 CO_2 Emissions Strategy

In 2010 OPG will implement a new strategy[47] to meet its CO_2 emissions limit of 15.6 Mt, a reduction of 20 percent from the maximum emissions limit for 2009. Under the revised strategy OPG will eliminate the use of CO_2 outages. In addition, OPG will eliminate the use of NOBA units and instead offer some coal units at a higher cost than its other coal units. OPG's rationale for submitting these higher cost offers is to avoid starting more

[47] See "OPG's Strategy to Meet on a Forecast Basis the 2010 CO_2 Emissions Target" at: http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202010%20CO2%20Emission%20Target.pdf

coal units than are necessary. Operating costs of a coal unit increase, and fleet reliability decreases, with the number of starts each unit makes per year. In the event that the higher-priced coal units are dispatched, OPG will adjust the offer prices of the units to a cost-based offer. In addition, OPG will continue to apply a uniform price adder to its coal units as a means of meeting its 2010 CO_2 emissions limit. Given the downturn in the North American economy and the associated weak level of Ontario Electricity demand, OPG will initially set this adder at $0.00/tonne.

Overall, the Panel believes that the proposed strategy is a positive directional change from OPG's 2009 CO_2 emissions strategy.[48] The Panel had previously recommended the elimination of CO_2 outages and NOBA designations and the use of a price adder only to the extent necessary to comply with the CO_2 emissions limits.[49]

The Panel does question the manner in which OPG will set the offer price for its higher priced units. OPG has advised the Panel that the offers for its higher priced units will not be cost-based, in that offers will not specifically reflect the higher costs associated with increasing the number of coal unit starts. While the Panel appreciates that OPG must recover the costs associated with coal unit starts, it would prefer that these incremental costs were the basis for OPG's offer price on its higher priced units. Directly incorporating the incremental costs associated with increased unit starts would also eliminate the need for OPG to subsequently lower the offer price on these units in the event they are selected to run. The Panel will continue to monitor the impact of OPG's 2010 CO_2 emissions strategy in a manner that is consistent with the Panel's draft document Monitoring Bids and Offers in the IESO-Administered Electricity Markets.[50]

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[48] While a positive change directionally, unless market conditions dramatically change from 2009 it appears that OPG could meet its 2010 CO_2 emissions limit of 15.6 Mt (which equates to approximately 16 TWh of energy production) without any strategic restraints on its coal units.
[49] See the Panel's July 2009 Monitoring Report, pp.181-188.
[50] The draft document is available at:
http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20091026.pdf

2.3 Lake Erie Circulation and PARs at the Michigan Intertie

Introduction

In past reports,[51] the Panel identified several issues related to the loopflow around Lake Erie (i.e. Lake Erie Circulation or LEC)[52] and provided recommendations on the use of the Phase Angle Regulators (PARs) at the Michigan borders.[53] Key conclusions and recommendations are summarized below:

- In the December 2005 report, the MAU informed the Panel of a reduction of about 400 MW in the import and export capacity at the Michigan intertie beginning in March 2005 after the two Lambton PARs were placed in service. Hydro One was aware that this reduction would occur but anticipated that the effect of controlling inadvertent loopflow (i.e. the Lake Erie Circulation) would more than offset the reduction in import/export capacity. Additional complications relating to the manufacturer's capacity ratings of the PARs and how the PARs were to be operated were also discussed in the December 2005 report. As a result, the PARs could not be used (except in emergency conditions) until an agreement for operation between Hydro One and International Transmission Company (ITC) in Michigan could be reached.
- Given that the Michigan intertie was generally import-congested at the time, the reduction in import capacity had the effect of increasing the HOEP. In the July 2006 Monitoring Report, the Panel reported a potential increase of \$2.59/MWh in HOEP for the period March 2005 to January 2006. To restore

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[51] The Panel's December 2005 Monitoring Report, pp 79-82; the July 2006 Monitoring Report, pp 100-102; the December 2006 Monitoring Report, pp 113-117; the January 2008 Monitoring Report, pp 146-151; the July 2008 Monitoring Report, pp 164-170; the January 2009 Monitoring Report, pp 193-197; and the July 2009 Monitoring Report, pp 164-181.
[52] Electricity flows from generators to loads along all available transmission paths (also called parallel paths). When transactions are scheduled between jurisdictions, there is an assigned path (called "contract path") which assumes that 100 percent of the transaction is flowing along that path. The difference between scheduled amount and actual flow is referred to as "unscheduled flow", "inadvertent flow" or "loopflow". The industry has given a specific name to the unscheduled flow near Lake Erie, i.e. Lake Eire Circulation (LEC).
[53] A Phase Angle Regulator (PAR, also called a Phase Shifter) is a special transformer that is used to control the power flowing over a transmission line within the design rating of the PAR.

the import and export capability, the IESO bypassed the PARs beginning in June 2006 pending agreement on an operating protocol for the PARs.

- In its December 2006 report, the Panel noticed an average increase of about 200 MW in counter-clockwise LEC and pointed out the potential efficiency loss due to re-dispatching of internal generators and lost trade opportunities.
- In its January 2008 report, the Panel noted developments which included the placing in-service of the B3N intertie with Michigan (and its associated PAR), the signing of the Interconnection Facilities Agreement (IFA) and the developing of a Standard Operating Procedure between Hydro One and ITC. The Panel recommended that the IESO expedite completion of the necessary remaining agreements with Hydro One, MISO and ITC for operation of the PARs, and that Hydro One develop operationally useful ratings that would safeguard the PARs.
- In its July 2008 report, the Panel observed a sharp increase in linked wheel transactions from NYISO to PJM through Ontario and Michigan beginning in January 2008 and identified the primary reason for such an increase as the difference in treatment of imports and exports among jurisdictions.[54] The Panel concluded that the increased linked wheel transactions appeared to have no significant efficiency impact on the Ontario market because there was little internal congestion along the path of linked wheel transactions.
- After communications between the MAU and its counterparts in the United States, NYISO sought tariff revisions on July 21, 2008, prohibiting linked wheel transactions on eight selected paths including the exports from NYISO

[54] There are two key factors in modelling intertie trades: distribution factors (i.e. the fraction of an intertie trade that flows along each physical path) and designation of source and sink area. PJM and MISO all use some sort of distribution factors, while Ontario and NYISO assume 100 percent flow across the scheduled intertie when determining schedules and prices. In other words, PJM and MISO check where the import/export transaction originates and where it ends up while NYISO and Ontario only check the transaction's immediate origin and sink. For example, an export from NYISO to PJM though Ontario and MISO will be treated as an export to Ontario by NYISO, an import from NYISO and an export to MISO by Ontario, an import from NYISO and an export to PJM by MISO, and an import from NYSIO by PJM.

to PJM through Ontario and MISO.[55] On November 17, 2008, the U.S. Federal Energy Regulatory Commission (FERC) accepted the tariff revisions as permanent and encouraged the parties to seek "long-term comprehensive solutions."[56] Since the implementation of these NYISO tariff provisions, linked wheel transactions from NYISO to PJM ceased, but exports from Ontario to PJM through MISO increased. Recognizing the potential efficiency impact of these exports on the Ontario market due to their induced Lake Erie Circulation, the Panel requested the MAU to continue monitoring the issue closely.

- In its July 2009 report, the Panel observed a continued increase in exports from Ontario to PJM through MISO. It also estimated that roughly 43 percent of exports scheduled to PJM actually went through NYISO. The Panel observed that the impact of exports to PJM on Ontario consumers had very different implications from the exports to PJM from NYISO on NYISO consumers because, unlike New York, there was little internal congestion within Ontario between Niagara and Lambton (i.e. the main LEC path). The Panel reiterated its prior recommendation to bring the PARs at the Michigan border into service to address loopflows, which were being exacerbated by the export volumes.

This section reports on further developments with respect to LEC issues during the summer of 2009, including the implications of recent NYISO procedure changes and the IESO's response.

[55]See: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2008/07/nyiso_exgnt_crcmstnc_extrnl_trnsctns_7_21_09.pdf
[56] FERC Docket: ER09-198-000, and -001, 'Order Accepting Tariff Sheets", November 17, 2008,

Recent Developments

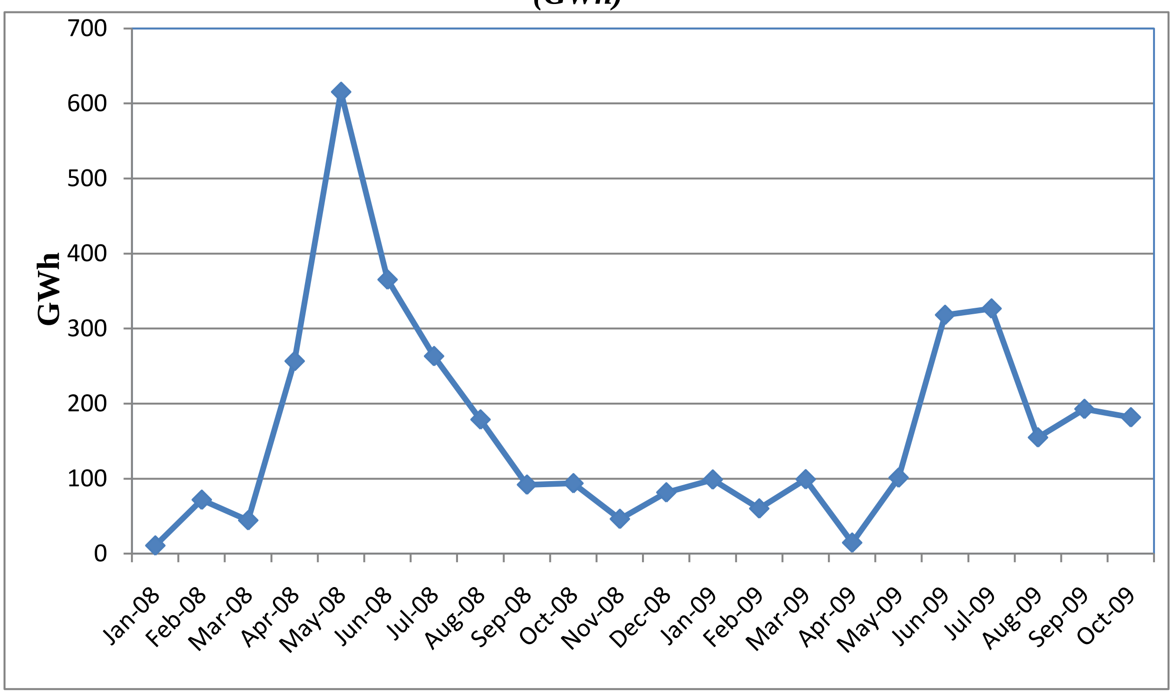
Over the summer of 2009, there have been five significant developments related to the LEC:

- On July 16, 2009, FERC issued an order to NYISO to work with neighbouring markets to develop long-term comprehensive solutions to the "loop flow problem".[57] The Panel understands that the IESO is actively engaged in this process with its counterparts (including NYISO, MISO, and PJM). The fundamental concept is that traders are responsible and thus should be appropriately charged for congestion that is induced by the loopflow that their transactions cause.[58]
- There are currently four PARs at the Michigan intertie (one near Windsor, one in Michigan, and two in Ontario at Lambton). As noted earlier, the latter two are bypassed but can be put in service under emergency situations. The one near Windsor has been functioning but the one in Michigan was damaged and is undergoing replacement. If all PARs are in service, up to 600 MW of LEC can be controlled.[59] The Panel has been notified that the two Lambton PARs might be ready for operation as early as April 2010 after several years of delays.
- NYISO began using the Transmission Loading Relief (TLR) procedure more regularly in March 2009 to deal with flows at the New York/Ontario intertie and at the Central-East flowgate within NYISO (although the procedure was rarely invoked until July 2009). In March and April, because of extended planned outages to transmission lines PA301 and PA302 (which link Ontario

[57] See "Order Authorizing Public Disclosure of Enforcement Staff Report and Directing the Filing of an Additional Report", 128 FERC 61,049, July 16, 2009. The Staff Report includes a discussion of the cause and consequences of the LEC and finds no market manipulation or wrongdoing by individual market participants.
[58] For details, see:
http://www.nyiso.com/public/committees/documents.jsp?com=bic_miwg&directory=2009-10-29 and
http://www.midwestmarket.org/publish/Document/35a4f6_1258eeb6df2_-7fff0a48324a?rev=1
[59] In its December 2005 Monitoring Report (pp. 79-82), the Panel noted that with the two Lambton PARs in service about 500 MW of LEC could be controlled. The PAR's capability of controlling loopflow varies with system conditions. An estimate of 600MW is believed to the maximum capability of all five PARs.

with NYISO at Niagara), all four system operators (NYISO, PJM, MISO and IESO) agreed to reduce their intertie scheduling limits and thus effectively reduced the LEC. As a result, NYISO did not have to rely on its TLR procedure to relieve congestion during the outage period. After PA301 and PA302 were returned to service in late April 2009, however, intertie transactions between markets became more active and clockwise LEC increased as Figure 3-3 below shows.[60] Because the clockwise LEC increased congestion at the Central-East interface within NYISO, NYISO started to frequently make use of the TLR process to manage the congestion.

Figure 3-3: Monthly Total Clockwise LEC
January 2008 to October 2009
(GWh)



- When NYISO invokes its procedure for calling TLRs, the IESO typically has to cut exports to relieve congestion, which usually means that some exports to PJM through MISO will be cut because a large portion of these exports

[60] These data are monthly total projected clockwise LEC in the IESO PD dispatch tool. IESO considers these numbers as firm LEC and uncontrollable by its dispatch schedules.

actually go through NYISO.[61] In June and July 2009, the IESO's response to the NYISO TLRs led to frequent and significant export failures, which caused operational concerns in Ontario and resulted in significant differences between pre-dispatch and real-time prices. The failures also led to the Transmission Rights account being underfunded (i.e. collected rent is lower than the TR payout to TR holders).

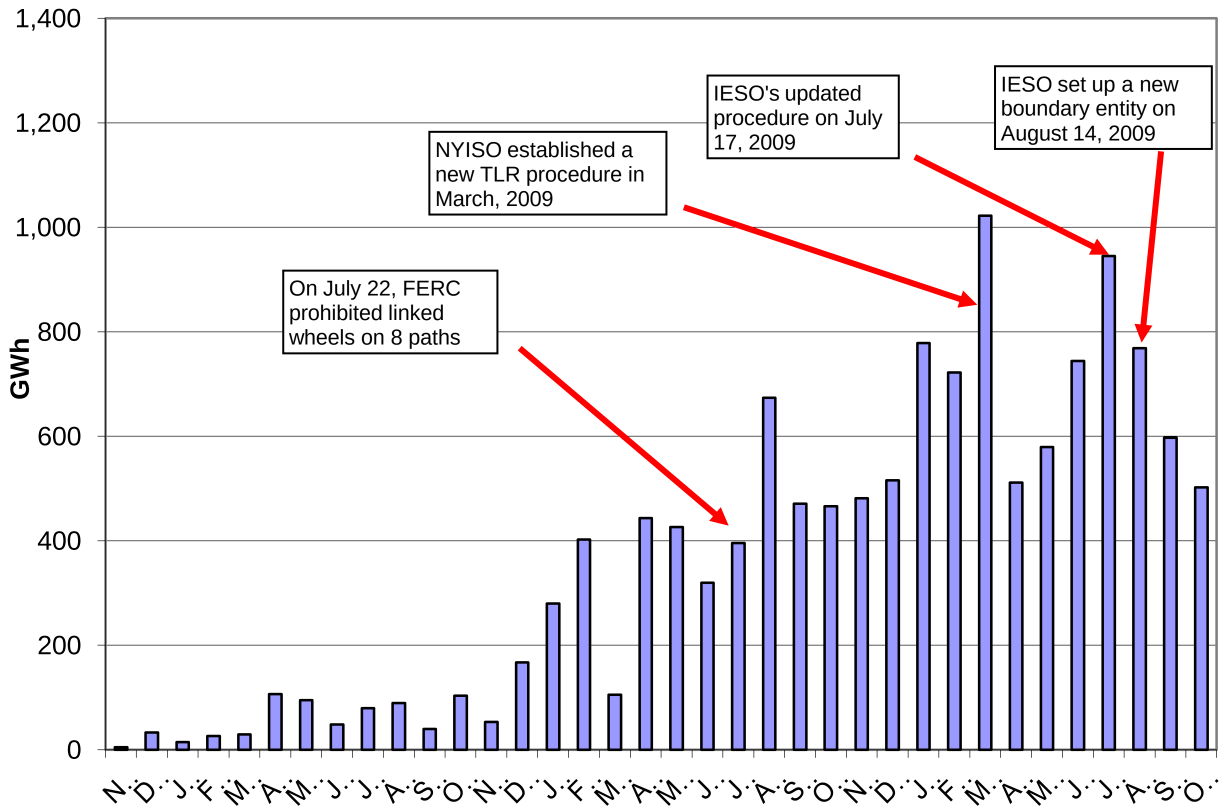
- On July 17, 2009 the IESO updated and clarified its procedure of removing intertie transactions before the final pre-dispatch run.[62] The IESO typically curtails exports in order to help external operators manage their internal congestion. However, when the congestion problems persist and are expected to last for a period of time, the IESO may remove exports (scheduled or unscheduled in pre-dispatch) before the final one hour pre-dispatch run.
- Because the IESO's pre-dispatch tool used the same "boundary entity" [63] for exports to PJM (through MISO) as for exports to MISO, the actual physical power flow of these exports was not properly modelled by the IESO Dispatch System Optimizer (DSO). On August 14, 2009, the IESO designated a new boundary entity for exports to PJM through MISO to better match the constrained schedules with their physical flow. This step should have the effect of reducing clockwise LEC.[64]

The NYISO procedure calling for TLRs, the IESO's pre-emptive curtailment procedure should have had the effect of reducing scheduled exports to PJM, and the designation of the new boundary entity by the IESO reduces the need for NYISO to invoke its TLR

[61] Exports to NYISO are generally not cut because they do not contribute to the congestion at the Central-East interface within NYISO, and they are properly priced even though they have contributed to the congestion at the New York/Ontario intertie. In fact, exports to NYISO could have contributed to congestion relief at the Central-East interface because a portion of these exports to NYISO west will go around Lake Erie, exiting from the Michigan intertie, all the way through MISO and PJM, and then coming in the West zone of NYISO through the Central-East interface.
[62] IESO's Procedure Update #153: Pre-emptive Curtailment of Transactions, July 17, 2009.
[63] The IESO's Market Rules (Chapter 11) define a boundary entity as "the capacity of one or more resources, including but not limited to generation facilities or load facilities, located at a point or points external to the IESO control area which a market participant is entitled to inject into or withdraw from the IESO-controlled grid and which shall be deemed to be located in an intertie zone ...".
[64] http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4837.

procedure. Figure 3-4 below depicts the monthly total exports from Ontario to PJM through MISO. It can be seen that exports to PJM started to increase in January 2008, reached a record high in March 2009, dropped significantly in April 2009 when PA301 and PA302 were on outage, increased gradually to their second highest level ever in July 2009, and then decreased gradually thereafter. It is worth noting that there are other factors (e.g. intertie capability and price differential between Ontario and PJM) that can also affect the export volume to PJM.

Figure 3-4: Exports From Ontario to PJM Through MISO November 2006 to October 2009 (GWh)



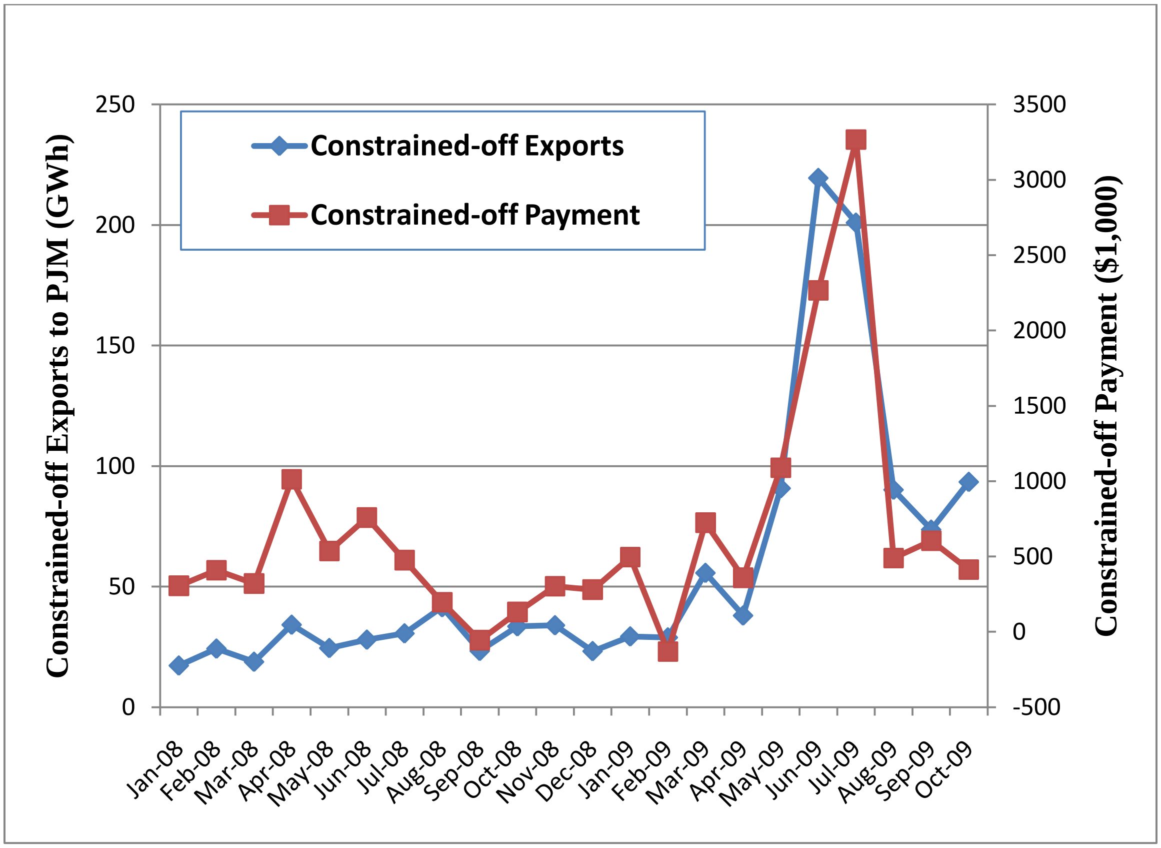
Although the new boundary entity set by the IESO for exports to PJM has had the effect of better matching the physical flow with the constrained schedules, it may also have caused the constrained schedules to further deviate from the unconstrained schedules, and thereby increased constrained off exports to PJM. The reason for this is that the unconstrained sequence does not take into account how the power flows on different paths while the constrained sequence does. For example, congestion at the NYISO intertie causes the constrained sequence to schedule fewer exports to PJM through the Michigan intertie, but the unconstrained sequence ignores the constraint at the NYISO intertie. The result is a greater discrepancy between the constrained and unconstrained schedules. The Panel has asked the MAU to continue monitoring the impact of the change of the boundary entity.

The increased clockwise LEC in recent months as shown in Figure 3-3 above further exaggerated the deviation between the constrained and unconstrained schedules. In establishing intertie capability it is the IESO’s practice to take into account the loopflow that is induced by transactions that have firm transmission service. For example, when LEC is expected to be 500 MW clockwise all of which is on firm transmission service, the IESO increases the export capacity at the Michigan intertie by 500 MW and reduces the export capacity at the New York intertie by 500 MW.

However, the constrained sequence takes a more complicated approach: scheduled intertie transactions are modelled dynamically by estimating incremental flow on multiple paths. With the new boundary entity set for exports to PJM via the MISO intertie, a greater fraction of power flow is modelled as going through the New York/Ontario intertie. When the New York/Ontario intertie is congested due to a higher clockwise LEC, fewer exports to PJM will be scheduled in the constrained sequence. As a result, the different treatment in the unconstrained and constrained sequences leads to an increase in constrained off exports to PJM.

Figure 3-5 shows the monthly constrained off exports to PJM and the associated CMSC payment since January 2008 (when exports to PJM started to increase). Constrained off exports to PJM have continued to increase since January 2008, reached a historical high level in June 2009, and remained at a high level throughout the summer of 2009. The constrained off payments have generally been moving together with the amount of constrained off exports, with the exception of recent months where the high constrained off amount did not result in a high constrained off payment (implying many constrained off exports were offered at a price close to the HOEP).

Figure 3-5: Constrained off Exports to PJM through MISO and Related CMSC Payments
January 2008 to October 2009



IESO's Pre-Emptive Curtailment

The IESO's procedure of pre-emptive removal of intertie transactions allows the IESO to cut exports before the final PD run. For example, when NYISO has issued a TLR 3A, leading the IESO to curtail exports to PJM for a period of time, IESO may contact the NYISO and discuss the duration and severity of the issue. The IESO then assesses which transactions are likely to be cut in future hours based on NERC's Interchange Distribution Calculator (IDC), and pre-emptively cuts these transactions based on their priority level and their offer/bid prices. In other words, the IESO cuts exports from the lowest priority level (typically exports that have no firm transmission service) to the highest priority level (i.e. exports that have firm transmission service), and then at the same priority level cuts exports from the lowest price to the highest price (which allows the high-valued exports to flow ahead of the low-valued exports).

The pre-emptive curtailment action has effectively relieved the congestion in NYISO. However, it also has important implications for the Ontario market. Among other things, the intertie price at the Michigan intertie is reduced and the operators' workload is increased at times. Given that the IESO cuts these exports from the lowest bid price to the highest bid price and the IESO curtails exports based on the best estimation of the IDC that is operated by the NERC, the Panel believes that the exports are not over-curtailed and that the overall efficiency impact on the Ontario energy market is likely to be minimal.

The pre-emptive curtailment action reduces exports that would be scheduled in the final pre-dispatch. As Table 3-7 below shows, exports at the Michigan intertie (including exports to both PJM and MISO) were reduced by 96 GWh (or 4 percent of total actual exports at the Michigan intertie) and by 9 GWh (or 1 percent of total actual exports) at the New York intertie from July 17 to October 31, 2009.

Table 3-7: Exports that Were Preemptively Curtailed
July 17 - October 31, 2009
(GWh)

	Michigan Intertie			New York Intertie		
Month	**Curtailed Exports**	**RT Schedules**	**Percentage (%)**	**Curtailed Exports**	**RT Schedules**	**Percentage (%)**
July-09	63	510	12	9	206	4
August-09	20	873	2	0	470	0
September-09	11	721	2	1	357	0
October-09	1	568	0	0	281	0
Total	95	2,671	4	10	1,314	1

The pre-emptive curtailment action not only effectively mitigated congestion at the intertie (or interfaces within NYISO) but also reduced the zonal price at the Michigan intertie. The removal of exports before the final PD run reduced export offers at the Michigan intertie and as a result that intertie price was generally equal to the Ontario price, which was typically low. This low intertie price benefited exporters who had a constrained schedule and likely induced more export bids from the Ontario market that would be subsequently curtailed.

Table 3-8 below lists the monthly total number of hours with congestion at the MISO intertie. "*Total*" hours in the table are the total number of hours without or with preemptive curtailment in a given month. In the three and half month period, the IESO preemptively curtailed exports in 163 hours. This reduced congestion, with only two of these hours experiencing export congestion (1 percent of the time). In contrast, in the 2,405 hours without pre-emptive curtailment, export congestion occurred about 12 percent of the time. This difference was most prominent in July 2009, when exports were congested 52 percent of the time when the IESO did not curtail exports, versus only 2 percent of the time when the IESO curtailed exports. By comparison, between June 1 and July 16, 2009 when NYISO was increasing the use of its TLR procedure, there was congestion at MISO in 311 of 1,104 hours (i.e. 28 percent of the time). Based on these observations it appears that the IESO's pre-emptive curtailment action led to a reduction in export congestion at the Michigan intertie.[65]

[65] As showed in Figure 3-6, some of the real-time congestion was avoided by additional IESO export curtailments after the final pre-dispatch run.

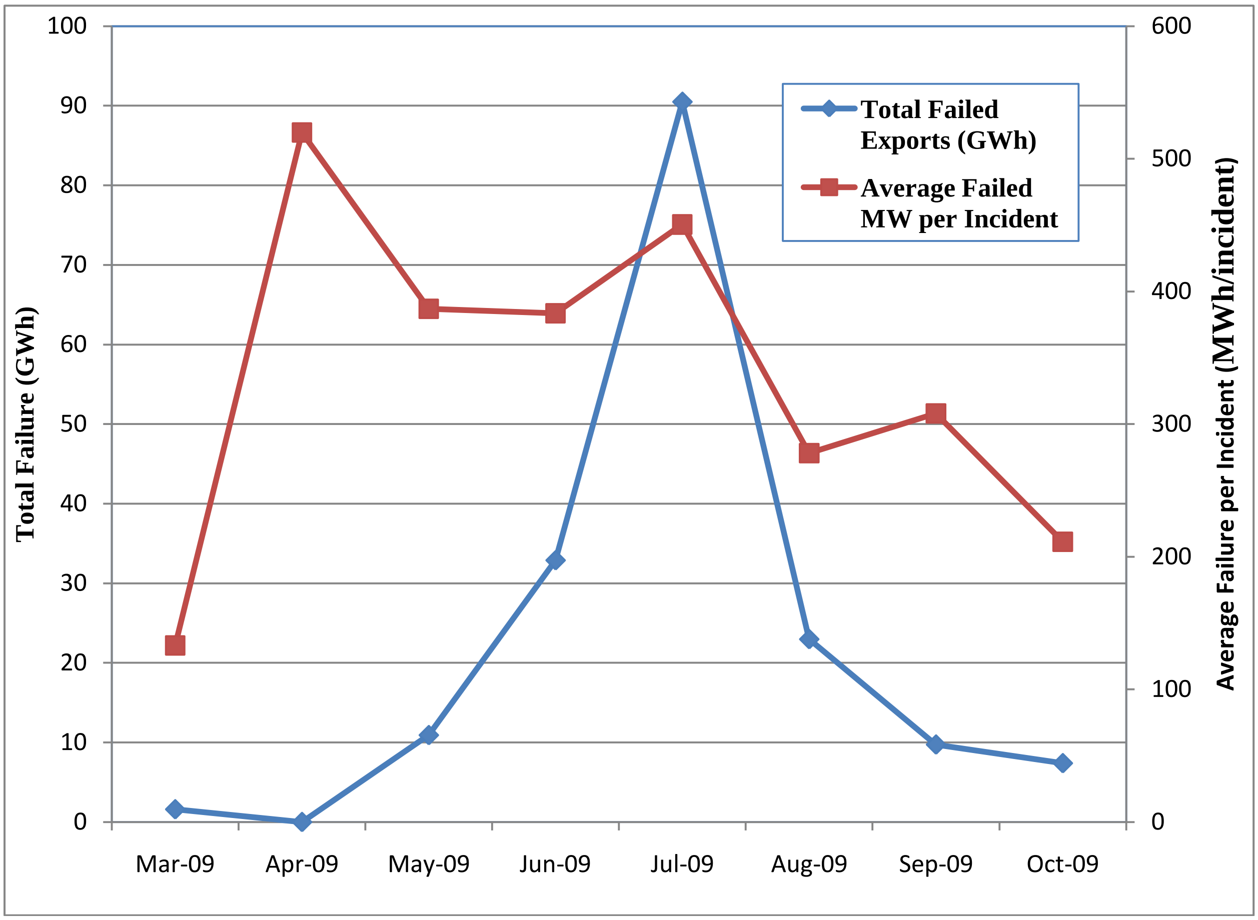
Table 3-8: Export Congestion to MISO in Hours with and without Pre-Emptive Curtailment Action
June 1 - October 31, 2009

Month	No. of Hours without Pre-emptive Curtailment			No. of Hours with Pre-emptive Curtailment		
	Congested	Total	Percentage (%)	Congested	Total	Percentage (%)
July 17 to 31	129	246	52	2	114	2
August	81	715	11	0	29	0
September	52	705	7	0	15	0
October	26	739	4	0	5	0
Total	288	2,405	12	2	163	1

The reduced congestion at the Michigan intertie resulting from curtailments several hours in advance also induced more export bids in subsequent hours. For example, after observing a low price at the Michigan intertie (because the earlier curtailments had led to a lack of congestion) exporters increased both their bid prices and quantities, which in turn increased the amount of exports that the IESO had to curtail in the subsequent pre-dispatch runs. After observing this sequential process, whereby curtailed exports only induced new export bids, the IESO stopped pre-emptively curtailing exports multiple hours out and instead pre-emptively curtailed exports only two hours prior to real-time. This precluded new export bids in response to the curtailment.

In additional to cutting exports before the final pre-dispatch run, the IESO may have to further curtail exports after the final pre-dispatch run if the pre-emptive cut is insufficient. Figure 3-6 below shows the monthly total exports curtailed after the final pre-dispatch run for NYISO TLR. One can see that the export failures after the final pre-dispatch run for NYISO TLR increased sharply in June 2009 and reached a historical high in August, before decreasing in September and October after the new boundary entity was implemented.

Figure 3-6: IESO Export Curtailment in Response to NYISO TLR after Fina Pre-Dispatch
July 17 - October 31, 2009
(GWh and MWh)



Assessment

Historically, the LEC has flowed counter-clockwise, helping to relieve congestion at the NYISO Central-East flowgate. However, beginning in January 2008, both linked wheel transactions from NYISO to PJM through IESO and MISO and transactions from IESO to PJM though MISO increased substantially. These transactions contributed to an increase in clockwise LEC and an increase in congestion at the NYISO Central-East interface.

NYISO's prohibition of linked wheel transactions at eight selected paths did help reduce the Central-East congestion within NYISO. But this reduction was partly offset by an increase in exports from Ontario to PJM through MISO. Increased clockwise LEC and more frequent use of TLR by NYISO in recent months may have led to market inefficiencies. In a recent submission to FERC on the benefits of broader regional markets, NYISO offered the following observation on the TLR process:

> *The NERC TLR procedures provide a blunt instrument for addressing the off-contract path impacts of scheduled transactions. Invoking the TLR procedures may result in market and operational inefficiencies because TLR requires the curtailment of expected energy deliveries without regard to economic rationing principles. The TLR process does not take into account the scheduling party's possible economic willingness to pay to maintain its transaction schedules, nor does the TLR process account for or assess the economic benefit of moving power between regions*.[66]

The following sections assess how much efficiency could have been improved if some components in the system had been in service to mitigate the LEC.

The Phase Angle Regulators (PARs) and Market Efficiency

The PARs offer potentially significant market efficiency/benefits.[67] Had all PARs been in place, a significant amount of LEC (about 600 MW in either direction) could have been controlled. This would have facilitated more imports or exports, both through scheduling additional transactions and fewer curtailments. More transactions across markets move

[66] NYISO January 12, 2010 submission to FERC, 'New York Independent System Operator, Inc.'s Report on Broader Regional Markets; Long-term Solutions to Lake Erie Loop Flow' at p. 6 and available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf

[67] The PARs can allow more intertie transactions which also impact the market price in Ontario. In its June 2006 Monitoring Report, the Panel reported a possible HOEP reduction of $2.59/MWh for the period March 2005 to January 2006 due to the outage of two PARs at the Lambton station. See the Panel's June 2006 Monitoring Report, pp. 100-102.

power from low cost areas to high cost areas and thus improve market efficiency (in all neighboring markets, not just Ontario).

Estimating efficiency loss in Ontario due to the bypass of the PARs is challenging. First, power flows on all available paths based on the physical characteristics of each path unless there are control devices on all transmission lines. As such, LEC cannot be eliminated. Second, all markets schedule inter-jurisdiction transactions based on a projection of loopflow that is outside of their control. In other words, there is a strong inter-relationship between the IESO's actions and the actions of other markets. As a result, it is difficult to predict what would have or would not have happened had the IESO taken different actions and had the PARs been in service. Bringing the two PARs at Lambton and others into service certainly will reduce LEC, but their ability to control LEC varies with the system conditions. Nevertheless, given that the NYISO and Michigan interties in Ontario and the NYISO Central-East interface have been frequently congested in the past,[68] the Panel expects that control of a large amount of LEC by the four PARs would likely result in significant efficiency gains to the marketplace.

Both the NYISO submission to FERC on July 21, 2008 and the subsequent FERC ruling on July 16, 2009, encourage relevant parties to bring the PARs into service as soon as practicable.[69] In a recent submission to the FERC on the benefits of broader regional markets, the NYISO restated the importance of these PARs on the control of LEC[70], but also pointed out that the process has been stalled by ITC*Transmission* (ITC):

[68] There is also often congestion between MISO and PJM, and from East to West within PJM.
[69] NYISO, in its submission to FERC "Request for Clarification or, in the alternative, rehearing of the New York Independent System Operator, Inc", dated on August 14, 2009, further stated that "implementing an effective physical solution (-- put the PARs at the Michigan border into service) to control or mitigate Lake Erie circulation should be a cornerstone of any comprehensive solution that the NYISO and its neighbouring ISO and RTOs develop" (page 5).
[70] The IESO submitted comments to FERC in support of NYISO's submission on broader regional markets. Specifically the IESO commented "implementing physical controls such as Phase Angle Regulators ("PARs") on the Ontario-Michigan interface in order to control loop-flows in the region is paramount … Although the increase in phase shifting capability will not eliminate unscheduled loop flows, the IESO believes that the installation of the new PARs is essential to reduce unscheduled flows". IESO comments available at: http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20100119-5010

> The NYISO has been informed by a representative of International Transmission Company d/b/a ITC*Transmission* ("ITC") that, although the various necessary operating agreements for the Ontario-Michigan PARs are in "final form," ITC will not execute them and "the Department of Energy will, accordingly, not be in a position to approve the pending amendment to ITC's Presidential Permit which is required to place the PARs into service" until consumers in the other markets surrounding Lake Erie agree to pay for a portion of the claimed $8 million annual cost ITC charges its consumers for constructing, operating and maintaining its PARs at the Ontario-Michigan border.[71] [72]

Recommendation 3-2

The Panel recommends that IESO and Hydro One work with their counterparts in Michigan and New York to bring the Phase Angle Regulators (PARs) into service as soon as possible. The Panel encourages the IESO and Hydro One to pursue available channels, including intra-regional discussions, to address any potential future delays resulting from issues raised by the owner of the Michigan PAR in order that Ontario and its neighbouring markets obtain the benefits available from operation of this equipment.

Implications of IESO's Pre-emptive Cutting of Exports

Because of the transmission limitation at the NYISO Central-East interface, the export capability at the Michigan intertie in Ontario is limited. The IESO has limited options under such circumstances: (i) failing exports after the final pre-dispatch run, or (ii)

[71] NYISO January 12, 2010 submission to FERC, 'New York Independent System Operator, Inc.'s Report on Broader Regional Markets; Long-term Solutions to Lake Erie Loop Flow' at p 13 and available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf

[72] A copy of ITC's communication with NYISO is available as exhibit "E" on the FERC website at: http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13784756

removing export schedules or offers before final pre-dispatch run, or (iii) implementing a reduced scheduling limit at the intertie or interties so that the Central-East interface in NYISO is not congested.

The first option, failing exports after the final pre-dispatch run, is highly undesirable as those failed exports would have resulted in more imports being scheduled (in pre-dispatch) that were not needed. This is inefficient. Failing exports after the final pre-dispatch run also distorts both the pre-dispatch and real-time price in Ontario and on all interties (by scheduling more exports that will fail and more imports that are not needed) and increases the price difference between pre-dispatch and real-time. This provides market participants with incorrect price signals. The Panel has repeatedly pointed out the importance of an efficient pre-dispatch price in past Monitoring Reports.

The second option, cutting exports before the final pre-dispatch run, can have the same result as the first option in relieving congestion in NYISO but also has the consequence of mitigating the price distortion between pre-dispatch and real-time. However, this pre-emptive action will have the effect of distorting the zonal price at the relevant intertie or interties. Because cutting exports before the final pre-dispatch run will confine the distortion to the interties where the exports are curtailed, this affects a smaller portion of the market, whereas the first option distorts the market as a whole. It appears that this option can lead to better results than the first option.

The third option, reducing the scheduling limit at the intertie (e.g. the Michigan intertie), is challenging to properly implement and could result in unintended consequences. For this reason, the IESO's practice is not to incorporate external congestion into its intertie capability setting process because of difficulties in understanding the nature and severity of congestion outside of the IESO-controlled grid. For example, congestion in NYISO could be the result of internal dispatches in NYISO and/or inadvertent loopflow, neither of which the IESO can control. It is also very difficult to set new scheduling limits because different transactions at a given intertie have different congestion implications on other interties and transmission paths. For example, exports to MISO at the Michigan intertie have a much smaller impact on congestion at the Central-East interface in NYISO than exports to PJM at the Michigan intertie because with the former transaction a smaller portion of exports flow through NYISO. Setting a scheduling limit that assumes all exports are scheduled to PJM may unnecessarily limit the export capability to MISO and create artificial congestion for exports to MISO. Conversely, setting a limit that assumes all exports go to MISO may not sufficiently mitigate the congestion in NYISO and would trigger a need to curtail exports after the final pre-dispatch run.

In summary, given the existing options, the most practical and efficient way for the IESO to independently assist NYISO to manage its congestion in the short term is to curtail exports before the final pre-dispatch run. In the longer term, a more efficient way to address the congestion problem might be achieved through improved coordination among market operators. By working collaboratively, market operators could properly price inter-jurisdictional transactions by including the congestion cost. The Panel understands that there are intensive discussions among market operators (particularly IESO, NYISO, MISO, PJM) on establishing a broader regional congestion management and settlement system, and that NYISO has recently submitted a report to the FERC advocating broader regional markets.[73] The Panel encourages this effort.

BP76 Transmission Line at the NYISO Intertie

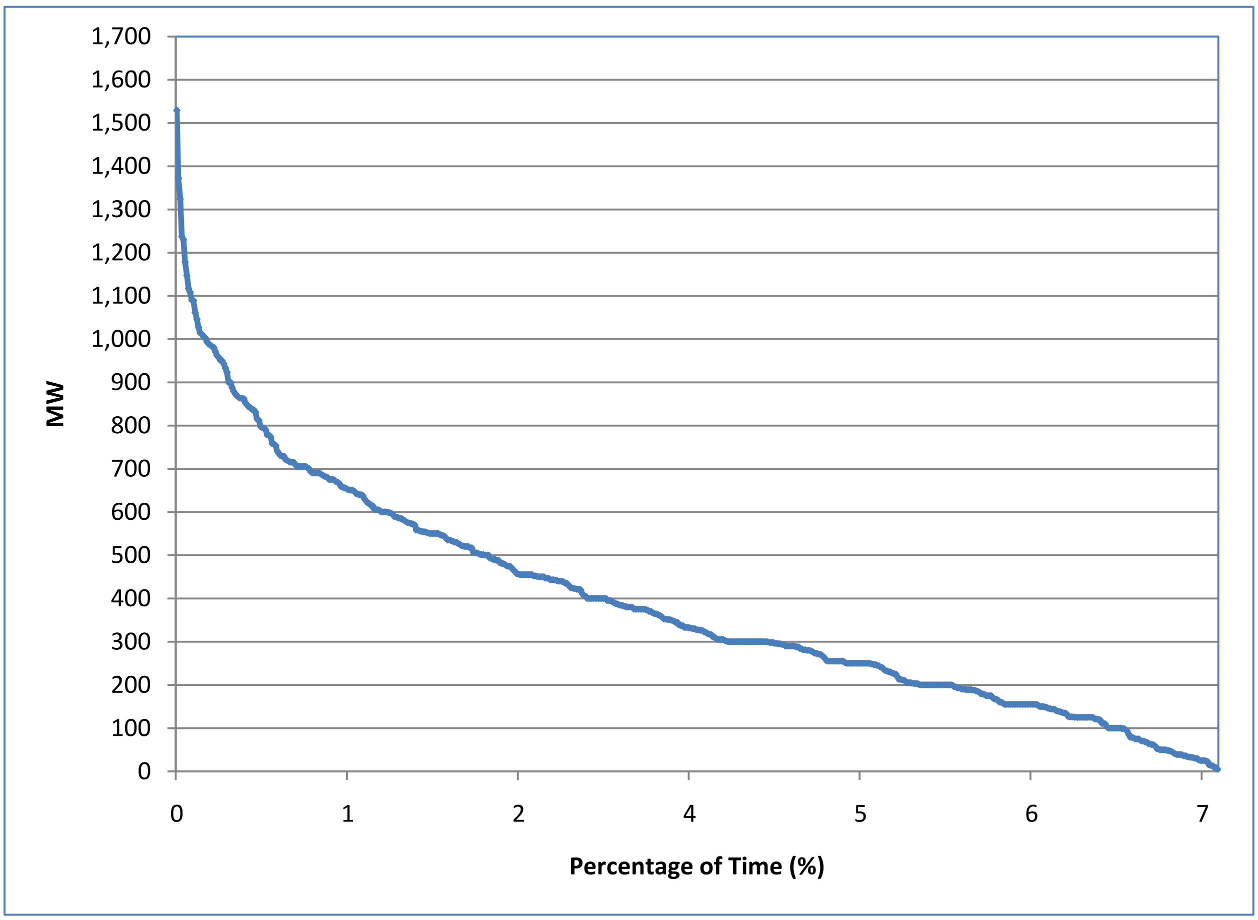
BP76 is a transmission line with a transfer capacity of about 500MW linking Ontario with NYISO at the Niagara border. The line was forced out of service on January 30, 2008 due to problems with one voltage regulator. The loss of the transmission line reduced import and export capability by about 500 MW.

The loss of BP76 contributed to more frequent congestion at the New York/Ontario intertie in recent months, which in turn reduced exports to both NYISO as well as MISO

[73] NYISO January 12, 2010 submission to FERC, ‘New York Independent System Operator, Inc.’s Report on Broader Regional Markets; Long-term Solutions to Lake Erie Loop Flow’, available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf

and PJM (through MISO). In the period November 2008 to October 2009, there were 620 hours (or 7.1 percent of the time) in which the IESO had to either curtail imports or manoeuvre nuclear generators to deal with Surplus Baseload Generation (SBG) situations. As Figure 3-7 below shows, had BP76 been in service during this period, the number of hours with SBG could have been significantly lower. For example, the number of hours with SBG would have decreased to 445 hours (5.2 percent of the time) had an additional 200 MW of exports been able to flow and 190 hours (1.9 percent of the time) had an additional 500 MW of exports been able to flow.

Figure 3-7: Duration Curve of Curtailed Imports and Constrained-down Nuclear for SBG
November 2008 to October 2009



To obtain a rough estimate of gains from trade that could have been achieved had BP76 been in service, the Panel studied five scenarios that assumed 100 MW, 200 MW, 300

MW, 400 MW and 500 MW of additional exports flowed when the NYISO intertie was export congested[74] or when PA301 and PA302 were on planned outage in March and April 2009. The Panel assumed the NYISO/OH zonal price to be the cost of providing energy in NYISO and the shadow price at the Beck station to be the cost of providing the additional exports. The supply curve is assumed to be linear and sloping upward.

Table 3-9 below lists the estimated potential gains from trade had BP76 been in service in the period November 2008 to October 2009. It can be seen that when PA301 and PA302 were on outage, the estimated gains could have been $2 to $11 million had BP76 been in service. In other periods of congestion, the estimated gains could have been $1 to $4 million during congestion hours. In aggregate, the gains could have been $3 to $15 million in the study period November 2008 to October 2009, depending on the increased volume of exports that would have flowed.

Table 3-9: Estimated Gains from Trade If BP76 Had Been in Service November 2008 - October 2009 ($ millions)

Average Additional Exports That Could Have Flowed (MW per Congestion Hour)	In Period When PA301 and PA302 Were Out of Service ($ Million)	In Hours When There Was Export Congestion to NYISO ($ Million)	Total ($ Million)
100	2.16	0.89	3.05
200	4.31	1.78	6.09
300	6.47	2.68	9.14
400	8.62	3.57	12.19
500	10.78	4.46	15.24

[74] The intertie was rarely import congested in the study period.

Recommendation 3-3

The Panel recommends that Hydro One work with its transmission counterpart in New York (National Grid) to return the BP76 transmission line at the New York/Ontario interface at Niagara into service in order to mitigate Surplus Baseload Generation (SBG) situations and realize gains from efficient trading opportunities for participants in the Ontario and New York markets.

3. New Matters

3.1 Issues in the Northwest Area

Introduction

The Northwest area has a large amount of generation compared to internal demand and limited transmission connections with the rest of Ontario as well as limited import/export capability at the Minnesota and Manitoba interties.

- Peak domestic demand in the Northwest is currently 450 MW and has steadily decreased to roughly one-half of its 2002 on-peak demand.
- The total generation capacity in the area is about 1,500 MW, with OPG accounting for 84 percent of the capacity, Abitibi Consolidated Company of Canada 11 percent, and four other participants 5 percent. Abitibi is also a large load. Most of the time it withdraws more energy than it generates (it was a net consumer for most of the period from November 2008 to October 2009).
- The maximum import/export capacity is 90/140 MW at the Minnesota intertie and 270/270 MW at the Manitoba intertie. Given that there is a large amount of baseload hydro generation in Manitoba, there are typically high volumes of imports into Ontario offered at the Manitoba intertie, potentially adding to the oversupply in the area.
- The maximum transmission capacity from the Northwest to the Northeast of Ontario is approximately 300 MW, but is frequently reduced in response to

storms (specifically lightning) in the area. Such reductions further exacerbate the surplus situation in the area.

As a result, there is abundant supply in the Northwest area from both OPG and Manitoba Hydro compared to demand by internal loads and exporters. Under a Locational Marginal Pricing structure, this surplus supply would likely lead to lower locational prices in the Northwest than the rest of Ontario.

However, the uniform pricing system in Ontario (i.e. a uniform price for generators and importers as long as they are scheduled in the unconstrained sequence) coupled with the CMSC payments arising from the constrained schedule has distorted generators' and importers' incentives to offer at their incremental or opportunity cost and has provided an incentive for exporters to bid strategically low in certain situations. Under the current uniform pricing system:

- The physical schedules of dispatchable resources are determined based on a locational marginal price structure. The difference between these physical schedules and the market schedule determined on a uniform price basis results in constraint payments to dispatchable resources.
- Generators and importers are paid constrained off payments for not producing and not importing. Because the constrained off payment is the difference between the HOEP and either their offer price or $0/MWh (whichever is greater), generators and importers may be incented to bid low or even at a negative price, rather than to offer at their incremental or opportunity cost.[75] To illustrate, assume the HOEP is $30/MWh and the incremental cost or opportunity cost for generators and importers is $5/MWh.[76] If they are constrained off, generators and importers will be paid $25/MWh ($30/MWh - $5/MWh) for not supplying energy if they offer

[75] Offering low or even at a negative price is a typical practice for a price taker. However, when the locational price is too low or negative, a price taker may not offer into the market. In the Ontario uniform price system, a market participant has incentives to offer in if the HOEP is positive even though the location (shadow) price is negative.
[76] It is possible that at times the opportunity cost for generators who are subject to environmental or regulatory constraints and importers who buy from a market with a negative price is negative.

their power at this incremental or opportunity cost. However, if they offer their energy at $0/MWh (or a negative price) and are constrained off, they will be paid $30/MWh. Thus the potential availability of a CMSC payment may motivate generators and importers to offer at a lower price (but still above the locational shadow price) to maximize constrained off payments. As a result and as the Panel has previously reported,[77] the zonal (shadow) price in the Northwest area is often very low or negative.

- As a result of low or even negative shadow prices in the Northwest, intertie shadow prices are also generally low or negative.[78] The result is that exporters may be scheduled even when they bid at low or negative prices (i.e. they may be constrained on if their bid price is less than the unconstrained one-hour ahead PD price). Because exporters are paid a constrained on payment, which is equal to the difference between the HOEP and their bid price, they end up being paid their bid, rather than the HOEP. Consequently, exporters have strong incentives to bid at low or negative prices (in the case of a negative bid price, exporters are paid to export). For example, assume the PD price and HOEP are both $30/MWh, but that the marginal generator (or importer) in the Northwest set the nodal or pre-dispatch shadow price with an offer of -$1,900/MWh. An export that bids at -$1,899/MWh will be constrained on as the IESO pre-dispatch tool calculates the transaction to be economic in the constrained sequence. As a result, the exporter will be paid a net amount of $1,899/MWh to export.[79]

CMSC Payments

Table 3-10 below lists the annual CMSC payments for the period from May 2002 to October 2009. Over the period, the total CMSC paid to all generators and intertie traders in the Ontario market was $1.005 billion (of which only $28 million were recovered to

[77]. See, for example, the Panel's July 2009 Monitoring Report, pp 36-42.
[78] For summer 2009, the average Northwest zonal price was -606.59$/MWh (by comparison, the average Richview price was $28.23/MWh)
[79] During the summer of 2009, the average intertie prices at Manitoba and Minnesota were $22.10/MWh and $23.13/MWh, respectively.

the market under Local Market Power and Constrained off Watch Zone provisions).[80] The total CMSC on the Minnesota and Manitoba intertie was $167 million (or 17 percent of total CMSC), of which $130 million was paid for constrained off imports and $37 million was paid for constrained on exports. Given the small size of these two interties (they represented approximately 7 percent of Ontario's aggregate intertie capability before the new Quebec intertie came into service in July 2009), the Northwest CMSC payments are very high. Beginning in 2007 constrained off payments in the Northwest area to importers have exceeded constrained off payments to internal generators, indicating that the majority of the constrained off payments in the area since 2007 have not been made to improve or maintain security of supply from internal resources.[81]

Table 3-10: Annual CMSC Payments
May 2002 to October 2009
($ millions)

	Northwest							Ontario[82]		
	Constrained Off			Constrained On						
Year	**Generators**	**MBSI**	**MNSI**	**Generators**	**MBSI**	**MNSI**	**Total**	**Constrained Off**	**Constrained On**	**Total**
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	0	4	35	68	39	107
2008	16	30	3	1	1	16	67	98	53	151
2009**	7	15	3	1	2	6	34	61	45	106
Total	151	105	25	9	3	34	327	572	433	1,005
Claw-back							10			28
Net CMSC							317			977

*from May to December 2002
** from January to October 2009

[80] The CMSC payments paid to dispatchable loads are excluded as the majority of these payments were clawed back under standard procedures set up in the Market Rules.
[81] Neither OPA nor IESO count import capacity as potential supply when they assess internal adequacy unless the import capacity is associated with a specific amount of imports under contracts. In other words, imports are not counted for Ontario reliability.
[82] Excluding dispatchable loads.

The total constrained off payments to generators and to importers on the Manitoba intertie in 2009 were lower than in 2008. This is primarily due to lower Ontario prices (as well as the fact that the 2009 data only covers 10 months). However, constrained on payments to exporters on the Manitoba intertie have been much higher.[83] The Panel's remedial recommendations are discussed later.

Issues at the Minnesota Intertie

The Minnesota intertie has approximately a dozen active traders who regularly participate at the intertie. However, traders who identify instances of little or no competition or who have a better understanding of the Ontario Market Rules or operational procedures may gain a large profit through CMSC payments that are not transparent to others and that provide no benefit to the Ontario market. Examples of how large CMSC's have been induced are shown below.

- Some traders have persistently offered a portion of their exports to MISO at a large negative price. These low-priced exports were rarely scheduled in the constrained sequence, but when scheduled they received significant constrained on payments. For example, on June 21, 2008, two exporters bid -$1,900/MWh to export up to 80 MW. In HE 23, the intertie pre-dispatch shadow price (in the constrained sequence) was -$1,953/MWh and the pre-dispatch price (in the unconstrained sequence) was $40.02/MWh. As a result, the exporters were constrained on and paid $1,900/MWh for exporting. In the overnight hours from June 21 to 22, 2008, the two exporters continued to bid at a negative price (with bids varying depending on the hour) and were scheduled. In total, the traders

[83] They increased significantly again in November 2009 ($761,000), compared to an average of $224,000 per month in the first 10 months in 2009).

were paid $2.2 million in CMSC for constrained on exports during these two days.[84]

- In late September 2009, a few exporters received large CMSC payments when the IESO was curtailing exports. Beginning on September 18, 2009, the net export capability at the Minnesota intertie was significantly reduced due to an outage to one of the interconnecting transmission lines. The net export capability remained as low as 20 MW until October 31, 2009. With such a low limit, even a small amount of exports could cause congestion. At the same time, there were frequent import failures (to Ontario) due to MISO ramp or transmission limitations within Minnesota. Following import failures, it became necessary to cut exports to prevent an overloading of the intertie. The IESO responded to the import failures by cutting an equivalent amount of exports. The IESO's procedure was to attach a TLRi code to these curtailed exports. As a result, these curtailed exports remained in the unconstrained sequence, triggering constrained off payments to exporters. In the period September 18 to October 31, 2009, the IESO paid about $1.7 million dollars for those constrained off exports, or on average $674/MWh (2,520 MWh in total).

Change in Coding for Export Curtailment in Response to Import Failure

The MAU identified the export CMSC issue when it occurred, reported it to the Panel and referred it to the IESO's Operations Analysis Department. The Panel has previously discussed the implications of the use of various codes for intertie transactions and observed that, when a transaction is failed by an external ISO or by the trader involved in the transaction, the transaction should be viewed as either not feasible independent of its offer/bid price in Ontario or not reflective of its willingness to pay or sell by the market

[84] One exporter has paid back just over $300,000 under the Local Market Power provisions and the MAU has ongoing proceedings which are seeking a CMSC recovery from the other exporter's constrained on payments according to the Market Rules section 7.6.

participant concerned.[85] A similar analysis can also be applied to the current case: the curtailed exports are not feasible independent of their bid prices in Ontario because they must be cut in direct response to the import failures for external reasons. As a result, the Panel recommended that the IESO adjust the unconstrained sequence accordingly (i.e. remove their unconstrained schedules) both to avoid unnecessary CMSC payments and to prevent distortion of the market price. The IESO changed its coding practice effective November 25, 2009, removing these curtailed exports from the unconstrained sequence and therefore making them ineligible for CMSC payments.[86]

Transmission Rights

As the market and system conditions continue to evolve, the dispatch of transactions at the Minnesota intertie has become more and more counter-intuitive and has contributed to the underfunding of the Transmission Rights market in aggregate. The purpose of Transmission Rights is to provide market participants a means to hedge the financial risk that results from transmission congestion. In the physical power system, an intertie can only be physically congested in the same direction as the power flow. However, with the two dispatch sequences in Ontario, an intertie could show as congested in the unconstrained sequence when in fact there is no actual power flow or transactional power flows in the opposite direction.

Table 3-11 below lists the total number of hours with import congestion in the unconstrained sequence at the Minnesota intertie and the total number of hours with no net imports in these hours.[87] Import congestion reached a peak in 2005. However, of the 1,637 hours, 733 hours (or 45 percent) had no net imports at all. Although the number of

[85] See, for example, the Panel's July 2008 Monitoring Report, pp 171-180.
[86] For details, see November 10, 2009 meeting materials at the Inter-Jurisdictional Trading Standing Committee website at: http://www.ieso.ca/imoweb/consult/intertieTrading_sub.asp. On the first day when the new code practice took place, a 5 MW export that was offered at $2,000/MWh was cut in HE 1-7. The use of TLRe reduced the constrained off payment by about $70,000.
[87] The statistics for export congestion are not reported because this intertie is rarely export congested.

hours with import congestion dropped in 2007 and 2008, it rebounded in 2009. Moreover, the percentage of the time with no net imports in the hours with congestion showing in the unconstrained schedule has increased steadily since 2004 and reached 93 percent in the first 10 months of 2009.

Table 3-11: Number of Hours with Import Congestion in the Unconstrained Sequence and Number of Hours without Net Imports at the Minnesota Intertie May 2002 to October 2009

Year	Number of Hours without Net Imports When There Is Import Congestion in the Unconstrained Sequence	Number of Hours with Import Congestion in the Unconstrained Sequence	Percentage of Time (%)
2002*	224	363	62
2003	12	95	13
2004	176	1,353	13
2005	733	1,637	45
2006	566	1,087	52
2007	451	623	72
2008	329	391	84
2009**	1,072	1,152	93
Total	3,563	6,701	53

*from May to December
**from January to October

This changing pattern of congestion has a significant implication on the Transmission Rights market. The TR account is under-funded when the congestion payments to TR holders (which are based on the congestion in the unconstrained sequence) are greater than the congestion rent collected from traders (which is based on the net flow in the same direction as the congestion). When there is no power flow or power flow in the opposite direction, there is no congestion rent being collected. This shortfall eventually has to be offset by the TR auction revenue (i.e. paying less rebate to Ontario consumers), or through other charges to consumers if the TR auction revenue is insufficient (this has never occurred since market opening)

Issues at the Manitoba Intertie

The Manitoba intertie has historically had a unique dynamic with only one effective trader (Manitoba Hydro). Manitoba Hydro typically offers at a low price to import into Ontario. However, these imports are constrained off, either in full or in part, the vast majority of the time due to an abundance of supply in the Northwest. As a result, over the last seven years Ontario ratepayers have paid approximately $80 million in constrained off payments to Manitoba Hydro with an average of about $23/MWh (based on actual scheduled imports at the interface).

In addition to receiving constrained off payments for its imports, Manitoba Hydro has been paid a significant amount of constrained on payments for constrained on exports from Ontario to Manitoba ($3 million from May 2002 to Oct 2009). In many instances, Manitoba Hydro bid a negative price to export back to Manitoba, and was constrained on. This strategy led to Manitoba Hydro being paid to export from Ontario to Manitoba. In summary, Manitoba Hydro has been receiving constrained off payments for not importing into Ontario and has also received constrained on payments to export from Ontario into Manitoba, often simultaneously. The Panel will discuss the simultaneous constrained on and constrained off issues in more detail in the assessment section later.

There were a few other traders who had actively offered imports on the Manitoba intertie. However, they were rarely successful due to difficulties in obtaining transmission service in Manitoba or MISO. Nevertheless, they frequently received constrained off payments for their offered imports, without needing to arrange for the physical flow. Both the trade volume and constrained off payments to these participants had been small.

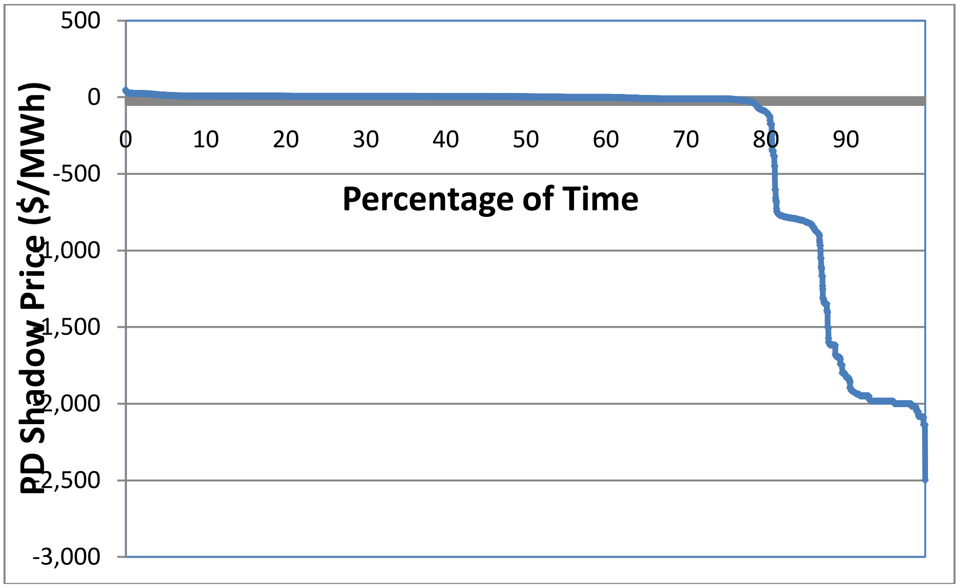
Historically, one reason traders were unable to obtain transmission service in MISO or Manitoba was that the timeframe in which the IESO released the non-firm transmission service was too late to allow traders to obtain necessary transmission service through Manitoba as well as into or out of MISO in time for scheduling. To address this problem, the IESO implemented a new procedure on September 8, 2009, which provides traders with sufficient time to obtain transmission service.[88] Since its implementation, one market participant has successfully acquired transmission service to export a large volume of energy to MISO through Manitoba.[89] Because the trader has managed to be scheduled at a low or even negative bid price, it has received a large amount of constrained on payments ($461,000 or $28/MWh from September 8 to November 17). Had some exports not failed due to the trader's inability to obtain ramp capability in MISO, the constrained on payments would have been greater.

Figure 3-8 below depicts the duration curve of the pre-dispatch shadow price at the Manitoba intertie for the period May to October 2009. The pre-dispatch shadow price was negative about 40 percent of the time, less than or equal to -$10/MWh 32 percent of the time, less than or equal to -$100/MWh 20 percent of the time, and less than or equal to -$1,000/MWh 13 percent of the time. The graph indicates that there have been extensive opportunities for exporters to bid at prices that would result in the receipt of large constrained on payments.

[88] Under the old procedure, ETAGs are adjusted 30 minutes before dispatch (T-30) after the 1 hour ahead pre-dispatch (PD) run is complete, with subsequent transmission release. Thus if Manitoba did not have a constrained schedule, the release of its transmission began only at T-30. 30 minutes does not allow enough time for MPs to acquire transmission service through Manitoba as well as into or out of MISO. As a result, MPs who do not initially acquire transmission service but are scheduled during the final PD run are forced out of the market and their transactions do 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 PD run.

[89] The Panel has asked the MAU to continue to monitor the extent to which additional trades are able to obtain transmission service and implement import or export transactions under the new procedure.

Figure 3-8: Duration Curve of the Pre-dispatch Shadow Price at the Manitoba Intertie May – Oct 2009($/MWh and %)



Similar to Minnesota intertie, the congestion in the unconstrained sequence has been persistently inconsistent with the power flow at the Manitoba intertie. Table 3-12 below lists the total number of hours with import congestion in the unconstrained sequence and the total number of hours with no net imports in these hours at the Manitoba intertie.[90] It can be seen that the intertie has been increasingly import congested in the past three years in the unconstrained sequence, yet there are more and more times (rising from 7 percent in 2005 to 69 percent in the first 10 months of 2009) in which there were no net imports within these hours.

[90] The intertie was never export congested.

Table 3-12: Number of Hours with Import Congestion in the Unconstrained Sequence and Number of Hours without Net Imports at the Manitoba Intertie
May 2002 - October 2009
(Number of Hours and %)

Year	Number of Hours without Net Imports When There Is Import Congestion in the Unconstrained Sequence	Number of Hours with Import Congestion in the Unconstrained Sequence	Percentage of Time (%)
2002*	0	71	0
2003	0	40	0
2004	6	77	8
2005	13	184	7
2006	3	27	11
2007	68	114	60
2008	193	314	61
2009**	532	771	69
Total	815	1,598	51

*from May to December
**from January to October

Assessment

In an effectively competitive market, the Market Clearing Price signals the true supply and demand condition and provides power suppliers and purchasers with appropriate incentives to participate in the market. However, in the uniform price regime, market participants pay or are paid CMSC payments in addition to the uniform Market Clearing Price. Absent competition, there is both a potential impact on efficiency and a potential to game the market. In the Northwest area, the impact on market efficiency might be relatively small as there is an abundance of low cost supply relative to external jurisdictions. In other words, power is generally flowing from the low cost area (the Northwest area) to higher cost external markets (e.g. MISO). For example, in the period November 2008 to October 2009 there were 343 hours (3.9 percent of the time) with a negative price at the Ontario zone in Minnesota, compared to 3,681 hours (42.0 percent of the time) with a negative shadow price at the Minnesota zone in Ontario.

The uniform price system provides market participants with opportunities to obtain excessive CMSC payments from the marketplace through strategic bidding practices. When importers and generators bid low to get constrained off payments, and exporters bid negatively to get constrained on payments the result is higher uplift costs for Ontario consumers.

Paying exporters to export power from the Northwest area has in general the implication of increasing costs to Ontario ratepayers.[91] Generators in the Northwest may have a negative opportunity cost at times due to environmental constraints, which induce them to offer below $0/MWh.[92] The constrained off payment, however, incents generators to offer at a negative price with little or no financial consequence, even though the opportunity cost of producing the power is positive. The negative offer price frequently results in a negative shadow price at the interties, thus resulting in exports being constrained on. Although the constrained off payments to generators and importers were capped at HOEP after a rule change in June 2003 following the Panel's recommendation,[93] the constrained on payments to exporters were not.

In the past, the Panel recommended removing all constrained off payments as these payments reduce efficiency and do not appear to be necessary for system reliability. They may also provide market participants with opportunities for gaming.[94] For example, the Panel's December 2003 report recommended that the IESO assess whether constrained off payments have provided corresponding value to the market and to look for other

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[91] For example, the DSO schedules 100 MW of exports to MISO. Assume the PD shadow price is -$1,900/MWh and the PD and RT price is $30/MWh. The exports are bid at -$1,899/MWh to export. As a result, it is constrained on. It will pay the price of $30/MWh to the market, but receives $1,929/MWh of constrain-on payment. As a result, it is paid $1,899/MWh to export. Because generators are paid $30/MWh to provide the power and exporters are paid $1,899/MWh for exporting, Ontario consumers end up paying $1,929/MWh for energy that they have not received.

[92] For example, generators may have to generate power at times when water is required to flow during the fish spawn season but cannot be spilled due to safety concerns for the dam or lack of remote access to the water gate.

[93] Generators and imports are not paid CMSC for the portion of their offer price below $0/MWh. For example, for a HOEP of $20/MWh and offer of - $100/MWh, the constrained off generator or importer receives CMSC of $20/MWh.

[94] See the Panel's 2003 special report "Constrained-off Payments and Other Issues in the Management of Congestion", and the Panel's previous Monitoring Reports.

alternatives to improve market efficiency and reliability.[95] Although the IESO did not implement this recommendation, it did cap constrained off payments to generators and importers by limiting payments to a level that would result from an offer at $0/MWh.

The Local Market Power and Constrained off Watch Zones (COWZ) have been developed to address some potential concerns with CMSC payments. However, they are relatively ineffective when intertie transactions are involved:

- Local Market Power mitigation was part of the initial Market Rules and was introduced in order to mitigate large CMSC payments at times when a market participant has market power in an area with transmission constraints/limitations.[96]

- Local Market Power was viewed as inadequate to deal with CMSC on the interties because of the "sufficient competition" and "historical price" screens. To overcome these limitations, the IESO introduced COWZ which allowed for clawing back CMSC when it occurred in a constrained off watch zone, and where the CMSC was persistent and significant. The Northwest is the only constrained off watch zone, but at present the COWZ process is limited to constrained-off supply (i.e. imports and generation).[97]

While the current Local Market Power/COWZ regimes allow for some recovery, the process has proven to be lengthy and difficult. The MAU recently completed an April - September 2008 case with one market participant, which clawed back several million dollars of CMSC payments that were generated in those months. With another intertie trader, the MAU is attempting to recover a portion of the close to $2 million in CMSC paid for constrained on exports that occurred on June 21-22, 2008 (see description above). The process has not been completed and has the potential to be delayed further if

[95] The Panel's December 2003 Monitoring Reports, pp 86-87.
[96] Market Design Committee – Final Report: at page 2-10, available at:
http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/FinalReport/Vol1/Volume%201.pdf
[97] See: http://www.ieso.ca/imoweb/marketSurveil/lmpm.asp

the participant chooses to dispute the recovery. There was also an extended process for the recovery of a portion of CMSC from another participant for constrained off exports during the same June 21-22, 2008 period. The Panel plans to review the operation of the Local Market Power/COWZ processes in 2010 to assess whether they can be made more effective, perhaps by standardizing CMSC recovery calculations within the Market Rules.

Although the Panel believes that an ideal long-term solution is a Locational Marginal Pricing regime, a hybrid regime that includes a uniform price to loads but Locational Marginal Pricing for generators and intertie traders, could also improve market efficiency. This could likely be implemented using a single schedule that reflects system constraints, with the load price being calculated as a province-wide average of locational supply-side prices. A locational marginal price for generators and traders would force them to bear the risk of a negative locational price and thus remove their incentives to bid below their incremental cost or opportunity cost. Although a uniform price (i.e. average generation cost) would not provide incentives for consumers with a high price responsiveness to respond to localized price signals.

While the Panel has on many occasions identified problems resulting from the two-schedule design of the Ontario market, it recognizes that a redesign could involve considerable time and resources. To address this particular concern in the short term, the IESO could take actions to limit the constrained on payment to exporters. One possible option is to replace (for CMSC calculation purposes) the participant's negative priced bid with $0/MWh, in a similar way as the importers and generators are constrained off.[98]

Table 3-13 below lists the potential monthly reductions to constrained on payments paid to exporters had the CMSC been calculated based on a replacement bid of $0/MWh when

[98] To deal with the over-supply situations, there are two alternatives: constraining down generators or constraining on exporters. To Ontario consumers, constraining down generators will cost them the HOEP (i.e. the constrained off CMSC payment). If constraining on exporters only costs them the HOEP (e.g. giving them free energy), they are no worse off. As a result, to Ontario consumers, the use of a replacement offer of $0/MWh for constrained on exports (i.e. giving exporters free energy) has the same consequence as constraining down generators.

exporters bid below $0/MWh. The total savings to Ontario consumers would have been $3.5M during the period November 2006 to October 2009.

Table 3-13: Potential Reduction in Constrained on Payments to Exporters November 2006 to October 2009 ($ thousands)

Period	Constrained on CMSC to Exporters	Estimated Constrained on CMSC With a Replacement Bid of $0/MWh	Reduction
Nov 06 -Oct 07	2,419	2,368	51
Nov 07 -Oct 08	28,346	26,007	2,339
Nov 08 -Oct 09	16,978	15,904	1,074
Total	47,743	44,279	3,464

It is worth noting that the cap does not solve all wealth transfer problems, as illustrated by the following example. On the Manitoba intertie, an importer offers $1.00/MWh to import from Manitoba and an exporter bids $2.00/MWh to export to MISO through Manitoba. Assume both the zonal pre-dispatch MCP and the hourly price at the Manitoba intertie (in the unconstrained sequence) are $30.00/MWh, and the zonal pre-dispatch shadow (in the constrained sequence) at the intertie is price $1.50/MWh. As a result, both the import and the export are scheduled in the constrained sequence (i.e. the export is constrained on), and there is no net flow at the intertie. The import is paid the price at the intertie of $30.00/MWh, but the constrained on exporter pays only $2.00/MWh (after CMSC adjustment). Consequentially, Ontario consumers pay $30/MWh to the importer but only charge $2/MWh on the exporter. The net result is that Ontario consumers pay $28.00/MWh for the exporter to move power from Manitoba to MISO.

Recommendation 3-4

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

create more consistent treatment with generators and importers that are constrained off.

3.2 The Expiration of the OPG Rebate Mechanism for its Non-prescribed Assets

As a publicly-owned generator, OPG has been subject to a variety of measures designed to constrain or reduce its potential to exercise market power since market opening in 2002. The most recent regulation of OPG's generation assets was to separate its assets into two categories: prescribed assets (all nuclear units and hydro units at Beck, Saunders and DeCew Falls)[99] and non-prescribed assets (all other generation units, except Lennox).[100] There has been a revenue cap of $48/MWh on 85 percent of the output from the non-prescribed generation facilities over each hour (subject to certain adjustments) beginning May 2006. On April 30, 2009 the revenue cap on OPG's non-prescribed assets was removed.
The total generation capacity in the non-prescribed category is about 10,870 MW, of which 6,720 MW (62 percent) is from coal-fired generators and 4,150 MW (38 percent) from hydroelectric generation. These assets currently account for roughly 30 percent of total installed capacity in Ontario. OPG announced on September 3, 2009 that four coal-fired generation units will be closed by October 2010, which represents a reduction of about 2,050 MW of generation capacity. By the end of 2014, all remaining coal-fired generation is scheduled to be phased out pursuant to a government objective.[101]

The elimination of the regulation is expected to incent OPG to respond more efficiently to the market price signal, which in turn generally improves market efficiency. However, the Panel is also concerned about the potential adverse impact of OPA's contracts with other generators as well as IESO programs on the efficient operation of OPG's peaking

[99] For a discussion of the most recent changes to the regulation of the prescribed assets, see the Panel's July 2009 Monitoring Report, pp 209-218.
[100] For more information, see the Panel's July 2009 Monitoring Report, pp. 209-217.
[101] See http://www.news.ontario.ca/opo/en/2007/06/mcguinty-government-sets-ambitious-realistic-greenhouse-gas-targets.html

hydro generators. Specifically, low cost water at OPG's peaking hydro facilities may be incented to spill at times when fossil-fired generators are online because of incentives created by OPA contracts or IESO programs. The Panel has asked the MAU to monitor the activities at the non-prescribed generation stations and assess whether the other IESO's programs or OPA contracts have affected OPG's operational strategy.

3.3 The Actions of a Combined cycle Market Participant

In the previous Monitoring Report the Panel advised of an ongoing assessment involving the behaviour and pricing by a combined cycle generator in the real-time generation cost guarantee (RT-GCG)[102] program and whether the behaviour constituted gaming or an abuse of market power.[103] The Panel subsequently identified six matters that required further review:

1. Changes to plant operating characteristics;
2. Allocation of costs between gas and steam units;
3. Increases in offer prices once a unit had been constrained on;
4. Offer strategy potentially designed to maximize revenues that resulted in overnight runs;
5. Participation in the OR market for the purposes of obtaining high CMSC payments; and
6. Offering of high prices during ramp up and ramp down hours.

The six matters have been addressed as described below.

Changes to plant operating characteristics

The focus of the Panel's assessment related to alterations to the market participant's generation plant operating characteristics. Specifically, the market participant increased the minimum run times (MRT) and minimum loading points (MLP) associated with its

102 This program has historically been referred to as spare generation online (SGOL) program.
103 See the Panel's July 2009 Monitoring Report at pp. ix to the executive summary and 247.

units. The Panel's concern was that these increases may have been motivated by financial considerations relating to RT-GCG program payments rather than genuine operating limitations. Subsequent discussions and additional information gathered by the MAU indicated that the market participant's submitted operational characteristics were not materially higher than the submitted operating characteristics of other comparable generation facilities.

At present generators are required to submit a technical explanation for changes to operating parameters. However, the IESO does not currently provide market participants with precise parameters for determining plant operating characteristics, nor does it have a clear means to confirm the validity of submitted characteristics. As such the Panel regards this as a general operational matter for the IESO. The IESO is aware of this issue and is at preliminary stages of considering how to set sufficiently precise parameters for operating plant characteristics.

Effective December 9, 2009 the IESO introduced a Market Rule amendment governing the RT-GCG and day-ahead generation cost guarantee (DA-GCG) programs.[104] The Market Rule amendment introduced more stringent eligibility requirements for the programs. Specifically, to attain program eligibility a generator must be economically scheduled at its MLP for at least half of its minimum generation block run-time (MGBRT).[105] This compares to the former program whereby generators needed only have one economically scheduled MW for one hour to achieve RT-GCG eligibility. The more stringent RT-GCG program requirements introduced under the Market Rule amendment should incent generators to provide the IESO with MLP's, MRT's and MGBRT's that do not exceed actual plant operating characteristics. A failure to do so would increase the risk that the generator would qualify for fewer GCG program runs.

104 Market Rule Amendment 356, available at: http://www.ieso.ca/imoweb/pubs/mr2009/MR-00356-R00-R02-BA.pdf
105 Minimum generation block run-time is defined as the number of hours specified by the market participant, that a generation facility must be operating at minimum loading point in accordance with the technical requirements of the facility.

Recommendation 3-5

(i) ***The Panel recommends that the IESO provide market participants with specific parameters for determining operating plant characteristics, including Minimum Loading Point (MLP), Minimum Run-Time (MRT) and Minimum Generation Block Run-Time (MGBRT) in order to ensure that submitted operating characteristics, which affect market outcomes, reflect actual operating capabilities.***

(ii) ***The Panel recommends that the IESO develop a compliance or other review mechanism for ensuring that submitted operating characteristics are appropriate having regard to the parameters specified and equipment capabilities.***

Allocation of costs between gas and steam units

The Panel's assessment focused on whether the market participant was gaining advantage from the lack of specificity in the GCG program as to how costs should be assigned between natural gas and steam units of a combined cycle plant. The Panel was originally concerned that certain costs incurred by the gas units were being allocated to the steam unit. In doing so, the market participant may have received payments on the steam unit for costs incurred by the gas units and inflated cost recovery relative to revenues and costs based on a plant-wide allocation.

The Panel recognized that neither Market Rules nor IESO procedures specified how costs were to be allocated between the gas and steam turbines of a combined cycle plant. It also observed that there are a variety of allocations which have been used by market participants and accepted by the IESO. Accordingly, in its last Monitoring Report the Panel recommended that the IESO should use a plant-wide approach for cost guarantees or otherwise eliminate allocations that result in over-compensation.[106]

106 See the Panel's July 2009 Monitoring Report at p ix to the executive summary and p 202.

As described in section 3.3 above, on December 9, 2009 IESO Market Rule amendment 356 changed the manner in which generation costs are recovered under the GCG program. As a consequence of the Market Rule amendment generators are no longer permitted to provide after-the-fact submissions of costs as the basis for recovering generation cost guarantees for their MGBRT. Rather, MGBRT costs are reimbursed based on the market participant's offer price. The Panel expects the IESO's Market Rule change should help to address various issues raised in previous Panel Reports and has asked the MAU to continue to monitor generator actions related to the programs. In addition, the Panel has learned of a proposed Market Rule amendment that may limit CMSC payments for the steam unit of a combined cycle generator to the offer price of the underlying gas unit.[107]

Increases in offer prices once a unit had been constrained on

The Panel was concerned that the market participant had occasionally increased its offer prices once it had been selected under the RT-GCG program. Although the market participant became ineligible for cost guarantees by virtue of raising its offer prices, it did receive CMSC payments for these time periods. Following further discussion with the market participant the Panel is satisfied that the incidents were isolated events, rather than a practice designed to increase CMSC payments.

While the Panel is satisfied the actions of the market participant did not constitute a concern in this case, the availability of CMSC payments to generators that raise their offer prices once constrained on raises broader concerns around the generation cost guarantee programs. As an example, in real-time a market participant that has been constrained on can increase its offer price and earn CMSC payments that may far exceed the cost guarantees foregone. Under the existing structure of the cost guarantee

107 Market Rule Amendment 252. Progress can be tracked at http://www.ieso.ca/imoweb/consult/consult_se84.asp

programs, the IESO has no recourse to recover these CMSC payments. The Panel is pleased to learn that the IESO has initiated a Market Rule amendment[108] that would deny or significantly limit the payment of CMSC payments to generators that revise their offer prices once constrained on under the generation cost guarantee programs. The Panel would have made a recommendation in this report to deny CMSC payment had the IESO not already initiated action on this front. At the time of drafting, the Market Rule amendment was scheduled to appear before the IESO's Technical Panel in early 2010.

Offer strategy potentially designed to maximize revenues that resulted in overnight runs

The Panel's assessment focused on whether the market participant's offer price strategy was designed to maximize revenues that resulted in the generation units running overnight. Specifically, the Panel was concerned that the market participant lowered its offer price over the course of the day so as to target high-priced afternoon peaks that would maximize revenue (energy payment plus CMSC). Due to the generation unit's long MRT, afternoon starts resulted in the unit running during some overnight hours. Running units overnight, when there is little likelihood of a need for spare generation, is contrary to the purpose of the GCG program.

In response to the Panel's concern, the market participant advised MAU that it does not target start-ups later in the day. Rather, throughout the day it weighed the benefits of recovering a portion of its costs against the cost of not running at all. It lowered its prices over the day because it incurred additional charges when the plant fails to meet minimum consumption requirements under its gas contract.

The Panel's concerns may be largely alleviated through the introduction of Market Rule amendment 356, which introduces more stringent eligibility requirements for the RT-

[108] *Ibid*

GCG program.[109] The Panel will monitor the impact of the Market Rule amendment on overnight RT-GCG runs.

Participation in the OR market for the purposes of obtaining high CMSC payments

Beginning September 2008, the IESO removed its control action operating reserve (CAOR) from the pre-dispatch sequence in response to an increase in export failures caused by NYISO and MISO refusing to accept recallable exports from Ontario. These recallable exports had been used to back up the scheduled CAOR in pre-dispatch (for 10 minute reserve).

Removing the CAOR from pre-dispatch eliminated the recallable export designation. However, eliminating CAOR from pre-dispatch also contributed to higher pre-dispatch OR shadow prices (in the constrained sequence) and at times OR shortages during the freshet period and during the summer, when peaking hydro resources provide energy rather OR. A higher pre-dispatch OR shadow price provides fossil-fired generators who offer OR an opportunity to be dispatched online even when their energy offer prices are high. For a fossil-fired generator to be able to supply OR, it has to be online and generating at least at its MLP. In pre-dispatch, if the net benefit associated with the generator providing OR exceeds the loss associated with the generator providing the energy, the IESO's DSO will constrain-on the generator to its MLP. Once constrained on, the generator receives CMSC payments that compensate it up to its energy offer price for the duration of its MRT.

Beginning in early 2009, the market participant began to offer 10 minute spinning reserve. It appears a driver for participation in the OR market was high CMSC payments that could be obtained through high energy offer prices.[110] During instances of extremely

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[109] Market Rule Amendment 356, available at: http://www.ieso.ca/imoweb/pubs/mr2009/MR-00356-R00-R02-BA.pdf

[110] The Panel presupposes that a generator participating in the OR market intends to provide OR. Although the generator was participating in the OR market, on a number of instances when called upon to provide OR, it failed to do so.

high OR prices in pre-dispatch, the market participant increased its energy offer prices. The increased energy offer prices were most notable at the market participant's steam unit, where prices previously set at $0/MWh rose to as high as $501/MWh (considerably above incremental cost) for hours during the market participant's schedule. Even at energy prices as high as $500/MWh, its units would be scheduled for energy and OR in pre-dispatch under certain circumstances and in certain hours. Once scheduled, the market participant's generation units were constrained on for the duration of its MRT. As a result, the market participant received very high CMSC payments on its steam units. Over a 15 day period in May and June 2009, the market participant received approximately $600,000 in payments associated with its OR offer strategy

Although similar opportunities have subsequently arisen, the market participant has ceased offering extremely high energy prices while participating in the OR market. In this instance the MAU discussed the Panel's potential concerns with the market participant but a formal gaming investigation was not initiated. However, a reimplementation of the strategy could trigger a formal gaming investigation.

Offering of high prices during ramp up and ramp down hours

The Panel was concerned that the market participant's offer price during ramp up and ramp down hours was higher than required to initiate unit start up or unit shut down. Generation units participating in the GCG program are permitted to ramp their units to the MLP in the hour prior to the GCG start. To indicate to the IESO that they do not wish to ramp beyond their MLP, generators typically offer at a high price during this hour. A high-priced offer during the ramp-up hour is not cost-based, but rather a signal. However, this offer is also the basis upon which CMSC payments are made. Where the offer price is higher than the Market Clearing Price (as is expected) the generator is paid CMSC payments which bring its overall compensation up to its offer price. For this reason, ideally generators would offer at a price that is no higher than what is required to prevent them from ramping beyond their MLP.

Similarly, generators typically use high price offers in the hour immediately following their MRT to signal to the IESO their desire to shut down. Again, these offers are not cost-based, but rather a signal that the generator wants to take its unit off-line. Due to equipment constraints, it can take generators multiple intervals to shut down. During this ramp down period generators are paid HOEP as well as CMSC payments on the difference between their offer price and HOEP. Since the offer price is only a signal, generators would ideally offer at a price that is no higher than what is required to shut down. The total magnitude of the CMSC payments depends on the generator's offer price as well as the unit's ramp rate.

In a previous report, the Panel recommended that the IESO take action to limit CMSC payments that are induced by generators strategically raising offer prices to signal ramping events.[111] The Panel remains concerned about this type of behavior and the use of extremely high offer prices during ramp up and ramp down could trigger a formal gaming investigation. The Panel is pleased to learn that the IESO proposed Market Rule amendment[112] would significantly limit or deny the payment of CMSC under these circumstances. The Panel will monitor the impact of this proposed IESO rule amendment, which is expected to be implemented in mid 2010.

3.4 The Impact of the New Quebec Direct Current (DC) intertie

Imports and exports are important for both system reliability and market efficiency. Ontario currently has about 7,400 MW of interconnected name-plate capacity with external markets or jurisdictions, of which about 5,000 MW are considered as achievable.[113] Of the 7,400 MW name-plate capacity, approximately 2,000MW are at

[111] See the Panels January 2009 Monitoring Report, at pp. 216 – 217.
112 Market Rule Amendment 252. Progress can be tracked at http://www.ieso.ca/imoweb/consult/consult_se84.asp
113 The effective transmission capability is smaller than the arithmetic sum of individual flow limits at all interties. The arithmetic sum of individual flow limits is not achievable because achieving it represents a significant reduction in internal generation. For detail, see: http://www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2009nov.pdf

each of the Michigan and New York interties, about 3,000 MW at the Quebec interties, about 270 MW at the Manitoba intertie, and about 100 MW at the Minnesota intertie.

This section focuses on the impacts of a new Quebec intertie that was brought partially into service in July 2009 and then fully into service in November 2009. It is a preliminary study on this intertie. The Panel has asked the MAU to continue monitoring the transactions at the intertie and to analyze whether and how the new intertie has induced behavioral changes by market participants. The Panel may report our findings in future reports.

Ontario-Quebec Interties

There are nine interties at the Ontario/Quebec border. Some interties (such as Rapide Des Iles, Bryson, Paugon and Beauharnois) only have import capability because these are generators on the Quebec side, some interties (such as Kipawa) only have export capability because there are only loads on the Quebec side, while others (such as Maclaren, Masson, and Outaouais) have both import and export capability. Table 3-14 below lists the normal import/export capability at these interties as well as their operational characteristics. The transmission capability at these interties varies from 50 MW up to 1,250 MW.

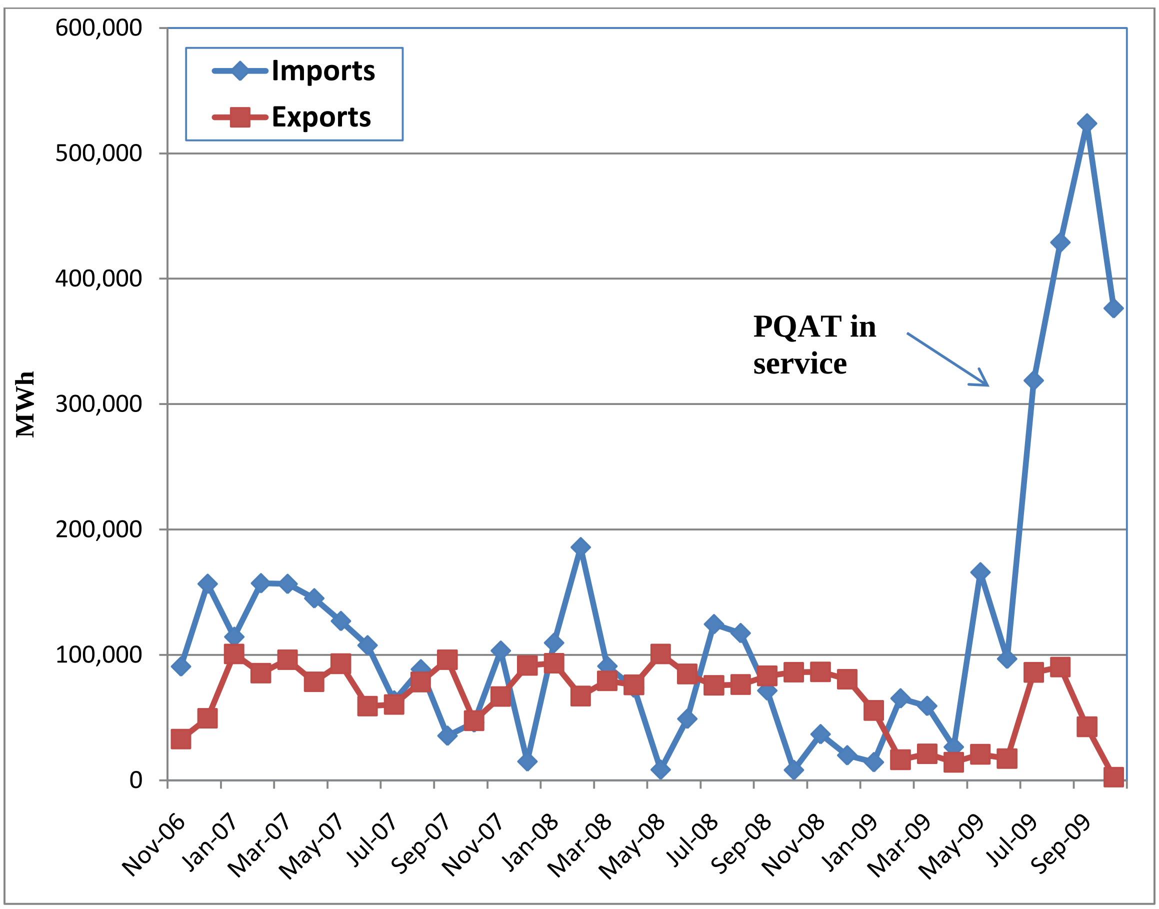
Table 3-14: Summer Import/Export Capability at the Quebec Interties (MW)

Tie Name	Maximum Export Capability (MW)	Maximum Import Capability (MW)	Notes
Rapide Des Iles	0	75	Only generators on Quebec side
Kipawa	100	0	Only loads on Quebec side
Bryson	0	65	Only generators on Quebec side
Quyon	115	115	
Paugan	0	335	Only generators on Quebec side
Masson	50	170	
Maclaren	190	240	
Beauharnois	0*	790	Only generators on Quebec side
Outaouais	1,250	1,250	Fully in service in November 2009

* OPG's Saunders units can export at this interface under Segregated Mode of Operation (SMO) but the export capacity is not available to the market.

Figure 3-9 below depicts the monthly total imports and exports at all Quebec interties. From January 2007 to January 2009, Ontario was a net importer in some months while a net exporter in others. Beginning February 2009, however, Ontario has been a net importer and a large importer since July 2009 when the Outaouais intertie came partially into service. Imports reached their highest level of 523 GWh in September 2009, while exports were only 43GWh in the same month.

Figure 3-9: Monthly Imports and Exports at All Quebec Intertie November 2006 to October 2009



New Intertie -- Outaouais

As shown above, the *Outaouais* intertie has led to a large quantity of imports from Quebec since the July 2009 in-service date. This intertie consists of two circuits with a voltage of 230KV. The transmission flows are controlled using back-to-back direct current (DC) technology and are the only lines at the Ontario border that have DC technology.

Table 3-15 below lists the monthly imports and exports under both the constrained and unconstrained sequence. It can be seen that imports far exceed exports (for example, total imports in the constrained sequence was 276 GWh in September but exports were only 42 GWh) and that imports have been constrained on. Imports and exports were much lower in October than early months because the intertie capability was limited for most of October as the intertie was commissioning to bring the second circuit into service. The full capacity of 1,250 MW was brought into service beginning on November 21, 2009.

Table 3-15: Scheduled Amount at Outaouais, GWh, July to October 2009 (GWh)

Month	Imports (GWh)			Exports (GWh)		
	Constrained Schedules	Unconstrained Schedules	Constrained on	Constrained Schedules	Unconstrained Schedules	Constrained on
Jul-09	191	115	76	74	68	6
Aug-09	237	104	133	90	94	-4
Sep-09	276	207	69	42	44	-2
Oct-09	26	25	1	0	0	0
Total	730	451	279	206	206	0

The large amount of constrained on imports was consistent with the high shadow price in the Ottawa area, where the transmission lines come into the province from Quebec. As the Panel demonstrated in past reports, the Ottawa area is an area with more demand than supply and the shadow prices there are generally higher than the HOEP (as well as the Richview shadow price in Toronto), implying that generators and importers in the area were more likely to be constrained on. In the past summer, the average shadow price in Ottawa zone was $25.52/MWh, while the average HOEP was $24.28/MWh.

Power Flow at the Outaouais Intertie

As mentioned above, this intertie allows significant competition and power flow between Ontario and external jurisdictions. Currently, there are seven active traders at the intertie, with one participant having the vast majority of imports (from Quebec) and another one dominating export transactions (to New England). Table 3-16 below lists the amount of energy transactions scheduled in each direction. One can see that the intertie was import dominated, with about 445 GWh from Quebec and 7 GWh from New York. Of the 205 GWh of exports, over 60 percent flowed to New England and one-quarter flowed to New York.

Table 3-16: Trade Flow at the Outaouais Intertie
July to October 2009
(GWh and %)

	From/To	Energy (GWh)	Percentage (%)
Imports	**From Quebec**	445	98
	From New York	7	2
	Total	**452**	**100**
Exports	**To Quebec**	24	12
	To New England	126	61
	To New Brunswick	3	1
	To New York	52	25
	Total	**205**	**200**

Assessment

The addition of the *Outaouais* intertie has had the effect of inducing more trading activities at the Ontario - Quebec border. The increased activities have the implication of improving efficiency both in Ontario and Quebec (as well as other external markets). First, increased imports from Quebec reduce the need for high cost generators in Ontario or more expensive imports from other markets. Second, the increase capability provides a potential for HQ to export from Ontario and improve the operation of its peaking hydro generators. Third, the significant increase in transfer capability between Ontario and Quebec provides other intertie traders opportunities to trade power between Ontario and other Northeast areas in the United States.

The Panel will report further findings in future reports when more data becomes available.

Chapter 4: The State of the IESO-Administered Markets

4.1 General Assessment

This is our 15th semi-annual Monitoring Report of the IESO-administered markets. It covers the summer period, May to October 2009. As in our previous reports, we conclude that the market has operated reasonably well according to the parameters set for it, although there were occasions where actions by market participants or the IESO lead to inefficient outcomes. We again observed some areas of concern that affect market efficiency and have made recommendations for improvement. These recommendations are summarized at the end of this Chapter.

4.2 The Panel's Monitoring of Offers and Bids Document

The Market Surveillance Panel issued a draft document October 26, 2009 for public comment on Monitoring Bids and Offers in the IESO-Administered Electricity Markets.[114] The document outlines the Panel's general evaluative criteria and monitoring process in respect of actions that may raise market prices above competitive levels. This document does not signal a new approach to market surveillance by the Panel. Rather, it is intended to explain how the Panel determines if market power has been exercised or abused.

The Panel has been monitoring participant conduct in the IESO-administered markets since market opening in May 2002. The approach used by the Panel helps it fulfill its mandate to monitor activity in Ontario's wholesale electricity market and explain unusual price movements.

114 http://www.oeb.gov.on.ca/OEB/Industry+Relations/Market+Surveillance+Panel/Monitoring+Offers+and+Bids

The Panel received two comments on the document from market participants.[115] It will consider those comments in early 2010 and determine the nature of any revisions to the document.

4.3 Two Schedule Market Structure in Ontario

The Ontario market operates on a uniform pricing structure with an associated Congestion Management Settlement Credit (CMSC) regime. This structure was based on the expedient and presumed temporary implementation of a two schedule market clearing process at market opening in 2002:[116]

- one schedule reflecting physical constraints to determine dispatch (constrained schedule); and
- one schedule ignoring many physical constraints (including transmission constraints) to determine the uniform Ontario clearing price (unconstrained schedule).

The difference between the two schedules determines CMSC payments that compensate dispatchable resources for costs or lost operating profit imposed on them by transmission congestion, ramp limitation, the IESO's manual actions, etc. The two dispatch sequence was expected to be reconsidered 12 months after the market opened, with the prospect that it would be replaced with a Locational Marginal Price structure.[117]

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[115] OPG and the Power Workers' Union submitted comments. Comments available at: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Electricity+Market+Surveillance/Monitoring+Offers+and+Bids

[116] Market Design Committee – *Final Report*: "We strongly reaffirm the review process and dates for congestion pricing that we recommended in the *Second Interim Report"* at pp 1-9, available at: http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/FinalReport/Vol1/Volume%201.pdf . Market Design Committee - *Second Interim Report:* "We thus recommend that during the first 18 months of market operations, some form of province-wide uniform (non-congestion) pricing be used, while the IMO prepares to implement pricing and determines the type of congestion pricing to use. … Beginning in the 19th month, and giving due consideration to its review of the first year of operations, the IMO would implement the form of congestion pricing adopted by its Board" at pp 3-13, available at: http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/InterimReport2/2ndRept.pdf.

[117] Straw-Plan for the Evolution of the Ontario Market Design, at p. 12, available at http://www.ieso.ca/imoweb/pubs/consult/IMO_PLN_0037_StrawPlan.pdf

The Panel has reported on many occasions that significant inefficient outcomes result from this two schedule structure and the resulting CMSC payments.[118] These inefficiencies include, but are not limited to the following areas:

- The two schedule structure does not provide correct incentives to energy suppliers and loads and thus induces inefficient production, consumption, and investment decisions.
- The current regime has led to significant market efficiency losses because exporters are incented by the low uniform Ontario price while the actual costs of providing those exports are higher at the interconnection zones. For example, in its July 2007 Monitoring Report, the Panel estimated the efficiency loss of exports to New York could have been as high as $49 million in 2006.
- Generators and importers may be incented to strategically offer far below their incremental cost or opportunity cost in order to receive constrained off payments that are greater than the profit that they would have received had they produced the power.
- Counter-intuitive prices have arisen: at certain times when there is a supply shortage the HOEP was too low; while at other times when the system had no supply problems the HOEP was too high. The former is often a consequence of IESO control actions that deal with the system condition but also have the effect of depressing the HOEP. The latter may be induced by constrained off imports or generators that have subsequently failed or been forced out of service. One such example is the August 8, 2009 high-priced event discussed in Chapter 2.

The issues in the Northwest that are discussed in Chapter 3 provide further illustration of problems arising from the two schedule system. Importers and generators are incented to

[118] All of the Panel’s previous reports are available at: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Electricity+Market+Surveillance/Market+Surveillance+Panel+Reports

offer below their cost, while exporters may strategically bid below the level of their willingness to pay in order to receive constrained on payments. Since market opening, this has contributed to more than $300 million in constraint payments in the Northwest area.[119]

Many changes have been implemented to curtail constraint payments, primarily to permit some 'unwarranted' CMSC payments to be recovered from participants. The Local Market Power and Constrained off Watch Zone provisions in the Market Rules have provided the IESO with an important means to recover components of CMSC that the IESO regarded as unintended.[120] However, they are not sufficient to remedy the design flaws of the two schedule regime, as illustrated in Chapter 3 of the current report. The underlying differences between the constrained and unconstrained schedules are so complex and the reasons for those differences subject to diverse interpretation. The Panel observes that the differences between the constrained and unconstrained schedules are a frequent and major source of payments and absent any changes these payments are expected to continue.

The Panel believes that it would be worthwhile to reconsider the two schedule implementation established at market opening. This is not to say that a full Locational Marginal Pricing regime must be pursued, although the Panel has previously noted the efficiency benefits of such an approach.[121] An alternative could be to allow Ontario to continue to use a uniform price for loads in the province, if desired, while exploring alternatives to directly compensate dispatchable resources consistent with the constrained schedule. This would eliminate the non-transparent CMSC payments and provide a better mechanism for market participants with dispatchable resources to respond to market signals, thereby improving market efficiency.

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[119] See Table 3.8 in Chapter 3 of the current report.
[120] For more information on Local Market Power Mitigation, see:
http://www.ieso.ca/imoweb/marketSurveil/lmpm.asp
[121] Multiple Panel Reports reference efficiency benefits associated with a Locational Marginal Pricing regime. All of the Panel's reports are available at:
http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Electricity+Market+Surveillance/Market+Surveillance+Panel+Reports

In the spring of 2009 the IESO introduced a Stakeholder Engagement initiative (SE-79)[122] titled "More Efficient Uniform Pricing" with the objective to "review the current real-time uniform pricing model."[123] In April 2009, the IESO made a presentation to the Market Pricing Working Group that provides a useful framework for which to consider the issue. This presentation is also useful in describing a number of inefficiencies, including many that the Panel has written about in past reports. However, due to the IESO's priorities, work on this initiative is presently not active.

The Panel believes that addressing this structural issue is a high priority for the industry. In coming reports the Panel intends to investigate options to improve the Ontario pricing structure by replacing the two schedule approach with one that improves the fidelity of the price signal and that better incents efficient bids and offers.

4.4 The Green Energy Act

In May 2009, Ontario's Green Energy Act (GEA)[124] came into law. An important aspect of the GEA was the announcement of a new Feed-in-Tariff (FIT) contract for renewable generators. The FIT provides renewable generators with long-term contracts to provide energy at guaranteed rates. [125] In late September 2009 the FIT contract was introduced.

At present, Ontario has 1,085 MW of transmission-connected wind generation capacity. In December 2009, the OPA announced that it had received FIT applications representing approximately 8,000 MW of potential electricity generation. Of those applications 79 percent or approximately 6,320 MW were for wind projects and 16 percent or

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[122] http://www.ieso.ca/imoweb/consult/consult_se79.asp
[123] Purpose of the work: "Recent discussions with stakeholders regarding day-ahead market design issues have highlighted the difficulties of evolving the electricity market under the current two schedule system: (i) the physical scheduling of resources (the constrained algorithm) and; (ii) the market schedule used as the basis for establishing financial compensation (the unconstrained algorithm). The Market Surveillance Panel (MSP) has also identified several issues relating to the inefficient incentives caused by the two schedule system." See: http://www.ieso.ca/imoweb/pubs/consult/mep2/MP_WG-20090407-MEUP_Presentation.pdf and http://www.ieso.ca/imoweb/pubs/consult/mep2/MP_WG-20090203-Presentation-Issue41.pdf
[124] See: http://www.mei.gov.on.ca/en/energy/gea/
[125] For more information see the OPA's FIT webpage at: http://fit.powerauthority.on.ca/Page.asp?PageID=1115&SiteNodeID=1052

approximately 1,280 MW were solar projects. For these FIT projects, the OPA has estimated that there is presently 2,500 megawatts of available transmission connection capacity. In March 2010, the OPA will begin offering FIT contracts to the most "shovel ready projects."[126]

Fit Contract Design

The addition of large quantities of new renewable generation capacity could exacerbate instances of surplus baseload generation (SBG). The reasons are twofold. First, renewable generation – in particular wind and solar – has typically been treated as non-dispatchable and therefore the IESO has not curtailed these generators to respond to SBG conditions. Second, wind resources, which will constitute the majority of new renewable generation, often have higher output overnight when SBG events are more likely to occur. To reduce such concerns, the Panel had recommended that the Ontario Power Authority include provisions in its contracts to improve the price responsiveness of generation to low market prices and SBG conditions.[127]

The Panel has recently learned that existing OPA renewable energy contracts do include price responsiveness measures. Specifically, renewable generators must "meet the requirements of the IESO Market Rules including the provision of dispatch data for Contract Energy and … to include these services into the IESO-Administered Markets at no less than minus $1.00 per MWh and no more than the Supplier's variable cost for generating same."[128] It does not appear that these provisions have been as effective as intended, and the Panel has asked the MAU to undertake further analysis in this area.

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[126] See:
http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=7136&SiteNodeID=564&BL_ExpandID=

[127] See the Panel's July 2009 Monitoring Report, p. 235, available at
http://www.oeb.gov.on.ca/OEB/_Documents/MSP/msp_report_200907.pdf .

[128] See section 3.2, of the Renewable Energy Supply II Contract (RES II Contract) available at:
http://www.powerauthority.on.ca/gp/Storage/17/1148_RESIIContract%5B1%5D.pdf . Note that the RES and RES III contracts a similar contractual term. The RES contract is available at:
http://www.powerauthority.on.ca/GP/Storage/16/1130_RESContract1_(RENEWABLE_ENERGY_SUPPLY_CONTRACT_(RES_Contract)).pdf; and the RES III contract is available at:

The recently introduced FIT contract also contains price-responsiveness measures.[129] A key difference between existing contracted renewable generation and the FIT contracts is that under certain circumstances FIT generators that reduce their generation output in response to IESO instructions may be eligible for an additional contract payment from the OPA. Specifically, a FIT generator will receive an additional contract payment if it responds to IESO instructions to reduce output when either of the following two conditions has been met:

- The Pre-Dispatch Price as published in the immediately preceding hour is less than $5.00 MWh; or
- The IESO has issued an over generation advisory or equivalent notice in respect of the hour during which the IESO issues instructions to reduce output.

The additional contract payment will be calculated as the hourly delivered electricity foregone multiplied by the FIT contract price. It is important to note, however, that many of the mechanisms for affecting these price-responsiveness measures – including the methodology for determining the hourly delivered electricity foregone – have yet to be developed and as such cannot yet be fully assessed. The Panel has asked the MAU to examine this issue in more detail, including implications on dispatch efficiency during periods of SBG, and will evaluate the need for any further recommendations when that assessment has been completed.

The Impact of New Renewable Generation on HOEP and the Global Adjustment

Most gas-fired and renewable generators in Ontario receive top-up payments from the OPA whenever the revenue from the IESO-administered market (typically from the energy market) fails to compensate them to their contracted price for energy. For example, a wind generator with a $135/MWh contract that produces during an hour with a $35/MWh HOEP will be paid the $35/MWh HOEP from the market. The OPA then tops up the total payment to $135/MWh by paying an additional $100/MWh to the

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http://www.powerauthority.on.ca/GP/Storage/17/1227_SETOR1-5337536-v27-cm_Ontario_Power_Authority_-_Renewable_Energy_Supply_III_Contract.pdf

[129] See FIT contract, specifically section 1.5 to Exhibit B dealing with “IESO Instructions”, at the OPA website: http://fit.powerauthority.on.ca/Page.asp?PageID=924&ContentID=10263

generator. These OPA payments are aggregated monthly as Global Adjustment and charged back to wholesale consumers on a pro rata basis per MWh of energy withdrawn.[130]

Since most renewable generation has a marginal production cost of near $0/MWh, whenever these generators produce energy they displace generation offered at above $0/MWh. This reduces HOEP. The reduced HOEP, in turn, is accompanied by an increased Global Adjustment payment. Historically, the Global Adjustment represented a small payment, but as more contracted generation has come online and as contract prices have increased, the Global Adjustment has formed a more substantial component of the total commodity cost of energy. In April 2009 the Global Adjustment charge exceeded HOEP for the first time ever and continued to exceed HOEP during each month of this reporting period. As discussed earlier in this section, the OPA has received FIT applications for approximately 6,320 MW of wind generation and a further 1,280 MW of solar generation. These generators have a marginal cost of production that is at or near $0/MWh, but will be paid at a minimum of $135 for every MWh generated. As these generators come online their output will put downward pressure on HOEP and upward pressure on the Global Adjustment.[131]

Figure 4-1 below plots the monthly average HOEP, payments made through the Global Adjustment, and the sum of both for the period April 2005 to October 2009.

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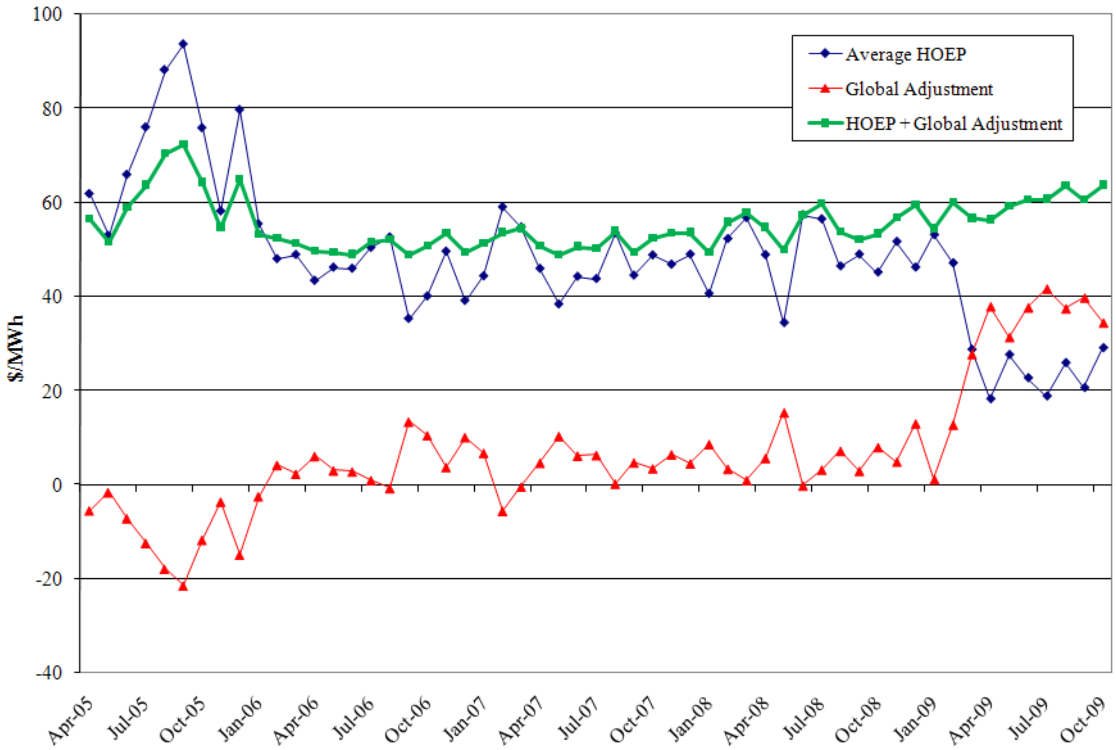
[130] Any consumer that uses 250,000kWh or more of electricity per year is a wholesale consumer. Consumers on the Regulated Price Plan (either Tiered or Time-of-Use rates) also pay the Global Adjustment, but the Global Adjustment is estimated over a six month period and blended into the rates. For more information on Regulated Price Plan rates, see the OEB website at: http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Electricity+Prices#rpp. Exports do not pay these Global Adjustments (although they do pay the hourly uplift which results from CMSC, IOG and IESO programs).

[131] Studies on other markets (e.g. Germany) have evidenced the downward pressure on market prices by renewable resources. For details, see “The Effect of the German Renewable Energy Act (EEA) on ‘the Electricity Price’” by Sven Bode and Helmuth Groscurth (HWWA Discussion Paper 358) available at http://www.arrhenius.de/fileadmin/redaktion/pdf/Bode_Groscurth_EEG_DP_358.pdf , and “Electricity Spot Markets and Renewables – A Feedback Analysis” by Carlo Obersteiner and Christian Redl at http://www.univie.ac.at/crm/simopt/Obersteiner_Redl_ENERDAY_long.pdf.

Figure 4-1: Monthly Average HOEP and Global Adjustment
April 2005 –October 2009
($/MWh)



With the Global Adjustment playing a more prominent component of the effective cost of energy (60 percent during the current reporting period), the manner in which such costs are allocated has become a subject of interest to market participants. The IESO has published some useful preliminary work on the subject. The Panel encourages the IESO and the OPA to focus on market efficiency as they explore alternative methods to allocate the Global Adjustment to consumers.[132]

4.5 Implementation of Panel Recommendations from Previous Report

The Panel's July 2009 report contained four recommendations. Two were directed to the IESO, one to OPG and one to OPA and OEFC.

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[132] Please see: *Effective Pricing in Ontario's Hybrid Electricity Market*, October 28th, 2009 at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20091028-Item_7-Electricity_Pricing.pdf

4.5.1 *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 (SAC).[133]

In this section we review the status of the recommendations from our last Monitoring Report, released in July 2009. The IESO responses to these are summarized in Table 4-1 below.

[133] See latest presentation to SAC on MSP Recommendations, "IESO Senior Management Update" dated October 28, 2009 at: http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20091028-Item3_MSP_Recommendation.pdf

Table 4-1: Summary of IESO Responses to Recommendations in the Panel's July 2009 Monitoring Report

Recommendation Number & Status	Subject	Summary of Action
3-2 **Open** **IESO to Monitor**	Cost Guarantees	"The IESO agrees with the principles of this recommendation however during the GCG stakeholder engagement processes it was determined that the enhancement of settling guarantee payments on an aggregate basis would not be introduced. A significant number of changes were introduced as a result of these discussions including interim changes to the SGOL/DA-GCG program, the implementation of EDAC (multi-part bids and 24hr optimization) and the Pseudo Unit settlement. Although these changes are not inclusive of the recommendation, many strides were made to improve the efficiencies of the guarantee programs. The IESO will continue to monitor this aspect of the guarantee framework and will consider changes at a future date."
3-3 **Closed as per IESO**	Daily Energy Limit for Hydroelectric Generation	"The IESO agrees that there are inefficiencies with the submission of inaccurate Daily Energy Limits. The DEL functionality is however a voluntary system that was developed to provide market participants with a process to assist in the management of energy limited resources. So long as this system is used properly, it can be a useful tool for market participants without any negative impact on the IESO-administered markets. The IESO has reviewed its compliance authority on the use of this tool and has determined that there are sufficient mechanisms to ensure accurate DEL data is provided and will be working with market participants to ensure their understanding of DEL obligations. The IESO has considered the recommendation and has concluded that it would be unnecessary at this time to discontinue the use of the DEL feature." Addendum: Compliance has reviewed this submission by the IESO, and discussed its meaning with IESO reps. Where it says that the IESO has "determined that there are sufficient mechanisms to ensure accurate DEL data is provided and will be working with market participants to ensure their understanding of DEL obligation", we are in agreement that this should be read as providing an indication to the Panel that an Interpretation Bulletin, or some equivalent vehicle, will be drafted to communicate to market participants the methods by which they can submit data such that MACD will deem them to be in effective compliance with the Market Rules related to accuracy of DEL submissions.

Recommendation 3-3 had encouraged the IESO to either discontinue the DEL mechanism or ensure that participants submitted accurate DELs. The Panel noted that since its last report was issued, some participants have significantly changed their DELs. The IESO considers the recommendation closed on the basis that sufficient mechanisms are in place to ensure accurate DEL submissions. The Panel will continue to monitor any potential inefficient outcomes that result from inaccurate DEL submissions.

The Panel understands that the Market Assessment and Compliance Division (MACD) and other IESO representatives are continuing to discuss how to implement the IESO's comment that it "will be working with market participants to ensure their understanding of DEL obligations", which may involve further communications to market participants regarding the methods by which they can submit data that MACD will consider to be in effective compliance with the Market Rules related to accuracy and DEL submissions.

4.5.2 *Recommendation to OPG*

Recommendation 3-1 urged OPG to discontinue two aspects of its 2009 CO_2 Emissions Strategy, the use of NOBA and CO_2 outage designations for the remainder of 2009, particularly as OPG appeared not to be in jeopardy of exceeding the 2009 target of 19.6 Mt of CO_2 emissions. Although NOBA and CO_2 outages were not formally discontinued in 2009, OPG has made some changes to its proposed CO_2 emissions strategy for 2010, effectively discontinuing CO_2 outages, while replacing NOBA with above-cost offers.[134] The Panel will monitor the impact of OPG's 2010 above-cost offer strategy.

4.5.3 *Recommendation to OPA and OEFC*

After observing an increased frequency of Surplus Baseload Generation (SBG) conditions last winter, the Panel noted that contractual arrangements did not incent some generators to shut down during low and often negative price hours when they were physically able to do so. In Recommendation 3-4, the Panel suggested that when the Non-utility Generation (NUG) contracts are renewed and renewable energy (primarily wind-power) contracts are designed, the OPA and OEFC should structure the contracts so that the price-responsiveness of generating resources during low and often negative price hours is improved.

The Panel has subsequently learned that existing OPA renewable energy contracts do include terms that encourage price-responsive behaviour, but to date these measures have not been effective in reducing renewable generation during periods of negative prices. The OPA has also introduced compensation mechanisms included under the terms of the FIT program as described in section 4 above. The FIT contracts should provide incentives

[134] For a summary of the changes to OPG's 2010 CO_2 Emissions Reduction Strategy, see section 3.3 in Chapter 3.

to renewable sources of generation to reduce output during negative price hours. The Panel is not aware of any other active developments regarding more price responsive contract structures.

4.6 Implementation of Recommendations from Other Panel Reports

In the last Report, the Panel provided an update on the status of all outstanding MSP recommendations since the July 2007 Report.[135] In the current and future reports, the Panel will discuss noteworthy changes to the status of these recommendations. During the current reporting period, a change to the status of one previous recommendation is considered noteworthy.

Table 4-2: Update on Outstanding Recommendations from Previous Panel Reports

Recommendation Number & Status	Subject	Recommendation	Change
MSP Report #12, 3-6 (part 1), (Chapter 3, section 3.3) **In Progress**	Intertie Coding Procedures	"For inter-jurisdictional 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)."	The IESO implemented a coding practice change on November 25, 2009 that partially addressed the Panel's concern as communicated in Recommendation 3-6 (part 1). Specifically, under circumstances when curtailed exports are a direct result of import failures for external reasons, the IESO will use the TLRe code instead of TLRi. The coding change removes the distortion in the unconstrained sequence and therefore the market price.[136]

[135] See Appendix 4-A of the Panel's July 2009 Monitoring Report, pp.264-272.
[136] See Chapter 3, section 3.1 of the current report for more details on the coding change.

4.7 *Summary of Recommendations*

The IESO's Stakeholder Advisory Committee has encouraged the Panel to provide information about the relative priorities of the recommendations to the IESO in its reports.[137] In doing so, the Panel notes that it has in the past and will continue to provide efficiency, frequency or other measures of quantitative impact where this is feasible, but that some issues are not readily quantifiable. In addition, the Panel has always recognized that recommendations may have implications which extend beyond its focus on market power, gaming and efficiency and that the mandate and resources of the Panel do not extend to stakeholdering of potential changes or detailed assessments of implementation issues. Accordingly, many of the Panel's recommendations are framed as encouraging responsible institutions such as the IESO to consider whether, when and how a particular recommendation should be implemented, including process issues such as whether stakeholdering is useful and the use of detailed cost-benefit analysis or other forms of evaluation.

As in previous reports, the Panel considered that it would be useful to group the recommendations thematically into four categories: price fidelity, dispatch, hourly uplift payments, and transparency. Some recommendations could have impacts in more than one category (e.g. a scheduling change could affect prices as well as uplift) and we have included the recommendation in the category of its primary effect. The Panel prioritized the two recommendations to the IESO (one of them directed at both the IESO and Hydro One) in the dispatch category.[138]

4.7.1 *Dispatch*

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

[137] See Agenda Item 4 in the minutes of the February 6, 2008 meeting of the Stakeholder Advisory Committee at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20080206-Minutes.pdf

[138] Although there were four recommendations in the dispatch category, only two of them involved the IESO.

<u>Recommendation 3-3 (Chapter 3, Section 2.3)</u>

The Panel recommends that Hydro One work with its transmission counterpart in New York (National Grid) to return the BP76 transmission line at the New York/Ontario interface at Niagara into service in order to mitigate Surplus Baseload Generation (SBG) situations and realize gains from efficient trading opportunities for participants in the Ontario and New York markets.

<u>Recommendation 3-5 (Chapter 3, Section 3.3)</u>

(i) ***The Panel recommends that the IESO provide market participants with specific parameters for determining operating plant characteristics, including Minimum Loading Point (MLP), Minimum Run-Time (MRT) and Minimum Generation Block Run-Time (MGBRT) in order to ensure that submitted operating characteristics, which affect market outcomes, reflect actual operating capabilities.***

(ii) ***The Panel recommends that the IESO develop a compliance or other review mechanism for ensuring that submitted operating characteristics are appropriate having regard to the parameters specified and equipment capabilities.***

<u>Recommendation 3-1 (Chapter 3, Section 2.1)</u>

(i) ***The Panel recommends that the Ontario Power Authority (OPA) should target all Demand Response Phase 3 (DR3) activations, except those required for 'testing' purposes, based on efficiency considerations. This would involve improved identification of periods when system need is greatest and the value of foregone consumption is less than the incremental cost of providing the energy.***

(ii) ***The Panel recommends that OPA explore the feasibility of introducing a bidding process to allow demand response resources to bid the value at which they are prepared to reduce consumption and work with the IESO to align such a process with the Enhanced Day-Ahead Commitment***

(EDAC) process in order to avoid over-commitment of generation and/or imports.

Recommendation 3-2 (Chapter 3, Section 2.3)

The Panel recommends that IESO and Hydro One work with their counterparts in Michigan and New York to bring the Phase Angle Regulators (PARs) into service as soon as possible. The Panel encourages the IESO and Hydro One to pursue available channels, including intra-regional discussions, to address any potential future delays resulting from issues raised by the owner of the Michigan PAR in order that Ontario and its neighbouring markets obtain the benefits available from operation of this equipment.

4.7.2 *Hourly Uplift Payments*

The Panel examines hourly uplift payments[139] both in respect of their contribution to the effective HOEP and also their impact on the efficient operation of the market.

Recommendation 3-4 (Chapter 3, Section 3.1)

The Panel recommends that, for the purposes of calculating Congestion Management Settlement Credit (CMSC) payments, the IESO should revise its constrained on payment calculation using a replacement bid (such as $0/MWh) when market participants (both exporters and dispatchable loads) bid at a negative price. This would create more consistent treatment with generators and importers that are constrained off.

[139] Hourly uplift is the term used to describe wholesale market related uplifts as opposed to other forms of uplift payments.