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 2008 – October 2008

January 2009

Ontario Energy Board

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January 26, 2009

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 13th semi-annual Monitoring Report of Ontario's wholesale electricity market, the IESO-administered markets.

This report, covering the period May, 2008 to October, 2008, 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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Overall Assessment

Ontario's IESO-administered wholesale electricity market once again performed reasonably well according to its design over the six-month period May 2008 to October 2008. Spot market prices generally reflected demand and supply conditions. The Market Surveillance Panel (MSP) found no evidence of gaming or abuse of market power, although there were occasions where actions by market participants or the IESO led to inefficient market outcomes. As in previous reports, the MSP identified several potential opportunities to improve the efficiency of the market which are reflected in the eight recommendations summarized below.

Market Prices and Uplift

The average Hourly Ontario Energy Price (HOEP) for the period May 2007 to October 2009 was $48.25/MWh, 5.7 percent higher than the same period a year ago, with on-peak HOEP being 6.9 percent higher and off-peak HOEP 5.4 percent higher. Prices were higher primarily due to higher natural gas and coal prices this year, although this was partially offset by more inframarginal generation (baseload hydro and nuclear). The effective load-weighted HOEP, which provides a more accurate reflection of what Ontario load pays for energy after accounting for the Global Adjustment and the OPG Rebate, increased by $3.04/MWh or 5.7 percent this summer compared to the previous summer period. Total hourly uplift payments charged to market participants increased by $49 million or 27 percent during the current period compared to the same period a year earlier. This was primarily due to higher congestion management settlement credit (CMSC) payments associated with more bottled energy in the Northwest, as well as increased prices for operating reserve (OR) due to a reduction in available OR supply and a larger required operating reserve in many hours.

In terms of the distribution of the HOEP, there was some shifting of energy prices from the $20 to $40/MWh range to the $30 to $50/MWh range, corresponding to higher fuel prices. The period also saw a greater incidence of prices below $20/MWh, 724 hours this year versus 331 hour last year, continuing a trend toward more low-priced hours in the past four years.

Demand and Supply Conditions

Total Ontario demand fell by 2.5 percent (1.9 TWh) this summer compared with summer 2007, due mostly to the decrease in demand from local distribution companies (LDCs), the largest component of Ontario demand. Wholesale load consumption had been observed in previous periods to be declining in absolute quantities and relative to LDC load, but this summer the ratio appears to have stabilized although the monthly consumption declined to its lowest level (since 2003) in October.

While Ontario demand decreased, the total market demand (Ontario demand plus exports) increased by 1.1 TWh. This was driven by a substantial rise in exports, to 9.2 TWh this year representing an increase of 46 percent. Total net exports (exports minus imports) increased by 3.0 TWh, more than double the net exports last summer, with somewhat more than half the increase in the on-peak hours.

The above export amounts exclude 2.8 TWh of exports which were part of 'linked wheels' (simultaneous import and export by market participants for the purpose of moving power between two other markets through Ontario). Since the import offsets the export in a linked wheel, there is no net effect on HOEP. Such transactions, most of which originated in New York and were destined for PJM, had been uncommon before 2008, but grew substantially during the year until July 2008. In July 2008 NYISO applied to the U.S. Federal Energy Regulatory Commission to prohibit scheduling over certain transmission paths for which there were more direct transmission paths. As a result, since July, wheeling transactions through Ontario have virtually stopped. There is another group of transactions originating in Ontario that have grown during 2008, which are wheeled through MISO and destined for PJM. These reached a peak level in August, after the NYISO tariff revisions.

Planned outage rates over the recent summer period were generally in line with historical rates and seasonality, although seasonal fluctuations were less dramatic than in past summer periods. Forced outage rates were slightly higher this summer, especially during the early summer months. In May, the forced outage rate increased to above 20 percent of capacity, which is the highest monthly forced outage rate since 2005. The increase was mainly due to higher nuclear forced outages during the early summer months.

High and Low HOEP

During the past summer, there were a relatively high number of hours when the HOEP either exceeded $200/MWh or fell below $0/MWh. These are assessed in Chapter 2. In total, there were 17 high-priced events this summer, the highest number of events since the summer of 2005, and 28 hours where the HOEP was negative, easily surpassing the total from any previous six-month period. The highest priced hour occurred on September 14, 2008 in Hour Ending (HE) 9 when the HOEP reached $435.00/MWh. The lowest priced hour this period occurred on July 6, 2008 in HE 6 when the HOEP dropped to minus $14.59/MWh, the lowest HOEP since market opening. While these outcomes are mostly explainable by reference to supply and demand conditions existing at the particular time, some of these outcomes were also influenced by elements of the market design that the Panel recommends be re-examined.

Minister's Directive Regarding the Reduction of CO_2 Emissions

In May 2008, the Minister of Energy issued a Declaration related to the reduction of CO_2 emissions from Ontario Power Generation's (OPG) coal-fired generating stations. As a result of the Declaration, OPG is required to meet annual limits on CO_2 emissions for the 2009 and 2010 calendars years of 19.6 and 15.6 million metric tonnes respectively. Furthermore, Ontario Regulation 496/07 (and a subsequent amendment) requires the cessation of usage of all of OPG's coal-fired stations by the end of 2014 with a hard cap of 11.5 million metric tonnes on CO_2 emissions in the calendar years 2011 to 2014.

On November 28, 2008, OPG released an implementation strategy to meet its 2009 emissions targets.[1] OPG intends to use a combination of four strategies to meet their target: extended planned ('CO_2') outages, shut down (or 'park') certain units during pre-selected low demand periods (known as "Not Offered but Available" (NOBA) units), apply an emissions cost adder to all offers from its coal-fired generators, and use a flexible coal purchasing strategy.

As coal-fired generation becomes an 'energy-limited' resource beginning in 2009, the use of an emissions adder would be expected to lead to efficient and transparent production and consumption responses in the market. However, OPG's NOBA parking and CO_2 planned outage strategies are likely to be less efficient as they are not designed to respond to price signals. Such efficiencies could be captured if decisions were made more frequently such as daily or hourly or by relying entirely on a full emissions adder on its offers rather than the planned 'partial' adder. The Panel has requested that the MAU monitor the effect of OPG's implementation strategies on the market during 2009.

Operational Issues & Recommendations

The Panel makes several suggestions for potential changes to the present IESO-administered markets based on its analysis of observed market outcomes over the past six months. These are summarized and then prioritized (at page xiii) below:

[1] "OPG's Strategy to Meet the 2009 CO2 Emission Target" at http://www.opg.com/safety/sustainable/emissions/carbon.asp

Recommendation 2-1 (Chapter 2, section 2.1.1)

To provide an efficient price signal to the market, the unconstrained schedule should reflect actual dispatch results as closely as possible including intertie ramping. Although imports and exports are scheduled on an hourly basis, the IESO currently ramps hourly changes to the net schedule at an intertie over two intervals (the last interval of the current hour and the first interval of the next hour). This is not currently captured by the pricing algorithm as the unconstrained schedule is completely ramped into the next hour during its first interval.

The Panel is of the opinion that the intertie ramping should be incorporated into the pricing algorithm consistent with the actual dispatch of these resources. Ramping intertie schedules correctly should provide a more efficient price signal to the market. The Panel recognizes the difficulty of making major changes to the algorithm unless it is being altered for other purposes. In the interim the IESO should consider modifying its procedures for certain intertie transaction failures coded as TLRe, OTH, MrNh, or ADQh which induce asymmetric ramping in the unconstrained schedule in the 12th interval of the prior hour.

The Panel recommends that the IESO's ramping of intertie schedules in the unconstrained process (the pricing algorithm) be consistent with actual intertie procedures and the treatment in the constrained scheduling process.

Recommendation 2-2 (Chapter 2, section 2.1.11)

In previous reports, the Panel has discussed how source codes applied to failed transactions can affect the unconstrained schedule and therefore the HOEP. Chapter 2 includes a review of an event where imports from a neighbouring jurisdiction were scheduled to flow in a specific hour, however were curtailed during the hour. The present IESO processes removed the trade for the whole hour and had the effect of suppressing the MCP during intervals when the imports actually flowed. The Panel recommends that, when a manual source code is applied to a transaction, it should be done on an interval basis rather than hourly to account for intertie transactions that only flow in some intervals.[2]

The Panel recommends that when an intertie trade fails in some intervals while not in others within the hour, the IESO should apply a failure code only for those intervals with the failure.

Recommendation 3-1 (Chapter 3, section 3.1)

In August 2008, the Ontario Power Authority (OPA) introduced a new demand response program known as DR3. Available to direct participants and aggregators, the objective of the program is to reduce system peak demand in hours of high-demand, high prices, and tight supply conditions. Activations under the DR3 program last for a minimum of four hours and are determined at least 2.5 hours ahead based on the IESO's pre-dispatch supply cushion statistic. Since the program began on August 1, 2008 there have been eight activations for a combined total of 32 hours in the four months to October 2008. Although the pre-dispatch supply cushion triggered these activations, the events were not always the highest demand or highest priced hours during the period and therefore did not necessarily reduce system peak demand in the hours when most needed. Deficiencies in the IESO's supply cushion statistic, which were identified in the July 2008 Panel report,[3] appear to be contributing to this less than effective targeting.

In Chapter 3 the short and long-term efficiency implications of the DR3 program are reviewed. In the short-term, market efficiency is achieved if a load's compensation for reducing its consumption equals the difference between the

[2] This is in addition to other procedure changes related to failures previously recommended by the Panel which would reduce distortions of the unconstrained schedule and counter-intuitive pricing results. See Recommendation 3-6 in the July 2008 Monitoring Report, pp. 171-180.
[3] July 2008 Monitoring Report at pp. 160-61.

value it derives from its consumption and HOEP. Payment above that amount leads to an inefficiency from over-reduction. Estimates provided in Chapter 3 suggest that short-term efficiency losses related to DR3 may range between \$43,000/MW-year and \$64,000/MW-year based on a hypothetical operation of the program using 2007 market outcomes.

In the longer term, the efficiency of the market could potentially be improved if the cost incurred by the program is smaller than the cost avoided from the construction of a peaking generator. However, the estimates in Chapter 3 suggest that the DR3 program on average has the potential to be more efficient only if DR3 successfully targets the highest demand hours. Based on the current design of the program, this appears unlikely to occur. The results from our review of the short-term and long-term efficiency estimates of the DR3 program suggest that the OPA should review the effectiveness and efficiency of the program.

1) In light of the Panel's findings on the inefficiency of the Demand Response Phase 3 (DR3) program, the Ontario Power Authority (OPA) should review the effectiveness and efficiency of the program.

2) Until that review is completed, to improve short term dispatch efficiency:

- ***(1) the IESO, with input from the OPA, should improve the supply cushion calculation; and/or***
- ***(2) the OPA should develop other triggers such as a pre-dispatch price threshold that could be better indicators of tight supply/demand conditions.***

<u>Recommendation 3-2 (Chapter 3, section 3.2)</u>

In Ontario, generating units are scheduled to provide energy based on economic selection of submitted offers. When a generator decides it is no longer profitable to produce at current price levels, it normally prices itself out of the market causing it to be ramped down and off. Slow-ramping generators such as fossil and nuclear units are limited in the time it takes to ramp down and go off-line. A slow-ramping generator will receive constrained on payments during intervals it is ramping down due to the different treatment of ramp rates in the constrained and unconstrained schedules. The constrained on payments are influenced by the offer price submitted for purposes of shutting down. The ability to self-induce large constrained on payments creates potential gaming opportunities and excessive uplift payments.

The Panel had previously recommended in the December 2007 Monitoring Report that CMSC payments to generators induced for specific safety, legal, environmental and regulatory requirements should be prevented or recovered by the IESO as they are not warranted.[4] The Panel recommends that constrained on payments resulting from the technical shut-down requirements of generators are another specific type of self-induced payment which should be prevented or made subject to recovery.

In an earlier report, the Panel encouraged the IESO to limit self-induced congestion management settlement credit (CMSC) payments to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons. The Panel further recommends that the IESO take similar action to limit CMSC payments where these are induced by the generator strategically raising its offer price to signal the ramping down of its generation.

Recommendation 3-3 (Chapter 3, section 3.3)

The Day Ahead Commitment Process was introduced by the IESO during the summer of 2006 as a result of challenging operating conditions one year earlier. The program commits sufficient resources (generators and imports) to meet demand day-ahead and provides financial guarantees.

The Day-Ahead Generation Cost Guarantee (DA-GCG) ensures generators recover production costs up to their minimum loading point for the minimum period they must run during the day. An important feature of the program is that compensation is not

[4] See Recommendation 3-4 in the Panel's December 2007 Monitoring Report, pp. 160-162.

linked to a generator's offer price. So participants have an incentive to submit artificially low offers in order to ensure they are scheduled while knowing that their production costs will be guaranteed through the DA-GCG program. In its July 2007 Monitoring Report, the Panel recommended that the IESO review the program to take costs into consideration when selecting units for commitment, to improve the effectiveness of the guarantee.[5] The IESO is currently working on an Enhanced Day-ahead Commitment (EDAC) process that includes three-part bidding and 24-hour optimization to make day-ahead commitment decisions. The program is expected to be operational by 2011.

Since the introduction of the DACP process the MAU has been monitoring guarantee payments and has recently observed significant increases in DA-GCG payments. With the increase in new gas-fired generation in Ontario that typically have long minimum run-times and high minimum loading points, bidding units below their marginal cost simply to be selected for the DACP may displace other low-cost generation in real-time. Until EDAC arrives, the Panel recommends that the IESO consider an interim solution that reflects the cost of generation in the scheduling process, rather than simply committing units based on offer prices alone that may be unrelated to costs.

In consideration of the length of time until the Panel's prior recommendation of an optimized Day Ahead Commitment Process (DACP) can be put in place (estimated to be 2011), the Panel recommends that the IESO consider basing the Generator Cost Guarantee on the offer submitted by the generator or other interim solutions that allow actual generation costs to be taken into account in DACP scheduling decisions.

[5] See Recommendation 3-2 in the Panel's July 2007 Monitoring Report, p. 121.

Recommendation 3-4 (Chapter 3, section 3.4)

Operating reserves are an important component of the Ontario market and represent stand-by capacity that may be needed to produce energy during unexpected adverse events. Historically, coal-fired generators in Ontario have offered a significant amount of their total capacity as OR. Beginning in 2009, the Minister of Energy and Infrastructure declared that Ontario coal-fired generators reduce CO_2 emissions through declining annual targets until 2014 when these units are required to shut-down. It is expected that as these units are constrained to meet their CO_2 emissions targets, they will offer a smaller amount of operating reserve. Therefore other existing resources and new entrants will be required to replace the OR currently supplied by coal units.

The Panel has observed that a significant amount of Ontario's new gas-fired generation that is required to replace coal units generally do not offer OR. Without new sources of OR, the market will tighten as a result of diminishing OR supply from the coal-fired generators. Tightened supply will lead both to high prices and potentially inefficient dispatch as Ontario will have to rely more on existing hydro units and dispatchable loads for OR. In order to better understand the new gas-fired generators' motivations for not offering OR, the Panel recommends that the IESO and the OPA discuss the matter with the relevant participants.

As coal-fired generators are eventually phased out, the market will require replacement for this source of Operating Reserve (OR). New gas-fired generators are generally not offering OR. The Panel recommends that the IESO and OPA explore alternatives for obtaining appropriate OR offers from recent and future gas-fired generation entrants.

Recommendation 3-5 (Chapter 3, section 3.5)

In early 2007, a market participant notified the Market Assessment Unit that they would be applying a negative adder to their offers on some fossil-fired units, meaning they would offer these units into the market at a price below their incremental production cost.

The participant explained that the negative adder was implemented to reduce aggregate emissions by ensuring that its lower emitter units would be dispatched before other units it operated. While the negative adder was relatively low in 2007, it steadily increased and by October 2008, it was approximately five-times as high as in 2007, driven by the relative price differences between the types of fuels used by the participant's generating units.

The participant's use of the adder did reduce emissions as the lower emitter units were dispatched before the other units, but the benefit was partially offset by increased inefficient exports which in turn increased the production from fossil-fired generation. The negative adder also induced an estimated $18.7 million efficiency loss between November 2007 and October 2008 due to the higher cost generating units being dispatched ahead of lower cost units.

The Panel believes that market participants can comply with government environmental standards without compromising the efficiency of the IESO-administered markets. The participant in question introduced the negative adder offer strategy to meet its own goals for reducing emissions, and not as a requirement to comply with standards from any regulatory authority. The Panel believes that environmental standards are best determined by public policy rather than by individual market participants and role of participants is to comply with these standards efficiently.

The Panel recommends that market participants' offers should reflect environmental costs flowing from the environmental standards established by the applicable regulatory authorities.

<u>Recommendation 4-1 (Chapter 4, section 2)</u>

Over the next few years, various wind generation projects are expected to connect to Ontario's electrical grid. The current practice in Ontario is that wind generators submit their own hourly production forecasts to the IESO. Wind energy has many desirable attributes; however the fact that it is an intermittent resource has led to significant discrepancies between forecast and actual energy production. The difference between their forecast and delivered energy can contribute to significant differences in pre-dispatch and real-time prices. The forecast error will continue to grow as more wind resources come online, and can lead to reduced market efficiency.

Some system operators in North America currently use (or will use in the near future) centralized wind forecasting to manage the forecast errors resulting from wind resources. The California ISO implemented a centralized wind forecasting service in 2004 and initial findings show a significant reduction in wind forecast error. The Panel believes that to help improve forecast errors attributable to wind resources, a centralized wind forecasting program may be appropriate for Ontario.

Furthermore, a move to a more frequent intertie dispatch schedule such as 15-minutes may also help incorporate the increasing wind generation by reducing the lead-time of the forecast and thereby reducing the impact of the wind forecast error on the market. The 15-minute schedule should allow the interties to quickly respond to changing generation and load conditions, including the fluctuations of wind generation and other renewable resources.

In an effort to efficiently accommodate greater levels of renewable resources in the Ontario Market:

- ***i)*** ***The Panel recommends the IESO consider centralised wind forecasting to reduce the forecast errors associated with directly connected and embedded wind generation in the pre-dispatch schedules;***
- ***ii)*** ***The Panel also reiterates its December 2007 recommendation that the IESO investigate a 15-minute dispatch algorithm which should further reduce forecast errors and allow for more frequent rescheduling of imports and exports in response to the different output characteristics of renewable resources.***

In response to a suggestion of the IESO's Stakeholder Advisory Committee, we have identified relative priorities among these recommendations. In this report, we have grouped the recommendations under three categories – price fidelity, dispatch and hourly uplift payments (there were no recommendations related to transparency this time)– and ranked them as follows:

RANK	PRICE FIDELITY	DISPATCH	TRANSPARENCY	HOURLY UPLIFT PAYMENTS
1	4-1	3-3		3-2
2	2-2	3-5		
3	2-1	3-4		
4		3-1		

The Panel regards each recommendation as important to improving the operation of the market. In particular, changes that may individually not be regarded as large can have a substantial cumulative effect, as well as spill-over benefits in improving the confidence that market participants have in the operation of the Ontario market. Many of the recommendations do not appear to involve significant implementation costs; however, it remains the task of those responsible to identify costs and benefits from a broader perspective and establish final priorities and implementation schedules.

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Chapter 1: Market Outcomes May 2008 – October 2008

1. Highlights of Market Indicators

This Chapter provides an overview of the results of the IESO-administered markets over the period May 1, 2008 to October 31, 2008, with comparisons to the same period a year earlier and in many instances a review of trends over several years. For ease of reference, the May to October period is sometimes referred to as the 'summer period'.

1.1 Pricing

The average Hourly Ontario Energy Price (HOEP) was $48.25/MWh this summer, up $2.59/MWh or 5.7 percent from the summer of 2007. Lower prices in May and August were more than offset by higher prices in June and July resulting from higher natural gas prices. It was also observed that the distribution of energy prices were more dispersed this period, with a noticeable increase in the number of hours when the HOEP was less than $20/MWh and greater than $100/MWh.

The effective load-weighted HOEP measures the actual amount that loads in Ontario pay for energy given the existence of OPA contracts and regulated prices. In Section 2.1.1, we show the effective load-weighted HOEP increased by $3.04/MWh.

Section 2.2 presents statistics on pre-dispatch and real-time price setters by resource type. Coal-fired units continue to set the real-time MCP more often than other resource types. In fact, they set the MCP more often this summer at 62 percent of all hours, up from 54 percent last summer while oil/gas units set the price 13 percent less than last summer. In pre-dispatch, generating units set the price slightly over half of all hours, followed by imports and then exports.

Section 2.3 provides statistics on differences between the one-hour and three-hour ahead pre-dispatch price and HOEP. Average differences declined this summer but were accompanied by increases in the standard deviations of the price differences suggesting more volatility relative to last year. The section provides a detailed analysis of the main factors that influence the discrepancy between pre-dispatch and real-time prices, the major factor being demand forecast error.

Section 2.4 examines the year-over-year changes in the HOEP using the econometric approach found in previous MSP reports. The results of the decomposition analysis that explores the causes of differences between the HOEP relative to last summer suggests that the rise in natural gas prices placed upward pressure on the HOEP.

Trends in the components of hourly uplift are discussed in Section 2.5. Over the latest summer period, uplift payments increased by $49 million (27 percent) over last summer mainly due to increases in CMSC and operating reserve payments.

Section 2.6 provides statistics on the average prices and CMSC payments by the 10 internal Ontario zones as defined by the IESO. Higher levels of losses and more frequent congestion in the Northeast and Northwest zones drove prices significantly below prices in the Southern zones of Ontario. Relative to last summer, CMSC payments were higher, specifically payments for constrained off supply and constrained on exports in the Northeast and Northwest zones due to increased hydro availability from high rainfall levels in the north, tighter transmission limits, and lower energy demand.

Summary statistics on the HOEP and the Richview nodal price are compared in Section 2.7. The average difference between the two prices increased this summer while there was little change in the median difference. The frequency of hours when the HOEP and Richview prices rose above $200/MWh increase dramatically this summer.

Section 2.8 focuses on trends in operating reserve prices. In general operating reserve prices increased significantly this summer, primarily due to the abundance of hydro resources providing energy to avoid spill leaving less operating reserve supply available and an increase in the reserve requirement as the largest contingency changed this past summer due to the introduction of new generating units.

1.2 Demand

Section 3 looks at trends in Ontario's demand conditions. Ontario Demand fell slightly by 2.5 percent this summer compared to 2007, however when incorporating higher export levels, we observed a small increase in total Market Demand by 1.2 percent. Wholesale load levels have been declining since 2003 and total wholesale load reached a low in October 2008 at slightly over 2,100 GWh.

1.3 Supply

Section 4 reviews recent trends and statistics related to the supply conditions in the province. Over the past summer, two significant gas-fired facilities and a wind facility began operating increasing Ontario's energy capacity by over 1,500 MW. In Section 4.2, the average pre-dispatch and real-time supply cushion statistics are presented. The average pre-dispatch supply cushion declined slightly, however in real-time the supply cushion improved by 2.8 percent. Section 4.3 compares the average supply curve this summer relative to last summer and shows a small increase in negative priced offers this summer, mainly due to increased baseload supply.

Generator performance has a large impact on the supply conditions and energy prices in the province. Planned and forced outage statistics are reported in Section 4.4 as well as by fuel type. Although planned outage rates showed their typical seasonal variations this summer, they appeared more evenly distributed across the summer relative to previous summers. Forced outage rates for oil/gas and coal-fired units were consistent with previous summers while nuclear forced outage rates increased, particularly during the early summer months.

Statistics on natural gas and coal prices are presented in Section 4.5. There was a significant appreciation in the price of both coal and natural gas this summer relative to last summer. Specifically, Central Appalachian coal prices more than doubled while Powder River Basin coal prices increased by over 30 percent this summer. Similarly, there was a noticeable appreciation in natural gas prices as they increased by almost 50 percent.

Sections 4.6 presents analyses that examine the profitability of a hypothetical new gas-fired entrant into the market. The system heat rate analysis suggests that a hypothetical 7,000 MMBtu combined-cycle gas generating unit would have been unable to recover its costs in the market over the last few years. Similarly, the net revenue analysis presented in Section 4.6 shows that estimated net revenues over the past November 2007 to October 2008 period were insufficient to cover all their debt and equity requirements.

1.4 Imports and Exports

Section 5 reports on trade outcomes over the recent summer period. Section 5.1 presents long-term statistics on net exports. Net export volumes reached all-time highs this summer with the largest increase occurring in the on-peak hours mainly due to falling Ontario Demand and the higher availability of low-priced energy. Net export volumes here highest at the Michigan interties as increased volumes of energy originating in Ontario and New York and destined for PJM were observed this year.

In Section 5.2, we show that import congestion levels were slightly lower this summer while the frequency of export congested hours more than doubled. Export congestion was higher primarily due to increased export volumes as well as a notable transmission outage affecting line limits between Ontario and New York. As a result of the increased level of export congestion, export congestion rents more than tripled when compared with last summer while import congestion rents fell by one-third. It is also notable that import and export TR payouts were significantly greater than the import/export congestion rents as TR payments at an intertie correspond roughly to the number of hours of congestion.

Sections 5.3 reports results from the export econometric model as in previous Monitoring Reports. New to this report is the introduction of a regression model for the Michigan intertie group. Previously, only estimates for the New York intertie group were reported. Elasticity estimates in the Michigan model were slightly higher in absolute terms than for New York suggesting that exports were more sensitive to change in HOEP at Michigan. Elasticity estimates at Michigan were also lower on-peak and greater off-peak, which is opposite to what we observe at New York.

Finally in Section 5.4, we compare wholesale electricity prices in Ontario with neighbouring jurisdictions. Consistent with previous periods, Ontario continues to be one of the lower priced areas relative to its neighbours while prices in New England and PJM were on average the highest.

2. Pricing

2.1 Ontario Energy Price

Table 1-1 presents the monthly average HOEP for May to October 2007 and 2008. The average HOEP increased by $2.59/MWh (5.7 percent) between the 2007 to 2008 summer months. On-peak average prices increased by 6.9 percent relative to last year, which is slightly higher than the 5.4 percent increase observed during the off-peak hours. The largest year-over-year declines occurred in the months of May and August, where the average prices fell by 10.2 and 13.1 percent respectively. Alternatively, average prices increased the most on a percentage basis in June (29.4 percent) and July (28.9 percent) compared to last summer.

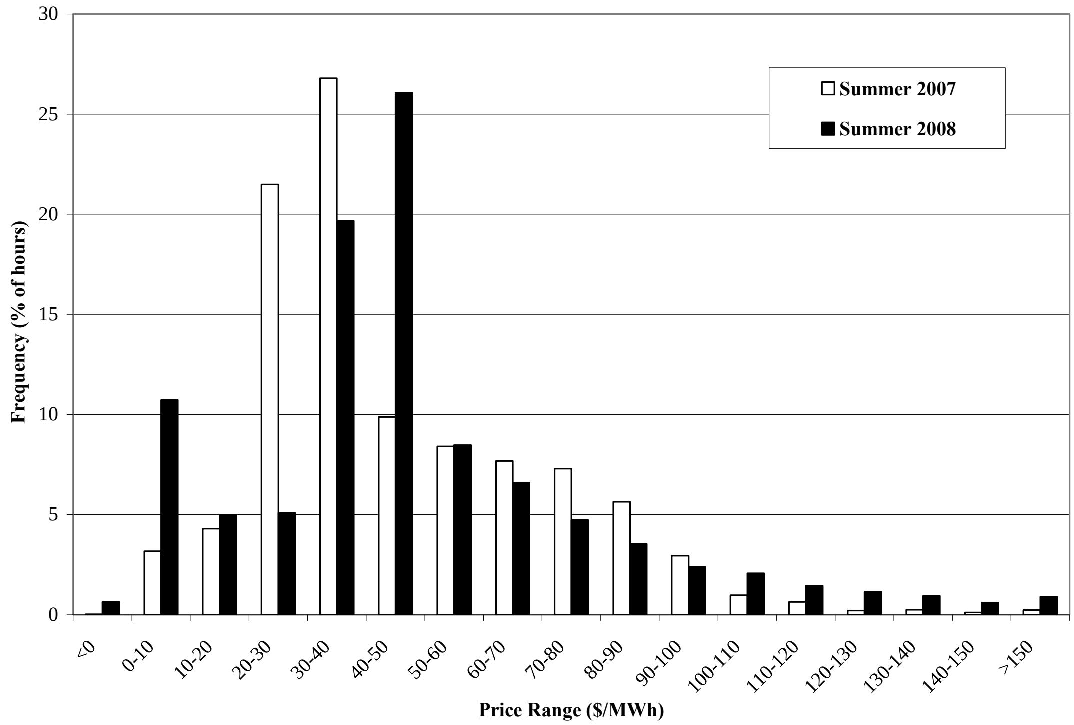
A major reason for the increase in the average HOEP this summer was due to higher natural gas prices, which is discussed in more detail in Section 4.5.2. The average Henry Hub natural gas prices rose by 45 percent over 2007 price levels. Although the six-month average price was higher this summer, there were declines in the average HOEP in May and August. Lower prices in May were partly the result of significant reductions in the export capability to New York, thus lowering total Market Demand. In August, we observed improved performance from baseload hydro and nuclear units as output from these two groups increased by an average of 800 MW per hour as shown later on in Table 1-29.

Table 1-1: Average HOEP, On-peak and Off-peak, May – October 2007 & 2008 ($/MWh)

	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2007	2008	% Change	2007	2008	% Change	2007	2008	% Change
May	38.50	34.56	(10.2)	53.78	47.12	(12.4)	24.77	24.21	(2.3)
June	44.38	57.44	29.4	57.32	76.57	33.6	33.06	42.13	27.4
July	43.90	56.58	28.9	57.70	82.78	43.5	32.54	35.00	7.6
August	53.62	46.57	(13.1)	69.80	60.63	(13.1)	39.10	35.96	(8.0)
September	44.63	49.09	10.0	58.27	58.58	0.5	34.66	40.78	17.7
October	48.91	45.27	(7.4)	60.19	55.87	(7.2)	38.77	35.75	(7.8)
Average	45.66	48.25	5.7	59.51	63.59	6.9	33.82	35.64	5.4

Figure 1-1 shows that the frequency distributions of HOEP over the last two summer periods vary considerably. In 2008, the figure shows an increase in the number of occurrences in all categories where HOEP is less than $20/MWh and greater than $100/MWh. During the summer 2007 months, the categories with the largest number of occurrences fell in the $20-30/MWh and $30-40/MWh categories. In 2008, there has been a shift in the categories with the most occurrences to the $30-40/MWh and $40-50/MWh categories, which is consistent with the higher observed HOEP this summer relative to last summer. Increased fossil fuel prices contributed to these changes (increasing HOEPs) while the increased frequency of HOEP below $20/MWh corresponds to the greater availability of baseload hydroelectric energy in August and September, increased nuclear output between July and October, and the much higher portion of the time that hydroelectric resources set prices off-peak.

Figure 1-1: Frequency Distribution of HOEP, November – April 2006/2007 & 2007/2008 (% of total hours in $10/MWh price ranges)



2.1.1 Load-weighted HOEP

Table 1-2 reports the load-weighted HOEP separated by load type for the last two summer periods. Load-weighted HOEP provides a more accurate representation of the actual price paid by loads since it is weighted by hourly demand. The load-weighted HOEP over all loads (the major component being LDC consumption) increased by $3.17/MWh or 6.5 percent, which was slightly higher than the increase of $2.59/MWh (5.7 percent) observed in the unweighted HOEP. The load-weighted HOEP for dispatchable load and other wholesale load increased 5.7 percent and 5.3 percent respectively. Finally, dispatchable load operating reserve revenues increased substantially over the current summer from $0.28/MWh of consumption in 2007 to $1.81/MWh in 2008, a result of very high operating reserve prices over the recent summer period. With the lower weighted average HOEPs shown for dispatchable load and other wholesale load, the table also demonstrates these load groups continue to avoid higher price periods, either by reducing load when on-peak prices are high or by consuming a higher than average proportion of energy off-peak.

Table 1-2: Load-Weighted Average HOEP and Dispatchable Load Operating Reserve Revenue, November – April 2006/2007 & 2007/2008 ($/MWh)

Year	Unweighted HOEP	Load-weighted HOEP[6]			Dispatchable Load OR Revenue
		All Loads	Dispatchable Load	Other Wholesale Loads	
2007	45.66	48.89	43.36	45.57	0.28
2008	48.25	52.06	45.83	47.99	1.81
Difference	2.59	3.17	2.47	2.41	1.53
% Change	5.7	6.5	5.7	5.3	546.4

2.1.2 Impact of the Global Adjustment and the OPG Rebate on the Effective Price

Figure 1-2 plots the average HOEP along with the effective HOEP, which includes payments made through the Global Adjustment (GA) and OPG Rebate. The GA and OPG Rebate tend to moderate the effective HOEP. That is, when the average HOEP is high (low) during a month, the GA and OPG Rebate tend to lower (raise) the net payments to generators and vice versa (this can be seen in Figure 1-2 from the opposite month to month movements of average HOEP and GA). The effective HOEP has remained relatively unchanged on a monthly basis since 2006 in a range from about $50/MWh to $55/MWh. However, the effective HOEP did rise to the $60/MWh range or above in June and July 2008 for the first time since December 2005.[7]

[6] Unadjusted – like the unweighted HOEP, the load-weighted HOEP does not include the impact of the Global Adjustment or the OPG Rebate.

[7] The Global Adjustment is expected to increase beginning next year given OPG's new prescribed asset agreement and as the OPA continues to procure new generation. For more details on the prescribed asset agreement, see the OEB's Decision dated November 3, 2008 at http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0905/dec_Reasons_OPG_20081103.pdf. Secondly, downward pressure will be placed on the OPG Rebate as OPG's fossil units begin to reduce production starting in 2009 and are eventually shutdown by 2014.

Figure 1-2: Monthly Average HOEP Adjusted for OPG Rebate and Global Adjustment, April 2005 – October 2008 ($/MWh)

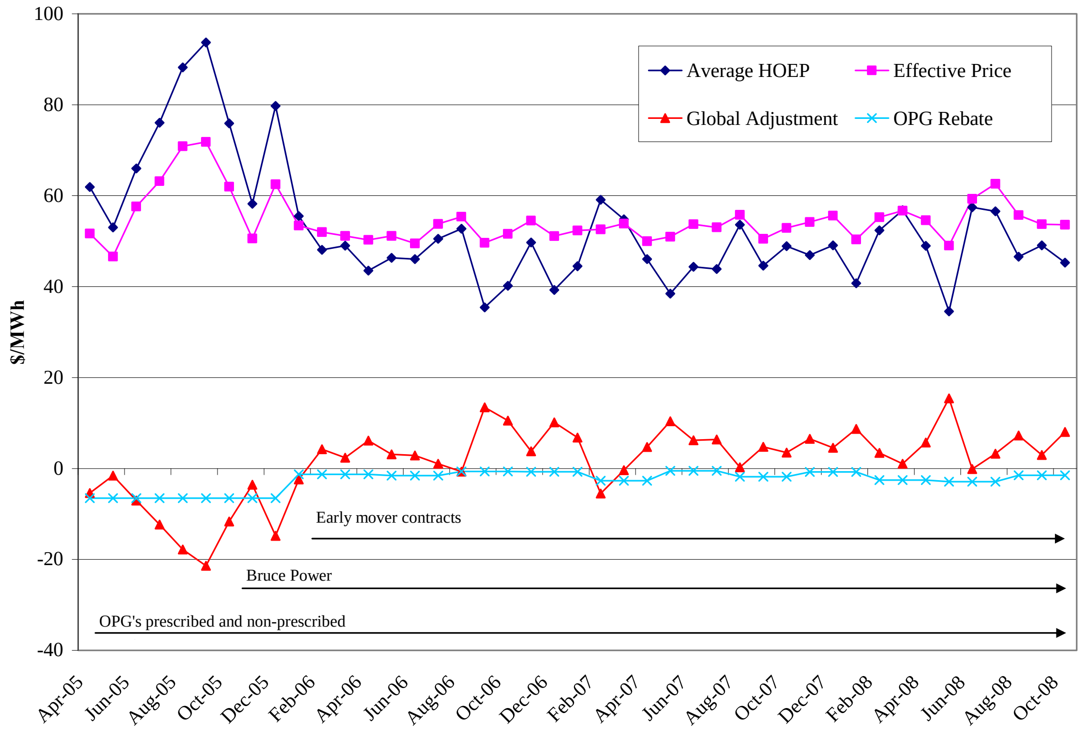


Table 1-3 reports the average six-month HOEP relative to the load-weighted HOEP with and without the Global Adjustment and OPG Rebate over the last two summer periods. The average OPG Rebate plus Global Adjustment fell slightly during the latest summer period relative to the 2007 summer period by $0.14/MWh while the average unweighted HOEP increased by $2.59/MWh and the load-weighted HOEP increased by $3.17/MWh. Since the tendency is for monthly Global Adjustment to decrease when the monthly HOEP increases, the nearly constant average Global Adjustment this summer compared with last, suggests a general upward movement of the base level of the Global Adjustment, around which monthly values fluctuate. This corresponds to generally more payments through the Global Adjustment as more OPA programs and contracts take effect.

Table 1-3: Impact of Adjustments on Weighted HOEP, May – October 2007 & 2008 ($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate[8]	Effective Load-Weighted HOEP
2007	45.66	48.89	(3.95)	52.84
2008	48.25	52.06	(3.81)	55.87
Difference ($)	2.59	3.17	0.14	3.04
% Change	5.7	6.5	3.5	5.7

2.2 Price Setters

In this section we look at which resources were marginal and set the real-time and pre-dispatch Market Clearing Prices (MCP). In real-time we are interested in the fuel types which set the price; in pre-dispatch we consider whether imports, exports or internal generation set the price.

2.2.1 Real-time Price Setters

Historically, the MCP has predominantly been set by coal generating units and the recent summer period was no different. Table 1-4 shows the average share of the real-time MCP set by resource type over the last two summer periods. Coal units set the real-time MCP 62 percent of all intervals during the 2008 summer months, up from 54 percent the previous summer. Oil/Gas units set the real-time MCP only 11 percent of the intervals in 2008, which is down from nearly one quarter of all intervals during the summer of 2007.

Table 1-4: Average Share of Real-time MCP set by Resource Type, May – October 2007 & 2008 (% of Intervals)

	2007	2008	Difference
Coal	54	62	8
Oil/Gas	24	11	(13)
Hydro	22	27	5

[8] A negative value represents a payment from consumers to generators

Tables 1-5 to 1-7 show the monthly shares of real-time MCP for all intervals, on-peak intervals, and off-peak intervals over the last two summer periods. In the past, coal typically set the real-time price much more frequently during the off-peak period compared to the on-peak period. For example, in the summer of 2007, coal set the MCP in 35 percent of all on-peak intervals and 70 percent of all off-peak intervals. Over the recent summer months, the share of real-time MCP set by coal-fired resources was almost identical for the on-peak and off-peak periods at 63 percent and 62 percent respectively.

The large increase in coal's on-peak share can be mainly attributed to an increase in low-priced energy this summer, which implies that gas was needed less and at the margin.[9] Table A-26 shows that improvements in inframarginal supply were mainly from increased nuclear supply by 1.46 TWh (3.6 percent) and increased hydroelectric supply by 3.51 TWh (21.8 percent), where the majority of the hydroelectric increase came in the first four months of the summer due to abundant water conditions.

Table 1-5: Monthly Share of Real-Time MCP set by Resource Type, May – October 2007 & 2008 (% of Intervals)

	Coal		Oil/Gas		Hydro	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**
May	61	67	13	3	26	31
June	61	60	18	16	21	24
July	58	57	20	17	22	26
August	44	65	38	9	17	27
September	52	59	25	12	23	28
October	46	67	30	8	24	25
Average	54	62	24	11	22	27

[9] Table A-26 in the Statistical Appendix indicates that Oil/Gas scheduled generation declined from 5.69 TWh last summer to 4.63 TWh this summer (a decline of 17 percent).

Table 1-6: Monthly Share of Real-Time MCP set by Resource Type, On-Peak, May – October 2007 & 2008 (% of Intervals)

	Coal		Oil/Gas		Hydro	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**
May	49	82	26	5	25	13
June	47	54	31	27	22	19
July	38	52	39	33	23	16
August	15	69	62	16	23	15
September	32	55	45	21	23	23
October	26	68	49	15	26	16
Average	35	63	42	20	24	17

Table 1-7: Monthly Share of Real-Time MCP set by Resource Type, Off-Peak, May – October 2007 & 2008 (% of Intervals)

	Coal		Oil/Gas		Hydro	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**
May	72	54	1	1	27	46
June	73	65	6	7	20	28
July	74	61	5	4	21	35
August	70	61	18	3	12	36
September	67	63	11	4	22	32
October	64	67	13	1	23	32
Average	70	62	9	3	21	35

2.2.2 Pre-dispatch Price Setters

Table 1-8 shows the percentage of hours that the one-hour pre-dispatch price was set by resource type on a monthly basis this summer compared to last summer. Although there were differences in shares on a monthly basis, there was no change between the two six-month periods as a whole. In pre-dispatch, prices were set by generators more than half of all hours followed by imports (29 percent) and then exports (18 percent).

Table 1-8: Monthly Share of Pre-dispatch Price set by Resource Type, May – October 2007 & 2008 (% of Hours)

	Imports		Exports		Generation	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**
May	37	28	15	18	49	54
June	28	29	14	15	58	55
July	25	30	22	17	54	53
August	29	21	15	17	56	62
September	25	34	22	20	54	46
October	30	32	21	20	48	48
Average	29	29	18	18	53	53

2.3 One-Hour and Three-Hour Ahead Pre-dispatch Prices and HOEP

Market participants rely on accurate pre-dispatch price signals when making production and consumption decisions. Improvements that help make price projections more accurate will benefit real-time scheduling efficiency. Therefore, the differences between one-hour ahead and three-hour ahead pre-dispatch prices and HOEP are important statistics to monitor.

2.3.1 <u>One-hour Ahead Pre-dispatch Price</u>

Table 1-9 presents monthly summary statistics on the differences between the one-hour ahead pre-dispatch price and the HOEP for May through October 2008 relative to the same months a year ago. The one-hour ahead average difference declined to $4.11/MWh this summer compared to $7.13/MWh last summer. The monthly average price differences fell in all months with the exception of June and the largest declines were observed between August and October reaching a minimum of $1.23/MWh in August 2008.

Although the average difference declined this summer, there were noticeable increases in the standard deviation of the price differences and the average hourly difference as a percentage of HOEP suggesting that average differences were more volatile than last year. The standard deviation was higher in five of the six months this summer with the largest deviations occurring in August and September 2008. Similarly, the average hourly difference as a percentage of HOEP increased from June to October relative to last year and climbed above 40 percent in June and August 2008.

There was a noticeable increase in hours when the HOEP was greater than $100/MWh during the 2008 summer months. This is illustrated by the frequency distribution of HOEP in Figure 1-1. Also during the past summer, there were 17 hours when the HOEP>$200/MWh, 10 of these hours occurred between August and October 2008. Furthermore, the six highest priced hours over the 2008 summer months all occurred in August or later. The increased frequency of high-prices resulted in a series of hours when the HOEP was significantly higher than the pre-dispatch price and placed downward pressure on the monthly average price differences observed in both Tables 1-9 and 1-10.

Table 1-9: Measures of Differences between One-Hour Ahead Pre-Dispatch Prices and HOEP, May – October 2007 & 2008 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	8.23	4.86	71.78	63.30	(77.17)	(45.40)	14.49	13.02	35.18	25.81
June	6.99	8.60	94.35	115.21	(331.10)	(217.42	21.84	22.60	25.21	48.62
July	5.26	5.21	62.02	61.08	(211.39)	(155.88)	15.91	17.67	22.34	37.13
August	8.16	1.23	74.60	36.54	(60.38)	(330.15)	13.56	22.67	20.05	42.82
September	5.96	1.88	83.01	334.24	(68.97)	(337.64)	12.46	27.03	22.37	38.06
October	8.17	2.88	66.75	38.77	(236.65)	(234.55)	14.99	18.14	30.09	35.46
Average	7.13	4.11	75.42	108.19	(164.28)	(220.72)	15.54	20.19	25.87	37.98

2.3.2 Three-hour Ahead Pre-dispatch Price

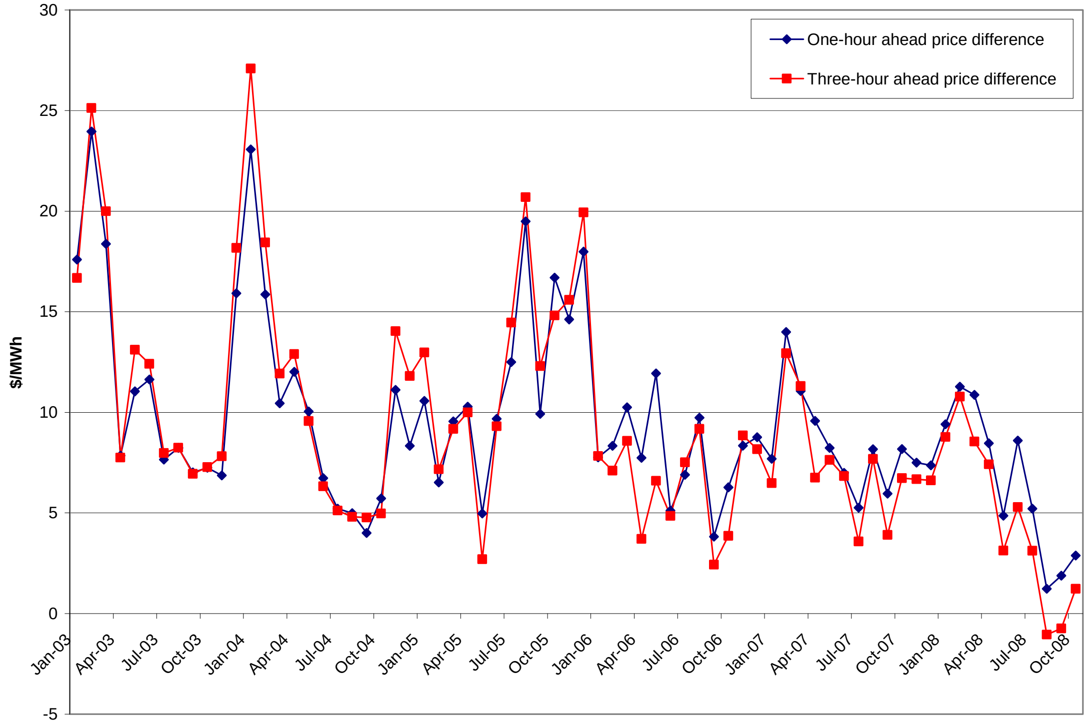
Table 1-10 reports the differences between the three-hour ahead pre-dispatch price and the HOEP for May through October 2008 compared to one year ago. Relative to the 2007 summer months, the average difference between the three-hour ahead and real-time price fell dramatically from $6.06/MWh in 2007 to $1.83/MWh in 2008. As described above, the decline was mainly driven by large price differences resulting from price spikes between August and October 2008. This is apparent by the large minimum differences observed in August and September 2008 at minus $306.69/MWh and minus $336.00/MWh respectively compared to minimum differences of greater than minus $70/MWh during the same months one year ago.

Table 1-10: Measures of Differences between Three-Hour Ahead Pre-Dispatch Prices and HOEP, May – October 2007 & 2008 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
May	7.63	3.13	72.88	44.97	(93.58)	(61.87)	16.11	14.12	30.63	19.23
June	6.83	5.29	99.04	176.97	(305.24)	(214.18)	22.95	25.31	25.54	47.93
July	3.58	3.12	62.49	72.09	(215.90)	(159.24)	16.64	19.73	15.97	34.16
August	7.68	(1.05)	79.74	36.67	(61.26)	(306.69)	14.90	22.85	19.45	33.57
September	3.91	(0.74)	60.95	50.45	(69.49)	(336.00)	12.18	25.16	17.71	33.35
October	6.73	1.23	82.25	38.91	(234.52)	(244.94)	15.40	18.64	25.54	27.24
Average	6.06	1.83	76.23	70.01	(163.33)	(220.49)	16.36	20.97	22.47	32.58

Figure 1-3 plots the average monthly difference between the one and three-hour ahead pre-dispatch versus real-time prices between January 2003 and October 2008. With the exception of August and September 2008, average prices in both the three-hour and one-hour ahead have, on average, been higher than the HOEP since 2003. The three-hour ahead average difference continues to be below the one-hour ahead average difference in most months since 2006.

Figure 1-3: Average Pre-dispatch to HOEP Price Differences One and Three-Hour Ahead, January 2003 – October 2008 ($/MWh)



2.3.3 Reasons for Differences

To date, the Panel has identified four main factors that lead to discrepancies between pre-dispatch and real-time prices:

- Demand forecast error;
- Performance of self-schedulers and intermittent (primarily wind) generators;
- Failure of scheduled imports and exports; and
- Frequency that imports (or exports) set the pre-dispatch price.

Table 1-11 presents the average and absolute average differences for each of the first three factors listed above for the May to October 2008 period. Monthly averages and absolute averages provide some indication as to which of the factors are most important in leading to discrepancies between pre-dispatch and real-time prices. However, each of these factors can lead to significant price discrepancies in a given hour. During the latest summer period, the largest contributor measured by average and absolute average MW error was demand forecast error. On average, peak-to-peak demand forecast error was only 2 MW but 179 MW in absolute terms.[10] On the other hand, absolute average demand forecast error differences measured peak-to-average were significantly larger at 242 MW and 295 MW respectively. In absolute average terms, hourly net export failures are next highest at 130 MW and finally self-scheduling and intermittent error at 62 MW.

Table 1-11: Average and Absolute Average Hourly Error by Discrepancy Factor, May – October 2008 (MW)

Discrepancy Factor	Average Error (MW)	Absolute Average Error (MW)	Average Error as % of Ontario Demand	Absolute Average Error as % of Ontario Demand
Peak-to-Peak Demand Forecast Error	2	179	0.01	1.09
Peak-to-Average Demand Forecast Error	242	295	1.47	1.79
Self-Scheduling and Intermittent Error	37	62	0.22	0.38
Net Export Failures	31	130	0.19	0.79

*Average hourly Ontario Demand for the six-month period was 16,490 MW

2.3.3.1 Demand Forecast Error

Table 1-12 reports the one-hour and three-hour ahead mean absolute demand forecast error on a monthly basis over the 2007 and 2008 summer months. Both peak-to-average demand forecast error and peak-to-peak demand forecast error fell for the three-hour ahead and one-hour ahead cases. Peak-to-average demand forecast error fell from 2.25 percent to 2.00 percent three-hours ahead and from 1.97 percent to 1.83 percent one-hour ahead. Peak-to-peak forecast error declined slightly less from 1.41 percent to 1.32 percent three-hours ahead and remained relatively unchanged one-hour ahead.

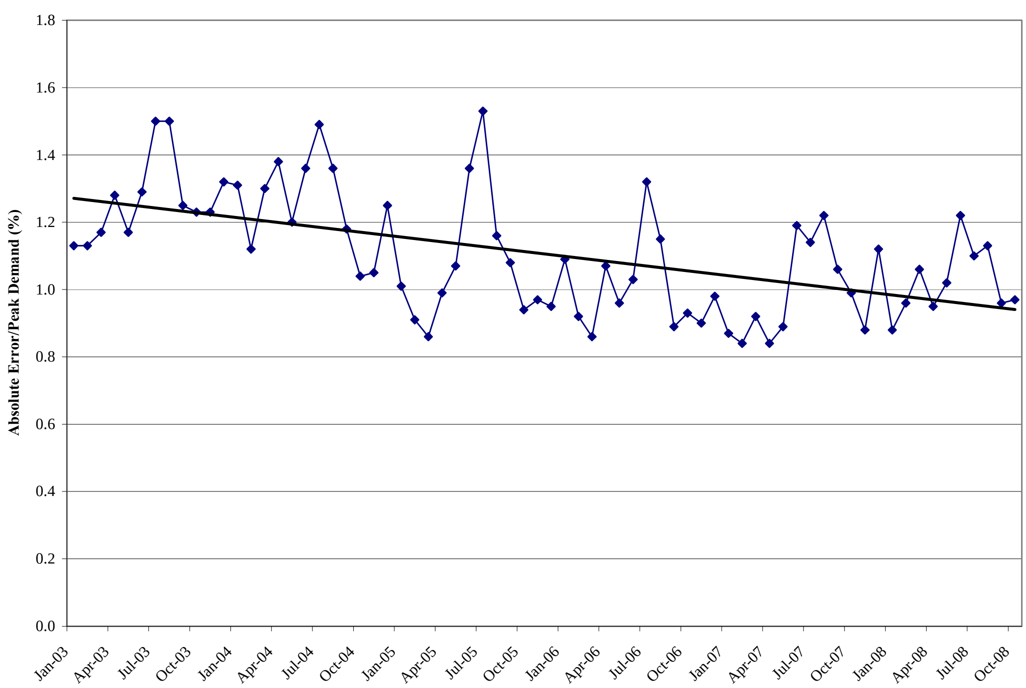
[10] Peak-to-peak demand forecast error compares the pre-dispatch peak demand forecast and the peak interval demand in real-time.

Table 1-12: Demand Forecast Error, May – October 2007 & 2008 (%)

	Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand			
	Three-Hour Ahead		One-Hour Ahead		Three-Hour Ahead		One-Hour Ahead	
	2007	2008	2007	2008	2007	2008	2007	2008
May	1.82	1.78	1.66	1.65	1.07	1.26	0.89	1.02
June	2.40	2.33	2.05	2.08	1.59	1.55	1.19	1.22
July	2.34	2.27	2.01	1.96	1.56	1.51	1.14	1.10
August	2.53	1.97	2.15	1.85	1.65	1.36	1.22	1.13
September	2.25	1.74	1.96	1.68	1.40	1.14	1.06	0.96
October	2.15	1.88	1.98	1.77	1.18	1.11	0.99	0.97
Average	2.25	2.00	1.97	1.83	1.41	1.32	1.08	1.07

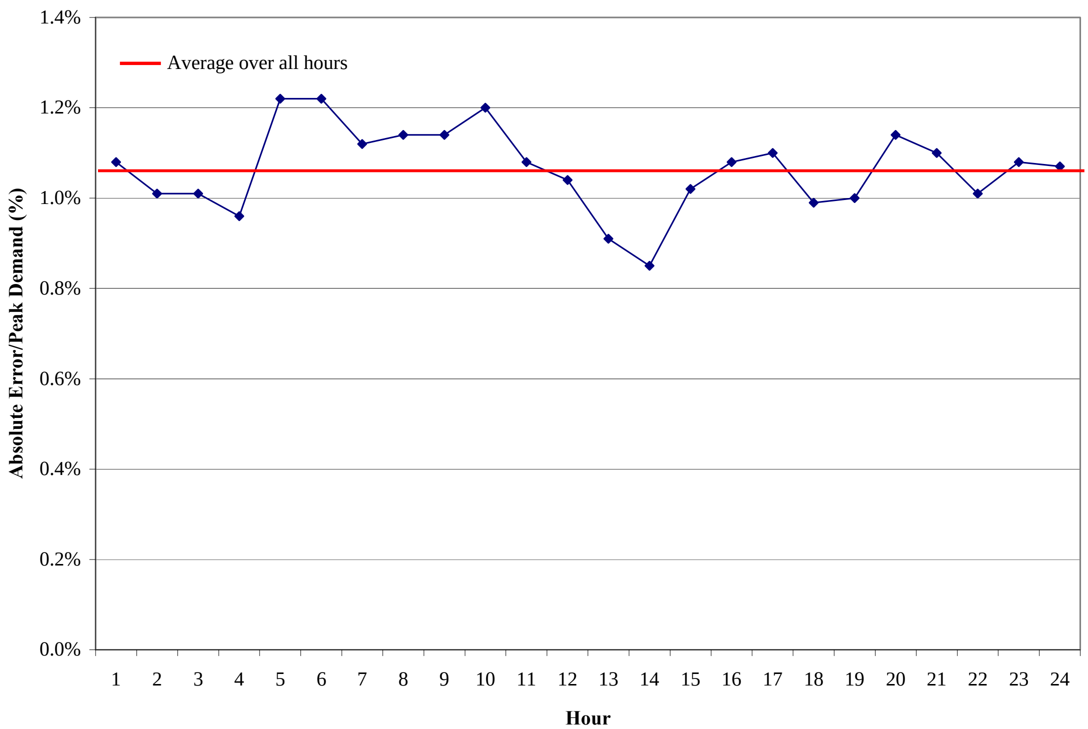
Figure 1-4 reports the one-hour ahead absolute demand forecast error on a monthly basis since January 2003. Although the long-term trend line shows a decline, monthly forecast error appears to have levelled off since the beginning of 2006 and with the exception of a few months has remained between 1.0 and 1.2 percent.

Figure 1-4: Absolute Average One-Hour Ahead Forecast Error, January 2003 - October 2008 (% of Peak Demand)



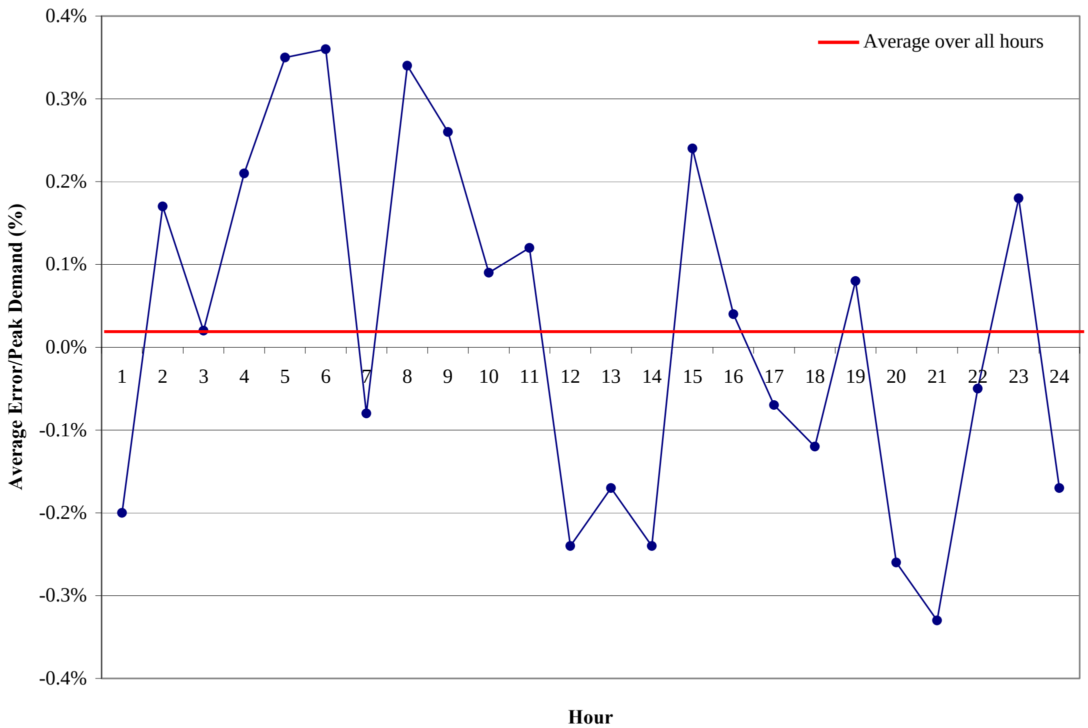
One-hour ahead absolute average forecast error, measured peak-to-peak, is isolated by hour of the day over the 2008 summer months in Figure 1-5. Average forecast error over all hours was 1.07 percent and is represented by the horizontal red line in the figure. Absolute average forecast error was the highest in hours 5 and 6 when it rose above 1.2 percent and lowest during the mid day hours reaching a daily minimum in hour 14 at 0.85 percent.

Figure 1-5: Absolute Average One-Hour Ahead Forecast Error by Hour, May 2008 – October 2008 (% of Peak Demand)



While the absolute average provides some insight into the magnitude of the hourly forecast errors, the arithmetic average provides information on biases in hourly forecast error. Figure 1-6 plots the one-hour ahead arithmetic average forecast errors (peak-to-peak) by hour of the day over the past summer. The average forecast error over all hours is represented by the red line in the figure below and was only slightly positive at 0.02 percent. Average errors show a clear positive bias prior to and during the morning load pick-up hours and prior to the evening peak hours. The behaviour of average errors over the evening peak hours is less clear, although negative in most hours with the exception of HE19.

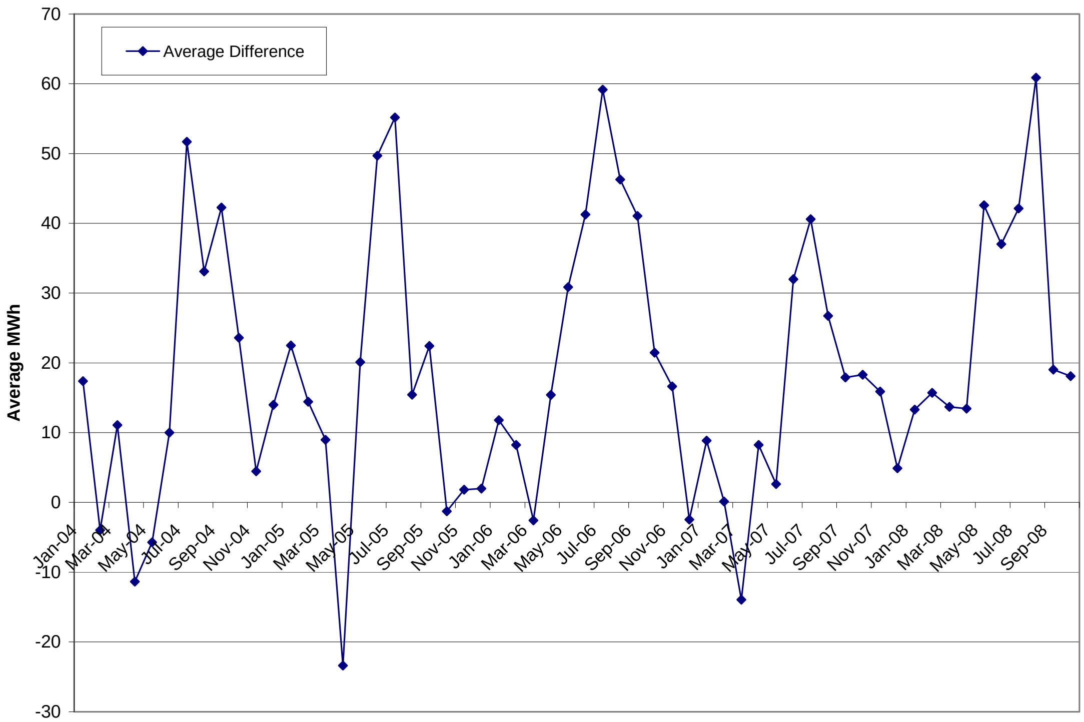
Figure 1-6: Arithmetic Average One-Hour Ahead Forecast Error by Hour, May 2008 – October 2008 (% of Peak Demand)



2.3.3.2 Performance of Self-Scheduling and Intermittent Generation

Changes in the amount of energy that self-scheduling and intermittent generator's forecast to deliver and the amount of energy they actually deliver in real-time can lead to discrepancies between pre-dispatch and real-time prices. Figure 1-7 plots monthly average differences between self-scheduling and intermittent generator's forecasted and delivered energy since January 2004. Historically, average differences peak during the summer months and this past summer was no different. In August 2008, average self-scheduler and intermittent generator error reached a peak of 61 MWh, which was slightly higher than the previous high of 59 MWh set in July 2006. In addition to the scheduling of wind generation, the peak in August was due in part to the commissioning of several units at a new fossil-fired plant.

Figure 1-7: Average Difference between Self-Scheduling and Intermittent Generator's Forecasted and Delivered Energy, January 2004 - October 2008 (MWh)



Wind generation makes up the most significant component of Ontario's intermittent generating fleet. As mentioned earlier, a wind generating facility in Port Alma, Ontario entered the market towards the end of the 2008 summer months with a capacity of 101.2 MW. Output levels from this facility were very low in August 2008 but noticeably increased middle of September 2008.[11]

Figure 1-8 presents the average and absolute average difference between wind generators' forecasted energy and actual energy produced along with the total wind

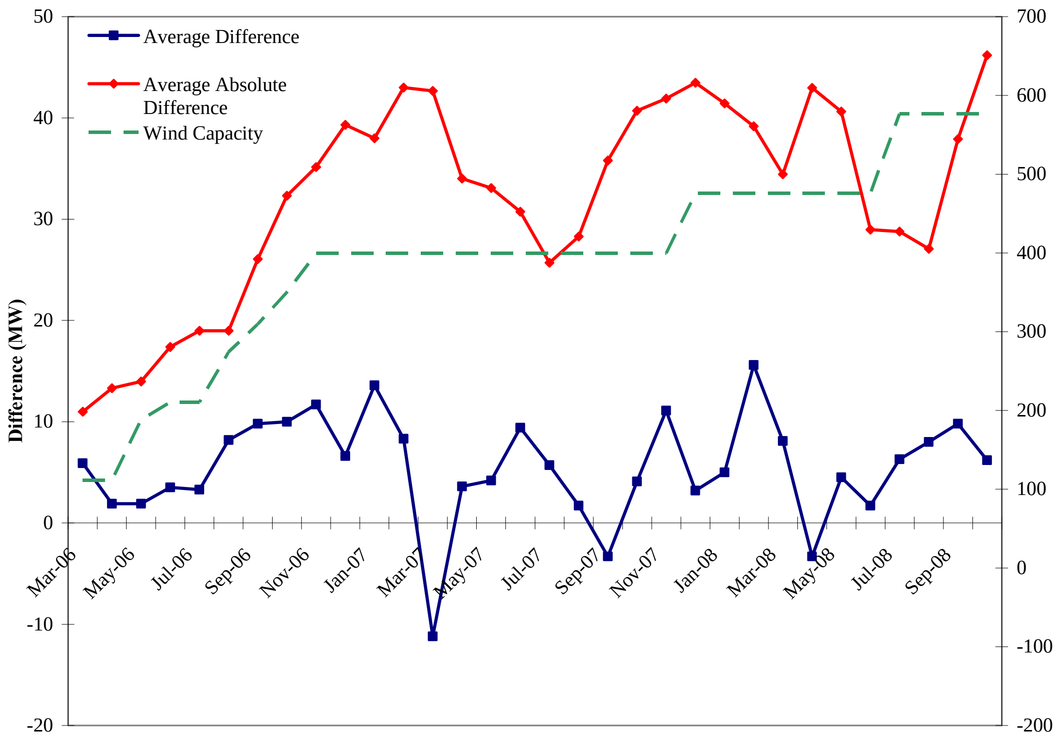
[11] Average hourly output from the Port Alma wind facility was 2.5 MW in August, 7.9 MW in September, and 34.1 MW in October 2008.

capacity.[12] Average monthly differences were always positive over the 2008 summer months and peaked at slightly less than 10 MW. Average absolute monthly differences have stayed above 25 MW since the summer of 2006 and reached a peak of 46 MW in October 2008. Average absolute differences also increased dramatically in September and October, which is consistent with the introduction of the new wind facility.

The figure shows that absolute average wind forecast error has increased relative to early 2006. A large reason for the increase is the entry of new wind supply into the market, especially during the second half of 2006 as represented by the green line in Figure 1-8. After 2006, wind capacity grew only moderately while monthly average absolute differences have remained relatively stable. However according to the OPA, three new wind projects will be introduced by the end of 2009 with a total capacity of 511 MW.[13] This should place upward pressure on absolute wind forecast error levels when they come online.[14]

[12] Wind Capacity is estimated using nameplate wind capacity figures from the OPA Wind-Power Projects webpage available at: http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=234. For estimation purposes, wind capacity is increased by a projects nameplate capacity in the first month it provides energy in the IESO market.
[13] According to the OPA, Melancthon II Wind Plant (132 MW) is expected to be in service by Q4-2008, Enbridge Ontario Wind Farm (181.5 MW by Q1-2009, and Wolfe Island Wind Project (197.8 MW) by Q2-2009. See the OPA's Wind-Power Projects webpage for more details at: http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=234.
[14] In the December 2007 MSP Monitoring Report (page 28), the Panel recommended that the IESO and wind generators review methods of reducing wind forecast errors as increasing amounts of wind generation enter the market.

Figure 1-8: Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy and Capacity, March 2006 - October 2008 (MW)



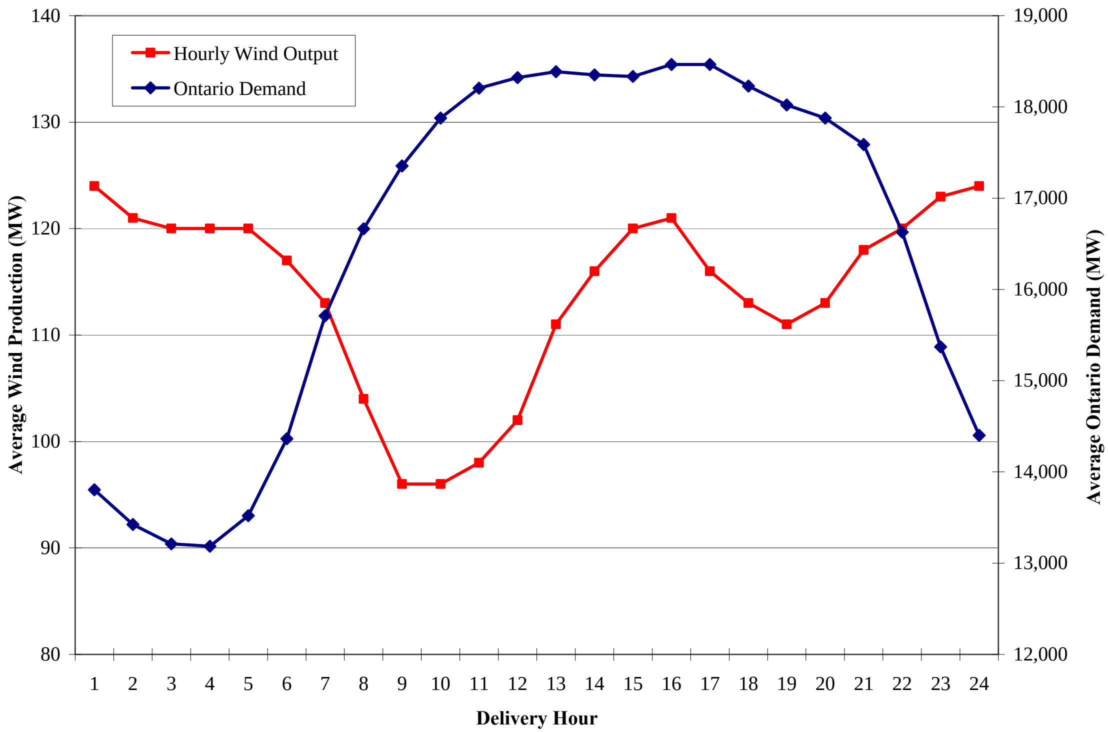
In an effort to reduce errors in forecasting wind generation, other jurisdictions have adopted a centralized wind forecasting system. Improved wind forecasts allow system operators to produce more efficient commitment decisions day ahead and in real-time and enhance the efficiency of scheduled inter-jurisdictional transactions. The California ISO first introduced the Participating Intermittent Resources Program (PIRP) during the summer of 2004. The main focus of the program is to allow intermittent resources (e.g. wind resources) to schedule energy in the forward market and avoid being penalized when there are differences between scheduled and delivered energy.[15] The program includes a centralized forecasting service provided by a 3rd party forecasting service provider. The forecasts are effectively sent to participating resources as their hourly schedules. New York also introduced a centralized wind forecasting system in June 2008

[15] For more information on the program, see http://www.caiso.com/docs/2003/01/29/2003012914230517586.html on the California ISO website.

which is used in both the NYISO's day ahead and real-time Security Constrained Economic Dispatch (SCED) processes.

Figure 1-9 compares the average hourly load profile represented by Ontario Demand and the average hourly wind production over the November 2007 to October 2008 period. It is apparent that wind output tends to be highest during the off-peak hours and in the middle of the day while production is lowest during the morning and evening ramping hours.

Figure 1-9: Average Ontario Demand and Wind Production by Delivery Hour, November 2007 - October 2008 (MWh)



2.3.3.3 Real-Time Failed Intertie Transactions

Failed import and export transactions are another major source of the differences between pre-dispatch prices and HOEP. In real-time, failed imports lead to a loss of supply that in pre-dispatch was expected to be available, while export failures represent a decline in real-time demand. Similar to the previous Panel report, linked wheel failures have been removed from the following tables as they have no impact on the discrepancy between pre-dispatch and real-time prices.[16]

Export Failures

Table 1-13 compares the number of incidents and rates of export failures over the 2007 and 2008 summer months. Although the frequency of failed exports, measured by the number of incidents, increased by 450 hours, the failure rate declined significantly from 6.64 percent in 2007 to 4.61 in 2008 mainly due to the increased level of exports during the recent summer months (larger denominator in failure rate calculation). Over the past summer, the largest increase in the volume of exports occurred at the Michigan intertie group, the majority of those transactions being destined for PJM.[17] Since Ontario exports destined for PJM are essentially price takers (a feature of the PJM market), they are on average more successful when scheduled compared to an export destined for New York since it must be successful economically in both markets. The large increase in exports to PJM this past summer led to an increase in the frequency of export failures, however the failure rate improved in all months with the largest declines coming in September and October 2008.

[16] See the July 2008 MSP Monitoring Report (page 22) for a more detailed explanation of why linked-wheel failures are removed.
[17] Refer to Chapter 3, Section 2.3 for more details on trade flows to PJM.

Table 1-13: Frequency and Average Magnitude of Failed Exports from Ontario, May – October 2007 & 2008

	Number of Hours when Failed Exports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
May	520	645	938	875	202	190	8.87	7.33
June	379	554	733	1,003	166	172	5.75	5.66
July	338	502	1,079	1,858	177	138	4.49	3.81
August	361	394	831	709	163	138	5.12	3.27
September	390	356	1,071	679	208	151	8.17	4.14
October	383	370	898	725	195	140	7.44	3.43
Total/Average	2,371	2,821	925	975	185	155	6.64	4.61

* The incidents with less than 1 MW and linked wheel failures are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled exports MWh (less the export leg of linked wheels) in the unconstrained schedule in a month

Import Failures

The frequency and failure rate of failed imports increased dramatically during the summer of 2008 compared to 2007 as shown in Table 1-14. The number of hours when import failures occurred rose from 922 hours in 2007 to 1,785 hours in 2008, an increase of 863 hours or 94 percent and increased in every month. Similarly, the import failure rate increased from 3.3 percent in 2007 to 8.5 percent in 2008 and reached a high of 10.5 percent in September 2008.

Table 1-14: Frequency and Average Magnitude of Failed Imports to Ontario, May – October 2007 & 2008

	Number of Hours when Failed Imports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2007	2008	2007	2008	2007	2008	2007	2008
May	189	289	453	1,085	135	182	6.24	9.87
June	131	285	400	807	98	176	2.71	7.35
July	104	271	700	818	123	163	2.69	7.07
August	192	254	546	880	118	145	3.43	7.36
September	144	348	525	989	149	218	2.44	10.46
October	162	338	607	1,029	118	187	2.35	8.89
Total/Average	922	1,785	539	935	124	179	3.31	8.50

* The incidents with less than 1 MW and linked wheel failures are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled imports MWh (less the import leg of linked wheels) in the unconstrained schedule in a month

Import failures were very frequent during the recent summer for a couple of reasons. First, there were various MISO flowgate[18] issues beginning in May leading to frequent failures coded "TLRe" suggesting the failures were issued by the external ISO (MISO) due to transmission constraints. Secondly, there was increase in the amount of failures coded "MrNh" towards the end of the reporting period.[19] The implications of the frequent occurrences of these failed imports are discussed in more detail in Chapter 3, section 2.1.

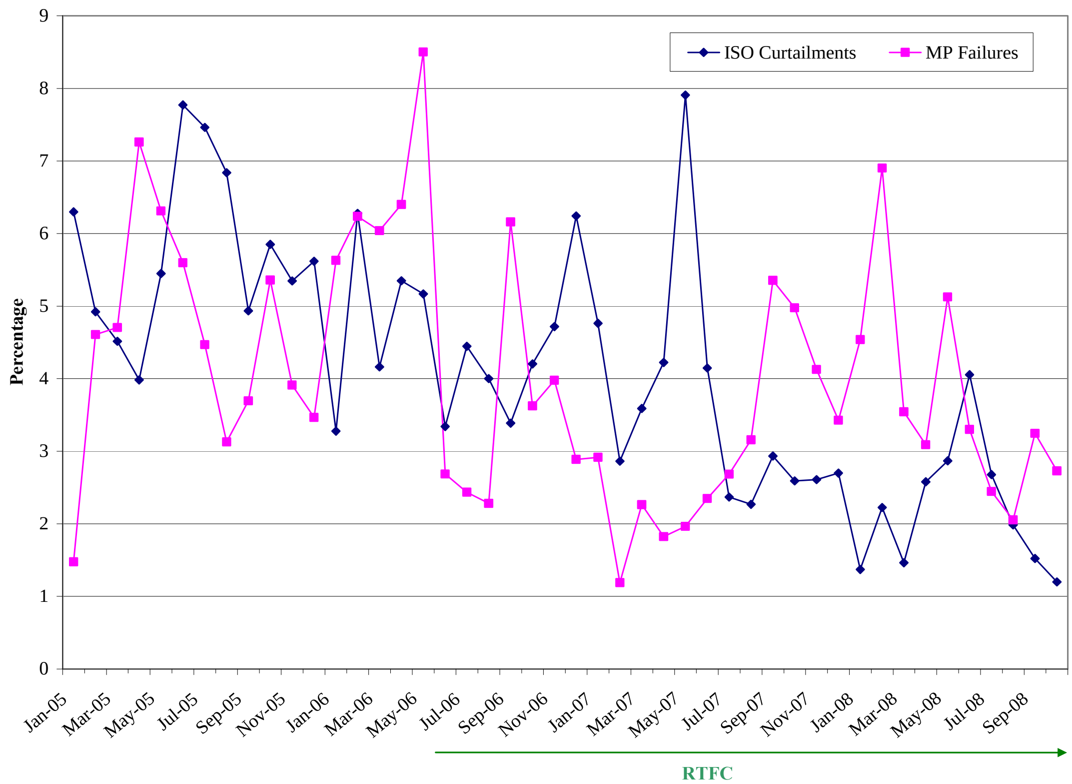
<u>Causes of Failures</u>

Figures 1-10 and 1-11 plot export and import failure rates since January 2005 separated by failures under the market participants' control (labelled MP failures) and those under the control of a system operator (labelled ISO curtailments).[20] The failure rate is determined as a percentage of failed to total exports (or imports) in MWh per month and linked-wheel failures are again not included.

[18] A flowgate is defined as, "A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions", according to NERC's Glossery of Terms Used in Reliability Standards available at http://www.nerc.com/files/Glossary_12Feb08.pdf.
[19] A transaction may fail due to an inability to acquire transmission service or ramping limitation in the external ISO and is coded 'MrNh' by the IESO.
[20] Data prior to 2005 is not considered given the introduction of the intertie failure charge in June 2006 and market participant entries and departures

Figure 1-10 shows that there has been a general decline in the percentage of export failures under the control of ISO's. Over the last three months of the summer, the failure rate for ISO curtailments was below 2 percent and, with the exception of June 2008, has not increased above 4 percent since the middle of 2007. Between January 2005 and June 2007, the failure rate for ISO curtailments fell below 4 percent only six months. Export failures under MP control fluctuated between 2 and 5 percent over the recent summer months, consistent with the general level of export failures since 2005.

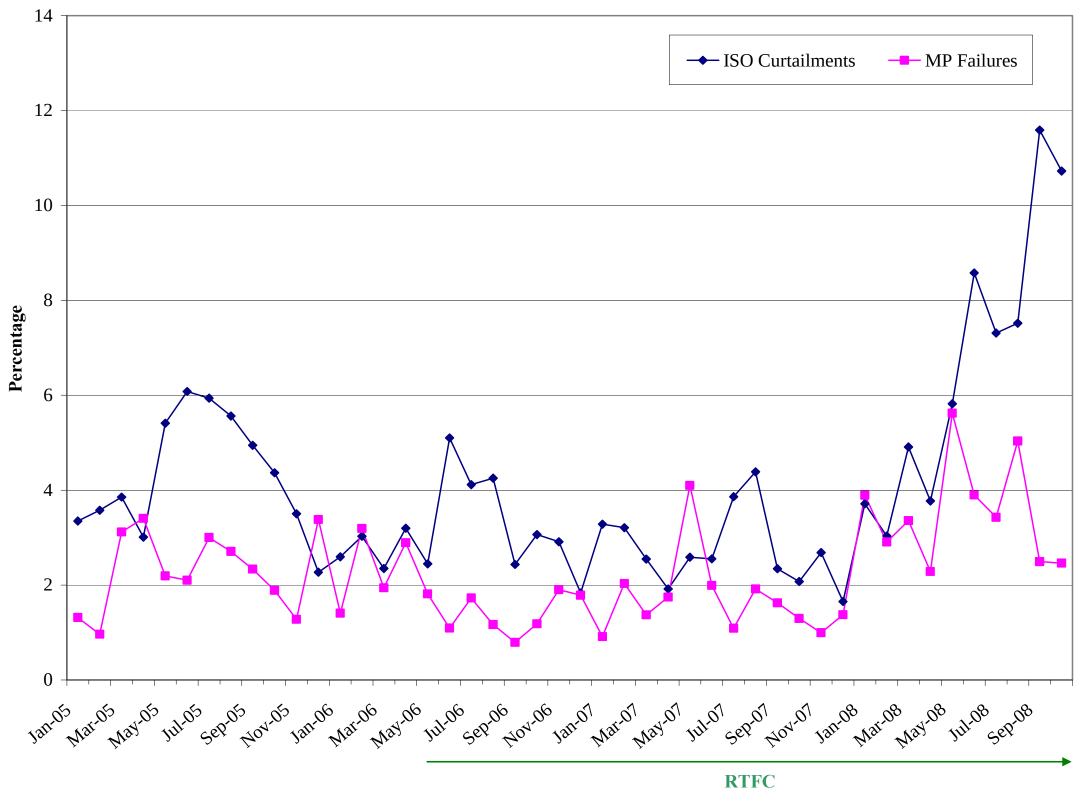
Figure 1-10: Monthly Export Failures as a Percentage of Total Exports by Cause, January 2005 – October 2008 (%)



For reasons discussed above, the monthly import failure rate increased dramatically over the latest summer period. Figure 1-11 plots the monthly import failure rate by cause between January 2005 and October 2008 and shows both types of import failures increased this past summer. Clearly, ISO caused curtailments increased the most and peaked at 11.6 percent in September 2008. As discussed above, the combination of

MISO flowgate issues in the early to mid summer months leading to increased "TLRe" failures at the Michigan intertie along with the increased "MrNh" failures in September and October contributed to the increase in the failure rate. The previous monthly high was only 6 percent back in June 2005. Although the increase was not as dramatic, the import failure rate for failures under market participant's control also peaked this summer at 5.6 percent in May 2008 and remained above 2 percent over all the summer months.

Figure 1-11: Monthly Import Failures as a Percentage of Total Imports by Cause, January 2005 – October 2008 (%)



Failures by Intertie Group

Tables 1-15 and 1-16 present statistics on failure rates by cause and intertie group between May and October 2008 for exports and imports respectively. Similar to the above tables and figures, linked wheel failures are excluded. The percent column represents the total of all failures of that type which occurred at the intertie group. ISO

Controlled export failures totalled 38.4 GWh this summer while participant controlled failures totalled 49.6 GWh.[21]

Export failures for both causes were most frequent at the New York intertie group. That is, 53.4 percent of all ISO controlled export failures and 91.3 percent of all participant controlled export failures occurred at the New York interface over the latest summer months. Export failures at MISO were also significant totalling 8.5GWh (22 percent) of all ISO controlled export failures. Although not illustrated in the table below, approximately 80 percent of these export failures at the MISO intertie were actually destined for PJM.

Table 1-15: Average Monthly Export Failures by Intertie Group and Cause, May – October 2008 (GWh and % Failures)

	Average Monthly Exports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
NYISO	894	20.5	53.4	45.3	91.3	2.3	5.1
MISO	517	8.5	22.1	3.4	6.9	1.6	0.7
Manitoba	1	0.1	0.3	0.1	0.2	10.0	10.0
Minnesota	71	4.4	11.5	0.2	0.4	6.2	0.3
Quebec	90	4.9	12.8	0.5	1.0	5.4	0.6
Total	1,573	38.4	100.0	49.6	100.0	2.4	3.2

During the 2008 summer period, ISO controlled import failures totalled 53.6 GWh, which more than doubled participant controlled failures at 22.2 GWh as presented in Table 1-16.[22] Import failures were frequent at the New York and Michigan intertie groups. Over 90 percent of ISO controlled import failures occurred at Michigan whereas participant controlled import failures were primarily shared between the New York and Michigan intertie groups with failure rates of 55.9 percent and 42.8 percent respectively.

[21] Over the latest summer period approximately one-third of all ISO-controlled export failures were under the IESO's control while two-thirds were under external ISO's control.
[22] Between May and October 2008, only 5 percent of ISO controlled import failures were under the IESO's control while 95 percent were under an external ISO's control.

Table 1-16: Average Monthly Import Failures by Intertie Group and Cause, May – October 2008 (GWh and % Failures)

	Average Monthly Imports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
NYISO	93	1.9	3.5	12.4	55.9	2.0	13.3
MISO	437	48.6	90.7	9.5	42.8	11.1	2.2
Manitoba	35	1.5	2.8	0	0.0	4.3	0.0
Minnesota	13	0.6	1.1	0.2	0.9	4.6	1.5
Quebec	28	1	1.9	0	0.0	3.6	0.0
Total	606	53.6	100.0	22.2	100.0	8.8	3.7

2.3.3.4 Imports or Exports Setting Pre-dispatch Price

A fourth factor that leads to discrepancies between pre-dispatch and real-time prices is the frequency of imports and exports setting the pre-dispatch market clearing price. Although they are able to set the pre-dispatch price, the design of the unconstrained schedule does not allow imports or exports to set the MCP in real-time as they are essentially moved to the bottom of the offer stack. When an import sets the pre-dispatch price in a given hour, a lower priced generating unit's offer will typically set the price in real-time because of lower average demand in real-time than the forecast peak demand in pre-dispatch. The result is a discrepancy between pre-dispatch and real-time MCP. Similarly, exports are eligible to be marginal in pre-dispatch but are unable to set the real-time MCP. Therefore, we expect that an increased incidence of imports or exports setting the pre-dispatch price will lead to an increased divergence between pre-dispatch and real-time prices.

Table 1-17 provides statistics on the frequency of hours that imports and exports set the pre-dispatch price for the last two summer periods. The number of hours fell slightly compared to the same months in 2007 from 2,017 hours to 1,908 hours with the largest monthly declines occurring in May and August 2008.

Table 1-17: Frequency of Imports or Exports Setting the Pre-Dispatch Price, May – October 2007 & 2008 (Number of Hours and % of Hours)

	2007		2008		Difference	
	Hours	**%**	**Hours**	**%**	**Hours**	**% Change**
May	362	49	298	40	(64)	(9)
June	295	41	298	41	3	0
July	330	44	320	43	(10)	(1)
August	322	43	269	36	(53)	(7)
September	329	46	355	49	26	3
October	379	51	368	49	(11)	(2)
Total	2,017	46	1,908	43	(109)	(3)

2.4 Analyzing Year-Over-Year Changes in the HOEP

Table 1-18 presents estimates for the econometric model of HOEP using monthly data over the time period January 2003 to October 2008 resulting in 70 observations. The dependent variable in model is the HOEP. The independent variables are: nuclear and self-scheduled generation in Ontario, Ontario non-dispatchable load, New York integrated demand, the Henry-hub natural gas price (in Canadian dollars), and eleven monthly dummies.[23]

[23] The natural gas price is converted to Canadian dollars by using the noon Bank of Canada noon exchange rate. The parameter estimates and p-values associated with the dummy variables are excluded from Table 1-18.

Table 1-18: Estimation Results of the Updated Econometric Model, January 2003 - October 2008

Variable	All Hours		On-peak Model		Off-peak Model	
	Coefficient	P-value	Coefficient	P-value	Coefficient	P-value
Constant	-22.17	0	-26.77	0	-18.15	0
LOG(Nuclear Output)	-0.76	0	-0.78	0	-0.7	0
LOG(Self Scheduler output)	-0.24	0.026	-0.17	0.122	-0.34	0.005
LOG(Ontario NDL)	1.82	0	1.47	0	2.39	0
LOG(New York Integrated Load)	1.62	0.002	2.36	0	0.68	0.292
LOG(Natural Gas Price)	0.5	0	0.59	0	0.38	0.002
R-squared	0.823		0.862		0.762	
Adjusted R-squared	0.77		0.821		0.691	
LM test of Serial Correlation	Normal		Normal		Normal	
JB test of normality of residuals	Absent		Absent		Absent	
Number of observations	70		70		70	

The signs of all of the estimates are intuitive and, for the most part, statistically significant. Two exceptions are the self scheduler generation variable in on-peak hours and New York integrated load in off-peak hours. This result is different from previous Panel reports in which all variables on-peak were significant, while all but self-scheduling generation were significant off-peak.

The statistical insignificance of self scheduler generation in determining the HOEP during on-peak hours indicates that while an increase in output of self-scheduling generators may have a negative impact on the HOEP (as indicated by the sign), we cannot conclude statistically that this is true.. Likewise, the statistical insignificance of the New York integrated load during off-peak hours suggests that demand in neighbouring jurisdictions is not an important indicator of the HOEP likely to prevail in Ontario.[24]

[24] It should be noted, however, that the performance of the New York integrated load variable as a predictor of the HOEP deteriorated significantly due to the addition of the last six observations. In fact, over the period January 2003 to April 2008, the p-value associated with the New York integrated load is 0.0721.

Table 1-19 presents a decomposition analysis using the regression model presented in the table above. This analysis quantifies what the monthly average HOEP would have been over the period May 2008 to October 2008 had the values of the explanatory variables observed one year earlier been used in place of the actual 2008 observations.

Table 1-19: Price Effect of Setting 2008 Factors Equal to 2007 Factors
All hours, On-peak hours and Off-peak hours
January 2003 to October 2008
($/MWh)

	Month	Nuclear Generation	Self Scheduler Generation	Ontario Load	New York Load	Natural Gas Price	2008 HOEP	
							Actual	Calibrated
All Hours	May	(4.59)	0.16	3.35	3.63	(6.39)	34.56	46.57
	June	(1.64)	(3.12)	5.62	(3.21)	(14.50)	57.44	65.32
	July	1.74	(2.48)	(2.63)	(5.93)	(15.80)	56.58	65.33
	August	2.60	(1.93)	7.28	5.88	(6.33)	46.57	50.38
	September	4.62	(0.61)	1.15	1.26	(8.65)	49.09	50.62
	October	5.36	0.54	1.01	3.76	(3.50)	45.27	40.24
	Average	**1.35**	**(1.24)**	**2.63**	**0.90**	**(9.19)**	**48.25**	**53.08**
On-peak Hours	May	(6.25)	0.80	4.76	8.49	-9.74)	47.12	61.48
	June	(1.75)	(3.02)	9.45	-0.47)	-20.94)	76.57	82.35
	July	1.87	(2.46)	-1.28)	-9.49)	-24.49)	82.78	88.55
	August	3.28	(1.37)	7.62	10.74	-9.12)	60.63	62.83
	September	6.26	(0.72)	3.29	6.27	-12.10)	58.58	61.53
	October	6.69	0.27	0.90	6.43	-5.06)	55.87	50.18
	Average	**1.68**	**(1.08)**	**4.12**	**3.66**	**-13.58)**	**63.59**	**67.82**
Off-peak Hours	May	(2.99)	(0.27)	1.15	0.60	(3.50)	24.21	33.44
	June	(1.29)	(3.01)	0.55	(2.37)	(8.37)	42.13	48.85
	July	1.30	(2.46)	(3.74)	(2.13)	(8.49)	35.00	45.33
	August	1.94	(2.25)	5.08	1.39	(3.91)	35.96	40.86
	September	3.06	(0.69)	0.96	0.28	(5.14)	40.78	39.26
	October	3.83	0.74	1.16	1.30	(2.05)	35.75	31.07
	Average	**0.97**	**(1.32)**	**0.86**	**(0.16)**	**(5.24)**	**35.64**	**39.80**

For example, had the average price of natural gas in May 2008 been the same as in May 2007, ceteris paribus, these results suggest that the average HOEP in May 2008 would have been $6.39/MWh lower. In fact, this analysis shows that had the natural gas prices in 2008 been the same as those that prevailed in 2007 the HOEP would have been lower in all months of each of the three models than they were observed to be. These results are economically intuitive in that the price of natural gas was higher in each month over the period May 2008 to October 2008 than in the same months of the year earlier. [25]

The decomposed effect of the natural gas price is greater during on-peak hours than off-peak hours. This result is due to the relatively greater importance of natural gas generation in setting the HOEP during on-peak hours compared to off-peak hours.

2.5 Hourly Uplift and Components

Table 1-20 reports the monthly total hourly uplift charge for the last two summer periods. Total hourly uplift charges increased from $183 million in 2007 to $232 million in 2008, an increase of 27 percent. Total hourly uplift increased in every month with the exception of August. With the exception of IOG payments, which decreased from $20 million last year to $11 million this year, there was an increase in all uplift categories between the 2007 and 2008 summer months. CMSC payments increased this summer by $35 million (45 percent) and increased in every month relative to the same months last year. Increased CMSC payments were due to more bottled energy in the Northwest this summer, as discussed in the next section. By far the largest percentage increase occurred in operating reserve payments which increased by 300 percent from only $6 million in 2007 to $24 million in 2008. The rise in operating reserve payments is a direct result of the dramatic increase in operating reserve prices which is described in more detail in Section 2.8. Finally, losses increased by only $5 million or 6 percent, which is similar to the percentage increase in HOEP over the past summer.

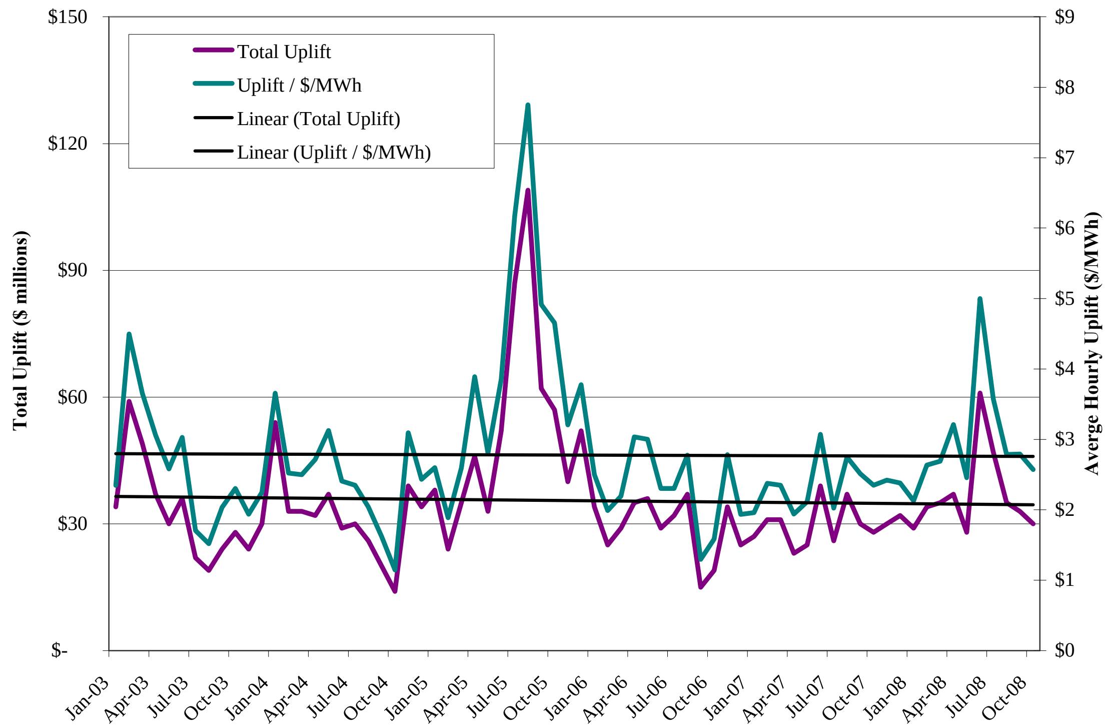
[25] The average price for natural gas increased by 45 percent between last summer and this summer. Natural gas price trends are discussed in more detail in Section 4.5.2.

Table 1-20: Monthly Total Hourly Uplift Charge by Component and Month, May – October 2007 & 2008 ($ millions and %)

	Total Hourly Uplift		IOG		CMSC		Operating Reserve		Losses	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
May	24	28	3	2	10	11	1	5	11	10
June	39	60	3	3	21	35	1	5	14	18
July	26	46	2	2	9	19	1	6	14	20
August	36	35	3	1	15	16	1	3	18	15
September	30	33	5	2	12	16	1	1	12	14
October	28	30	4	1	10	15	1	4	13	10
Total	183	232	20	11	77	112	6	24	82	87
% of Total	100	100	11	5	42	48	3	10	45	37

Figure 1-12 plots hourly uplift charges in millions of dollars and in $/MWh between January 2003 and October 2008. Prior to the recent summer period, uplift payments appeared relatively stable since 2006. However for reasons described above, there was a clear increase in uplift payments in both $ and $/MWh in June 2008. Total uplift charges climbed to $60 million ($35 million from CMSC) in June and reached $5.00/MWh, which is the third highest $/MWh charge since 2003.

Figure 1-12: Total Hourly Market Uplift and Average Hourly Market Uplift, January 2003 - October 2008 ($ millions and $/MWh)



2.6 Internal Zonal Prices and CMSC Payments

Table 1-21 presents average nodal prices for the 10 internal Ontario zones for each six month period for the last three 6-month periods.[26] Figure 1-13 shows the same average nodal prices graphically for each zone for the recent winter period. The average nodal price for a zone, also referred to here as the internal zonal price, is calculated as the average of the nodal prices for generators in the zone.[27]

[26] See the IESO's "Ontario Transmission System" publication for a detailed description of the IESO's ten zone division of Ontario at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2005jun.pdf

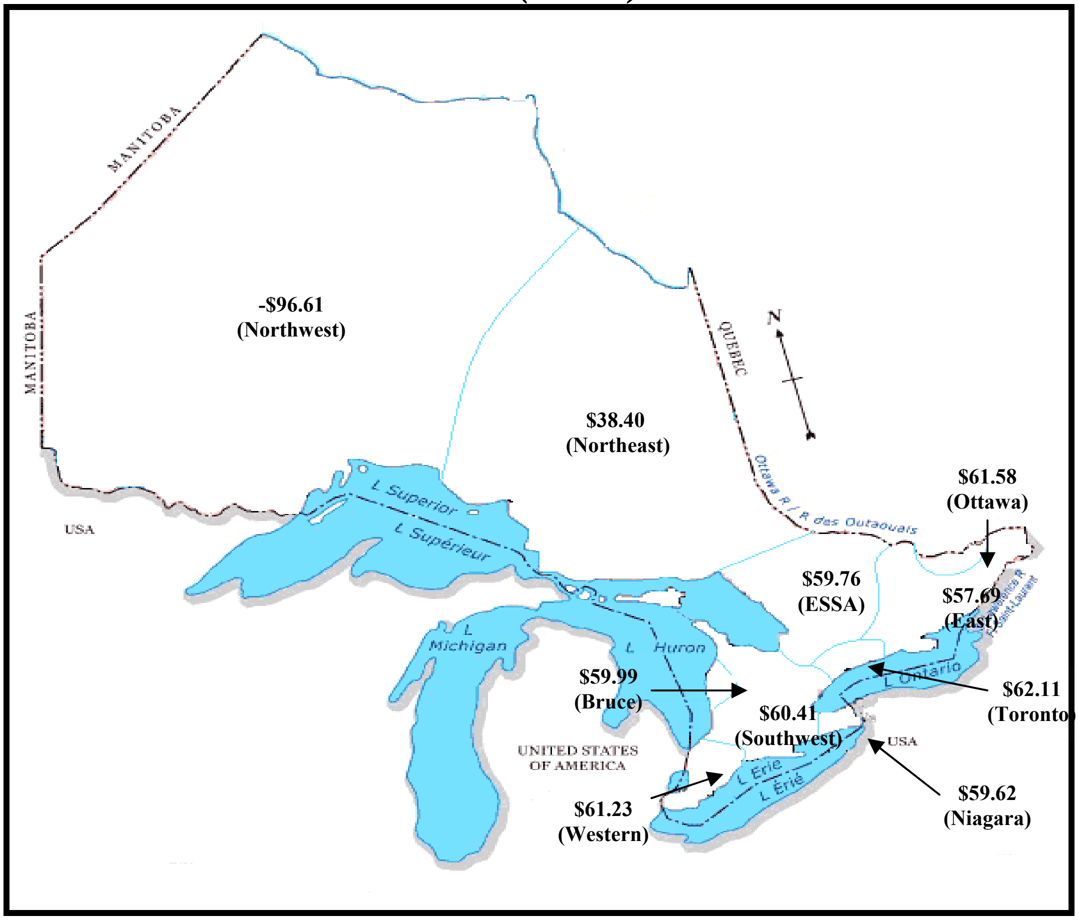
[27] All nodal and zonal prices have been modified to +$2,000 (or -$2,000) when the raw interval value was higher (or lower). This is a refinement in the calculation which previously truncated prices on an hourly basis, and has resulted in currently reported Zonal prices differing slightly from those in previous Monitoring Reports

Table 1-21: Internal Zonal Prices,
May 2007 – October 2008
($/MWh and %)

Zone	May -Oct 07	Nov 07-Apr 08	May – Oct 08	% Change from May – Oct 07 to May – Oct 08
Bruce	53.80	56.82	59.99	12
East	54.42	58.36	57.69	6
Essa	52.16	57.06	59.76	15
Northeast	42.38	49.18	38.40	(9)
Niagara	52.29	56.01	59.62	14
Northwest	(136.65)	(43.86)	(96.61)	29
Ottawa	56.03	60.51	61.58	10
Southwest	54.50	57.22	60.41	11
Toronto	56.36	58.55	62.11	10
Western	55.23	57.53	61.23	11
Richview Nodal Price	55.14	57.96	63.15	15

For most zones other than the Northeast, the table shows that current internal zonal prices are higher than those of the previous year, between 10 to 15 percent above the earlier values, except for the East zone which is only 6 percent higher. These price movements in the southern zones are largely related to generally higher supply costs in southern Ontario, which is also seen as an increase in the Richview nodal prices. The average Richview nodal price was $63.15/MWh over the recent summer which is $8.01/MWh, or 15 percent, higher than the 2007 summer period.

Figure 1-13: Average Internal Zonal Prices
May 2008 – October 2008
($/MWh)



For the Northwest and Northeast, higher levels of losses and more frequent congestion in the zone (either at the interface with the rest of the system, or in more remote locations for example in the far Northeast area near James Bay) continue to drive the nodal prices significantly below prices in the south. As observed for previous periods, congestion in the Northwest is the primary reason for the average prices there to be quite low, at -$96.61 this last summer, which is not as low as -$136.65 (the average price last summer), but lower than the recent winter average price of -$43.86. With record rainfalls this last summer, the abundant supply of very low-priced water in the Northwest, including energy available from imports, coupled with the decreasing demand in the area continues to create more supply than needed in the zone or capable of being transmitted to the rest of the province. More rainfall also tends to increase the possible risk of lightning strikes on transmission lines, which in turn requires the IESO to apply lower flow limits. The

Northeast also had a large amount of hydroelectric supply but experienced less surplus and less congestion than the Northwest. However, prices in the Northeast declined significantly relative to the previous two periods, which partly reflects significant transmission outages in the area in June and lower offer prices when the generator was attempting to avoid spill. For each of these two zones, the low average prices are highly influenced by a smaller numbers of hours (on the order of 15 to 25 percent) when prices are much lower than normal.

Figure 1-14 provides a comparable summary of congestion payments (CMSC) across the same 10 zones for the last summer period. For each zone, there is a total for CMSC paid for constraining off generation or imports (into the zone) or constraining on exports from the zone. A second figure shows the total CMSC for constrained on generation or imports, or constrained off exports. The data has been aggregated in this manner since constraining on exports is an alternative to constraining off supply when supply is bottled (oversupply in zone), and so the figure is to some degree a measure of the bottling of supply in the zone. Similarly, the second sub-total is a measure of the need for additional or out-of merit supply in a zone (undersupply in zone).[28] However, not all CMSC is induced by transmission (including losses) or security (e.g. the 3-times ramp rate or slow ramping of fossil units can induce CMSC) so the total CMSC is not entirely a measure of congestion or losses.

[28] CMSC paid to dispatchable load is omitted here since the largest portion of those payments are self-induced.

Figure 1-14: Total CMSC Payments by Internal Zone, May – October 2008 ($ millions)

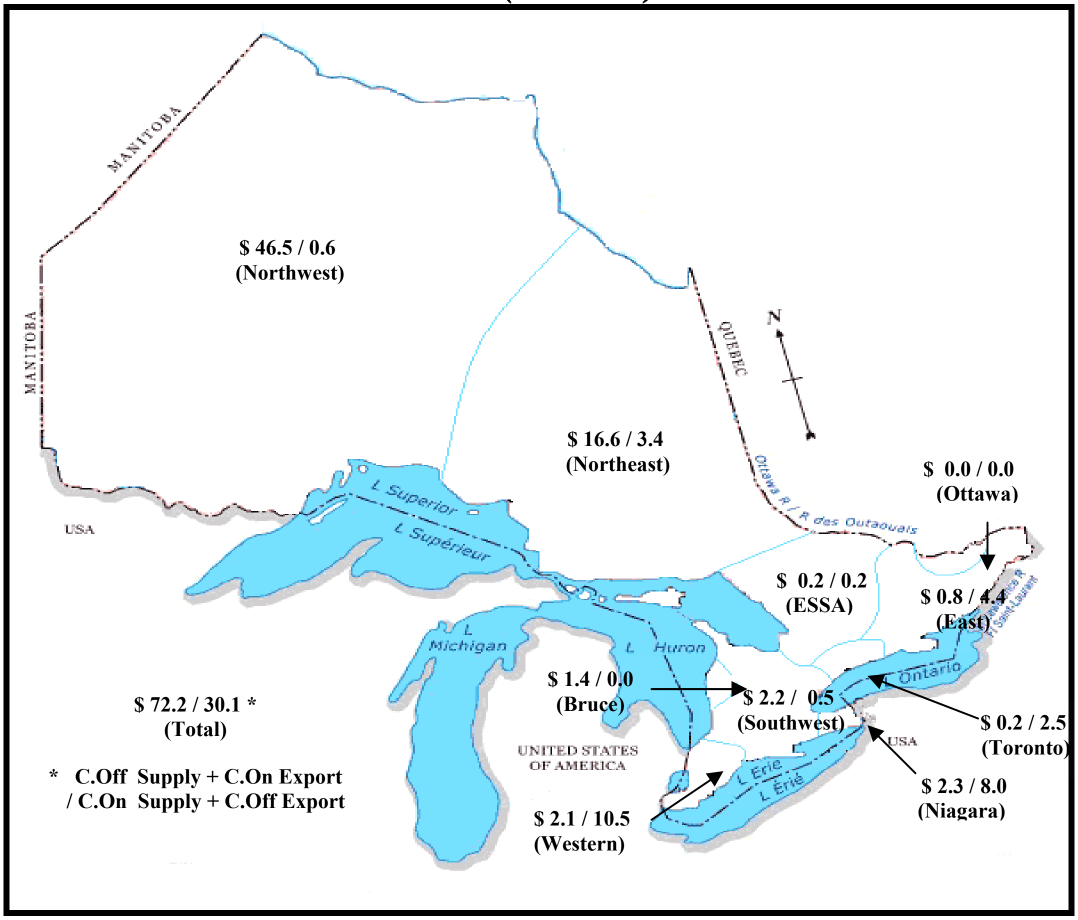


Table 1-22 presents the CMSC payments by internal zone for the 2007 and 2008 summer periods. Total CMSC payments were much larger this summer than for the same period a year ago. This was due to the $72 million CMSC payments for constrained off supply plus constrained on exports, representing a year-over-year increase of $35 million (or 96 percent). Total CMSC for constrained on supply plus constrained off exports was $30 million this winter, about $2 million or 5 percent less than last summer. The Northwest zone contributed most to the increase in CMSC for constrained off supply plus constrained on exports, more $23 million, with the Northeast also showing a large increase of $8 million.

Table 1-22: Total CMSC Payments by Internal Zone, May – October 2007 & 2008 ($ millions)

Zone	Constrained off Supply plus Constrained on Exports			Constrained on Supply plus Constrained off Exports		
	2007	2008	% Change	2007	2008	% Change
Bruce	0.1	1.4	1,300	0.0	0.0	0
East	0.3	0.8	167	5.9	4.4	(25)
Essa	0.2	0.2	0	0.5	0.2	(60)
Northeast	8.0	16.6	108	2.8	3.4	21
Niagara	0.8	2.3	188	7.8	8.0	3
Northwest	22.9	46.5	103	1.1	0.6	(45)
Ottawa	0.0	0.0	0	1.6	0.0	(100)
Southwest	1.6	2.2	38	0.2	0.5	150
Toronto	0.2	0.2	0	1.5	2.5	67
Western	2.8	2.1	(25)	10.3	10.5	2
Total	36.9	72.2	96	31.8	30.1	(5)

Referencing Table 1-20, the largest monthly increases in total CMSC can be seen in June and July, with a combined increase of $24 million. These were the months that most contributed to record rainfalls this summer resulting in increased hydroelectric resources in the north and increased imports from Manitoba. As noted in the zonal price discussion, the rainy weather also resulted in tighter limits on transmission through the Northwest and Northeast as the result of the increased risk of lightning strikes. Coupled with the continued reduced demand in the north, the greater supply and somewhat more restricted transmission limits, led to the much larger CMSC payments those months and for the summer period.

2.7 A Comparison of HOEP and Richview Nodal Price

Table 1-23 provides summary statistics for the HOEP and Richview nodal price over the last two summer periods.[29]

[29] As for the MCP in each interval, the Richview nodal price has been modified to +$2,000/MWh (or -$2,000/MWh) when the raw interval value was higher (or lower). Interval values were averaged to provide an hourly Richview price for comparison with the HOEP.

Table 1-23: HOEP and Richview Price Summary Statistics, May – October 2007 & 2008 ($/MWh and Hours)

	HOEP			Richview Price			Richview - HOEP	
	2007	2008	% Change	2007	2008	% Change	2007	2007
Average ($/MWh)*	45.66	48.25	5.7	55.14	63.15	14.5	9.48	14.90
Median ($/MWh)*	36.28	42.49	17.1	40.06	46.25	15.5	3.78	3.76
# of Hours Price < $20/MWh	331	724	118.7	399	682	70.9	68	(42)
# of Hours Price > $200/MWh	4	17	325.0	54	122	125.9	50	105

Similar to 2007, the average and median Richview prices were higher than the comparable HOEP values over the past summer. The average difference between the Richview price and the HOEP was $14.90 in 2008, which is higher than the average difference of $9.48 in 2007 while the median difference remained virtually unchanged. Both the HOEP and the Richview price fell below $20/MWh and rose above $200/MWh much more frequently in 2008 compared to 2007. The HOEP fell below $20/MWh in 724 hours (331 hours in 2007) during the 2008 summer months while the Richview price fell below $20/MWh in 682 hours (399 hour in 2007). The Richview price was above $200/MWh during 122 hours in 2008, which was over double the 54 hours observed in 2007. The HOEP was above $200/MWh for 17 hours in 2008, which is much higher than the 4 high-priced hours in 2007.

2.8 Operating Reserve Prices

Overall, operating reserve prices dramatically increased this summer relative to the previous summer. One of the major reasons was the abundance of water in the province giving hydro resources the capability to provide energy rather than operating reserve in order to avoid spilling the water. In Ontario, hydro resources historically provided about three-quarters of all operating reserve scheduled. However, over the past summer, they only provided about half of all operating reserve scheduled. We discuss potential operating reserve supply issue in the future later in Chapter 3.

Table 1-24 presents average monthly operating reserve (OR) prices during the on-peak hours over the last two summer periods. The average on-peak 10-minute spinning reserve (10S) price increased by 188 percent from $2.78/MWh in 2007 to $7.99/MWh, while the 10-minute non-spinning (10N) and 30 minute total reserve (30R) prices increased even more at 450 percent and 383 percent respectively. The prices for 10S and 10N were also almost identical during the recent summer months as the average 10N price was only $0.08/MWh lower than the average 10S price. The convergence between the 10S and 10N prices is a result of dispatchable loads being allowed to offer 10S reserve starting in March 2008, thus shifting supply from 10N to 10S. Last summer, there was a difference of $1.34/MWh between on-peak 10S and 10N prices.[30]

Finally, the total operating reserve requirement in Ontario increased in many hours after mid-September 2008, which increased demand and placed upward pressure on operating reserve prices. The total operating reserve requirement is calculated as the size of the single largest contingency in Ontario plus half of the second largest contingency less an adjustment for Regional Reserve Sharing (RRS).[31] Historically, the largest contingency has been the loss of a Darlington unit. Recently, the entry of a new gas-fired generating facility became the single largest contingency for Ontario when all units are running based on the gas valve configuration at the facility.

[30] The change to make Regional Reserve Sharing eligible to offer 10-minute spinning reserve beginning early December 2008 should also contribute to 10-minute spinning and 10-minute non-spinning reserve prices to converge even more.
[31] NPCC document A-6 – Operating Reserve Criteria available at: http://www.npcc.org/viewDoc.aspx?name=A-6.pdf&cat=regStandCriteria describes the calculation of the operating reserve requirement and its relationship with the single largest contingency in a control area.

Table 1-24: Operating Reserve Prices On-Peak, May – October 2007 & 2008 ($/MWh)

	10S			10N			30R		
	2007	2008	% Change	2007	2008	% Change	2007	2008	% Change
May	1.96	10.18	419.4	1.40	10.15	625.0	1.40	7.40	428.6
June	4.30	10.13	135.6	2.35	10.10	329.8	2.35	9.46	302.6
July	3.19	12.62	295.6	1.92	12.50	551.0	1.92	12.13	531.8
August	2.82	6.03	113.8	0.64	6.02	840.6	0.64	5.69	789.1
September	2.34	1.67	(28.6)	1.21	1.63	34.7	1.21	1.57	29.8
October	2.05	7.29	255.6	1.09	7.04	545.9	1.09	5.52	406.4
Average	2.78	7.99	187.4	1.44	7.91	449.3	1.44	6.96	383.3

Table 1-25 presents average monthly operating reserve (OR) prices during the off-peak hours over the last two summer periods. Similar to on-peak prices, off-peak operating reserve prices increased for all categories of reserve, although the increase in 10S was not as dramatic as the increases in off-peak 10N and 30R. Average off-peak 10S reserve prices increased by 33 percent this summer while the average price for the other two categories of operating reserve increased seven-fold relative to 2007.

Table 1-25: Operating Reserve Prices Off-Peak, May – October 2007 & 2008 ($/MWh)

	10S			10N			30R		
	2007	2008	% Change	2007	2008	% Change	2007	2008	% Change
May	2.36	3.21	36.0	0.22	2.43	1,004.5	0.22	2.05	831.8
June	1.83	2.90	58.5	0.22	2.84	1,190.9	0.22	2.63	1,095.5
July	0.97	3.03	212.4	0.24	2.83	1,079.2	0.24	2.78	1,058.3
August	0.84	0.95	13.1	0.20	0.92	360.0	0.20	0.92	360.0
September	1.67	0.77	(53.9)	0.20	0.56	180.0	0.20	0.56	180.0
October	1.77	1.68	(5.1)	0.20	0.97	385.0	0.20	0.81	305.0
Average	1.57	2.09	32.8	0.21	1.76	724.2	0.21	1.63	661.7

Figure 1-15 plots average operating reserve prices between January 2003 and October 2008 by operating reserve reserve category. Although operating reserve prices were very high this summer relative to last summer, the 2008 prices are not out of line when compared to previous spring peaks, although the duration of the high average prices appears to have been longer than in the past. The figure also highlights the recent convergence of the operating reserve prices by type beginning in early 2008.

Figure 1-15: Monthly Operating Reserve Prices by Class, January 2003 - October 2008 ($/MWh)

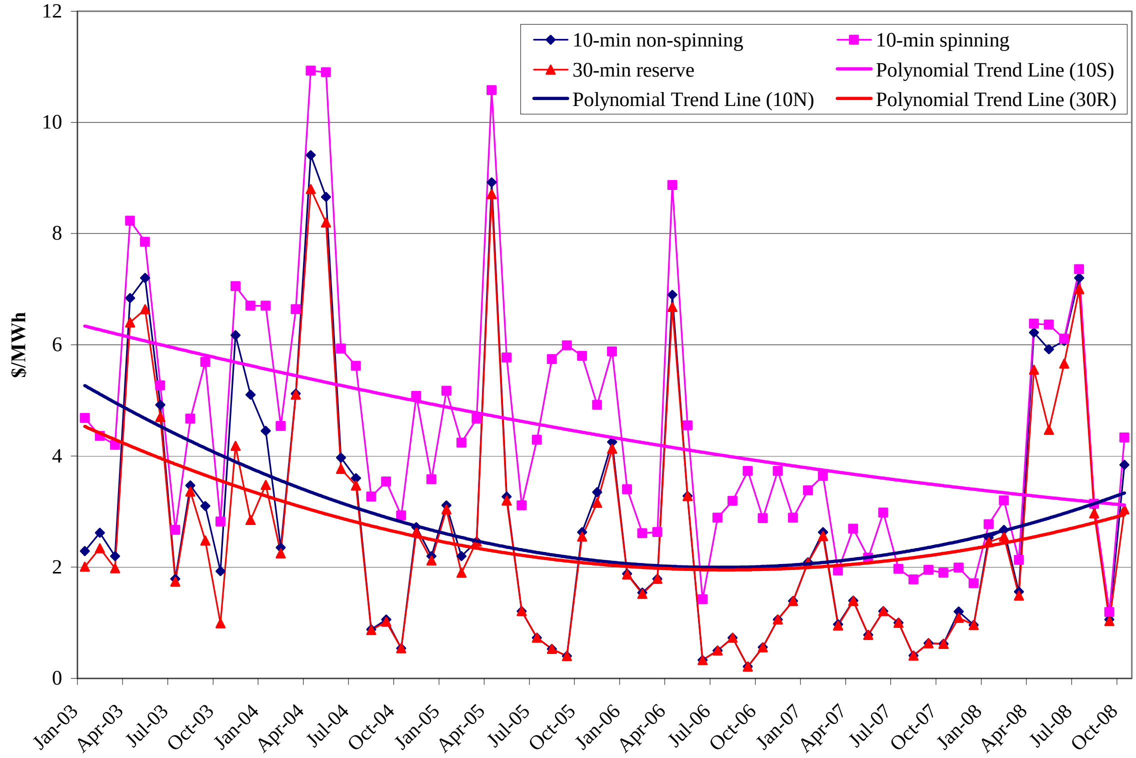
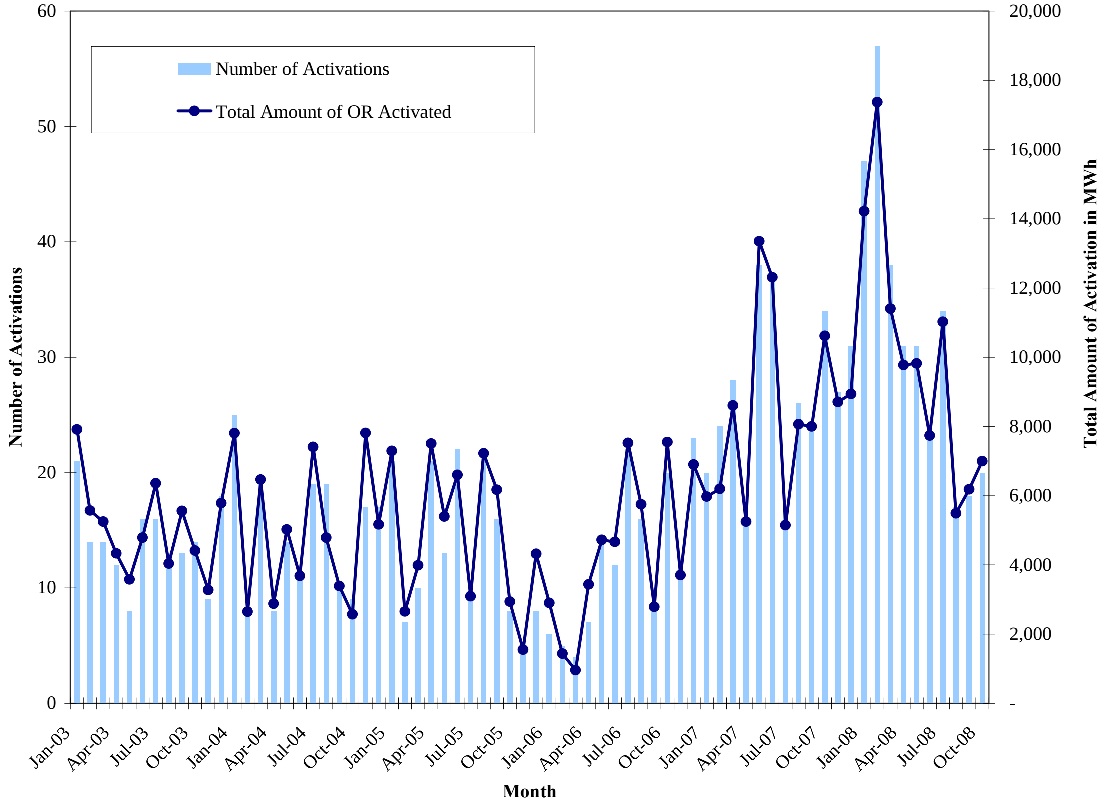


Figure 1-16 shows the monthly frequency (in number of activations) and cumulative magnitude (in MW) of operating reserve activations since January 2003. Although the number and magnitude of operating reserve activations climbed steadily since mid-2006, there was a slight decline over the current summer months to activation levels more consistent prior to 2007. The reasons for the increase in operating reserve activations in 2007/2008 were discussed in the Panel's previous report.[32]

[32] See the July 2008 MSP Monitoring Report, pages 192 – 203.

Figure 1-16: Monthly Operating Reserve Activations, January 2003 - October 2008 (Frequency and Cumulative MW)



3. Demand

3.1 Aggregate Consumption

Table 1-26 compares total monthly energy demand and exports for the 2007 and 2008 summer periods. The export leg of linked-wheel transactions, which were frequent between May and July 2008, were removed from exports since they do not directly influence the level of the market clearing price. The sum of Ontario Demand and exports is known as total Market Demand.

Exports, excluding linked wheel transactions, increased significantly this summer by 46 percent, or 2.9 GWh. A large portion of these export were scheduled transactions beginning in Ontario, through MISO, and destined for PJM.[33]

Table 1-26: Monthly Energy Demand, Market Schedule, May – October 2007 & 2008 (TWh)

	Ontario Demand*			Exports (excluding Linked Wheels)			Total Market Demand (excluding Linked Wheels)		
	2007	2008	% Change	2007	2008	% Change	2007	2008	% Change
May	11.83	11.41	(3.6)	1.08	1.55	43.5	12.91	12.96	0.4
June	12.69	12.20	(3.9)	1.03	1.59	54.4	13.72	13.79	0.5
July	12.85	13.15	2.3	1.27	1.75	37.8	14.12	14.9	5.5
August	13.47	12.57	(6.7)	1.09	1.61	47.7	14.56	14.18	(2.6)
September	11.95	11.82	(1.1)	0.91	1.25	37.4	12.86	13.07	1.6
October	11.92	11.67	(2.1)	0.93	1.46	57.0	12.85	13.13	2.2
Total	74.71	72.82	(2.5)	6.31	9.21	46.0	81.02	82.03	1.2
Average	12.45	12.14	(2.5)	1.05	1.54	46.2	13.5	13.67	1.3

* Non-dispatchable loads plus dispatchable loads

3.2 Wholesale and LDC Consumption

Figure 1-17 plots the monthly total energy consumption separated by wholesale load and Local Distribution Companies (LDC's) between January 2003 and October 2008. Although the long-term trend for LDC consumption appears flat since 2003, there are obvious seasonal fluctuations. Typically, LDC consumption is highest during the December/January and July/August months. The long-term trend for wholesale load consumption has been declining and reached it's lowest monthly level in October 2008 at just over 2,100 GWh.

[33] Refer to Chapter 3, section 2.3 for more details on trade flows to PJM.

Figure 1-17: Monthly Total Energy Consumption, LDC vs. Wholesale Loads, January 2003 – October 2008 (GWh)

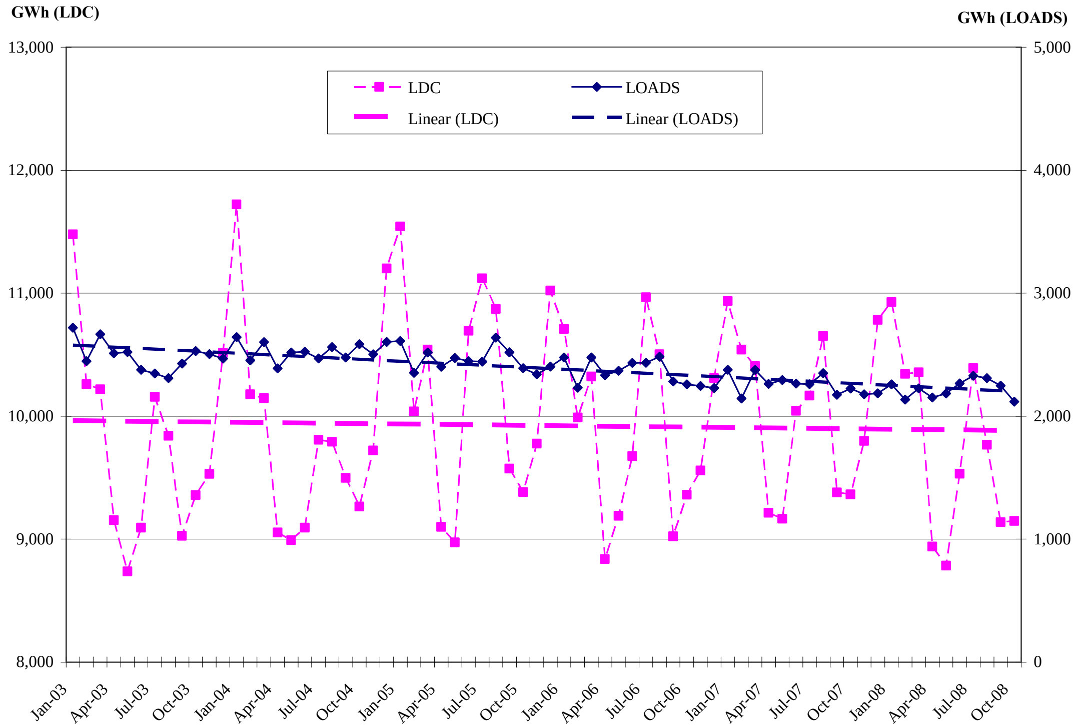
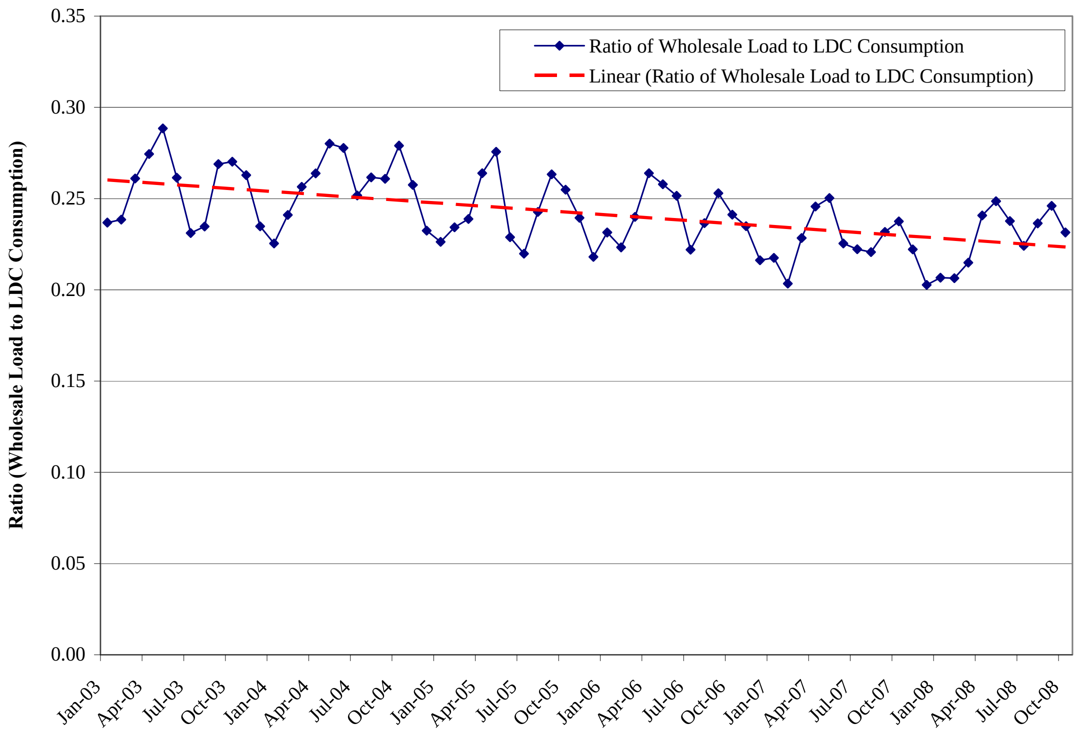


Figure 1-18 presents the ratio of wholesale load to LDC consumption since 2008. The declining trend in the ratio is consistent with the decline in wholesale load presented above while LDC consumption has remained stable. However since the summer of 2006, the ratio appears to have levelled out and remained between 0.20:1 and 0.25:1.

Figure 1-18: Ratio of Wholesale Load to LDC Consumption, January 2003 – October 2008 (%)



4. Supply

4.1 New Generating Facilities

Over the latest summer period, two notable gas-fired generating facilities and a wind generating facility began operating in Ontario. The largest facility was the Greenfield Energy Centre, which is a gas-fired generating facility located in Sarnia that includes four units (one being a steam unit) with a combined nameplate capacity of 1,005 MW (although based on their maximum capability found in the IESO`s Hourly Production and Capability Reports, total capacity is slightly over 1,120 MW).[34] Greenfield was commissioning for most of the summer and began operating as a 'typical' unit in October 2008. Portlands Energy Centre, the second gas-fired entrant is a combined-cycle facility

[34] As an example, see the Capability statistics for Greenfield G1-G4 in the October 19th, 2008 report at: http://reports.ieso.ca/public/GenOutputCapability/PUB_GenOutputCapability_20081019.xml

located in Toronto that saw limited operation throughout May 2008 as it was commissioning. The unit is expected to be in full production in the first quarter of 2009 and has a capacity of 550 MW (2 combustion turbine generating units, 1 steam unit). Finally, Kruger Energy Port Alma Wind-Power Project located in Port Alma, Ontario came online during the summer of 2008 with a total capacity of 101.2 MW.[35] The addition of these units represents almost 6 percent of total installed capacity in Ontario.[36]

4.2 The Supply Cushion

Tables 1-27 and 1-28 present monthly summary statistics on the pre-dispatch and real-time supply cushion respectively for the last two summer periods. Based on the averages, pre-dispatch supply conditions worsened slightly this summer while real-time supply conditions improved. The average pre-dispatch supply cushion fell from 20.3 percent in 2007 to 19.8 percent in 2008 while the real-time average supply cushion increased significantly from 19.7 percent in 2007 to 22.5 percent in 2008. Consistent with this trend, the number of hours when the pre-dispatch supply cushion fell below 10 percent increased from 771 hours in 2007 to 907 hours in 2008 while in real-time, the number of hours fell by 667 hours this summer.

[35] Nameplate capacity statistics can be found on the OPA`s Electricity Contracts webpage at: http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=123
[36] On page 11 of the IESO`s 18-month Outlook Report dated September 23, 2008), it is reported that existing installed generation resources as of September 9, 2008 totalled 31,668 MW. The report is available at: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2008sep.pdf

Table 1-27: Pre-Dispatch Total Supply Cushion, May – October 2007 & 2008 (% and Number of Hours under Certain Levels)

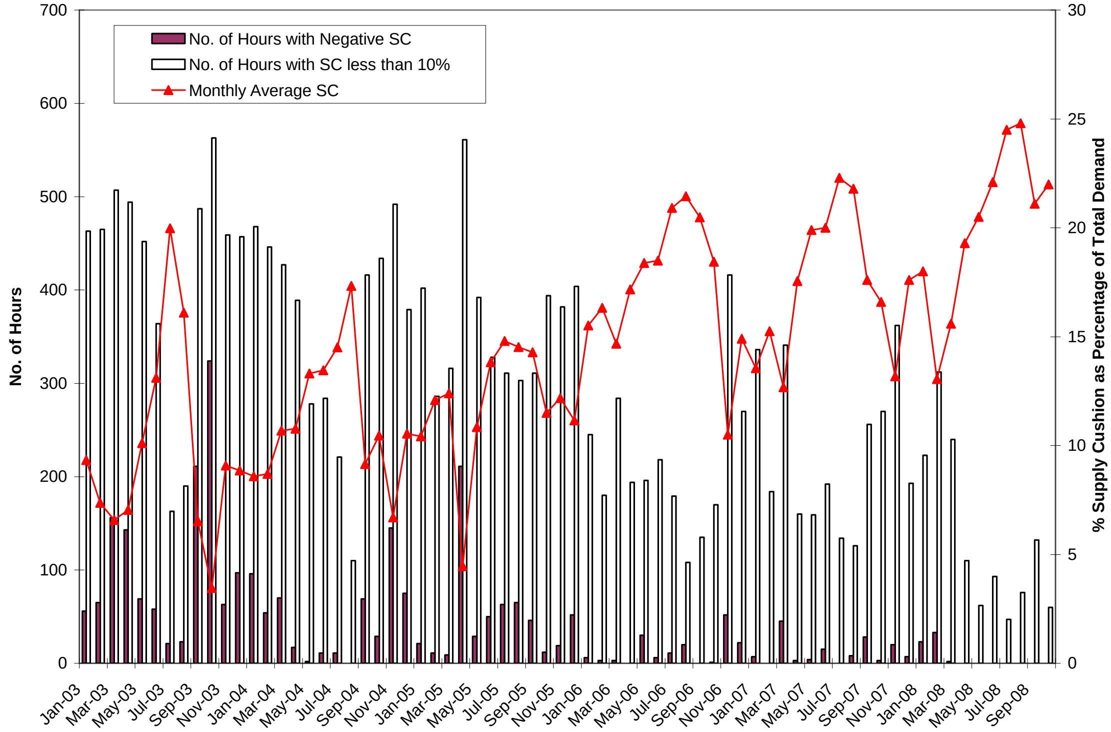
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2007	**2008**	**2007**	**%**	**2008**	**%**	**2007**	**%**	**2008**	**%**
May	19.0	15.7	0	0.0	1	0.1	145	19.5	255	34.3
June	17.8	19.2	0	0.0	0	0.0	205	28.5	167	23.2
July	19.1	19.6	0	0.0	0	0.0	198	26.6	153	20.6
August	23.7	21.6	0	0.0	0	0.0	52	7.0	120	16.1
September	24.3	22.9	0	0.0	0	0.0	17	2.4	62	8.6
October	18.1	19.7	0	0.0	0	0.0	154	20.7	150	20.2
Total	20.3	19.8	0	0.0	1	0.0	771	17.5	907	20.5

Table 1-28: Real-time Domestic Supply Cushion, May – October 2007 & 2008 (% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2007	**2008**	**2007**	**%**	**2008**	**%**	**2007**	**%**	**2008**	**%**
May	19.9	20.5	4	0.5	0	0.0	159	21.4	62	8.3
June	20.0	22.1	15	2.1	0	0.0	192	26.7	93	12.9
July	22.3	24.5	0	0.0	0	0.0	134	18.0	47	6.3
August	21.8	24.8	8	1.1	0	0.0	126	16.9	76	10.2
September	17.6	21.1	28	3.9	0	0.0	256	35.6	132	18.3
October	16.6	22.0	3	0.4	0	0.0	270	36.3	60	8.1
Total	19.7	22.5	58	1.3	0	0.0	1,137	25.7	470	10.6

Figure 1-19 provides long-term real-time supply cushion summary statistics between January 2003 and October 2008. The real-time supply cushion has consistently been improving since 2003 and reached its highest levels over the past summer. In August 2008, the real-time average supply cushion peaked at 24.8 percent, which is well above the previous high of 22.3 percent in July 2007. While the average supply cushion has improved, the frequency of hours when the supply cushion is low (less than 10 percent and negative) have been falling and over the latest summer, there were no hours when the supply cushion was negative.

Figure 1-19: Monthly Real-time Domestic Supply Cushion Statistics, January 2003 – October 2008 (% and Number of Hours under Certain Levels)



4.3 Average Supply Curves

Figure 1-20 presents average domestic offer curves for the last two summer periods. The offer curve appears to have shifted to the right this past summer, indicating improved baseload supply conditions this summer compared to last summer.

Figure 1-20: Average Domestic Offer Curve,
May – October, 2007 & 2008
($/MWh)

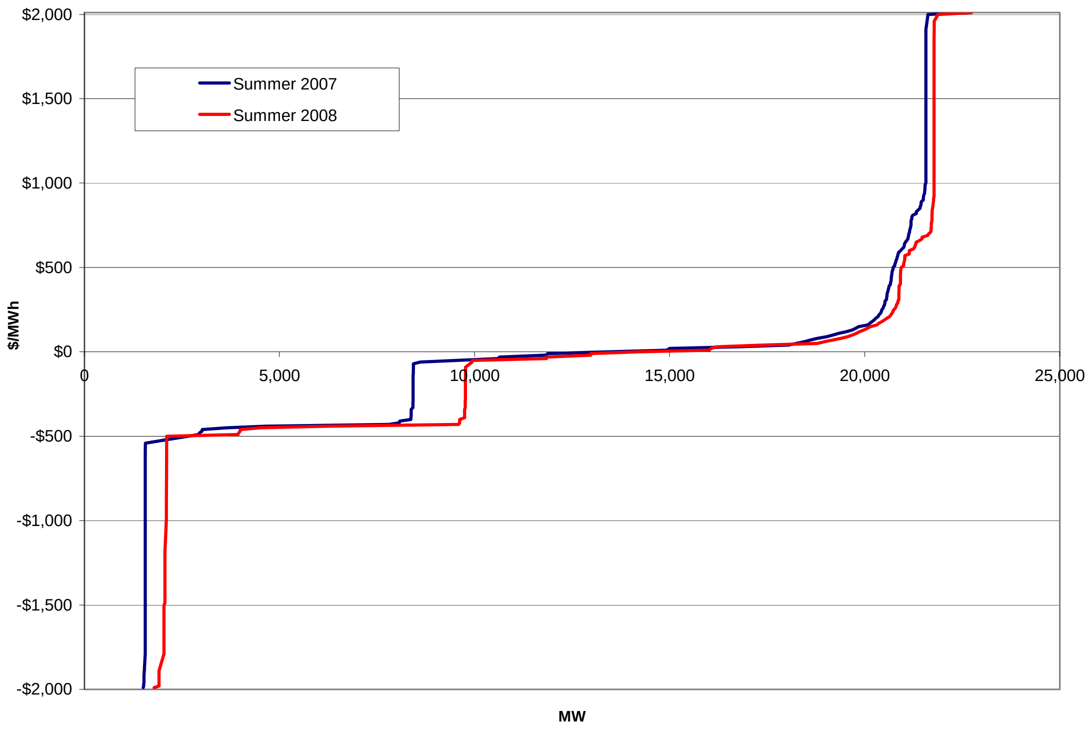


Table 1-29 presents average monthly hourly market schedules by baseload generation category along with average hourly Ontario Demand. For the recent six-month period, average hourly baseload supply improved to 12.4 GW compared to 12.2 GW in 2007, an increase of 1.6 percent. On a monthly basis, baseload supply declined during the first two months of the summer relative to 2007 but improved in the final four months. Improved baseload supply resulted from better performance from nuclear generating units as average hourly supply increased from 9.2 GW last summer to 9.5 GW this summer. Finally, average hourly baseload supply made up 78 percent of average hourly Ontario Demand over the recent summer period, which is up from 74 percent of Ontario Demand last summer.

Table 1-29: Average Hourly Market Schedules by Baseload Generation Type and Ontario Demand, May – October 2007 & 2008 (GW)

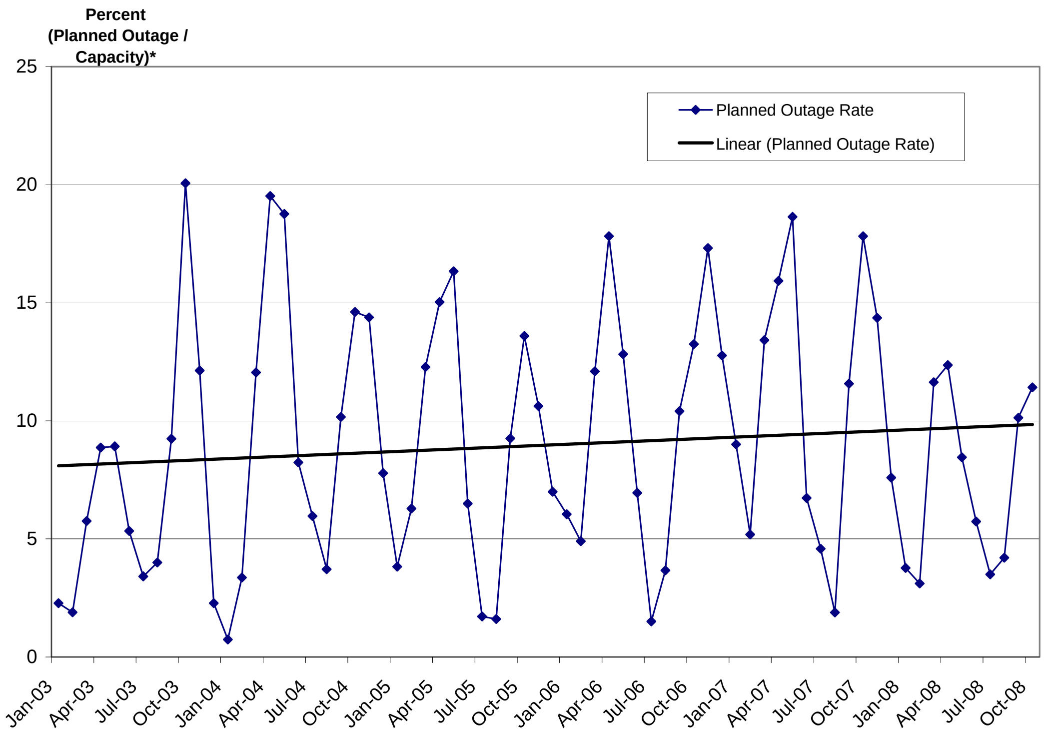
	Nuclear		Baseload Hydro		Self-Scheduling Supply		Total Baseload Supply		Ontario Demand (Non-Dispatchable Load)	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	9.4	8.2	2.2	2.2	1.0	1.0	12.6	11.4	15.4	14.8
June	9.4	9.1	2.0	2.0	0.9	0.8	12.3	11.9	17.1	16.4
July	9.7	10.0	1.9	2.1	0.9	0.7	12.5	12.8	16.8	17.1
August	9.5	10.1	1.8	2.0	0.9	0.7	12.2	12.8	17.6	16.4
September	8.7	9.8	1.8	2.0	0.9	0.8	11.4	12.6	16.1	15.9
October	8.2	9.7	2.0	1.9	1.1	1.1	11.3	12.7	15.5	15.3
Average	9.2	9.5	2.0	2.0	1.0	0.9	12.2	12.4	16.4	16.0

4.4 Outages

4.4.1 Planned Outages

Figure 1-21 plots the monthly planned outages as a percentage of capacity. Historically, planned outages are taken by generating units during low demand periods such as the spring and fall, typically April/May and October/November, months when both demand and prices are usually low. Although planned outage rates did increase in May and October 2008, they did not rise as high as in previous years. However, planned outage rates were slightly higher during the peak summer months this year compared to previous years so it appears that planned outages were more evenly distributed during this summer compared to past summers.[37]

Figure 1-21: Planned Outages Relative to Capacity, January 2003 – October 2008 (% of Capacity)



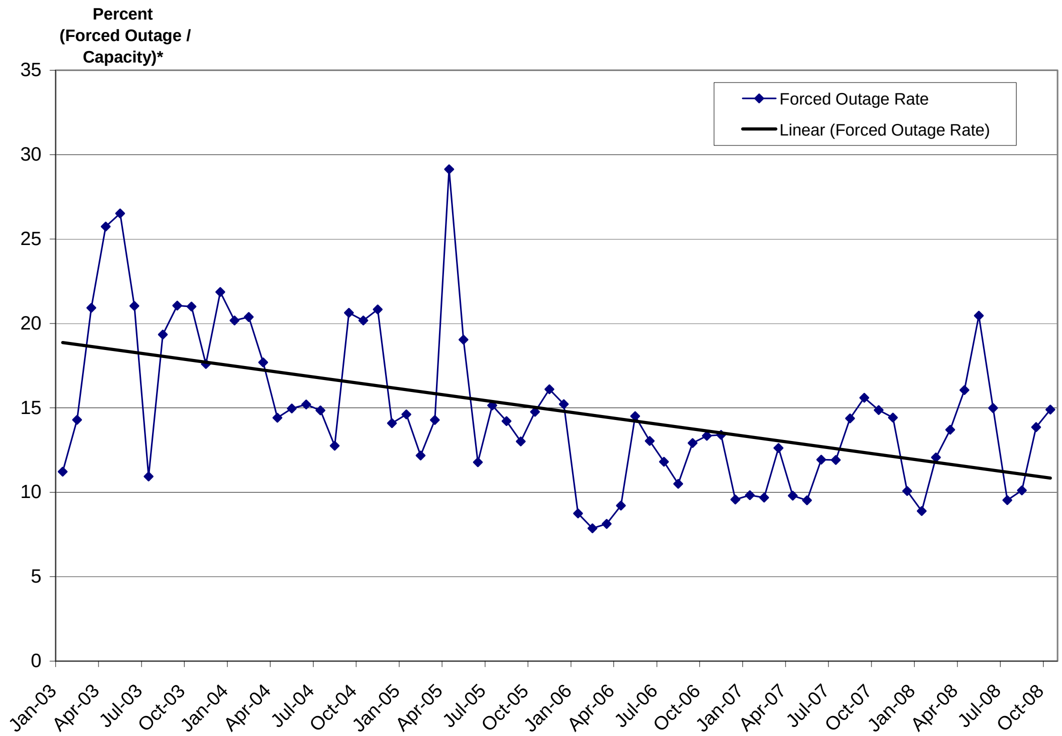
*Includes Nuclear, Coal, and Oil/Gas units.

4.4.2 <u>Forced Outages</u>

Figure 1-22 plots monthly forced outages as a percentage of capacity between January 2003 and October 2008. Since the summer of 2005, forced outage rates have typically fallen between 10 and 15 percent of capacity with the exception of May 2008, where the forced outage rate climbed to 20 percent due to poor nuclear performance. The last time the forced outage rate was above 20 percent of capacity was in April 2005.

[37] Outages are calculated for Nuclear, Coal, and Oil/Gas units. The operational characteristics of hydroelectric facilities and the nature of the fuel (water) make it difficult to separate outages and run-time decisions.

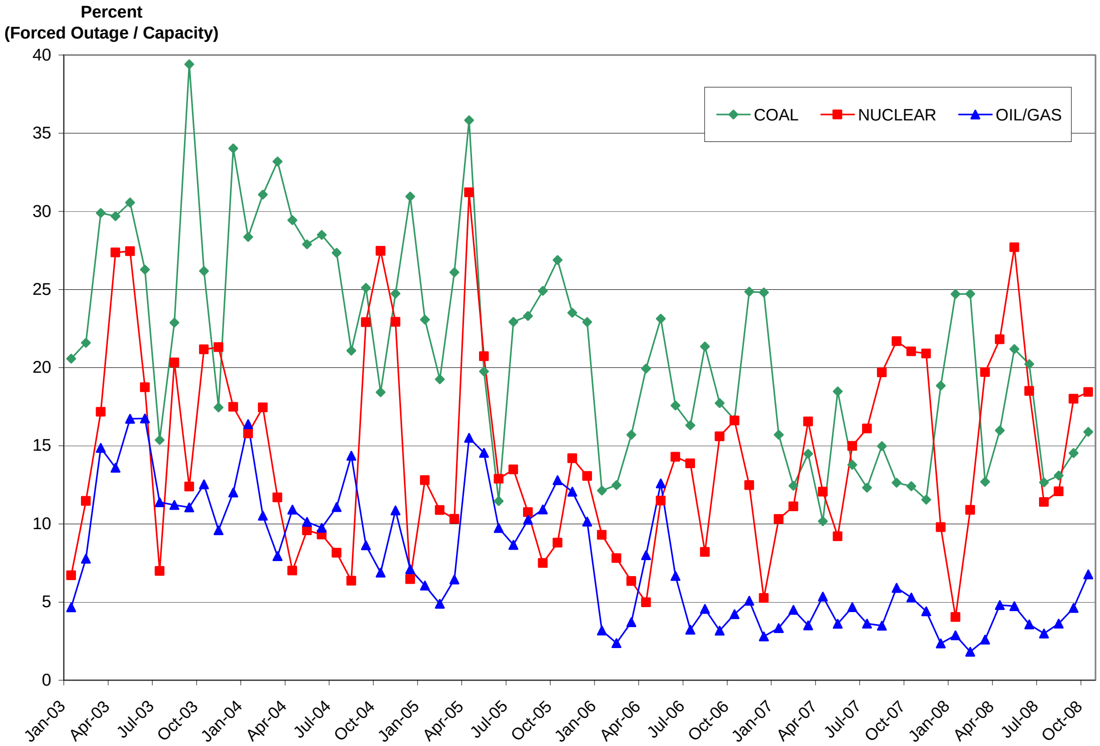
Figure 1-22: Forced Outages Relative to Capacity,*
January 2003 – October 2008
(% of Capacity)



* Includes Nuclear, Coal, and Oil/Gas units.

Figure 1-23 separates forced outages as a percentage of total capacity by fuel type since January 2003. As mentioned above, nuclear forced outage rates were relatively high at the beginning of the 2008 summer period as they climbed above 20 percent in April and peaked at above 28 percent of capacity in May. Oil/gas outages remained at or slightly below 5 percent this summer with the exception of October 2008 where the forced outage rate reached almost 7 percent. Finally, the performance of Ontario's coal units was consistent with forced outage rates observed over the past 3 summer periods typically fluctuating between 10 and 25 percent.

Figure 1-23: Forced Outages Relative to Total Capacity by Fuel Type, January 2003 – October 2008 (% of Capacity)



4.5 Changes in Fuel Prices

Tables 1-30 and 1-31 presents average monthly coal and natural gas prices over the last two summer periods. Generally, fuel costs noticeably increased this summer relative to last year for both fuel types.

4.5.1 Coal Prices

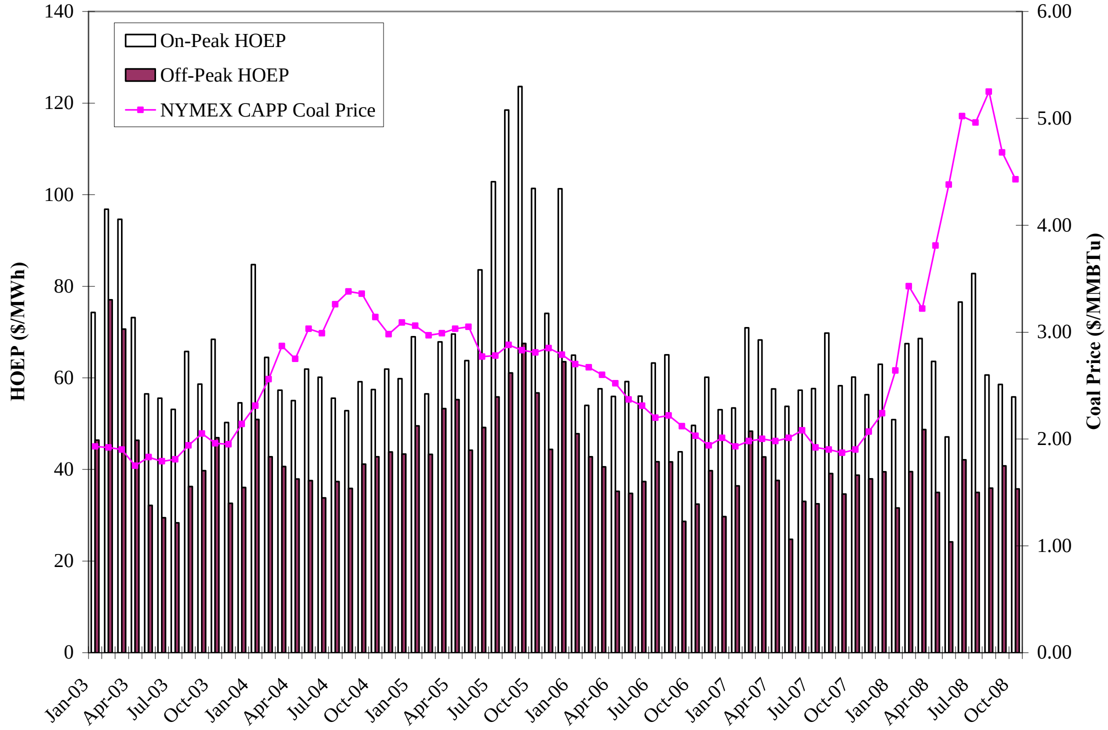
Average monthly NYMEX OTC Central Appalachian (CAPP) and Powder River Basin (PRB) Coal prices are presented in Table 1-30 for the last two summer months. Although both types of coal appreciated in price relative to last summer, there was a large difference in the amount of the increase. CAPP coal prices increased by 146 percent this summer from an average of $1.95/MMBtu in 2007 to $4.79/MMBtu in 2008, much higher than the 34 percent increase in PRB prices. Although CAPP coal prices increased throughout the summer, they ended up virtually unchanged between May and October 2008. Based on their inherent technologies, certain fossil units in Ontario are required to use CAPP coal while others use PRB coal. The recent surge in CAPP prices relative to PRB prices have led to a significant fuel cost change making units using PRB much cheaper.

Table 1-30: Average Monthly Coal Prices by Type, May – October 2007 & 2008 ($CDN/MMBtu)

	NYMEX OTC Central Appalachian			Powder River Basin		
	2007	**2008**	**% Change**	**2007**	**2008**	**% Change**
May	2.01	4.38	117.9	0.55	0.80	46.5
June	2.08	5.02	141.3	0.56	0.80	43.4
July	1.92	4.96	158.3	0.57	0.78	37.9
August	1.90	5.25	176.3	0.63	0.71	13.5
September	1.87	4.68	150.3	0.64	0.72	13.8
October	1.90	4.43	133.2	0.60	0.96	60.0
Average	1.95	4.79	145.9	0.59	0.80	34.4

Figure 1-24 plots the monthly average CAPP coal price along with the on-peak and off-peak HOEP prices. Since 2003, there does not appear to be a close relationship between the HOEP and coal prices. Even with the dramatic increase in coal prices this past summer, on-peak and off-peak average HOEP did not show a similar increase.

Figure 1-24: NYMEX OTC Central Appalachian Coal Price and HOEP, January 2003 – October 2008 ($/MWh and $/MMBtu)



4.5.2 Natural Gas Prices

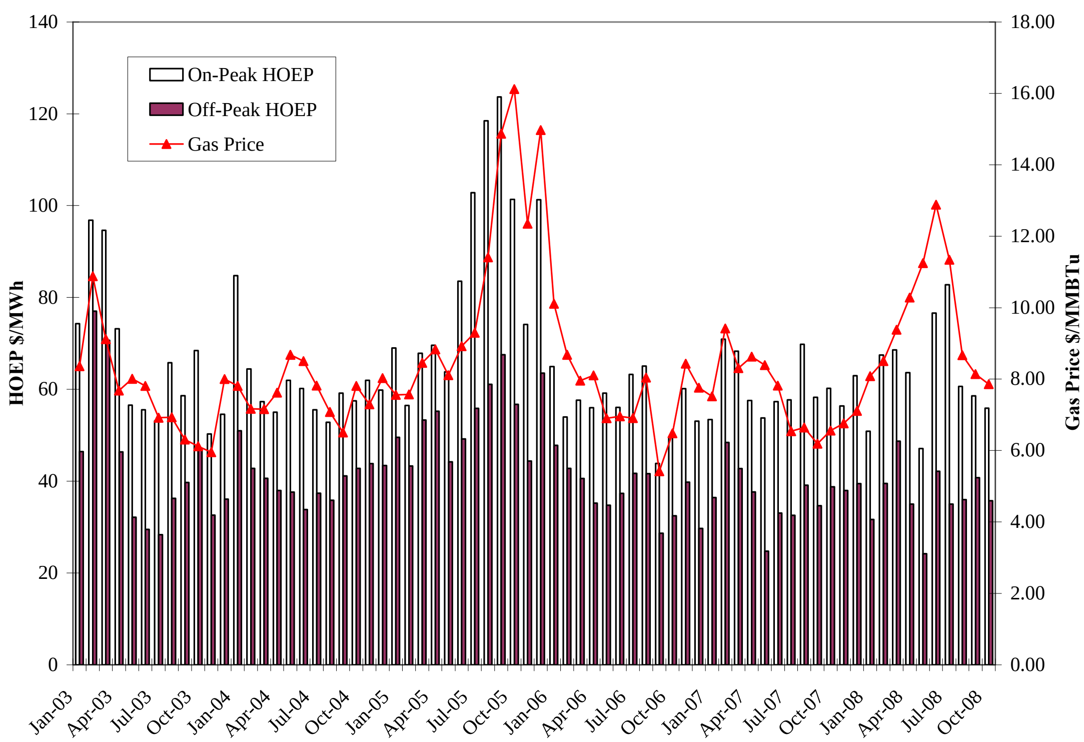
Similar to coal prices, natural gas prices also increased over the latest summer months relative to summer 2007. Table 1-31 shows that the Henry Hub Spot price and the Dawn Daily Gas price increased by 45 percent and 42 percent respectively. The Henry Hub price peaked at $12.88/MMBtu in June 2008 and slowly began to decline for the rest of the summer months ending up at $7.86/MMBtu in October, 20 percent higher than October 2007. A similar price movement pattern was observed with the Daily Dawn price over the last summer.

Table 1-31: Average Monthly Natural Gas Prices by Type, May – October 2007 & 2008 ($CDN/MMBtu)

	Henry Hub Spot Price			Dawn Daily Gas Price		
	2007	2008	% Change	2007	2008	% Change
May	8.39	11.25	34.1	8.76	11.67	33.2
June	7.82	12.88	64.7	8.07	13.05	61.7
July	6.54	11.34	73.4	6.77	11.64	71.9
August	6.64	8.67	30.6	6.54	8.88	35.8
September	5.61	8.14	45.1	6.31	8.01	26.9
October	6.56	7.86	19.8	6.82	8.15	19.5
Average	6.93	10.02	44.7	7.21	10.23	41.9

Figure 1-25 plots the monthly average Henry Hub spot price along with the on-peak and off-peak HOEP prices. Natural gas prices do tend to move with the HOEP prices, which is contrary to what we observed in the case of coal prices above. Although natural gas prices did increase in the middle of the summer, by October they did fall back to levels that were in line with monthly average gas prices over the last five years.

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP, January 2003 – October 2008 ($/MWh and $/MMBtu)



4.5.3 Heat Rate

Figure 1-26 plots the estimated system heat rate since January 2003, which is calculated by taking the average HOEP (or Richview Shadow Price) in a month divided by the average natural gas price measured by the Henry Hub spot price converted to Canadian dollars. This estimated heat rate is useful for a couple of reasons. First, gas-fired generators are typically marginal or near marginal. The system heat rate provides information on what efficiency level a gas-fired generator needs to recover its incremental costs through market revenue. Secondly, since new generation capacity in the province will most likely be gas-fired, the system heat rate provides investors information on what efficiency type of gas-fired generator can be potentially scheduled in the market and thus able to recover their incremental costs. The figure suggests that a hypothetical 7,000 MMBtu combined-cycle gas-fired generating unit would be unable to recover its costs in the market over the last few years with the exception of a few months in 2007 based on the average heat rate using HOEP. The same analysis using the Richview shadow price shows that, a 7,000 BTU heat rate generator in the constrained world may potentially be close to recovery. This simple analysis highlights a major reason why the majority of Ontario's new generation operates under some form of contract, which compensates them for losses in the market.

Figure 1-26: Estimated Monthly Average System Heat Rate using HOEP and Shadow Price, January 2003 – October 2008 (MMBtu/MWh)

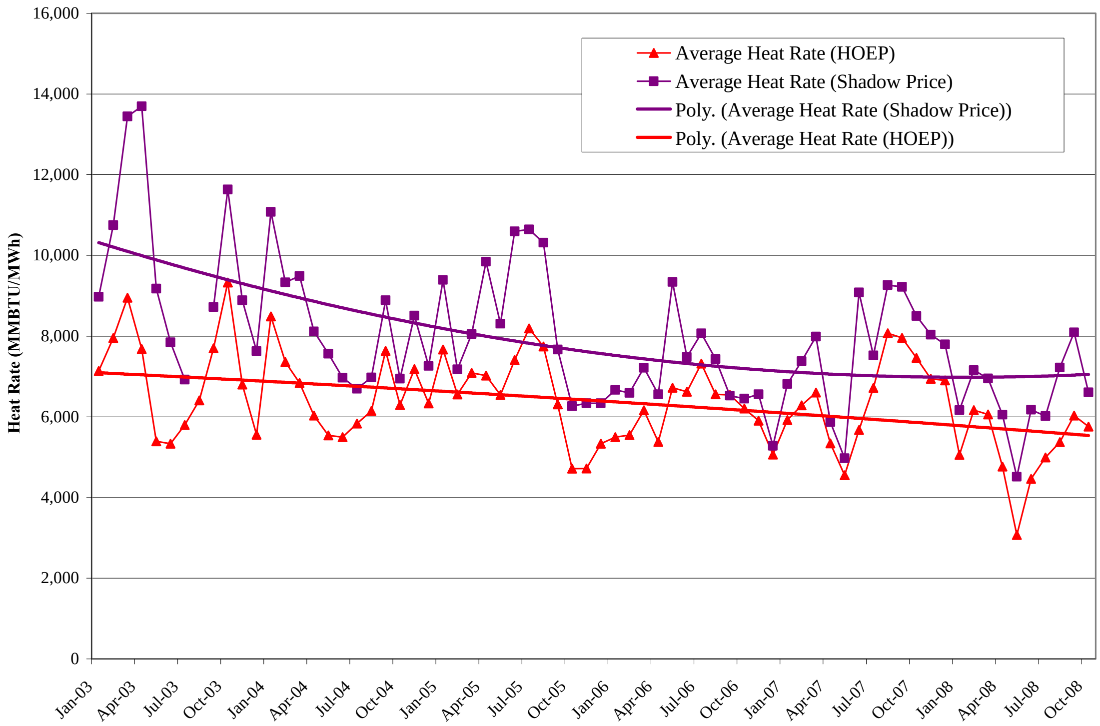
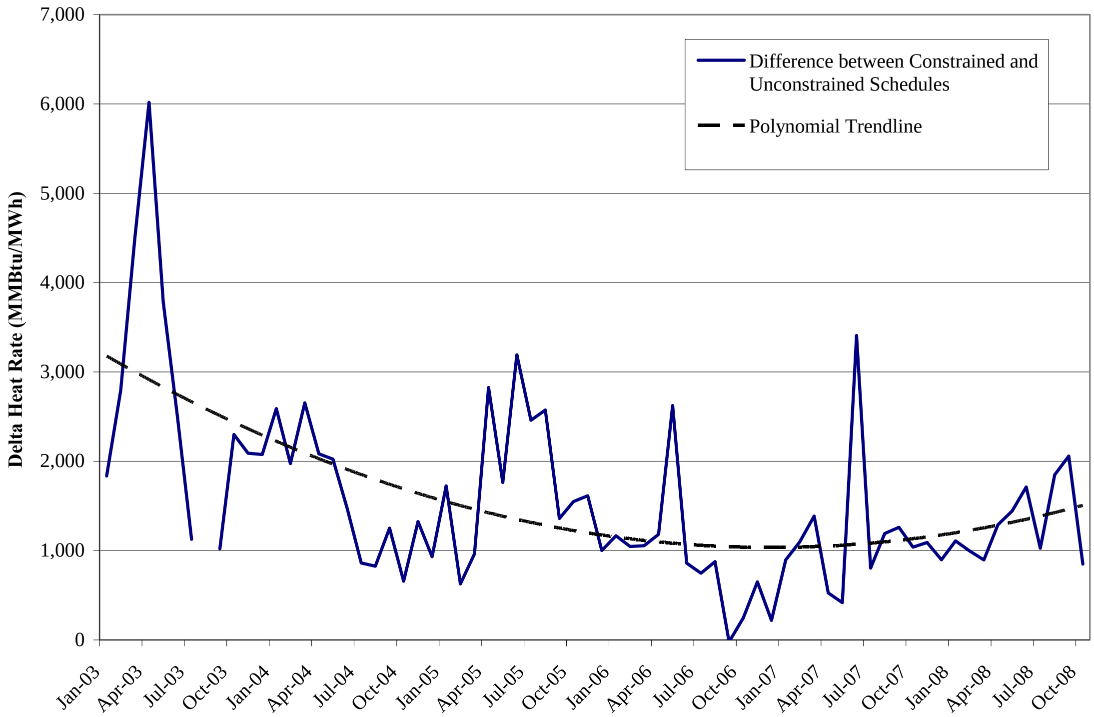


Figure 1-27 presents the difference (or delta) between the average system heat rate series presented above. The HOEP series approximates the unconstrained schedule while the shadow price series is representative of the constrained schedule. It is expected that the system heat rate using that shadow price would be higher than when using the HOEP as shadow prices are on average higher. Last summer, the delta generally remained between 1,000 and 2,000 MMBtu/MWh and was slightly higher than the monthly deltas back to 2006 with the exception of a couple of months.

Figure 1-27: Heat Rate Differential Between Constrained less Unconstrained Schedules, January 2003 - October 2008 (MMBtu/MWh)



4.6 Net Revenue Analysis

Similar to previous reports, we find that net revenues that could potentially have been earned in the market over the latest annual period would be insufficient to cover incremental costs. A standardized model developed by the Federal Energy Regulatory Commission (FERC) was used to assess whether there are sufficient revenues for a new gas-fired generator in Ontario to make an adequate rate of return on an investment with typical characteristics.[38]

Table 1-32 presents estimated net revenues for two types of hypothetical gas-fired generators: a 7,000 Btu/KWh combined-cycle unit with O&M costs of US$1.00/MWh and a less efficient 10,500 Btu/KWh with slightly higher O&M costs of US$3.00/MWh.[39]

[38] For details, see FERC 2004 State of the Markets Report, Docket MO05-4-000.
[39] FERC assumes US$1/MWh for the combined cycle unit and US$3/MWh for combustion turbine unit. The O&M costs are converted to Canadian dollars using the average exchange rate over each annual November to October period.

In the analysis, an assumed an outage rate of 5 percent was used. Over the latest November to October annual period, estimated net revenues totalled \$53,016. This continues to be well below FERC's estimated requirement of US\$80,000-90,000/MW-year for a combined cycle unit to meet all debt and equity requirements. Estimated net revenues were also insufficient for the less efficient combustion turbine unit as they totalled \$16,139 between November 2007 and October 2008.[40] The average net revenue over the last 5 annual periods was only \$61,299, well bellow the FERC requirement suggesting that some type of contract would have been necessary for this type of generating unit to be profitable.

Table 1-32: Yearly Estimated Net Revenue Analysis for Two Generator Types, November 2003 – October 2008 (\$/MWh)

Generator Type	7,000 Btu/KWh of Combined-cycle with variable O&M cost of US\$1/MWh	10,500 Btu/KWh of Combustion turbine with variable O&M cost of US\$3/MWh
Nov 2003 – Oct 2004	\$52,393	\$10,696
Nov 2004 – Oct 2005	\$94,824	\$27,719
Nov 2005 – Oct 2006	\$45,008	\$10,123
Nov 2006 – Oct 2007	\$61,252	\$15,146
Nov 2007 – Oct 2008	\$53,016	\$17,009
Average	\$61,299	\$16,139

5. Imports and Exports

5.1 Overview

Table 1-33 shows that monthly net exports during on-peak and off-peak hours significantly increased this summer relative to last summer. The larger portion of the increase in net exports occurred during the on-peak hours as average monthly net exports increased by 319.4 GWh, or slightly over 300 percent this summer. Although the increase in actual and percentage terms was not as dramatic, off-peak exports also increased by a monthly average of 184.4 GWh, or 53 percent Both on-peak and off-peak net exports reached summer highs in July, as net exports in the month totalled 1,163

[40] FERC also estimates that a less efficient combustion turbine unit would require US\$60,000-70,000/MW-year to meet all debt and equity requirements.

GWh over all hours, while August exports were almost as high. Increased exports this summer is consistent with the lower Ontario Demand and the higher availability of low-priced energy. Even though average HOEP increased this summer, Ontario still exhibited lower average prices than other nearby markets, as seen later in section 5.4.1 Price Comparisons.

Table 1-33: Net Exports (Imports) from Ontario On-peak and Off-peak, May – October 2007 & 2008 (GWh)

	Off-Peak			On-Peak			Total		
	2007	**2008**	**% Change**	**2007**	**2008**	**% Change**	**2007**	**2008**	**% Change**
May	424.3	600.6	41.6	269.7	469.7	74.2	694.0	1,070.3	54.2
June	474.5	506.6	6.8	94.0	448.0	376.8	568.5	954.6	67.9
July	524.0	668.5	27.6	285.2	494.3	73.3	809.1	1,162.8	43.7
August	367.3	655.1	78.3	88.0	489.7	456.3	455.4	1,144.8	151.4
September	112.9	343.8	204.5	(57.6)	250.7	534.9	55.3	594.5	975.1
October	180.3	415.1	130.2	(47.5)	396.0	933.7	132.8	811.1	510.8
Average	347.2	531.6	53.1	105.3	424.7	303.4	452.5	956.4	111.3

When the market opened in 2002, Ontario was a net importer of energy but over the years it has become a net exporter of energy as favourable supply conditions in the province had made it less dependent on imports to meet internal energy needs. As can be seen in Figure 1-28, Ontario was a net exporter of energy during the on-peak and off-peak hours in all months since late 2007, and in most months since Jan 2006.

Figure 1-28: Net Exports (Imports) from Ontario, On-peak and Off-peak, January 2003 – October 2008 (GWh)

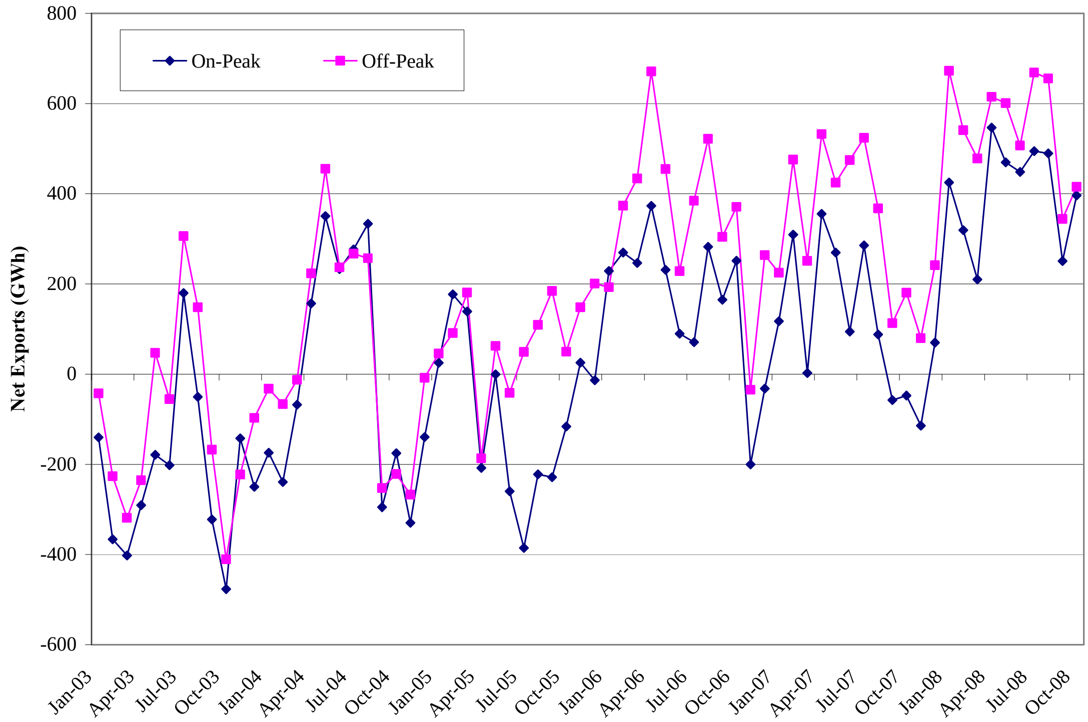


Table 1-34 presents total net exports by neighbouring intertie group for the 2007 and 2008 summer months. The previous figure reports total provincial net exports, therefore linked wheel volumes are not relevant to the figure since each linked wheel includes a simultaneous injection and withdrawal of energy, thus netting to zero. However, net exports by intertie group account for linked wheel volumes since either the import or export leg is scheduled at the intertie group, but not both, thus they do not net to zero at a given intertie.

Historically, Ontario has been a net importer of energy at the Michigan intertie but that has been slowly shifting to Ontario becoming a net exporter of energy at Michigan. In the 2007 summer months, Ontario was a net importer at the Michigan interface totaling 632 GWh, while in 2008 Ontario became a net exporter to Michigan as net exports climbed to 4,167 GWh. Finally, Ontario has always been a net exporter of energy at the New York interface and this continued during the latest summer period, except in May when Ontario was a net importer of 232 GWh of energy at New York.

Table 1-34: Net Exports (Imports) from Ontario by Neighbouring Intertie Group May – October 2007 & 2008 (GWh)

	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	(48)	(92)	351	1,298	6	3	404	(232)	(20)	93	694	1,070
June	(116)	(144)	5	925	(18)	(30)	735	164	(37)	39	568	955
July	(129)	(151)	(15)	850	(14)	(25)	955	522	13	(33)	809	1,163
August	(144)	(166)	(11)	739	(35)	(21)	632	620	13	(28)	455	1,145
September	(136)	(136)	(518)	143	(54)	(29)	692	567	72	50	55	594
October	(106)	(160)	(444)	212	(30)	(35)	690	705	22	89	133	811
Total	(679)	(849)	(632)	4,167	(145)	(137)	4,108	2,346	63	210	2,714	5,738

By reference to Appendix Tables A-28 and A-29 which show monthly exports (Offtakes) and imports (Injections) on-peak and off-peak by intertie, it can be seen that the above increase of 4,799 GWh of net exports to Michigan was due almost entirely to the 4,782 GWh increase in exports, with total imports for the summer period remaining virtually constant. The 1,762 GWh decrease in net exports at the New York intertie can be attributed to an increase of 755 GWh of exports and increase of 2,516 GWh of imports. This is noteworthy in that the total linked-wheel transactions this summer amounted to 2,819 GWh, most of which originated in New York. Thus linked wheels alone could have accounted for the increased imports from New York, but just over half the increase in exports to Michigan. The other half would have been primarily accounted for by energy exported from Ontario and destined for PJM.

5.2 Congestion

Congestion levels tend to increase at the Ontario's interties as the volume of inter-jurisdictional transactions increase.[41] In general, import congestion levels moderately

[41] In this section we focus on intertie congestion which occurs in the unconstrained schedule and leads to intertie prices diverging from the uniform price. This is different from congestion in the constrained schedule at interfaces internal to Ontario, which can lead to imports or exports being constrained on or off and receiving CMSC payments.

declined this summer while export congestion levels increased dramatically. This is consistent with the large increase in exports discussed in section 5.1 above.

5.2.1 Import Congestion

Tables 1-35 reports the number of occurrences of import congestion by month and intertie group over the last two summer periods. The largest declines occurred at the Michigan and Minnesota interties, which more than offset increased import congestion levels at New York and Manitoba. Michigan import congestion declined dramatically by 93 percent, from 195 hours in 2007 to only 14 hours in 2008 and the number of import congested hours at Minnesota fell from 472 hours to 226 hours (52 percent).

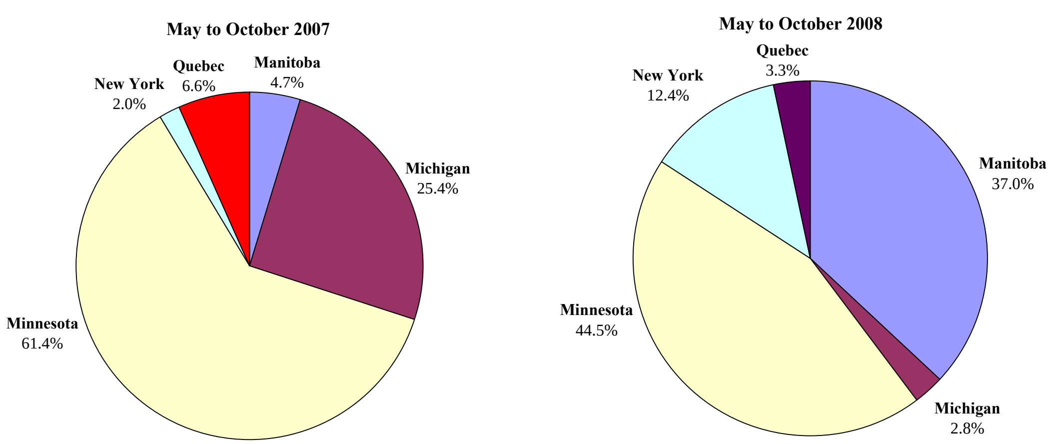
As a consequence of the much higher intertie capability at Minnesota this October relative to October 2007, there was a significant reduction in the import congested hours, dropping from 297 hours last October to 57 hours this year. Manitoba congestion increased in all months but mostly in August and October (even though intertie capabilities in those months were similar to other months); the congestion was due to more aggressive competition among the small number of traders competing to import on the Manitoba intertie in these months. The changes at New York and Michigan were largely the result of the increased wheels from New York through Ontario until July 22, 2008, and the increased exports from Ontario to PJM (through MISO); the former used up a portion of the import capability from New York and both offset some of the import flows from Michigan.

Table 1-35: Import Congestion in the Market Schedule by Intertie, May – October 2007 & 2008 (Number of Hours)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	2	0	0	1	1	6	4	51	2	0
June	11	19	1	3	8	48	0	10	16	0
July	2	6	3	0	29	22	0	1	26	9
August	8	100	5	0	123	15	11	0	6	6
September	7	10	122	9	14	78	0	1	0	2
October	6	53	64	1	297	57	0	0	1	0
Total	36	188	195	14	472	226	15	63	51	17

Figure 1-29 compares the percentage of import congested hours by intertie group for the 2007 and 2008 summer months. Over the last two summers, the Minnesota intertie group was the largest source of import congestion. However, the proportion of import congested hours at Manitoba increased from 5 percent of all import congested hours in 2007 to 37 percent in 2008 as Minnesota and Michigan's proportions declined.

Figure 1-29: Percentage of Import Congestion in the Market Schedule by Intertie, May – October 2007 & 2008 (Percentage of Congested Hours)



5.2.2 Export Congestion

Table 1-36 provides the frequency of export congestion by month and intertie group for the 2007 and 2008 summer months. Increased export volumes from Ontario have led to higher levels of export congestion. The most significant increases occurred at the New York (123 percent), Michigan (858 percent), and Quebec (55 percent) intertie groups while export congestion at Minnesota declined. The increase in the number of congested hours at New York and Michigan is generally attributable to the increased volume of exports identified in the previous sections of this Chapter. The tendency to congest at New York was further augmented by an extended outage on the BP76 circuit between Ontario and New York, which has been unavailable since the end of January 2008. In addition very high levels of clockwise Lake Erie Circulation (LEC) have been experienced in 2008, which further reduced the export capability to New York making it more likely to be export congested. The clockwise LEC also increased the export capability to Michigan, reducing the tendency for export congestion to Michigan.[42]

Table 1-36: Export Congestion in the Market Schedule by Intertie, May – October 2007 & 2008 (Number of Hours)

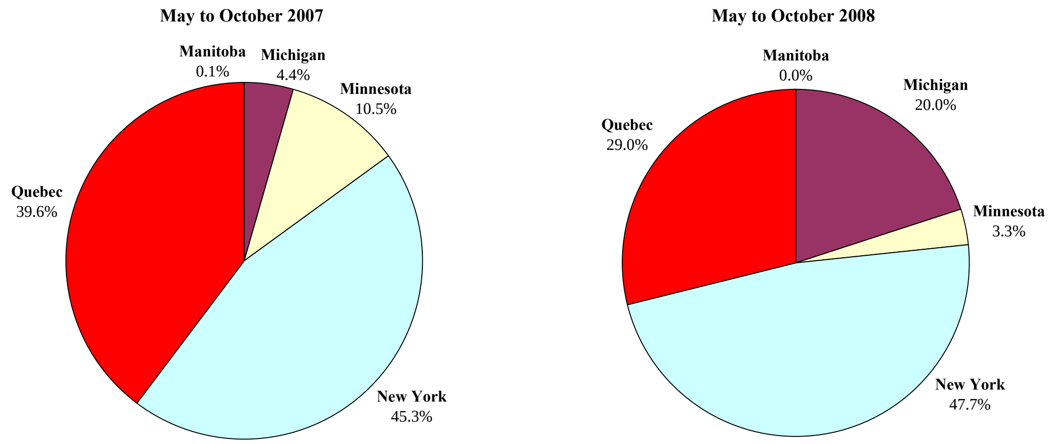
	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	1	0	39	243	26	47	32	162	321	300
June	0	0	11	153	4	9	149	233	92	203
July	0	0	5	129	108	13	247	348	159	101
August	0	0	14	131	35	25	146	391	34	75
September	0	0	3	30	0	7	83	297	41	181
October	0	0	1	13	1	14	91	235	7	153
Total	1	0	73	699	174	115	748	1,666	654	1,013

Figure 1-30 compares the percentage of export congested hours by intertie group for the last two summer periods. While the shares of export congested hours were similar at New York for both periods, the largest percentage increase occurred at Michigan while the proportion of congestion occurring at Quebec and Minnesota declined.[43]

[42] There may be many factors which contributed to these increased clockwise loop flows. One of these would have been the higher volumes of exports from Ontario through Michigan that were destined for PJM (See section 2.3 in Chapter 3 for more information on Ontario to PJM exports). The contract path for these would show the entire volume as scheduled through Michigan. However actual physical flows for an export destined for PJM are roughly equal through Michigan and New York. Linked wheels from New York to PJM through Ontario also contribute to more clockwise LEC. The difference between the scheduled path and actual flows for these transactions is observed as clockwise loop flow.

[43] Issues relating to increased import congestion at the Michigan interface are further discussed in section 2.1 in Chapter 3.

Figure 1-30: Percentage of Export Congestion in the Market Schedule by Intertie, May – October 2007 & 2008 (Percentage of Congested Hours)



5.2.3 Congestion Rent

Congestion rents occur as the result of different prices seen by importers and Ontario load, or exporters and Ontario generation. These price differences are induced by congestion at the interties, with importers and exporters receiving or paying the intertie price, and Ontario generators and loads receiving or paying the uniform Ontario price (either the interval price or HOEP). When there is export congestion and exporters are competing for the limited intertie capability, the intertie price rises above the Ontario price, and congestion rent is collected from the exporters. When there is import congestion, the intertie price would fall below the Ontario price, and congestion rent would be the result of the lower price paid to importers, relative to the uniform price.

Tables 1-37 and 1-38 report the congestion rents for the five intertie groups in summer 2008 compared to summer 2007. Congestion rent is calculated as the MW of net import or net export that actually flows (i.e. the constrained schedule) multiplied by the price difference between the congested intertie zone in Ontario and the uniform price. This represents a cost to traders, either in the form of a congestion price premium paid for exports or the reduction in the payment for imports. A trader that has a transaction in the opposite direction to the congested flow may actually benefit from the intertie price. For example, an import on an export congested interface would receive a higher payment than HOEP because of the higher intertie price. Such counter flows in the constrained schedule can induce negative components in the congestion rents as occasionally observed below.

Table 1-37: Import Congestion Rent by Intertie, May – October 2007 & 2008 ($ thousands)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON		Total	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	2	0	0	(1)	0	(9)	9	931	2	0	14	922
June	50	46	2	6	(4)	(75)	0	386	23	0	71	363
July	6	6	2	0	(6)	(38)	0	2	9	16	11	(14)
August	21	163	57	0	(26)	(17)	47	0	46	30	144	176
September	17	7	1,479	21	(3)	(130)	0	0	0	2	1,493	(100)
October	15	21	388	1	(21)	(10)	0	0	1	0	383	12
Total	111	243	1,927	27	(59)	(279)	56	1,320	80	48	2,115	1,359

Table 1-38: Export Congestion Rent by Intertie, May – October 2007 & 2008 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	0	0	829	8,700	23	86	291	741	468	492	1,611	10,019
June	0	0	163	6,351	9	6	3,217	3,997	71	328	3,460	10,682
July	0	0	97	4,389	61	11	4,972	5,946	127	122	5,257	10,468
August	0	0	329	2,757	79	19	3,310	6,098	44	102	3,762	8,976
September	0	0	25	200	0	4	1,422	4,087	55	205	1,502	4,496
October	0	0	6	52	0	5	982	2,507	3	346	991	2,910
Total	0	0	1,449	22,449	172	131	14,194	23,376	768	1,595	16,583	47,551

Total congestion rent for exports ($47.6 million) this summer represented nearly a tripling of the rents for exports last summer ($16.6 million). In contrast, congestion rents for imports reduced by almost one-third to $1.4 million this summer compared with $2.1 million last summer. In total congestion rents this summer amounted to $48.9 million, an increase of $30.3 million, or 162 percent, above last summer. The largest components of congestion rents this summer, and the largest contribution to the year-over-year increase, were the rents for exports at the New York and Michigan interties. Each of these was close to $23 million, representing an increase of about 65 percent at New York, and more than a 15-fold increase at Michigan.

The magnitude of monthly congestion rents corresponds only roughly to the pattern of hours of congestion seen in Tables 1-35 and 1-36, with the highest rents at an intertie occurring in the months with the greatest numbers of hours of congestion. There are several factors which can influence the size of hourly congestion rents, by affecting either the magnitude of actual imports or exports at the intertie and/or the difference between the uniform Ontario price and the intertie zonal price. The price difference, which is the Intertie Congestion Price (ICP), depends on the price of marginal import or export at the intertie, and the marginal resource within Ontario in the unconstrained scheduling process. The magnitude of the actual import or export flow is dependent on:

i) the maximum capability of the intertie,
ii) temporary reductions in the intertie capability,
iii) loop flows, which use up part of, or add to, the intertie capability,
iv) import or export failures, and
v) constrained on or constrained off imports or exports.

Table 1-39 summarizes the average size of congestion rents per hour of congestion, by intertie. Total congestion rents are largest at New York and Michigan since the import/export capabilities at these interties are significantly larger than other interties.

Table 1-39: Average Congestion Rents per hour of Congestion by Intertie May – October 2007 & 2008 ($ thousands/hour)

	Import Congestion Rent (per hour of import congestion)			Export Congestion Rent (per hour of export congestion)		
	2007	**2008**	**% Change**	**2007**	**2008**	**% Change**
New York	4	21	425	19	14	(26)
Michigan	10	2	(80)	20	32	60
Manitoba	3	1	(67)	0	0	0
Minnesota	0	0	0	1	1	0
Quebec	2	3	50	1	2	100
Average	3	3	0	10	14	40

Congestion rents can be viewed as the risk that an importer may be paid less than the Ontario uniform price or an exporter may pay more than the uniform price. To hedge the risk, the IESO makes available Transmission Rights (TR) which will compensate the TR holder for differences in the intertie and uniform price. In an earlier Monitoring Report, the Panel reviewed TR payments and observed that these exceeded the congestion rents, with the implication that TR payments were not being fully funded (by the congestion rents alone).[44] Tables 1-40 and 1-41 show TR payments by intertie for each month of the 2007 and 2008 summer periods, separately for import congestion events and export congestion events. The total TR payouts for imports were $2.9 million, which was more than double the import congestion rents of $1.4 million (see Table 1-37) for the period. The total TR payouts for exports were $70.4 million, which was 48 percent higher than the export congestion rents of $47.6 million (see Table 1-38) for the same period. Again the monthly patterns of TR payments at an intertie correspond roughly to the number of hours of congestion.

[44] For a more complete explanation of TR and the TR market's, see the Market Surveillance Panel's June 2006 Report, pp.83-91 available at: http://www.oeb.gov.on.ca/documents/msp/msp_report_final_130606.pdf

Table 1-40: Monthly Import Transmission Rights Payouts by Intertie, May – October 2007 & 2008 ($ thousands)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON		Total	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	4	0	0	2	1	8	10	860	2	0	17	870
June	66	182	2	15	14	102	0	393	21	0	103	692
July	8	39	2	0	32	36	0	4	2	59	44	138
August	116	517	76	0	205	26	94	0	71	37	562	580
September	968	100	1,625	44	73	184	0	0	0	3	2,666	331
October	42	209	517	1	742	61	0	0	1	0	1,302	271
Total	1,204	1,047	2,222	62	1,067	417	104	1,257	97	99	4,694	2,882

Table 1-41: Monthly Export Transmission Rights Payouts by Intertie, May – October 2007 & 2008 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	1	0	895	6,342	94	87	306	4,958	642	684	1,938	12,071
June	0	0	680	6,474	9	6	3,748	9,994	140	512	4,577	16,986
July	0	0	135	4,582	380	13	6,153	13,011	180	184	6,848	17,790
August	0	0	764	3,367	170	20	3,715	9,551	46	126	4,695	13,064
September	0	0	73	481	0	8	1,623	6,010	61	246	1,757	6,745
October	0	0	61	59	0	93	1,342	3,146	6	406	1,409	3,704
Total	1	0	2,608	21,305	653	227	16,887	46,670	1,075	2,158	21,224	70,360

Tables 1-42 and 1-43 provide the absolute value of monthly average Intertie Congestion Prices (ICP's) by intertie for imports and exports respectively. The absolute ICP represents the difference in the intertie price and the uniform price, which is the basis for both congestion rents and TR payouts (averages are taken across hours where there is congestion, with imports and exports congestion averaged separately). These tables indicate that monthly average ICP's tend to be less than about $35/MWh, with few examples of averages above that.

Table 1-42: Monthly Average Import Congested Prices by Intertie, May – October 2007 & 2008 ($/MWh)

	MB to ON		MI to ON		MN to ON		NY to ON		QC to ON	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	8.85	0.00	0.00	1.40	10.00	14.76	2.29	15.72	3.23	0.00
June	29.43	40.01	1.10	4.37	20.59	25.05	0.00	36.60	3.71	0.00
July	19.14	27.12	0.42	0.00	13.76	19.32	0.00	3.90	0.54	21.71
August	65.16	22.97	10.11	0.00	19.48	20.77	4.81	0.00	20.25	9.76
September	606.60	44.24	11.29	3.36	57.56	27.71	0.00	0.44	0.00	2.52
October	34.29	16.41	7.34	0.45	29.41	12.59	0.00	0.00	2.00	0.00
Average	148.69	24.11	9.74	3.04	26.56	21.71	4.18	18.60	4.84	15.23

Table 1-43: Monthly Average Export Congested Prices by Intertie, May – October 2007 & 2008 ($/MWh)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC	
	2007	2008	2007	2008	2007	2008	2007	2008	2007	2008
May	6.55	0.00	17.01	19.84	25.82	12.95	7.07	23.36	23.52	25.56
June	0.00	0.00	33.57	32.30	15.43	4.96	13.87	32.74	21.20	29.52
July	0.00	0.00	14.69	26.35	25.90	6.78	13.74	36.41	13.37	21.25
August	0.00	0.00	29.63	19.07	34.76	5.73	14.03	23.79	15.86	19.55
September	0.00	0.00	18.68	14.03	0.00	8.24	10.61	18.19	17.41	15.99
October	0.00	0.00	54.22	4.11	2.95	47.48	8.10	12.06	9.62	31.02
Average	6.55	0.00	22.27	23.06	27.30	13.90	12.50	24.97	19.77	24.60

Both TR payouts and congestion rents increase with (absolute) ICP. However, unlike congestion rents, TR payouts are influenced only by the magnitude of TR's sold in the auction and the ICP. There is a large tendency for actual net imports and net exports, and thus congestion rents, to be less than the full capability of the intertie, and the TR's sold. Consequently the TR payouts continue to exceed the congestion rents in aggregate.

By comparing totals from Table 1-37 and 1-40, it can be seen that overall import TR payouts were over twice as large as congestion rents this summer and last year, at $2.9 million versus $1.4 million in 2008 and $4.7 million versus $2.1 million in 2007. However, differences for exports were far more dramatic, especially in 2008. This can be seen in Table 1-44, which shows export TR payouts less Congestion Rents by Intertie. Export TR payouts exceeded rents by $22.8 million in 2008, compared with $4.6 million in 2007, an increase of $18.2 million or almost 5 times as large. The excess of TR payout over congestion rents is almost entirely attributable to congestion and payouts at the New York intertie, with monthly differences increasing to a peak of over $7 million in July.

Table 1-44: Monthly Export TR Payouts less Congestion Rents by Intertie, May – October 2007 & 2008 ($ thousands)

	ON to MB		ON to MI		ON to MN		ON to NY		ON to QC		Total	
	2007	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
May	1	0	66	(2,358)	71	1	15	4,217	174	192	327	2,052
June	0	0	517	123	0	0	531	5,997	69	184	1,117	6,304
July	0	0	38	193	319	2	1,181	7,065	53	62	1,591	7,322
August	0	0	435	610	91	1	405	3,453	2	24	933	4,088
September	0	0	48	281	0	4	201	1,923	6	41	255	2,249
October	0	0	55	7	0	88	360	639	3	60	418	794
Total	1	0	1,159	(1,144)	481	96	2,693	23,294	307	563	4,641	22,809

5.3 Analysis of the Determinants of Exports from Ontario to New York

This section reports elasticity estimates from the demand for exports model for exports from Ontario to both New York (NYISO) and Michigan (MISO). The econometric approach makes use of the two-stage least squares/instrumental variables methodology.[45] The variables used to instrument for the HOEP are: Ontario nuclear and self-scheduled output; Ontario (non-dispatchable) and New York (integrated) loads; the natural gas (Henry hub) price; and monthly dummy variables (excl. December). The New York model is estimated over January 2003 to October 2008 (70 observations) while the Michigan model uses data between April 2005 and October 2008 (43 observations).[46]

The model tests whether the average hourly volume of exports from Ontario to each of its neighbouring jurisdictions (New York and Michigan, respectively) is decreasing in relation to the HOEP and increasing in relation to the neighbouring jurisdiction's price. We also make use of monthly dummies.

[45] This methodology is used in an attempt to resolve an endogeneity problem arising from the notion that HOEP both determines and is determined by (in part) the level of exports.
[46] MISO began operating energy markets on Aril 1, 2005.

Table 1-45 presents estimates for all-hours, on-peak hours only, and off-peak hours only for exports from Ontario to New York (NYISO). With respect to the price variables, all results are statistically significant and economically intuitive. In particular, for all hours, we find that a 1 percent increase of the HOEP leads to a 4.89 percent decrease in export volume, while a 1 percent increase of the New York West zonal price leads to a 4.92 percent increase in export volume. These results are broadly in line with the estimates presented in the last Panel report, where the elasticity estimates were 4.16 percent and 4.58 percent, respectively.

The elasticity estimates are, in absolute value, greater on-peak and lower off-peak than the all-hours estimates.

Table 1-45: New York Export Model Estimation Results, January 2003 – October 2008

Variable	All Hours		On-peak		Off-peak	
	Coef.	P-value	Coef.	P-value	Coef.	P-value
Constant	6.11	0.00	6.99	0.00	6.13	0.00
Log(HOEP)	-4.89	0.00	-5.44	0.00	-2.46	0.02
Log(New York Price)	4.92	0.00	5.22	0.00	2.54	0.02
January	0.17	0.24	0.37	0.14	0.04	0.76
February	0.06	0.70	0.02	0.94	0.09	0.57
March	0.06	0.68	-0.11	0.59	0.11	0.50
April	-0.20	0.13	-0.34	0.26	-0.12	0.32
May	0.05	0.81	-0.17	0.67	0.07	0.63
June	0.06	0.78	0.09	0.63	0.00	0.99
July	-0.18	0.47	0.13	0.61	-0.22	0.44
August	-0.33	0.23	-0.18	0.61	-0.27	0.36
September	-0.27	0.13	-0.29	0.23	-0.22	0.08
October	0.33	0.10	-0.24	0.34	-0.41	0.09
November	-0.07	0.60	-0.16	0.28	-0.16	0.39
Model Diagnostics						
Correlation between actual and fitted values	0.823		0.862		0.762	
Number of observations	70		70		70	

Table 1-46 presents similar results for exports from Ontario to Michigan (MISO). As with the New York, the estimates with respect to the price variables are all statistically significant and economically intuitive. For all hours we find that a 1 percent increase in the HOEP leads to a 7.1 percent reduction of exports to Michigan whereas a 1 percent increase in the Michigan hub price leads to a 6.8 percent increase of exports. Unlike the New York results we find that the elasticity estimates for exports to Michigan are, in absolute value, lower on-peak and greater off-peak than the estimates over all hours.

Table 1-46: Michigan Export Model Estimation Results, January 2003 – October 2008

Variable	All Hours		On-peak		Off-peak	
	Coef.	P-value	Coef.	P-value	Coef.	P-value
Constant	6.41	0.11	7.17	0.04	8.52	0.09
Log(HOEP)	-7.10	0.00	-4.83	0.00	-8.47	0.00
Log(Michigan Hub Price)	6.80	0.00	4.38	0.00	7.64	0.01
January	-0.97	0.05	-0.79	0.07	-1.20	0.04
February	0.38	0.66	0.57	0.44	-0.10	0.93
March	-0.40	0.55	-0.20	0.68	-0.74	0.32
April	-0.13	0.84	0.21	0.70	-0.59	0.43
May	-0.34	0.66	-0.06	0.89	-0.78	0.51
June	-0.26	0.66	-0.24	0.54	-0.23	0.81
July	-0.25	0.69	0.21	0.58	-0.93	0.29
August	-0.36	0.61	0.06	0.90	-0.94	0.23
September	-0.27	0.77	-0.36	0.61	-0.30	0.81
October	-0.31	0.65	0.01	0.99	-1.07	0.16
November	-0.78	0.13	-0.84	0.08	-0.99	0.12
Correlation between actual and fitted values	0.898		0.920		0.845	
Number of observations	43		43		43	

5.4 Wholesale Electricity Prices in Neighbouring Markets

Market prices are an important driver of trade flows as participants have an incentive to move low-priced energy into regions with higher prices. Given Ontario's significant intertie capacity, neighbouring market prices are a useful statistic to monitor.

5.4.1 Price Comparisons

Table 1-47 provides average market prices for Ontario and other neighbouring jurisdictions over the last two summer periods. In an attempt to make these prices more comparable, they have been converted to Canadian dollars. On average, energy prices in Ontario have been generally lower than energy prices in most neighbouring jurisdictions. Over the latest six-month period, this trend continued as prices in Ontario were lower when analysed over all hours and on-peak and off-peak hours only. The average HOEP was $48.25/MWh this summer while the next highest priced jurisdictions were Michigan (Michigan Hub price) and then New York (Zone OH price) at $53.59/MWh and $59.83/MWh respectively. The highest priced region was New England, where the Internal Hub price was $89.05/MWh, 85 percent higher than the average HOEP over the same period.

Table 1-47: Average HOEP Relative to Neighbouring Market Prices, May – October 2007 & 2008 ($CDN/MWh)

	All Hours			Off-peak Hours			On-peak Hours		
	2007	2008	% Change	2007	2008	% Change	2007	2008	% Change
Ontario - HOEP	45.66	48.25	5.7	33.82	35.64	5.4	59.51	63.59	6.9
MISO – Michigan Hub	50.95	53.59	5.2	36.27	38.53	6.2	68.64	72.06	5.0
New England – Internal Hub	65.72	89.05	35.5	57.26	79.10	38.1	75.9	101.09	33.2
NYISO – Zone OH	53.12	59.83	12.6	40.86	52.10	27.5	67.81	69.13	1.9
PJM – West	66.02	77.06	16.7	51.13	63.64	24.5	84.61	93.51	10.5
Average	56.29	65.56	16.5	43.87	53.80	22.6	71.29	79.87	12.0

Figures 1-31 to 1-33 compare monthly average prices for Ontario's neighbouring jurisdictions for the latest summer period, for all hours, on-peak hours, and off-peak hours respectively. Although the six-month average HOEP was lower than other prices in neighbouring jurisdictions, there were individual months when the HOEP wasn't the lowest price in the area. For example when averaged over all hours, the New York OH price was lower than the HOEP in May 2008 and the Michigan Hub price was lower than HOEP in September 2008. For the on-peak and off-peak hours only, the monthly average HOEP was the lowest priced or second lowest priced jurisdiction relative to neighbouring prices.

The Richview nodal price is included in the figures as it is a better measure of the actual cost of energy in the Southern Ontario region, and potentially more consistent with market prices in other jurisdictions that operate under a nodal price regime. When the Richview nodal price is compared to prices in neighbouring jurisdictions, Ontario does not appear as the lowest cost region as it does when using HOEP, which is most obvious during the on-peak hours. For all months over the past summer, the on-peak Richview price was on average higher than the on-peak average Michigan Hub and New York OH prices.

Figure 1-31: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, All Hours, May - October 2008 ($CDN/MWh)

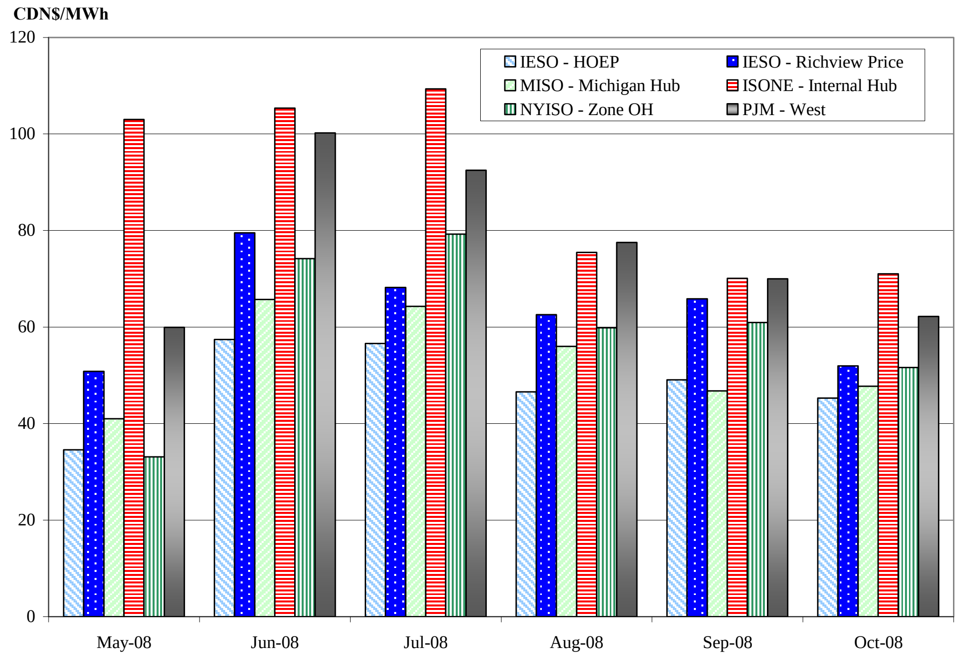


Figure 1-32: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, On-Peak, May – October 2008 ($CDN/MWh)

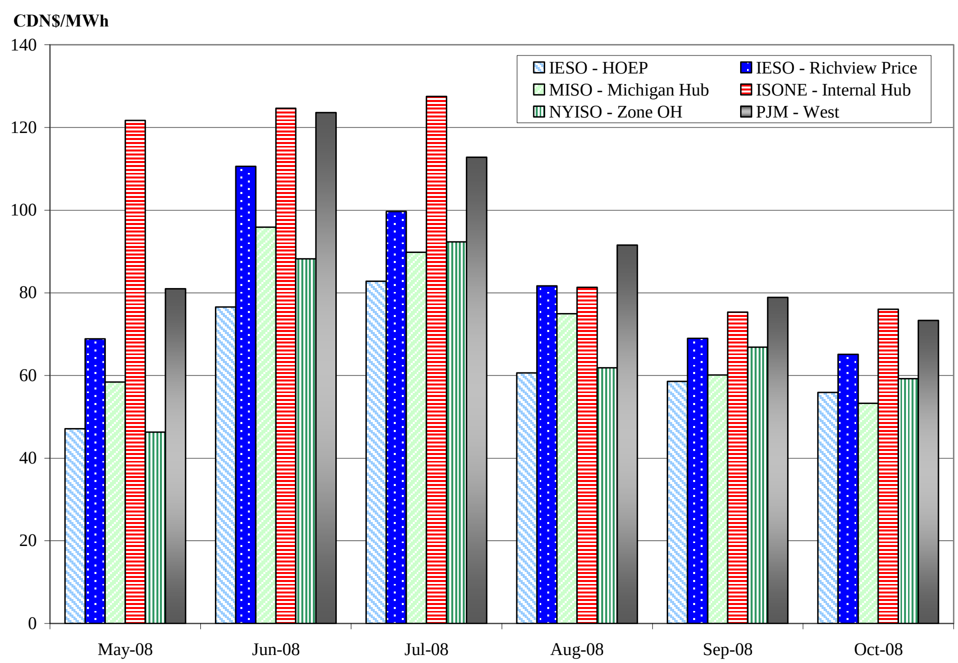
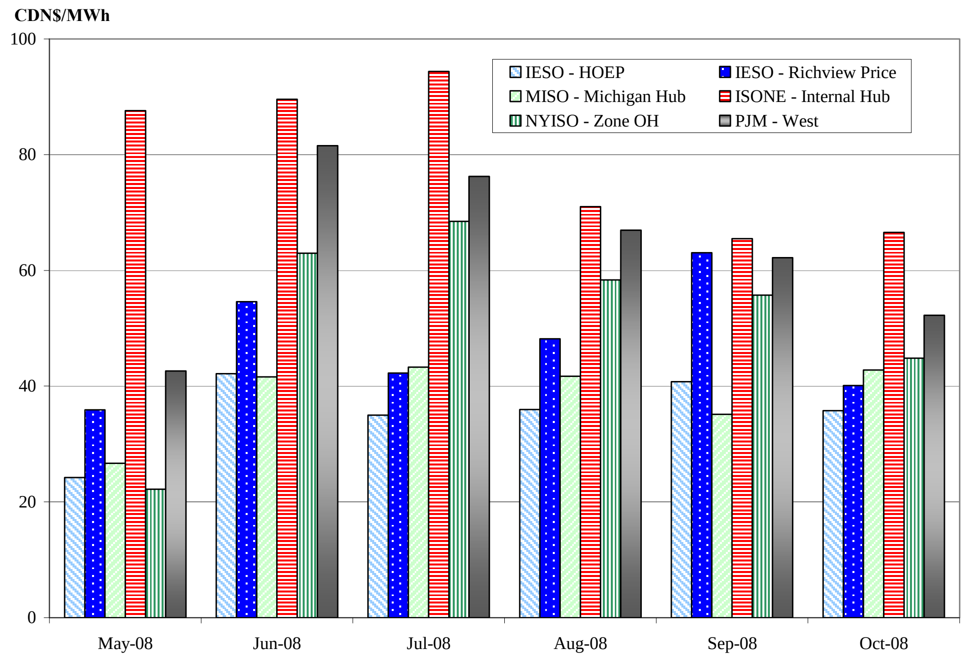


Figure 1-33: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, Off-Peak, May – October 2008 ($CDN/MWh)



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 behaviours. 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 other events that appear to be anomalous, even though they may not meet bright-line price tests. The Panel believes that the explanations of these events provides transparency on why certain outcomes occur in the market and leads 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.

Daily, the MAU reviews the previous day, not only to discern anomalous events but also to review:

- changes in 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 may lead to identifying anomalous events that may be discussed with the relevant market participants and/or the IESO.

During the current reporting period, the Panel did not identify any gaming or abuse of market power by market participants. However, the review has led the Panel to make recommendations primarily to the IESO to take certain actions to improve market efficiency.

The Panel has defined high priced hours as all hours in which the HOEP was greater than $200/MWh and a low priced hour as all hours in which the HOEP was less than $20/MWh.[47]

There were 17 hours during the review period May through October 2008 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.

In this review period there were 724 hours in which the HOEP was less than $20/MWh including 28 hours where the HOEP was negative. A negative price implies generators are paying loads and export customers to consume energy. Section 2.2 of this Chapter reviews the factors typically driving prices to low levels in these hours.

In our July 2008 Monitoring Report, the Panel indicated that we were looking for alternative approaches to defining anomalous uplift. In previous reports, the Panel reviewed the hours where uplift was greater than the HOEP. We noticed that in many cases, uplift greater than the HOEP was simply a result of a low or negative HOEP and as such, provided little worthwhile information. As a result, our analysis has focused on several components of the hourly uplifts that, if understood and anticipated by participants, could potentially be avoided. These include IOG, CMSC and OR payments. Thresholds of $500,000/hour for CMSC or IOG payments and $100,000/hour for OR are proposed as reasonable metrics for discerning anomalous uplifts. A further threshold of $1,000,000 dollars of either CMSC or IOG per day is also considered as an important threshold in the intertie zones. Appendix 2A to this Chapter shows how these thresholds were chosen.

[47] $200/MWh is typically an upper bound for the cost of a fossil generation unit while $20/MWh is a lower bound for the cost of a fossil unit.

In the study period, there were no hours with an IOG greater than $500,000, and no hours with an OR payment greater than $100,000. There were two hours with a CMSC payment greater than $500,000 and two days in which the total CMSC exceeded $1,000,000 on one interface. We will discuss these incidents in section 3.

2. Anomalous HOEP

2.1 Analysis of High Price Hours

The MAU regularly reviews all hours where the HOEP exceeds $200/MWh. The objective of this review is to understand the underlying causes that led to these prices and determine whether any further analysis of the design or operation of the market or any further investigation of the conduct of market participants is warranted.

Table 2-1 depicts the total number of hours with a HOEP greater than $200/MWh by month. There were 17 hours with a high HOEP in 2008, in contrast to 4 hours in 2007.

Table 2-1: Number of Hours with a High HOEP May – October, 2007 and 2008

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

In our previous reports, we noted that a HOEP greater than $200/MWh typically occurs in 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.

Each of these factors has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. Spikes of the HOEP above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[48]

2.1.1 June 2, 2008 HE 21

Prices and demand

Table 2-2 below lists the summary information for HE 20 and 21. HE 20 was not a high-priced hour but listed in order to illustrate the MCP behaviour before the price spike in HE 21. The MCP in HE 20 was about $10/MWh below the PD price in most intervals except in interval 12 in which the RT MCP jumped to $82.65/MWh, $29.64/MWh greater than the PD price.

In interval 1 of HE 21, the MCP increased to $739.44/MWh, far above the projected price of $66.58/MWh in PD. The MCP stayed above $600/MWh in intervals 2 and 3 and then gradually declined to $111.87/MWh in intervals 8 to 12.

[48] In our March 2003 Monitoring Report, we noted that a supply cushion lower than 10 percent was likely to induce a price spike. We have reported an improved supply cushion calculation since our July 2007 Monitoring Report and found that the 10 percent threshold still roughly holds.

Table 2-2: MCP, Ontario Demand and Net Exports, Real-Time and final Pre-dispatch June 2, 2008, HE 20 and 21

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($MWh)	Difference (RT-PD) ($MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
20	**1**	36.43	53.01	-16.58	17,366	17,723	1,195	1,452
20	**2**	41.49	53.01	-11.52	17,382	17,723	1,195	1,452
20	**3**	41.07	53.01	-11.94	17,317	17,723	1,195	1,452
20	**4**	41.07	53.01	-11.94	17,301	17,723	1,195	1,452
20	**5**	41.13	53.01	-11.88	17,333	17,723	1,195	1,452
20	**6**	41.24	53.01	-11.77	17,341	17,723	1,195	1,452
20	**7**	45.87	53.01	-7.14	17,451	17,723	1,195	1,452
20	**8**	45.87	53.01	-7.14	17,533	17,723	1,195	1,452
20	**9**	41.85	53.01	-11.16	17,444	17,723	1,195	1,452
20	**10**	41.96	53.01	-11.05	17,463	17,723	1,195	1,452
20	**11**	48.77	53.01	-4.24	17,558	17,723	1,195	1,452
20	**12**	82.65	53.01	29.64	17,758	17,723	1,195	1,452
Average		45.78	53.01	-7.23	17,437	17,723	1,195	1,452
21	**1**	739.44	66.58	672.86	17,620	17,672	2,380	1,896
21	**2**	633.58	66.58	567.00	17,657	17,672	2,380	1,896
21	**3**	609.75	66.58	543.17	17,758	17,672	2,380	1,896
21	**4**	330.09	66.58	263.51	17,805	17,672	2,380	1,896
21	**5**	178.58	66.58	112.00	17,742	17,672	2,380	1,896
21	**6**	178.58	66.58	112.00	17,742	17,672	2,380	1,896
21	**7**	178.58	66.58	112.00	17,742	17,672	2,380	1,896
21	**8**	111.87	66.58	45.29	17,388	17,672	2,380	1,896
21	**9**	111.87	66.58	45.29	17,388	17,672	2,380	1,896
21	**10**	111.87	66.58	45.29	17,388	17,672	2,380	1,896
21	**11**	111.87	66.58	45.29	17,388	17,672	2,380	1,896
21	**12**	111.87	66.58	45.29	17,388	17,672	2,380	1,896
Average		284.00	66.58	217.42	17,584	17,672	2,380	1,896

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 21 was 17,885 MW, with a projected price of $38.31/MWh. The DACP scheduled 14 fossil-fired dispatchable generators online, with a total supply of about 2,300 MW. With no imports scheduled, the day-ahead supply cushion was 35 percent.

Pre-dispatch Conditions

Imports and exports are normally scheduled immediately after the DACP run, (i.e. in the pre-dispatch runs subsequent to the DACP run), and the net exports were almost the same as the final value in the one-hour ahead pre-dispatch. As Table 2-3 below shows, although the forecast Ontario demand was gradually decreasing from 18,037 MW 10 hours ahead to 17,672 MW one-hour ahead, both net exports and the PD MCP changed little. Before the 5 hour-ahead PD run, two fossil-fired units whose incremental cost was higher than the pre-dispatch price were removed from the DACP obligation at the request of the owner. With the pre-dispatch prices in the order of $60/MWh and the two units' offering at over $140/MWh, the pre-dispatch was signalling that these units were not economic.

Table 2-3: Pre-Dispatch Prices, Ontario Demand and Exports/Imports for Selected Hours Ahead, June 2, 2008, HE 21

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Notable Events
DACP (30)	38.33	17,885	0	n/a	n/a	
10	66.30	18,037	3,020	4,897	1,877	
5	69.77	17,791	3,020	4,907	1,887	two fossil-fired units removed from DACP
4	67.69	17,724	3,099	4,987	1,888	
3	69.82	17,788	3,415	5,358	1,943	
2	74.20	17,852	3,555	5,496	1,941	
1	66.58	17,672	3,594	5,490	1,896	

The one-hour ahead forecast Ontario demand forecast for HE 21 was 17,672 MW, with a projected price of $66.58/MWh. There were 3,594 MW of imports and 5,490 MW of exports scheduled in pre-dispatch. The one hour-ahead PD supply cushion was 12.0 percent.

Real-time Conditions

Before the RT run for HE 21, 489 MW of imports failed, of which 250 MW failed on the Michigan interface due to ramp limitation and 239 MW failed on the NY interface because they were not scheduled in New York. At the same time, 5 MW of export being failed on the Quebec interface due to Quebec security. The net import failure in the hour amounted to 484 MW.

The RT Ontario demand came in heavier than forecast in PD. The average demand in HE21 was 17,584 MW, with a peak demand of 17,805 MW (133 MW or 0.8 percent higher than forecast). The real-time supply cushion dropped to 0.9 percent

The increase in scheduled net exports (from 1,195 MW to 1,896 MW), import failures (484 MW) and higher Ontario demand (133 MW RT peak vs. PD peak) led to an operating reserve shortfall in the constrained sequence in the middle of the hour. In response, the IESO cut 400 MW of exports (from interval 7 to12) using the TLRi code, which constrained off the export but retained it in the market sequence.

Coincidentally, from interval 6 to 11, the unconstrained sequence failed and the total demand was incorrectly calculated.[49] The failure of the unconstrained sequence resulted in administered prices and schedules for these intervals. The modified prices and demand are reported in Table 2-2, with intervals 6 and 7 reflecting the values from interval 5, and intervals 8 to 11 reflecting values from interval 12.

Assessment

The high HOEP in HE 21 was mainly a consequence of a sharp increase of 1,184 MW in net exports for the hour (an import failure of 484 MW plus a net export scheduled increase of 700 MW).

[49] The constrained sequence was not affected.

Although the IESO cut exports by 400 MW for internal reliability, the TLRi code was used for these curtailments. When TLRi is used, the IESO procedure is that the unconstrained schedules for these exports will not be changed. As a result, the export curtailment did not cause a suppression of the HOEP.[50]

Anomalous Outcome in HE 20 Interval 12

In interval 11 of HE20, the MCP was $48.77/MWh and was set by a fossil-fired generator. In interval 12, the MCP increased sharply to $82.65/MWh. Two factors contributed to this price increase: a 200 MW increase in Ontario demand and the interaction between the constrained and unconstrained sequences in interval 12 due to changes in inter-tie schedules and the use of IESO's transaction codes (which will be explained below).

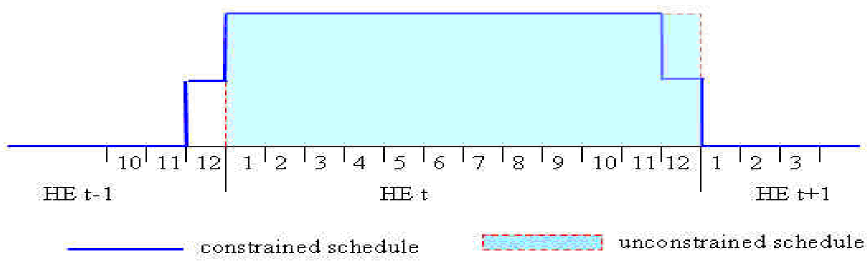
While imports and exports are considered as being scheduled for the hour, the hour-to-hour change to the net schedule at an intertie is ramped in over two intervals (the last interval of the current hour and the first interval of the next hour). This is the standard operating procedure between ISO's.

To determine the actual dispatch, in the constrained sequence, half the change in the net schedule for each import or export is added to interval 12. Resources are dispatched to account for this net change in schedule and in turn the shadow price in the constrained sequence is calculated. For settlement purposes, the schedules of the affected imports or exports are adjusted back to their interval 11 level. Maintaining the level from interval 11 in interval 12 reflects the market design that requires the import/export schedules be fixed hourly (this is also the typical treatment in other markets). What is important to note is that shadow prices in interval 12 are calculated based upon the actual net schedule changes which correctly reflect both the actual ramping of the schedule changes over 2 intervals and the actual generation being used to meet the schedules.

[50] For a detailed discussion on TLRi and other codes, refer to our July 2008 Monitoring Report, pages 171-180.

Meanwhile in the unconstrained schedule, all net ramp changes are made strictly on the hour in interval 1. Figure 2-1 illustrates the inter-tie schedules used in both the constrained sequence to calculate the shadow price and the unconstrained sequence to determine the HOEP.

Figure 2-1: Inter-Tie Schedules used in the Constrained and Unconstrained Sequence With Codes AUTO, TLRi or ORA



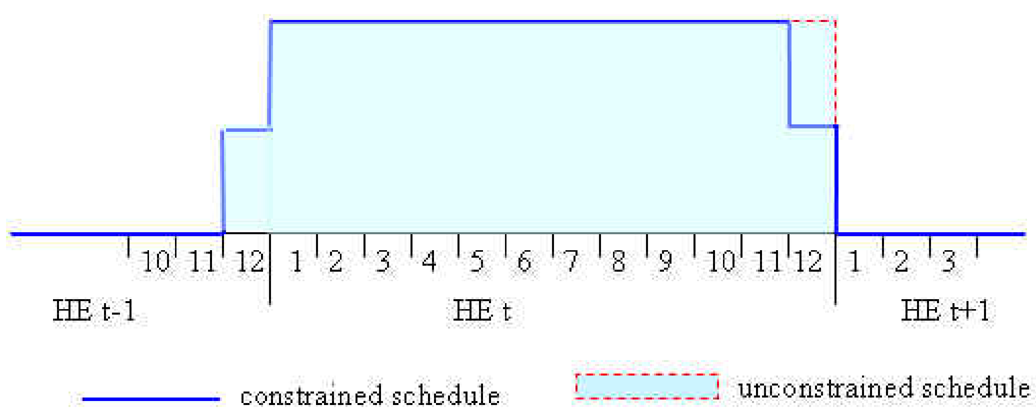
As an example, if the net inter-tie change is an increase of 700 MW of exports for the next hour, in the constrained sequence 350 MW of net exports would be added to interval 12 of the current hour, generators would be dispatched accordingly and the shadow price would be calculated on the basis of these dispatches. For settlement purposes, the schedules in the constrained sequence are then immediately reset to their interval 11 schedule and thus the trade has the same quantity within the hour. Interval 1 of the next hour would have the whole 700 MW of net exports included in the constrained sequence and thus there is no need to adjust the quantities.

In the unconstrained sequence, however, the whole 700 MW change in net exports is introduced in interval 1 of the next hour and the Market Clearing Price (MCP) is calculated as though the whole change in net exports ramped over the single interval. The dissimilar treatment in net schedule changes creates a further inconsistency in interval prices between the two sequences, in addition to those mentioned in earlier Monitoring

Reports, such as the artificial 12 or 3-times ramp rate assumption and non-existence of transmission congestion in the unconstrained sequence. [51]

This inconsistency is further complicated by the fact that the net import/export treatment in the unconstrained sequence turns out to be code dependent. If the code is AUTO, TLRi or ORA, then the above treatment holds. But if the transaction code is OTH, MrNh, TLRe or ADQh, the schedule of an intertie trade in the unconstrained sequence is set equal to the schedule in the constrained sequence. [52] Thus the unconstrained schedule in interval 12 of the current hour would be equated to the constrained schedule which has been modified to reflect half the change for the next hour. These modified unconstrained schedules are inputs for the unconstrained MCP calculation. So with certain codes these transactions are reflected strictly in interval 1 of the next hour and with other codes half of the impact is reflected in interval 12 of the current hour. Figure 2-2 below illustrates the different treatments between the two schedules based upon the code.

Figure 2-2: Inter-Tie Schedules used in the Constrained and Unconstrained Sequence With Codes OTH, MrNh, TLRe or ADQh



As an example, on June 2 there were three imports totalling 578 MW which failed in HE 21, as showed in Table 2-4 below. For the purposes of the DSO, the schedules in the constrained and unconstrained sequence were 289 MW in interval 12 of HE20, which is

[51] Especially see the Panel's December 2003 Monitoring Report, pages 110-113.
[52] These codes were created for intertie transactions that are scheduled for different reasons. For a detailed discussion and the Panel's comments, see our July 2008 Monitoring Report, page 118-120 and 171-180.

halfway between the HE 20 interval 11 constrained schedule and the HE 21 interval 1 constrained schedules. The unconstrained sequence in interval 12 was also set to 289 MW for the DSO run leading to a decrease in imports of 236 MW (from interval 11 to interval 12).[53] As a result of the decrease in imports and increase in demand, the MCP in interval 12 jumped to $82.65/MWh, as seen in Table 2-1. If the codes had not been MrNh or OTH (i.e. had they been AUTO or TLRi) the whole price effect would have been felt in interval 1.

While it captures the ramp rate effect before the hour, the treatment of intertie trades associated with TLRe/OTH/MrNh/ADQh is not fully correct because the IESO tools look ahead and assign the reason code of the next hour to the quantity in interval 12 of the current hour.[54] As a result, the ramping in the unconstrained sequence occurs only in interval 12 before the hour, so there may not be a corresponding ramping up of the schedule at the end of the prior hour, as in Figure 2-1 (assuming a one-hour schedule for simplicity). The price impact of such treatment is thus asymmetric.

Table 2-4: Schedules that are used for MCP Calculation and for Settlement June 2, 2008 HE 20 and 21

	Hour	20							21	
	Interval	11			12				1	
		Constrained & Unconstrained Schedules			Unconstrained Schedules Used in MCP Calculation		Unconstrained Schedules Used in Settlements		Constrained & Unconstrained Schedules	
MP	Import/ Export	Cons. Schedule	Uncon. Schedule	Reason Code	Schedule	Reason Code	Schedule	Reason Code	Schedule	Reason Code
A	Import	200	200	AUTO	100	MrNh	200	AUTO	0	MrNh
B	Import	178	125	AUTO	89	MrNh	125	AUTO	0	MrNh
C	Import	200	200	AUTO	100	OTH	200	AUTO	0	OTH
Total		578	525		289		525		0	

53 Note the constrained sequence runs about 9 minutes ahead of the unconstrained sequence.
54 When a trader ceases offering or bidding on a particular boundary source or sink, AUTO is automatically used for the quantity in the last interval.

The Panel has long supported a pricing algorithm that would reflect actual ramp rate. [55] We have observed an inconsistent pricing treatment in the unconstrained (market) schedule for changes in inter-tie schedules.

If the pricing algorithm is to reflect actual dispatch, which ramps in the changes over two intervals, then the treatment of inter-tie trades that have the code AUTO/TLRi/ORA and which account for almost 99 percent of intertie schedules is incorrect and the treatment of intertie trades associated with TLRe/OTH/MrNh/ADQh is only partially correct.

It should be noted that the present IESO procedures are consistent with the Market Rules. Chapter 7 section 6.4.3 states:

> *The IESO shall determine for registered facilities that are boundary entities a market schedule for each dispatch hour using the outcome of the projected market schedule determined as at the preceding dispatch hour and modified as required by the IESO.*

Thus Market Rules allow the IESO to adjust the schedules as required although the intertie schedules are set hourly. The adjustment of certain intertie transactions in the last interval of an hour could more accurately reflect the true ramp condition.

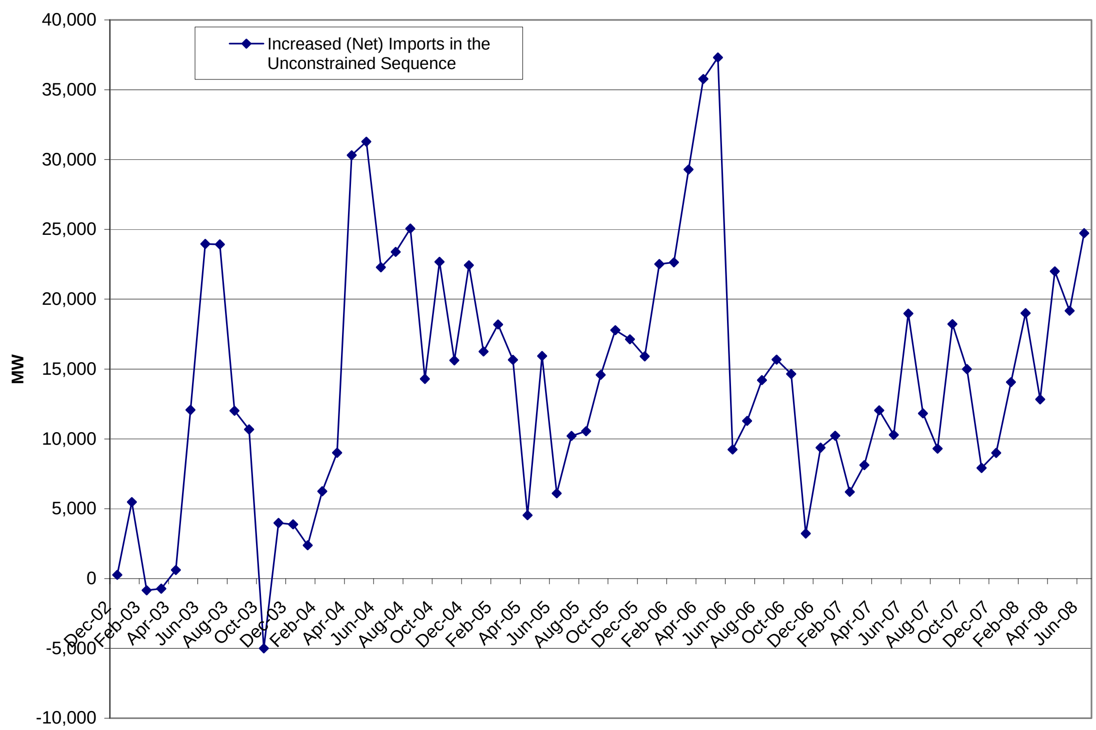
1. Background of Intertie Ramp Treatment

Before November 14, 2002, the IESO (then IMO) did not adjust the schedules in the unconstrained sequence in response to any change in the constrained sequence. As a result, the unconstrained sequence was not affected by the actual intertie ramping. In fact, almost all associated codes for intertie trades were “AUTO” before then. On November 14, 2002, the IESO changed its procedure to equalize the unconstrained schedules to the constrained schedules if a trade failed due to non-IESO reasons.

[55] The Panel’s December 2003 Monitoring Report, page 112.

Figure 2-3 below shows the monthly total change in net imports in the unconstrained sequence due to the ramping adjustment in interval 12, for the period December 2002 to June 2008. A positive number indicates that for a given month there were more (net) imports in interval 12 than in interval 11 in the same hour, while a negative number indicates more (net) exports. It appears that in general there were more (net) imports in interval 12, implying a tendency toward a lower MCP in interval 12. The increase in net imports is consistent with the fact that exports were more likely to fail due to non-IESO reasons, leading to fewer exports in next hour and thus fewer exports in interval 12 of the current hour due to the ramping down of exports.

Figure 2-3: Monthly Total Increase in Net Imports in Interval 12 Relative to Interval 11 December 2002 to June 2008



2. The potential price impact of the treatment

There are two alternatives to the current algorithm: (1) all intertie trades are allowed to ramp 50 percent in interval 12, and (2) no ramp is allowed at all. If the first alternative is chosen, the procedures for all codes should be revised because AUTO/TLRi/ORA don't allow any ramp at all while TLRe/OTH/MrNh/ADQh only allow ramp at one end of the hour. If the second alternative is chosen, the ramp of TLRe/OTH/MrNh/ADQh should be removed.

To see the potential price impact, the MAU ran three simulations: (1) the present situation; (2) a simulation where there is no ramping whatsoever in interval 12 of the unconstrained sequence; and (3) a simulation with all intertie transactions ramping in interval 12 in the unconstrained sequence. Table 2-5 reports the simulation results for the period September 12, 2007 to June 30, 2008.[56] September 12, 2007 was chosen as the starting date as the 3X ramp rate assumption took place on this day.

Table 2-5: Price Comparison of With and Without Ramp Scenarios, $/MWh, September 12, 2007 to June 30, 2008

	"Actual" HOEP	HOEP with no ramping	HOEP with All Intertie Trades ramped
Average	47.68	47.69	47.58
Maximum Difference (Relative to Actual HOEP)		10.40	66.71
Minimum Difference (Relative to Actual HOEP)		-26.86	-46.25

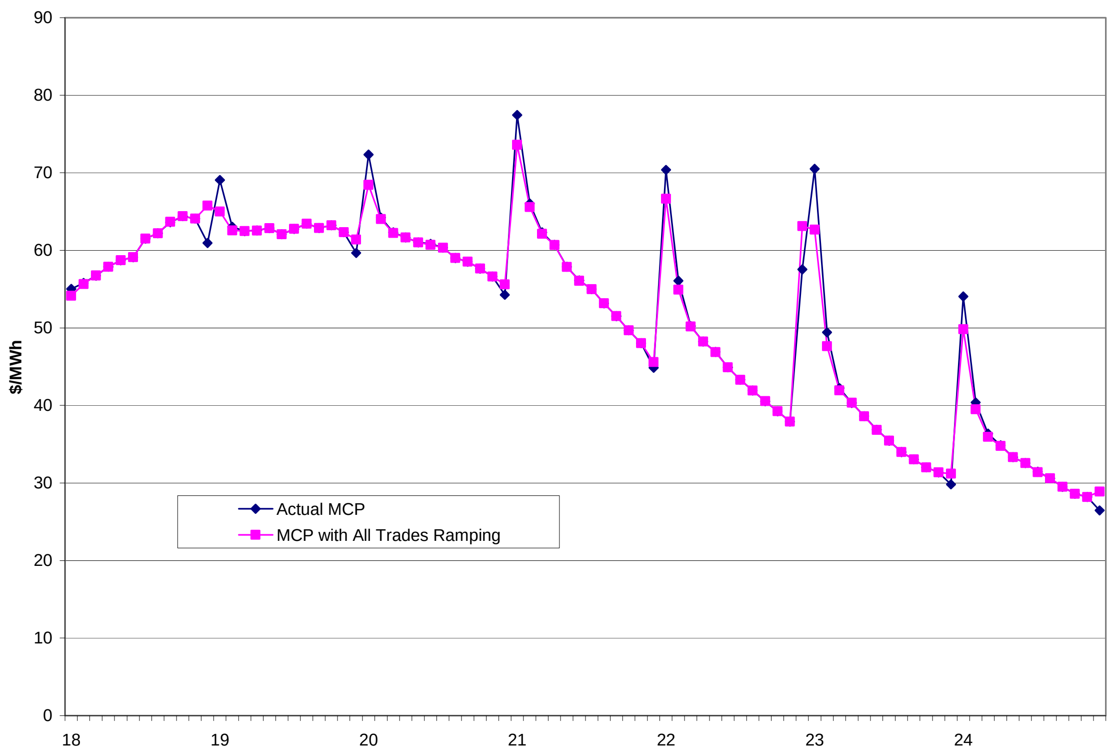
The average HOEP in the study period was $47.68/MWh. Had the ramping of intertie trades with TLRe/OTH/MrNh/ADQh not occurred, the average HOEP would have been $47.69/MWh, or only 1 cent higher. Although the average effect was almost zero, the effect in specific hours was much greater: the HOEP could have been $10.40/MWh higher in some hours or $26.86/MWh lower in others.

If the ramping of all intertie trades had been considered, the HOEP would have been $47.58/MWh, or $0.10/MWh lower than the actual HOEP due to the smoothing effect of ramping over two intervals straddling the hour-to-hour changes.

[56] Of the total 7,008 simulated hours, 11 hours with a large simulated HOEP (>$300/MWh) were removed because these simulated HOEP are far greater than the actual HOEP, indicating the simulated results for these hours may be not reliable for comparison.

The lower average HOEP was mainly a result of a lower HOEP during load drop-off periods. In these hours, exports are typically increasing from hour to hour. With all ramping for exports required in the first interval of the hour, the MCP in interval 1 is typically very high. Had half of the intertie ramping been allocated to interval 12 of the previous hour, the ramping requirement in interval 1 would have been much smaller and as a result the MCP would have been smaller. Figure 2-4 below depicts the MCP comparison for the load drop-off period (HE 18 to 24). As one can see, the MCP in interval 1 would have been a few dollars lower had the ramping of intertie trades been shared by interval 12 of the previous hour.

Figure 2-4: "Actual" and Simulated MCP, HE 18 to 24, September 12, 2007 to June 30, 2008



3. Assessment

The Panel believes that to provide an efficient price to the market, the unconstrained sequence should reflect actual dispatch as closely as possible. Consequently, the Panel is of the opinion that the intertie ramping should be incorporated into the pricing algorithm, which should provide a more efficient price signal to the market.

Although the simulation for the nine and a half month period shows a price drop ($0.10/MWh) had the intertie ramping been incorporated into the pricing model, we cannot project that this would be the general trend. In other periods, incorporating the ramping may alternately lead to a higher HOEP.

From discussions with IESO staff, we understand that:

- There would be little cost or effort to include the constrained ramp into the unconstrained model, but this is not precisely correct as the unconstrained ramp schedule would be different than the constrained ramp schedule because the unconstrained and constrained sequence runs independently.
- There would be a significant software cost for the IESO to incorporate the unconstrained intertie ramping into the unconstrained sequence because the inter-tie scheduling tool (which makes the ramp determination) does not include the unconstrained import and export schedules. For example, a transaction may ramp up 100 MW in the constrained sequence but zero in the unconstrained sequence. Establishing the ramping in the unconstrained sequence requires separate software from the current Interchange Scheduler, which could be very costly.
- IESO can fix the asymmetric ramping due to TLRe/OTH/MrNh/ADQh as a start. The cost for such a change should be relatively small. This may not change the average market price in the long run, but does correct the asymmetric price distortion in some hours.

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Recommendation 2-1

The Panel recommends that the IESO's ramping of intertie schedules in the unconstrained process (the pricing algorithm) be consistent with actual intertie procedures and the treatment in the constrained scheduling process.

2.1.2 June 9, 2008 HE 11 and 13

Prices and Demand

HOEP exceeded $200/MWh in HE 11 and 13. Table 2-6 below lists the summary information for these hours as well as for HE 10 and 12 in order to gain a better understanding of the MCP behaviour just before each high priced hour.

The PD prices ranged from $144/MWh to $165/MWh for these four hours, while the RT MCP was higher in all intervals in HE 11 and 13 and more than $100/MWh higher in some intervals. The largest price increase occurred in HE 11 interval 10, where the MCP was $170/MWh greater than projected in PD.

Table 2-6: MCP, Ontario Demand and Net Exports, Real-Time and Final Pre-dispatch June 9, 2008 HE 10-13

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Difference (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
10	1	181.55	164.00	17.55	21,987	22,195	1,100	1,000
10	2	183.55	164.00	19.55	22,061	22,195	1,100	1,000
10	3	183.55	164.00	19.55	22,131	22,195	1,100	1,000
10	4	184.86	164.00	20.86	22,267	22,195	1,100	1,000
10	5	184.86	164.00	20.86	22,313	22,195	1,100	1,000
10	6	186.69	164.00	22.69	22,470	22,195	1,100	1,000
10	7	187.72	164.00	23.72	22,530	22,195	1,100	1,000
10	8	187.72	164.00	23.72	22,535	22,195	1,100	1,000
10	9	200.31	164.00	36.31	22,676	22,195	1,100	1,000
10	10	202.39	164.00	38.39	22,729	22,195	1,100	1,000
10	11	223.56	164.00	59.56	22,825	22,195	1,100	1,000
10	12	188.40	164.00	24.40	22,577	22,195	1,100	1,000
Average		**191.26**	**164.00**	**27.26**	**22,425**	**22,195**	**1,100**	**1,000**
11	1	196.56	144.10	52.46	22,916	22,918	970	399
11	2	172.79	144.10	28.69	22,884	22,918	970	399
11	3	196.68	144.10	52.58	22,993	22,918	970	399
11	4	199.76	144.10	55.66	23,041	22,918	970	399
11	5	216.43	144.10	72.33	23,157	22,918	970	399
11	6	217.78	144.10	73.68	23,224	22,918	970	399
11	7	216.43	144.10	72.33	23,179	22,918	970	399
11	8	229.10	144.10	85.00	23,289	22,918	970	399
11	9	304.68	144.10	160.58	23,358	22,918	970	399
11	10	314.68	144.10	170.58	23,409	22,918	970	399
11	11	229.20	144.10	85.10	23,313	22,918	970	399
11	12	228.20	144.10	84.10	23,294	22,918	970	399
Average		**226.86**	**144.10**	**82.76**	**23,171**	**22,918**	**970**	**399**
12	1	151.61	144.20	7.41	23,401	23,278	210	270
12	2	147.75	144.20	3.55	23,302	23,278	210	270
12	3	147.80	144.20	3.60	23,318	23,278	210	270
12	4	148.42	144.20	4.22	23,380	23,278	210	270
12	5	148.42	144.20	4.22	23,387	23,278	210	270
12	6	148.46	144.20	4.26	23,411	23,278	210	270
12	7	153.99	144.20	9.79	23,518	23,278	210	270
12	8	164.90	144.20	20.70	23,515	23,278	210	270
12	9	157.39	144.20	13.19	23,550	23,278	210	270
12	10	159.00	144.20	14.80	23,630	23,278	210	270
12	11	159.01	144.20	14.81	23,667	23,278	210	270
12	12	171.29	144.20	27.09	23,839	23,278	210	270

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Difference (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
Average		**154.84**	**144.20**	**10.64**	**23,493**	**23,278**	**210**	**270**
13	**1**	242.52	165.01	77.51	23,724	24,144	777	22
13	**2**	245.80	165.01	80.79	23,915	24,144	777	22
13	**3**	245.80	165.01	80.79	23,914	24,144	777	22
13	**4**	274.56	165.01	109.55	24,002	24,144	777	22
13	**5**	274.56	165.01	109.55	24,007	24,144	777	22
13	**6**	274.68	165.01	109.67	24,012	24,144	777	22
13	**7**	245.81	165.01	80.80	24,007	24,144	777	22
13	**8**	245.81	165.01	80.80	23,986	24,144	777	22
13	**9**	245.80	165.01	80.79	23,934	24,144	777	22
13	**10**	269.56	165.01	104.55	24,064	24,144	777	22
13	**11**	245.81	165.01	80.80	24,058	24,144	777	22
13	**12**	200.01	165.01	35.00	23,579	24,144	777	22
Average		**250.89**	**165.01**	**85.88**	**23,934**	**24,144**	**777**	**22**

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 10-13 varied from 22,257 MW to 22,966 MW, with projected prices of $70.12/MWh to $129.53/MWh. The DACP scheduled 26 fossil-fired dispatchable generators online, with a total schedule between 6,400 MW to 7,000 MW. Exports were excluded from the DACP run and no imports were scheduled. The day-ahead supply cushion ranged between 19 percent in HE 10 and 14 percent in HE 13. Table 2-7 below lists day-ahead summary information.

Table2-7: Day-Ahead Conditions
June 9, 2008 HE10-13

Hour	MCP ($/MWh)	Ontario Demand (MW)	Supply Cushion (%)
10	70.12	22,257	19
11	87.02	22,801	17
12	94.82	22,966	16
13	129.53	23,495	14

Pre-dispatch Conditions

From June 8 to 15, transmission capability from generation in the James Bay area to southern Ontario was reduced from about 800 MW to 100-200 MW due to structural problems with one tower of a 500 kV line. However, this bottled generation had no impact on HOEP because the unconstrained (market) sequence assumes it to be available.

Table 2-8 below depicts the changes in pre-dispatch prices, forecast demand, and net exports following DACP for HE 11 and 13.

- For HE 11, the pre-dispatch MCP, demand and net exports had changed little from 10 hours ahead to the final one-hour ahead.
- For HE 13, the forecast demand increased gradually from 23,495 MW day-ahead to 24,144 MW one-hour ahead (a 2.8 percent increase) The PD price fluctuated around $150/MWh from 10 to two hours ahead, and increased to $165.01/MWh in the final pre-dispatch. Net exports also dropped to 22 MW from 880 MW 10 hours ahead. The one-hour ahead PD price was set by an import.

Table 2-8: Pre-dispatch MCP, Demand and Net Exports June 9, 2008, HE 11 and 13

Hour-ahead	11			13		
	MCP ($MWh)	Ontario Demand (MW)	Net Exports (MW)	MCP ($MWh)	Ontario Demand (MW)	Net Exports (MW)
DACP	87.02	22,789	0	129.53	23,495	0
10	135.90	22,850	483	149.00	23,544	883
5	138.68	22,884	350	156.00	23,582	794
4	139.51	22,792	350	145.93	23,436	612
3	139.54	22,890	350	140.00	23,509	-25
2	141.04	22,740	612	147.64	23,807	169
1	144.10	22,918	399	165.01	24,144	22

The final one-hour ahead PD supply cushion was 8.6 percent for HE 11 and 5.0 percent for HE 13. The relatively low supply cushion indicates a possible real-time price spike if there is a large forced outage or a large amount of failed imports, or real-time demand becomes heavier than expected.

Real-time Conditions

HE 11

Before the RT run, 571 MW of net imports failed in the unconstrained sequence (597 MW imports and 26 MW exports failed due to either MISO security or ramp rate limitation).[57]

One small hydro generator was scheduled in PD but was forced out of service, representing a loss of 50 MW.

Self-scheduling and intermittent generators produced 165 MW (or 10.5 percent) less than they had projected one-hour ahead. One-third of the deviation was from a single wind generator.

The RT Ontario demand came in heavier than forecast in PD. The average demand in HE11 was 23,171 MW, with a peak demand 23,409 MW (491 MW or 2.1 percent higher than forecast). The real-time supply cushion at the beginning of the hour was 0.7 percent.

In total, there was 790 MW of lost supply and 491 MW of greater than anticipated demand, leading to a higher MCP and HOEP than projected in the final one-hour ahead pre-dispatch. The MCP spiked later in the hour as demand kept increasing. The MCP in all intervals was set by peaking hydro generators and the HOEP reached $226.86/MWh.

[57] In the constrained sequence, the failed imports amounted to 806MW in HE 11. In responding to such a high volume of import failure, the IESO cut 787MW of exports for either transmission congestion relief or resource adequacy in Ontario. Because the TLRi was used, those reduced exports were not deducted from the market demand and thus the curtailment had no effect on the market price.

HE13

In HE 13, failed imports amounted to 755 MW in the unconstrained sequence, due to transmission congestion in Michigan. Although the IESO curtailed a significant amount of exports for congestion management, the curtailment had no impact on the price as the TLRi code was used.[58]

Self-scheduling and intermittent generators produced 189 MW (10.4 percent) less than they had projected one-hour ahead. About one third of the deviation was from a single wind generator.

In HE 13, the average RT Ontario demand was 23,934 MW, with a peak demand of 24,064 MW (79 MW or 0.3 percent lower than forecast in the final pre-dispatch). The real-time supply cushion at the beginning of the hour was -0.5 percent.

Failed imports and the under-performance of self scheduling and intermittent generators were the main factors contributing to the price spike. The MCP was set by either peaking hydro generators or a fossil generator that just came online in the hour. The HOEP was $250.89/MWh in the hour.

Assessment

As Table 2-6 illustrates, the MCP was persistently high in HE 11 and 13, indicating that the high HOEP was induced by the tight supply/demand condition in these hours.

The IESO took actions to deal with transmission congestion and internal resource adequacy by curtailing exports after a large quantity of imports failed on the Michigan

[58] In the constrained sequence, failed imports were 1,453MW in HE 13 (the vast majority of which was due to congestion in Michigan). In response, the IESO cut 1,225MW of exports for internal security or resource adequacy. Because the TLRi was used for those export curtailments, these exports were not deducted from the market demand and thus the curtailment had no effect on the market prices.

interface due to transmission congestion in Michigan. However, the curtailment had no impact on the market price because the IESO used the TLRi code for those exports.

2.1.3 June 20, 2008 HE 17

Prices and Demand

Table 2-9 below lists the summary information for HE17 and 18. In all intervals except interval 12 of HE 18, the real-time MCP was higher than the MCP in pre-dispatch. The real-time MCP jumped to $264.91/MWh in interval 4 of HE 17 from $135.12/MWh in interval 3. The largest price difference between PD and RT occurred in interval 10 of HE17 when real-time MCP rose $200/MWh above the one-hour ahead pre-dispatch price. Ontario was a large net exporter in these hours, and Ontario demand was gradually decreasing from a peak of 18,307 MW early in HE 17 to 17,526 MW at the end of HE18.

Table 2-9: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch
June 20, 2008, HE17 and 18

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
17	**1**	105.32	89.00	16.32	18,289	17,988	2,268	2,268
17	**2**	125.00	89.00	36.00	18,255	17,988	2,268	2,268
17	**3**	135.12	89.00	46.12	18,307	17,988	2,268	2,268
17	**4**	264.91	89.00	175.91	18,288	17,988	2,268	2,268
17	**5**	260.18	89.00	171.18	18,222	17,988	2,268	2,268
17	**6**	264.90	89.00	175.90	18,282	17,988	2,268	2,268
17	**7**	260.18	89.00	171.18	18,217	17,988	2,268	2,268
17	**8**	250.00	89.00	161.00	18,205	17,988	2,268	2,268
17	**9**	224.68	89.00	135.68	18,174	17,988	2,268	2,268
17	**10**	289.90	89.00	200.90	18,184	17,988	2,268	2,268
17	**11**	260.18	89.00	171.18	18,131	17,988	2,268	2,268
17	**12**	145.07	89.00	56.07	17,900	17,988	2,268	2,268
Average		**215.45**	**89.00**	**126.45**	**18,204**	**17,988**	**2,268**	**2,268**
18	**1**	155.10	93.60	61.50	18,071	17,901	2,151	2,364
18	**2**	150.22	93.60	56.62	18,012	17,901	2,151	2,364
18	**3**	147.65	93.60	54.05	17,947	17,901	2,151	2,364
18	**4**	147.55	93.60	53.95	17,947	17,901	2,151	2,364
18	**5**	140.12	93.60	46.52	17,896	17,901	2,151	2,364
18	**6**	109.69	93.60	16.09	17,780	17,901	2,151	2,364
18	**7**	125.00	93.60	31.40	17,844	17,901	2,151	2,364
18	**8**	109.69	93.60	16.09	17,802	17,901	2,151	2,364
18	**9**	104.32	93.60	10.72	17,759	17,901	2,151	2,364
18	**10**	104.31	93.60	10.71	17,738	17,901	2,151	2,364
18	**11**	107.10	93.60	13.50	17,793	17,901	2,151	2,364
18	**12**	92.64	93.60	-0.96	17,526	17,901	2,151	2,364
Average		**124.45**	**93.60**	**30.85**	**17,843**	**17,901**	**2,151**	**2,364**

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 17 was 17,915 MW, with a projected price of $13.72/MWh. The DACP scheduled 15 fossil-fired dispatchable generators online, with a total supply of about 3,000 MW. No imports were scheduled. The day-ahead supply cushion was 44 percent.

Pre-dispatch Conditions

Imports and exports began to be scheduled immediately after the DACP run. As Table 2-10 below shows, Ontario demand had changed little from 26 hours ahead to one-hour ahead. However, imports and exports changed significantly, with net exports rising from 1,606 MW 10 hours ahead to 2,268 MW one-hour ahead (a 41.2 percent increase). The pre-dispatch price increased from $13.72/MWh in DACP to $89.00/MWh one-hour ahead as additional net exports were scheduled. Before the 16 hour-ahead PD run, a market participant applied to remove four fossil-fired units from the DACP commitment. The IESO approved the request as there appeared to be no supply problems and these units were either offering at their incremental energy costs which were higher than the pre-dispatch price or the units were in congested areas.

Table 2-10: Pre-Dispatch Prices, Ontario Demand and Exports/imports for Selected Hours Ahead
June 20, 2008, HE 17

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Notable Events
26 (DACP)	13.72	17915	0	0	0	Four units removed from DACP 17 hours ahead
10	44.42	17,963	2,250	3,856	1,606	
5	75.08	17,974	2,553	4,599	2,046	
4	67.81	17,968	2,503	4,399	1,896	
3	71.44	18,025	2,503	4,549	2,046	
2	86.00	17,855	1,750	4,127	2,377	
1	89.00	17,988	1,750	4,018	2,268	

The one-hour ahead forecast Ontario demand was 17,988 MW, with a projected price of $89.00/MWh. There were 1,750 MW of imports and 4,018 MW of exports scheduled. The final one-hour ahead PD supply cushion was 8.6 percent.

Real-time Conditions

In HE 17 Interval 1, a nuclear unit experienced problems with the reactor and started to ramp down. The unit was disconnected from the power grid in interval 4, for a loss of 500 MW of baseload generation.

At the time the nuclear unit was forced out of service, the Area Control Error (ACE) reached minus 400 MW. In response, the IESO activated 350 MW of operating reserves. 250 MW of activated operating reserves was deactivated in interval 2 and the remaining 100 MW was deactivated in interval 3 after the ACE crossed zero.

The RT Ontario demand came in heavier than forecast in PD. The average demand in HE 17 was 18,204 MW, with a peak demand 18,307 MW (319 MW or 1.8 percent higher than forecast). The real-time supply cushion at the beginning of HE 17 dropped to 3.3 percent.

In HE 17, self scheduling and intermittent generators performed almost as expected, producing only 30 MW (2.5 percent) less than forecast. There were no import or export failures except one linked wheel through transaction which had no impact on the real-time price because the import leg and the export leg cancelled out each other.

Assessment

The high price in HE 17 was mainly due to the loss of a nuclear unit (500 MW) and demand coming in heavier than expected (319 MW), both having the effect of pushing up the MCPs and the HOEP.

In responding to the loss of the nuclear unit, the IESO activated up to 350 MW of operating reserve in interval 2, and deactivated 250 MW a few minutes later but in the same interval. By the time the unconstrained sequence ran for interval 2, there was only

100 MW activated for OR and correspondingly the reduction in the OR requirement for interval 2 was 100 MW. Typically a reduction in the OR requirement will put downward pressure on the HOEP during tight supply situations. However, in the current case, there was no price impact based on our simulation. The OR requirement returned to normal in interval 3 when all activated OR were deactivated.

The MCP in HE 17 interval 12 dropped to $145.07/MWh from $260.18/MWh in interval 11. Part of the reason for the drop was that the Ontario demand decreased by 231 MW. There was also a 161 MW increase in net imports due to the ramping effect in the unconstrained sequence for intertie transactions with a OTH code (for details see the commentary on the June 2, 2008 events in Section 2.1.1 above).

In HE 18, the HOEP dropped to $124.45/MWh. The average Ontario demand was 17,843 MW, with a peak demand of 18,071 MW, or only 170 MW (0.9 percent) greater than the forecast. The 213 MW net export failure [59] partially compensated for the loss of 500 MW of the nuclear unit. The HOEP was still greater than the projected price in PD, indicating some effect from the forced outage of the nuclear unit which occurred after the PD run for HE 18.

2.1.4 July 8, 2008 HE 10

Prices and Demand

Table 2-11 below lists the summary information for HE 10 and 11. The MCPs in the first few intervals of HE 10 were much lower than the PD price as the demand started at a low level and was ramping up. The high HOEP in HE 10 was a result of a high MCP in the last three intervals. In interval 10, the MCP reached $609.09/MWh. The MCP then fell to $146.99/MWh in HE 11 interval 1, which was very close to the price of $145/MWh in the one-hour ahead pre-dispatch.

[59] 363 MW of exports failed on the New York interface due to not being scheduled in New York and 150 MW of imports failed on the Michigan interface due to an incorrect NERC tag in MISO.

Table 2-11: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch July 8, 2008 HE10 and 11

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
10	**1**	50.04	146.48	-96.44	21,789	22,684	1,692	1,642
10	**2**	87.75	146.48	-58.73	21,915	22,684	1,692	1,642
10	**3**	90.46	146.48	-56.02	21,998	22,684	1,692	1,642
10	**4**	130.12	146.48	-16.36	22,190	22,684	1,692	1,642
10	**5**	104.95	146.48	-41.53	22,233	22,684	1,692	1,642
10	**6**	120.43	146.48	-26.05	22,243	22,684	1,692	1,642
10	**7**	128.32	146.48	-18.16	22,339	22,684	1,692	1,642
10	**8**	139.44	146.48	-7.04	22,461	22,684	1,692	1,642
10	**9**	140.11	146.48	-6.37	22,526	22,684	1,692	1,642
10	**10**	609.09	146.48	462.61	22,473	22,684	1,692	1,642
10	**11**	579.85	146.48	433.37	22,535	22,684	1,692	1,642
10	**12**	402.00	146.48	255.52	22,629	22,684	1,692	1,642
Average		**215.21**	**146.48**	**68.73**	**22,278**	**22,684**	**1,692**	**1,642**
11	**1**	146.99	145	1.99	22,738	23,275	1,216	1,216
11	**2**	146.48	145	1.48	22,633	23,275	1,216	1,216
11	**3**	147.09	145	2.09	22,774	23,275	1,216	1,216
11	**4**	148.21	145	3.21	22,825	23,275	1,216	1,216
11	**5**	148.63	145	3.63	22,886	23,275	1,216	1,216
11	**6**	148.63	145	3.63	22,891	23,275	1,216	1,216
11	**7**	149.33	145	4.33	22,942	23,275	1,216	1,216
11	**8**	150.75	145	5.75	23,072	23,275	1,216	1,216
11	**9**	151.57	145	6.57	23,097	23,275	1,216	1,216
11	**10**	150.75	145	5.75	23,072	23,275	1,216	1,216
11	**11**	151.57	145	6.57	23,111	23,275	1,216	1,216
11	**12**	151.84	145	6.84	23,169	23,275	1,216	1,216
Average		**149.32**	**145.00**	**4.32**	**22,934**	**23,275**	**1,216**	**1,216**

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 10 was 22,148 MW, with a projected price of $41.42/MWh. The DACP scheduled 19 fossil-fired dispatchable generators online, with a total supply of 4,736 MW. No imports were scheduled. The day-ahead supply cushion was 26 percent.

Pre-dispatch Conditions

As Table 2-12 below shows, the forecast Ontario demand gradually increased from 22,148 MW day-ahead to 22,684 MW one hour head. The pre-dispatch price also increased from $41.21/MWh day-ahead to $146.48/MWh one-hour ahead. Both imports and exports decreased approaching real-time; but overall the net exports changed little between the 10 hour-ahead pre-dispatch and the one-hour ahead pre-dispatch.

Table 2-12: Pre-Dispatch Prices, Ontario Demand and Exports/Imports in Selected Hours Ahead
July 8, 2008, HE 10

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
19 (DACP)	41.42	22,148	0	0	0	
10	119.58	22,302	2,879	4,650	1,771	One baseload fossil unit removed from DACP 7 hours ahead
5	120.00	22,333	2,922	4,650	1,728	
4	113.92	22,325	2,899	4,640	1,741	
3	130.12	22,590	2,866	4,241	1,375	
2	125.00	22,609	2,357	3,743	1,386	
1	146.48	22,684	2,179	3,821	1,642	

The one-hour ahead forecast Ontario demand was 22,684 MW, with a price of $146.48/MWh. There were 2,179 MW of imports and 3,821 MW of exports being scheduled. The PD supply cushion was 9.2 percent. A fossil-fired unit was approved by the IESO 7 hours ahead of real-time to withdraw from the DACP commitment as there appeared to be no supply problems. All other fossil units that were scheduled in DACP were online and generating power above their respective DACP schedules.

Real-time Conditions

The real-time supply and demand conditions were similar to what had been expected in pre-dispatch. Before the RT run, 50 MW of imports failed on the New York interface for New York security. However, this was almost exactly offset by the RT Ontario demand coming in lighter than forecast in PD. The average demand in HE10 was 22,278 MW, with a peak demand of 22,629 MW (55 MW or 0.2 percent lighter than the one-hour ahead forecast). The RT supply cushion was 9.2 percent at the beginning of the hour.

In interval 7, a nuclear unit experienced a contingency and started to ramp down from its maximum output level of 815 MW. In response to this large generation outage, the IESO activated 500 MW of OR in interval 8, then a further 400 MW of OR in interval 9 and a further 200 MW in interval 11. The last 200 MW was activated to deal with a high negative ACE. [60] In interval 12, 500 MW of OR was deactivated and the rest was deactivated in HE 11 interval 1.

The activation of OR led to a corresponding reduction in the OR requirement. Under normal circumstances, a reduction in the OR requirements would cause a reduction in the MCP that would have otherwise signalled the extent of the change in the supply/demand balance. However, in the current case, the reduction in the OR requirement actually led to an increase in the energy price. Table 2-13 below lists the simulated MCP, the actual interval OR requirement and the unconstrained schedules of the nuclear unit that was forced out of service. Had the OR requirement not been reduced, the HOEP would have been $130.55/MWh, or 87.48/MWh lower than the “actual” HOEP. The reason for this is that had the OR requirement not been reduced, a few fossil-fired generators would have ramped up faster, which in turn would have been operating at a higher ramp rate when their output had reached a higher level. When the nuclear unit was suddenly removed from the market sequence, these fossil-fired units could have smoothed the price spike, leading to a lower HOEP for the hour. According to the simulation, with a full OR requirement, the MCP would have been higher in interval 8 and 9, as expected. However, the MCP in interval 10 to 12 would have been much lower because the few ramped-up fossil units could provide more energy to accommodate the sudden loss of the nuclear.

[60] It appeared that in this case the IESO may have over-reacted to the negative ACE situation when generators took time to ramp up for energy as a result of OR activation. In fact, 5 minutes later the ACE became +300 MW, and 10 minutes later +600MW. The IESO then had to manually dispatch down some hydro units to bring down the positive ACE.

Table 2-13: "Actual" and Simulated MCP, Actual OR Requirements and the Schedules of the Nuclear Unit, July 8, 2008, HE 10

Interval	"Actual" MCP ($/MWh)	Simulated MCP ($/MWh)	Actual OR Requirements (MW)	Unconstrained Schedule of the Nuclear Unit (MW)
1	50.04	50.04	1318	815
2	87.75	87.75	1318	815
3	90.48	90.48	1318	815
4	137.22	137.22	1318	815
5	120.43	120.43	1318	815
6	120.94	120.94	1318	815
7	141.03	141.03	1318	815
8	139.44	146.12	818	815
9	140.11	143.92	418	815
10	609.09	195.02	418	0
11	579.85	174.99	218	0
12	400.00	158.66	718	0
Average	**218.03**	**130.55**	**985**	**611**

Assessment

The loss of the nuclear unit (up to 815MW) in the latter half of the hour drove up the MCP to above $400/MWh in three intervals and the HOEP to above $200/MWh.

The price effect of the outage did not take place until interval 10 although the outage started in interval 7 and the unit was fully ramped down to 0 MW in interval 9.[61] The reason for this lag is that the unit's breaker was not opened until interval 10 before the station service was transferred off the unit. A nuclear station requires a large amount of power to maintain the nuclear units for reliable operation. The power supply can be either provided by own generation units when they are operating or the power grid. In the current case, the unit was providing power for the station and took some time to switch the service to other units or the power grid. Table 2-14 below shows the actual output (or consumption), and schedules in the constrained and unconstrained sequences for the unit.

[61] In interval 9, the unit was actually consuming power for station service, but the DSO scheduled 615MW in the constrained sequence and 815MW in the unconstrained sequence. As a result, the unit received $2,331 of constrained off payment. The unit was not paid a CMSC in interval 10 and 11 because the breaker was open at the time.

Because the breaker was still closed, the unconstrained sequence scheduled the full name plate capability on the unit in intervals 7 to 9 although the unit was actually ramping down (and was actually consuming but not generating power in intervals 9 through 12).

Table 2-14: The Nuclear Unit's Actual Output, Constrained and Unconstrained Schedules, July 8, 2008 HE10 (MW)

Delivery Hour	Interval	Actual Generation*	Constrained Schedule	Unconstrained Schedule
10	1	814	815	815
10	2	813	815	815
10	3	814	815	815
10	4	814	815	815
10	5	814	815	815
10	6	814	815	815
10	7	571	815	815
10	8	440	815	815
10	9	-25	615	815
10	10	-47	400	0
10	11	-46	340	0
10	12	-46	0	0

*negative indicates that the unit was consuming power for station service.

The overstatement of generating capability in the unconstrained schedule was a consequence of time delay in inputting outage slips to the dispatch tool. Normally, it takes about two intervals (10 minutes) for the generator to report and the IESO to verify an outage or derating and input outage slips to the dispatch tools. It is this time lag that leads the dispatch tool to continue to dispatch a generator beyond its capability in the unconstrained sequence even though the generator is actually ramping down.

2.1.5 July 16, 2008 HE 16

Prices and Demand

Table 2-15 below lists the summary information for HE 16 and 17. The high HOEP in HE 16 was the result of high MCPs in intervals 3 to 12, which in turn resulted from a 300

MW import failure in RT in addition to a 196 MW import that failed before RT. By HE17, the HOEP was close to the one-hour ahead PD price with supply and demand in RT close to the levels anticipated in the final pre-dispatch.

Table 2-15: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch
July 16, 2008 HE 16 and 17

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
16	**1**	165.22	168.79	-3.57	23,091	23,274	987	791
16	**2**	199.91	168.79	31.12	23,364	23,274	987	791
16	**3**	239.79	168.79	71.00	23,221	23,274	1,287	791
16	**4**	225.12	168.79	56.33	23,162	23,274	1,287	791
16	**5**	245.73	168.79	76.94	23,244	23,274	1,287	791
16	**6**	225.12	168.79	56.33	23,169	23,274	1,287	791
16	**7**	225.12	168.79	56.33	23,171	23,274	1,287	791
16	**8**	239.79	168.79	71.00	23,191	23,274	1,287	791
16	**9**	239.79	168.79	71.00	23,239	23,274	1,287	791
16	**10**	249.79	168.79	81.00	23,248	23,274	1,287	791
16	**11**	274.79	168.79	106.00	23,280	23,274	1,287	791
16	**12**	239.79	168.79	71.00	23,204	23,274	1,287	791
Average		**230.83**	**168.79**	**62.04**	**23,215**	**23,274**	**1,237**	**791**
17	**1**	175.11	164.52	10.59	23,238	23,028	779	779
17	**2**	175.11	164.52	10.59	23,223	23,028	779	779
17	**3**	175.11	164.52	10.59	23,284	23,028	779	779
17	**4**	175.11	164.52	10.59	23,321	23,028	779	779
17	**5**	185.11	164.52	20.59	23,347	23,028	779	779
17	**6**	175.11	164.52	10.59	23,291	23,028	779	779
17	**7**	175.11	164.52	10.59	23,306	23,028	779	779
17	**8**	175.11	164.52	10.59	23,320	23,028	779	779
17	**9**	175.11	164.52	10.59	23,350	23,028	779	779
17	**10**	167.87	164.52	3.35	23,253	23,028	779	779
17	**11**	165.11	164.52	0.59	23,228	23,028	779	779
18	**12**	164.94	164.52	0.42	23,198	23,028	779	779
Average		**173.66**	**164.52**	**9.14**	**23,280**	**23,028**	**779**	**779**

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 16 was 22,334 MW, with a projected price of $126.29/MWh. The DACP run scheduled 20 fossil-fired dispatchable generators online, with a total supply of about 5,200 MW. No imports were scheduled. The day-ahead supply cushion was 22 percent.

Pre-dispatch Conditions

As Table 2-16 below shows, although the forecast Ontario demand was gradually increasing from 22,757 MW 10 hours ahead to 23,274 MW 1 hour-ahead, the PD MCP changed little. Net exports dropped by almost half, from 1,466 MW 10 hours ahead to 791 MW one-hour ahead. A small fossil-fired generator was removed from the DACP schedule at the generator's request 15 hours ahead of real-time.

Table 2-16: Pre-Dispatch Prices, Ontario Demand and Exports/Imports for Selected Hours Ahead
July 16, 2008, HE 16

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Notable Events
25 (DACP)	126.29	22,334	0	0	0	
10	165.06	22,757	2,373	3,839	1,466	One fossil unit removed from DACP 15 hours ahead
5	162.01	22,817	2,343	4,089	1,746	
4	165.00	23,144	2,758	4,136	1,378	
3	158.87	23,052	3,068	4,139	1,071	
2	160.44	23,235	2,130	3,100	970	One fossil unit experiencing turbine problems
1	168.79	23,274	2,216	3,007	791	

The one-hour ahead forecast Ontario demand was 23,274 MW, with a projected price of $168.79/MWh. There were 2,216 of imports and 3,007 MW of exports being scheduled. All fossil units that were scheduled in DACP were online except one fossil unit, which was removed by the IESO from the DACP schedule at the request of the market participant concerned as there appeared to be no supply problems. The final PD supply cushion was 5.4 percent.

One fossil unit experienced turbine problems two hours ahead of real-time and started to shut down. The unit was scheduled at 430 MW in the final PD for HE 16.

Real-time Conditions

The fossil unit that experienced turbine problems was fully shut down before the real-time run.

At the same time, 196 MW of imports failed on the New York interface because these transactions failed to be scheduled in New York. [62] With the shutting down of the fossil unit and the loss of 196 MW imports, the DSO indicated a shortage in all reserve classes for HE 16 even with all CAOR being fully utilized. In response, the IESO cut 528 MW of exports to cover the OR shortfall. Because TLRi was used for the curtailment of these exports, these failed exports had no impact on the HOEP.

The RT Ontario demand was very close to the forecast in PD. The average demand in HE 16 was 23,215 MW, with a peak demand 23,364 MW (90 MW or 0.4 percent higher than forecast). The RT supply cushion at the beginning of the hour was -0.7 percent, indicating market resources were insufficient to meet the total demand for energy and OR, and that Control Action Operating Reserves (CAOR) were needed.

In interval 3, 300 MW of imports from New York were cut by NYISO for reliability in New York, which drove the MCP from $199.91/MWh in interval 2 to $239.79/MWh in interval 3. The MCP remained above $200.00/MWh in the rest of the intervals in HE 16.

Assessment

Supply and demand conditions were tight as indicated by the pre-dispatch supply cushion (5.4 percent) and a relatively high PD price ($168.79/MWh). The loss of a large fossil

[62] Another 251MW of linked wheeling transactions failed in HE 16 but had no impact on the MCPs or HOEP, because the import and export leg cancelled out each other.

unit (430 MW) and large import failures (up to 496MW) pushed the HOEP above $200/MWh.

Although the IESO curtailed exports for resource shortfall, this manual action did not suppress the HOEP because of the use of TLRi for these curtailments. The Panel has previously observed that the IESO's manual actions should not interfere with the market, which might lead to counter-intuitive prices at times when the market is actually tight. [63] The use of TLRi for export curtailments in the current situation met the bright line test and the actual HOEP did reflect the level of scarcity at the time.

2.1.6 July 19, 2008 HE 10

Prices and Demand

Table 2-17 below lists the summary information for HE 10 and 11. In HE 10, the forecast peak demand was 19,501 MW. The real-time demand came in at a level close to the forecast demand at the beginning of the hour, but then rapidly increased to 20,363 MW at the end of the hour, which was 863 MW (or 4.5 percent) greater than forecast. At the same time, the real-time MCP also increased from $93.35/MWh in interval 1 to $608.05/MWh in interval 12. It dropped sharply to $119.48/MWh in HE 11 interval 1 and stayed in the range of $120-135/MWh thereafter.

[63] The Panel's July 2008 Monitoring Report, pages 171-180.

Table 2-17: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch
July 19, 2008, HE 10 and 11

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
10	**1**	93.35	77.20	16.15	19,422	19,501	2,054	1,788
10	**2**	93.35	77.20	16.15	19,540	19,501	2,054	1,788
10	**3**	98.00	77.20	20.80	19,642	19,501	2,054	1,788
10	**4**	126.99	77.20	49.79	19,745	19,501	2,054	1,788
10	**5**	160.12	77.20	82.92	19,877	19,501	2,054	1,788
10	**6**	165.12	77.20	87.92	19,960	19,501	2,054	1,788
10	**7**	165.12	77.20	87.92	19,978	19,501	2,054	1,788
10	**8**	168.89	77.20	91.69	20,061	19,501	2,054	1,788
10	**9**	179.87	77.20	102.67	20,157	19,501	2,054	1,788
10	**10**	330.1	77.20	252.90	20,192	19,501	2,054	1,788
10	**11**	608.05	77.20	530.85	20,294	19,501	2,054	1,788
10	**12**	608.05	77.20	530.85	20,363	19,501	2,054	1,788
Average		**233.08**	**77.20**	**155.88**	**19,936**	**19,501**	**2,054**	**1,788**
11	**1**	119.48	98.00	21.48	20,437	20,498	1,502	1,354
11	**2**	120.89	98.00	22.89	20,404	20,498	1,502	1,354
11	**3**	122.30	98.00	24.30	20,452	20,498	1,502	1,354
11	**4**	125.12	98.00	27.12	20,528	20,498	1,502	1,354
11	**5**	126.53	98.00	28.53	20,587	20,498	1,502	1,354
11	**6**	127.94	98.00	29.94	20,627	20,498	1,502	1,354
11	**7**	130.35	98.00	32.35	20,654	20,498	1,502	1,354
11	**8**	132.17	98.00	34.17	20,709	20,498	1,502	1,354
11	**9**	134.99	98.00	36.99	20,760	20,498	1,502	1,354
11	**10**	133.58	98.00	35.58	20,728	20,498	1,502	1,354
11	**11**	137.80	98.00	39.80	20,822	20,498	1,502	1,354
11	**12**	134.99	98.00	36.99	20,790	20,498	1,502	1,354
Average		**128.85**	**98.00**	**30.85**	**20,625**	**20,498**	**1,502**	**1,354**

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 10 was 19,144 MW, with a projected price of $40.45/MWh. The DACP scheduled 16 fossil-fired dispatchable generators online (out of 26 units that were expected to be available for the day), with a total supply of about 3,600 MW. No imports were scheduled. The day-ahead supply cushion was 37 percent.

Pre-dispatch Conditions

As Table 2-18 below shows, the forecast Ontario demand gradually increased from 19,221 MW 10 hours ahead to 19,501 MW one hour head, and the pre-dispatch price increased from $68.79/MWh to $77.20/MWh during the same period. Both imports and exports increased gradually, with the net exports decreasing from 2,075 MW 10 hours ahead to 1,788 MW one-hour ahead.

Table 2-18: Pre-Dispatch Prices, Ontario Demand and Exports/Imports for Selected Hours Ahead
July 19, 2008, HE 10

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Notable Events
19 (DACP)	40.45	19,144	0	0	0	
10	68.79	19,221	2,258	4,333	2,075	
5	65.34	19,233	2,489	4,330	1,841	
4	67.25	19,231	2,587	4,480	1,893	
3	73.84	19,361	2,587	4,780	1,893	
2	74.20	19,328	2,797	4,785	1,988	
1	77.20	19,501	2,922	4,710	1,788	

The one-hour ahead forecast Ontario demand was 19,501 MW, with a projected price of $77.20/MWh. All fossil units that were scheduled in DACP were online. 2,922 MW of imports and 4,710 MW of exports were scheduled. The PD supply cushion was 9.6 percent.

Real-time Conditions

Before the RT run, 266 MW of imports failed, of which 200 MW failed on the Michigan interface because of ramp limitations in MISO and 66 MW failed on the New York interface because they were not scheduled in NYISO. Self-scheduling or intermittent generators were performing as expected, with output being over-projected by only 48 MW.

The RT Ontario demand rose quickly from 19,422 MW in interval 1 to 20,363 MW in interval 12 (a 4.8 percent increase within the hour, which was unusually high given that HE 10 is not a normal load pickup hour). The forecast peak demand for the hour was only 19,501 MW so that real-time peak demand was 863 MW or 4.5 percent greater than forecast. The real-time supply cushion was 7 percent at the beginning of the hour.

Assessment

The high price was caused by a significant under-forecast of demand (863 MW) combined with a 266 MW import failure.

The significant under-forecast of demand was primarily a result of weather forecast error by the IESO's weather data supplier. In HE 10, the actual temperature with humidity was 35ºC, or 3ºC above the forecast. The under-forecast of temperature led to an under-forecast of real-time demand of approximately 600 to 800 MW.

2.1.7 August 5, 2008 HE 10

Prices and Demand

Table 2-19 provides summary information for HE 10 and 11. In HE 10, the MCP increased rapidly from $90.56/MWh in interval 1 to $727.51/MWh in interval 12, as Ontario demand increased from 20,459 MW to 21,228 MW. The peak MCP in the hour was $727.52/MWh in interval 11. The MCP collapsed to slightly above $100/MWh in HE 11 interval 1 but rose above $200/MWh in later intervals. There was little in the way of import failures in either hour.

Table 2-19: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch August 5, 2008 HE 10 and 11

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD MCP) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
10	**1**	90.56	82.89	7.67	20,459	20,474	1,365	1,359
10	**2**	125.12	82.89	42.23	20,549	20,474	1,365	1,359
10	**3**	135.10	82.89	52.21	20,664	20,474	1,365	1,359
10	**4**	196.22	82.89	113.33	20,805	20,474	1,365	1,359
10	**5**	224.33	82.89	141.44	20,891	20,474	1,365	1,359
10	**6**	224.33	82.89	141.44	20,877	20,474	1,365	1,359
10	**7**	280.10	82.89	197.21	20,910	20,474	1,365	1,359
10	**8**	608.99	82.89	526.10	20,999	20,474	1,365	1,359
10	**9**	292.57	82.89	209.68	20,963	20,474	1,365	1,359
10	**10**	608.99	82.89	526.10	21,018	20,474	1,365	1,359
10	**11**	727.52	82.89	644.63	21,170	20,474	1,365	1,359
10	**12**	727.51	82.89	644.62	21,228	20,474	1,365	1,359
Average		**353.45**	**82.89**	**270.56**	**20,878**	**20,474**	**1,365**	**1,359**
11	**1**	105.64	100.00	5.64	21,318	21,135	743	731
11	**2**	106.46	100.00	6.46	21,341	21,135	743	731
11	**3**	104.82	100.00	4.82	21,278	21,135	743	731
11	**4**	110.48	100.00	10.48	21,330	21,135	743	731
11	**5**	108.09	100.00	8.09	21,364	21,135	743	731
11	**6**	115.48	100.00	15.48	21,472	21,135	743	731
11	**7**	110.48	100.00	10.48	21,459	21,135	743	731
11	**8**	115.48	100.00	15.48	21,538	21,135	743	731
11	**9**	115.48	100.00	15.48	21,608	21,135	743	731
11	**10**	224.32	100.00	124.32	21,618	21,135	743	731
11	**11**	224.32	100.00	124.32	21,654	21,135	743	731
11	**12**	224.32	100.00	124.32	21,700	21,135	743	731
Average		**138.78**	**100.00**	**38.78**	**21,473**	**21,135**	**743**	**731**

Day-Ahead Conditions

The total energy scheduled day-ahead for HE 10 during the DACP run was 20,672 MW. Of 28 fossil-fired units that were expected to be available for the day, 16 were scheduled for a combined supply of 4,100 MW. No imports/exports were scheduled in DACP. The day-ahead supply cushion was 32 percent for the hour.

Pre-dispatch Conditions

Table 2-20 illustrates the progressive change in forecast demand, projected price and scheduled imports/exports for HE 10. The forecast Ontario demand in DACP was the highest demand in the sequence of forecasts but was revised downward and by 10 hours ahead was 500 MW less than originally estimated. From 10 hours ahead to one-hour ahead, both forecast Ontario demand and the projected PD price gradually increased. Both scheduled imports and exports increased over the 10 hour period, with net exports in the 1,200 to 1,400 MW range. A baseload fossil unit, which was scheduled in DACP, was forced out of service due to a broken turning gear; all other generators that were scheduled in DACP were online.

Table 2-20: PD Price, Ontario Demand and Exports/imports, August 5, 2008, HE 10

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
19 (DACP)	43.09	20,672	0	0	0	
10	69.25	20,182	496	1,937	1,441	
5	77.62	20,283	564	1,932	1,368	
4	80.00	20,430	718	1,932	1,214	
3	84.12	20,431	881	2,257	1,376	A 165 MW fossil unit forced out of service
2	82.50	20,364	1,211	2,634	1,423	
1	82.89	20,474	1,298	2,606	1,308	

The one-hour ahead supply cushion was 7.5 percent. There were about 1,100 MW being offered between $83/MWh and $730/MWh.

Real-time Conditions

Before the RT run, 50 MW of imports failed due to ramp limitations in Michigan. [64] At the same time, 44 MW of exports failed on the New York interface because of not being scheduled in New York. Net import failures were only 6 MW for HE10. This had a negligible effect on the HOEP.

[64] There were 100 MW of imports failure in the constrained sequence. Because one 50 MW transaction was a constrained on import, which did not show up in the unconstrained sequence, the unconstrained sequence had only 50 MW of failed imports.

The forecast peak demand for the hour was 20,474 MW. The RT Ontario demand rose quickly from 20,459 MW in interval 1 to 21,228 MW in interval 12, which was 754 MW or 3.7 percent greater than forecast. The significant under-forecast of demand was mainly a consequence of an under-forecast of the temperature by the IESO's weather data supplier. The temperature in HE 10 was 1 ºC higher and the illumination level was 60 klux greater,[65] which together led to demand being 350~700 MW higher than forecast.[66] The real-time supply cushion was 5 percent at the beginning of the hour.

In interval 4, the IESO received a request from New York to supply 96 MW of Shared Activation of Reserve (SAR). The IESO immediately activated 96 MW of OR, but at the same time observed that the ACE was -300 MW. To restore the ACE, the IESO further activated 204 MW of OR, leading to a total of 300 MW OR being activated. The activation of OR resulted in 300 MW reduction in the OR requirements (from 1,318 MW to 1,018 MW). In interval 5, 150 MW of OR was deactivated and the total OR requirement was increased to 1,268 MW. The remaining 150 MW of OR activation was deactivated in interval 6 and the full OR requirement was restored. As the Panel has pointed out in various prior reports, the reduction in the OR for ACE deviations can result in counter-intuitive prices.[67] The activation of OR for external markets/jurisdictions warrants a further discussion, and we will address this issue in the assessment section.

Self-scheduling or intermittent generators were producing less in RT than they projected one-hour ahead. In HE 10, these generators produced 237 MW less than they offered in pre-dispatch. Of this 237 MW, 193 MW was from a new gas-fired generator which was on commissioning tests. The generator was forced out of service because of problems with de-mineralized water.

[65] The illumination level reflects the cloudiness: the higher the level, the clearer the sky. The highest level is 120 klux. Lux is a unit of measure of the amount of visible light per square meter incident on a surface: 1 lux = 1 lumen/square meter = 0.093 foot-candles, a very small number. Klux=1000 lux. Electrical demand increases in the summer with increased illumination due primarily to the air-conditioning load.

[66] The power demand has a strong relationship with the (dry bulb) temperature as the Panel showed in its first report. The relationship between the power demand and the illumination level is not so obvious, and conditional on many other factors such as temperature and humidex.

[67] For example, the Panel's July 2008 Monitoring Report, pages 192-203.

Assessment

The price spike was a combined result of a significant under-forecast of Ontario demand and the under-performance of self-scheduling generators.

In past reports the Panel has observed that during large outage situations the IESO may request SAR from external markets and this SAR activation is essentially taken as free energy at the time when it is activated. As a consequence, the HOEP is artificially suppressed and does not reflect the shortage conditions. The Panel's has recommended these emergency supplies should not affect the HOEP.[68]

In the current situation, however, the IESO was exporting energy to meet its SAR commitment. Because total demand is the total output measured at all generation units (plus net intertie schedules), this energy production for SAR was counted as a part of internal demand. In other words, the HOEP was higher than the actual internal demand alone would have reflected. [69]

Table 2-21 below provides SAR statistics from January 1, 2007 to August 20, 2008. In the period, the IESO received SAR 17 times from external markets, but provided SAR 48 times. Total MW is the sum of MW that was activated in these events. The total MW that the IESO received and supplied were almost the same, with the average magnitude per event of received SAR much greater than the average per event for SAR provided. The reason for such differences is that, when the IESO receives SAR, the magnitude of SAR is typically half of the contingency (such as a loss of one Darlington or Nanticoke unit),[70] while when providing SAR the IESO is one of several markets that combined provide half of the loss from the external contingency. This also explains why there are fewer incidents when the IESO needs SAR support for its contingencies, versus when it provides SAR for a contingency in one of several other markets.

[68] The Panel's December 2006 Monitoring Report, pages 73-76.
[69] In addition to importing or exporting SAR, the charge for losses is also affected. In the case of exporting SAR, because loss, which is the difference between generation and consumption, includes the SAR exports, consumers (and exporters) pay a higher uplift as well as a higher HOEP. In contrast, in the case of importing SAR, consumers (and exporters) pay a lower HOEP and a lower (and even a negative) charge for losses.
[70] The other half is provided internally.

Table 2-21: Shared Activation Reserves (SAR) Statistics January 2007 to August 20, 2008

	Received	Supplied
Number of SAR	17	48
Total MW	6,072	6,140
Average MW/event	357	128
Duration (intervals)	76	120
Average duration (intervals)	4	2
MWh	2,669	1,238

The above table also shows the average duration of receiving SAR is 4 intervals, in contrast to 2 intervals of providing SAR. When the IESO received SAR with an average duration of 4 intervals or about 20 minutes per event, the energy received was 2,669MWh in the 20 month period. The energy for SAR exports was 1,238 MWh, which is less than half of the SAR imports.

When SAR is received, the IESO generally has serious supply problems which, coupled with the relatively large magnitude, implies these activations would be expected to have had a large impact on the HOEP. In contrast, when the IESO provides SAR, the amount is usually small, the duration is generally short and there is usually no systematic supply issue in Ontario at the time, so the price impact would be expected to be much smaller.

2.1.8 August 24, 2008 HE 14

Prices and Demand

Table 2-22 lists the real-time and pre-dispatch information for HE 13 and 14. The real-time MCP in HE 13 was about $100/MWh, roughly $30/MWh higher than the pre-dispatch price. The high real-time price in HE 13 was associated with a higher real-time demand than forecast one-hour ahead (on average the RT demand was 274 MW greater than the PD forecast).

In HE 14, although the one-hour ahead forecast price was only $46.99/MWh, the real-time MCP jumped to above $600/MWH in the first five intervals and then gradually decreased to about $120/MWh later in the hour. The HOEP for HE 14 was $377.14/MWh a sharp contrast to the projected $46.99/MWh in pre-dispatch.

Table 2-22: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch August 24, 2008 HE 13 and 14

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD MCP) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
13	**1**	102.20	74.00	28.20	19,163	18,906	1,298	1,298
13	**2**	102.20	74.00	28.20	19,175	18,906	1,298	1,298
13	**3**	98.36	74.00	24.36	19,120	18,906	1,298	1,298
13	**4**	93.88	74.00	19.88	19,063	18,906	1,298	1,298
13	**5**	102.20	74.00	28.20	19,214	18,906	1,298	1,298
13	**6**	102.20	74.00	28.20	19,208	18,906	1,298	1,298
13	**7**	102.20	74.00	28.20	19,214	18,906	1,298	1,298
13	**8**	102.20	74.00	28.20	19,204	18,906	1,298	1,298
13	**9**	102.20	74.00	28.20	19,211	18,906	1,298	1,298
13	**10**	102.20	74.00	28.20	19,246	18,906	1,298	1,298
13	**11**	112.20	74.00	38.20	19,254	18,906	1,298	1,298
13	**12**	98.28	74.00	24.28	19,091	18,906	1,298	1,298
Average		**101.69**	**74.00**	**27.69**	**19,180**	**18,906**	**1,298**	**1,298**
14	**1**	608.99	46.99	562.00	19,206	18,140	1,825	1,925
14	**2**	608.99	46.99	562.00	19,249	18,140	1,825	1,925
14	**3**	608.99	46.99	562.00	19,245	18,140	1,825	1,925
14	**4**	608.99	46.99	562.00	19,230	18,140	1,825	1,925
14	**5**	608.05	46.99	561.06	19,232	18,140	1,825	1,925
14	**6**	534.28	46.99	487.29	19,318	18,140	1,825	1,925
14	**7**	280.00	46.99	233.01	19,363	18,140	1,825	1,925
14	**8**	152.12	46.99	105.13	19,382	18,140	1,825	1,925
14	**9**	122.20	46.99	75.21	19,390	18,140	1,825	1,925
14	**10**	157.00	46.99	110.01	19,425	18,140	1,825	1,925
14	**11**	113.89	46.99	66.90	19,326	18,140	1,825	1,925
11	**12**	122.20	46.99	75.21	19,339	18,140	1,825	1,925
Average		**377.14**	**46.99**	**330.15**	**19,309**	**18,140**	**1,825**	**1,925**

Day-Ahead Conditions

The total MW scheduled day-ahead for HE 14 via the DACP run was 18,198 MW. 16 fossil-fired units, out of 26 fossil-fired units that were expected to be available for the day, were scheduled for a combined supply of 2,200 MW. No imports/exports were scheduled in DACP. The day-ahead supply cushion was 44 percent.

Pre-dispatch Conditions

Table 2-23 illustrates the progressive change in forecast demand, projected prices and scheduled imports/exports for HE14. Although the DACP demand forecast was only 18,198 MW, the demand forecast between 10 hours ahead and two hours ahead was increased by the IESO to around 19,000 MW. The two hours ahead forecast of Ontario demand of 19,047 MW was the highest forecast, leading to a projected price of $73.00/MWh. However, the one-hour ahead forecast demand suddenly dropped to 18,140 MW (or by 907 MW), with a low PD price of $46.99/MWh. This low one-hour ahead Ontario demand in turn led to more exports being scheduled. The one-hour ahead supply cushion was 14.3 percent.

The DACP schedules for three fossil units were removed at the request of their owners and approved by the IESO as there appeared to be no reliability problems. These withdrawals occurred well ahead of HE 14 as illustrated in Table 2-23 below.

Table 2-23: PD Price, Ontario Demand and Exports/imports, August 24, 2008, HE 14

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
23 (DACP)	37.94	18,198	0	0	0	
10	50.01	18,949	303	1,284	981	Two fossil units removed from DACP
5	49.40	18,903	303	1,302	999	another fossil unit removed from DACP
4	55.03	18,996	265	1,332	1,067	
3	70.45	18,842	265	1,782	1,517	
2	73.00	19,047	337	1,890	1,553	
1	46.99	18,140	265	2,190	1,925	

Real-time Conditions

Before the RT run, 100 MW of exports failed on the Michigan interface due to a missing NERC tag in MISO. The effect of this failure would be to reduce the HOEP relative to the pre-dispatch price.

The RT Ontario demand came in at 19,206 MW in interval 1, which was 1,066 MW (or 5.9 percent) greater than the one-hour ahead forecast. The real-time supply cushion was 2.0 percent at the beginning of the hour. The real-time interval demand was relatively stable within the hour, with a peak of 19,425 MW in interval 10.

Assessment

Except for the 100 MW export failure, there were no generation outages or import failures between the final one-hour ahead pre-dispatch and real-time. It appears that the factors that drove the HOEP above $200/MWh were the significant under-forecast of demand and a significant increase (527 MW) in net exports relative to the previous hour partially due to the under-forecast of demand in pre-dispatch.

The real-time demand was trending heavier than expected starting from HE 8, and the IESO adjusted the demand forecast for HE 8 to 24 several time across the day. The forecast demand for HE 14 was very accurate from 16 hours ahead up to two hours ahead. However, the one-hour ahead demand was suddenly reduced by 907 MW right before the final PD run, even though the real-time demand continued increasing. The abrupt adjustment in demand forecast may have been an incorrect forecast adjustment by the IESO.

The significant under-forecast of demand had the effect of scheduling slightly fewer imports and considerably more exports. Assuming that the intended one-hour pre-dispatch demand was 19,140 MW instead of 18,140 MW,[71] the MAU ran the pre-dispatch simulator and found that there would have been 1 MW more imports and 450 MW fewer exports (all affected exports were on the New York interface). Under this assumption, the HOEP would have been $98.75/MWh, in contrast to the “actual” HOEP of $376.49/MWh. As showed in Table 2-24.

Table 2-24: Actual and Simulated One-hour ahead Pre-dispatch Results August 24, 2008 HE 14

	Demand Forecast (MW)	PD MCP ($/MWh)	Imports (MW)	Exports (MW)	HOEP ($/MWh)
“Actual”	18,140	46.99	265	2,190	376.49
Assume 1,000 MW more in PD demand	19,140	78.05	266	1,740	98.75
Difference	1,000	31.06	1	-450	-277.74

The estimated efficiency loss due to a 1,000 MW under-forecast of demand amounted to $36,000.[72] The efficiency loss is a result of higher cost generators being scheduled in Ontario to displace lower cost generators in New York.

[71] The IESO forecasts the hourly average demand, and then estimates the hourly peak demand based on a linear function. Because it is difficult to uncover what was the actual demand that IESO had intended to input, we assume the intended forecast peak demand could be 19,140 MW, or a 1,000 MW increase on the two hour ahead forecast. This number is close to 907 MW which the IESO had reduced.

[72] We calculated the efficiency loss for those overscheduled exports because the import was only under-scheduled by 1MW from Quebec, for which the cost is difficult to approximate as there is no market there. The efficiency loss is the extra generation cost ($74,000 in the unconstrained sequence for the 450 MW of exports that would not have been scheduled minus the avoided generation cost in New York (which is approximated as the real-time New York price, $83.46/MWh, times 450 MW).

2.1.9 September 2, 2008 HE 17

Prices and Demand

Table 2-25 lists the real-time and pre-dispatch information for HE 17. The real-time MCP in interval 1 to 9 in HE 17 was about $10-50/MWh higher than the pre-dispatch price, but jumped sharply to above $700/MWh in interval 10. The MCP returned to $200/MWh in the last interval of the hour.

Table 2-25: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch September 2, 2008 HE 17

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Diff (RT-PD MCP) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
17	**1**	124.61	115.02	9.59	22,695	22,203	322	358
17	**2**	131.51	115.02	16.49	22,631	22,203	322	358
17	**3**	155.00	115.02	39.98	22,664	22,203	322	358
17	**4**	147.99	115.02	32.97	22,642	22,203	322	358
17	**5**	154.67	115.02	39.65	22,650	22,203	322	358
17	**6**	147.99	115.02	32.97	22,648	22,203	322	358
17	**7**	155.00	115.02	39.98	22,624	22,203	322	358
17	**8**	163.97	115.02	48.95	22,648	22,203	322	358
17	**9**	154.67	115.02	39.65	22,620	22,203	322	358
17	**10**	702.48	115.02	587.46	22,663	22,203	322	358
17	**11**	330.09	115.02	215.07	22,613	22,203	322	358
17	**12**	200.05	115.02	85.03	22,617	22,203	322	358
Average		**214.00**	**115.02**	**98.98**	**22,643**	**22,203**	**322**	**358**

Day-Ahead Conditions

The total demand forecast day-ahead during the final DACP run was 21,657 MW in HE 17. 18 fossil-fired units, out of 21 fossil-fired units that were expected to be available for the day, were scheduled under the DACP for a total of 5,200 MW. With no imports/exports scheduled in DACP, the day-ahead supply cushion for HE 17 was 20 percent.

Pre-dispatch Conditions

Table 2-26 illustrates the progressive change in forecast demand, projected price and scheduled imports/exports for HE17. Although the DACP demand forecast was only 21,657 MW, it was adjusted upward to about 22,200 MW in all pre-dispatch sequences from 10 hours ahead onwards. The final one-hour ahead pre-dispatch price was $115.02/MWh, with 358 MW of net exports.

The DACP schedule for a fossil unit was removed at the request of the owner and approved by the IESO as there appeared to be no reliability problems. In HE 14 interval 11, a market participant informed the IESO that they had only two hours of water left in one of their hydro stations.

Table 2-26: Pre-Dispatch Prices, Ontario Demand and Exports/Imports for Selected Hours Ahead
September 2, 2008, HE 17

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
26 (DACP)	98.33	21,657	0	0	0	
10	98.00	22,320	1,364	1,295	-69	One 500 MW fossil unit removed from DACP
5	100.46	22,245	1,101	1,495	394	
4	101.00	22,343	1,153	1,395	242	
3	101.95	22,242	1,201	1,395	194	
2	115.01	22,165	1,326	1,719	393	A MP notified that two hours water left in one station
1	115.02	22,203	1,337	1,695	358	

The one-hour ahead supply cushion was 10.3 percent.

Real-time Conditions

Before the HE 17 real-time DSO run, 47 MW exports failed on the Quebec interface due to lost load in Quebec. At the same time, there were 11 MW of imports from New York that failed because they were not scheduled in New York. Everything else being equal, the 36 MW net export failure should have reduced the HOEP relative to the pre-dispatch price.

The Ontario demand came in at 22,695 MW in interval 1, which was 492 MW (or 2.2 percent) greater than the one-hour ahead forecast. The real-time supply cushion was 5.9 percent at the beginning of the hour. The real-time interval demand was very stable within the hour, with a high 22,695 in interval 1 and a low 22,613 MW in interval 11.

In interval 3, a market participant informed the IESO that a few units at a hydro station needed to be derated to 0 MW as a result of low water levels. The derating led to a loss of 270 MW in baseload generation from interval 3 on.

In interval 9, the same market participant indicated that five units at another hydro station needed to be derated to 0 MW because of low water levels. This derating together with the 270 MW noted above led to a loss 730 MW baseload generation from interval 10 onwards.

Self-scheduling and intermittent generators produced 87 MW less than expected, putting an additional upward pressure on the HOEP.

Assessment

As illustrated above, there are three factors that had contributed to the price spike in HE 17: (1) 492 MW of demand under-forecast; (2) 730 MW of derating at two hydro stations; and (3) 87 MW of underperformance by self-scheduling and intermittent generators. The combination of these events drove the MCP from $154.67/MWh in interval 9 to $702.48/MWh in interval 10.

It is the Panel's view that the derating at the hydro station could have been avoided had the generator properly offered the available energy. The generator called the IESO three hours ahead, indicating that they had only two hours water left in one of its hydro station, which is jointly operated with other stations that were subsequently derated. Presumably the generator also noticed the lower forebay at the complex, but it did not take actions to revise its offers to reflect the actual water availability and thus to avoid the real-time derating. The Compliance Unit at the IESO is currently investigating the event.

The derating in real-time led to an efficiency loss to the market as economic imports that could have been scheduled were not scheduled and some inefficient exports that should not have been scheduled were scheduled. To estimate the potential impact on the market, we assumed that the market participant had offered those units at their derated level one-hour ahead. The simulation results are listed in Table 2-27 below. The pre-dispatch would have scheduled 39 MW more imports from New York and 208 MW fewer exports (of which 108 MW to Michigan and 100 MW to New York). The HOEP would have been $169.71/MWh or $47.73/MWh (or 72 percent) lower.

Table 2-27: Comparison of "Actual"* and Simulated Results September 2, 2008 HE17

	PD MCP ($/MWh)	Imports (MW)	Exports (MW)	HOEP ($/MWh)
"Actual"	115.02	1,337	1,695	217.44
Simulated	125.20	1,376	1,487	169.71
Difference	10.18	39	208	-47.73
% Difference	9	3	12	-22

* "Actual" is our simulated base case which mimics the unconstrained sequence.

The efficiency loss is estimated at $20,000.[73] The efficiency loss is a result of higher cost generators being scheduled in Ontario which effectively displaced lower cost generators in New York and Michigan.

2.1.10 September 14, 2008 HE 11 to 13 and HE 19

Prices and Demand

[73] The efficiency loss is the extra generation cost ($42,000) for the 247MW (208 MW + 39 MW) net exports minus the avoided generation cost in New York (which is approximated as the real-time price in New York, $139.75/MWh, times 61MW of net exports) and the avoided generation cost in Michigan (the real-time price in Michigan Hub, $124.98/MWh, times 108 MW of exports).

Table 2-28 lists the HOEP, pre-dispatch prices, and demand for the high-priced hours as well as one hour before and after the event. The HOEP was well above $200.00/MWh in HE 11, 12, 13 and 19. HE 19 had the highest HOEP of $435.00/MWh in this study period.

Associated with the high HOEP in these fours hours was either a RT demand being significantly greater than the forecast (e.g. HE 11) or large amount of net import failures (e.g. HE 12, 13 and 19).

Table 2-28: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch
September 14, 2008, HE 10 to 14 and HE 18 to 20

Delivery Hour	HOEP	PD MCP ($/MWh)	Diff (HOEP - PD) ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)	Net Import Failure (MW)
10	111.20	49.12	62.08	17,220	17,033	1,766	1,603	163
11	279.43	75.00	204.43	18,150	17,592	1,473	1,398	75
12	331.15	99.95	231.20	18,571	18,406	1,187	860	327
13	344.93	100.00	244.93	18,900	18,798	965	634	331
14	167.55	135.11	32.44	19,088	19,297	665	265	400
18	131.77	87.14	44.63	19,690	19,314	875	325	550
19	435.00	97.36	337.64	19,629	19,564	565	175	390
20	156.37	490.61	-334.24	19,323	19,882	234	414	-180

Day-Ahead Conditions

As indicated in Table 2-29, the MCPs at the final DACP run were all below $20/MWh for HE 11 to 13 and $37.75/MWh for HE 19. The DACP prices are not unusual given that it was a Sunday (with typically low Ontario demand) and exports are not scheduled in DACP. The total demand forecast day-ahead was between 17,000 MW to 18,000 MW for the hours of interest. Twelve fossil-fired units, out of 23 fossil-fired units that were expected to be available for HE 11 to 13, were scheduled for a total of 1,200 MW. Two additional gas-fired units were scheduled online for HE 19, resulting in total scheduled output of 2,800 MW from 14 units for HE 19. No imports/exports were scheduled in

DACP. The day-ahead supply cushion was 45 to 48 percent for HE 11 to 13 and 36 percent for HE 19.

Table 2-29: Day-ahead Price, Demand, and Supply Cushion September 14, 2008 HE 11, 12, 13 and 19

Hour	MCP ($/MWh)	Ontario Demand (MW)	Supply Cushion (%)
11	17.07	17,022	48
12	10.00	17,149	47
13	4.70	17,347	45
19	37.75	17,949	36

Pre-dispatch Conditions

Table 2-30 below depicts the changes in pre-dispatch prices, demand forecast, and net exports following the DACP run. Forecast Ontario demand increased as real-time was approached, with particularly large increases from two to one-hour ahead for HE 12 and 19 (by 600 MW and 500 MW, respectively). For HE 11-13, the pre-dispatch price increased from less than $20/MWh day-ahead to $75-100/MWh one-hour ahead. For HE 19 the pre-dispatch price was relatively stable around $100/MWh from 10 hours to one-hour ahead.

Table 2-30: Pre-dispatch Prices, Ontario Demand and Net Exports for Selected Hours Ahead September 14, 2008, HE 11, 12, 13 and 19

	11			12			13			19		
Hours Ahead	MCP ($MWh)	Ontario Demand (MW)	Net Export (MW)	MCP ($MWh)	Ontario Demand (MW)	Net Export (MW)	MCP ($MWh)	Ontario Demand (MW)	Net Export (MW)	MCP ($MWh)	Ontario Demand (MW)	Net Export (MW)
DACP	17.07	17,022	0	10.00	17,149	0	4.70	17,347	0	37.75	17,949	0
10	40.87	17,140	1,239	41.18	17,276	1,539	41.71	17,517	1,539	100.00	18,112	546
5	45.00	17,658	1,217	54.85	17,863	1,429	74.00	18,148	1,108	99.00	18,839	552
4	42.52	17,661	1,162	74.00	17,965	1,084	78.00	18,009	1,147	100.01	19,121	543
3	54.83	17,765	1,073	78.00	17,841	1,168	78.00	17,955	1,256	99.00	19,083	421
2	75.00	17,639	1,364	82.00	17,794	1,326	95.32	18,569	825	95.20	19,061	264
1	75.00	17,592	1,398	99.95	18,406	860	100.00	18,798	634	97.36	19,564	175

The NISL was binding for HE 19 as a result of 550 MW of net import failure in HE 18 (when a number of traders in the MISO were unable to obtain transmission services, or had submitted export bids to MISO without an associated NERC tag). The binding NISL led to a 99 MW export on the New York interface being scheduled even though it was bid below the pre-dispatch price in the NY zone and a 11 MW import not being scheduled on the Michigan interface even though it was offered below the pre-dispatch price in the MISO zone. The out-of-merit scheduling in the New York zone directly led to a congestion price in the zone ($120.61/MWh in the New York zone vs. $97.36/MWh in the Ontario zone).

The one-hour ahead supply cushion ranged from 12 to 16 percent for these hours.

Real-time Conditions

HE 11

Before the RT run, 75 MW imports failed on the Michigan interface due to being unable to obtain the MISO transmission service.

The RT Ontario demand came in at 18,150 MW, with a peak demand of 18,386 MW, or 794 MW (or 4.5 percent) greater than the one-hour ahead forecast. The real-time supply cushion was 9.2 percent at the beginning of the hour.

A nuclear unit came into service from an outage, but the unit was slow to ramp up. It was scheduled to produce 156 MW in pre-dispatch, but was able to generate only 90 MW in real-time.

Self-scheduling and intermittent generators produced 125 MW less than expected, of which 90 MW was from wind generators. The 125 MW under-generation put an additional upward pressure on the HOEP.

HE 12

Before the RT run, 575 MW imports failed, of which 325 MW failed on the Michigan interface due to the ramping limitation in MISO and 150 MW on the New York interface because they were not economic and thus not scheduled in New York. At the same time 200 MW exports to New York failed because of not being scheduled in New York. The net import failure for HE 12 amounted to 375 MW.

The Ontario demand came in at 18,429 MW in interval 1, with a real-time supply cushion at 2.5 percent. The average demand in the hour was 18,571 MW, with a peak demand of 18,715 MW, or 309 MW (or 1.7 percent) greater than the one-hour ahead forecast.

Self-scheduling and intermittent generators produced 173 MW less than expected, of which 120 MW was from wind generators. Given the tight supply cushion at the beginning of the hour, the 173 MW under-generation put a significant additional upward pressure on the HOEP.

HE 13

Before the RT run, 481 MW of imports failed on the Michigan interface due to internal congestion in MISO. At the same time a 150 MW export to New York failed because it was not scheduled in New York. The net import failure for HE 12 was 331 MW.

The RT Ontario demand came in at 18,900 MW, with a peak demand of 18,956 MW, which was only 158 MW (or 0.8 percent) greater than the one-hour ahead forecast. The real-time supply cushion was 2.7 percent at the beginning of the hour.

Self-scheduling and intermittent generators produced 243 MW less than expected, of which 179 MW was from wind generators.

HE 19

Before the RT run, 989 MW imports failed on the Michigan interface due to the ramp limitation in MISO. At the same time a 50 MW export to New York failed because it was not scheduled in New York.

A fossil-fired unit was forced out of service 17 minutes before HE 19, because of flooding in a switchyard in the area (caused by Hurricane 'Ike'), representing a loss of 480 MW of baseload generation.

The RT Ontario demand came in at 19,629 MW, with a peak demand of 19,788 MW, which was 224 MW (or 1.2 percent) greater than the one-hour ahead forecast. The real-time supply cushion was 0.7 percent at the beginning of the hour.

In responding to the large import failure on the Michigan interface and the forced outage of the fossil-fired generator, the IESO curtailed 600 MW of exports from interval 4 onwards and then a further 199 MW for adequacy (by using the code 'ADQh').

Self-scheduling and intermittent generators produced 121 MW more than expected even though a wind generator produced 40 MW less than its forecast. The 121 MW over generation helped mitigate the RT price spike.

HE 20

HE 20 was not a high-price hour but warrants a detailed analysis.

The real-time demand came in at 19,323 MW, with a peak demand of 19,602 MW, 280 MW (1.4 percent) lower than forecast one-hour ahead.

About 30 minutes before real-time, 450 MW of imports from MISO failed due to ramp limitation in MISO. At the same time, 230 MW of exports failed either due to a missing

NERC tag or security concerns in external markets. The net import failure was 220 MW, leading to resource inadequacy in Ontario. In response, the IESO cut 400 MW of exports for adequacy. The net export failure in the hour was 180 MW.

The HOEP in HE 20 dropped to $156.37/MWh, well below the HOEP in HE 19. The main reasons for the decrease were that the peak demand was 280 MW over-forecast and net export failure amounted to 180 MW.

Assessment

The high prices in these hours were due to demand under-forecasts, import failures, forced generation outages, or a combination of these factors.

The price in HE 19 and 20 was suppressed by the use of ‘ADQh’ for export curtailment. As the Panel stated in previous reports, the IESO should consider not reducing exports in the market schedule when the code ‘ADQh’ is used. [74] By using the code of ‘ADQh”, the IESO essentially overrode the value that exporters put on those exports and effectively administered the price. Had the IESO not removed the curtailed exports from the unconstrained sequence, the HOEP would have been $1,652.82/MWh for HE 19 and $443.48/MWh for HE 20, as shown in the simulation in Table 2-31 below. Such prices would have reflected the tight supply/demand conditions that prevailed during these two hours.

[74] The Panel’s July 2008 Monitoring Report, pages 171-180.

**Table 2-31: "Actual"* and Simulated MCP
September 14, 2008, HE 19 and 20**

		"Actual" MCP ($/MWh)	Simulated MCP ($/MWh)	Curtailed Export for Adequacy (MW)
19	**1**	638.73	638.73	0
19	**2**	664.99	664.99	0
19	**3**	530.09	530.09	0
19	**4**	228.10	1,999.99	600
19	**5**	535.51	2,000.00	600
19	**6**	664.99	2,000.00	600
19	**7**	571.89	2,000.00	799
19	**8**	212.55	2,000.00	799
19	**9**	228.10	2,000.00	799
19	**10**	212.55	2,000.00	799
19	**11**	212.55	2,000.00	799
19	**12**	535.51	2,000.00	799
Average		**436.30**	**1,652.82**	**550**
20	**1**	212.45	691.89	400
20	**2**	212.45	654.65	400
20	**3**	202.30	654.65	400
20	**4**	194.93	571.89	400
20	**5**	130.05	490.61	400
20	**6**	195.14	616.94	400
20	**7**	154.68	564.61	400
20	**8**	130.04	291.05	400
20	**9**	123.59	212.55	400
20	**10**	123.59	212.55	400
20	**11**	109.00	195.59	400
20	**12**	97.50	164.77	400
Average		**157.14**	**443.48**	**400**

* "Actual" is the base case simulation that mimics the unconstrained sequence.

2.1.11 October 8, 2008 HE 17

Prices and Demand

Table 2-32 lists the real-time and final pre-dispatch information for HE 16 to 18. The real-time MCP increased sharply from $135.38/MWh in HE 16 interval 12 to $272.22/MWh in HE 17 interval 1 and then stayed above $200/MWh in most intervals that hour. The MCP in HE 17 was between $135 and $423/MWh higher than that projected in pre-dispatch. The MCP dropped to $85.69/MWh in HE 18 interval 1. There were few failed net exports in these hours, but the real-time Ontario demand in HE 16 and 17 was significantly greater than forecast. Peak demand in HE 16 was 18,396 MW in real-time compared with 17,710 MW in pre-dispatch (3.9 percent higher), while the peak demand in HE 17 was 18,565 MW in real-time compared with 17,841 MW in pre-dispatch (4.1 percent higher).

Table 2-32: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch October 8, 2008 HE 16 to 18

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Difference ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
16	1	88.59	67.77	20.82	18,068	17,710	274	254
16	2	88.59	67.77	20.82	18,079	17,710	274	254
16	3	88.59	67.77	20.82	18,085	17,710	274	254
16	4	105.21	67.77	37.44	18,211	17,710	274	254
16	5	94.60	67.77	26.83	18,180	17,710	274	254
16	6	94.60	67.77	26.83	18,168	17,710	274	254
16	7	95.44	67.77	27.67	18,250	17,710	274	254
16	8	95.54	67.77	27.77	18,272	17,710	274	254
16	9	106.80	67.77	39.03	18,355	17,710	274	254
16	10	106.80	67.77	39.03	18,364	17,710	274	254
16	11	106.79	67.77	39.02	18,341	17,710	274	254
16	12	135.38	67.77	67.61	18,396	17,710	274	254
Average		**100.58**	**67.77**	**32.81**	**18,231**	**17,710**	**274**	**254**
17	1	272.22	57.00	215.22	18,458	17,841	443	443
17	2	250.00	57.00	193.00	18,477	17,841	443	443
17	3	272.22	57.00	215.22	18,493	17,841	443	443
17	4	192.50	57.00	135.50	18,478	17,841	443	443
17	5	272.22	57.00	215.22	18,496	17,841	443	443
17	6	480.12	57.00	423.12	18,561	17,841	443	443
17	7	226.78	57.00	169.78	18,505	17,841	443	443
17	8	192.50	57.00	135.50	18,499	17,841	443	443
17	9	348.35	57.00	291.35	18,556	17,841	443	443
17	10	348.35	57.00	291.35	18,565	17,841	443	443
17	11	226.79	57.00	169.79	18,531	17,841	443	443
17	12	192.51	57.00	135.51	18,525	17,841	443	443
Average		**272.88**	**57.00**	**215.88**	**18,512**	**17,841**	**443**	**443**
18	1	85.69	74.94	10.75	18,532	18,423	102	22
18	2	85.82	74.94	10.88	18,552	18,423	102	22
18	3	51.47	74.94	-23.47	18,378	18,423	102	22
18	4	50.61	74.94	-24.33	18,536	18,423	-166	22
18	5	51.08	74.94	-23.86	18,507	18,423	-166	22

Delivery Hour	Interval	RT MCP ($/MWh)	PD MCP ($/MWh)	Difference ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	RT Net Exports (MW)	PD Net Exports (MW)
18	**6**	82.54	74.94	7.60	18,601	18,423	-166	22
18	**7**	85.70	74.94	10.76	18,700	18,423	-166	22
18	**8**	84.30	74.94	9.36	18,687	18,423	-166	22
18	**9**	89.19	74.94	14.25	18,788	18,423	-166	22
18	**10**	120.65	74.94	45.71	18,719	18,423	52	22
18	**11**	181.09	74.94	106.15	18,891	18,423	52	22
18	**12**	104.14	74.94	29.20	18,666	18,423	52	22
Average		**89.36**	**74.94**	**14.42**	**18,630**	**18,423**	**-63**	**22**

Day-Ahead Conditions

The DACP run failed because of software problems. The day-ahead supply cushion for HE 17 was 33 percent based on generation offers and demand forecast.

Pre-dispatch Conditions

Table 2-33 illustrates the progressive change in forecast demand, projected price and scheduled imports/exports for HE 17. The forecast demand varied only slightly in the range of 17,831 to 17,891 MW from 10 hours ahead to one-hour ahead. The highest pre-dispatch price was only $67.81/MWh, which occurred four hours ahead. The final one-hour ahead pre-dispatch price was $57.00/MWh, with 443 MW of net exports.

Table 2-33: PD Price, Ontario Demand and Exports/imports
October 8, 2008, HE 17

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
10	56.75	17,835	1,115	1,603	488	
5	56.00	17,831	1,059	1,630	571	
4	67.81	17,853	1,205	1,603	398	
3	62.00	17,851	1,053	1,546	493	
2	57.00	17,891	1,174	1,496	322	
1	57.00	17,841	1,053	1,496	443	

The hour-ahead supply cushion was 13.0 percent.

Real-time Conditions

The average RT Ontario demand came in at 18,512 MW, with a peak of 18,565 in interval 10, which was 724 MW (or 4.1 percent) greater than the one-hour ahead forecast. The real-time supply cushion was 1.2 percent at the beginning of the hour, indicating a very tight demand/supply condition. The real-time interval demand was relatively flat within the hour, with a high of 18,565 MW in interval 10 and a low of 18,458 MW in interval 1.

Self-scheduling and intermittent generators produced 82 MW less than expected, putting an additional upward pressure on the HOEP.

There were no generation outages within the hour.

Assessment

Demand under-forecasting and self-scheduling and intermittent generators under-producing contributed to the price spike.

Of interest is the consequence of the IESO's coding practice for intertie failure in HE 18.

The MCP in HE 18 fell below $100/MWh in the first nine intervals, which was largely due to demand forecast error being significantly reduced as well as failed net exports in the unconstrained sequence. The failed net exports in the unconstrained sequence were induced by failed imports in the constrained sequence as a consequence of the use of the code TLRe. The IESO's practice of dealing with intertie failure is to set the unconstrained schedule equal to the actual constrained schedule when a transaction has an associated code of TLRe (as well as MrNh, OTH, ORA).[75] Thus when a constrained on import fails partially, it may appear to be an increase in imports in the unconstrained schedule. For example, in pre-dispatch a 100 MW import is scheduled in the constrained

[75] For a detailed discussion, see the Panel's July 2008 Monitoring Report, page 171-190.

sequence but 0 MW in the unconstrained sequence. If the import fails 10 MW in real-time for TLRe (in other words, the actual schedule is 90 MW in the constrained sequence in real-time), 90 MW will show up in the unconstrained sequence, leading to a 90 MW increase in imports in the unconstrained sequence in real-time.

The transaction failure in HE 18 was slightly different from what typically has happened before. The problem in this hour was the way the IESO codes those imports that failed in some intervals but not in others. Table 2-34 below lists the five failed transactions that were assigned a TLRe code: one on the Quebec interface and the other four on the Michigan interface. We combined the four transactions on the Michigan interface into one for illustration simplicity.

Before RT, a 189 MW import on the Quebec interface was failed by 89 MW due to reliability concerns in Quebec. This import had been constrained on, with 0 MW in the unconstrained sequence. Due to the use of TLRe, the RT unconstrained schedule was set to equal the actual (after failure) constrained schedule of 100 MW in RT. As a result, import schedules were increased by 100 MW compared to the PD schedule in the unconstrained sequence, which had the effect of suppressing the HOEP.

At the same time, due to reliability concerns in the MISO, four imports were partially curtailed in the first three and last three intervals. (Note, in MISO imports and exports are dispatched every 15 minutes.) These four imports flowed at the full amount in intervals 4 to 9 only. Due to the use of TLRe for the whole hour, there appeared to be an increase in imports of 138 MW in the unconstrained sequence in the middle of the hour although there was no transaction failed in the constrained sequence. This increase in imports in the unconstrained sequence suppressed the MCP in those intervals.

Table 2-34: Failed Imports on the Quebec and Michigan Interfaces October 8, 2008, HE 18

Hour	Interval	Quebec (one import)						Michigan (four imports)					
		Constrained			Unconstrained			Constrained			Unconstrained		
		PD	RT	Failure	PD	RT	Failure	PD	RT	Failure	PD	RT	Failure
18	**1**	189	100	89	0	100	-100	318	50	268	180	50	130
18	**2**	189	100	89	0	100	-100	318	50	268	180	50	130
18	**3**	189	100	89	0	100	-100	318	50	268	180	50	130
18	**4**	189	100	89	0	100	-100	318	318	0	180	318	-138
18	**5**	189	100	89	0	100	-100	318	318	0	180	318	-138
18	**6**	189	100	89	0	100	-100	318	318	0	180	318	-138
18	**7**	189	100	89	0	100	-100	318	318	0	180	318	-138
18	**8**	189	100	89	0	100	-100	318	318	0	180	318	-138
18	**9**	189	100	89	0	100	-100	318	318	0	180	318	-138
18	**10**	189	100	89	0	100	-100	318	100	218	180	100	80
18	**11**	189	100	89	0	100	-100	318	100	218	180	100	80
18	**12**	189	100	89	0	100	-100	318	100	218	180	100	80

To the Panel, this event highlights the feasibility of 15 minute dispatching of intertie trades in Ontario. The Panel, in its December 2008 report, observed that a 15 minute dispatch of intertie trades can improve market efficiency and system reliability by enhancing responsiveness of imports and exports. By separating an hour into four quarters, an hourly offer/bid essentially becomes four separated transactions.

In the current example, each of the four transactions on the Michigan interface should be considered as four separate transactions: one for each 15 minute interval. In essence, even though a transaction is conducted by one participant, it is four products because its is scheduled for four blocks of time within the hour. Correspondingly, the code associated with the hourly offer should be different for each 15 minute period, based of the different dispatch situations. For example, in the intervals when the three transactions on the Michigan interface failed partially, a TLRe should be used, while in intervals when they flowed in the full amount, the original code (which is assigned in PD) rather than TRLe should be used. In so doing, there would have been no increase in imports in the unconstrained sequence in interval 4 to 9 as there was no failure in the constrained sequence.

Recommendation 2-2

The Panel recommends that when an intertie trade fails in some intervals while not in others within the hour, the IESO should apply a failure code only for those intervals with the failure.

2.1.12 October 24, 2008, HE19

Prices and Demand

Table 2-35 lists the real-time and pre-dispatch information for HE 18 and 19. The real-time MCP in HE 18 sharply increased from $124.11/MWh in interval 11 to $239.78/MWh in interval 12. The real-time peak demand (18,134 MW in interval 12) was only slightly under-forecast. There were 178 MW of failed net imports in HE 18. The HOEP was below $200/MWh this hour.

Table 2-35: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch
October 24, 2008 HE 18 and 19

Delivery Hour	Interval	RT MCP	PD MCP	Diff (RT-PD)	RT Ontario Demand	PD Ontario Demand	RT Net Exports	PD Net Exports
18	**1**	85.11	75.00	10.11	17,656	18,102	528	350
18	**2**	85.11	75.00	10.11	17,639	18,102	528	350
18	**3**	92.35	75.00	17.35	17,727	18,102	528	350
18	**4**	97.30	75.00	22.30	17,858	18,102	528	350
18	**5**	99.77	75.00	24.77	17,912	18,102	528	350
18	**6**	105.00	75.00	30.00	17,945	18,102	528	350
18	**7**	113.66	75.00	38.66	17,994	18,102	528	350
18	**8**	169.01	75.00	94.01	18,063	18,102	528	350
18	**9**	122.62	75.00	47.62	18,039	18,102	528	350
18	**10**	170.16	75.00	95.16	18,074	18,102	528	350
18	**11**	124.11	75.00	49.11	18,018	18,102	528	350
18	**12**	239.78	75.00	164.78	18,134	18,102	528	350
Average		**125.33**	**75.00**	**50.33**	**17,922**	**18,102**	**528**	**350**
19	**1**	311.45	69.00	242.45	18,063	17,888	1,038	901
19	**2**	311.44	69.00	242.44	18,035	17,888	1,038	901
19	**3**	295.78	69.00	226.78	17,953	17,888	1,038	901
19	**4**	298.19	69.00	229.19	17,954	17,888	1,038	901
19	**5**	298.19	69.00	229.19	17,954	17,888	1,038	901
19	**6**	194.45	69.00	125.45	17,858	17,888	1,038	901
19	**7**	245.94	69.00	176.94	17,948	17,888	1,038	901
19	**8**	190.84	69.00	121.84	17,836	17,888	1,038	901
19	**9**	204.90	69.00	135.90	17,880	17,888	1,038	901
19	**10**	135.24	69.00	66.24	17,726	17,888	1,038	901
19	**11**	172.47	69.00	103.47	17,747	17,888	1,038	901
19	**12**	171.32	69.00	102.32	17,736	17,888	1,038	901
Average		**235.85**	**69.00**	**166.85**	**17,891**	**17,888**	**1,038**	**901**

In HE 19, the MCP reached $311.45/MWh in the first interval and gradually decreased to $171.32/MWh in the last interval. The MCP in all intervals was well above the PD projected price. The real-time peak demand (18,063 MW in interval 1) was 175 MW greater than the PD forecast. There were 137 MW of failed net imports in the hour. RT net exports increased by 510 MW from HE 18 to HE 19.

Day-Ahead Conditions

The total energy scheduled day-ahead during the final day-ahead commitment process (DACP) run was 17,994 MW for HE 19. Seventeen fossil-fired units, out of 25 fossil-fired units that were expected to be available for the day, were scheduled for a combined supply of 2,100 MW. With no imports/exports scheduled in DACP, the day-ahead supply cushion for HE 19 was 35 percent.

Pre-dispatch Conditions

Table 2-36 illustrates the progressive change in forecast demand, projected price and scheduled imports/exports for HE 19. The forecast demand was very stable in all pre-dispatch runs. The highest pre-dispatch price was only $87.00/MWh, which occurred three hours ahead. The final one-hour ahead pre-dispatch price was $69.00/MWh, with 901 MW of net exports.

A nuclear unit with 880 MW of capacity was forced out of service due to a transmission problem four hours ahead of real-time. Because it was a transmission related problem, the unit was not removed from the unconstrained pre-dispatch sequence and was scheduled to the full capacity in all pre-dispatch sequences. However, because the transmission was unavailable, the unit was dispatched to zero in all constrained pre-dispatch sequences. [76]

[76] Pre-dispatch sequences do not check the breaker status of generation units. To remove a unit in pre-dispatch, the IESO must have an outage slip from the generator. In the current case, the problem was associated with the transmission service, not the generator itself. Thus the generator did not submit an outage slip.

Table 2-36: PD Price, Ontario Demand and Exports/imports October 24, 2008, HE 19

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
DACP (28)	33.72	17,994	0	0	0	
10	85.00	17,923	986	2,099	1113	
5	79.00	17,955	1,033	2,046	1016	
4	84.40	17,915	1,046	2,281	1235	Transmission problems with a 880 MW nuclear unit
3	87.00	17,899	1,094	2,081	987	
2	69.00	17,895	555	1,441	886	
1	69.00	17,888	540	1,441	901	

The one-hour ahead supply cushion was 8.0 percent.

The total OR requirement for the hour (and all hours from HE 5 to 24) was increased to 2,159 MW from a normal 1,318 MW to reflect the fact that the largest single contingency was the loss of two Bruce units rather than a single Darlington unit due to the switching configuration in the switchyard. [77] The increase in the OR requirement put upward pressure on OR prices as well as the HOEP because they are jointly optimized.

Real-time Conditions

Before real-time, 137 MW of imports failed, of which 69 MW failed on the Michigan interface due to the ramp limitation in MISO and 68 MW failed on the New York interface because it was not scheduled in New York.

A coal-fired generator was in the process of shutting down for a planned outage, and was derated to 100 MW in order to burn the coal that was stored in bunker before the planned outage. The unit was scheduled at 200 MW in PD.

[77] The IESO's practice is that the total OR requirement is the largest single contingency plus half of the second largest contingency. The total 10 minute OR is the largest single contingency, of which the 10 minute spinning OR is about 25 percent.

The average RT Ontario demand in HE 19 came in at 17,891 MW, with a peak of 18,063 MW in interval 1, which was 175 MW (or 0.9 percent) greater than the one-hour ahead forecast. The real-time supply cushion was -1.7 percent at the beginning of the hour, indicating a very tight demand/supply condition and required CAOR to balance the demand and supply.

Self-scheduling and intermittent generators produced 47 MW more than expected, slightly offsetting the upward pressure of the forced outages at the nuclear unit and the derating at the coal-fired unit and failed imports on the HOEP.

Assessment

The most important factor contributing to the price spike was the forced outage of a nuclear unit as a result of a transmission problem. Failed imports, a demand under-forecast and the derating of a coal-fired unit also contributed to the price spike.

In our last two Monitoring Reports, [78] the Panel observed the inconsistent treatment of transmission and generation outages in the unconstrained sequence: the generation supply is not reduced in the case of a transmission outage affecting hydroelectric plant, but is reduced in the case of a generation outage. In the case of a transmission outage, the IESO's DSO removes the affected generators from the constrained sequence but not from the unconstrained sequence, resulting in fictitious conditions being assumed in the uniform pricing regime.

In the case at hand, however, the transmission outage resulted in the breaker of the nuclear unit being open. With the breaker open, the IESO's real-time (not the pre-dispatch) sequence immediately recognized the outage and removed the generator from the market schedule.[79] As a result, the HOEP did reflect supply conditions, leading to a HOEP of $235.85/MWh. In contrast, the PD unconstrained sequence, which ignores

[78] The Panel's December 2006 report, pages 73-76, and the December 2007 report, pages 89-95.
[79] The RT unconstrained sequence also recognizes the open breaker in this situation.

breaker status, continued to schedule the generator for 880 MW, leading to a PD price of $69.00/MWh.

There are efficiency losses in the current case because the unconstrained PD sequence, which ignores breaker status, kept misleading market participants that the HOEP would be low, thus inducing inefficient exports and/or losing efficient imports in the unconstrained sequence, where HOEP (as well as the Richview shadow price) were actually going to be high. However, it is an uncommon case that such a large generator is affected by transmission limitations.

The Panel considered whether a simple correction to this problem was achievable by modifying the PD unconstrained sequence to take breaker status into account. However, the Panel understands that the change to the PD unconstrained sequence could require significant resources, and would have some adverse side effects. Much of the time, ignoring an open breaker status in PD is appropriate since a unit may be in the process of getting ready to synchronize and will have its breaker open until it does. Thus a modification to the tool could be costly and induce incorrect results far more often than correcting for this rarer problem of transmission impacting generator status.

2.1.13 October 27, 2008, HE 8

Prices and Demand

Table 2-37 lists the real-time and pre-dispatch information for HE 8 and 9. The real-time MCP increased sharply in HE 8 from $138.55/MWh in interval 1 to $689.14/MWh in interval 10. The HOEP reached $294.56/MWh, in a sharp contrast to the final PD projected price of $60.01/MWh. The peak real-time demand was 17,874 MW in interval 10, which is 628 MW (or 3.6 percent) greater than the final PD forecast demand. There was no intertie transaction failure in HE 8.

In HE 9, the MCP fell to about $80/MWh, but still approximately $21/MWh greater than the final PD price. The peak demand was 17,996 MW in interval 11, which is 230 MW

(1.3 percent) greater than the PD forecast demand. Net export failures amounted to 120 MW.

Table 2-37: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch October 27, 2008 HE 8 and 9

Delivery Hour	Interval	RT MCP	PD MCP	Diff (RT-PD)	RT Ontario Demand	PD Ontario Demand	RT Net Exports	PD Net Exports
8	**1**	138.55	60.01	78.54	17,698	17,246	1,899	1,899
8	**2**	183.56	60.01	123.55	17,745	17,246	1,899	1,899
8	**3**	182.01	60.01	122.00	17,736	17,246	1,899	1,899
8	**4**	267.52	60.01	207.51	17,818	17,246	1,899	1,899
8	**5**	257.78	60.01	197.77	17,806	17,246	1,899	1,899
8	**6**	229.91	60.01	169.90	17,784	17,246	1,899	1,899
8	**7**	267.40	60.01	207.39	17,764	17,246	1,899	1,899
8	**8**	267.52	60.01	207.51	17,757	17,246	1,899	1,899
8	**9**	307.68	60.01	247.67	17,797	17,246	1,899	1,899
8	**10**	689.14	60.01	629.13	17,874	17,246	1,899	1,899
8	**11**	335.96	60.01	275.95	17,791	17,246	1,899	1,899
8	**12**	407.69	60.01	347.68	17,808	17,246	1,899	1,899
Average		**294.56**	**60.01**	**234.55**	**17,782**	**17,246**	**1,899**	**1,899**
9	**1**	85.90	58.05	27.85	17,883	17,766	1,354	1,474
9	**2**	79.70	58.05	21.65	17,834	17,766	1,354	1,474
9	**3**	75.79	58.05	17.74	17,829	17,766	1,354	1,474
9	**4**	75.79	58.05	17.74	17,851	17,766	1,354	1,474
9	**5**	77.23	58.05	19.18	17,900	17,766	1,354	1,474
9	**6**	79.92	58.05	21.87	17,911	17,766	1,354	1,474
9	**7**	79.92	58.05	21.87	17,924	17,766	1,354	1,474
9	**8**	79.92	58.05	21.87	17,901	17,766	1,354	1,474
9	**9**	79.92	58.05	21.87	17,897	17,766	1,354	1,474
9	**10**	79.92	58.05	21.87	17,890	17,766	1,354	1,474
9	**11**	81.68	58.05	23.63	17,996	17,766	1,354	1,474
9	**12**	79.92	58.05	21.87	17,956	17,766	1,354	1,474
Average		**79.63**	**58.05**	**21.58**	**17,898**	**17,766**	**1,354**	**1,474**

Day-Ahead Conditions

The total energy scheduled day-ahead during the DACP run was 17,291 MW for HE 8. Thirteen fossil-fired units, out of 24 fossil-fired units that were expected to be available for the day, were scheduled for a combined supply of 1,800 MW. With no imports/exports scheduled in DACP, the day-ahead supply cushion for HE 8 was 41 percent.

Pre-dispatch Conditions

The total OR requirement was 1,510 MW for HE 1 to 18, which is almost 200 MW greater than the normally required 1,318 MW. The increased requirement reflected the largest single contingency being two Pickering units and the second largest contingency being a large gas-fired generator. Everything being equal, the increase in the OR requirement put upward pressure on the PD and RT prices (as well as OR prices).

Table 2-38 illustrates the progressive change in forecast demand, projected price and scheduled imports/exports for HE 8. The forecast demand was essentially the same in all pre-dispatch runs. The final one-hour ahead pre-dispatch price was $60.01/MWh, with 1,899 MW of net exports. The one-hour ahead supply cushion was 5.5 percent.

Table 2-38: PD Price, Ontario Demand and Exports/imports October 27, 2008, HE 8

Hours Ahead	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Main Events
DACP (17)	35.59	17,291	0	0	0	
10	49.90	17,263	225	1,513	1,288	
5	46.45	17,306	302	1,563	1,261	
4	46.88	17,308	277	1,613	1,336	
3	49.62	17,311	277	1,888	1,611	
2	60.01	17,337	277	2,190	1,913	
1	60.01	17,246	277	2,176	1,899	

Real-time Conditions

Before RT, a steam-turbine driven unit in a combined cycle plant declared a delay to its start because two other units which supply steam to it were having problems. The delayed unit was scheduled to 90 MW in PD. In interval 6, the two units that were supposed to supply steam were also derated by 30 MW in total because of thermal stresses.

One coal-fired unit was derated by up to 50 MW just before RT due to fuel transportation problems. A similar problem caused two more units to be derated by 155 MW in total in the middle of the hour.

In total, the lost supply in the later intervals of the hour amounted to 325 MW.

The average RT Ontario demand came in at 17,782 MW, with a peak of 17,874 MW in interval 10, which was 628 MW (or 3.6 percent) greater than the one-hour ahead forecast. The real-time supply cushion was -0.4 percent at the beginning of the hour, indicating a very tight demand/supply condition and requiring CAOR to be scheduled to balance demand and supply.

Self-scheduling and intermittent generators produced 125 MW less than expected, putting additional upward pressure on the HOEP. Almost all these deviations were from wind generators.

Assessment

It appears that the spike in HOEP in HE 8 was largely a consequence of an under-forecast of demand and the derating or start-up delay of a few fossil-fired generators. The production deviation of wind generators also put upward pressure on the HOEP.

When the demand forecast error was largely eliminated in HE 9, the HOEP fell below $80/MWh, but was still about $20/MWh higher than the PD price. A 120 MW export had failed on the New York interface as a result of not being scheduled in the NYISO, which put downward pressure on the HOEP. However, this downward pressure was almost totally offset by the under-performance of self-scheduling and intermittent generators (especially wind-power generators) which generated 125 MW less than projected.

2.2 Analysis of Low Price hours

Table 2-39 shows that the total number of hours with a low HOEP has been increasing period over period since 2004, with the 2008 summer experiencing a much higher number of events. The increase in the number of low priced hours is consistent with the improving supply and demand conditions over the past years. The significantly high number of low priced hours in 2008 was largely a consequence of a sizable increase in baseload hydro production as well as a reduction in the Ontario demand due to cool weather, as illustrated in Chapter 1.

Table 2-39: Number of Hours with a Low HOEP
May - October, 2004 – 2008

	Number of Hours with HOEP < $20/MWh				
	2004	**2005**	**2006**	**2007**	**2008**
May	70	11	17	115	193
June	84	25	14	67	87
July	70	4	30	57	144
August	75	3	4	11	126
September	15	0	63	45	90
October	0	9	21	36	84
Total	314	52	149	331	724
% Change	n/a	-83	187	122	119

The primary factors generally leading to a low HOEP are:

- Low market demand: This typically occurs in the overnight hours, on holidays or during the spring and fall seasons. The low market demand may be due to a combination of low Ontario demand and low net export volume. The latter might be due to low external demand or reduced export capability because of high loop-flows.
- Abundant baseload supply from hydro-electric generators: This occurs most frequently during the spring-time months of April and May when even peaking hydroelectric plants have abundant water from spring snow melt and increased rainfall, but it can occur at other times.

While these are the primary factors that contribute to a HOEP less than $20/MWh, other factors may also be at play:

- Demand over-forecast: This can lead to over-scheduling imports in pre-dispatch, putting a downward pressure on the HOEP as in RT these exports are essentially repriced at -$2,000/MWh by the DSO.
- Dispatching resources based on-peak demand in pre-dispatch: Even when the peak demand is accurately forecast, a low HOEP can also result because of the lower demand in other intervals. The flat import schedule over the hour, which was economic for the peak demand, may not be economic in other intervals, thus driving HOEP down.
- Failed export transactions: These can place downward pressure on the HOEP. Increased wind generation: The volume of wind generation has been increasing in the past two years, as demonstrated in Chapter 1. Because these generators are price-takers and typically produce more in off-peak hours, a low off-peak price is more likely to result, everything else being equal.

Table 2-40 below summarises the average monthly data on low priced hours by month for the period May through October 2008. *Demand Deviation* is the difference between the pre-dispatch demand (which is the forecast peak demand) and the real-time average demand. This can be a result of forecast errors or simply the difference between the peak and the average demand within the hour. It appears that net export failure played an important role in leading to a low HOEP in May and June, while the demand deviation dominated the effect in later months

Table 2-40: Average Monthly Summary Data for Low-priced Hours May - October 2008

	Number of Low-Priced Hours	Failed Net Exports (MW)	RT Average Demand (MW)	Pre-dispatch Demand (MW)	Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT - Pre-dispatch) ($/MWh)
May	193	180	13,096	13,289	-193	6.84	18.33	-11.48
June	87	130	13,360	13,642	-282	8.11	24.69	-16.58
July	144	52	14,140	14,461	-321	7.22	17.66	-10.44
August	126	66	13,582	13,834	-252	7.35	20.17	-12.82
September	90	52	13,219	13,425	-206	7.65	22.16	-14.52
October	84	44	13,129	13,334	-205	9.85	27.70	-17.85
Total / Average	724	97	13,439	13,681	-242	7.61	20.84	-13.23

2.2.1 Negative Prices

Table 2-41 below lists the monthly total number of hours with a negative HOEP for the summer periods from 2004 to 2008. There were 30 hours with a negative HOEP in the past five summers, of which 28 hours occurred in the 2008 summer alone. The lowest HOEP since the beginning of the market was -$14.59/MWh, which occurred on July 6, 2008 HE 6. We analyze the low-priced hours on that day in subsection 2.2.2.

Table 2-41: Number of Hours with a Negative HOEP May - October, 2004 – 2008

	Number of Hours with HOEP < $0/MWh				
	2004	**2005**	**2006**	**2007**	**2008**
May	0	0	0	0	6
June	0	0	0	0	0
July	0	0	0	0	16
August	0	0	0	0	4
September	0	0	1	1	0
October	0	0	0	0	2
Total	0	0	1	1	28

The MAU’s review of these low priced hours between May and October 2008 indicates that they were mainly a result of low Ontario demand in combination with failed exports and over-forecasts of demand. When real-time demand is low, baseload generation may be sufficient to meet it, leading to very low prices.

Table 2-42 below lists the summary information for the 28 hours with a negative HOEP in the period May to October 2008. Failed net exports and demand under-forecast appear to have equally impacted the HOEP. Table A-53 in the Statistical Appendix has detailed hourly statistics on these hours.

Table 2-42: Average Monthly Summary Data for Negative-priced Hours May - October 2008*

	Number of Negative-Priced Hours	Failed Net Exports (MW)	RT Average Demand (MW)	Pre-dispatch Demand (MW)	Demand Difference (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT-Pre-dispatch) ($/MWh)
May	6	428	12,969	13,159	-190	-4.57	8.66	-13.23
July	16	103	12,963	13,195	-231	-8.23	-3.07	-5.16
August	4	280	12,799	12,854	-54	-1.92	2.37	-4.28
October	2	50	11,626	11,817	-191	-6.02	2.05	-8.07
Total / Average	28	194	12,846	13,040	-194	-6.00	0.58	-6.97

*there was no negative HOEP in June and Sep.

2.2.2 July 6, 2008 HE 1 to 7

The HOEP was negative in seven consecutive hours from HE 1 to 7 on the day. The lowest HOEP since the market opening was -$14.59/MWh, which occurred in HE 6.

Prices and Demand

Table 2-43 below depicts the real-time and pre-dispatch summary information for July 6, 2008, HE 1 to 7. For five of these hours, the negative HOEP's were predicted by the one-hour ahead pre-dispatch price, even though the pre-dispatch uses the forecast peak demand.

Table 2-43: MCP, Ontario Demand and Net Exports, Real-time and Final Pre-dispatch July 6, 2008, HE 1 to 7

Delivery Hour	HOEP	PD MCP ($/MWh)	RT Ontario Demand (MW)	PD Ontario Demand (MW)	Demand Deviation (MW)	RT Net Exports (MW)	PD Net Exports (MW)	Net Export Failure (MW)
1	-6.4	1.40	13,323	13,517	194	1,604	1,671	67
2	-10.92	-1.01	12,786	13,131	345	1,707	1,749	42
3	-11.27	-10.68	12,488	12,641	153	2,030	2,055	25
4	-13.03	-10.87	12,264	12,433	169	1,995	2,112	117
5	-12.68	-10.78	12,141	12,346	205	2,270	2,312	42
6	-14.59	-10.78	12,162	12,553	391	1,965	2,115	150
7	-10.67	0.00	12,932	13,428	496	1,945	1,935	-10

Day-ahead Conditions

As shown in Table 2-44,the day-ahead forecast Ontario demand was below 13,000 MW in most of the hours, with a negative price below -$30.00/MWh in all hours. The extremely low DACP price (below -$30/MWh) was mainly a consequence of the exclusion of exports in the DACP run. The DACP run scheduled only four fossil-fired dispatchable generators online in these hours, all being scheduled at their respective minimum level with a total supply of 240MW. These units were offered at a very low price for their minimum level so that they could stay online overnight for ramping up the next morning. The supply cushion was around 100 percent, indicating the large amount of spare generation that was expected to be available for these hours in real-time.

Table 2-44: Day-Ahead Prices, Demand and Supply Cushions July 6, 2008, HE 1 to 7

Hour	MCP ($/MWh)	Ontario Demand (MW)	Supply Cushion (%)
1	-33.00	13,446	96
2	-35.00	12,988	102
3	-39.00	12,461	107
4	-39.00	12,433	110
5	-53.00	12,295	112
6	-53.00	12,518	109
7	-37.00	13,379	96

Pre-dispatch Conditions

Table 2-45 below lists the pre-dispatch prices. Except HE 1 and 7, the negative HOEP was largely predicted several hours ahead, indicating there might be too much baseload supply to meet the total demand (Ontario demand plus net exports) in the coming hours.

Table 2-45: Pre-dispatch Prices, July 6, 2008, HE 1 - 7

Hours Ahead	Delivery Hour						
	1	2	3	4	5	6	7
DACP	-33	-35	-39	-39	-53	-53	-37
5	0	-9.72	-9.81	-10.68	-10.78	-10	0
4	-0.28	0	-10.18	-10.49	-10.49	-10	1.01
3	3.1	-5	-10	-10	-10.18	-10	1.01
2	1.01	-5	-10.49	-10.87	-10.87	-10.68	2.4
1	1.4	-1.01	-10.68	-10.87	-10.78	-10.78	0
HOEP	-6.4	-10.92	-11.27	-13.03	-12.68	-14.59	-10.67

In fact, starting from HE 23 of the previous day, July 5, 2008, the Ontario market was already experiencing Excess Baseload Generation (EBG),[80] and the IESO sequentially constrained down several hydro generators. Table 2-46 lists the constrained off generation (including baseload hydro and nuclear generation) each hour. The table also shows, somewhat surprisingly, constrained on imports and constrained off exports in these hours which were partially the consequence of IESO's control action of constraining down internal generation in pre-dispatch. It can be seen that the IESO's manual action led to as much as 1,399 MW of constrained off generation in HE 7, and correspondingly 200 MW of constrained on imports and 578 MW of constrained off exports, both of which were the largest of the day.

[80] An EBG event is defined as an event "when the amount of baseload generation (which may largely consist of a supply mix of high minimum load fossil, nuclear and run-of-the-river hydroelectric resources) exceeds the market demand." (The IESO Procedure 2.4-2: Responding to Market and System Events, Section 7, Respond to Excess Baseload Generation Events)

Table 2-46: Constrained off Generation for EBG, and Constrained on Imports and Constrained off Exports in Pre-dispatch, July 6, 2008

Hour	Constrained off Baseload Generation for EBG	Constrained on Imports	Constrainedoff Exports
1	190	-27	300
2	750	86	425
3	443	50	300
4	810	150	347
5	1,147	50	475
6	1,158	170	334
7	1,399	200	578
8	n/a	44	118
9	n/a	-156	55
10	n/a	-263	96
11	n/a	-82	44
12	n/a	-12	51
13	n/a	-68	108
14	n/a	-65	-62
15	n/a	-263	-200
16	n/a	-47	208
17	n/a	-47	95
18	n/a	-154	44
19	n/a	-108	177
20	n/a	-118	-40
21	n/a	-298	63
22	n/a	-237	-59
23	n/a	-384	191
24	n/a	-263	187

Another important factor that contributed to the negative price is that the maximum net export capacity on the New York interface was reduced by the IESO to 1,000MW, which was about half the normal export capability. This reduction was made to account for the firm clockwise Lake Eire Circulation, which varied from 400 to 1,000MW in the morning hours. The IESO’s practice is to determine the expected amount of firm loopflow (i.e. induced by firm transactions) based on information from the NERC Interchange Distribution Calculator (IDC) and then correspondingly adjusts the import/export capability on an interface ahead of real-time.

Real-time Conditions

Table 2-47 depicts real-time and pre-dispatch Ontario demand. Real-time peak Ontario demand came in slightly lighter than expected in most hours except HE 1, in which the peak demand was slightly greater than forecast. The peak demand for HE 6 was over-forecast by 197 MW (or 1.6 percent), which was the largest forecast error in these hours. Real-time demand kept ramping down in HE 1 to 5 and then up in HE 6 and 7, with HE 7 having the greatest increase in demand within an hour which is reflected by the 425 MW of difference between the real-time peak and the average demand.

Table 2-47: Real-time and Pre-dispatch Demand July 6, 2008, HE 1 to 7

Delivery Hour	RT Peak Ontario Demand (MW)	PD Ontario Demand (MW)	Forecast Error (PD – RT Peak) (MW)	RT Average demand (MW)	RT Peak - Average Demand (MW)
1	13,546	13,517	-29	13,323	223
2	13,010	13,131	121	12,786	224
3	12,616	12,641	25	12,488	128
4	12,352	12,433	81	12,264	88
5	12,291	12,346	55	12,141	150
6	12,356	12,553	197	12,162	194
7	13,357	13,428	71	12,932	425

Export failure was a small contributing factor in these hours except in HE 6 in which the failed exports amounted up to 150 MW, or about 1.2 percent of the actual demand.

Self-scheduling and intermittent generators produced much more power than scheduled in pre-dispatch. These generators were scheduled about 300 MW in pre-dispatch in most hours, but actually produced about 500 MW in real-time. We will return to the issue later in this section.

Assessment

As illustrated above, there are two main factors that contributed to the low HOEP in these hours: too much baseload generation to meet demand and over-generation by self-scheduling and intermittent generators.

As demonstrated above, the negative HOEP in most hours were well projected by the negative pre-dispatch price several hours ahead. Presumably exporters should have offered to buy out of the Ontario market as there was a profit opportunity. Table 2-48 below shows the real-time prices in Ontario and its neighbouring markets. Except exports to PJM in HE 5 and 6, there appeared to be a large profit margin in all hours.

Table 2-48: Real-time Prices in Ontario and External Markets, July 6, 2008, HE 1 to 7

Area/Zone	Delivery Hour						
	1	2	3	4	5	6	7
Ontario	-6.4	-10.92	-11.27	-13.03	-12.68	-14.59	-10.67
NYISO (Zone OH)	15.94	90.2	34.59	90.2	74.45	127.78	78.42
MISO (Michigan Hub)	16.12	16.44	4.6	15.96	15.08	5.39	22.53
MISO (Minnesota Hub)	18.16	15.63	4.36	15.03	14.28	5.49	22.45
PJM (IMO proxy)	34.84	26.92	5.55	32.19	-18.19	-19.59	23.21
ISO-NE (Internal Hub)	93.09	97.96	92.76	89.67	92.75	75.02	74.49

However, the interties at New York, Minnesota and Quebec at Kipiwa (at H4Z which allows access for Ontario exports to New England and New York through Quebec) were congested in most hours. For example, although the HOEP was negative in Ontario, exporters paid congested intertie prices of $40 to $65/MWh for exports to New York in most hours, indicating a potential loss in some hours. Limited intertie export capability (due to normally limited capability or loop-flow reducing the capability) prevented more exports even though there was a profit opportunity based on the spread between HOEP and prices in other markets.

An interesting observation is that there were only 354 MW of exports to MISO being bid in the market. Of the 354 MW bid, only 154 MW were scheduled in most of these hours.

In contrast, there were 555 MW of imports being offered into Ontario on the same interface, with 155 MW to 455 MW being scheduled depending on hour. These imports received $10,251 of constrained on payments and $758 of IOG. It is unclear to us why there was a lack of export offers in the MISO direction given that the negative HOEP's and profit opportunities were projected several hours ahead and that much of this flow would have been counter to the clockwise loop flow.

Self-scheduling and Intermittent Generators

Self-scheduling and intermittent generators are price-takers. The Panel in past reports as well as Chapter 1 of this report has shown that this type of generation historically had relatively small production deviations. However, the deviations have been increasing as more and more wind-power generation has come to market since early 2006. The Panel in the December 2007 Monitoring Report recommended that the IESO review the forecasting process with wind generators.

Table 2-49 below lists the schedules for self-scheduling and intermittent generators in pre-dispatch and real-time. Except in HE 1 and 7, these generators produced much more than they were scheduled in pre-dispatch. However, in the current case, the production deviation was not a result of the forecast error; it was a consequence of the way some of these generators had offered into the market.

Table 2-49: Self-scheduling and Intermittent Generation Deviation July 6, 2008, HE 1 to 7

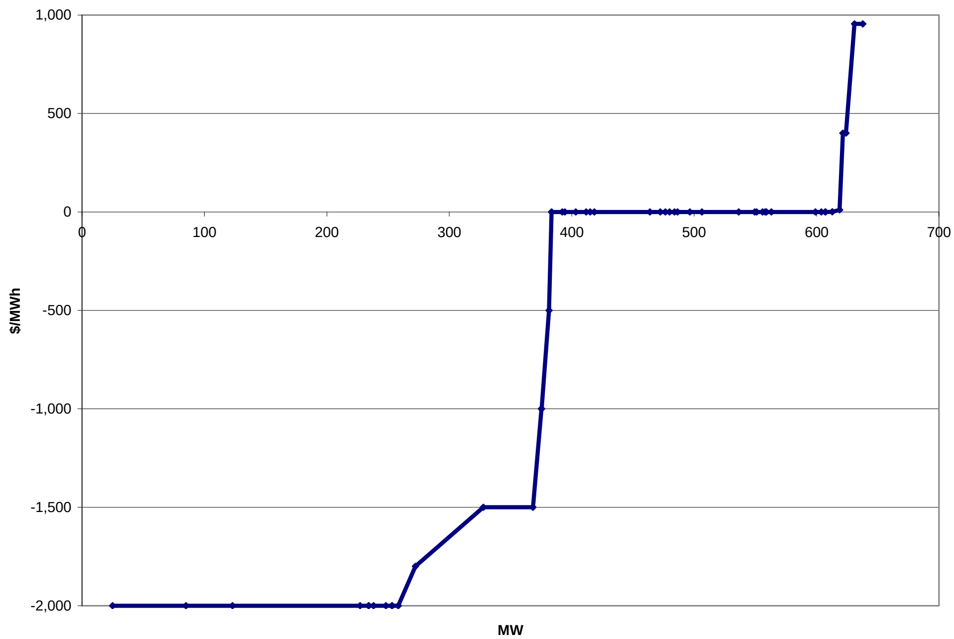
Delivery Hour	PD (MW)	RT (MW)	RT-PD (MW)	Percentage of PD (%)
1	505	463	-42	-8
2	310	475	166	54
3	310	485	176	57
4	310	512	203	65
5	310	502	193	62
6	310	487	178	57
7	459	476	17	4

Although self-scheduling and intermittent generators are not dispatchable, the Market Rules still require them to offer into the market in the same way as a dispatchable generator. [81] The IESO's pre-dispatch tool schedules generators based on their offers, while the real-time dispatch tool separates self-scheduling and intermittent generators from dispatchable generators: it uses the actual production at a self-scheduling or intermittent generator as its schedule and schedules a dispatchable generator based on its offer. The difference in treatment may lead to a self-scheduling (or intermittent) generator not being scheduled in pre-dispatch if it offers a too high price but scheduled in real-time regardless of its offer.

Figure 2-5 plots the cumulated offer curve from all self-scheduling and intermittent generators for HE 4 (the offer curve was essentially the same for other hours studied). It can be seen that there were about 200 MW being offered at $0/MWh. If the pre-dispatch price dropped below $0/MWh, these generators would not be scheduled, but would show up in real-time anyway. This was the cause of over-generation by these generators in HE 2 to 6, putting a further downward pressure on the HOEP.

[81] Market Rules, Chapter 7, section 3: Data Submission for the Real-time Markets

Figure 2-5: Offer Curve of Self-scheduling and Intermittent Generators July 6, 2008, HE 4



According to the Market Rules,[82] all generators are required to reasonably follow their pre-dispatch schedules. This appeared to be violation of the Market Rules and the Compliance department of the IESO had taken corresponding actions. To the Panel's understanding, these self-scheduling and intermittent generators can avoid such a violation by simply offering the output at -$2,000/MWh.

Following the incident, the IESO issued a request to all self-scheduling and intermittent generators to revise their offer prices down to reflect their desired generation level.

IESO's Actions Dealing with Excess Baseload Generation

The IESO has a standard procedure to deal with the situations of Excess Baseload Generation. [83] The procedure allows the IESO to take pre-cautionary measures in pre-dispatch or actions in real-time to reduce internal generation. These actions include shutting down fossil-fired or hydroelectric generators, constraining down nuclear generators (within their cycling capability), and curtailing imports. These actions are

[82] Market Rules, Chapter 7, section 3, Data Submissions for the Real-time Markets
[83] The IESO Procedure 2.4-2, Responding to Market and System Events, section 7: Respond to Excess Base-Load Generation Events.

applied to the constrained sequence only. [84] If actions of manual constraining off baseload generators are taken in pre-dispatch, the final pre-dispatch sequence will be affected, implying a potential impact on the schedules of imports and exports and thus market efficiency.

Due to the tool limitations, the MAU could not run the simulation for the July 6 2008 event. Instead, the MAU ran a simulation for the EBG event on October 13, 2008, illustrating the efficiency impact of the control actions that were taken in pre-dispatch. On October 13, 2008, HE 3 to 6, the IESO constrained down several nuclear units in pre-dispatch to deal with a foreseeable EBG situation. Table 2-50 below highlights the impact of the control action in these hours. Constrained Down Nuclear is the total constrained down MW on all nuclear units, Actual Net Exports is the total net exports in real-time, Simulated Net Exports is the net exports had the nuclear units not been constrained down in pre-dispatch and all rescheduled imports and exports been successful, and Efficiency Loss the estimated efficiency loss due to the IESO actions in pre-dispatch. [85] In the four hours, the control actions reduced net exports by 946MW and resulted in an an efficiency loss of $32,000.

Table 2-50: Impact of EBG Control Actions in Pre-dispatch, October 13, 2008

Delivery Hour	Constrained Down Nuclear (MW/MWh)	Actual Net Exports (MW/MWh)	Simulated Net Exports (MW/MWh)	Difference (MW/MWh)	Efficiency Loss ($1,000)
3	300	1,632	1,632	0	0
4	410	1,521	1,723	202	4
5	595	1,608	2,181	573	17
6	300	1,475	1,646	171	11
Total	1,605	6,236	7,182	946	32

It is interesting to note in HE 5 almost all the reduction in internal nuclear generation led to an equivalent amount of net export reduction. More precisely, based on our simulation, the 595 MW reduction in nuclear generation led to a 363 MW increase in imports and

[84] The curtailment of imports can affect the unconstrained sequence because the IESO will use “ADQh” for the curtailment in this case, putting an upward pressure on the HOEP. It is a rare case that the IESO curtailed imports for internal adequacy.
[85] The efficiency estimation is the missed exports and overscheduled imports times the difference between the respective external price (in this case all affect intertie transactions were on the Michigan interface) and the presumed generation cost at the nuclear station in Ontario. We assume the incremental generation cost at the nuclear station is $10/MWh.

210 MW reduction in exports. In other words, the IESO's manual action to deal with real-time EBG was fully offset by the change in imports/exports in that hour.

The Panel understands that the IESO has to take certain control actions to deal with EBG situations when the nuclear units are marginal. There are significant risks and thus opportunity costs associated with dispatching these units up and down frequently. It is typically efficient and technically safe to dispatch down these unit to a steady level for a relatively longer period in the case of EBG. However, the Panel believe that these actions should not affect the pre-dispatch sequence, because these actions can change the merit order of suppliers, generators and/or intertie traders. As illustrated in the example above, these actions led to more imports (and fewer exports) being scheduled when actually there was too much baseload generation in Ontario. In turn, these additional imports further aggravated the EBG situation in real-time.

The Panel has learned that the IESO has revised its PD procedures after the MAU identified and raised the problems. As it currently stands, the IESO may take precautionary actions in PD to deal with the EBG situations but these actions have no impact on the PD schedules, which do not affect market efficiency.

3. Anomalous Uplift

In the period May to October 2008, there were two hours with a CMSC payment greater than $500,000 and two days with a CMSC greater than $1,000,000 in a single intertie zone. There was no hour with either IOG greater than $500,000 or the OR payment greater than $100,000.

3.1 Hours with CMSC greater than $500,000

3.1.1 June 9, 2008, HE 13

The total CMSC amounted to $651,230 in the hour or $24.17/MWh. This hour was a high priced hour, with an HOEP of $250.89/MWh, and was discussed in the high-priced hour section.

The high CMSC in the hour was due to a combination of high price and high quantity of constrained off energy. The high level of constrained off energy was a result of derating of the transmission line D501P, which links Northeastern hydro generation to load in the southern part of Ontario, and control actions that the IESO took in response to a large amount of import failure on the Michigan interface.

On the day (and many other consecutive days), the D501P line experienced a derating due to structural problems with a tower. The derating limited about 600 MW of hydro generation, and in turn the market paid about $205,000 of CMSC payments in HE 13 to constrained off generators.

In HE 13, there were 1,453MW of failed imports (the vast majority of which was due to congestion in Michigan). In response, the IESO cut 1,225MW of exports for internal security or resource adequacy. Because of using the TLRi code for the curtailment, these exports showed up as being constrained off and were paid $247,000.

In addition, the Northwest area is a commonly congested area with a large amount of CMSC being paid to constrained off importers and generators and sometimes to constrained on exporters. In the hour, there was $132,000 of constrained off payment, of which $75,000 was paid to importers.

In summary, the market paid a $584,000 constrained off payment, which is about 90 percent of the total CMSC in the hour.

3.1.2 September 14, 2008, HE 19

The total CMSC amounted to $570,000 in the hour or $26.78/MWh. This was a high priced hour, with an HOEP of $435.00/MWh, and was also discussed in the high-priced hour section.

In this hour, the Richview shadow price exceeded $2,000/MWh in all intervals and $30,000/MWh in three intervals, indicating an energy shortage. A few dispatchable loads were constrained off a total of 450 MW resulting in $180,000 of CMSC paid to the loads.

Again, due to the high HOEP, importers and generators in Northwest were paid $196,000 of constrained off payments.

In summary, the two causes for constraining-off resources (the energy shortage affecting dispatchable loads, and Northwest congestion affecting importers and generators) accounted for $376,000 of CMSC, or 66 percent of total CMSC payments. Most of the remaining CMSC was paid to internal peaking generators, again because of the supply shortage when all available resources were dispatched on.

3.2 Days with total CMSC greater than $1,000,000 on an intertie

3.2.1 June 21, 2008, on the Minnesota interface

The total CMSC payment on the Minnesota interface exceeded $1.2 million on the day. Table 2-51 below lists the pre-dispatch shadow price and MCP on the interface and the hourly CMSC payment for imports and exports. It appears that the constrained on payment for exports accounted for about 97 percent of the total CMSC payment, and the vast majority of these payment occurred in HE 16 to 23.

This was a rare case in which the Minnesota interface had such a large CMSC payment. The interface had a 140 MW of export capability and a 90 MW import capability on the day. Typically, there are five or more traders competing at the interface for the limited transmission capability, with daily CMSCs being well below $200,000, 95 percent of the time. However, this was a Saturday, and there were only two exporters and one importer who were actively trading. Two exporters bid their exports at prices above the PD shadow price but well below the PD uniform prices and were thus scheduled in the constrained sequence but not the unconstrained sequence.[86] As a result, these exporters were paid a constrained on payment equal to their exports times the difference between the HOEP and their bid price.[87] In the current case, the end result is that these two exporters were paid (up to more than $1,900/MWh) to export.

[86] The nodal shadow price is publicly available at the IESO website.
[87] Since there was no congestion at the intertie in any hour on the day, the average intertie price equalled HOEP. Essentially, the constrained on payment ensures that exporters "pay" what they have bid (even when the bid prices are negative).

Table 2-51: PD Prices and CMSC Payment to Importers and Exporters on the Minnesota Interface, June 21, 2008

Delivery Hour	PD Shadow Price	PD MCP	HOEP	Constrained on Exports ($)	Constrained off Imports ($)
1	17.01	37.74	37.3	0	534
2	5.27	37.46	36.88	1,425	878
3	12.29	37.30	38	0	1,013
4	11.54	38.41	41.4	0	1,194
5	0.00	38.42	35.5	4,240	1,420
6	0.00	37.67	27	3,036	1,076
7	0.00	40.41	38	4,639	1,534
8	-11.00	45.85	43	7,465	1,724
9	-9.00	69.18	62	7,713	2,491
10	-51.00	73.13	72	12,305	2,894
11	-150.88	82.51	70	16,807	1,127
12	-176.00	89.95	77	21,460	1,267
13	-211.00	85.55	64	14,576	1,044
14	-1006.00	80.01	83	27,733	1,941
15	-1900.00	83.49	85	58,038	1,999
16	-1897.00	85.50	89	113,571	2,070
17	-1956.00	74.86	81	135,243	1,659
18	-1951.00	75.00	61	64,641	1,217
19	-1953.00	55.00	49	32,980	1,497
20	-1950.99	50.50	66	141,908	2,643
21	-1953.00	65.12	75	163,165	3,017
22	-1953.00	44.44	45	107,861	1,796
23	-1953.00	40.02	39	198,867	1,576
24	-900.00	33.94	15	56,701	-121
Total				1,194,374	37,490

3.2.2 June 22, 2008, on the Minnesota interface

The total CMSC payment on the Minnesota interface exceeded $1.1 million on the day. This was a Sunday and the story was almost the same as the day before: there were only two active exporters and one importer. However, close to $1 million of CMSC was paid to one exporter for its constrained on exports in HE 2 to 5, when it bid below negative $1,900/MWh and was scheduled.

Assessment

The Minnesota interface has a small amount of import and export capability and is located in the congested area of Northwest Ontario. As a result, the shadow price on the interface is usually much lower than the shadow price in southern Ontario although the unconstrained price is the same. This leads to imports being constrained off and exports constrained on.

Typically the Minnesota interface is a competitive interface, with more than five active traders usually competing for profit opportunities. When all or most of these traders are active on the interface, the CMSC payment is typically small, well below $200,000/per day.

The incidents of June 21 and 22 were rare cases, since daily CMSC in excess of $1 million has occurred only one other time in the six years since market opening.[88] These two days were on the weekend and only two exporters were actively trading. Lack of competition allowed these two traders to follow the pre-dispatch signal and gain large constrained off CMSC payments. The Panel does not consider this as gaming or violation of the Market Rules given the current market design, and the market will work its way to reduce such payments. Moreover, Appendix 7.6 of the Market Rules already deals with Local Market Power and the possible recovery of CMSC payments under specified situations.

The root of such a large CMSC payment is the Ontario uniform pricing design, which allows some market participants in some situations to pay (or be paid) what they have bid. However, CMSC treatment of supply (generation and imports) and consumption (exports and dispatchable load) is not symmetrical when prices are below zero, ever since 2003 when the Market Rules were modified to limit CMSC payments to suppliers when

[88] This occurred on August 1, 2002, with a CMSC of about $3 million.

their offers are below zero.[89] CMSC to exporters or dispatchable load is not truncated in a similar fashion. In the current case, the Northwest generators were effectively paid the HOEP for what was scheduled in the unconstrained sequence, even though they offered a large negative price. While the generator's CMSC was limited, the low offer price still led to a low shadow price in the zone (below -$1,900/MWh). The low shadow price in turn benefited exporters who could bid negative prices above the shadow price (and the generator's marginal offer prices) and receive large CMSC payments, with the net effect being that the exporters "paid" what they had bid.[90] To the scheduling program scheduling exports whose value of consumption (the bid price) exceeds the cost of generation (the offer price) appears economic. If CMSC payments were symmetrically defined, i.e. if both were calculated as the difference between HOEP and the bid or offer price, the CMSC would also be lower because of this scheduling. However, with asymmetrical payments CMSC to the constrained on exports can greatly exceed the alternative payments avoided if generation were constrained off instead.

The Panel has often stated that for benefit of the market, a Locational Marginal Pricing (LMP) should be adopted in Ontario. An LMP will remove such adverse incentives of bidding far below the cost because a large negative price would mean a generator could end up paying exporters or consumers to consume. To the Panel, the constrained on payment to the exporters in the current case was a subsidy from Ontario consumers to exporters. When an LMP is adopted, such a subsidy would be eliminated.

[89] Suppliers get paid CMSC as if they had offered a price of zero (unless the energy price is lower), which means they receive CMSC equal to HOEP.
[90] For example, a constrained on export bidding negative $500/MWh when HOEP is $50/MWh, pays HOEP for the energy then receives (HOEP – bid) = 50 – (-500) = 550/MWh in CMSC. The net payment is $50 - $550 = -$500/MWh.

Appendix 2A: Identifying Anomalous Uplift Events

This note illustrates how the Panel established the thresholds for anomalous uplift events.

In general, the hourly uplift can be separated into four categories: Congestion Management Settlement Credit (CMSC), Inter-tie Offer Guarantee (IOG), operating reserves (OR) and others (primarily losses plus other hourly or non-hourly charges or adjustment that are reallocated to the hour). Because of the complexity and unpredictability of the last category, it appears to be very difficult and of little use to establish criteria for triggering an anomalous event for this category. As a result, we only discuss the hourly CMSC, IOG, and OR payment.

A daily CMSC or IOG payment on a given interface is also assessed because at times these payments could be very high as a result of operational issues or lack of competition.

These hourly or daily uplift payments are highly volatile, varying with the system configuration, market prices, and the IESO's control actions. The Panel has not yet established a robust method to assess the relationship between these payments and their influential factors because some factors are difficult to quantify while others difficult to model. Instead, we established a simple threshold for each uplift component, above which the uplift is considered to be too high and warrants a further study. A second consideration for the threshold is that the number of events that trigger the threshold should be within a reasonable range so that we do not over-commit our resources on these analyses.

Hourly CMSC

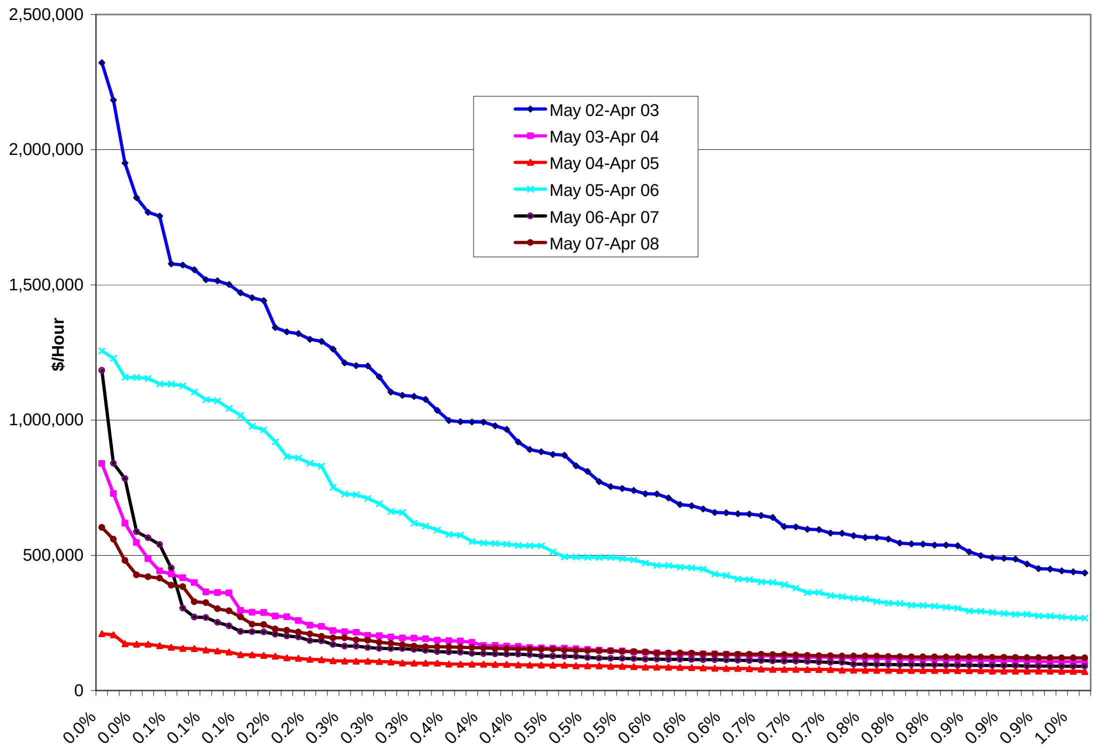
The CMSC payment includes the constrained -on and -off payment to generators, dispatchable loads, and intertie traders. Occasionally a CMSC payment can be negative but typically small, implying that the market participant has to pay a CMSC to the market.

- Generators: typically the constrained off payment is paid to generators who are bottled in Northwest and the constrained on payment to generators located in southern Ontario. When the HOEP is high, the constrained off payment is high but the constrained on payment is low. In contrast, when the HOEP is low, the Ontario market is not significantly congested and thus both the constrained on and off payment are low. An anomalous event happens typically when the IESO constrains on a high cost fossil generator for reliability concerns.
- Dispatchable loads: dispatchable loads can be manually constrained off for reliability because of supply shortage or operating reserve activations. They can also be constrained off for transmission outage. Because this type of consumers typically has a high willingness to consume and thus bids a high price into the market for reduction, the constrained off payment to these consumers can be very large at times.
- Intertie traders: Intertie traders are eligible for CMSC because of congestions on interfaces to external markets. A very large amount of constrained on payment can be paid when a high-price import is constrained on for reliability, or a negative priced exports is constrained on as a result of a negative zonal price in the export zone.

Appendix Figure 2-1 below depicts the duration curve of top 1 percent of hourly CMSC by period.[91] It is apparent that the hourly CMSC was very volatile within and between periods. Within each period, the hourly CMSC quickly dropped from above $500,000 to below $100,000 in 0.5 percent of time or about 40 hours. Between periods, May 02 – April 03 and May 05 – April 06 have the highest CMSC, while May 04 – April 05 the lowest.

[91] Because of the high concentration of the hourly CMSC (as well as IOG) around the mean, a full duration curve or histogram does not provide meaningful information.

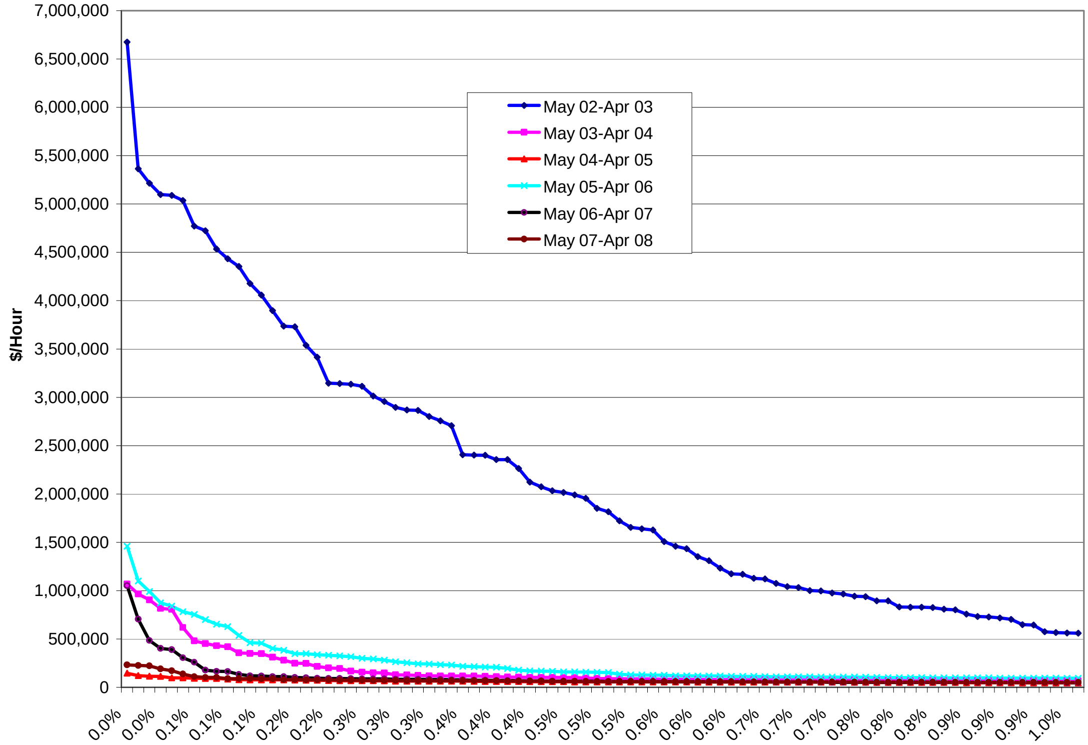
Appendix Figure 2-1: Top 1% of Hourly CMSC, May- April, 2002-2008



Hourly IOG

Appendix Figure 2-2 shows the duration curve of top one percent of hourly IOG. Similar to the hourly CMSC, May 02 – April 03 had the hourly IOG far above other periods. Again, May 04 – April 05 (and May 07 – April 08) has a persistently low IOG. $500,000 appears to be an appropriate threshold for anomalous IOG as the number of hours above this threshold appeared to be reasonable except in May 02 – April 03.

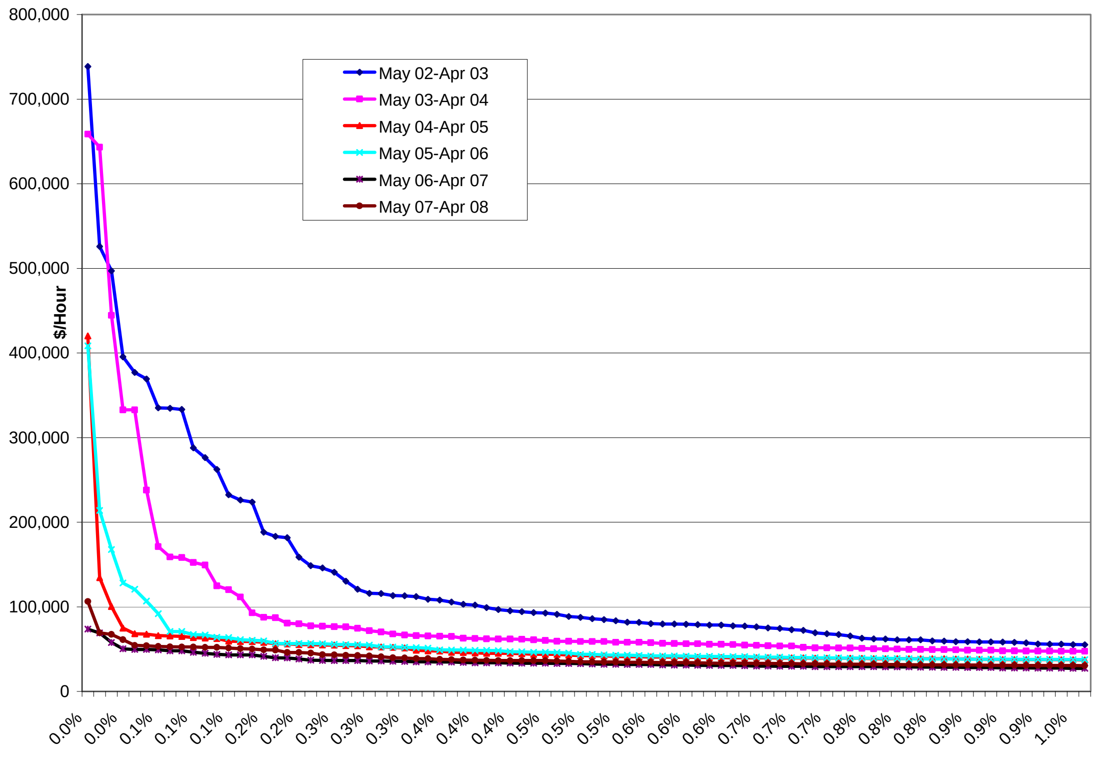
Appendix Figure 2-2: Top 1% of Hourly IOG, May- April, 2002-2008



Operating Reserve

Appendix Figure 2-3 reports the duration curve of top one percent of hourly OR. The pattern of OR is different from the CMSC and IOG: the OR payment continues to decrease from year to year. It is consistent with the observation in Chapter 1 that the OR price continues to drop over time, largely independent of the HOEP. In the past four years, the number of hours with an OR payment above $100,000 was well below 10.

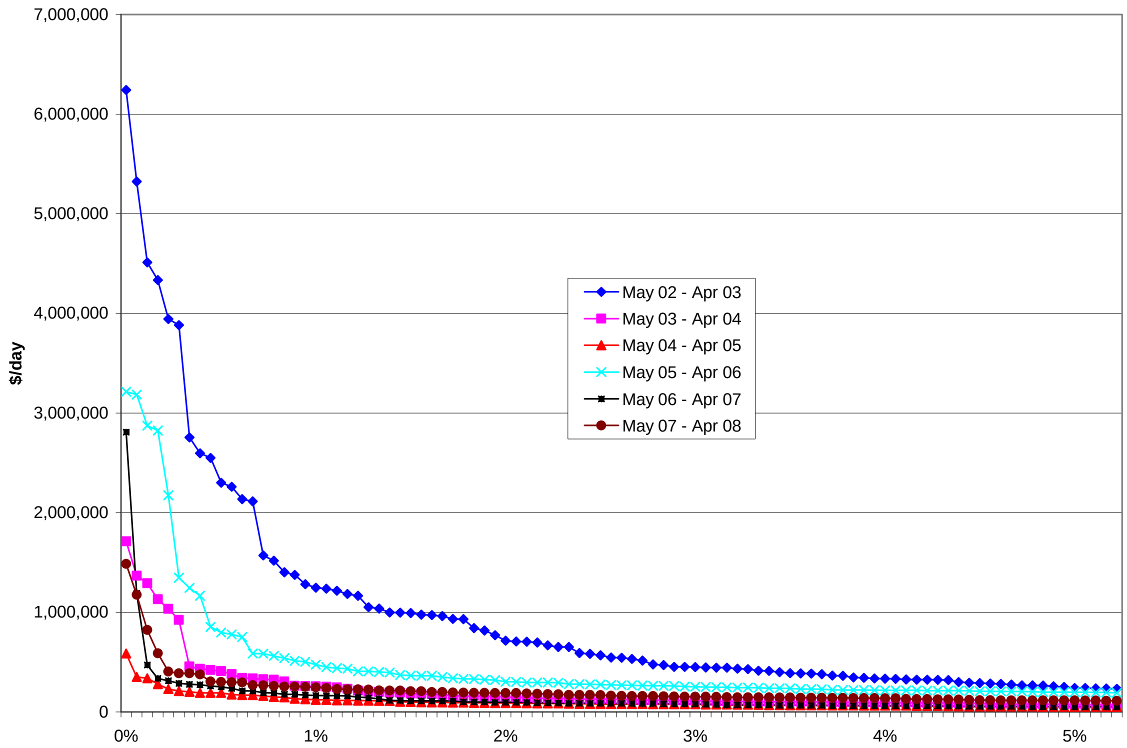
Appendix Figure 2-3: Top 1% of Hourly OR Payment, May- April, 2002-2008



Daily Total CMSC and IOG on Interties

Appendix Figure 2-4 depicts the pooled duration curve of top five percent of daily CMSC at each interface. The daily CMSC dramatically dropped from a few million dollars to below $500,000. Except in May 02 to April 03, the number of days with a CMSC greater than $1 million was within 10, and none in May 04 – April 05.

Appendix Figure 2-4: Daily CMSC on A Given Interface, May - April, 2002-2008



The daily IOG was never above $1 million on any interface since summer 2005. The vast majority of high IOG days were in summer 2002, when the market was extremely tight and relied on imports. There were also a few days in summer 2005 in which the IOG went above $1 million per day.

Thresholds for Anomalies

Based on the distribution of the hourly CMSC and IOG, a $500,000/hour can be the first screening criterion. A $1 million per day for CMSC or IOG on a given interface is also chosen as the trigger point.

The OR payment is highly related to the HOEP, but can be high when the OR supply is short. Because an OR payment is in general reflective of the corresponding HOEP, a high OR payment is thus predicted by a high HOEP. Consumers can avoid such high OR payment if they can correctly forecast and respond to the high HOEP. In this sense, it is the shortage price that is unpredictable and anomalous. A $100,000/hour threshold can be the threshold of first screening, but only shortage OR price should be analyzed.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This chapter summarises changes in the market since the Panel's last report that impact on the efficient operation of the IESO-administered markets. It also discusses new developments arising in the marketplace.

Section 2 identifies material changes that have occurred in the market since our last report. This section includes three issues:

- The Midwest Independent Transmission System Operator (MISO) introduced a new Available Flowgate Capability (AFC) calculation in late August that led to a significant increase in import failures from MISO.
- The IESO removed Control Action Operating Reserves (CAOR) in the pre-dispatch schedule in late September 2008 in response to increased export failures due to the rejection by the New York Independent System Operator (NYISO) and MISO of exports that were designated by the IESO as CAOR.
- After NYISO banned the linked wheeling from NYISO to PJM through Ontario, exports from Ontario to PJM increased.

In Section 3 the Panel comments on new issues arising:

- The Ontario Power Authority's (OPA) Demand Response Program Phase 3.
- Self-induced Congestion Management Settlement Credit (CMSC) payments made to generators when they are shutting down.
- Behaviour of new gas-fired generation in the Day Ahead Commitment Program (DACP).
- The implications of diminishing offers for operating reserves by fossil-fired generators.
- The efficiency impact of a market participant's response to environmental issues.

- Comments on Ontario Power Generation's (OPG) plan in response to the government's Declaration on emission reduction at its coal-fired generating stations.

2. Changes to the Marketplace since the Panel's Last Report

2.1 Increased Import Failure on the Michigan Interface

As shown in Chapter 1, import failures have significantly increased on the Michigan interface since September 2008. The increase in transaction failures was a consequence of a significant change in MISO's Available Flowgate Capability (AFC) calculation which occurred on August 26, 2008.[92] The new AFC calculation takes into consideration the interaction of power flow between MISO and external markets and the power flow inside the MISO jurisdiction. Transactions will be allowed as long as they do not cause internal flows to exceed MISO's internal limits on their flowgates.

At the same time, MISO also reduced its Net Scheduled Interchange (NSI, which is equivalent to the IESO's NISL or Net Interchange Scheduling Limit)[93] from 1,000 MW to 500 MW every 15 minutes from 6:00 through 22:00 EST and to 600 MW from 22:15 through 05:45 EST, following a recommendation by the Independent Market Monitor for MISO.[94] Everything else being equal, the reduction in NSI has the potential to increase intertie transaction failures between MISO and Ontario because a reduced NSI tends to increase the frequency of a binding NSI in MISO.[95] When the NSI is binding, some imports or exports in MISO will not be scheduled even though they are economic and have been scheduled in Ontario. A transaction that is scheduled in Ontario but not in MISO is a failed transaction in Ontario, leading to more incidents of counter-intuitive pricing in Ontario. However, because the change in the NSI and AFC occurred at the same time, it is difficult to precisely distinguish failures due to the implementation of the new AFC from failures due to the reduction in NSI.

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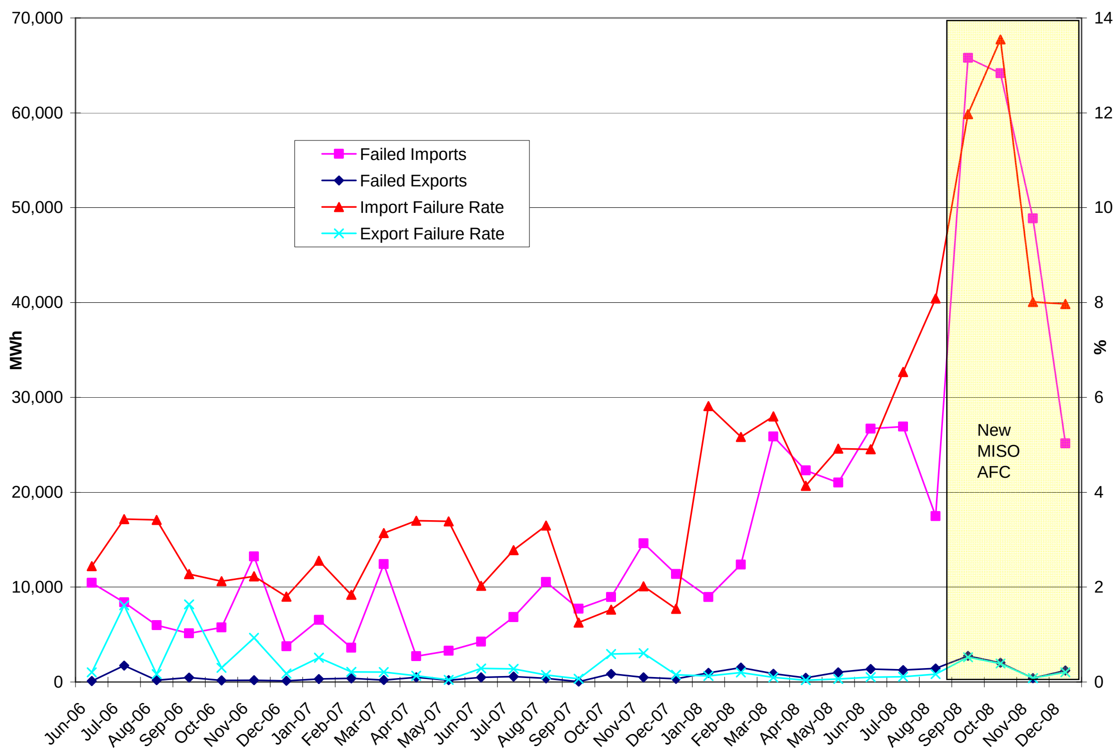
[92] MISO: "Evaluating Transmission Services in the Energy Market Environment" at http://www.midwestmarket.org/home . AFC represents the limit on the net flow on a flowgate (transmission interface) and can limit the net import or exports scheduled.
[93] The NSI limits schedule changes from one 15 minute period to the next and the NISL limits schedule changes from one hour to the next. See our July 2008 Monitoring Report at pp.103-110 for background information on the NISL.
[94] Potomac Economics, "2007 State of the Market Report for the Midwest ISO" at http://www.potomaceconomics.com/
[95] Unfortunately there is no public information on the statistics of a binding NSI in MISO.

Figure 3-1 below plots the monthly import and export failures due to MISO transmission or ramp limitations for the period June 2006 to December 2008.[96] Failed imports in September 2008 reached a record high since the Ontario market opened in May 2002 and were far higher than the export failures. This suggests that either the new AFC calculation and/or the reduced NSI put more restrictions on imports to Ontario or simply that the transmission lines tend to have easterly flow, which limits other flows in the same direction (e.g. imports to Ontario).

Figure 3-1: Import and Export Failure due to the MISO Transmission or Ramp Limitation,
June 2006 to December 2008



In light of the increased import failure rate, the IESO contacted MISO in mid-September to address the issue. MISO refined the parameters in their AFC calculation on October

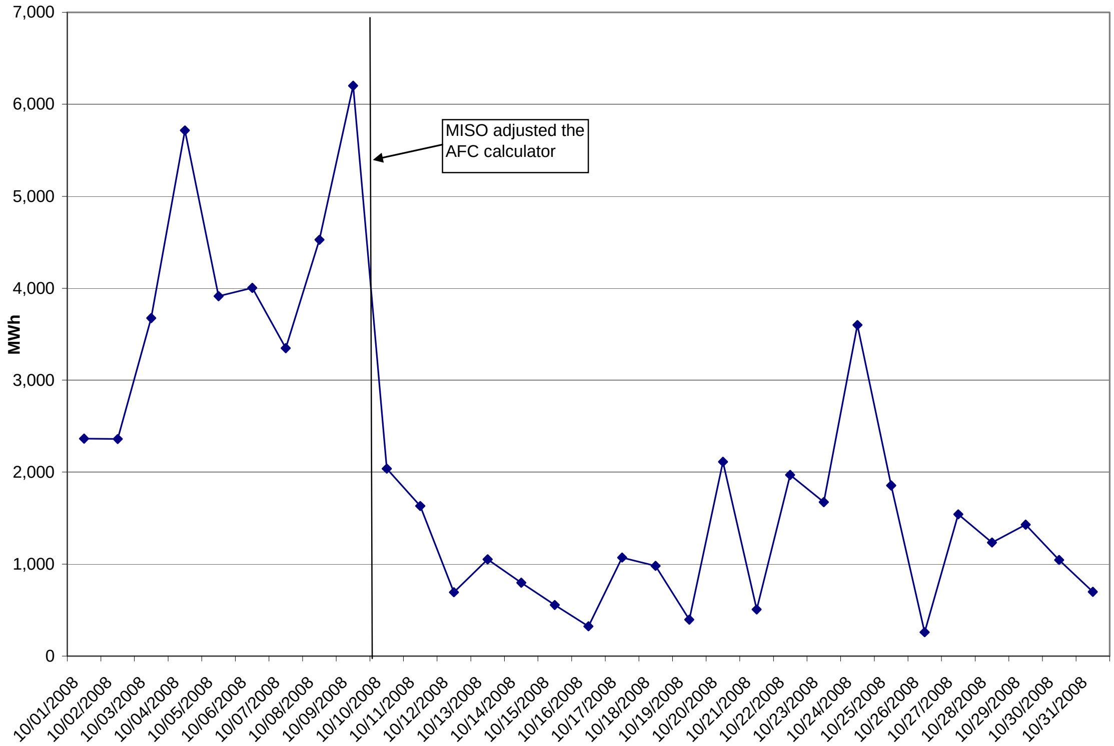
[96] The IESO introduced the code MrNh for transmission and ramp limitation on the Michigan interface in June 2006. Before then it used the same code for external security and transmission/ramp limitation. Thus there is no way to separate transaction failures due to transmission or ramp limitation from transaction failures due to MISO security before June 2006.

10, 2008, and at the same time the IESO put a new procedure in place.[97] Figure 3-2 shows that import failures on the Michigan interface in the month of October 2008 have dropped significantly since October 10. This low rate continued through November and December (beyond the period covered by this report). In fact, as Figure 3-1 shows, the import failure rate dropped to about 8 percent in November 2008 which was much lower than in September and October but still higher than early months. Although the IESO's new procedure partly contributed to the reduction in import failures, it played a very limited role because it has been activated only in four incidents since its implementation.[98] Apparently the decrease in import failure was mainly a result of the AFC parameters being revised. This graph also suggests that the reduced NSI was not a significant cause for the increase in import failure before October 10, 2008 because the same NSI was applied throughout the whole October period.

[97] The IESO's Interim Procedure 66: MISO Import Failure at Michigan Interface, issued on October 10, 2008. The procedure is to limit imports from MISO into Ontario to 700 MW for the coming hour if the failure is greater than 500MW in the current hour or if the failure is greater than 300 MW in two consecutive hours, subject to the IESO discretion.

[98] The hours were October 24, 2008, HE 17, 18 and 23, and October 25, 2008, HE 15. (None of them were either high-priced or low-priced hours using the definitions applied by the Panel in Chapter 2 of this report).

Figure 3-2: Failed Imports due to MISO Transmission and Ramping Limitations on the Michigan Interface, October 1 to October 31, 2008



2.1.1 <u>Assessment</u>

This section extends our discussion to a broader seams issue between Ontario and its adjacent markets on the scheduling of intertie transactions.

Each market has a different offer window and a different treatment of the intertie transactions. Table 3-1 below lists the offer window and scheduling information in the five markets of Northeastern North America. One can see that the market designs are significantly different and coordination between markets can be very complicated.

Table 3-1: Comparison of Real-Time Intertie Transaction Dispatch among Selected Markets

Market	Offer/Bid Window	Dispatch Frequency	NSI/NISL
IESO	120 minutes ahead	1 hour	700 MW per hour
NYISO	75 minutes ahead	1 hour with IESO and NE-ISO, but 15 minutes with PJM	700 MW per hour
MISO	30 minute ahead	1 hour with IESO, but 15 minute with PJM	500 MW per 15 minute interval (600 MW off-peak)
ISO-NE	75 minutes ahead	1 hour	600MW per hour
PJM	Before 6:00pm day ahead	15 minutes with MISO and NYISO but one hour with Ontario	500 MW per 15 minute interval

In general, participant controlled intertie failures in Ontario are mainly a consequence of the offer/bid scheduling time differences between Ontario and adjacent markets and the traders' offer strategy in different markets. For example, the IESO has a 120 minute offer window while the NYISO uses a 75 minute window and MISO a 30 minute window. The long lead time in Ontario imposes a greater risk to traders because the HOEP in Ontario may turn out to be unfavourable for them. To avoid an unfavourable price in Ontario, a trader whose transaction is successfully scheduled in pre-dispatch in Ontario has the ability to fail the transaction by avoiding selection in NYISO or MISO (for example by adjusting the offer/bid price or submitting an incorrect NERC tag in these markets).

The IESO and ISO-NE employ an hourly dispatch algorithm for intertie transactions, in contrast to a 15 minute dispatch in NYISO, MISO, and PJM. The hourly fixed schedule is based on the IESO's forecast peak demand for the hour, which induces an efficiency loss in the marketplace as the Panel pointed out in an earlier report.[99] The hourly fixed dispatch forgoes an important opportunity for more efficient dispatch of intertie transactions with major external markets.

In a previous report, the Panel recommended that the IESO should investigate the possibility of a 15 minute dispatch algorithm for intertie scheduling.[100] A shorter dispatch interval would result in several benefits to the Ontario market, given that NYISO and MISO have adopted such an algorithm. Firstly, it improves market efficiency by increasing import/export responsiveness (by allowing rescheduling within the hour). This benefit was demonstrated in the previous report. Secondly, it can reduce price volatility that is induced by sharp changes in import/export flows across the hour and thus reduce traders' risks[101] As a result, it may also help reduce intertie transaction failures and thus the number of incidents with counter-intuitive prices. And thirdly, it can effectively increase the NISL limit so that more imports/exports can flow between Ontario and other markets.[102] For example, in MISO the original hourly Net Scheduled Interchange was 1,000 MW per hour, but is now effectively 2,000 MW per hour (500 MW every 15 minutes).[103] A greater allowed intertie change would permit intertie trades to more quickly respond to the market situation in Ontario and neighbouring markets. This appears to be increasingly important in light of the growth of wind generation (which can fluctuate across the hour).

2.2 CAOR Schedules in the Pre-dispatch

In our July 2008 Monitoring Report,[104] the Panel discussed the efficiency impact on the Ontario market of NYISO's practice of refusing recallable imports from other jurisdictions (implemented in June 2007)[105] and of MISO's implementation of a similar

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[99] The Panel's December 2007 Monitoring Report, pages 151-160.
[100] Recommendation 3-3 in the Panel's December 2007 Monitoring Report, page 160.
[101] Potomac Economics, Independent Market Monitor for the Midwest ISO, 2007 State of the Market Report for the Midwest ISO, pages 121-127.
[102] The Panel has previously suggested the IESO to review the existing NISL limit. For details, see the Panel's July 2008 Monitoring Report, page 103-110 and July2007 Report, pages 97-100.
[103] 2,400 MW/h (600 MW every 15 minutes) off-peak
[104] The Panel's July 2008 Monitoring Report, page 180-192.
[105] New York ISO, Technical Bulletin 151: Import Transactions, June 5, 2007 at http://www.nyiso.com/public/index.jsp

policy in June 2008. NYISO and MISO reject all exports from Ontario that are designated as recallable, leading to exports failing in Ontario as these recallable exports were scheduled in the final pre-dispatch run as a backup for scheduled Control Action Operating Reserve (CAOR).[106] Such export failures lead to both greater pre-dispatch to real-time price discrepancies and a market efficiency loss in Ontario due to lost export/import opportunities or overscheduling of generation (e.g. via SGOL) for failed exports.

The Panel identified four alternative remedies and recommended that the IESO explore solutions to the problem. The options presented were:

- Re-pricing pre-dispatch CAOR to a price point where recallable exports are no longer scheduled in pre-dispatch;
- Removing the 400 MW tranche of CAOR in both the pre-dispatch and real-time schedules;
- Ceasing the backing of CAOR with recallable exports;
- Investigating with the other ISO's the option of receiving recallable exports, as the energy trade on its own is efficient.

On September 26, 2008, the IESO removed all CAOR from its pre-dispatch sequences (effectively equivalent to the first option above), so that Ontario no longer offers exports that are alternatives to a potential voltage cut. While this action eliminates the distortion between pre-dispatch prices and HOEP resulting from the rejection of recallable exports, the Panel believes that from a market efficiency point of view the ideal solution to this problem is for all ISO's to accept recallable exports (the last option list above). If this approach were taken, cheaper imports could be utilized to meet internal demand and market efficiency would be enhanced in Ontario and in neighbouring markets. We understand that this option involves the coordination of all interconnected markets and requires a significant effort among the market dispatch authorities. We encourage the IESO to explore this option with its surrounding counterparts.

[106] The IESO's practise has been to make the same amount of exports recallable as the amount of ten minute CAOR scheduled in pre-dispatch.

We understand that the Market Pricing Working Group (a stakeholder group organized by the IESO) has considered a complete CAOR study as part of their 2009 priority work. A detailed and complete study may result in a more efficient solution to the issue.

2.3 Linked Wheeling through Ontario

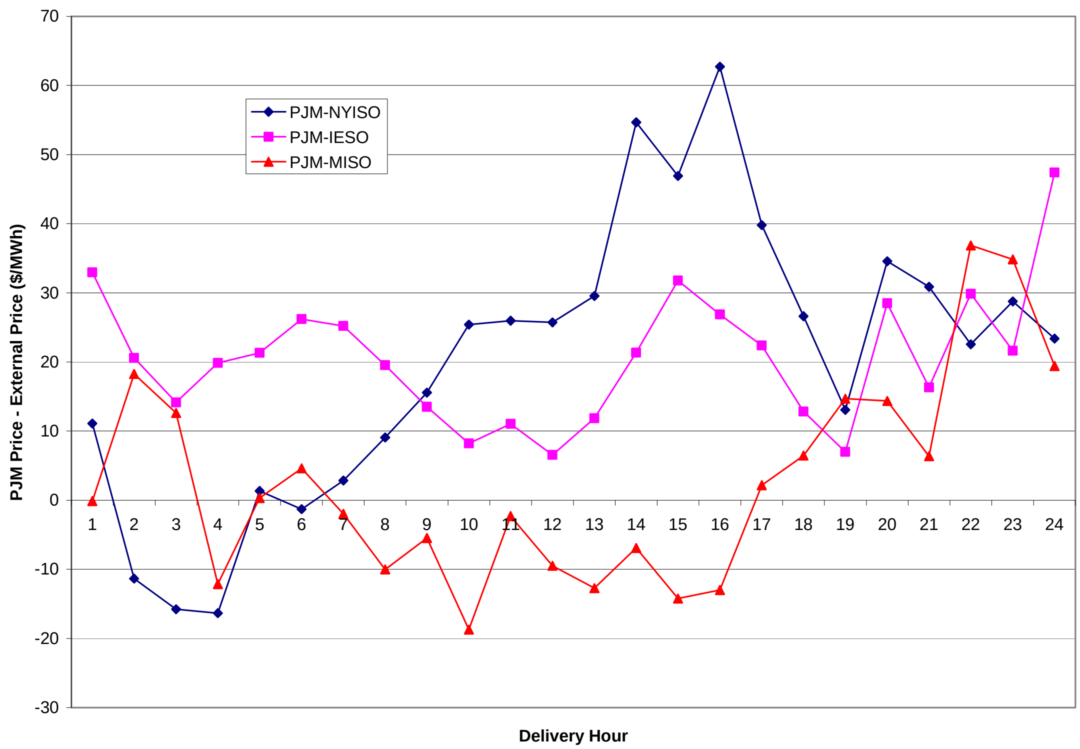
In our July 2008 Monitoring Report, we observed that the linked wheeling transactions through Ontario, especially transactions from New York to PJM, began to increase dramatically in January 2008. The root of the large amount of linked wheels from New York to PJM lay in the different pricing algorithms among markets: New York (as well as Ontario) uses a contract path to establish market prices while PJM (as well MISO) uses distributional factors (i.e. the physical power flow is modelled).[107] The difference in pricing algorithms resulted in an understatement of the cost of the exports from New York because physically about 80 percent of the power still flows directly from New York to PJM which is largely located south-west of NY, despite the contract path of the transaction being designated from New York west through Ontario and MISO to PJM. The physical flow of these transactions caused transmission congestion in New York but the cost of the congestion was barely born by the exporters (the congestion cost is shared by New York consumers and exporters based on their volumes).

Figure 3-3 below shows the average difference by hour between the PJM price for imports and the prices in NYISO (OH Zone), IESO, and MISO (FE hub) for the 30 days before July 22, 2008, the date on which NYISO took action to prevent the linked wheels from NYISO to PJM through Ontario. It appears that the price difference between PJM and Ontario was large enough to support exports from Ontario in most hours (given that exports from Ontario to PJM will need to pay about $7-10/MWh transmission and other charges in Ontario and MISO). The price difference between PJM and NYISO was even greater during most on-peak hours, indicating a better profit opportunity for linked

[107] For a detailed discussion, see our July 2008 Monitoring Report, pp. 164-170

wheels from NYISO to PJM. For most hours, there was little profit opportunity for exports from MISO to PJM. The price differences indicate that the most profitable opportunities were to export from NYISO to PJM through Ontario and MISO, followed by exports from Ontario to PJM, and only a few hours where exports from MISO to PJM would have been most profitable.

Figure 3-3: Average Price Difference Between PJM and its Neighbouring Markets June 22 to July 21, 2008

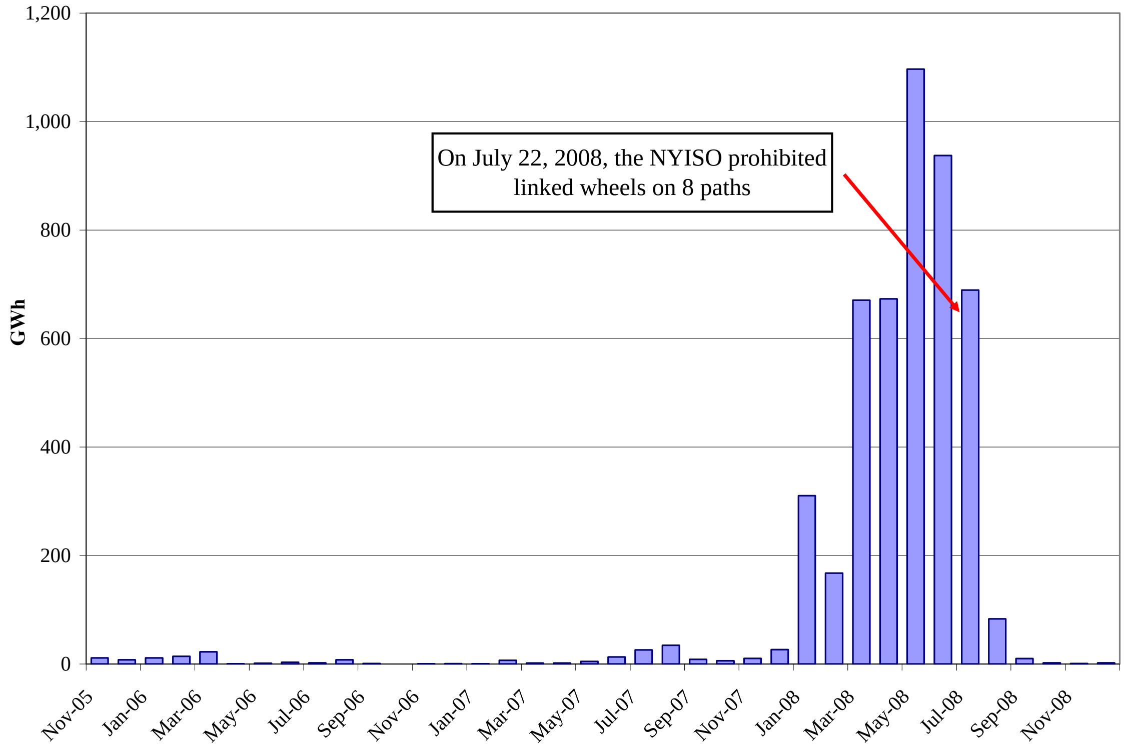


In light of a significant increase in congestion payments due to the linked wheeling transactions, NYISO sought tariff revisions on July 21, 2008.[108] This amendment prohibited linked wheels on eight selected paths, including the wheeling transactions from NYISO to PJM through Ontario and MISO. When the new rule took effect on July 22, 2008, the linked wheels from New York to PJM ceased and total linked wheeling transactions (from any source) through Ontario immediately dropped to a much lower level, as Figure 3-4 shows. On November 17, 2008, the U.S. Federal Energy Regulatory

[108] http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2008/07/nyiso_exgnt_crcmstnc_extrnl_trnsctns_7_21_09.pdf

Commission accepted permanent tariff revisions and encouraged the parties to seek "long-term comprehensive solutions".[109]

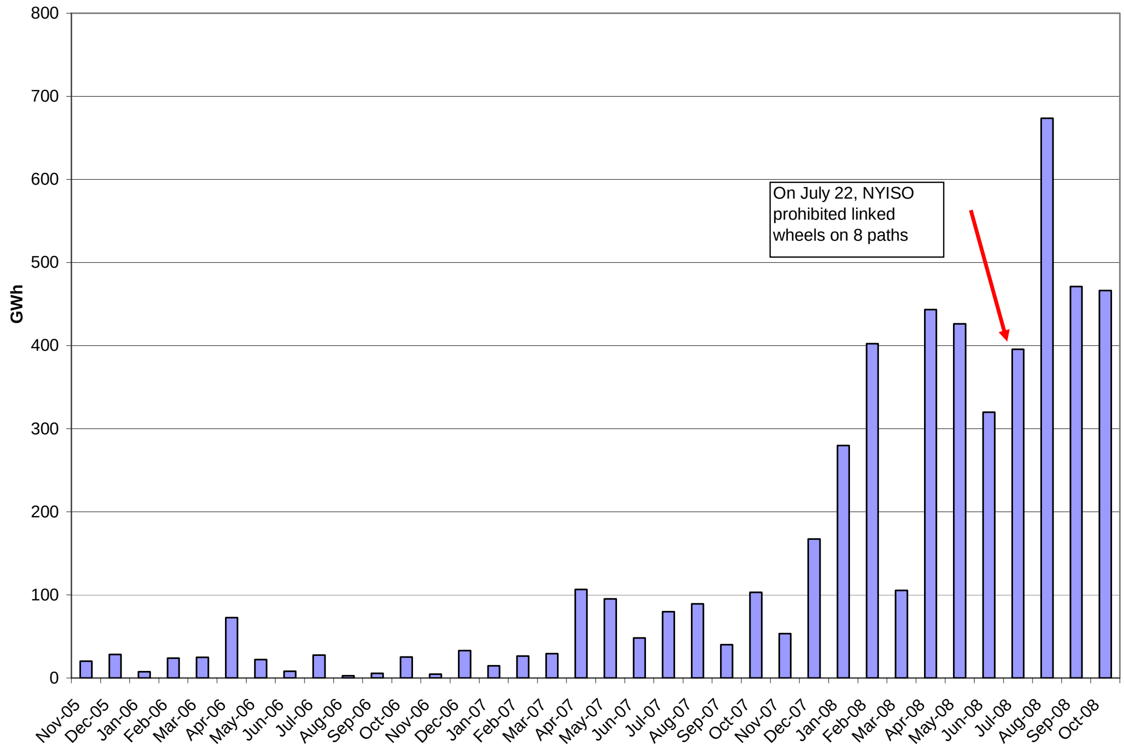
Figure 3-4: Monthly Linked Wheels
November 2005 to October 2008 (GWh)



Exports from Ontario through MISO to PJM have also increased this year. The increase was a consequence of a high price paid in PJM for imports from Ontario, compared to the Ontario HOEP. Figure 3-5 below shows the monthly exports directly from Ontario to PJM. It appears that the exports started to increase in December 2007 and reached a record high in August 2008, just after NYISO prohibited the linked wheels from New York to PJM. The one-month increase may indicate some substitution of exports from Ontario as the next best alternative for the prohibited exports from New York although these exports dropped again in the following months, closer to the April and May levels.

[109] FERC Docket: ER09-198-000, and -001.

***Figure 3-5: Exports From Ontario to PJM (GWh)
May 2005 to October 2008***



The increase in exports to PJM is an important issue to Ontario because of its potential for increasing Lake Erie Circulation[110] which impacts the efficiency of internal dispatches. PJM has no direct link with Ontario, and an export from Ontario to PJM has to go through either NYISO or MISO in terms of contract path, although the physical power flows through both.[111] Because the physical flow of power goes through both paths, the difference between the contract quantity and the actual power flow contributes to Lake Erie Circulation . As long as there is no internal transmission congestion between the Beck station and the Lambton station, the increased Lake Erie Circulation does not lead to significant problems in Ontario. In the period November 2007 to October 2008, these major transmission lines were congested only 2.6 percent of the time, indicating that during this period the loop flow was not a significant issue in causing internal transmission congestion within Ontario. Nevertheless, the Panel is concerned that if

[110] A description of Lake Erie Circulation is in our December 2006 Monitoring Report at pp.113-117.
[111] Although an export may show a path from Ontario to PJM through MISO, the actual power flow is partially through MISO and partially through NYISO. This occurs because the transmission system is in fact a mesh with several paths between any two points and power will flow over all available paths.

internal transmission congestion were to increase, Ontario may suffer the same inefficiencies as occurred in New York. The Panel has asked the MAU to monitor this issue closely and report back with their observations.

3. New Matters

3.1 OPA's Demand Response Program Phase 3

3.1.1 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.[112] OPA set a target load reduction of 2,700 MW by 2010, and an additional 3,600 MW by 2025.[113]

The OPA views developing Demand Response (DR) as one of the means to achieve this goal and describes it in the following terms:

> "The OPA foresees significant DR opportunities in Ontario and is working towards launching a suite of demand response programs.DR is a flexible resource that provides significant benefits for participants (who may be able to gain financially), for system reliability, and ultimately for all electricity customers as it motivates more efficient use of a key resource. Over the longer term, by reducing demand on our electricity system, DR reduces the need for building additional capacity, as well as the related financial costs and environmental impact."[114]

In August 2008 OPA introduced a new Demand Response program known as DR3. Its objective is:

> "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."[115]

In this section of the report we assess the design and early results of the implementation of DR3. We make some specific recommendations for improvement and raise again the

[112] Ontario Ministry of Energy news release, "Securing Reliability for Ontario's Long Term Electricity Supply", June 13, 2006.
[113] http://www.powerauthority.on.ca/Storage/75/7112_Paul_Shervill_Carbon_Offsets_Conference_Ottawa_June_17-08.pdf
[114] See the OPA's Demand Response homepage at http://www.powerauthority.on.ca/Page.asp?PageID=861&SiteNodeID=147
[115] 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

general principle that demand response programs are fundamentally wasteful if they do not take into consideration the users' value of consuming electricity.[116]

In what follows we first summarize the salient features of the DR3 program. Next we report on results for the program over the period from its start, August 1, 2008, until the end of the review period of this report, October 31, 2008. We discuss the link between DR3 and the supply cushion employed as a trigger to activate the program, identifying deficiencies of the supply cushion measure employed. Finally, we present our efficiency assessment of the DR3 program, applying two measures: 1) whether consumption is reduced when the underlying true cost of the power is greater than its real-time price (short run efficiency), and 2) whether DR3 as presently structured is indeed an efficient alternative to investment in additional peaking electricity generation (long run efficiency).

3.1.2 Key elements of DR 3 Program

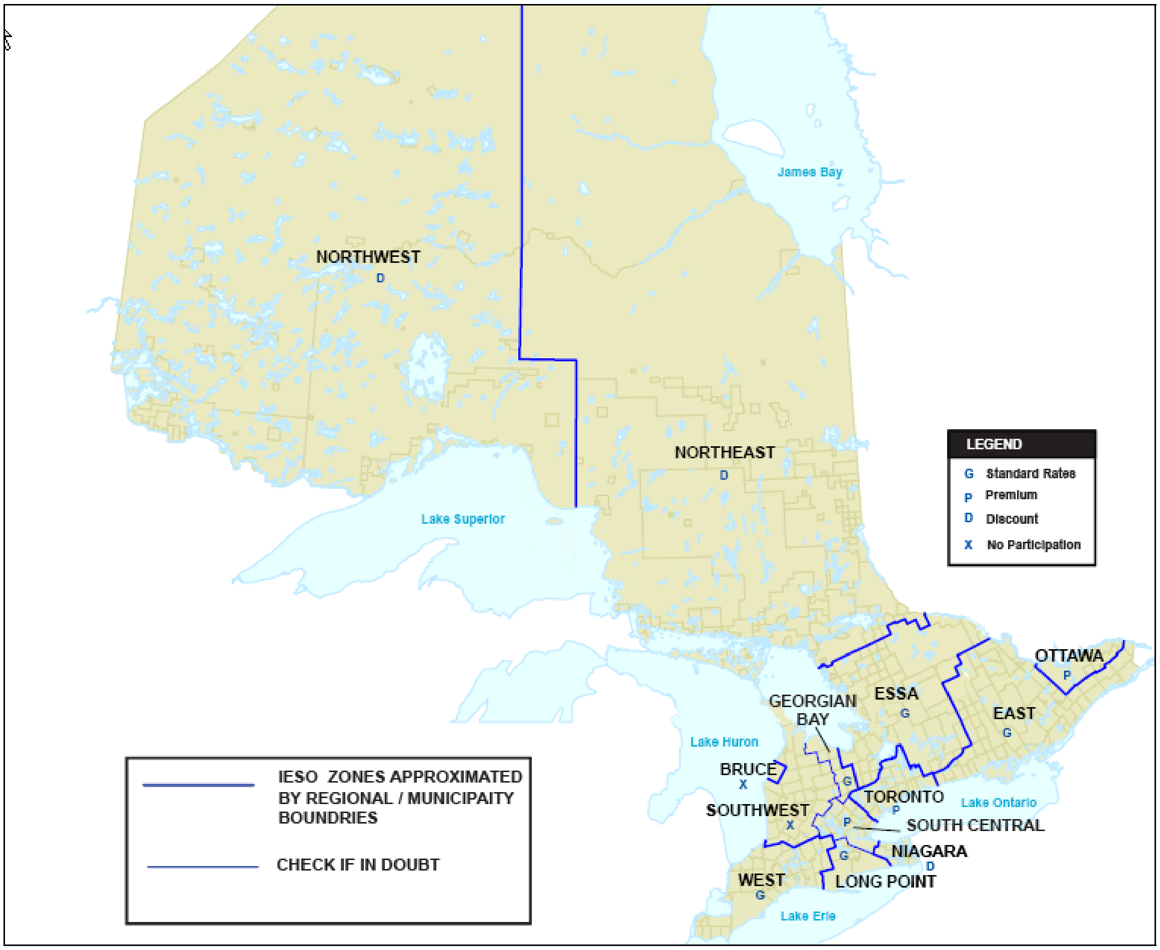
The DR3 program is open to both direct participants and aggregators, provided they contract for minimum load level reductions of 5 MW and 25 MW respectively. A direct participant can consist of multiple interruptible loads with individual minimum loads of 0.5 MW and/or multiple loads with embedded generators with individual minimum capabilities to curtail consumption or produce output of 0.5 MW.[117] An aggregator must consist of multiple interruptible loads with individual minimum loads of 50kW and/or multiple loads with embedded generators with individual minimum capabilities to curtail consumption or produce output of 50 kW. Given these restrictions, OPA expected that aggregators would be important for the success of the program.[118]

DR3 is available in all regions of Ontario except the Bruce area, south western Ontario and a portion of York Region, where the benefit of DR programs may be much lower.

[116] Previous Panel assessments of demand response programs can be found in our December 2006 and December 2007 Monitoring Reports at pp. 128-41 and pp. 142-46 respectively.
[117] 0.5 MW in the summer, 0.4 MW in the winter and 0.3 MW in the each of the shoulder seasons.
[118] Aggregators are allowed to start with a small response capacity and recruit more contributors for the first 12 months after they have registered in the program. It is only in the second year after becoming a participant that an aggregator must meet the minimum 25MW requirement.

These areas, coded as to rate eligibility (explained in the payments section later), are shown in Figure 3-6 below.[119]

Figure 3-6: Applicable Rate by Zone



Source: Ontario Power Authority

Unlike DR1 under which curtailment is voluntary and payments are made if a participant chooses to curtail when instructed by OPA, a participant in the DR3 program must curtail in accordance with activation instructions or face a financial penalty. This program design reflects an assumption that the load reductions are necessary to avoid building a similar amount of peaking generation capacity. In return, the participant is paid a yearly lump-sum standby payment as well as payments for curtailment when instructed. The yearly lump sum payment to a DR3 participant is $130,000/MW-year. We take this as roughly equivalent to the fixed annual cost of a peaking generator.

[119] For details, see: www.powerauthority.on.ca/Page.asp?PageID=924&ContentID=6127.

A participant can be registered in either a 100 hour or a 200 hour category established by the program. In other words, the participant can elect to reduce its contracted demand for periods up to either 100 or 200 hours per year. If a participant wishes to participate beyond the 100 or 200 maximum contract hours, the OPA may approve this, depending on the real time market situation. A contract can last for 1, 3 or 5 years.

As of October 31, 2008, there were six participants with nine accounts (three accounts in the 200 hour category and six accounts in the 100 hr category). The total contracted demand response was 83 MW (approximately 0.44 percent of the average peak Ontario demand of 18,731 MW in 2008). The number of participants is expected to increase, and the demand response available for activation in 2009 is predicted to be 200 to 300 MW.

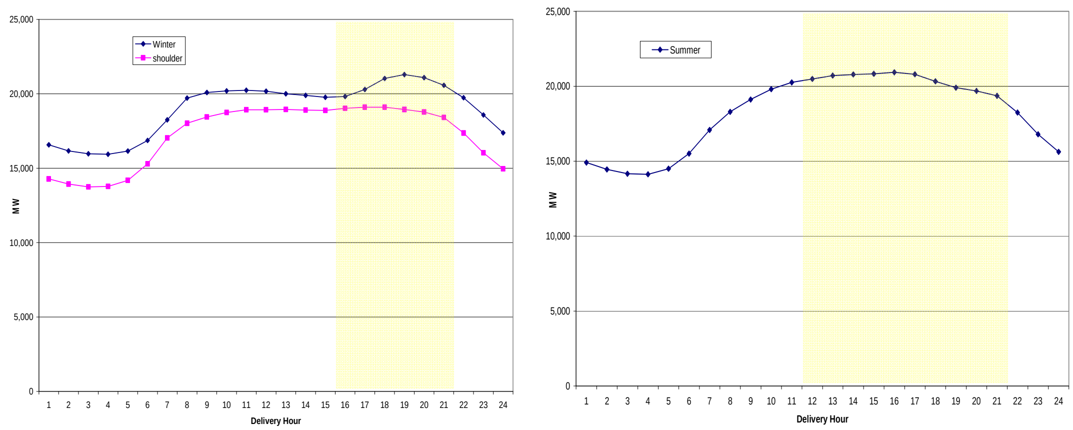
While participants only have to reduce their consumption in 100 or 200 hours per year, they must be available to curtail demand during approximately 1,600 hours, specified as Hours of Availability in each year. Hours of Availability are shown in Table 3-2 below.

Table 3-2: Hours of Availability of DR3

Season	Date Range or Month	Hours of Availability (Business Days Only)
Winter	December 1 to March 31	4:00 pm to 9:00 pm EST
Summer	June 1 to September 30	12:00 pm to 9:00 pm EST
Shoulder	April, May October, November	4:00 pm to 9:00 pm EST

These Hours of Availability roughly reflect the high demand hours in the specified period. Figure 3-7 below depicts the average hourly Ontario demand by season for weekdays in 2007. One can see that the Hours of Availability generally cover the peak demand hours during the day.

Figure 3-7: Average Hourly Demand by Season, 2007



OPA allocates the demand reduction activations of the contracted dispatch hours (100 or 200 hours per year) by season: 60 percent in the summer, 10 percent in the winter, and 15 percent in the spring and fall shoulders respectively. These allocations are approximate; actual dispatch can vary to reflect real-time conditions.

Each activation lasts for a period of at least four hours, with the OPA sending out an Activation Notice at least 2.5 hours ahead. In other words in the 100 hour category there are 25 four hour activations available. Activation is based on the IESO calculated pre-dispatch supply cushion, a measure of potential shortage or tight supply conditions in Ontario. Table 3-3 below lists the trigger supply cushion for each category, which is published on the OPA’s website. The OPA adjusts the trigger supply cushion from time to time.

Table 3-3: Trigger Supply Cushion since the Implementation of DR3, for both the current day and the day ahead, August – October 2008

Effective Period	Supply Cushion Triggers	
	100 Hour (%)	200 Hour (%)
August 1 - August 26, 2008	24	25
August 27 - September 18, 2008	29	30
September 19 - October 31, 2008	18	23

In advance of activation, participants can receive Fixed or Open Standby notices:
When the pre-dispatch supply cushion is equal to or less than the trigger for a period of one hour or more, a Fixed Standby Notice may be issued to participants. Should the conditions persist, this would be followed by an Activation Notice requiring participants to dispatch their demand response resources in 2.5 hours.

When the Supply Cushion is negative (less than 0 percent) for a period of five hours or more, an Open Standby Notice may be issued. Should these conditions persist, the Open Standby Notice would be followed by an Activation Notice.

An Open Standby Notice allows participants to offer and provide demand response resources greater than the contract obligation. In other words, the Open Standby Notice is intended to invite more response than a participant has contracted, although the excess above the contract is not mandatory.

3.1.3 Payments under the DR3 Program

A participant receives a monthly payment from OPA, which includes an availability payment based on the participant's location and a utilization (or activation) payment based on how much consumption is actually curtailed.

Table 3-4 below lists the rate of payment for each type of contract by contract term and location. The table makes reference to premium (+25 percent) or discounted rates (-50 percent), which are applied for different zones in the province, as shown in Figure 3-6.

For example, a participant in the Greater Toronto Area (GTA) with a 25 MW contract capacity and a 5 year contract in the 100 hour category would receive $3.25 million per year (25 MW * 1600 Hours of Availability * $81.25/MWh). By comparison, a participant in the Northwest in the same category would receive $1.3 million per year (25 MW *

1600 Hours of Availability * $32.5/MWh). If activated, each would receive an additional $200/MWh for the first four hours and $300/MWh thereafter.

Table 3-4: Rate Scheme under DR3

	Option A (100 h)			Option B (200 h)		
Reliabililty Rates	95%			95%		
Schedule Term (Years)	1	3	5	1	3	5
Availability Rate ($/MW)	35	50	65	40	60	80
Adjusted Availability Rate (Premium) ($/MW)	43.75	62.5	81.25	50	75	100
Adjusted Availability Rate (Discount) ($/MW)	17.5	25	32.5	20	30	40
Availability Over-Delivery Rate ($/MW)	10			10		
Consecutive Hour of Utilization	Utilization Rate ($/MWh)					
1	200					
2	200					
3	200					
4	200					
5	300					
6	300					
7	300					
8	300					
9	300					

*The premium availability rate is the rate for DR resources located in Toronto, South Central (Hamilton area) and Ottawa zone, the discount rate is for resources in Northwest, Northeast and Niagara zone, and the (standard) availability rate is applied for resources in all other zones expect the Bruce and Southwest zone in which the DR3 program is not available.

***Reliability Rate* is calculated per interval, equal to $\frac{Actual\ \ Activated\ \ MWh\ \ per\ \ interval}{Activation\ \ MW\ \times\ 1/12} \times 100$, where Activation MW is the number of MW, if any, in respect of which the OPA issues an Activation Notice. When a reliability rate is less than 95 percent for a given interval, the DR resource is subject to a payment reduction based on pre-stipulated formula.

3.1.4 Program Activation

From August 1 to October 31, 2008, DR3 was activated eight times for a total of 32 hours, of which 24 hours were in two summer months and 8 hours in one shoulder month. The distribution of activations is roughly in line with the original target allocation. Table 3-5 lists the activation hours, average HOEP and Richview nodal price in these hours, and the total DR payment. (We explain the relevance of including data on the Richview price and a comparison with HOEP in our section on the efficiency assessment below.)

Table 3-5: DR3 Activations, Market Prices, and Payment per Activation August 1 to October 31, 2008

Date	Activation Hour	Activated (MW)	Average HOEP ($/MWh)	Average Richview Price ($/MWh)	Difference (Richview - HOEP) ($/MWh)	Total DR Payment per Activation ($)
08/18/2008	15 - 18	3.0	87.45	94.93	7.48	605
09/02/2008	14 - 17	15.7	136.91	180.64	43.73	3,135
09/03/2008	14 - 17	15.7	103.69	108.14	4.45	3,135
09/04/2008	15 - 18	15.7	76.99	89.52	12.53	3,135
09/12/2008	14 - 17	15.7	52.59	51.65	-0.94	3,135
09/17/2008	15 - 18	15.7	40.89	45.34	4.45	3,135
10/28/2008	17 - 20	47.6	69.26	64.33	-4.93	9,525
10/29/2008	18 - 21	47.6	72.98	68.97	-4.01	9,525
Average		22.1	76.33*	79.75*	3.42	4,416

*these two average prices are weighted by activated MW, i.e. they are the sum of the price times the corresponding activated MW in Column 4 divided by the total activated MW.

Given that most participants were in the 100 hour category and each activation was a four hour block, the target should be the top 25 high demand periods or the top high priced hours in a year. Unless the activation occurs in these hours the peak demand for the system will not be reduced and the construction of peaking generation is unlikely to be reduced.

Table 3-6 below ranks the demand and HOEP of each DR3 activation relative to the peak demand and peak HOEP's in the August to October period of 2008 (since the beginning of the program to the end of this report period). In addition a ranking of the activations to date against the peak demands and HOEP's throughout 2008 was undertaken. The purpose of this second ranking was to use a full year of data as a proxy for seasonal variations that the DR3 program will confront over the course of a year. (The DR3 program is a yearly program the lump sum payment is calculated yearly and the frequency of activation is distributed seasonally).

During August to October of 2008 these activations were neither the high demand hours nor the high priced hours in 2008, implying that the DR3 has so far not met its specific target of “reducing the system peak demand”. In fact, in most activation events, the highest demand or the highest HOEP activation hours were far outside the top 25th Ontario demand and prices. In practice only a portion of the top 25 demand or price events would be expected to fall in the August – October period. The activations on September 2nd and 3rd did hit two of the highest demand hours in the August to October period. Using the full calendar year 2008 as a measure of the success of the seasonal allocation, only one activation would have made the top 25 both on a demand basis and on a HOEP basis. Thus the experience during the first three months of the program suggests a great potential for improvement in triggering activation. It would appear that OPA’s fixed allocation of activations into certain periods of the year including shoulder months such as October and November may cause activations at times when neither the demand nor the price are high.

Table 3-6: Ranks of the Peak Demand and HOEP of Each Activation within Specific Period

Date	Activation Hour	Highest Demand in the hours (MW)	Rank of the Highest Demand in Each Activation		Highest HOEP in the Hours ($/MWh)	Rank of the Highest HOEP in Each Activation	
			Aug - Oct 2008	All 2008		Aug - Oct 2008	All 2008
08/18/2008	15 - 18	22,477	9	58	100.12	78	477
09/02/2008	14 - 17	22,643	3	40	214.00	10	19
09/03/2008	14 - 17	23,016	1	23	105.87	57	371
09/04/2008	15 - 18	21,606	37	184	83.25	173	897
09/12/2008	14 - 17	18,921	268	1,965	78.53	206	1,085
09/17/2008	15 - 18	18,793	301	2,103	41.81	1,282	4,634
10/28/2008	17 - 20	19,320	172	1,521	83.85	169	871
10/29/2008	18 - 21	19,322	171	1,518	87.72	132	733

3.1.5 IESO’ Supply Cushion

The IESO supply cushion calculation that OPA uses for triggering the DR3 is defined as:

> "the total internal resources offered and total imports offered, minus wheels offered minus (forecast Ontario) demand minus OR requirements, as a percentage of (forecast) demand and OR requirements".[120]

The Panel has previously noted that this definition of the supply cushion has defects.[121] The use of total imports as offered is the most problematic. Not all imports can be used as offered because they may exceed the import capability of the different interties, so offers alone may overstate the resource availability. For example, in November 17, 2008 HE 7 to 24, the import capacity on the New York interface was reduced to zero because of transmission outages. However, 600 to 900 MW of imports were still being offered into the Ontario market, which accounted for 4 to 5 percent of the 3 hour ahead supply cushion, although not a single MW could be used by Ontario.

In addition, there can be large variations of import offers across the various pre-dispatch runs so that the supply cushion in the final pre-dispatch run may differ significantly from the three-hour ahead pre-dispatch run which is the latest information available when the DR3 activation decision is made. The effectiveness and efficiency of DR activation is reduced if inexpensive imports are available and scheduled in the final pre-dispatch after DR3 has already been activated. Alternately, if actual imports are lower than implied by the three-hour ahead supply cushion (either because of import limits at the interties or because fewer imports were offered in the final pre-dispatch) there might be no activation when supply is tight.

From January 1 to October 31, 2008, the hourly import offers (corresponding to the defined Hours of Availability (Table 3-2) varied from 6,000 MW to 1,000 MW, for the three-hour ahead pre-dispatch. Figure 3-8 below plots the duration curve of these hourly import offers as a fraction of total domestic demand (i.e. forecast Ontario demand plus OR requirements) for the same period. Import offers (excluding linked wheels) were equivalent to 6 percent to 31 percent of three hour ahead domestic demand as defined by the IESO.

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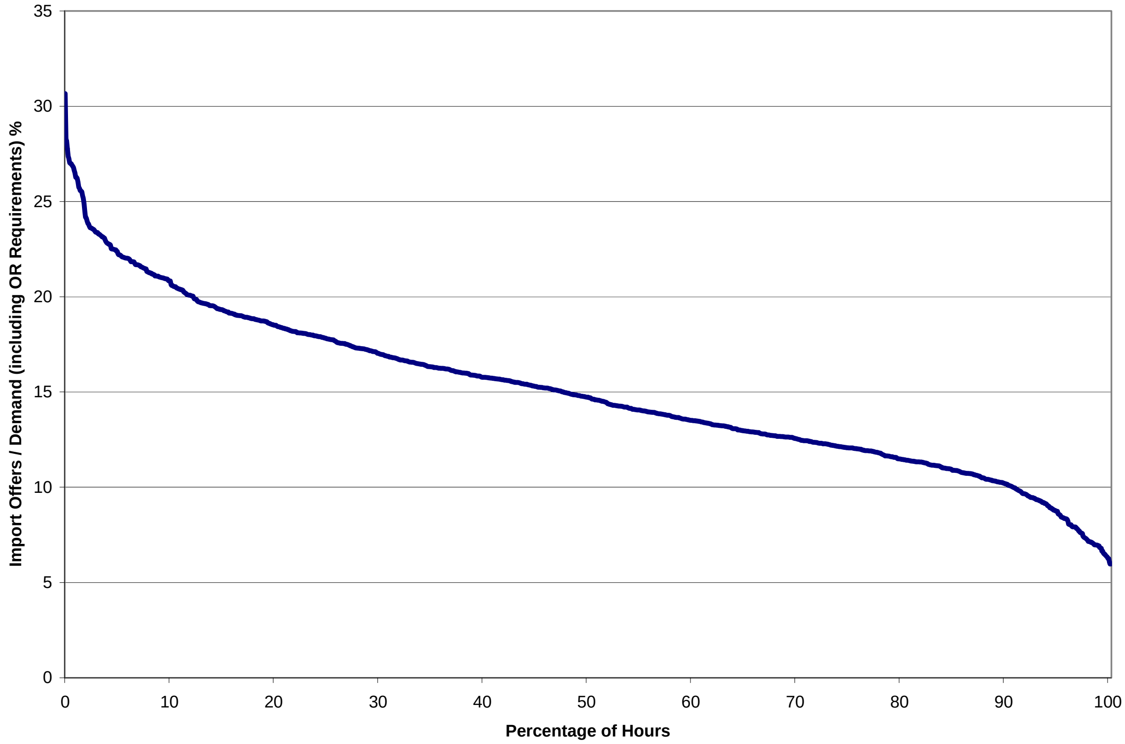
[120] IESO Adequacy Report, accessible at http://www.ieso.ca/imoweb/marketdata/adequacy.asp.
[121] The Panel's July 2007 Monitoring Report, pp 79-82.

Figure 3-8: Hourly 3 Hour-ahead Import Offer Duration Curve
January 1, to October 31, 2008



Because of the imperfectly defined pre-dispatch supply cushion, DR3 activations have led to unnecessary load curtailment in some cases when there is no supply problem or no load reduction at all in other periods when the system was actually tight.

3.1.6 Efficiency Assessment

Short-term Efficiency

The DR3 program has the potential to reduce short-term inefficiencies that arise as a result of deviations between the HOEP and the Richview price (our proxy for the actual cost of electricity).[122] The logic is as follows: (A more technical summary is contained in the appendix at the end of the chapter.)

[122] One of the outcomes of Ontario's uniform price market design is that HOEP does not always reflect the true cost of electricity and so we have adopted the shadow price generated at the Richview proxy bus as the more accurate representation of this cost. This is described in our December 2004 Monitoring Report, pages 57-66..

The focus is on loads that pay the HOEP. These loads consume because they value the electric power concerned more than the HOEP (which is what they pay for it). But the true cost of generation is Richview which may be higher than the HOEP. So there may be loads who value their consumption greater than the HOEP but less than Richview. So this consumption is valued less than its cost. It is efficient if this consumption goes away. But the most we should pay it to go away is the excess of Richview over HOEP. This is because the amount we need to pay people to go away is their consumer's surplus foregone. If we pay more than the excess of Richview over HOEP we will be attracting participants whose consumers surplus foregone exceeds the excess of Richview over HOEP and it is inefficient for them to go away (they value their consumption at more than the Richview price).

As shown in Table 3-5, the difference between the Richview nodal price and the HOEP varied from -$4.93/MWh to $43.73/MWh, with a reduction-weighted average of $3.42/MWh for the eight events. The DR3 paid $200/MWh for every MW reduction (plus the annual lump sum payment), which is well above either the Richview price or the difference between the Richview price and the HOEP in all events.

A difficulty of quantifying efficiency gains or losses induced by this program is that the consumers' true consumption valuation is not revealed. However, DR3's $200/MWh for activation and the yearly lump sum payment may imply that some of these consumers (to be referred to as 'marginal participants') do have a large valuation and/or a large implementation cost for standing-by and curtailing consumption and thus need a large compensation for their participation. The large consumption valuation may include the lost profit opportunity of producing downstream goods or services. In equilibrium, the yearly total payment received by the marginal participant in the DR3 should be just equal to the participant's implementation cost plus its forgone consumer surplus (which is the difference between its consumption valuation and the HOEP). In other words, the marginal participant's real cost of participating in the DR3 program is equal to the yearly total DR3 payment. By definition, the cost incurred by inframarginal participants in the DR3 program will be less. A working assumption would be that the average real cost incurred by all participants (represented as the 'average participant') in the DR3 program would be half the cost incurred by the marginal participant.

To estimate the effect of the DR3 program on allocative efficiency, we assume the Richview price and HOEP are not affected by the load reduction. This assumption is plausible given the relative small size of the DR 3 program at the current stage. We further assume that DR3 activation has perfectly targeted all 100 (or 200) hours with the highest difference between the Richview price and HOEP as these hours offer the highest efficiency gains. This should provide the maximum potential benefit from DR3, given that activation cannot occur in all these hours as a result of the 4 hour block requirement and as shown by the activation events that have occurred so far. Table 3-7 below shows the maximum benefit and the cost of a marginal and average participant in the GTA with a 5 MW reduction capacity in 2007. We choose the Greater Toronto Area as the study location as it is the largest load pocket area in Ontario so that a DR program in the area if well designed could provide the most efficiency gains. 2007 was chosen since it was when the DR3 was designed and the market situation in 2007 should best demonstrate the operation of the program.

The potential yearly benefit from DR3 is the sum of the respective differences between the Richview price and the HOEP during the 100 or 200 hours when this difference is the greatest. This sum comes to $32,000/MW-year over 100 hours and $36,000/MW-year over 200 hours. Assuming that the payments made under the program are just sufficient to cover the costs of the marginal participant, these costs would be $150,000/MW-year for 100 hours and $200,000/MW-year for 200 hours.[123] This implies a net efficiency loss of $118,000/MW-year on the last MW of participation in the 100 hour category and $164,000/MW-year in the 200 hour category.

[123] These are the yearly lump sum payment plus the total activation fees for the 100/200 hour activations.

Table 3-7: Cost-Benefit Analysis for a Marginal and Average Resource, 2007

Category	Maximum Benefit ($/MW-year)	Marginal Resource		Average Resource	
		Cost of Participation ($/MW-year)	Net Benefits ($/MW-year)	Cost of Participation ($/MW-year)	Net Benefits ($/MW-year)
Option A (100 hours)	32,000	150,000	-118,000	75,000	-43,000
Option B (200 hours)	36,000	200,000	-164,000	100,000	-64,000

If the cost of an average participation for all DR resources is assumed to be half the cost incurred by the marginal participant, the average net efficiency loss would be $43,000/MW-year for participation in the 100 hour category and $64,000/MW-year in the 200 hour category.

In summary, the DR3 program as presently designed leads to inefficient consumption decisions by the participants and therefore imposes a cost on the sector.

Long-term efficiency

An argument may be that the DR3 may lead to short term efficiency loss but can still result in long term efficiency gain by avoiding the costly generation construction. As we mentioned before, DR3 can improve long term efficiency if the cost incurred by the program is smaller than the cost of an avoided peaking generator. In this sense, an appropriate comparison between the two alternatives is to compare the real cost of participating in the DR3 program and the additional revenue requirement for a peaking generator or generators to break even. The additional revenue requirement (i.e. revenue shortfall) is the cost that a peaking generator cannot recover from the marketplace through pricing, which represents the required subsidy from another source.

Table 3-8 below compares the required subsidy for a peaking generator and the cost for load participating in the DR3 program The revenue shortfall is the difference between the annualized total cost (fixed cost plus variable costs)[124] and the revenue from the market based on the HOEP.

Table 3-8: Comparison of a Peaking CTU Generator and DR3 Program, 2007

	Revenue Shortfall for a peaking generator ($/MW-year)	Cost to a Marginal DR3 Participant ($/MW-year)	Cost to an Average DR3 Participant ($/MW-year)
All hours when peaking generator is efficient (1146 hours)	111,000	n/a	n/a
Top 200 hours	n/a	200,000	100,000
Top 100 hours	n/a	150,000	75,000

If the peaking generator had operated in all hours when it was efficient to do so (i.e. in all hours when the HOEP is greater than the variable costs), the required subsidy would have been $111,000/MW-year, which is lower than the cost of participating for the marginal participant attracted to DR3 ($150,000 or $200,000), but higher than the cost of an average participant ($75,000 or $100,000). Since the DR3 program payment and assumed cost to the marginal participant would have exceeded the subsidy to the peaking generator, the DR3 program at the margin would be less efficient than a peaking generator in the long run. In other words, the DR3 would have induced long term inefficiency for the marginal participant in addition to the short term inefficiency as demonstrated before.

However, compared to an average participant, the subsidy to a peaking generator would have been higher than the cost of an average participant in either the 200 hour category or the 100 hour category. This indicates that the DR3 program on average has the potential to be more efficient than the peaking unit in the long run.

The potential for the DR3 to be more efficient in the long run however depends on the DR3 successfully targeting the 100/200 highest demand hours, and that this would

[124] We assume that the fixed cost for a peaking generator is $130,000/MW-year which is the yearly lump sum payment to a DR3 participant. The variable cost of a peaking generator is the heat rate of 10,000BTu/KWh times the daily Henry Hub gas price plus $3.3/MWh. These are the same assumptions for a CTU unit in the net revenue analysis of Chapter 1. Note the total cost is not sensitive to the heat rate assumption because the vast majority of the cost is the fixed cost.

actually lead to not building the additional peaking unit. The recent performance of the current DR3 program does not suggest that the DR3 would actually reduce demand at peak (with any certainty) and that therefore additional capacity would still need to be built.

It should be recognised that the DR3 has a shorter contract term (a maximum of 5 year period) than would be required for installing a peaking generator (typically 15 to 20 years). This provides OPA more flexibility in improving the operation of the contracts as well as a more flexible response to changing system conditions that may no longer require the additional capacity.

3.1.7 Conclusions

We first analyzed the short term cost and benefit of the DR3 program and concluded that the program was inefficient as the cost of implementing the program appeared to be much higher than the induced benefit to the market. This conclusion applies to either marginal or average participants.

We also observed no long run efficiency gains if the program attracts loads with high valuation or cost of implementing reduction to curtail consumption. However, the program has the potential to be efficient if the participating loads have a lower consumption valuation or a lower cost of curtailing their consumption and the curtailment were properly targeted to the high demand hours. Unfortunately, the eight activations in the study period have demonstrated that the program was ineffective at targeting those high demand hours. In other words, if the program continues to be applied as in the recent period reviewed, peaking generation could not be avoided and the program will simply be wasteful.

If the DR3 program is to continue, both the IESO and the OPA should assess methods to improve the accuracy of the activation. The main issue about activation is the poor correspondence between the IESO calculated supply cushion hours ahead and actual high demand, high prices or even tight supply in real time. The IESO could derive a supply cushion which is a better predictor of real-time high prices or tight supply and we understand work is underway by the IESO to do so. Whether or not the supply cushion changes, OPA might consider both a second trigger related to the pre-dispatch price as well as reconsider the necessity to allocate activations sesonally.

The short term efficiency can be improved if the DR3 program pays participants only the difference between the Richview price and the HOEP for each MWh of consumption forgone. The long term efficiency could be improved if the DR3 payment were limited to the required subsidy for a peaking generator to break even, and if activations were to occur only in high demand hours. The current payment scheme and trigger for the activation appear to do neither.

Recommendation 3-1:

1) In light of the Panel's findings on the inefficiency of the Demand Response Phase 3 (DR3) program, the Ontario Power Authority (OPA) should review the effectiveness and efficiency of the program.

2) Until that review is completed, to improve short term dispatch efficiency:

- ***(3) the IESO, with input from the OPA, should improve the supply cushion calculation; and/or***
- ***(4) the OPA should develop other triggers such as a pre-dispatch price threshold that could be better indicators of tight supply/demand conditions.***

3.2 Self-Induced CMSC Payments made to Generators Shutting Down

Since electricity demand and prices in Ontario vary across the day, fossil-fired generation typically finds it profitable to operate in the high demand and thus higher priced hours whereas much of the fossil-fired generation will shut-down in other hours when profits cannot be realised.

To be dispatched in the Ontario market, a generator has to be economical to operate. It shuts-down when it views the market as no longer profitable. Slow-ramping generators (typically coal, gas and nuclear units) have technical limitations affecting the time it takes to ramp down and go off-line. Rather than simply removing its offers in hours when it does not wish to operate and being immediately dispatched off, a slow ramping generator has to raise its offer price above the pre-dispatch forecast market price and be dispatched off at its offered ramp rate (MW/minute). The dispatch tools take the rate at which a generator ramps down into account in order to achieve accurate dispatch schedules for all units. The dispatch schedules of all other units reflect the energy being provided by a generator that is ramping down and off.

The price a generator offers when shutting-down may be strategic. When dispatching a generator off, the constrained algorithm respects its ramp rate. However, the unconstrained algorithm assumes the generator is being dispatched down and off three times as fast as the constrained algorithm. Generators in this situation are paid a constrained on payment, the value of which depends on the difference between output in the constrained and market schedules respectively and on the generators offer price. The higher the price at which a generator offers while shutting down, the higher is its constrained on payment. In this case, constrained on payments are self-induced in that they depend on the extent to which generators' offer prices exceed the HOEP while they are shutting down.

The purpose of constrained on payments is to ensure that a generating unit that is constrained on is kept whole based on its offer. This payment assumes that generators' offers are based on their costs. In the shut-down scenario, however, the offers of constrained on units are intended to be well out of the money and are thus not reflective of their costs. These offers are intended solely to facilitate ramping down and eventually off at the pre-specified pace (i.e. the ramp rate) of the generator involved.

Table 3-9 details the monthly constrained on payments to generators for the last hour prior to their shut-down from November 2006 through October 2008. The MAU observed a sharp increase in these payments beginning in October 2008 as a result of a new large gas-fired generator becoming dispatchable. In the past two years, coal-fired generators have received $835,000 in constrained on payments and gas-fired generators have received $6.884 million while shutting down. On average, coal-fired generators were paid $16.30/MWh above the HOEP while shutting down, while gas-fired generators $91.83/MWh while shutting down.

Table 3-9 Monthly Constrained-on Payments by Fuel Type Resulting from Shutdown, (December 2006 to November 2008)

	Coal-fired Generators			Gas-fired Generators		
Month	**CMSC ($1,000)**	**Schedules in the last hour (GWh)**	**$/MWh**	**CMSC ($1,000)**	**Schedules in the last hour (GWh)**	**$/MWh**
Dec-06	45	2448	18.38	256	2,532	101.11
Jan-07	20	1510	13.25	309	2,746	112.53
Feb-07	29	1618	17.92	423	3,612	117.11
Mar-07	53	2304	23.00	296	3,252	91.02
Apr-07	38	1506	25.23	217	1,479	146.72
May-07	16	1836	8.71	183	2,091	87.52
Jun-07	15	1170	12.82	296	3,519	84.11
Jul-07	65	2786	23.33	199	2,206	90.21
Aug-07	47	1158	40.59	297	4,813	61.71
Sep-07	30	1946	15.42	211	2,797	75.44
Oct-07	28	1307	21.42	199	3,192	62.34
Nov-07	29	1447	20.04	252	2,909	86.63
Dec-07	37	2482	14.91	216	3,731	57.89
Jan-08	24	2173	11.04	237	2,628	90.18
Feb-08	35	2091	16.74	280	3,090	90.61
Mar-08	50	1783	28.04	305	3,138	97.20
Apr-08	0	1863	0.00	179	1,961	91.28
May-08	25	2744	9.11	131	994	131.79
Jun-08	38	1986	19.13	359	4,225	84.97
Jul-08	71	3105	22.87	227	3,629	62.55
Aug-08	62	3936	15.75	185	2,167	85.37
Sep-08	7	2064	3.39	279	3,055	91.33
Oct-08	32	2120	15.09	519	3,064	169.39
Nov-08	13	1368	9.50	587	4,514	130.04
Total	835	51,238	16.30	6,884	74,965	91.83

An analogue to self-induced constrained on payments is the self-induced constrained off payments. In one of its early reports, the Panel discussed the issue of self-induced constrained off payments and recommended that:

> "The [IESO] initiate a rule change which does not require the [IESO] to make such payments in the first place or authorises the [IESO] to completely recover self-induced constrained off CMSC payments to generation or dispatchable load."[125]

As a result, a Market Rule change was put into place to enable the recovery of self-induced CMSC payments to dispatchable loads. At that time, there were also discussions with market participants regarding self-induced CMSC payments for generators, but the IESO concluded it was too challenging to devise a general remedy because of the many possible situations leading to these payments and the difficulty of establishing an appropriate / fair CMSC adjustment.

In its December 2007 Monitoring Report, the Panel discussed the issue of self-induced CMSC payments to generators for specific safety, legal, environmental and regulatory requirements. The Panel observed that many of these CMSC payments are not warranted, and recommended that the IESO recover them.

While this recommendation has not yet been implemented by the IESO, the Panel further recommends that CMSC payments resulting from the technical shut-down requirements of generators are another specific type of self-induced payment which should be subject to recovery. The Panel understands that discussions are underway with market participants to make these recommended market rule changes as quickly as possible.

Recommendation 3-2

In an earlier report, the Panel encouraged the IESO to limit self-induced congestion management settlement credit (CMSC) payments to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons. The Panel further recommends that the IESO take similar action to limit CMSC payments where

[125] The Panel's "Constrained Off Payments and Other Issues in the Management of Congestion", July 3, 2003

these are induced by the generator strategically raising its offer price to signal the ramping down of its generation.

3.3 The Day-Ahead Commitment Process

In its report for the period November 2006 to April 2007 the Panel undertook a review of the Day Ahead Commitment Process (DACP).[126] The DACP was introduced by the IESO in the summer of 2006 following a sustained period of extremely challenging operation in summer 2005. The intent of the program was to ensure that sufficient resources are committed day-ahead to meet Ontario's forecast demand. The DACP schedules both imports and domestic generation day-ahead in the constrained pre-dispatch schedule, and offers a guarantee to keep an importer or generator whole provided they are committed via the DACP and actually deliver the energy.

Programs aimed at improving reliability typically provide suppliers with certain financial benefits or guarantees to limit their financial risks if their resources are committed pursuant to the program. As one might expect, the provision of such benefits or guarantees can change supplier offer behaviour and may also affect dispatch efficiency.

The day-ahead cost guarantee allows a generator to recover its production costs to its minimum loading point (MLP), its start and speed-no-load costs plus its variable operating and maintenance costs (O&M) for its minimum run-time. While most of the guarantee components are similar to those of the real-time Spare Generation On-Line program (SGOL), variable O&M is not included in the SGOL. Thus, if a generator believes it will commit its facility in real-time and has a risk it may not fully recover its costs from the market, the variable O&M component of the DA-GCG provides an incentive to be committed day-ahead.

[126] The Market Surveillance Panel's July 2007 Monitoring Report, pages 114-127.

The MAU observed that, as a result of the self-commitment structure where the cost guarantee is independent of a generator's energy offer in the wholesale market, a generator has little or no risk being online and thus has incentives to underbid its marginal cost in order to be scheduled in the DACP. Since its implementation, the DACP has paid generators $58 million for Day-Ahead Generator Cost Guarantees (DA-GCG). As Figure 3-9 illustrates, the DA-GCG has increased in 2008.

Figure 3-9: Monthly DA-GCG Payments
June 2006 through October 2008

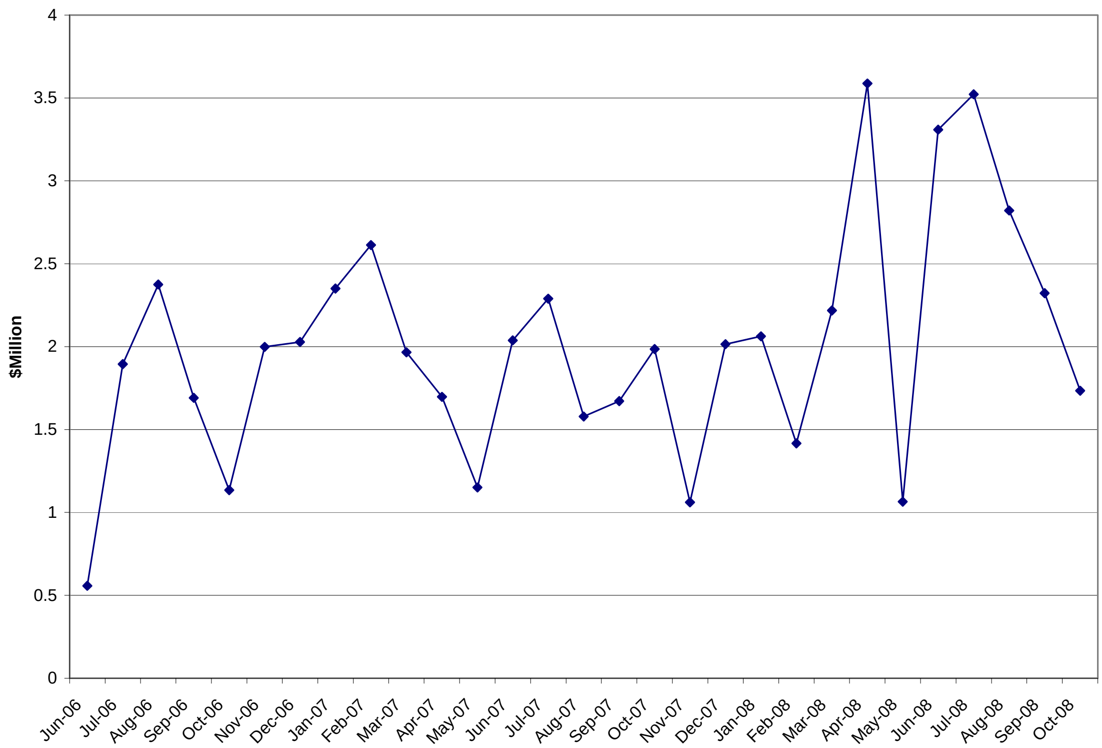


Table 3-10 below shows DA-GCG payments segmented between weekdays and weekends. It can be seen that there has been more and more DA-GCG paid during weekends when there appears to be little or no reliability concern. For example, in 2006 (from June when it was implemented to December) 13 percent of DA-GCG was paid to generators that were online during weekends, while in 2008 (from January to October) 23 percent was paid on weekends.

Table 3-10: DA-GCG on Weekdays and Weekends, ($ million)
June 2006 to October 2008

	2006	2007	2008	Total
Weekdays	11.65	18.39	17.22	47.26
Weekends	1.74	3.93	5.11	10.89
Percentage of GCG on weekend	13	18	23	19

In its July 2007 Monitoring Report, the Panel reported how much coal capacity was unused when one particular large gas-fired generator was committed through DACP on many days during the period of June 2006 to April 2007. Although the results were not conclusive, there was spare coal-fired generation on-line in excess of the gas-fired gas production 60 percent of the time, suggesting much of the gas-fired generation was not needed for reliability. The resulting efficiency loss was estimated at $6.3 million.

The Panel recommended that:

> "the IESO review the DACP in order to reduce the costs and improve the effectiveness of the Generator Cost Guarantee. Three-part bidding with 24 hour optimization, similar to the NYISO methodology, may be one such approach. We further recommend as an interim alternative that the IESO consider mechanisms which allow the full magnitude of domestic generator costs to be taken into account in DACP scheduling decisions."[127]

The IESO has accepted the Panel's recommendation as a high priority and has begun a stakeholder process for an Enhanced Day Ahead Commitment process (EDAC): the implementation of three-part bidding in making Day-Ahead unit commitment decision. The IESO indicates that such a solution is scheduled to be implemented by early 2011.

In the interim, it has recently become evident that new gas-fired generators entering the market are recognising the incentive provided by the present DACP structure to assure themselves of being on-line. During this period, a large gas-fired generator became dispatchable and is consistently offering at a low price into the DACP allowing it to

[127] July 2007 Monitoring Report, p.121.

recover its costs on its relatively high Minimum Loading Point (MLP) through the Generation Cost Guarantee

Under the existing DACP, all eligible generators continue to have an incentive to underbid their marginal cost in order to be scheduled in DACP. Once scheduled and dispatched the generators actual costs are submitted after the fact for recovery via the cost guarantee. Underbidding their marginal cost can lead to either more energy being scheduled at gas-fired generators (ahead of low cost base-load generators) or more gas-fired generators each being scheduled at their minimum output (a greater system-wide start-up cost), both leading to market losses.

By the summer of 2009 close to 2000 MW of new gas-fired generation will be on-line and could use the same Day-Ahead mechanism in the same manner.

Goreway – 860 MW,
St-Clair - 570 MW
Portlands – 550 MW

The Panel believes that until such time as a 24 hour optimisation program can be implemented, more active management of the DACP process by the IESO could reduce reliability premiums and improve efficiency without sacrificing reliability.

The interim solution the Panel recommends includes some form of recognition of the three part bid structure in assessing the guarantee. Rather than comparing revenue received to the total cost submitted after-the-fact, the IESO could use the energy cost bid in the DACP as the energy portion of their required guarantee. The participant would then submit their realized start and speed-no-load costs to determine their total guarantee.

Recommendation 3-3

In consideration of the length of time until the Panel's prior recommendation of an optimized Day Ahead Commitment Process (DACP) can be put in place (estimated to be 2011), the Panel recommends that the IESO consider basing the Generator Cost Guarantee on the offer submitted by the generator or other interim solutions that allow actual generation costs to be taken into account in DACP scheduling decisions.

3.4 Diminishing Operating Reserve Offered by Fossil-Fired Generators

Operating reserve (OR) is a key component of system reliability. In the Ontario Electricity Market, energy and operating reserve are cross-optimised in order to determine the most efficient solution for providing both energy and OR. In this section, we consider the implications of the diminishing amount of OR available from coal-fired generation.

As demonstrated in Chapter 1, OR prices in all categories rose significantly last summer. This was caused by hydroelectric generators having sufficient water to generate energy rather than supply OR as well as by a reduction of OR supply from coal-fired generators to reflect their actual ability to meet Operating Reserve Activations. In the past, the coal-fired generators were often not able to follow the IESO's OR activation instructions as the single ramp rate registered in the IESO database exceeded the actual ramping capability of these generators.[128] Reducing their OR offers was expected to reduce the frequency of non-compliance events and improve system reliability.

Ontario Regulation 496/07 requires the owner and operator of all coal-fired generating stations (Atikokan, Lambton, Nanticoke and Thunder Bay) to cease using coal as of December 31, 2014. The Ontario Government, in a declaration to Ontario Power

[128] Actual ramping capability depends on a variety of factors, including the current production level of the generator. The alternative to offering less OR is to reduce the OR ramp rate. A significant shortcoming of this approach is that due to joint optimization of OR and energy which uses the registered ramp rate as well as ramp rates in the offer / bid, a lower OR ramp rate may reduce energy supply on these units and lead to market inefficiency.

Generation, has set a ceiling on CO_2 emissions from these plants beginning in 2009. It is expected by the Panel that as these coal-fired generators are 'constrained', they will offer less of their capacity as Operating Reserve, which will then have to be acquired from other resources.

When reviewing as alternative sources of OR, it is apparent that OR supply may become a significant concern in the future. For reasons that are unclear to the Panel, gas-fired generators that are being built to replace coal-fired generation generally do not offer operating reserve into the Ontario market.[129] If this situation continues, the full burden of OR supply will fall mainly on hydroelectric generators and dispatchable loads. This will lead to a situation in which gas-fired generators have to be constrained on so that hydro generators can reduce energy production in order to provide OR, even though this will mean spilling water.

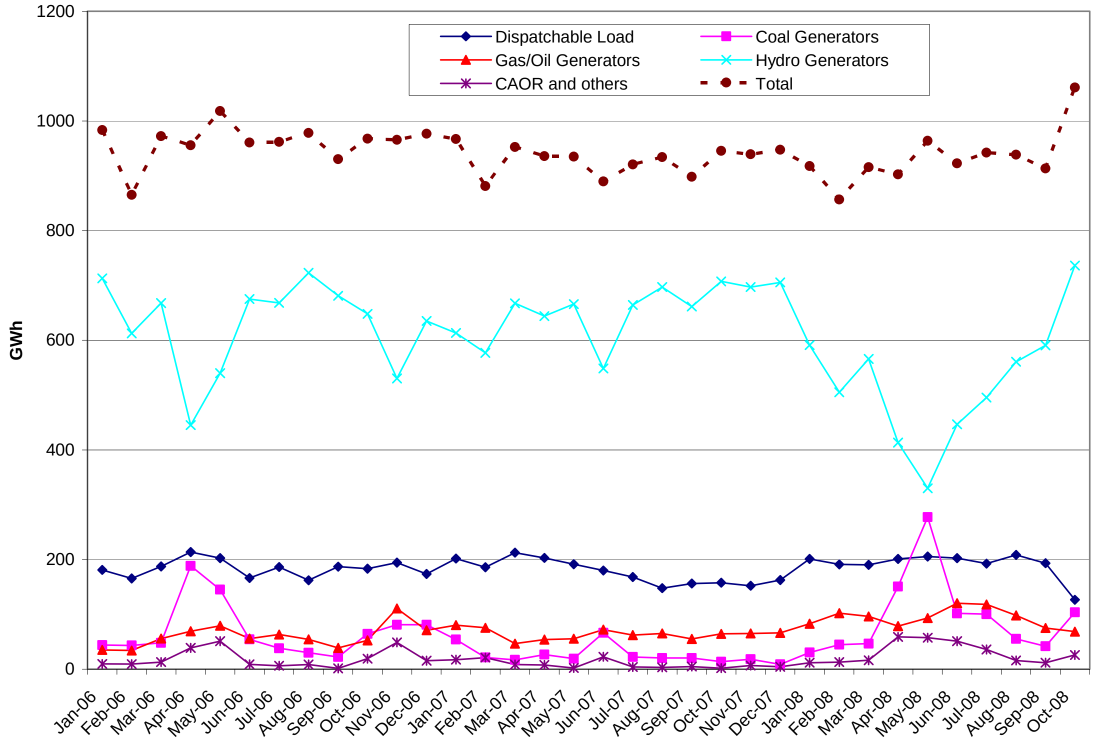
Figure 3-10 below lists the monthly total OR scheduled by resource type since January 2006.[130] Approximately three-quarters of operating reserves were provided by hydro generators in 2006 and 2007 declining to around two-thirds in 2008. From April to July 2008, hydro generators provided less than half the total OR. The total OR scheduled during this period also decreased slightly in May 2007 as a result of a further 50 MW reduction in the OR requirements in May 2007 under the NPCC Regional Reserve Sharing (RRS) program.[131] The significant decrease in scheduled hydro OR largely resulted from greater than normal water availability in the spring and summer of 2008 and hence fewer OR offers during the summer of 2008. The greater availability of water increased the opportunity cost of providing OR because water cannot be stored and would have been spilled if OR were scheduled.

[129] A gas-fired generator can also increase the OR required if the generator has a larger size than a Darlington unit (945 MW), which is currently the largest single contingency in Ontario. The increase in OR requirements will further tighten the OR supply. Currently the total OR requirement is one and half of the size of the Darlington unit minus 100 MW RRS (1.5*945 MW – 100 MW=1,318). However, since mid September 2008, the Ontario OR requirement was periodically increased to reflect the status of a new natural gas-fired generation station which presents a single contingency greater than the output of the largest Darlington unit.

[130] All generators located in Northwest are excluded because the transmission lines from Northwest to South are congested most of the time and the OR supply in Northwest is not critical to Ontario in general.

[131] As a part of the NPCC RRS program, the IESO already reduced the OR requirement by 50 MW in January 2006.

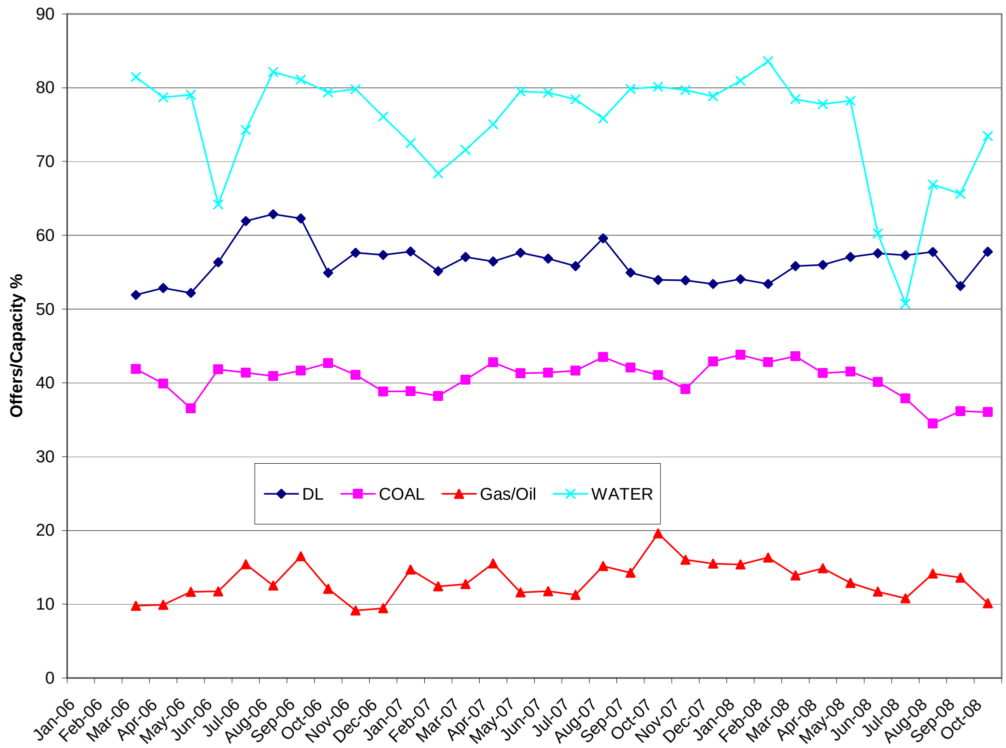
Figure 3-10 Total OR Scheduled by Fuel Type, January 2006 to October 2008



The schedules of 'CAOR and others' (over 95 percent were CAOR) also increased materially during the period April to June 2008. A historical high of 50 GWh was reached in May 2008. Real-time CAOR is backed by a voltage reduction rather than by generation.

Figure 3-11 below depicts the percentage of capacity offered for operating reserves by resource type.

Figure 3-11: Total OR Offered Relative to Capacity by Type of Resource January 2006 to October 2008



- Peaking hydro generators typically offer 70 to 80 percent of their capacity as OR. These resources are the most flexible in providing OR because most have no minimum output level and can ramp from zero MW to their maximum capacity in a few minutes. The remaining capacity is typically baseload hydro resources (which also provide AGC). Scheduling OR on baseload units would mean spilling water, which is inefficient. It can also be seen that since June 2008, the MW offered for OR has declined.
- Dispatchable loads typically offer 50 percent to 60 percent of their maximum consumption level as OR.
- Coal-fired generators have offered about 40 percent of their capacity in most months. The drop in the OR offers in the summer of 2008 was a result of an effort by coal-fired generators to improve ORA compliance.

- Gas/oil-fired generators generally have been offering only 10 to 20 percent of their capacity.

It is most efficient to use inexpensive resources for energy and extra marginal resources for OR. In the Ontario market these are gas-fired generators and energy-limited hydroelectric generators priced at opportunity cost. Although the installed capacity of gas-fired generators has been increasing over the last few years, most of the OR offers are from a small gas generator that was built long before the market was opened. Newly built gas-fired generators are not offering OR. It is the Panel's understanding that there are no technical reasons why these generators cannot provide OR, although the high Minimum Loading Point (MLP) on these generators prevents them from offering a large amount of OR.

The lack of OR offers from gas-fired generators may lead to dispatch inefficiency. When total energy and OR demand requires the scheduling of hydro, coal and gas-fired generation, the efficient solution is normally to run the lower cost generation, baseload hydro and coal, for energy and to schedule dispatchable loads, gas-fired generation and peaking hydro for OR. The inefficiency comes when gas-fired generation cannot be used for OR, because they have not offered, and high cost gas-fired generators are constrained on (automatically by the DSO or manually by the IESO) so that either baseload hydro or coal-fired generators can be released to provide OR. The DSO responds to a shortfall in OR supply by dispatching down some lower-cost generation such as baseload hydro or coal generators, in order to release their capacity for OR. The DSO then dispatches high cost gas generators to replace the hydro and coal generators. With coal generators being phased out, the only resource presently that can be constrained down to provide OR will be baseload hydro generators, even if this leads to spilling water. This will most likely occur during the freshet period.

The Panel noticed that the Market Rules count the revenues from supplying Operating Reserve as part of total revenue when DA-GCG and SGOL-GCP is calculated.[132] In other

[132] Market rules, Chapter 9, section 4.7B.1 for SGOL-GCG and section 4.7D.1 for DA-GCG.

words, when a GCG payment is made to a generator, any revenue derived from supplying OR will be subtracted from that payment by the IESO. This rule would appear to discourage generators receiving a cost guarantee payment from providing OR.

The Panel will continue to examine this issue to determine if the reluctance of new gas-fired generation to supply operating reserve stems from technical problems or whether there are issues of market or contractual design involved.

Recommendation 3-4

As coal-fired generators are eventually phased out, the market will require replacement for this source of Operating Reserve (OR). New gas-fired generators are generally not offering OR. The Panel recommends that the IESO and OPA explore alternatives for obtaining appropriate OR offers from recent and future gas-fired generation entrants.

3.5 A Market Participant's Response to Environmental Issues

3.5.1 Introduction

In March 2007, a market participant notified the MAU that it intended to change its offer strategy by applying a negative adder to offers submitted for fossil-fired generation at its 'Facility A'. A negative adder means that the market participant would offer this capacity into the market at a price below incremental cost. This generation is equipped to remove most of their sulphur dioxide (SO_2) and nitrogen oxide (usually referred to NO_X, a generic term for mono-nitrogen oxides). The participant explained that the negative adder was implemented to ensure that 'Facility A' capacity would be dispatched before generation at 'Facility B' that is considered by comparison a higher emitter.

The market participant's fossil-fired units at Facility A and B use blends of different types of fuel. Since 2007, the cost of the principal type of fuel used by Facility A has increased substantially relative to the fuel cost of Facility B. As a consequence, in order to have its lower emitted units at Facility A running in preference to units at Facility B, the participant progressively increased the negative adder applied to the two lower emitted units offer prices.

When provided with a MAU assessment of the potential market impact of its offer strategy in August 2008, the market participant responded as follows:

> "*[we], modified [our] offer strategy for these units in order to improve the air quality in the Ontario air-shed and to act in a manner consistent with the Government's environmental policies. While the change results in a small impact to the overall market and [us], this cost is more than offset by the public benefits that flow from the change in strategy. [We do] not believe that it is in the public interest to have cleaner units sitting idle while units that have a greater environmental impact are running.*"[133]

While the market participant was unable to provide even a rough indication of the magnitude of the public benefits resulting from its offer strategy, its actions clearly reduce market efficiency and the magnitude of this efficiency loss can be estimated. In the following sections we estimate the potential efficiency and price impacts of this offer strategy and examine its rationale and relationship to the relevant provincial environmental regulatory framework.

3.5.2 Background

The market participant introduced its negative adder in order to reduce aggregate emissions of SO2 and NOx from its fossil-fired units. These emissions are different from emissions of green house gas (CO2) which were the subject of a Directive by the Ontario Government May 15, 2008.[134] Our understanding is that the Facility A generations emits approximately one-third of the NOx emission and about one-fourth of the SO2 emissions relative to generation at Facility B.

[133] Letter dated September 29, 2008 from the participant to the MAU.
[134] See Chapter 3, section 3.6 for a discussion of the CO_2 Directive.

The market participant has confirmed that the offer strategy described above is not required to comply with environmental standards imposed the Ontario government with respect to NO_X and SO_2 emissions.

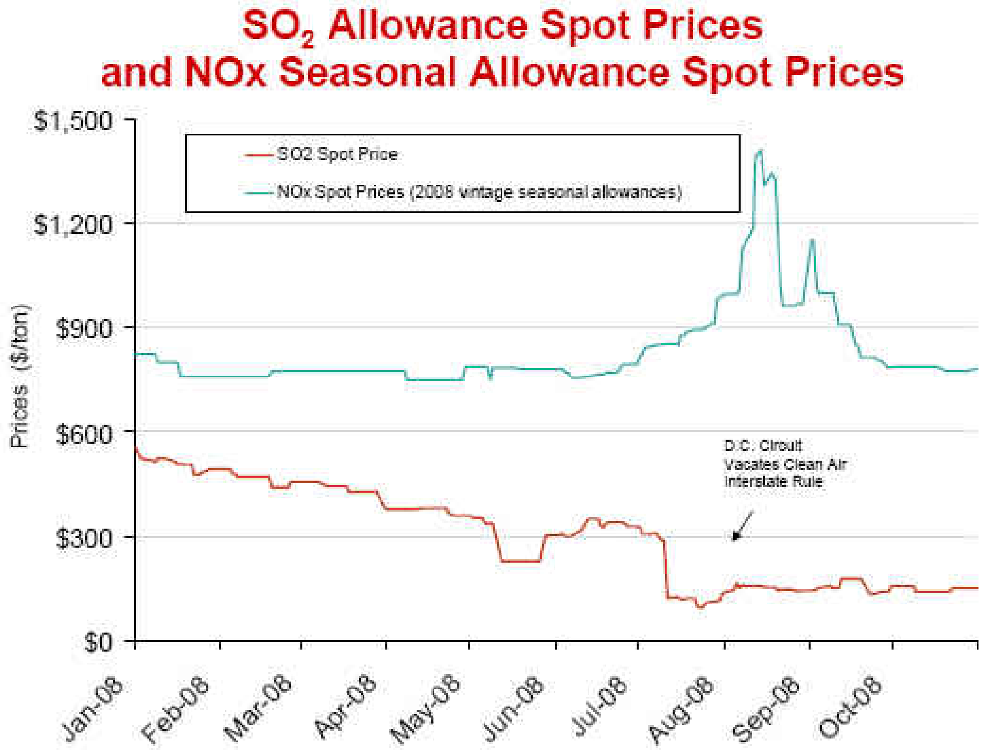
A 'cap, credit, and trade' emissions trading program covering NOx and SO_2 emissions has been in place in Ontario since December 2001. The Ontario Ministry of Environment allocates the emission allowance and has established the Ontario Emissions Trading Code, which sets out rules on the creation and transfer of Emissions Reduction Credits (ERC's) among participants and outlines the rules for the operation of the Emissions Trading Registry.[135]

In 2002, the program was limited to Ontario's coal-fired and oil-fired electricity generators. Today, the emissions trading program has been expanded to include seven major industrial sectors. Emissions allowances are granted annually based on the Ontario government's emissions targets (established allowances) for each sector and region. Each emitter (facility specific) with a soft cap is required to keep its annual emissions levels below the allowed amount or purchase additional credits from other emitters in the same category or reallocate allowance between its own facilities. Emitters with a soft cap can also bank excess allowances and use them in subsequent years. Finally, if approved by the Ministry, participants that emit below their cap can earn ERC's and can sell their credits to other participants to help them meet their emissions targets.

Although allowance and ERC price information does not appear to be publicly available in Canada, the United States provides some information on allowance prices in their cap-and-trade program. Figure 3-12 plots SO_2 and NOx prices (in $USD) between January 1 and October 31, 2008.[136] The figure shows that NOx and SO_2 credits do have significant value, although prices can be volatile as seen in 2008 as prices for NOx credits spiked in the middle of the year while prices for SO_2 credits have been steadily declining since the beginning of the year.

[135] Ontario's Emissions Trading Code is available at http://www.ene.gov.on.ca/programs/5295e.pdf
[136] This figure is available on the Federal Energy Regulatory Commission's (FERC) website at: http://www.ferc.gov/market-oversight/othr-mkts/emiss-allow/othr-emns-no-so-pr.pdf

Figure 3-12: Daily U. S. SO_2 and NOx Prices, $USD/ton, January 1 to October 31, 2008

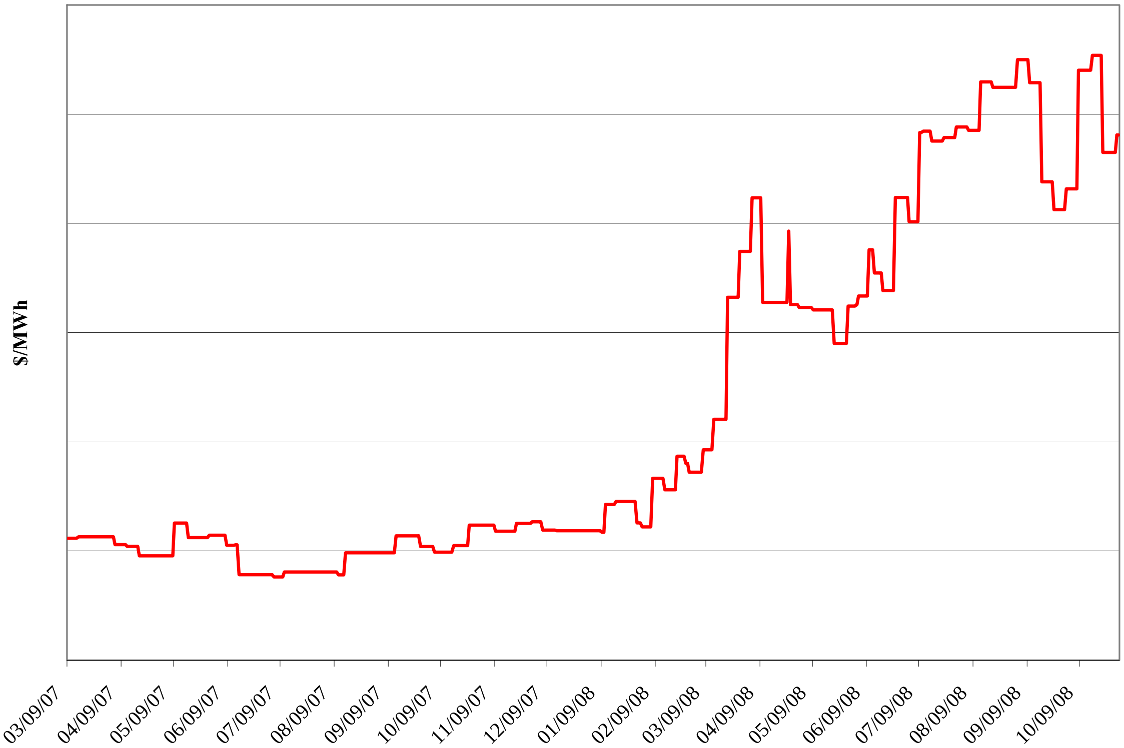


(Source: FERC)

3.5.3 Estimated Price Impact

Figure 3-13 presents the relative change in negative adder values that the market participant applied to Facility A offers between early March 2007 and October 2008. The negative adder increased markedly after March 2008 and this continued into the autumn of 2008.

***Figure 3-13: Negative Adder Applied to Offers at Facility A,
(March 9, 2007 – October 31, 2008)***



The generation with the negative adder and the generation at Facility B are often the price-setters in real-time, especially during off-peak hours. Over the past 12 months, these units were marginal over 45 percent of all intervals combined (almost 54 percent during off-peak intervals). Everything else being unchanged (including exports), the participant's offer strategy would have suppressed the HOEP and this effect was greatest during the recent summer months when the negative adder rose to much higher levels. To assess the effect on the HOEP of offering Facility A generation units at prices below their incremental costs, the MAU ran the real-time unconstrained simulation tool for all hours between November 2007 and October 2008 without the negative adder. The real-time simulation assumes no changes in real-time export/import schedules. The results are reported in Table 3-11 below.

Table 3-11: Simulated Monthly Price Levels with and without the Negative Adder at Facility A
November 2007 – October 2008
($/MWh)

Month	All Hours				On-peak hours				Off-peak Hours			
	Base Case MCP*	Simulated MCP	Diff	% Diff	Base Case MCP	Simulated MCP	Diff	% Diff	Base Case MCP	Simulated MCP	Diff	% Diff
Nov-07	47.05	47.25	0.21	0.4	56.47	56.55	0.08	0.1	38.04	38.36	0.32	0.8
Dec-07	49.27	49.89	0.62	1.3	63.07	63.40	0.33	0.5	39.74	40.56	0.82	2.1
Jan-08	40.63	41.50	0.87	2.1	50.64	51.05	0.41	0.8	31.64	32.93	1.29	4.1
Feb-08	51.00	51.45	0.45	0.9	66.14	66.23	0.09	0.1	38.75	39.48	0.73	1.9
Mar-08	56.89	58.49	1.60	2.8	68.79	69.60	0.81	1.2	48.67	50.81	2.14	4.4
Apr-08	47.37	49.28	1.91	4.0	62.40	65.06	2.66	4.3	34.09	35.34	1.25	3.7
May-08	34.31	36.05	1.74	5.1	47.03	49.39	2.36	5.0	23.84	25.07	1.23	5.2
Jun-08	56.80	58.70	1.91	3.3	75.18	77.14	1.95	2.6	42.08	43.95	1.87	4.4
Jul-08	56.49	58.88	2.39	4.2	82.73	84.92	2.20	2.6	34.88	37.44	2.56	7.3
Aug-08	46.46	50.46	4.00	8.6	60.50	65.72	5.22	8.6	35.87	38.95	3.08	8.6
Sept-08	49.05	53.45	4.40	9.0	58.61	63.38	4.78	8.1	40.68	44.76	4.08	10
Oct-08	45.06	50.04	4.99	11.1	55.70	62.35	6.65	11.9	35.52	39.02	3.50	9.9
Nov 07 to Apr 08	48.70	49.64	0.94	1.9	61.25	61.98	0.73	1.2	38.49	39.58	1.09	2.8
May 08 to Oct 08	48.03	51.26	3.24	6.7	63.29	67.15	3.86	6.1	35.48	38.2	2.72	7.7
Nov 07 to Oct 08	48.36	50.45	2.09	4.3	62.27	64.57	2.29	3.7	36.98	38.89	1.91	5.2

* Base Case is the simulated price using actual real-time information. It may or may not be exactly the same as the actual HOEP because of a slightly different convergence algorithm between the MAU's simulator and the IESO DSO.

The simulation suggests that between November 2007 and October 2008, everything else unchanged, the HOEP would have been $2.09/MWh higher ($0.94/MWh higher for the November 2007 to April 2008 winter period and $3.24/MWh for the May to October 2008 summer period), on average, if the market participant had offered the Facility A generation at incremental cost (which would include the costs of emissions permits and compliance). Table 3-11 also illustrates that as the negative adder increases, the impact on the HOEP increases, estimated at almost $5/MWh in October 2008. When separated by off-peak and on-peak hours, the average price differences were $1.91/MWh and $2.29/MWh respectively. However, when the percentage differences are compared, off-peak prices were suppressed by 5.2 percent compared with on-peak at 3.7 percent.

It is important to note that these price simulation results represent the upper bound of the impact of the negative adder on the HOEP. That is, the price-suppressing effect of the market participant's offer strategy was likely smaller than the simulation implies. The reason is that the simulation does not allow for an import/export response to the price change. The downward pressure on the HOEP would have been offset at least in part by an increase in exports and a decrease in imports. Any increase in net exports would require the scheduling of more Ontario generation and reduce the suppression of HOEP.

3.5.4 Efficiency Impact

Based on information provided by the market participant (negative adder data and confirmation that it includes all emissions costs in its offers), the MAU was able to estimate the true incremental cost for the generation with the negative adder and thus approximate the magnitude of the consequential efficiency loss. Efficiency loss results when generating units are scheduled out of merit with respect to the true cost of producing the energy. In this case, the negative adder had the effect of reducing the offer price for the Facility A generation so that these units were scheduled ahead of other units even though they had a higher incremental cost.

Efficiency loss occurred if generation with a negative adder or generation at Facility B was marginal in a given hour.[137] When these units were at the margin, some cheaper generation capacity at Facility B was displaced by the generation with the negative adder. The efficiency loss is approximately equal to the displaced output times the difference between the incremental cost of the generation with the negative adder and the generation at Facility B.

To estimate the magnitude of the efficiency loss resulting from the use of the negative adder, we calculated the amount of lower-cost energy at Facility B that was displaced by

[137] When the generation with the negative adder and generation at Facility B were both inframarginal, there is no efficiency loss because Facility B capacity is not displaced by Facility A. By the same token, when a cheaper unit than the generation with the negative adder is marginal, neither Facility B nor the Facility A negative adder generation are needed and as a result there is no efficiency loss.

the higher cost output from Facility A (above minimum loading point)[138] and multiplied the result by the price differential between the average offer of generation with a negative adder and the average offer by Facility B.[139]

The total efficiency loss was estimated to be $18.7 million between November 2007 and October 2008. Of this, $2.2 million was attributable between November 2007 and April 2008, compared with $16.5 million between May and October 2008 when the negative adder was at higher levels.[140]

3.5.5 Conclusion

The negative adder may have led to some reduction in emissions of NOx and SO_2 by replacing the output from Facility B, but the effort was partially offset by increased inefficient exports which in turn increased the overall production from fossil-fired generation. The negative adder also induced an $18.7 million efficiency loss because of higher cost generating units being dispatched ahead of lower cost units.

Under a cap-and-trade system, a generator's offer price should include the cost of purchasing the requisite emission credits (or the opportunity cost of using them rather than selling them). Similarly, if there is an emissions ceiling (such as has been placed on CO_2 from coal fired generators) a positive adder can be used to limit the number of occasions during which the generators concerned are dispatched and ensure that this dispatch is confined to the highest priced hours.[141] The negative adder does not properly reflect generation and environmental costs.

[138] In the efficiency analysis, we only considered scheduled output above the Minimum Loading Point (MLP) as it can be argued that the relevant units would likely have been online in many of the hours for at least their minimums regardless of the whether the negative adder was applied or not. The assumption that units would have been online in all of the hours for at least their minimums is considered conservative.

[139] Typically, fossil generators offer energy in 20 price-quantity pairs. For simplicity of the efficiency calculation, offers made at price-quantity pair 10 were analyzed.

[140] If the assumption about only considering output above MLP in the efficiency estimate is relaxed, the efficiency loss was $21.9 million. We did not consider the case where Facility A offers might also have undercut the offers at competing gas-fired generators as a result of the negative adder. There were a few days in the relevant period where the offer prices of some gas-fired generators were lower than the offers of some coal-fired generators and the negative adder generation at Facility A was offered ahead of these cheaper gas-fired generators. In situations where one of these units was marginal, the estimated efficiency loss may be slightly understated.

[141] See the discussion in section 3.6 below.

We have considered whether the market participant's strategy constitutes gaming or abuse of market power and conclude that it does not. A market participant is free to offer their resources at whatever price they deem appropriate and we would investigate and refer the matter to the OEB, the IESO, or other authorities only if we had reasonable grounds to believe that the market participant had taken advantage of the market rules leading to unintended consequences (gaming) or that effective competition was impeded by actions of a market participant with market power (abuse). Although it would appear that the market participant has offered some of its resources below cost, we have seen no evidence suggesting that this could be considered predatory pricing; e.g., causing competitors to withdraw from the Ontario market or in some other manner disciplining or chilling competitive behaviour. Based on our review it would appear that active intertie competition has to some extent neutralized the price depressing impact of the negative adder. We have asked the MAU to continue to monitor the situation.

While we have concluded that the market participant's conduct should not be referred to the OEB or other bodies, we believe that market efficiency could be improved had the market participant taken a different approach. As detailed in Chapter 4, there are quite acceptable ways to respond to environmental standards. The Panel believes that self-determined environmental targets do not excuse inefficient practices.

Emission targets established by the proper regulatory authorities implicitly reflect a judgement about the relative overall benefits and costs of the chosen level of pollution. The benefit of a further reduction in the emission levels below the established standard is likely to lead to greater inefficiencies in the market. In the current case, the over-reduction by the market participant led to an estimated net efficiency loss of $18.7 million to the market.

Recommendation 3-5

The Panel recommends that market participants' offers should reflect environmental costs flowing from the environmental standards established by the applicable regulatory authorities.

3.6 Minister's Directive Regarding the Reduction of CO2 Emissions

3.6.1 Introduction

In May 2008 the Minister of Energy issued a Declaration related to the reduction of CO_2 emissions from OPG's coal-fired generating stations. The Declaration and subsequent Shareholder Resolution required OPG to meet annual limits on CO_2 emissions for the 2009 and 2010 calendars years.[142] The targets of 19.6 and 15.6 million metric tonnes, respectively, are to be achieved 'on a forecast basis' with a plan for doing so being submitted to the Minister no later than November 30 prior to each year.

Additional emissions are allowed if needed for reliability (i.e. as a result of a reliability-must-run contract, or pursuant to a direction by the IESO). The directors of OPG are to ensure the resolution is carried out in "a prudent and cost-efficient manner" and "in accordance with sound commercial practice for a corporation involved in the generation of electricity".

This Declaration followed Ontario Regulation 496/07 requiring the cessation of usage of all of OPG's coal-fired stations by the end of 2014, and the subsequent amendment that placed a 'hard cap' of 11.5 million metric tonnes on CO_2 emissions in the calendar years 2011 to 2014 (well under one-half those experienced in recent years).[143]

In addition to the stakeholder Declaration, the Minister directed the Ontario Energy Board to amend the licences of OPG and the IESO, with respect to Market Based

[142] "Addressing Carbon Dioxide Emissions Arising from the Use of Coal at its Coal-fired Generating Stations, May 15, 2008." http://www.opg.com/about/governance/open/directives.asp
[143] Ontario Environmental Registry at http://www.environet.lrc.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTAzNDQx&statusId=MTU0NTQ3&language=en

Ancillary Services.[144] The change allows OPG to "…offer less than the maximum available amount of any category of operating reserve where this is necessary in order for OPGI to satisfy its obligations… relating to, carbon dioxide (CO2) emissions arising from the use of coal at OPGI's coal-fired stations"[145]

3.6.2 The Plan

On November 28, 2008, OPG submitted its *Implementation Strategy for 2009* to the Minister, highlighting OPG's business strategies to meet the emission target in 2009.[146] In the implementation plan, OPG indicates it will use a combination of four strategies:

(i) Planned outage strategy: designating certain planned outages as "CO_2 outages":

(ii) Operating strategy: not offering all units that are available at the Nanticoke and Lambton stations, i.e., assigning some units at the two stations as "Not Offered but Available" (NOBA):

(iii) Offer strategy: applying a uniform emissions cost adder to all offers made for all coal-fired generating units in all hours in 2009: and

(iv) Fuel strategy: purchasing coal on contract to meet the emission target on a forecast basis, and on the spot market to provide flexibility to adjust production capability if requirements exceed forecast.

OPG will use the existing planned outage process to designate certain planned outages as "CO_2 outages". No CO_2 outages will be scheduled in January, July and August. OPG expects that the IESO could recall these outages for reliability, but only where the IESO cannot resolve the reliability problem with other available actions. The emissions associated with such recalls will be excluded from OPG's emission monitoring calculation.

[144] OEB Decision and Order EB-2008-011 at http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0114/dec_order_ieso_opgi_20080624.pdf , June 24, 2008.
[145] Electricity Generation Licence EG-2003-0104 Ontario Power Generation Inc. October 8, 2008 (most recent version) , Part 5(a.1) http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/83486/view/amd_licence_dec_order_eg_opgi_20081002.PDF
[146] "OPG's Strategy to Meet the 2009 CO2 Emission Target" at http://www.opg.com/safety/sustainable/emissions/carbon.asp

OPG will not offer all remaining available units into the market at all times. By doing so, OPG expects to reduce the number of starts at its coal-fired fleet and thus its total costs. Those NOBA units can be offered into the market and operated within a short time if required by the IESO for reliability reasons and the resulting emissions will be excluded from OPG's emission monitoring calculation. OPG plans to utilize 78 unit-weeks of NOBA designations in 2009, but none will occur during January, July and August. This is equivalent to 2 units per week for the remaining 39 weeks of the year. OPG will provide the IESO sufficient notice and details of its NOBA strategy to incorporate the information in its outage approval and reliability assessment processes.

OPG has estimated an emission adder of $7.50/tonne (approximately $7.50/MWh) that when added to the effects of the CO_2 outages and NOBAs would yield total annual CO_2 emissions that would meet the 2009 target of 19.6 million metric tonnes on a forecast basis.

Because of market uncertainty and the limitations of its simulation tools, OPG has reserved the option of adjusting its emission adder and / or the number of NOBA units so that the emission, on a forecast basis, falls within the annual target. OPG will make any change in the emission adder public one month before its implementation. (Note that, NOBA and CO_2 outages will only be known indirectly as part of the IESO's outage approval process and adequacy assessment information.) OPG also will provide the Ministry with the year-to-date actual emissions and updated forecasts of year-end emissions each month starting in March 2009.

3.6.3 Assessment

Generally, the Panel views OPG's adder strategy as consistent with the efficient operation of the Ontario market, with some potential reservations on the application of the NOBA and extended CO_2 planned outage strategies. The Panel appreciates that this is the first year of an ambitious effort to respond to the government's CO_2 reduction targets and the comments below are offered with a view to encouraging OPG to implement this directive in a manner which minimizes negative impacts on market efficiency.

In principle, the Panel believes that an adder strategy is in line with the concept of opportunity cost pricing which can be the efficient way to manage the supply of a scarce resource. Whether or not the magnitude of the adder is adequate to meet the target is a different question. In light of the emissions cap, the Panel considers OPG's coal-fired generation as an energy-limited resource because the total annual production level is effectively capped as a result of the emission target. The Panel views the $7.50 adder as the opportunity cost of the scarce emission limit, although it is only an estimated value at a point in time. By reflecting the emissions' opportunity cost into its offers, the cost is transparent to the market in that it affects market prices and other suppliers and consumers can respond to this signal. The panel is encouraged that OPG may revise the adder periodically if the actual results are not close to the emissions target.

The Panel has no comments on OPG's fuel strategy, as it does not appear to have any direct connection to the Panel's mandate to monitor for market power and efficiency of the market.

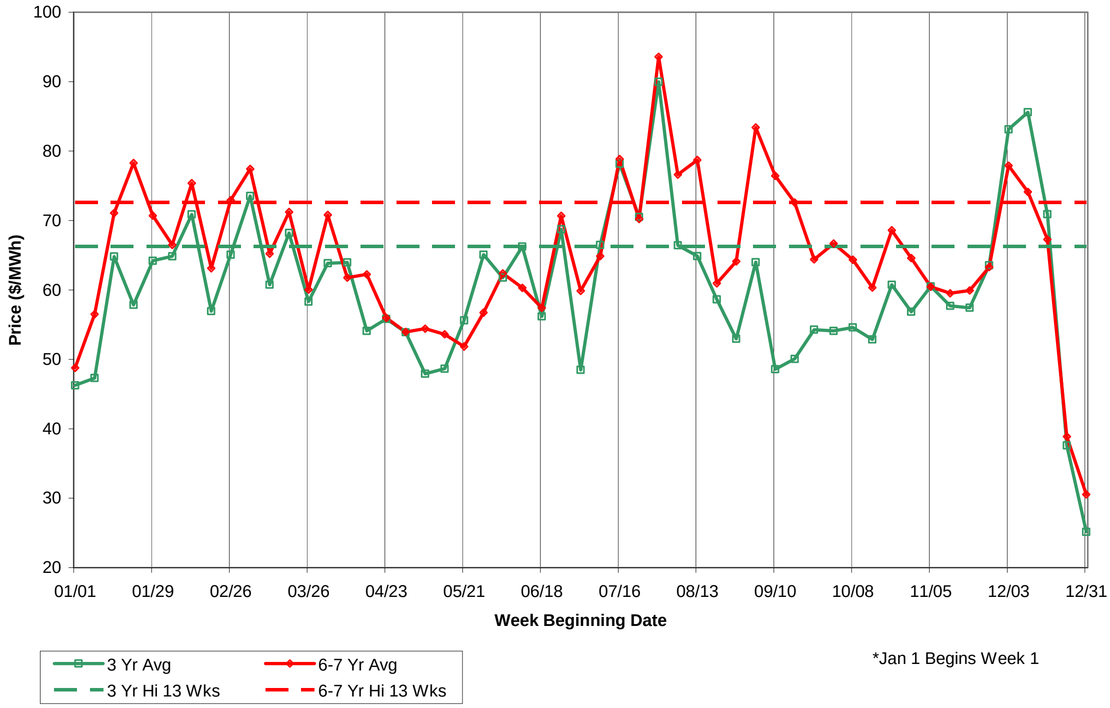
With respect to the NOBA operating strategy, however, the Panel questions its necessity and is concerned about its adverse impact on market efficiency. By 'parking' (not offering) some available units, OPG expects to avoid running these units and thereby minimize the associated costs (such as the start-up cost and the cost to run the unit at its minimum production level). If the units are needed because of forced outages at other coal-fired units or the IESO's directives, OPG would place offers into the market so they could be scheduled. Except for using a NOBA unit to replace other units that are forced out of service, these units would only be offered following out-of-market actions by the IESO for reliability, rather than in response to market signals.

The Panel sees this as neither necessary nor efficient. OPG could avoid parking units and set a higher adder that would lead to meeting the annual emissions target. This would be more efficient in that whenever market prices rise sufficiently, coal units would be scheduled, rather than running other units whose price exceeds the coal unit costs including the higher adder.

The underlying efficiency concern with the NOBA strategy is that it is insensitive to actual prices in the market. It relies on a somewhat general and inflexible expectation about periods of time when prices may generally be expected to be high. On an ongoing basis OPG may choose the number of NOBA units weekly, but has initially determined it will not park units in January, July and August, and will park a total of 78 unit-weeks at other times of the year. In light of historical data, this monthly selection and granularity is likely to miss the best opportunities for not parking units, and by implication lead to parking units when it would be efficient to utilize them.

The following Figure 3-14 demonstrates the point. It shows two sets of weekly on-peak average prices, for two periods. One set of averages covers a three-year period ending November 2008. The second period runs from market opening, May 2002, to November 2008, which yields weekly averages based on 6 or 7 years, depending on the week. Also shown is the price associated with the top 13 weeks in each of the two 52 week series. For example, based on the three-year average, the top 13 weeks have averages prices of $66.26/MWh or higher. We can observe based on the 3 year averages that none of the weeks in January had averages in the upper quartile (13 weeks) and only 5 of the 8 weeks in July and August fell in the upper quartile. That means that, based on this 3-year sample, only 5 of the highest-priced 13 weeks occurred in January, July and August. It further implies that OPG is likely to have a least 1 NOBA unit in the 8 other weeks whose average prices were higher than 8 weeks currently identified as not having NOBA units. The overall result is fairly similar based on the average for the longer period, with most of the 13 high priced weeks occurring outside the identified three months.

Figure 3-14: Weekly Average On-Peak HOEP*
May 2002 - Nov 2008 and Dec 2005 - Nov 2008



This figure demonstrates that pricing can be volatile across the year. It highlights the fact that a year-ahead or even months ahead projection can easily miss identifying when coal generation would be most valuable. On a daily (or hourly) basis, in a given year, prices would be even more volatile, and high-priced days (or hours) could be expected to occur from time-to-time within but not uniformly throughout many months (or weeks). Thus a NOBA strategy that is not responsive to price is guaranteed to miss efficiency opportunities that could be realized using an adder strategy.

OPG explains that parking units is required to avoid unnecessary start-up costs for its units and to improve the emission efficiency of units it does run by operating at higher output levels. The Panel believes that this may overstate the opportunity to reduce costs and understate the ability for OPG to manage its fleet through its offer strategy. Prior to 2009 OPG has managed to avoid the running all its coal-units all the time, although a particular unit may have been economic based on its individual marginal cost. In other words, presumably OPG could also identify when it would be uneconomic to run units after accounting for its start-up and no-load costs. It could then modify its offers to avoid calling the unit to market. The Panel expects that OPG could likely avoid starting units which are uneconomic through its offer strategy, without needing to resort to parking units.

If OPG can demonstrate how its NOBA strategy reduces its costs, that information would be relevant as part of an efficiency assessment. As currently viewed, the Panel believes that the NOBA strategy is likely to induce market inefficiency because it will lead to periods (whether days or even entire weeks) when the coal-fired units that would have been economic after accounting for start-up costs and the CO_2 adder, are not offered to the market. Although the NOBA strategy is not designed for that purpose, the Panel will be monitoring to determine whether it could be viewed as having the effect of further increasing market prices in some periods when prices are already high.

Regarding OPG's CO_2 outages, the Panel has some potential concern about extending the planned outages of OPG's coal units, for similar reasons.

Extended outages may reduce maintenance costs, presumably by avoiding overtime. These longer planned outages will be subject to the IESO's scrutiny to ensure reliability. Since total planned outage capacity by fuel type is publicly available information,[147] this will allow market participants to consider how they can respond to the change in supply conditions in the market.

However, by extending outages the reduced availability of the units can induce some inefficiency and/or the potential to raise the HOEP higher than would have been the case had this generation not been withheld in periods when market prices are already high. The Panel recognizes there is less flexibility for OPG to use planned outage capacity in

[147] The IESO reports aggregate planned outages by fuel type up to five weeks ahead. See http://www.ieso.ca/imoweb/marketdata/genOutage.asp .

the market than for NOBA units, and that extending outages should have the potential for lowering maintenance costs. The Panel's reservation is whether extending the outages as much as OPG has planned is entirely necessary, or whether the incremental gains from the extended portion of these outages is in fact less than the potential incremental efficiency gain occasioned by maintaining the normal level of planned availability in the market.

In summary, the Panel agrees that applying an emissions adder to OPG's coal costs is an efficient approach to valuing the scarce emissions resource, and would not be viewed as economic withholding having regard to the Minister's directive. The Panel acknowledges that OPG can choose not to offer its capacity to respect its emissions limits, for example, as was clearly indicated by the change to OPG's licence which specifically allows OPG to offer less than the maximum available operating reserve if necessary. However, strategies that withhold capacity from the market are likely to be less efficient in targeting supply of an energy-limited resource into high-priced hours and may be inefficient overall unless this is outweighed by operating cost savings. The Panel does not have adequate information about the incremental savings of OPG's planned NOBAs and extended CO_2 outages, so is uncertain at this time whether on an overall basis they will be more or less efficient. For both NOBA and CO_2 outages, the Panel may request additional information from OPG over the upcoming months, in order to assess the overall efficiency impact of these strategies and to confirm that they are not being used to depart from competitive outcomes.

Appendix A3: Short-term Efficiency Implications of DR3

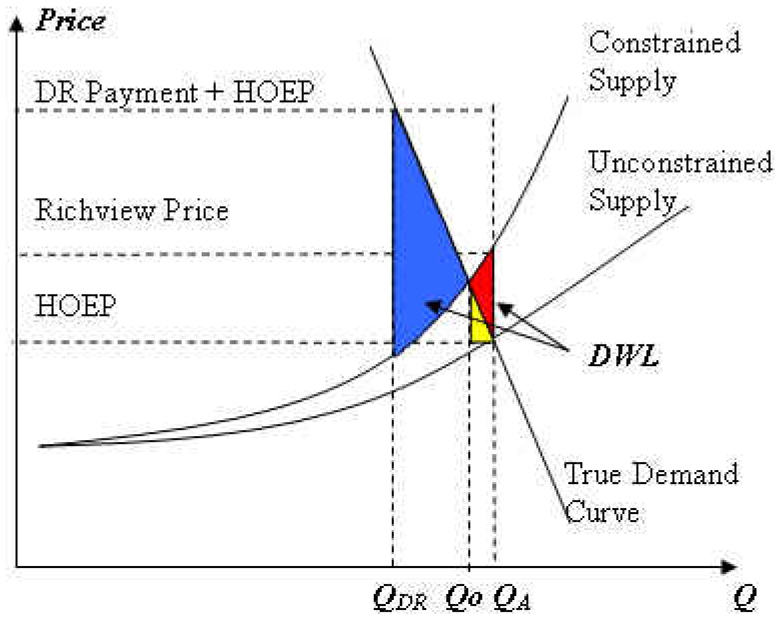
An influential argument in other markets that a DR program (which pays for not consuming) can also improve market efficiency is that a consumer who pays an average price (e.g. a contract price) has no incentives to reduce consumption during on-peak hours when the true price (and thus the marginal production cost) is greater than the average price. A DR program then induces the consumer to reduce consumption (up to the optimal consumption point) would be efficiency improving.[148]

An analogue to the efficiency argument in Ontario is that the unconstrained price, i.e. the HOEP that a consumer pays, is typically lower than the constrained price, i.e. the Richview nodal price, which is considered to more accurately reflect the true cost of serving the last MW of consumption. A HOEP lower than Richview induces inefficient consumption, leading to so-called Dead Weight Loss (DWL).

Figure 3A-1 illustrates how the DWL can be caused and how a DR can improve market efficiency. *Constrained Supply* represents the supply curve in the constrained sequence, taking into account the ramp and transmission limitations. *Unconstrained Supply* is the supply curve in the unconstrained sequence, assuming a 3 (previously 12) times ramp rate and no transmission limitation. *True Demand* is the actual demand curve with a downward slope, representing some extent of demand response. An equilibrium price to which consumers are exposed (i.e. the HOEP) and the actual consumption (Q_A) will be where *True Demand* curve intersects *Unconstrained Supply*. Given the consumption Q_A, the Richview price would be higher than the HOEP as a result of a steeper and high *Constrained Supply* curve. The lost efficiency (DWL) is the red shaded area.

[148] See Neenan Associates, 2001, 2002, 2003, and 2004 DRP Evaluation for NYISO, available at www.nyiso.com

Figure 3A-1: Efficiency Implication of DR Program



An optimal DR program is to find the optimal Q_O, or the optimal reduction ($Q_A - Q_o$), and the optimal compensation scheme that induces such a reduction. It is apparent that market efficiency can be improved only when a portion of those consumers who have a consumption valuation smaller than the Richview price have reduced their consumption. These consumers have a consumer surplus equal to the area below the demand curve and above the HOEP (the yellow shaded area). To compensate these consumers for not consuming, a DR payment equal to the yellow area is necessary and sufficient. This payment represents their lost consumer surplus.

This illustration highlights the possibility that many DR programs (such as a program that pays the DR resources a market price or some high fixed price higher than the market price) may have over-compensated the DR resources and thus have induced excessive consumption reduction and efficiency loss. These programs have ignored the fact that the DR resources also avoid paying the charge by reducing their consumption.

If a DR program pays more than the lost consumer surplus, some consumers with a higher consumption valuation will be attracted to reduce consumption, leading to more curtailment than needed and thus a DWL (the blue shaded area). As a result, an over-generous DR program may lead to more DWL (the blue area) than it has reduced (the red area).

Assume a DR program has induced the optimal reduction in consumption. The efficiency gain is approximately the red shaded area between the HOEP and the Richview price. Roughly speaking, the higher difference between the Richview price and the HOEP, the greater the efficiency gain.

In the current case, the first best solution is to implement a Locational Marginal pricing algorithm to allow consumers to face the true cost of generation. The second best solutions are: either imposing a tax for consumption or providing a subsidy for consumption reduction. This requires a uniform tax or subsidy if consumers' valuation is not revealed and thus they cannot be differentiated. The former requires a tax equal to the difference between the new Richview price (where the True Demand Curve intersects the Constrained Supply curve) and the HOEP. The latter is a DR payment equal to the difference between the new Richview price and the new HOEP (which is the unconstrained price at Q_0), which is approximately equal to the difference between the actual Richview price and the actual HOEP.

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Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is our 13th semi-annual Monitoring Report of the IESO-administered markets. It covers the summer period, May 2008 to October 2008. 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 led to inefficient outcomes. We did notice some areas of concern that affect market efficiency and made a number of recommendations for improvement. These recommendations are summarized at the end of this Chapter.

The average monthly HOEP of $48.25/MWh was $2.59/MWh (5.7 percent) higher than the HOEP corresponding to the same period a year ago. The on-peak HOEP was 6.9 percent higher and off-peak HOEP was 5.4 percent higher. The effective HOEP, which takes into account the OPG Rebates and Global Adjustment, increased period-over-period by $3.04/MWh (5.7 percent). The major reason for the increase was significantly higher fossil fuel costs. The average Henry Hub natural gas price rose by 45 percent over the summer 2007 levels. The average price of Appalachian coal, which is used by approximately one-third of the coal-fired generators in Ontario, rose 146 percent relative to the previous summer. At the same time more inframarginal generation (baseload hydro and nuclear) mitigated some of the price impact.

Market-related uplift payments for congestion, supply guarantees, and other matters were about 27 percent higher than the corresponding period a year ago. This was primarily the result of more congestion resulting in higher CMSC payments, particularly in the Northwest of the province, and a marked increase in operating reserve costs.

In this period, there were 17 hours when HOEP exceeded $200/MWh, compared with only 4 hours last year. There were 724 hours (approximately 16 percent of all the hours over the period) with prices below $20/MWh, compared to 331 hours in the same period last year, continuing a trend toward more low-priced hours in the past four years, as shown in Table 4-1. These included 28 hours with a negative HOEP. Our review of these and other apparently anomalous hours led us to conclude that the price movements in these hours were, for the most part, consistent with the supply/demand conditions prevailing at the time.

Table 4-1: Number of Hours with HOEP < $20/MWh May-October, 2002-2008

Month	2002	2003	2004	2005	2006	2007	2008
May	119	8	70	11	17	115	193
June	43	39	84	25	14	67	87
July	0	20	70	4	30	57	144
August	0	1	75	3	4	11	126
September	0	10	15	0	63	45	90
October	0	0	0	9	21	36	84
Total	162	78	314	52	149	331	724

As is customary, the MAU communicated with market participants from time to time to review and understand market behaviour.[149] One such situation involved the sale of electricity below cost by a market participant in an effort to advance the position of some of its relatively lower emitter fossil units in the merit order. In another situation we again drew to the IESO's attention the existence of the potential for large self-induced constrained on payments.

Ontario demand fell slightly by 2.5 percent (1.9 TWh) this summer compared to 2007 with the majority of it caused by a reduction in Local Distribution Company demand. Wholesale load levels have also been declining since 2003 and the total wholesale demand reached a low in October 2008 at slightly over 2,100 GWh. However, when we incorporate higher export levels from Ontario, which increased by 46 percent (2.9 TWh),

[149] In spite of this general conclusion, the Panel observes that as usual there have been many instances of CMSC adjustment through the administrative activity performed by the MAU under the Local Market Power mitigation rules.

we observed a small increase of 1.3 percent in the total market demand to 82.0 TWh for the period.

The remainder of this Chapter is organized as follows: section 2 discusses the ability of markets to facilitate efficient consumption and production decisions in light of environmental constraints. We illustrate this with two examples of offer strategies employed in the market in relation to emissions from fossil generating plants. We also discuss the anticipated growth in wind generation in the Ontario market and suggest possible measures to accommodate this growth more efficiently. Section 3 provides a status report of actions in response to previous Panel recommendations. Finally, Section 4 excerpts and lists the recommendations made in the body of this report.

2. Accounting for Environmental Constraints within Markets

The Panel believes that market participants can comply with government environmental standards without compromising the efficiency of the IESO-administered markets. Recent experience reveals, however, that they have not always done so. The Panel believes that environmental standards are best determined by public policy rather than by individual market participants and that the role of market participants is to comply with these objectives efficiently. We will continue to highlight inefficient responses by market participants to government environmental policies. Below, we discuss efficiency issues arising in connection with the reduction of emissions from fossil-fired generating plants and from the integration of wind generation into the grid.

The Panel notes that we also reviewed the efficiency implications of the Ontario Power Authority's Demand Reduction Phase 3 program in Chapter 3. We concluded there that the program as presently structured reduces market efficiency. It could become more efficient if it were more closely targeted to high demand and/or high-priced hours.

Fossil-fired generation

As tougher environmental standards are imposed, more and more emphasis is being placed on the environmental implications of electricity generation. Electricity markets have had to adjust to nitrogen oxide (NO_X) and sulphur dioxide (SO_2) restrictions of various kinds over the past several years. Concerns over greenhouse gas emissions are beginning to result in similar restrictions. For example, beginning in 2009 as the Regional Greenhouse Gas Initiative[150] goes into operation, it is expected that the cost of emission credits will be reflected in the offer prices of fossil-fired generators in both the New York and the New England electricity markets, thus leading to higher electricity prices. Generators with lower emissions will have a competitive advantage and be scheduled more often than those whose incremental cost is higher as a result of having to purchase emission credits.

In the Panel's opinion, the price of electric power should reflect the costs of complying with the environmental standards the government has established. The manner in which environmental costs are taken into account, however, is crucial. Improper incorporation of environmental costs into pricing and output decisions can be as inefficient as ignoring environmental costs altogether.

In an efficient electric power market, the Panel would expect that the actual environmental compliance costs including requisite emissions, effluent or other environmental permits or credits are accurately reflected in the offers submitted. Similarly, in situations in which there are government mandated ceilings on emissions, efficiency requires that the affected generation be priced on an opportunity cost basis so that the limited generation involved can be allocated to the time periods when it is most valuable.

When environmental costs are properly taken into account, the resulting equilibrium in the Ontario market is efficient in the broadest sense of the word. That is, the choice of

[150] For details, see: www.**rggi**.org. The RGGI is the first mandatory, market-based effort in the United States to reduce greenhouse gas emissions. Ten Northeastern and Mid-Atlantic states will cap and reduce CO_2 emission from power sector 10 percent by 2018.

sources of generation will be efficient, the choice of consumers between electrical energy and other sources of energy will be efficient and the tradeoffs between electrical energy and its associated environmental impacts will be efficient. Moreover, the market for electrical power can evolve efficiently as environmental standards change – for example, as permits or credits become more costly, or emissions ceilings are lowered.

In sum, the Panel holds strongly to the view that efficiency concerns should be central to the design of any program directed at reducing the impact of electric power generation on the environment. Recent experience (summarized below) has shown that actions taken without proper regard for their efficiency consequences can do more harm than good.

In Chapter 3 we examined the case of a market participant offering some of its fossil-fired generating units well below cost. The emissions from the various generating units in the market participant's portfolio varied. Some units emitted more sulphur dioxide and nitrous oxides and required more emissions credits than the others. The compliance costs, including the required emissions credits, initially were properly reflected by the market participant in the offer prices of each generating unit. Other things being equal, this would place the low emissions units lower in the offer stack than the higher emissions units implying that they would be scheduled first. This alone would have resulted in a globally efficient market outcome (a market price that reflected all costs, including environmental costs).

However, in order to compensate for the rising fuel cost of its lower emissions generation, the market participant offered this capacity into the market well below cost. This flipped the merit order, ensuring that the lower emissions generation was scheduled before the higher emissions units even though the latter had a lower 'all-in' (fuel plus environmental compliance) cost. In addition to the dispatch inefficiencies involved in using higher cost generation before lower cost generation, the action of the market participant resulted in some inefficient consumption in Ontario and the surrounding markets. The below-cost pricing of the lower emitter fossil units resulted in more exports than would otherwise have occurred; this in turn, required more fossil-fired generation than would otherwise have been required. In part, what the market participant was doing was importing fossil fuel and exporting the power made from it at a loss.

In Chapter 3 we also reviewed the method proposed by OPG to reduce energy generated by its coal-fired plants to the level that would allow it to meet the CO_2 emissions target set by the provincial government for 2009.[151] OPG intends to apply an adder to its offer prices for coal-fired generation. An appropriately chosen adder would reduce the dispatch and production from coal-fired units to a level consistent with the provincial government's CO_2 target. Moreover, the hours in which coal-fired generation continues to be dispatched would be the hours in which it is most valuable.

By attaching such an appropriately chosen adder to its coal-fired offers, OPG would essentially be pricing its coal-fired generation on an opportunity cost basis. The limited available coal-fired energy would be used when it is most valuable. Such a result would be an efficient and transparent production and consumption response to the environmental standards set by the provincial government. This approach would also readily adapt to more demanding standards. Compliance with a lower ceiling CO_2 target in 2010 can be achieved by increasing the adder on offers of coal-fired generation.

However, OPG has chosen to rely only partially on the adder strategy. The Panel has concerns regarding other aspects of the strategy OPG has chosen to meet the provincial government's ceiling on CO_2 emissions from coal-fired generation. During nine months of the year, OPG proposes to 'park' on average two coal-fired generating units (i.e. the units identified as Not Offered But Available). In addition OPG will use longer planned outages than normal for the regular maintenance of its coal-fired units ('CO_2 outages'). Parked units and units on elongated planned outages will have no offer in the market and thus will not respond to market signals. OPG is allocating parked units and CO_2 outages to all months except January, July and August, on the assumption that these are the highest priced months. While these tend to be amongst the highest-priced months on

[151] See "OPG's Strategy to Meet the 2009 CO2 Emission Target" at http://www.opg.com/safety/sustainable/emissions/carbon.asp

average, a more granular approach would be more effective at targeting the highest-priced weeks, days or hours.

As currently defined, it would appear that OPG's parking and CO_2 outage strategies are both arbitrary (not responding to price signals) and lumpy in its outcome (targeting months or weeks) rather than days or hours. Having coal-fired units with an appropriate full rather than partial adder available to respond to market signals would likely be more efficient. Unless this approach allows OPG to realize cost savings (that could not be obtained using only the adder) in excess of the production inefficiencies from such arbitrary targeting, these strategies will reduce efficiency in the market. We have asked the MAU to carefully monitor the effect of OPG's parked and CO_2 unit strategies on the market closely over the coming year.

Wind Generation

Ontario's electricity market is not alone in seeking to incorporate increasing renewable sources of power. In many US markets this is reflected through Renewable Portfolio Standards (RPS).[152] Retailers in some U.S. jurisdictions for example have to meet the RPS by purchasing a certain portion of the energy for their load from renewable resources.

Under the leadership of the Ontario Power Authority renewable resources will make up an increasing portion of the energy portfolio in Ontario. Wind is expected to be the main renewable energy source in Ontario in the foreseeable future. There are about 600 MW of wind capacity currently online and there will be an additional 500 MW online by 2010.[153]

[152] For example, see U.S. Environmental Protection Agency, Renewable Portfolio Standards Fact Sheet , August 2008 http://epa.gov/CHP/state-policy/renewable_fs.html . A more popular mechanism in Europe is the "Feed-in-Tariff" that obligates utilities to purchase available renewable energy sources at a set price. For example see European PV Associations, "Position Paper On A Feed-In Tariff For Photovoltaic Solar Electricity", 2005 http://www.epia.org/fileadmin/EPIA_docs/publications/epia/FeedInTariffEPIA.pdf .

[153] For details, see: www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=123 .

Despite the desirable attributes of wind energy (e.g. emission free and no fuel cost), the fact that wind is an intermittent resource has been a source of concern for system operators:

- Lack of dispatchability: Wind generation depends on wind velocity and is therefore intermittent.
- Production pattern that is the opposite of the load pattern: Wind generation is typically lower on-peak and higher off-peak.
- Lack of transparency: In many cases, wind generators are embedded within Local Distribution Companies (LDCs) and their output simply offsets the power withdrawn from the IESO-controlled grid. Production fluctuation at these wind generators simply appears as a demand forecast error to the IESO.

In Chapter One we show both the growth of wind generation in Ontario and the discrepancy between forecast and actual wind generation. This forecast error is likely to continue to grow and to reduce market efficiency.[154]

State-of-the-art wind-power production forecast systems have demonstrated that they can significantly reduce the error between forecast and actual wind generation. California centralized its wind-power forecast a few years ago and has experienced reduced forecast error as a consequence.[155] Recently, the New York ISO, announced a plan to undertake a central wind forecasting program with the intent of better utilizing wind resources and accommodating the variable nature of wind-powered generation while enhancing efficiency.[156] A study by GE Energy estimated the forecast performance achievable by central wind forecasting programs, if applied to 3,300 MW of wind generation in New

[154] The Panel identified wind forecast error as one of several factors contributing to a negative HOEP price. See the December 2007 Monitoring Report, pp. 112-115.
[155] The day-ahead ensemble-mean forecast reduced mean absolute error by 3 to 5 percent. J.W. Zack, PIRP System and CEC Research Project Results" UWIG Fall Technical Workshop, Sacramento, CA November 8, 2005 http://www.uwig.org/Sacramento/Session1-Zack.pdf
[156] NYISO News Release, "NYISO Readies the Grid for More Wind" September 24, 2008 http://www.nyiso.com/public/webdocs/newsroom/press_releases/2008/NYISO_Readies_Grid_for_More_Wind_09232008.pdf

York State, would reduce utility system operating costs by about $125 million per year compared to no central forecasts.[157]

We recommended in our December 2007 Monitoring Report that the IESO explore a better forecast methodology with the wind generators.[158] If the experience of other ISOs is any guide,[159] a centralised wind forecasting program may be appropriate for Ontario.

Because a large portion of wind generation is anticipated to be embedded within LDCs (as opposed to being directly connected to the IESO grid), fluctuations in wind production can only be indirectly observed as a part of the load fluctuation of the LDC. Thus better forecasts of embedded wind generation will indirectly help avoid the likely poorer forecasts of LDC load that might otherwise occur.

The Panel expects that the incorporation of wind generators, among other things, may also be enhanced if the IESO were to move to a 15-minute dispatch of intertie schedules. The benefits of such an approach are two-fold. With 15-minute schedules rather than hourly, the forecasts that go into resource dispatches should exhibit improved accuracy, given that they are produced closer to real-time. This should apply equally to wind generation forecasts, demand forecasts, and the availability of other generation. The second benefit of 15-minute scheduling is that imports and exports can respond more quickly to changing generation and load conditions, including the fluctuations of wind generation.

The Panel previously recommended that the IESO begin investigation of a 15-minute dispatch algorithm for intertie scheduling in its December 2007 Monitoring Report, largely because of the inefficiencies associated with the abrupt demand and supply changes that occur hourly.[160]

[157] AWS Truewind, "Wind Energy Forecasting: The Economic Benefits of Accuracy" Wind-power Asia, June 26-29, 2006 http://www.awstruewind.com/files/WP_Asia_2006_Forecasting.pdf.pdf; and GE Energy, "The Effects of Integrating Wind-power on Transmission System Planning, Reliability, and Operations" prepared for New York State Energy Research and Development Agency, March 4, 2005. http://www.nyserda.org/publications/wind_integration_report.pdf
[158] December 2007 Monitoring Report, pp. 24-28.
[159] In addition to the California and New York programs, MISO is also moving in this direction. See David W. Hadley, Midwest ISO, "Renewable Fuels Action Summit Integrating Wind", May 19, 2008 http://www.bismarckstate.edu/energysummit/ppt/IntegratingWind.pdf

Recommendation 4-1

In an effort to efficiently accommodate greater levels of renewable resources in the Ontario Market:

iii) The Panel recommends the IESO consider centralised wind forecasting to reduce the forecast errors associated with directly connected and embedded wind generation in the pre-dispatch schedules;

iv) The Panel also reiterates its December 2007 recommendation that the IESO investigate a 15-minute dispatch algorithm which should further reduce forecast errors and allow for more frequent rescheduling of imports and exports in response to the different output characteristics of renewable resources.

3. Implementation of Previous Panel Recommendations

Many of the recommendations in the Panel's reports are directed to the IESO. The IESO formally reports on the status of actions it has taken in response to these 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).[161]

In this section we review the status of the recommendations from our last Monitoring Report, released in August 2008. The IESO responses to these are summarized in Table 4-1 below.

[160] December 2007 Monitoring Report, pp. 151-160.
[161] See latest presentation to SAC, "IESO Response to MSP Recommendations" dated August 19, 2008, at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20080820-Item4_MSP.pdf

Table 4-2: Summary of IESO Responses to Recommendations

Recommendation Number & Status	Subject	Summary of Action
3-7 [162] **Partial Resolution Broader Review In Progress**	CAOR & Recallable Exports	On September 26, the IESO removed Control Action Operating Reserve (CAOR) from pre-dispatch, thereby eliminating the failure of recallable exports, because of reliability concerns. This avoids the related counter-intuitive price effects but may still result in the loss of efficient exports.[163] The Market Pricing Working Group has identified a complete review of CAOR as one of their priorities for 2009 priority work.
3-6 (2) **In Progress Q2, 2009**	Export Curtailment for Resource Adequacy	"This is a standing issue before the Market Pricing Working Group under IESO Stakeholder Engagement plan (SE 67)." SE 67 includes a variety of operating reserve and market schedule issues, and has been assigned as a priority item for 2009.
3-8 (1) **In Progress Q2, 2009**	Operating Reserve during Activation for Area Control Error	"This is a standing issue before the Market Pricing Working Group under IESO Stakeholder Engagement plan (SE 67)." SE 67 has been assigned as a priority item for 2009.
3-6 (1) **Open Low Priority**	Transaction Failures & the Unconstrained Schedule	In discussions with the MAU, further clarity has been brought to this recommendation. The IESO is and has been aware of this characteristic within its systems and will consider the merits and values of the change.
2-2 **In Progress Q2, 2009**	Shared Activation of Reserve, Replenishment of the Operating Reserve, & Regional Reserve Sharing	IESO initiated an assessment of Shared Activation in 2007 as part of the stakeholder engagement plan "Operating Reserve Initiatives (SE ‑ 37)". The IESO will also consider Regional Reserve Sharing. "This is a standing issue before the Market Pricing Working Group under IESO Stakeholder Engagement plan (SE 67)." SE 67 has been assigned as a priority item for 2009.

[162] Recommendations are labelled according to the numbering in the Panel's July 2008 Monitoring Report, e.g. "1-1" , and are listed in the order as summarized in that report.
[163] For further discussion see section 2.2. in Chapter 3 of this report.

Recommendation Number & Status	Subject	Summary of Action
2-1 **On-Going Assessment**	Net Interchange Scheduling Limit (NISL)	"New reports published recently will help participants manage binding NISL events. The IESO retains the ability to change the NISL value during reliability events. Without the benefit of a rigorous study, it is the IESO's judgment that 700 MW is a reasonable value for the NISL. The IESO, with the new NISL reports, will continue to monitor the frequency and impact of binding NISL events to determine any future actions." [164] The IESO has also revised its procedures to allow expanding NISL to 1000 MW when nuclear units are being dispatched down.
3-8 (2) **In Progress Q2, 2009**	Responses to Area Control Error	See below 3–8(3).
3-8 (3) **In Progress Q2, 2009**	Interim Response to Area Control Error	"The NERC control performance standards are undergoing significant change. … It is believed that meeting this [new] standard would require less frequent generation changes as once performed to meet the Control Performance Standards (CPS). The IESO's current actions are based on a belief that it is more efficient to use an OTD [One-time Dispatch] than an ORA [Operating Reserve Activation] and consistent with this approach the IESO includes these considerations when developing new systems and procedures." "This is a standing issue before the Market Pricing Working Group under IESO Stakeholder Engagement plan (SE 67)." SE 67 has been assigned as a priority item for 2009.
3-5 **Open Low Priority**	Supply Cushion	"This supply calculation is based on offered energy in the market. This is consistent with the capacity calculation that is published in the System Status Report and the IESO believes that being consistent with the application is important as it is used for OPA program integration. The IESO will need to consider any changes to other processes." [165]

[164] As of June 4, 2008, the IESO publishes a report following each pre-dispatch run, identifying the shadow value ($/MWh) of the NISL in each hour.
[165] For a discussion of the impact of the supply cushion formulation on OPA's DR3 demand response program, see section 3.1 of Chapter 3 of this report..

Recommendation Number & Status	Subject	Summary of Action
3-3 **Open** **Low Priority**	Generating Unit Output	"The IESO agrees with the idea of transparency and will consider the feasibility of implementing this recommendation."
3-4 **Open** **Low Priority**	Fuel Type of Generating Units Forced from Service	"The IESO agrees with the principle of providing more information to the market participants. Because interested participants can generally use the generation disclosure reports to extract this information, the IESO has assigned a low priority."
3-2 **Open** **Low Priority**	Masked Bid and Offer Data	"The IESO does not disagree with the recommendation however this would need stakeholder feedback. The IESO will establish an SE in 2009 to request written responses from stakeholders regarding their interest or concerns with publishing this information."
3-9 **Open** **Low Priority**	Constrained Off Payments	"This recommendation has been discussed on numerous occasions. This would be a fundamental change to the current market design and would have pricing implications. The IESO considers this as low priority."
3-1 **Open** **Low Priority**	Real-time Intertie Offer Guarantees	"This is a standing issue before the Market Pricing Working Group."

4. Summary of Recommendations

The IESO's Stakeholder Advisory Committee has encouraged the Panel to provide information about the relative priorities of the recommendations in its reports.[166] The Panel endeavours to do so below for the recommendations made in this report. 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

[166] 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

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.

In providing comments regarding the relative priorities of the recommendations in this report, the Panel considered that it would be useful to group the recommendations thematically under the same categories used in its last report: price fidelity, dispatch and hourly uplift payments.[167] 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. Within each group, the Panel has identified the recommendations in the order that it believes would have the most significant impacts. However, this should not be regarded as implying that other recommendations are unimportant. The Panel will not put forward a recommendation unless it believes that it would make a meaningful contribution to improving the operation of the market. Note also that changes that may individually not be regarded as large can have a substantial cumulative effect, as well as a spill-over benefit in improving the confidence that market participants have in the operation of the Ontario market.

4.1 Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market. Based on the frequency and magnitude of occurrences, the Panel would rank the three recommended procedural changes in this area in the following relative order:

[167] There are no recommendations in the transparency category in the current report.

<u>Recommendation 4-1 (Chapter 4, section 2)</u>

In an effort to efficiently accommodate greater levels of renewable resources in the Ontario Market:

- ***i) The Panel recommends the IESO consider centralised wind forecasting to reduce the forecast errors associated with directly connected and embedded wind generation in the pre-dispatch schedules;***
- ***ii) The Panel also reiterates its December 2007 recommendation that the IESO investigate a 15-minute dispatch algorithm which should further reduce forecast errors and allow for more frequent rescheduling of imports and exports in response to the different output characteristics of renewable resources.***

<u>Recommendation 2-2 (Chapter 2, section 2.1.11)</u>

The Panel recommends that when an intertie trade fails in some intervals while not in others within the hour, the IESO should apply a failure code only for those intervals with the failure.

<u>Recommendation 2-1 (Chapter 2, section 2.1.1)</u>

The Panel recommends that the IESO's ramping of intertie schedules in the unconstrained process (the pricing algorithm) be consistent with actual intertie procedures and the treatment in the constrained scheduling process.

4.2 Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market. Based on the frequency and magnitude of occurrences, the Panel would rank the four recommended procedural changes in this area in the following relative order: [168]

[168] As a result of action already taken by the IESO related to Excess Baseload Generation, a formal recommendation by the Panel was unnecessary. For a discussion of the issue, see section 2.2.2 of Chapter 2 of this report.

Recommendation 3-3 (Chapter 3, section 3.3)

In consideration of the length of time until the Panel's prior recommendation of an optimized Day Ahead Commitment Process (DACP) can be put in place (estimated to be 2011), the Panel recommends that the IESO consider basing the Generator Cost Guarantee on the offer submitted by the generator or other interim solutions that allow actual generation costs to be taken into account in DACP scheduling decisions.

Recommendation 3-5 (Chapter 3, section 3.5)

The Panel recommends that market participants' offers should reflect environmental costs flowing from the environmental standards established by the applicable regulatory authorities.

Recommendation 3-4 (Chapter 3, section 3.4)

As coal-fired generators are eventually phased out, the market will require replacement for this source of Operating Reserve (OR). New gas-fired generators are generally not offering OR. The Panel recommends that the IESO and OPA explore alternatives for obtaining appropriate OR offers from recent and future gas-fired generation entrants.

Recommendation 3-1 (Chapter 3, section 3.1)

1) In light of the Panel's findings on the inefficiency of the Demand Response Phase 3 (DR3) program, the Ontario Power Authority (OPA) should review the effectiveness and efficiency of the program.

2) Until that review is completed, to improve short term dispatch efficiency:

- ***i)*** ***the IESO, with input from the OPA, should improve the supply cushion calculation; and/or***
- ***ii)*** ***the OPA should develop other triggers such as a pre-dispatch price threshold that could be better indicators of tight supply/demand conditions.***

4.3 Hourly Uplift Payments

The Panel examines hourly uplift payments[169] both in respect of their contribution to the effective HOEP and also their impact on the efficient operation of the market. [170]

Recommendation 3-2 (Chapter 3, section 3.2)

In an earlier report, the Panel encouraged the IESO to limit self-induced congestion management settlement credit (CMSC) payments to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons. The Panel further recommends that the IESO take similar action to limit CMSC payments where these are induced by the generator strategically raising its offer price to signal the ramping down of its generation.

[169] Hourly uplift is the term used to describe wholesale market related uplifts as opposed to other forms of uplift payments.
[170] The Panel is aware that the IESO has already begun stakeholdering of the issues referred to in this recommendation.

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

Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2008 – October 2008

PUBLIC

2009

In some instances, the data reported in this Report has been updated or recalculated and therefore may differ from values previously quoted in our earlier reports.

List of Tables

Table A-1: Monthly Energy Demand, May 2007 – October 2008 (TWh)

	Ontario Demand*		Exports		Total Market Demand	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	11.83	11.41	1.08	2.65	12.91	14.06
Jun	12.69	12.20	1.04	2.52	13.74	14.72
Jul	12.85	13.15	1.30	2.43	14.15	15.59
Aug	13.47	12.57	1.12	1.69	14.60	14.26
Sep	11.95	11.82	0.92	1.26	12.88	13.08
Oct	11.92	11.67	0.93	1.46	12.85	13.13
Nov	12.39	N/A	0.97	N/A	13.35	N/A
Dec	13.45	N/A	1.31	N/A	14.76	N/A
Jan	13.63	N/A	2.06	N/A	15.70	N/A
Feb	12.90	N/A	1.65	N/A	14.54	N/A
Mar	13.01	N/A	1.89	N/A	14.89	N/A
Apr	11.52	N/A	2.42	N/A	13.94	N/A
May – Oct	74.71	72.82	6.39	12.01	81.13	84.84
Nov - Apr	76.90	N/A	10.30	N/A	87.18	N/A
May - Apr	151.61	N/A	16.69	N/A	168.31	N/A

* Data includes dispatchable loads

Table A-2: Average Monthly Temperature, May 2003 – October 2008 (°Celsius)*

	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009
May	12.23	13.31	12.14	14.59	14.77	11.98
Jun	18.53	17.78	22.54	19.76	20.84	19.39
Jul	21.71	20.65	24.09	23.50	21.42	21.73
Aug	21.85	19.57	22.53	21.22	22.27	19.66
Sep	17.12	18.4	18.33	15.79	18.34	17.08
Oct	9.04	10.85	11.01	9.07	14.11	9.13
Nov	4.91	5.29	5.06	5.25	2.91	N/A
Dec	(0.03)	(2.54)	(3.13)	1.94	(2.12)	N/A
Jan	(9.13)	(6.78)	0.30	(2.65)	(2.07)	N/A
Feb	(3.29)	(3.60)	(3.56)	(7.99)	(4.99)	N/A
Mar	2.26	(1.29)	1.21	0.59	(1.46)	N/A
Apr	6.88	8.18	8.36	6.29	9.48	N/A
May - Oct	16.75	16.76	18.44	17.32	18.63	16.50
Nov - Apr	0.27	(0.12)	1.37	0.57	0.29	N/A
May - Apr	8.51	8.32	9.91	8.95	9.46	N/A

* Temperature is calculated at Toronto Pearson International Airport

Table A-3: Number of Days Temperature Exceeded 30°C, May 2003 – October 2008 (Number of days)*

	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009
May	0	0	0	2	1	0
Jun	4	2	9	3	6	4
Jul	4	1	11	9	4	3
Aug	4	0	7	3	8	0
Sep	0	0	2	0	4	1
Oct	0	0	0	0	1	0
Nov	0	0	0	0	0	N/A
Dec	0	0	0	0	0	N/A
Jan	0	0	0	0	0	N/A
Feb	0	0	0	0	0	N/A
Mar	0	0	0	0	0	N/A
Apr	0	0	0	0	0	N/A
May - Oct	12	3	29	17	24	8
Nov - Apr	0	0	0	0	0	N/A
May - Apr	12	3	29	17	24	N/A

* Temperature is calculated at Toronto Pearson International Airport

Table A-4: Outages, May 2007 - October 2008
*(TWh)**

	Total Outage		Planned Outage		Forced Outage	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	5.38	5.43	3.63	1.69	1.75	3.74
Jun	3.58	4.15	1.36	1.21	2.22	2.94
Jul	3.34	2.99	0.95	0.90	2.39	2.09
Aug	3.59	3.24	0.45	1.00	3.14	2.24
Sep	5.43	5.09	2.41	2.32	3.02	2.77
Oct	6.47	5.38	3.77	2.68	2.70	2.70
Nov	5.47	N/A	2.96	N/A	2.51	N/A
Dec	3.69	N/A	1.58	N/A	2.11	N/A
Jan	2.88	N/A	0.96	N/A	1.92	N/A
Feb	3.10	N/A	0.79	N/A	2.31	N/A
Mar	4.97	N/A	2.39	N/A	2.58	N/A
Apr	5.30	N/A	2.44	N/A	2.86	N/A
May – Oct	27.79	26.28	12.57	9.80	15.22	16.48
Nov - Apr	25.41	N/A	11.12	N/A	14.29	N/A
May - Apr	53.20	N/A	23.69	N/A	29.51	N/A

* There are two sets of data that reflect outages information. Past reports have relied on information from the IESO's outage database. This table reflects the outage information that is actually input to the DSO to determine price. The MAU has reconciled the difference between the two sets of data by applying outage types from the IESO's outage database to the DSO outage information.

Table A-5: Average HOEP, On and Off-Peak, May 2007 – October 2008 ($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	38.50	34.56	53.78	47.12	24.77	24.21
Jun	44.38	57.44	57.32	76.57	33.06	42.13
Jul	43.90	56.58	57.70	82.78	32.54	35.00
Aug	53.62	46.57	69.80	60.63	39.10	35.96
Sep	44.63	49.09	58.27	58.58	34.66	40.78
Oct	48.91	45.27	60.19	55.87	38.77	35.75
Nov	46.95	N/A	56.35	N/A	37.96	N/A
Dec	49.08	N/A	62.96	N/A	39.48	N/A
Jan	40.74	N/A	50.89	N/A	31.62	N/A
Feb	52.38	N/A	67.48	N/A	39.52	N/A
Mar	56.84	N/A	68.60	N/A	48.72	N/A
Apr	48.98	N/A	63.61	N/A	34.99	N/A
May – Oct	45.66	48.25	59.51	63.59	33.82	35.64
Nov - Apr	49.16	N/A	61.65	N/A	38.72	N/A
May - Apr	47.41	N/A	60.58	N/A	36.27	N/A

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Table A-6: Average Monthly Richview Slack Bus Price, All hours, On and Off-Peak,
May 2007 – October 2008
($/MWh)

	All Hours		On-peak		Off-Peak	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	41.69	50.81	57.84	68.89	27.18	35.92
Jun	71.03	79.49	103.80	110.58	42.38	54.61
Jul	49.16	68.20	66.92	99.70	34.54	42.26
Aug	61.53	62.59	82.04	81.67	43.10	48.19
Sep	51.71	65.84	71.36	69.01	37.35	63.06
Oct	55.73	51.94	68.24	65.14	44.49	40.09
Nov	54.33	N/A	64.14	N/A	44.94	N/A
Dec	55.46	N/A	71.37	N/A	44.47	N/A
Jan	49.67	N/A	64.99	N/A	35.92	N/A
Feb	60.84	N/A	78.58	N/A	45.73	N/A
Mar	65.23	N/A	79.77	N/A	55.19	N/A
Apr	62.24	N/A	80.80	N/A	44.49	N/A
May – Oct	55.14	63.15	75.03	82.50	38.17	47.36
Nov - Apr	57.96	N/A	73.28	N/A	45.12	N/A
May - Apr	56.55	N/A	74.15	N/A	41.65	N/A

Table A-7: Ontario Consumption by Type of Usage, May 2007 – October 2008 (TWh)*

	LDC's**		Wholesale Loads		Generators		Metered Energy Consumption***		Transmission Losses		Total Energy Consumption****	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
• May	9.16	8.79	2.30	2.18	0.13	0.07	11.59	11.04	0.23	0.37	11.82	11.41
Jun	10.05	9.53	2.26	2.27	0.11	0.09	12.42	11.89	0.27	0.30	12.69	12.19
Jul	10.17	10.39	2.26	2.33	0.11	0.09	12.54	12.81	0.30	0.35	12.84	13.16
Aug	10.65	9.77	2.36	2.31	0.13	0.08	13.14	12.16	0.31	0.39	13.45	12.55
Sep	9.38	9.14	2.18	2.25	0.12	0.09	11.68	11.47	0.24	0.32	11.92	11.79
Oct	9.36	9.15	2.23	2.12	0.08	0.09	11.67	11.35	0.24	0.28	11.91	11.63
Nov	9.79	N/A	2.18	N/A	0.09	N/A	12.06	N/A	0.29	N/A	12.35	N/A
Dec	10.77	N/A	2.20	N/A	0.08	N/A	13.05	N/A	0.36	N/A	13.41	N/A
• Jan	10.92	N/A	2.26	N/A	0.07	N/A	13.25	N/A	0.36	N/A	13.61	N/A
• Feb	10.35	N/A	2.13	N/A	0.06	N/A	12.54	N/A	0.36	N/A	12.90	N/A
• Mar	10.37	N/A	2.22	N/A	0.09	N/A	12.68	N/A	0.32	N/A	13.00	N/A
• Apr	8.94	N/A	2.15	N/A	0.08	N/A	11.17	N/A	0.35	N/A	11.52	N/A
May – Oct	58.77	56.77	13.59	13.46	0.68	0.51	73.04	70.72	1.59	2.01	74.63	72.73
Nov - Apr	61.14	N/A	13.14	N/A	0.47	N/A	74.75	N/A	2.04	N/A	76.79	N/A
May - Apr	119.91	N/A	26.73	N/A	1.15	N/A	147.79	N/A	3.63	N/A	151.42	N/A

* The data in this table has been revised back to May 2007 using updated participant data.
** LDC's is net of any local generation within the LDC
*** Metered Energy Consumption = LDC's + Wholesale Loads + Generators
**** Total Energy Consumption = Metered Energy Consumption – Transmission Losses

Table A-8: Frequency Distribution of HOEP, May 2007 – October 2008
(Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	< 10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	6.59	20.03	9.01	5.91	26.61	5.11	**27.55**	**34.81**	6.72	17.20	5.65	7.53	5.11	4.03	10.75	4.57	2.02	0.81	0.00	0.00
Jun	3.19	8.61	6.11	3.47	26.11	4.31	**27.36**	**22.50**	7.08	18.75	6.39	6.53	9.17	6.81	10.00	14.17	4.31	14.31	0.28	0.56
Jul	2.82	11.96	4.84	7.39	24.19	4.84	**27.96**	13.71	9.01	**20.03**	8.74	3.63	6.59	5.78	13.98	16.13	1.75	16.13	0.13	0.40
Aug	0.81	12.63	0.67	4.30	14.52	5.78	27.55	13.04	10.35	**36.02**	7.93	6.45	6.99	4.30	**28.09**	13.04	3.09	4.17	0.00	0.27
Sep	3.06	9.44	3.19	3.06	20.42	5.83	**26.94**	18.47	13.61	**25.83**	11.25	10.69	6.53	11.25	13.33	10.56	1.67	4.17	0.00	0.69
Oct	2.69	5.78	2.15	5.51	17.61	4.84	**22.98**	15.46	12.37	**37.77**	10.62	15.73	11.69	7.39	18.82	5.91	0.94	1.21	0.13	0.40
Nov	0.97	N/A	0.42	N/A	10.14	N/A	**35.14**	N/A	17.78	N/A	15.28	N/A	7.64	N/A	11.81	N/A	0.83	N/A	0.00	N/A
Dec	5.38	N/A	5.11	N/A	15.32	N/A	**21.24**	N/A	11.29	N/A	9.27	N/A	9.14	N/A	19.49	N/A	3.76	N/A	0.00	N/A
Jan	4.84	N/A	3.09	N/A	19.09	N/A	**37.77**	N/A	13.31	N/A	6.72	N/A	4.30	N/A	8.60	N/A	2.28	N/A	0.00	N/A
Feb	3.16	N/A	1.15	N/A	5.60	N/A	**30.03**	N/A	16.95	N/A	13.07	N/A	10.78	N/A	13.22	N/A	5.89	N/A	0.14	N/A
Mar	0.00	N/A	0.00	N/A	0.13	N/A	24.46	N/A	**26.34**	N/A	15.73	N/A	10.35	N/A	17.74	N/A	5.24	N/A	0.00	N/A
Apr	8.61	N/A	3.06	N/A	3.47	N/A	**32.78**	N/A	13.75	N/A	12.64	N/A	5.83	N/A	14.86	N/A	4.86	N/A	0.14	N/A
May –Oct	3.19	11.41	4.33	4.94	21.58	5.12	**26.72**	19.67	9.86	**25.93**	8.43	8.43	7.68	6.59	15.83	10.73	2.30	6.80	0.09	0.39
Nov - Apr	3.83	N/A	2.14	N/A	8.96	N/A	**30.24**	N/A	16.57	N/A	12.12	N/A	8.01	N/A	14.29	N/A	3.81	N/A	0.05	N/A
May -Apr	3.51	N/A	3.23	N/A	15.27	N/A	**28.48**	N/A	13.21	N/A	10.27	N/A	7.84	N/A	15.06	N/A	3.05	N/A	0.07	N/A

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2007 – October 2008
(Percentage of Hours within Defined Range)

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
• May	6.59	18.68	8.06	6.45	22.04	5.38	**30.65**	**25.67**	7.93	24.06	4.30	8.20	6.18	5.11	11.42	5.24	2.82	1.21	0.00	0.00
Jun	3.06	7.64	4.86	3.89	20.14	3.75	**31.11**	15.83	8.75	**22.92**	6.39	7.64	6.81	7.22	12.64	13.89	5.83	16.53	0.42	0.69
Jul	2.96	11.83	4.03	6.18	18.82	5.11	**30.38**	9.68	11.83	**23.39**	6.59	4.70	7.93	4.57	15.32	15.32	2.02	18.68	0.13	0.54
Aug	0.94	11.29	0.67	4.70	9.68	5.11	29.03	11.96	11.69	**32.80**	6.99	10.75	7.80	4.84	**29.57**	13.04	3.63	5.11	0.00	0.40
Sep	2.92	8.61	3.33	3.75	16.11	5.28	**28.19**	14.17	13.89	**28.33**	11.25	10.28	7.22	9.72	14.03	14.44	3.06	4.72	0.00	0.69
Oct	2.55	4.97	2.28	5.91	12.90	4.97	**23.92**	11.42	13.44	**36.02**	9.54	18.15	11.96	9.27	20.83	7.39	2.42	1.48	0.13	0.40
Nov	0.97	N/A	0.42	N/A	6.39	N/A	**32.64**	N/A	18.89	N/A	15.42	N/A	10.97	N/A	12.64	N/A	1.67	N/A	0.00	N/A
Dec	4.84	N/A	4.84	N/A	13.58	N/A	**21.37**	N/A	10.89	N/A	9.95	N/A	9.41	N/A	18.82	N/A	6.32	N/A	0.00	N/A
Jan	4.70	N/A	2.69	N/A	15.99	N/A	**36.56**	N/A	15.32	N/A	7.53	N/A	5.11	N/A	9.01	N/A	3.09	N/A	0.00	N/A
Feb	3.16	N/A	1.01	N/A	5.03	N/A	**25.86**	N/A	17.24	N/A	13.36	N/A	12.79	N/A	14.66	N/A	6.75	N/A	0.14	N/A
Mar	0.00	N/A	0.00	N/A	0.00	N/A	17.61	N/A	**29.97**	N/A	15.86	N/A	10.89	N/A	19.22	N/A	6.45	N/A	0.00	N/A
Apr	8.06	N/A	3.33	N/A	3.61	N/A	**25.83**	N/A	16.53	N/A	13.75	N/A	6.67	N/A	16.81	N/A	5.28	N/A	0.14	N/A
May- Oct	3.17	10.50	3.87	5.15	16.62	4.93	**28.88**	14.79	11.26	**27.92**	7.51	9.95	7.98	6.79	17.30	11.55	3.30	7.96	0.11	0.45
Nov - Apr	2.73	N/A	2.05	N/A	7.43	N/A	**26.65**	N/A	18.14	N/A	12.65	N/A	9.31	N/A	15.19	N/A	4.93	N/A	0.05	N/A
May -Apr	2.97	N/A	2.96	N/A	12.02	N/A	**27.76**	N/A	14.70	N/A	10.08	N/A	8.65	N/A	16.25	N/A	4.11	N/A	0.08	N/A

* Bolded values show highest percentage within month.

Table A-10: Total Hourly Uplift Charge as a Percentage of HOEP, On and Off-Peak, May 2007 – October 2008
(%)

	All Hours		On-Peak		Off-Peak	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	4.68	7.06	6.13	6.24	3.38	7.73
Jun	5.69	8.23	6.77	6.18	4.74	9.87
Jul	4.47	6.70	4.87	5.13	4.13	7.99
Aug	4.26	7.97	4.97	4.91	3.62	10.29
Sep	4.65	6.40	5.60	5.43	3.94	7.24
Oct	4.27	6.42	5.17	5.08	3.45	7.62
Nov	5.08	N/A	5.58	N/A	4.61	N/A
Dec	4.57	N/A	4.46	N/A	4.65	N/A
Jan	4.40	N/A	5.09	N/A	3.79	N/A
Feb	3.80	N/A	5.20	N/A	2.61	N/A
Mar	4.24	N/A	4.53	N/A	4.04	N/A
Apr	7.72	N/A	5.93	N/A	9.43	N/A
May- Oct	4.67	7.13	5.59	5.50	3.88	8.46
Nov - Apr	4.97	N/A	5.13	N/A	4.86	N/A
May -Apr	4.82	N/A	5.36	N/A	4.37	N/A

Table A-11: Total Hourly Uplift Charge by Component,
May 2007 – October 2008
($ Millions)

	Total Hourly Uplift*		RT IOG**		DA IOG*		CMSC***		Operating Reserve		Losses	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	24.03	28.44	2.48	1.56	0.33	0.05	9.70	11.33	1.00	5.06	10.54	10.44
Jun	39.12	60.39	2.26	3.38	1.08	0.1	20.58	34.69	1.24	4.70	13.97	17.51
Jul	26.25	46.34	1.51	1.89	0.65	0.06	8.75	18.79	1.10	6.08	14.24	19.52
Aug	35.96	35.13	2.31	1.01	0.64	0.03	14.58	16.31	0.60	2.66	17.83	15.13
Sep	29.76	32.54	1.72	1.52	2.79	0.22	12.30	16.05	0.77	0.89	12.18	13.87
Oct	27.81	30.11	2.47	1.44	1.35	0.02	10.21	14.54	0.84	4.21	12.94	9.90
Nov	30.72	N/A	2.98	N/A	1.20	N/A	11.70	N/A	1.49	N/A	13.35	N/A
Dec	32.94	N/A	3.98	N/A	0.25	N/A	11.38	N/A	1.10	N/A	16.22	N/A
Jan	30.04	N/A	4.05	N/A	0.10	N/A	9.42	N/A	2.25	N/A	14.22	N/A
Feb	34.10	N/A	5.68	N/A	0.27	N/A	11.31	N/A	2.27	N/A	14.57	N/A
Mar	35.62	N/A	3.99	N/A	0.22	N/A	12.82	N/A	1.40	N/A	17.19	N/A
Apr	37.39	N/A	4.22	N/A	0.11	N/A	14.31	N/A	4.77	N/A	13.99	N/A
May- Oct	182.93	232.95	12.75	10.80	6.84	0.48	76.12	111.71	5.55	23.60	81.70	86.37
Nov - Apr	200.81	N/A	24.90	N/A	2.15	N/A	70.94	N/A	13.28	N/A	89.54	N/A
May -Apr	383.74	N/A	37.65	N/A	8.99	N/A	147.06	N/A	18.83	N/A	171.24	N/A

* Total Hourly Uplift = RT IOG + DA IOG + CMSC + Operating Reserve + Losses
** The IOG numbers are not adjusted for IOG offsets, which was implemented in July 2002. IOG offsets are reported in Table A-16. All IOG Reversals have been applied to RT IOG.
*** Numbers are adjusted for Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments.

Table A-12: Operating Reserve Prices,
May 2007 – October 2008
($/MWh)

	10N		10S		30R	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.78	5.92	2.17	6.36	0.78	4.47
Jun	1.21	6.07	2.98	6.11	1.21	5.66
Jul	1.00	7.20	1.97	7.36	1.00	7.00
Aug	0.41	3.11	1.78	3.14	0.41	2.97
Sep	0.63	1.06	1.95	1.19	0.63	1.03
Oct	0.62	3.84	1.90	4.33	0.62	3.04
Nov	1.20	N/A	1.99	N/A	1.09	N/A
Dec	0.96	N/A	1.71	N/A	0.96	N/A
Jan	2.53	N/A	2.77	N/A	2.45	N/A
Feb	2.67	N/A	3.20	N/A	2.55	N/A
Mar	1.56	N/A	2.13	N/A	1.49	N/A
Apr	6.22	N/A	6.38	N/A	5.55	N/A
May- Oct	0.78	4.53	2.13	4.75	0.78	4.03
Nov - Apr	2.52	N/A	3.03	N/A	2.35	N/A
May -Apr	1.65	N/A	2.58	N/A	1.56	N/A

*Table A-13: Baseload Supply Relative to Demand and HOEP, Off-Peak, May 2007 – October 2008 (Average Hourly MW)**

	Nuclear		Baseload Hydroelectric		Self-Scheduling Supply		Total Baseload Generation		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
• May	9,360	8,180	1,999	2,037	809	779	12,168	10,996	13,543	13,352	24.77	24.21
Jun	9,380	9,027	1,806	1,886	719	617	11,905	11,530	15,005	14,934	33.06	42.13
Jul	9,695	10,098	1,720	1,963	699	597	12,114	12,658	14,703	15,243	32.54	35.00
Aug	9,490	10,143	1,610	1,888	748	628	11,848	12,659	15,493	14,751	39.10	35.96
Sep	8,797	9,798	1,662	1,797	772	703	11,231	12,298	14,400	14,255	34.66	40.78
Oct	8,162	9,645	1,861	1,780	993	1073	11,016	12,498	13,983	13,771	38.77	35.75
Nov	8,369	N/A	1,840	N/A	1002	N/A	11,211	N/A	14,941	N/A	37.96	N/A
Dec	10,355	N/A	1,783	N/A	1042	N/A	13,180	N/A	16,230	N/A	39.48	N/A
• Jan	10,978	N/A	1,788	N/A	1077	N/A	13,843	N/A	16,127	N/A	31.62	N/A
• Feb	9,987	N/A	1,974	N/A	1017	N/A	12,978	N/A	16,416	N/A	39.52	N/A
• Mar	8,708	N/A	2,232	N/A	960	N/A	11,900	N/A	15,803	N/A	48.72	N/A
• Apr	8,640	N/A	2,104	N/A	823	N/A	11,567	N/A	13,931	N/A	34.99	N/A
May- Oct	9,147	9,482	1,776	1,892	790	733	11,714	12,107	14,521	14,384	33.82	35.64
Nov - Apr	9,506	N/A	1,954	N/A	987	N/A	12,447	N/A	15,575	N/A	38.72	N/A
May -Apr	9,327	N/A	1,865	N/A	888	N/A	12,080	N/A	15,048	N/A	36.27	N/A

* The definition of on-peak and off-peak hours was changed to be consistent with the IESO's definition of on-peak and off-peak and also consistent with the rest of the tables in the Appendix

Table A-14: Baseload Supply Relative to Demand and HOEP, On-Peak, May 2007 – October 2008 (Average Hourly MW)*

	Nuclear		**Baseload Hydroelectric**		**Self-Scheduling Supply**		**Total Baseload Generation**		**Ontario Demand (NDL)**		**Average HOEP ($/MWh)**	
	2007/2008	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**	**2007/2008**	**2008/2009**
• **May**	9,399	8,193	2,464	2,368	1201	1287	13,064	11,848	17,417	16,558	53.78	47.12
Jun	9,344	9,091	2,266	2,225	1166	937	12,776	12,253	19,597	18,204	57.32	76.57
Jul	9,719	9,983	2,129	2,296	1044	890	12,892	13,169	19,250	19,442	57.70	82.78
Aug	9,477	10,114	2,061	2,259	1013	899	12,551	13,272	19,978	18,484	69.80	60.63
Sep	8,647	9,787	1,969	2,146	1058	1017	11,674	12,950	18,415	17,776	58.27	58.58
Oct	8,231	9,662	2,062	2,100	1176	1216	11,469	12,978	17,229	17,023	60.19	55.87
Nov	8,611	N/A	2,304	N/A	1235	N/A	12,150	N/A	18,520	N/A	56.35	N/A
Dec	10,287	N/A	2,140	N/A	1265	N/A	13,692	N/A	19,463	N/A	62.96	N/A
• **Jan**	10,959	N/A	2,063	N/A	1310	N/A	14,332	N/A	19,624	N/A	50.89	N/A
• **Feb**	9,921	N/A	2,216	N/A	1222	N/A	13,359	N/A	19,812	N/A	67.48	N/A
• **Mar**	8,798	N/A	2,432	N/A	1239	N/A	12,469	N/A	18,606	N/A	68.60	N/A
• **Apr**	8,567	N/A	2,425	N/A	1180	N/A	12,172	N/A	17,025	N/A	63.61	N/A
May- Oct	9,136	9,472	2,159	2,232	1,110	1,041	12,404	12,745	18,648	17,915	59.51	63.59
Nov - Apr	9,524	N/A	2,263	N/A	1,242	N/A	13,029	N/A	18,842	N/A	61.65	N/A
May -Apr	9,330	N/A	2,211	N/A	1,176	N/A	12,717	N/A	18,745	N/A	60.58	N/A

* The definition of on-peak and off-peak hours was changed to be consistent with the IESO's definition of on-peak and off-peak and also consistent with the rest of the tables in the Appendix

Table A-15: RT IOG Payments, Top 10 Days, May 2008 – October 2008

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)*	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
2008/06/09	8,406	0.47	55.72	27,074
2008/06/10	12,728	0.36	28.50	25,870
2008/06/06	8,535	0.28	32.47	24,847
2008/05/01	12,942	0.25	19.21	22,278
2008/07/18	13,626	0.24	17.26	26,518
2008/06/27	11,306	0.23	20.07	25,330
2008/07/09	10,715	0.19	17.66	27,100
2008/06/23	8,964	0.19	21.51	23,580
2008/06/30	10,347	0.18	17.67	22,952
2008/10/11	13,413	0.17	12.43	17,234
	Total Top 10 days	**2.56**	**22.98**	
	Total for Period	**11.09**	**12.30**	
	% of Total Payments	**23.08**		

* Numbers are not netted against IOG offset for the ‘implied wheel’.

Table A-16: IOG Offsets due to Implied Wheeling,
May 2007 – October 2008
($ '000 and %)

	Real-time IOG Payments ($'000)		IOG Offset ($'000)		IOG Offset (%)	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	2,493	1,610	225	187	9.03	11.61
Jun	2,345	3,472	72	415	3.06	11.95
Jul	1,579	1,950	160	333	10.13	17.06
Aug	2,424	1,035	132	136	5.44	13.17
Sep	1,845	1,563	138	122	7.47	7.83
Oct	2,708	1,459	156	161	5.77	11.06
Nov	3,221	N/A	234	N/A	7.27	N/A
Dec	4,069	N/A	379	N/A	9.33	N/A
Jan	4,145	N/A	216	N/A	5.21	N/A
Feb	5,822	N/A	400	N/A	6.86	N/A
Mar	4,091	N/A	301	N/A	7.36	N/A
Apr	4,330	N/A	347	N/A	8.02	N/A
May- Oct	13,394	11,011	883	1,354	6.59	12.21
Nov - Apr	25,678	N/A	1,877	N/A	7.31	N/A
May -Apr	39,072	N/A	2,760	N/A	7.06	N/A

Table A-17: CMSC Payments, Energy and Operating Reserve,
May 2007 – October 2008
($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009
May	9.57	5.57	1.77	3.42	11.76	9.87	0.59	2.06	12.35	11.93
Jun	11.93	23.06	5.75	9.47	19.91	34.43	1.46	1.7	21.37	36.13
Jul	7.50	12.52	2.27	5.37	9.52	19.48	0.92	1.43	10.45	20.92
Aug	9.76	11.14	4.26	3.92	14.59	16.49	0.49	0.69	15.08	17.18
Sep	8.33	11.86	4.04	4.69	12.72	17.56	0.49	0.63	13.21	18.19
Oct	10.13	9.13	2.13	3.89	12.72	13.81	0.53	1.26	13.26	15.07
Nov	8.37	N/A	3.45	N/A	12.29	N/A	0.52	N/A	12.81	N/A
Dec	7.40	N/A	4.02	N/A	11.93	N/A	0.45	N/A	12.38	N/A
Jan	6.21	N/A	3.37	N/A	9.92	N/A	0.77	N/A	10.69	N/A
Feb	6.51	N/A	3.77	N/A	11.04	N/A	0.98	N/A	12.02	N/A
Mar	7.00	N/A	4.03	N/A	11.89	N/A	1.40	N/A	13.29	N/A
Apr	8.02	N/A	4.39	N/A	13.44	N/A	1.77	N/A	15.21	N/A
May- Oct	57.22	73.28	20.22	30.76	81.22	111.64	4.48	7.77	85.72	119.42
Nov - Apr	43.51	N/A	23.03	N/A	70.51	N/A	5.89	N/A	76.40	N/A
May -Apr	100.73	N/A	43.25	N/A	151.73	N/A	10.37	N/A	162.12	N/A

* The sum for energy being constrained on and off does not equal the total CMSC for energy in some months. This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC amounts.
** The totals for CMSC payments do not equal the totals for CMSC payments in Table A-11: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months. Neither table includes Local Market Power adjustments.

Table A-18: Share of Constrained On Payments for Energy by Type of Supplier, May 2007 – October 2008
(%)

	Domestic Generators		Imports	
	2007/2008	2008/2009	2007/2008	2008/2009
May	60	58	40	42
Jun	67	64	33	36
Jul	74	56	26	44
Aug	68	87	32	13
Sep	67	76	33	24
Oct	71	77	29	23
Nov	69	N/A	31	N/A
Dec	61	N/A	39	N/A
Jan	61	N/A	39	N/A
Feb	64	N/A	36	N/A
Mar	56	N/A	44	N/A
Apr	46	N/A	54	N/A
May- Oct	68	70	32	30
Nov - Apr	60	N/A	41	N/A
May -Apr	64	N/A	36	N/A

Table A-19: Share of CMSC Payments Received by Top Facilities,
May 2007 – October 2008
(%)

	Share of Total Payments Received by Top 10 Facilities				Share of Total Payments Received by Top 5 Facilities			
	Constrained Off		Constrained On		Constrained Off		Constrained On	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	58.89	49.47	41.69	48.14	45.46	36.17	27.10	30.78
Jun	57.61	68.08	46.56	57.38	34.93	46.00	30.40	44.37
Jul	59.77	61.59	53.11	57.37	47.84	53.32	38.24	46.66
Aug	67.12	67.07	51.85	57.06	54.33	58.32	34.86	46.03
Sep	67.24	70.98	53.98	46.13	53.91	57.84	38.09	32.57
Oct	75.42	67.55	50.83	49.92	68.27	56.22	34.78	37.62
Nov	64.73	N/A	59.43	N/A	53.27	N/A	38.67	N/A
Dec	55.99	N/A	53.48	N/A	45.72	N/A	38.16	N/A
Jan	55.64	N/A	55.45	N/A	47.39	N/A	38.54	N/A
Feb	44.57	N/A	59.55	N/A	33.94	N/A	42.48	N/A
Mar	57.87	N/A	53.29	N/A	45.63	N/A	37.34	N/A
Apr	46.04	N/A	44.50	N/A	34.32	N/A	27.51	N/A
May – Oct	64.34	64.12	49.67	52.67	50.79	51.31	33.91	39.67
Nov - Apr	54.14	N/A	54.28	N/A	43.38	N/A	37.12	N/A
May - Apr	59.24	N/A	51.98	N/A	47.08	N/A	35.51	N/A

Table A-20: Supply Cushion Statistics, All Hours,
May 2007 – October 2008
(% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	19.0	15.7	0	1	145	255	19.9	20.5	4	0	159	62
Jun	17.8	19.2	0	0	205	167	20.0	22.1	15	0	192	93
Jul	19.1	19.6	0	0	198	153	22.3	24.5	0	0	134	47
Aug	23.7	21.6	0	0	52	120	21.8	24.8	8	0	126	76
Sep	24.3	22.9	0	0	17	62	17.6	21.1	28	0	256	132
Oct	18.1	19.7	0	0	154	150	16.6	22.0	3	0	270	60
Nov	17.6	N/A	0	N/A	164	N/A	13.2	N/A	20	N/A	362	N/A
Dec	19.6	N/A	0	N/A	93	N/A	17.6	N/A	7	N/A	193	N/A
Jan	16.0	N/A	0	N/A	271	N/A	18.0	N/A	23	N/A	223	N/A
Feb	15.7	N/A	0	N/A	208	N/A	13.1	N/A	33	N/A	312	N/A
Mar	17.2	N/A	0	N/A	143	N/A	15.6	N/A	2	N/A	240	N/A
Apr	12.7	N/A	6	N/A	383	N/A	19.3	N/A	0	N/A	110	N/A
May- Oct	20.3	19.8	0	1	771	907	19.7	22.5	58	0	1,137	470
Nov - Apr	16.4	N/A	6	N/A	1,262	N/A	16.1	N/A	85	N/A	1,440	N/A
May -Apr	18.4	N/A	6	N/A	2,033	N/A	17.9	N/A	143	N/A	2,577	N/A

* This category includes hours with a negative supply cushion

Table A-21: Supply Cushion Statistics, On-Peak,
May 2007 –October 2008
(% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	11.3	9.6	0	1	133	193	11.1	14.4	4	0	156	58
Jun	10.5	11.4	0	0	162	129	10.3	14.6	15	0	168	69
Jul	10.8	12.5	0	0	168	118	12.5	16.4	0	0	129	38
Aug	15.5	13.5	0	0	52	94	12.4	16.0	8	0	115	59
Sep	16.1	14.4	0	0	16	59	8.3	12.8	28	0	213	108
Oct	12.2	12.9	0	0	144	129	8.7	15.2	3	0	234	53
Nov	11.9	N/A	0	N/A	131	N/A	6.8	N/A	16	N/A	292	N/A
Dec	14.0	N/A	0	N/A	68	N/A	10.9	N/A	5	N/A	140	N/A
Jan	9.6	N/A	0	N/A	221	N/A	10.1	N/A	23	N/A	186	N/A
Feb	10.2	N/A	0	N/A	172	N/A	6.7	N/A	30	N/A	239	N/A
Mar	12.2	N/A	0	N/A	108	N/A	9.3	N/A	0	N/A	184	N/A
Apr	6.9	N/A	4	N/A	289	N/A	13.2	N/A	0	N/A	100	N/A
May- Oct	12.7	12.4	0	1	675	722	10.6	14.9	58	0	1,015	385
Nov - Apr	10.8	N/A	4	N/A	989	N/A	9.5	N/A	74	N/A	1,141	N/A
May -Apr	11.8	N/A	4	N/A	1,664	N/A	10.0	N/A	132	N/A	2,156	N/A

* This category includes hours with a negative supply cushion

Table A-22: Supply Cushion Statistics, Off-Peak, May 2007 – October 2008 (% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	25.9	20.7	0	0	12	62	27.7	25.5	0	0	3	4
Jun	24.2	25.5	0	0	43	38	28.4	28.1	0	0	24	24
Jul	25.9	25.5	0	0	30	35	30.4	31.1	0	0	5	9
Aug	31.1	27.7	0	0	0	26	30.3	31.5	0	0	11	17
Sep	30.3	30.3	0	0	1	3	24.4	28.4	0	0	43	24
Oct	23.4	25.9	0	0	10	21	23.7	28.1	0	0	36	7
Nov	23.0	N/A	0	N/A	33	N/A	19.3	N/A	4	N/A	70	N/A
Dec	23.4	N/A	0	N/A	25	N/A	22.2	N/A	2	N/A	53	N/A
Jan	21.6	N/A	0	N/A	50	N/A	25.1	N/A	0	N/A	37	N/A
Feb	20.4	N/A	0	N/A	36	N/A	18.5	N/A	3	N/A	73	N/A
Mar	20.6	N/A	0	N/A	35	N/A	20.0	N/A	2	N/A	56	N/A
Apr	18.3	N/A	2	N/A	94	N/A	25.3	N/A	0	N/A	10	N/A
May- Oct	26.8	25.9	0	0	96	185	27.5	28.8	0	0	122	85
Nov - Apr	21.2	N/A	2	N/A	273	N/A	21.7	N/A	11	N/A	299	N/A
May -Apr	24.0	N/A	2	N/A	369	N/A	24.6	N/A	11	N/A	421	N/A

* This category includes hours with a negative supply cushion

Table A-23: Share of Real-time MCP Set by Resource Type,
May 2007 – October 2008
(%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	61	67	0	0	13	3	26	31
Jun	61	60	0	0	18	16	21	24
Jul	58	57	0	0	20	17	22	26
Aug	44	65	0	0	38	9	17	27
Sep	52	59	0	0	25	12	23	28
Oct	46	67	0	0	30	8	24	25
Nov	55	N/A	0	N/A	23	N/A	22	N/A
Dec	47	N/A	0	N/A	27	N/A	26	N/A
Jan	70	N/A	0	N/A	12	N/A	18	N/A
Feb	60	N/A	0	N/A	19	N/A	21	N/A
Mar	59	N/A	0	N/A	15	N/A	26	N/A
Apr	62	N/A	0	N/A	13	N/A	25	N/A
May – Oct	54	63	0	0	24	11	22	27
Nov - Apr	59	N/A	0	N/A	18	N/A	23	N/A
May - Apr	56	N/A	0	N/A	21	N/A	23	N/A

Table A-24: Share of Real-time MCP Set by Resource Type, Off-Peak, May 2007 – October 2008 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	72	54	0	0	1	1	27	45
Jun	73	65	0	0	6	7	20	28
Jul	74	61	0	0	5	4	21	35
Aug	70	61	0	0	18	3	12	35
Sep	67	63	0	0	11	4	22	32
Oct	64	67	0	0	13	1	23	32
Nov	76	N/A	0	N/A	7	N/A	17	N/A
Dec	57	N/A	0	N/A	15	N/A	28	N/A
Jan	78	N/A	0	N/A	2	N/A	20	N/A
Feb	75	N/A	0	N/A	4	N/A	21	N/A
Mar	73	N/A	0	N/A	5	N/A	22	N/A
Apr	65	N/A	0	N/A	4	N/A	31	N/A
May – Oct	70	62	0	0	9	3	21	35
Nov - Apr	71	N/A	0	N/A	6	N/A	23	N/A
May - Apr	70	N/A	0	N/A	8	N/A	22	N/A

Table A-25: Share of Real-time MCP Set by Resource Type, On-Peak, May 2007 – October 2008 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	49	82	0	0	26	5	25	13
Jun	47	54	0	0	31	27	22	19
Jul	38	52	0	0	39	33	23	16
Aug	15	69	0	0	62	16	23	15
Sep	32	55	0	0	45	21	24	23
Oct	26	68	0	0	49	15	26	16
Nov	33	N/A	0	N/A	40	N/A	27	N/A
Dec	32	N/A	0	N/A	45	N/A	23	N/A
Jan	60	N/A	0	N/A	23	N/A	17	N/A
Feb	42	N/A	0	N/A	36	N/A	22	N/A
Mar	39	N/A	0	N/A	29	N/A	32	N/A
Apr	59	N/A	0	N/A	22	N/A	19	N/A
May – Oct	35	63	0	0	42	20	24	17
Nov - Apr	44	N/A	0	N/A	33	N/A	23	N/A
May - Apr	39	N/A	0	N/A	37	N/A	24	N/A

Table A-26: Resources Selected in the Real-time Market Schedule, May 2007 – October 2008 (TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Domestic Generation*	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.39	1.58	1.08	2.65	1.59	1.40	0.81	0.69	2.99	4.04	6.98	6.09	12.36	12.22
Jun	0.47	1.57	1.04	2.52	2.45	2.19	0.85	0.83	3.07	3.50	6.74	6.52	13.11	13.03
Jul	0.49	1.27	1.30	2.43	2.58	2.31	0.86	0.80	2.85	3.63	7.22	7.47	13.51	14.21
Aug	0.67	0.55	1.12	1.69	3.17	2.10	1.15	0.72	2.35	3.22	7.06	7.54	13.73	13.58
Sep	0.87	0.66	0.92	1.26	2.38	1.80	0.90	0.77	2.23	2.60	6.29	7.05	11.80	12.23
Oct	0.80	0.65	0.93	1.46	2.07	1.47	1.02	0.82	2.61	2.62	6.10	7.18	11.79	12.09
Nov	1.00	N/A	0.97	N/A	2.30	N/A	0.97	N/A	2.74	N/A	6.11	N/A	12.12	N/A
Dec	1.00	N/A	1.31	N/A	2.02	N/A	1.07	N/A	2.72	N/A	7.68	N/A	13.49	N/A
Jan	0.97	N/A	2.06	N/A	2.17	N/A	0.92	N/A	3.19	N/A	8.16	N/A	14.44	N/A
Feb	0.79	N/A	1.65	N/A	2.48	N/A	0.91	N/A	3.20	N/A	6.93	N/A	13.52	N/A
Mar	1.20	N/A	1.89	N/A	2.65	N/A	0.92	N/A	3.36	N/A	6.51	N/A	13.44	N/A
Apr	1.26	N/A	2.42	N/A	1.87	N/A	0.76	N/A	3.64	N/A	6.19	N/A	12.46	N/A
May – Oct	3.69	6.28	6.39	12.01	14.24	11.27	5.59	4.63	16.10	19.61	40.39	41.85	76.30	77.36
Nov - Apr	6.22	N/A	10.30	N/A	13.49	N/A	5.55	N/A	18.85	N/A	41.58	N/A	79.47	N/A
May - Apr	9.91	N/A	16.69	N/A	27.73	N/A	11.14	N/A	34.95	N/A	81.97	N/A	155.77	N/A

* Domestic generation is the sum of *Coal, Oil/Gas, Hydroelectric, and Nuclear*.

Table A-27: Share of Resources Selected in Real-time Market Schedule, May 2007 – October 2008 (% of MW Scheduled)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	3	13	9	22	13	11	7	6	24	33	56	50
Jun	4	12	8	19	19	17	6	6	23	27	51	50
Jul	4	9	10	17	19	16	6	6	21	26	53	53
Aug	5	4	8	12	23	15	8	5	17	24	51	56
Sep	7	5	8	10	20	15	8	6	19	21	53	58
Oct	7	5	8	12	18	12	9	7	22	22	52	59
Nov	8	N/A	8	N/A	19	N/A	8	N/A	23	N/A	50	N/A
Dec	7	N/A	10	N/A	15	N/A	8	N/A	20	N/A	57	N/A
Jan	7	N/A	14	N/A	15	N/A	6	N/A	22	N/A	57	N/A
Feb	6	N/A	12	N/A	18	N/A	7	N/A	24	N/A	51	N/A
Mar	9	N/A	14	N/A	20	N/A	7	N/A	25	N/A	48	N/A
Apr	10	N/A	19	N/A	15	N/A	6	N/A	29	N/A	50	N/A
May – Oct	5	8	8	16	19	15	7	6	21	25	53	54
Nov - Apr	8	N/A	13	N/A	17	N/A	7	N/A	24	N/A	52	N/A
May - Apr	6	N/A	11	N/A	18	N/A	7	N/A	22	N/A	53	N/A

*Table A-28: Offtakes by Intertie Zone, On-Peak and Off-Peak, May 2007 – October 2008 (GWh)**

		MB		MI		MN		NY		PQ	
		2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	Off-peak	3.1	0.0	170.2	814.3	11.8	10.6	334.2	525.9	57.6	59.0
	On-Peak	3.5	0.0	257.4	781.4	10.9	12.3	197.2	402.9	36.0	42.8
Jun	Off-peak	0.5	0.0	65.9	697.8	4.0	3.2	566.6	606.5	39.5	54.9
	On-Peak	0.7	0.0	109.9	630.5	6.9	5.8	228.6	492.6	20.3	33.1
Jul	Off-peak	0.0	0.0	76.4	624.4	6.3	6.1	638.4	599.8	42.2	49.8
	On-Peak	0.2	0.0	130.5	528.7	8.9	4.0	376.9	593.3	19.7	28.6
Aug	Off-peak	0.0	0.0	61.9	494.0	3.5	5.3	556.0	379.6	52.4	50.4
	On-Peak	0.1	0.0	201.6	398.6	6.0	8.1	215.6	327.0	27.2	29.3
Sep	Off-peak	0.0	0.0	21.3	304.5	0.3	0.8	491.4	362.7	65.7	53
	On-Peak	0.0	0.0	52.7	240.1	0.7	2.5	258.0	257.2	31.9	36
Oct	Off-peak	0.0	0.0	72.6	315.0	0.4	2.6	453.1	395.0	30.1	54.7
	On-Peak	0.0	0.0	68.6	242.0	0.5	1.5	284.9	413.4	22.9	36.3
Nov	Off-peak	0.0	N/A	30.8	N/A	1.6	N/A	496.9	N/A	43.8	N/A
	On-Peak	1.3	N/A	51.3	N/A	7.7	N/A	307.9	N/A	25.5	N/A
Dec	Off-peak	4.0	N/A	140.1	N/A	7.3	N/A	523.4	N/A	64.0	N/A
	On-Peak	1.2	N/A	90.3	N/A	6.0	N/A	446.5	N/A	31.6	N/A
Jan	Off-peak	4.7	N/A	383.8	N/A	23.8	N/A	553.4	N/A	56.7	N/A
	On-Peak	6.9	N/A	328.2	N/A	19.6	N/A	645.6	N/A	41.0	N/A
Feb	Off-peak	0.3	N/A	365.7	N/A	10.7	N/A	448.4	N/A	43.4	N/A
	On-Peak	0.2	N/A	353.4	N/A	10.7	N/A	388.2	N/A	26.0	N/A
Mar	Off-peak	0.0	N/A	473.9	N/A	11.2	N/A	614.3	N/A	54.7	N/A
	On-Peak	0.2	N/A	364.5	N/A	15.4	N/A	324.7	N/A	30.0	N/A
Apr	Off-peak	4.9	N/A	561.9	N/A	7.1	N/A	601.7	N/A	45.9	N/A
	On-Peak	2.5	N/A	599.8	N/A	8.4	N/A	560.9	N/A	31.1	N/A
May- Oct	Off-peak	3.6	0	468.3	3250.1	26.3	28.6	3,039.7	2869.4	287.5	321.8
	On-Peak	4.5	0	820.7	2821.3	33.9	34.2	1,561.2	2486.5	158.0	206.0
	Total	8.1	0	1,289.0	6071.4	60.2	62.9	4,600.9	5355.8	445.5	527.8
Nov– Apr	Off-peak	13.9	N/A	1,956.2	N/A	61.7	N/A	3,238.1	N/A	308.5	N/A
	On-Peak	12.3	N/A	1,787.5	N/A	67.8	N/A	2,673.8	N/A	185.2	N/A
	Total	26.2	N/A	3,743.7	N/A	129.5	N/A	5,911.9	N/A	493.7	N/A
May- Apr	Off-peak	17.5	N/A	2,424.5	N/A	88.0	N/A	6,277.8	N/A	596.0	N/A
	On-Peak	16.8	N/A	2,608.2	N/A	101.7	N/A	4,235.0	N/A	343.2	N/A
	Total	34.3	N/A	5,032.7	N/A	189.7	N/A	10,512.8	N/A	939.2	N/A

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

*Table A-29: Injections by Intertie Zone, On-Peak and Off-Peak, May 2007 – October 2008 (GWh)**

		MB		MI		MN		NY		PQ	
		2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	Off-peak	36.9	53.4	33.5	144.5	7.0	11.3	71.1	599.8	4.1	0.2
	On-Peak	17.4	38.6	43.6	153.2	9.4	9.0	55.8	560.9	109.2	8.1
Jun	Off-peak	68.0	86.3	84.5	254.4	16.1	19.9	10.0	482.4	23.3	12.8
	On-Peak	49.3	57.4	86.0	148.8	13.1	18.9	50.6	452.7	73.5	36.2
Jul	Off-peak	88.5	81.5	121.4	145.4	16.6	18.0	7.1	344.8	5.7	22.0
	On-Peak	40.9	69.6	100.7	158.0	12.2	17.6	53.6	326.1	43.5	89.0
Aug	Off-peak	79.1	90.1	173.9	96.4	23.3	19.6	24.4	48.1	5.8	20.1
	On-Peak	65.3	75.9	100.3	57.0	21.4	14.8	115.1	38.5	60.3	87.2
Sep	Off-peak	79.0	77.0	340.3	245.0	29.1	16.9	10.4	32.1	6.9	6.3
	On-Peak	57.5	59.1	252.1	157.0	25.7	15.5	46.6	20.5	19.1	33.1
Oct	Off-peak	60.2	84.8	275.4	207.3	15.7	21.4	10.3	38.1	14.3	0.5
	On-Peak	45.6	75.2	309.5	137.3	14.8	17.6	37.6	65.1	16.9	1.9
Nov	Off-peak	65.6	N/A	390.6	N/A	14.3	N/A	13.6	N/A	9.3	N/A
	On-Peak	53.1	N/A	315.5	N/A	10.8	N/A	58.2	N/A	70.4	N/A
Dec	Off-peak	52.3	N/A	351.1	N/A	16.5	N/A	76.3	N/A	1.1	N/A
	On-Peak	60.3	N/A	321.4	N/A	14.3	N/A	102.9	N/A	7.1	N/A
Jan	Off-peak	44.4	N/A	32.3	N/A	8.9	N/A	243.8	N/A	20.8	N/A
	On-Peak	46.4	N/A	76.3	N/A	11.3	N/A	405.2	N/A	77.5	N/A
Feb	Off-peak	34.0	N/A	80.0	N/A	8.1	N/A	162.3	N/A	43.0	N/A
	On-Peak	27.5	N/A	120.1	N/A	8.5	N/A	171.9	N/A	131.4	N/A
Mar	Off-peak	53.1	N/A	219.3	N/A	13.7	N/A	367.6	N/A	22.1	N/A
	On-Peak	36.8	N/A	130.4	N/A	10.4	N/A	278.7	N/A	68.8	N/A
Apr	Off-peak	53.1	N/A	188.6	N/A	11.1	N/A	343.6	N/A	10.3	N/A
	On-Peak	41.3	N/A	215.3	N/A	12.0	N/A	323.9	N/A	63.4	N/A
May - Oct	Off-peak	411.7	473.1	1,029.0	1093.0	107.8	107.1	133.3	1545.3	60.1	61.9
	On-Peak	276.0	375.8	892.2	811.3	96.6	93.4	359.3	1463.8	322.5	255.5
	Total	687.7	848.9	1,921.2	1904.3	204.4	200.5	492.6	3009.1	382.6	317.4
Nov– Apr	Off-peak	302.5	N/A	1,261.9	N/A	72.6	N/A	1,207.2	N/A	106.6	N/A
	On-Peak	265.4	N/A	1,179.0	N/A	67.3	N/A	1,340.8	N/A	418.6	N/A
	Total	567.9	N/A	2,440.9	N/A	139.9	N/A	2,548.0	N/A	525.2	N/A
May - Apr	Off-peak	714.2	N/A	2,290.9	N/A	180.4	N/A	1,340.5	N/A	166.7	N/A
	On-Peak	541.4	N/A	2,071.2	N/A	163.9	N/A	1,700.1	N/A	741.1	N/A
	Total	1,255.6	N/A	4,362.1	N/A	344.3	N/A	3,040.6	N/A	907.8	N/A

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

Table A-30: Net Exports, May 2007 – October 2008
(MWh)

	On-peak		Off-peak		Total	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	269,688	469,712	424,277	600,609	693,966	1,070,321
Jun	93,969	448,028	474,515	506,570	568,484	954,598
Jul	285,182	494,270	523,963	668,496	809,145	1,162,766
Aug	88,026	489,663	367,333	655,126	455,359	1,144,789
Sep	(57,635)	250,635	112,928	343,827	55,293	594,461
Oct	(47,499)	396,042	180,297	415,100	132,798	811,142
Nov	(114,506)	N/A	79,738	N/A	(34,769)	N/A
Dec	69,711	N/A	241,428	N/A	311,139	N/A
Jan	424,622	N/A	672,407	N/A	1,097,030	N/A
Feb	319,136	N/A	541,020	N/A	860,156	N/A
Mar	209,884	N/A	478,247	N/A	688,131	N/A
Apr	546,762	N/A	614,612	N/A	1,161,374	N/A
May- Oct	631,731	2,548,350	2,083,313	3,189,728	2,715,045	5,738,077
Nov - Apr	1,455,609	N/A	2,627,452	N/A	4,083,061	N/A
May -Apr	2,087,340	N/A	4,710,765	N/A	6,798,106	N/A

Table A-31: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP, May 2007 – October 2008 ($/MWh)

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	7.63	3.13	72.88	44.97	(93.58)	(61.87)	16.11	14.12	30.63	19.23
Jun	6.83	5.29	99.04	176.97	(305.24)	(214.18)	22.95	25.31	25.54	47.93
Jul	3.58	3.12	62.49	72.09	(215.90)	(159.24)	16.64	19.73	15.97	34.16
Aug	7.68	(1.05)	79.74	36.67	(61.26)	(306.69)	14.90	22.85	19.45	33.57
Sep	3.91	(0.74)	60.95	50.45	(69.49)	(336.00)	12.18	25.16	17.71	33.35
Oct	6.73	1.23	82.25	38.91	(234.52)	(244.94)	15.40	18.64	25.54	27.24
Nov	6.68	N/A	50.18	N/A	(54.74)	N/A	13.48	N/A	18.56	N/A
Dec	6.62	N/A	48.05	N/A	(50.61)	N/A	14.24	N/A	28.43	N/A
Jan	8.78	N/A	63.38	N/A	(84.51)	N/A	14.28	N/A	30.31	N/A
Feb	10.79	N/A	68.85	N/A	(505.62)	N/A	25.50	N/A	23.44	N/A
Mar	8.55	N/A	77.36	N/A	(125.90)	N/A	20.29	N/A	19.54	N/A
Apr	7.42	N/A	82.12	N/A	(145.17)	N/A	22.34	N/A	19.39	N/A
May – Oct	6.06	1.83	76.23	70.01	(163.33)	(220.49)	16.36	20.97	22.47	32.58
Nov - Apr	8.14	N/A	64.99	N/A	(161.09)	N/A	18.36	N/A	23.28	N/A
May - Apr	7.10	N/A	70.61	N/A	(162.21)	N/A	17.36	N/A	22.88	N/A

Table A-32: Measures of Difference between 1-Hour Ahead Pre-dispatch Prices and HOEP, May 2007 – October 2008 ($/MWh)

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	8.23	4.86	71.78	63.30	(77.17)	(45.40)	14.49	13.02	35.18	25.81
Jun	6.99	8.60	94.35	115.21	(331.10)	(217.42)	21.84	22.60	25.21	48.62
Jul	5.26	5.21	62.02	61.08	(211.39)	(155.88)	15.91	17.67	22.34	37.13
Aug	8.16	1.23	74.6	36.54	(60.38)	(330.15)	13.56	22.67	20.05	42.82
Sep	5.96	1.88	83.01	334.24	(68.97)	(337.64)	12.46	27.03	22.37	38.06
Oct	8.17	2.88	66.75	38.77	(236.65)	(234.55)	14.99	18.14	30.09	35.46
Nov	7.50	N/A	56.65	N/A	(58.16)	N/A	12.91	N/A	20.87	N/A
Dec	7.37	N/A	52.08	N/A	(52.54)	N/A	13.32	N/A	28.86	N/A
Jan	9.41	N/A	64.78	N/A	(66.65)	N/A	13.52	N/A	34.39	N/A
Feb	11.28	N/A	107.12	N/A	(485.46)	N/A	25.08	N/A	32.04	N/A
Mar	10.87	N/A	77.36	N/A	(124.21)	N/A	18.68	N/A	23.08	N/A
Apr	8.46	N/A	77.91	N/A	(143.82)	N/A	21.38	N/A	68.30	N/A
May – Oct	7.13	4.11	75.42	108.19	(164.28)	(220.17)	15.54	20.19	25.87	37.98
Nov - Apr	9.15	N/A	72.65	N/A	(155.14)	N/A	17.48	N/A	34.59	N/A
May - Apr	8.14	N/A	74.03	N/A	(159.71)	N/A	16.51	N/A	30.23	N/A

Table A-33: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP, May 2007 – October 2008 ($/MWh)

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2007 / 2008	2008 / 2009	2007 / 2008	2008 / 2009
May	1.13	(5.06)	13.6	27.8
Jun	(1.59)	(4.79)	8.4	18.5
Jul	(1.87)	(6.84)	6.3	8.8
Aug	0.99	(9.75)	6.1	12.9
Sep	(2.35)	(10.44)	11.5	12.4
Oct	(3.59)	(8.31)	6.8	7.7
Nov	(6.48)	N/A	(1.6)	N/A
Dec	(5.45)	N/A	3.3	N/A
Jan	(2.76)	N/A	8.9	N/A
Feb	(0.84)	N/A	12.8	N/A
Mar	(1.74)	N/A	3.3	N/A
Apr	(9.05)	N/A	15.1	N/A
May – Oct	(1.21)	(7.53)	8.78	14.68
Nov - Apr	(4.39)	N/A	6.97	N/A
May - Apr	(2.80)	N/A	7.88	N/A

* This is an average of hourly differences relative to hourly peak MCP

Table A-34: Average Monthly HOEP Compared to Average Monthly Peak Hourly MCP, May 2007 – October 2008 ($/MWh)

	Hourly Peak MCP		HOEP		Peak minus HOEP	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	45.60	44.48	38.50	34.56	7.11	9.93
Jun	52.95	70.68	44.38	57.44	8.57	13.24
Jul	51.04	68.63	43.90	56.58	7.13	12.05
Aug	60.80	57.55	53.62	46.57	7.18	10.98
Sep	52.94	61.41	44.63	49.09	8.31	12.32
Oct	60.66	56.49	48.91	45.27	11.76	11.22
Nov	60.93	N/A	46.95	N/A	13.98	N/A
Dec	61.92	N/A	49.08	N/A	12.85	N/A
Jan	52.94	N/A	40.74	N/A	12.20	N/A
Feb	64.50	N/A	52.38	N/A	12.12	N/A
Mar	69.45	N/A	56.84	N/A	12.61	N/A
Apr	66.50	N/A	48.98	N/A	17.52	N/A
May – Oct	54.00	59.87	45.66	48.25	8.34	11.62
Nov – Apr	62.71	N/A	49.16	N/A	13.55	N/A
May - Apr	58.35	N/A	47.41	N/A	10.95	N/A

*Table A-35: Frequency Distribution of Difference between 1-Hour Pre-dispatch and HOEP, May 2007 – October 2008 (%)**

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)															
	< -$50.01		-$50.00 to -$20.01		-$20.00 to -$10.01		-$10.00 to -$0.01		$0.00 to $9.99		$10.00 to $19.99		$20.00 to $49.99		> $50.00	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.7	0.0	2.4	3.6	1.5	3.6	11.0	21.9	48.5	42.6	17.7	14.5	17.5	13.4	0.8	0.3
Jun	1.3	0.8	1.7	3.8	2.5	5.0	13.6	15.0	50.4	37.8	13.6	14.9	14.6	18.8	0.0	3.9
Jul	0.8	1.5	2.2	2.8	2.6	4.6	13.0	19.2	53.1	40.2	16.5	15.7	11.3	15.2	0.4	0.8
Aug	0.1	1.7	1.1	5.0	1.7	4.4	13.0	17.3	51.9	47.8	16.7	14.2	14.0	9.4	3.1	0.0
Sep	0.4	1.4	1.3	3.7	3.7	5.8	13.9	22.4	51.8	40.3	19.4	17.1	8.8	9.2	0.0	0.1
Oct	0.3	1.2	0.5	2.0	2.0	3.9	14.9	22.0	45.3	47.0	20.3	15.6	16.5	8.2	0.1	0
Nov	0.1	N/A	1.5	N/A	3.7	N/A	14.4	N/A	44.9	N/A	20.1	N/A	14.7	N/A	0.4	N/A
Dec	0.1	N/A	2.3	N/A	2.7	N/A	18.0	N/A	42.7	N/A	18.4	N/A	15.6	N/A	1.2	N/A
Jan	0.3	N/A	0.5	N/A	2.3	N/A	11.6	N/A	47.2	N/A	17.9	N/A	19.1	N/A	0.0	N/A
Feb	0.1	N/A	2.0	N/A	2.2	N/A	8.9	N/A	40.4	N/A	21.1	N/A	22.1	N/A	2.2	N/A
Mar	0.8	N/A	2.2	N/A	1.9	N/A	16.0	N/A	34.8	N/A	18.7	N/A	22.6	N/A	1.1	N/A
Apr	1.7	N/A	3.7	N/A	3.6	N/A	12.5	N/A	34.7	N/A	18.8	N/A	23.5	N/A	1.3	N/A
May – Oct	0.6	1.1	1.5	3.5	2.3	4.6	13.2	19.6	50.2	42.6	17.4	15.3	13.8	12.4	0.7	0.9
Nov – Apr	0.5	N/A	2.0	N/A	2.7	N/A	13.6	N/A	40.8	N/A	19.2	N/A	19.6	N/A	1.0	N/A
May - Apr	0.6	N/A	1.8	N/A	2.5	N/A	13.4	N/A	45.5	N/A	18.3	N/A	16.7	N/A	0.9	N/A

* Bolded values show highest percentage within price range.

Table A-36: Difference between 1-Hour Pre-dispatch Price and HOEP within Defined Ranges, May 2007 – October 2008

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	84.3	70.8	0.1	0.0	15.6	29.2
Jun	80.7	75.1	0.3	0.3	19.0	24.6
Jul	81.2	71.9	0.3	0.0	18.6	28.1
Aug	83.9	71.1	0.1	0.4	16.0	28.5
Sep	80.7	66.7	0.0	0.0	19.3	33.3
Oct	82.3	70.3	0.0	0.5	17.7	29.2
Nov	80.1	N/A	0.0	N/A	19.9	N/A
Dec	76.9	N/A	0.0	N/A	23.1	N/A
Jan	85.1	N/A	0.3	N/A	14.7	N/A
Feb	86.6	N/A	0.1	N/A	13.2	N/A
Mar	79.0	N/A	0.1	N/A	20.8	N/A
Apr	78.2	N/A	0.3	N/A	21.5	N/A
May – Oct	82.2	71.0	0.1	0.2	17.7	28.8
Nov – Apr	81.0	N/A	0.1	N/A	18.9	N/A
May - Apr	81.6	N/A	0.1	N/A	18.3	N/A

Table A-37: Difference between 1-Hour Pre-dispatch Price and Hourly Peak MCP within Defined Ranges, May 2007 – October 2008

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	62.1	47.8	2.4	1.6	35.5	50.5
Jun	57.1	46.7	2.9	1.8	40.0	51.5
Jul	55.7	41.9	3.6	2.7	40.7	55.4
Aug	58.7	38.8	2.4	3.6	38.8	57.5
Sep	46.8	35.1	3.5	2.4	49.7	62.5
Oct	48.9	38.4	2.8	3.2	48.3	58.3
Nov	41.7	N/A	3.1	N/A	55.3	N/A
Dec	46.0	N/A	2.0	N/A	52.0	N/A
Jan	54.7	N/A	2.2	N/A	43.1	N/A
Feb	61.5	N/A	1.9	N/A	36.6	N/A
Mar	50.9	N/A	3.2	N/A	45.8	N/A
Apr	51.2	N/A	1.5	N/A	47.2	N/A
May – Oct	54.9	41.5	2.9	2.6	42.2	56.0
Nov – Apr	51.0	N/A	2.3	N/A	46.7	N/A
May - Apr	52.9	N/A	2.6	N/A	44.4	N/A

Table A-38: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2007 – October 2008

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	285	269	259	247	173	193	142	156	1.8	1.8	1.7	1.6	1.1	1.3	0.9	1.0
Jun	418	390	350	343	287	269	209	210	2.4	2.3	2.1	2.1	1.6	1.5	1.2	1.2
Jul	399	396	337	336	275	274	201	198	2.3	2.3	2.0	2.0	1.6	1.5	1.1	1.1
Aug	455	333	382	307	307	241	225	197	2.5	2.0	2.2	2.0	1.7	1.4	1.2	1.1
Sep	368	280	318	267	237	208	180	159	2.3	2.0	2.0	2.0	1.4	1.1	1.1	1.0
Oct	336	290	307	272	192	241	160	153	2.1	2.0	2.0	2.0	1.2	1.1	1.0	1.0
Nov	310	N/A	300	N/A	178	N/A	154	N/A	1.8	N/A	1.8	N/A	1.0	N/A	0.9	N/A
Dec	352	N/A	316	N/A	256	N/A	203	N/A	1.9	N/A	1.7	N/A	1.4	N/A	1.1	N/A
Jan	367	N/A	327	N/A	205	N/A	163	N/A	2.0	N/A	1.8	N/A	1.1	N/A	0.9	N/A
Feb	344	N/A	313	N/A	212	N/A	180	N/A	1.9	N/A	1.7	N/A	1.1	N/A	1.0	N/A
Mar	344	N/A	302	N/A	238	N/A	188	N/A	2.0	N/A	1.7	N/A	1.3	N/A	1.1	N/A
Apr	284	N/A	263	N/A	182	N/A	154	N/A	1.8	N/A	1.7	N/A	1.1	N/A	1.0	N/A
May – Oct	377	326	326	295	245	238	186	179	2.2	2.1	2.0	2.0	1.4	1.3	1.1	1.1
Nov – Apr	334	N/A	304	N/A	212	N/A	174	N/A	1.9	N/A	1.7	N/A	1.2	N/A	1.0	N/A
May - Apr	355	N/A	315	N/A	229	N/A	180	N/A	2.1	N/A	1.9	N/A	1.3	N/A	1.0	N/A

*Table A-39: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2007 – October 2008 (%)**

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	1	1	12	13	15	15	21	18	22	22	16	15	13	16	0	1	49	47	51	54
Jun	4	5	19	21	14	14	17	16	16	14	12	12	15	16	3	2	54	56	46	44
Jul	4	4	21	18	12	12	17	17	17	16	14	15	13	16	1	3	54	51	45	50
Aug	5	3	24	15	16	13	15	18	12	16	11	13	15	20	2	3	60	49	40	52
Sep	3	0	16	13	16	11	20	19	18	23	11	16	15	16	2	1	55	43	46	56
Oct	1	1	18	15	19	17	18	21	21	19	13	16	9	11	1	1	56	54	44	47
Nov	2	N/A	15	N/A	15	N/A	23	N/A	19	N/A	15	N/A	11	N/A	0	N/A	55	N/A	45	N/A
Dec	3	N/A	19	N/A	11	N/A	14	N/A	17	N/A	14	N/A	20	N/A	2	N/A	47	N/A	53	N/A
Jan	3	N/A	18	N/A	18	N/A	22	N/A	19	N/A	11	N/A	10	N/A	0	N/A	61	N/A	40	N/A
Feb	3	N/A	20	N/A	15	N/A	18	N/A	20	N/A	11	N/A	11	N/A	2	N/A	56	N/A	44	N/A
Mar	2	N/A	24	N/A	13	N/A	18	N/A	16	N/A	11	N/A	15	N/A	1	N/A	57	N/A	43	N/A
Apr	1	N/A	14	N/A	16	N/A	19	N/A	22	N/A	14	N/A	13	N/A	1	N/A	50	N/A	50	N/A
May – Oct	3	2	18	16	15	14	18	18	18	18	13	15	13	16	2	2	54	50	46	51
Nov – Apr	2	N/A	18	N/A	15	N/A	19	N/A	19	N/A	13	N/A	13	N/A	1	N/A	54	N/A	46	N/A
May - Apr	3	N/A	18	N/A	15	N/A	19	N/A	18	N/A	13	N/A	13	N/A	1	N/A	55	N/A	45	N/A

* Data includes both dispatchable and non-dispatchable load.

*Table A-40: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, May 2007 – October 2008 (MW and %)**

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW: Maximum		Minimum		Average		Fail Rate** (%)	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	741,893	782,035	182.2	466.4	(194.2)	(187.6)	2.6	42.6	0.0	4.4
Jun	691,114	572,393	276.5	257.9	(144.7)	(138.3)	32.0	37.0	3.7	5.0
Jul	665,874	574,125	233.8	259.5	(147.9)	(524.7)	40.6	42.1	4.7	5.3
Aug	669,870	599,291	167.5	666.2	(167.3)	(178.7)	26.7	60.9	2.9	7.5
Sep	655,691	625,327	186.6	874.77	(162.4)	(1014.62)	17.9	19.02	2.1	2.0
Oct	817,009	861,952	177.9	1055.63	(247.5)	(334.10)	18.3	18.09	1.6	0.8
Nov	815,131	N/A	218.8	N/A	(161.6)	N/A	15.9	N/A	1.4	N/A
Dec	846,484	N/A	199.2	N/A	(214.2)	N/A	4.9	N/A	0.6	N/A
Jan	893,372	N/A	285.9	N/A	(163.5)	N/A	13.3	N/A	1.2	N/A
Feb	784,525	N/A	195.2	N/A	(171.5)	N/A	15.7	N/A	1.4	N/A
Mar	809,244	N/A	233.7	N/A	(190.5)	N/A	13.7	N/A	1.3	N/A
Apr	727,988	N/A	314.2	N/A	(243.2)	N/A	13.4	N/A	1.6	N/A
May – Oct	706,909	669,187	204.1	596.7	(177.3)	(396.3)	23	37	2.5	4.2
Nov – Apr	812,791	N/A	241.2	N/A	(190.8)	N/A	13	N/A	1.3	N/A
May - Apr	759,850	N/A	222.6	N/A	(184.0)	N/A	18	N/A	1.9	N/A

* Self-scheduled generators comprise list as well as those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.
** Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-41: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2007 – October 2008

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	68,746	107,523	137.8	173.9	(199.9)	(178.0)	4.2	4.5	4.8	2.6
Jun	54,863	59,868	146.7	144.1	(153.0)	(162.9)	9.4	1.7	14.8	0.4
Jul	44,078	61,196	154.0	154.8	(187.8)	(125.6)	5.7	6.3	14.2	(317.9)
Aug	54,869	60,478	159.1	122.0	(148.8)	(209.2)	1.7	8.0	(11.1)	14.3
Sep	74,113	81,062	143.3	182.1	(205.8)	(182.0)	(3.3)	9.8	(2.2)	8.6
Oct	106,536	157,750	150.1	191.9	(227.9)	(234.7)	4.1	6.2	0.8	3.9
Nov	113,859	N/A	178.0	N/A	(166.1	N/A	11.1	N/A	9.3	N/A
Dec	120,139	N/A	183.8	N/A	(203.0)	N/A	3.2	N/A	4.2	N/A
Jan	152,155	N/A	205.7	N/A	(155.4)	N/A	5.0	N/A	5.6	N/A
Feb	105,099	N/A	148.2	N/A	(166.8)	N/A	15.6	N/A	12.0	N/A
Mar	119,586	N/A	136.1	N/A	(169.9)	N/A	8.1	N/A	5.3	N/A
Apr	107,994	N/A	180.9	N/A	(240.4)	N/A	(3.3)	N/A	(1.7)	N/A
May – Oct	67,201	79,313	148.5	158.2	(187.2)	(187.3)	3.6	2.1	3.6	(53.5)
Nov – Apr	119,805	N/A	172.1	N/A	(187.1)	N/A	6.6	N/A	5.8	N/A
May - Apr	93,503	N/A	160.3	N/A	(187.2)	N/A	5.1	N/A	4.7	N/A

* Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-42: Failed Imports into Ontario, May 2007 – October 2008
(Incidents and Average MW)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	192	364	453	1,085	135	212	6.3	4.7
Jun	148	402	400	1,369	95	234	2.9	5.7
Jul	112	339	700	979	123	182	2.8	4.6
Aug	207	271	546	880	118	142	3.5	6.6
Sep	155	350	525	989	146	218	2.5	10.4
Oct	173	340	607	1,029	116	188	2.4	9.0
Nov	214	N/A	677	N/A	137	N/A	2.8	N/A
Dec	182	N/A	597	N/A	125	N/A	2.2	N/A
Jan	354	N/A	1,255	N/A	259	N/A	8.7	N/A
Feb	342	N/A	1,500	N/A	315	N/A	12.0	N/A
Mar	488	N/A	1,586	N/A	340	N/A	12.1	N/A
Apr	303	N/A	660	N/A	157	N/A	3.6	N/A
May-Oct	987	344	539	1,055	122	196	3.4	6.8
Nov-Apr	1,883	N/A	1,046	N/A	222	N/A	6.9	N/A
May-Apr	2,870	N/A	792	N/A	172	N/A	5.2	N/A

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

Table A-43: Failed Imports into Ontario, On-Peak,
May 2007 – October 2008
(Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	107	156	453	680	146	182	6.2	3.6
Jun	83	185	289	1,369	98	225	2.9	5.5
Jul	69	165	700	979	114	172	3.0	4.1
Aug	121	120	546	880	104	144	3.4	5.9
Sep	80	141	421	702	139	175	2.7	8.0
Oct	97	147	607	1,029	123	181	2.7	8.2
Nov	110	N/A	446	N/A	120	N/A	2.5	N/A
Dec	82	N/A	500	N/A	115	N/A	1.8	N/A
Jan	202	N/A	1,255	N/A	281	N/A	8.4	N/A
Feb	165	N/A	1,500	N/A	305	N/A	9.9	N/A
Mar	246	N/A	1,190	N/A	349	N/A	14.0	N/A
Apr	166	N/A	660	N/A	165	N/A	4.0	N/A
May-Oct	557	914	503	940	121	180	3.5	5.9
Nov-Apr	971	N/A	925	N/A	223	N/A	6.8	N/A
May-Apr	1,528	N/A	714	N/A	172	N/A	5.1	N/A

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

Table A-44: Failed Imports into Ontario, Off-Peak, May 2007 – October 2008 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	85	208	450	1,085	120	235	6.3	5.7
Jun	65	217	400	1,225	91	242	2.9	5.8
Jul	43	174	662	818	138	192	2.4	5.2
Aug	86	151	500	600	138	141	3.7	7.2
Sep	75	209	525	989	153	247	2.4	12.0
Oct	76	193	435	950	107	193	2.1	9.6
Nov	104	N/A	677	N/A	155	N/A	3.2	N/A
Dec	100	N/A	597	N/A	133	N/A	2.6	N/A
Jan	152	N/A	892	N/A	228	N/A	9.0	N/A
Feb	177	N/A	1,300	N/A	324	N/A	14.9	N/A
Mar	242	N/A	1,586	N/A	330	N/A	10.6	N/A
Apr	137	N/A	400	N/A	146	N/A	3.2	N/A
May-Oct	430	1,152	495	945	125	208	3.3	7.6
Nov-Apr	912	N/A	909	N/A	219	N/A	7.3	N/A
May-Apr	1,342	N/A	702	N/A	172	N/A	5.3	N/A

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

Table A-45: Failed Exports from Ontario,
May 2007 – October 2008
(Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	522	671	938	1,100	202	225	8.9	5.4
Jun	382	605	733	1,450	167	235	5.8	5.3
Jul	350	564	1,079	1,858	175	160	4.5	3.6
Aug	373	404	900	709	163	140	5.2	3.2
Sep	397	359	1,071	729	208	152	8.2	4.2
Oct	390	377	898	725	194	139	7.5	3.5
Nov	368	N/A	876	N/A	171	N/A	6.1	N/A
Dec	438	N/A	932	N/A	185	N/A	5.8	N/A
Jan	563	N/A	1,840	N/A	288	N/A	7.3	N/A
Feb	533	N/A	1,675	N/A	387	N/A	11.1	N/A
Mar	582	N/A	1,574	N/A	334	N/A	9.3	N/A
Apr	564	N/A	943	N/A	205	N/A	4.5	N/A
May-Oct	2,414	2,980	937	1,095	185	175	6.7	4.2
Nov-Apr	3,048	N/A	1,307	N/A	262	N/A	7.4	N/A
May-Apr	5,462	N/A	1,122	N/A	223	N/A	7.0	N/A

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

Table A-46: Failed Exports from Ontario, On-Peak, May 2007 – October 2008 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	199	306	938	915	224	211	8.1	4.9
Jun	150	261	733	1,100	179	246	6.8	5.3
Jul	164	242	1,079	1,263	201	184	5.8	3.7
Aug	155	170	900	558	154	139	5.0	3.0
Sep	146	167	942	610	204	148.2	8.0	4.4
Oct	160	178	645	725	171	149.7	6.8	3.7
Nov	147	N/A	633	N/A	149	N/A	5.3	N/A
Dec	175	N/A	650	N/A	182	N/A	5.3	N/A
Jan	283	N/A	1,840	N/A	336	N/A	8.4	N/A
Feb	226	N/A	1,675	N/A	355	N/A	9.3	N/A
Mar	253	N/A	1,300	N/A	387	N/A	11.8	N/A
Apr	272	N/A	820	N/A	219	N/A	4.7	N/A
May-Oct	974	1,324	873	862	189	180	6.8	4.2
Nov-Apr	1,356	N/A	1,153	N/A	271	N/A	7.5	N/A
May-Apr	2,330	N/A	1,013	N/A	230	N/A	7.1	N/A

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

Table A-47: Failed Exports from Ontario, Off-Peak, May 2007 – October 2008 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	323	365	902	1,100	188	237	9.5	5.8
Jun	232	344	570	1,450	159	227	5.2	5.4
Jul	186	322	627	1,858	152	141	3.6	3.4
Aug	218	234	722	709	170	140	5.2	3.4
Sep	251	192	1,071	729	209	154	8.3	4.0
Oct	230	199	898	492	211	130	8.0	3.3
Nov	221	N/A	876	N/A	186	N/A	6.7	N/A
Dec	263	N/A	932	N/A	187	N/A	6.2	N/A
Jan	280	N/A	1,705	N/A	239	N/A	6.2	N/A
Feb	307	N/A	1,517	N/A	410	N/A	12.7	N/A
Mar	329	N/A	1,574	N/A	294	N/A	7.7	N/A
Apr	292	N/A	943	N/A	191	N/A	4.4	N/A
May-Oct	1,440	1,656	798	1,056	182	172	6.6	4.2
Nov-Apr	1,692	N/A	1,258	N/A	251	N/A	7.3	N/A
May-Apr	3,132	N/A	1,028	N/A	216	N/A	7.0	N/A

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

Table A-48: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2007 – October 2008

	Average Hourly Reserve (MW)		% of Total Requirements										Export	
			Dispatchable Load		Hydroelectric		Fossil		CAOR		Import			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	1,346	1,374	19.0	20.3	71.1	46.0	4.4	28.8	0.1	1.2	0.2	0.0	3.4	3.7
Jun	1,334	1,316	19.2	21.6	68.6	54.6	5.6	18.2	0.3	1.5	1.0	0.0	3.4	4.2
Jul	1,317	1,315	18.0	20.4	70.8	55.4	6.1	18.7	0.1	2.1	0.8	0.0	2.4	3.4
Aug	1,324	1,317	16.3	21.9	72.7	59.0	5.5	14.4	0.0	0.6	1.2	0.0	3.1	4.1
Sep	1,320	1,323	17.0	20.7	72.7	67.3	5.2	7.7	0.1	0.1	1.3	0.0	3.1	4.3
Oct	1,330	1,491	16.9	11.1	74.3	70.4	5.7	13.1	0.0	1.7	0.4	0.1	2.5	3.6
Nov	1,382	N/A	16.4	N/A	68.7	N/A	7.3	N/A	0.1	N/A	2.1	N/A	3.9	N/A
Dec	1,315	N/A	17.4	N/A	70.8	N/A	6.2	N/A	0.1	N/A	0.7	N/A	3.5	N/A
Jan	1,317	N/A	20.6	N/A	64.1	N/A	9.5	N/A	0.4	N/A	0.4	N/A	4.4	N/A
Feb	1,319	N/A	21.0	N/A	61.5	N/A	11.5	N/A	0.6	N/A	0.8	N/A	4.3	N/A
Mar	1,316	N/A	19.4	N/A	67.5	N/A	8.7	N/A	0.4	N/A	0.2	N/A	3.3	N/A
Apr	1,315	N/A	21.8	N/A	52.2	N/A	18.8	N/A	2.4	N/A	0.5	N/A	3.2	N/A
May-Oct	1,329	1,356	17.7	19.3	71.7	58.8	5.4	16.8	0.1	1.2	0.8	0.0	3.0	3.9
Nov-Apr	1,327	N/A	19.4	N/A	64.1	N/A	10.3	N/A	0.7	N/A	0.8	N/A	3.8	N/A
May-Apr	1,328	N/A	18.6	N/A	67.9	N/A	7.9	N/A	0.4	N/A	0.8	N/A	3.4	N/A

Table A-49: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2007 – October 2008

	Average Hourly Reserve (MW)		% of Total Requirements										Export	
			Dispatchable Load		Hydroelectric		Fossil		CAOR		Import			
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	1,340	1,333	19.6	23.2	66.8	57.2	6.4	15.1	0.0	0.2	0.0	0.1	4.7	4.2
Jun	1,315	1,357	20.4	22.1	66.4	60.0	5.9	13.1	0.0	0.4	0.6	0.0	4.2	4.3
Jul	1,318	1,315	19.5	20.7	68.5	61.9	6.9	13.2	0.0	0.4	0.0	0.0	3.0	3.7
Aug	1,316	1,321	17.2	22.1	68.6	62.5	7.4	10.9	0.0	0.1	0.0	0.0	4.7	4.5
Sep	1,317	1,329	18.2	22.0	68.8	64.2	7.0	9.2	0.0	0.1	0.0	0.0	4.9	4.5
Oct	1,316	1,476	18.1	14.5	69.6	73.4	7.8	8.3	0.0	0.1	0.9	0.0	2.9	3.7
Nov	1,415	N/A	16.9	N/A	66.2	N/A	8.4	N/A	0.0	N/A	2.1	N/A	4.4	N/A
Dec	1,358	N/A	18.1	N/A	67.8	N/A	7.3	N/A	0.0	N/A	0.2	N/A	4.4	N/A
Jan	1,316	N/A	22.4	N/A	61.1	N/A	9.9	N/A	0.0	N/A	0.1	N/A	4.7	N/A
Feb	1,316	N/A	22.9	N/A	58.3	N/A	12.8	N/A	0.0	N/A	0.1	N/A	4.6	N/A
Mar	1,323	N/A	21.9	N/A	61.9	N/A	11.2	N/A	0.0	N/A	0.0	N/A	3.7	N/A
Apr	1,351	N/A	22.6	N/A	58.2	N/A	13.2	N/A	0.7	N/A	0.2	N/A	3.4	N/A
May-Oct	1,320	1,355	18.8	20.8	68.1	63.2	6.9	11.6	0.0	0.2	0.3	0.0	4.1	4.2
Nov-Apr	1,347	N/A	20.8	N/A	62.3	N/A	10.5	N/A	0.1	N/A	0.5	N/A	4.2	N/A
May-Apr	1,333	N/A	19.8	N/A	65.2	N/A	8.7	N/A	0.1	N/A	0.4	N/A	4.1	N/A

Table A-50: Day Ahead Forecast Error, May 2007 – October 2008 (as of Hour 18)

	Average Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 3%		Percentage of Hours with Absolute Error ≥ 3%	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	(26)	(101)	1.31	1.58	53	100	7	13
Jun	0	113	2.67	2.45	252	215	35	30
Jul	98	61	2.61	2.77	227	312	31	42
Aug	113	(13)	2.21	1.99	188	177	25	24
Sep	68	(82)	1.79	1.58	139	80	19	11
Oct	(70)	5	1.53	1.36	92	76	12	10
Nov	(93)	N/A	1.31	N/A	51	N/A	7	N/A
Dec	(115)	N/A	1.81	N/A	147	N/A	20	N/A
Jan	65	N/A	1.74	N/A	128	N/A	17	N/A
Feb	(17)	N/A	1.42	N/A	65	N/A	9	N/A
Mar	69	N/A	1.83	N/A	145	N/A	19	N/A
Apr	(101)	N/A	1.69	N/A	130	N/A	18	N/A
May-Oct	31	(3)	2.02	1.96	951	960	22	22
Nov-Apr	(32)	N/A	1.63	N/A	666	N/A	15	N/A
May-Apr	(1)	N/A	1.83	N/A	1,617	N/A	18	N/A

Table A-51: Average One Hour Ahead Forecast Error, May 2007 – October 2008

	Peak Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 2%		Percentage of Hours with Absolute Error ≥ 2%	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	(2)	(15)	0.89	1.02	63	87	8	12
Jun	19	39	1.19	1.22	129	136	18	19
Jul	39	14	1.14	1.10	126	115	17	15
Aug	61	(17)	1.22	1.13	125	114	17	15
Sep	22	(22)	1.06	0.96	94	81	13	11
Oct	39	(13)	0.99	0.97	92	69	12	9
Nov	19	N/A	0.88	N/A	59	N/A	8	N/A
Dec	(2)	N/A	1.12	N/A	102	N/A	14	N/A
Jan	53	N/A	0.88	N/A	66	N/A	9	N/A
Feb	40	N/A	0.96	N/A	77	N/A	11	N/A
Mar	40	N/A	1.06	N/A	90	N/A	12	N/A
Apr	2	N/A	0.95	N/A	67	N/A	9	N/A
May-Oct	30	(2)	1.08	1.07	629	602	14	14
Nov-Apr	25	N/A	0.98	N/A	461	N/A	11	N/A
May-Apr	28	N/A	1.03	N/A	1,090	N/A	12	N/A

Table A-52: Monthly Payments for Reliability Programs,
May 2007 – October 2008
($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		ELRP		Total	
	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009	2007/2008	2008/2009
May	0.33	0.05	2.33	1.42	1.01	5.07	1.15	1.07	0.11	0.13	0.00	0.00	4.93	7.74
Jun	1.08	0.10	2.27	3.06	1.24	4.79	2.04	3.31	0.07	0.03	0.01	0.00	6.71	11.29
Jul	0.65	0.06	1.42	1.62	1.10	6.09	2.29	3.52	0.22	0.15	0.00	0.00	5.68	11.44
Aug	0.64	0.03	2.29	0.90	0.61	2.66	1.58	2.82	0.06	0.01	0.00	0.00	5.18	6.42
Sep	2.79	0.22	1.71	1.44	0.78	0.89	1.67	2.32	0.03	0.03	0.01	0.00	6.99	4.90
Oct	1.35	0.02	2.55	1.30	0.85	4.21	1.99	1.73	0.04	0.12	0.00	0.00	6.78	7.38
Nov	1.20	N/A	2.99	N/A	1.50	N/A	1.06	N/A	0.06	N/A	0.00	N/A	6.81	N/A
Dec	0.25	N/A	3.69	N/A	1.07	N/A	2.01	N/A	0.01	N/A	0.00	N/A	7.03	N/A
Jan	0.10	N/A	3.93	N/A	2.25	N/A	2.06	N/A	0.11	N/A	0.00	N/A	8.45	N/A
Feb	0.27	N/A	5.44	N/A	2.25	N/A	1.42	N/A	0.20	N/A	0.00	N/A	9.58	N/A
Mar	0.22	N/A	3.79	N/A	1.40	N/A	2.22	N/A	0.09	N/A	0.00	N/A	7.72	N/A
Apr	0.11	N/A	3.98	N/A	4.77	N/A	3.59	N/A	0.06	N/A	0.00	N/A	12.51	N/A
May – Oct	6.84	0.48	12.57	9.74	5.59	23.71	10.72	14.77	0.53	0.47	0.02	0.00	36.27	49.17
Nov – Apr	2.15	N/A	23.82	N/A	13.24	N/A	12.36	N/A	0.53	N/A	0.00	N/A	52.10	N/A
May - Apr	8.99	N/A	36.39	N/A	18.83	N/A	23.08	N/A	1.06	N/A	0.02	N/A	88.37	N/A

* In certain situations, payments for the same import are made via the DA IOG and RT IOG programs but subsequently one of the payments is recovered through the IOG reversal. Since June 2006, approximately $2.66 million has been received through the IOG reversal. The data reported in this table does not account for the IOG reversal.

Table A-53: Hours when HOEP < $0/MWh,
May 2008 – October 2008

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
05/04/2008	5	11,296	11,578	2.5	431	1.53	(3.09)	(4.6)
05/04/2008	6	11,672	11,732	0.5	481	0.00	(9.41)	(9.4)
05/04/2008	7	12,440	12,328	(0.9)	449	2.84	(8.32)	(11.2)
05/04/2008	24	13,105	12,682	(3.2)	331	10.80	(6.35)	(17.2)
05/06/2008	6	14,997	13,877	(7.5)	0	32.07	(0.14)	(32.2)
05/14/2008	3	12,194	12,078	(1.0)	875	4.70	(0.12)	(4.8)
07/05/2008	3	12,099	12,113	0.1	237	3.05	(0.58)	(3.6)
07/05/2008	4	12,037	11,898	(1.2)	200	1.00	(10.39)	(11.4)
07/05/2008	5	11,966	11,816	(1.3)	(81)	(10.87)	(11.71)	(0.8)
07/05/2008	6	12,251	12,033	(1.8)	0	(10.87)	(12.53)	(1.7)
07/05/2008	7	13,486	13,016	(3.5)	125	2.00	(9.77)	(11.8)
07/05/2008	24	13,834	13,336	(3.6)	75	3.90	(2.32)	(6.2)
07/06/2008	1	12,903	12,691	(1.6)	67	1.40	(6.40)	(7.8)
07/06/2008	2	12,479	12,134	(2.8)	42	(1.01)	(10.92)	(9.9)
07/06/2008	3	11,989	11,836	(1.3)	25	(10.68)	(11.27)	(0.6)
07/06/2008	4	11,781	11,607	(1.5)	117	(10.87)	(13.03)	(2.2)
07/06/2008	5	11,689	11,484	(1.8)	42	(10.78)	(12.68)	(1.9)
07/06/2008	6	11,896	11,505	(3.3)	150	(10.78)	(14.59)	(3.8)
07/06/2008	7	12,848	12,353	(3.9)	(10)	0.00	(10.67)	(10.7)
07/14/2008	1	13,494	13,281	(1.6)	375	3.30	(0.15)	(3.5)
07/14/2008	4	12,856	12,785	(0.6)	101	0.00	(2.04)	(2.0)
07/14/2008	5	13,451	13,103	(2.6)	177	2.04	(2.62)	(4.7)
08/03/2008	5	11,968	11,994	0.2	320	3.20	(0.66)	(3.9)
08/11/2008	1	12,639	12,455	(1.5)	300	3.11	(3.08)	(6.2)
08/11/2008	3	12,017	12,037	0.2	150	0.25	(0.18)	(0.4)
08/11/2008	4	12,327	12,141	(1.5)	350	2.91	(3.74)	(6.7)
10/13/2008	2	11,491	11,198	(2.5)	0	3.40	(8.73)	(12.1)
10/13/2008	3	11,125	11,043	(0.7)	100	0.70	(3.31)	(4.0)
May - Oct	**28**	**12,440**	**12,219**	**(1.8)**	**194**	**0.58**	**(6.39)**	**(7.0)**

** May to Oct totals reflect the total number of negative-priced hours and averages of the Net Failed Exports, PD and RT Demand, and PD and HOEP prices, during those hours.

Table A-54: Summary Statistics on Low Price Hours, May 2008 – October 2008

Month	Low Price Hours*	PD Demand (MW)**	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	% Change in Price	Minimum HOEP
May	193	12,706	12,498	(1.6)	180	18.33	6.84	(62.7)	(9.41)
Jun	87	13,000	12,718	(2.2)	130	24.69	8.11	(67.2)	1.55
Jul	144	13,861	13,532	(2.4)	51	17.66	7.22	(59.1)	(14.59)
Aug	126	13,231	12,964	(2.0)	66	20.17	7.35	(63.6)	(3.74)
Sep	90	12,816	12,580	(1.8)	50	22.16	7.65	(65.5)	1.81
Oct	84	12,852	12,633	(1.7)	44	27.70	9.85	(64.5)	(8.73)
May – Oct	**724**	**13,093**	**12,837**	**(2.0)**	**97**	**20.84**	**7.61**	**(63.5)**	**(14.59)**

* Low price hours are defined as hours when the HOEP is less than $20/MWh.
** Monthly figures reflect the average of hourly PD and RT Demand, Net Failed Exports, and PD and HOEP prices over all low price hours.