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 2007- October 2007

PUBLIC

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Neil Campbell
Chair, Market Surveillance Panel

Président, Comité de surveillance du marché

December 31, 2007

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 11th semi-annual Monitoring Report of Ontario's wholesale electricity market, the IESO-administered markets.

This report, covering the period May 1, 2007 to October 31, 2007, 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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Executive Summary

Ontario's wholesale electricity spot market once again performed reasonably well according to its design over the six-month period May 2007 to October 2007. Spot market prices generally reflected demand and supply conditions. The Market Surveillance Panel (MSP) found no evidence of gaming, abuse of market power or other inappropriate conduct by market participants or the market and system operator, the Independent Electricity System Operator (IESO). However, as in previous reports, the MSP identified several potential opportunities to improve the efficiency of the market which are reflected in the 13 recommendations summarized below.

Market Prices and Uplift

The average Hourly Ontario Energy Price (HOEP) for the period May 2007 through October 2007 increased by 1 percent compared to the same period in 2006 (although prices were generally lower in the beginning and higher in the final two months of the period). 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 OPG Rebate, increased by $1.20/MWh or 2.3 percent in the summer of 2007 compared to 2006. Total hourly uplift payments charged to market participants increased by $16 million or 10 percent during the current period compared to the same period in 2006.

Energy prices were more dispersed relative to last year, with more hours above $70/MWh and more below $20/MWh. There were 4 hours when the HOEP was above $200/MWh, down from 6 a year ago, while the number of hours when the HOEP fell below $20/MWh increased by 122 percent to 331 hours.

Demand and Supply Conditions

Total Market Demand fell by 0.39 TWh or 0.5 percent during May through October 2007 compared to the same period last year. Wholesale load levels continued to decline, particularly in the Northwest. Although Market Demand fell, total exports increased by over 3 percent.

Net exports (total exports less total imports) declined by 640 GWh or 19 percent relative to last summer. The majority of the decline in net exports occurred in the last three months coinciding with the rapid appreciation of the Canadian/US dollar exchange rate and the increased imports that occurred.

Planned outage rates have been fairly constant since late 2003. However, forced outage rates increased in September and October to rates not seen since 2005. These high rates were primarily a result of outages at two nuclear generating stations during the second half of the summer.

High and Low HOEP

We assessed the four hours during May 2007 though October 2007 period when the HOEP was greater than $200/MWh and the one hour when the HOEP was negative. The highest priced hour occurred on June 12, 2007 in Hour Ending 15 when the HOEP reached $436.53/MWh. We provide a detailed assessment of the conditions contributing to this price. The IESO used almost all available tools to maintain reliability including cutting exports, purchasing emergency energy, curtailing dispatchable loads, activating Operating Reserve, and eventually implementing a 5 percent voltage cut.

Operational Issues & Recommendations

The Panel has made several suggestions for potential changes to the present IESO-administered market based on its analysis of observed market outcomes over the past six months.

Recommendation 1-1 (Chapter 1 Section 2.4.3)

Over the next few years, various new wind projects are scheduled to connect to the IESO's energy grid. Currently, wind generators submit forecasts to the IESO indicating how much energy they will provide on an hourly basis. The discrepancy between forecasted and delivered energy can cause significant differences between pre-dispatch and real-time prices as well as potential reliability issues for the IESO. There has been an increase in the absolute average forecast error since early 2006, coinciding with the introduction of new wind projects in Ontario. Expected new wind generation will increase the magnitude of the overall error and potentially reduce the predictability of real-time prices.

The Panel encourages the IESO to continue to review the forecasting process with wind generators and determine methods to reduce forecast errors. Such generators should have incentives (positive or negative) to encourage accurate forecasting.

Recommendation 2-1 (Chapter 2 Section 2.1.2.3)

After the final pre-dispatch run, the IESO can curtail exports for 'security' or 'adequacy' reasons. The 'security' code is used when an internal or intertie transmission limitation requires the IESO to cut the export. The 'adequacy' code is used to cut an export when there are insufficient internal resources to meet the Market Demand. Adequacy curtailments are removed from both the constrained and unconstrained sequences while security curtailments are only removed from the constrained sequence. Removal from the unconstrained sequence has the effect of lowering demand and suppresses the market price during times of scarcity. This may undermine efficient responses by market participants. For example, the resulting lower HOEP may have the effect of encouraging traders to continue seeking exports from the IESO in the next hours in spite of the potential scarcity situation.

Export curtailment due to 'adequacy' has an effect of suppressing the market price during times of serious scarcity since the curtailed amount is removed from the market schedule, thus distorting the market price signal. The Panel recommends that the IESO not remove the curtailed amount due to 'adequacy' from the market schedule.

<u>Recommendation 3-1 (Chapter 3 Section 2.3)</u>

In the July 2007 MSP Report, the Panel identified that the consumption deviation of dispatchable load can be a source of forecast error. The IESO's forecast model counts the deviation as a portion of forecast demand of non-dispatchable load. The Panel recommended that the IESO should explore possible improvements to the load predictor tool to reduce dispatch inefficiencies from forecast errors arising from changes in dispatchable load consumption

In this report, the Panel identifies another issue that might be resolved by an improvement in the load predictor tool. Given that the constrained sequence uses a ten-minute-ahead demand forecast and the unconstrained sequence uses actual demand,[1] we find that demand has been persistently under-forecasted since early 2005.

Consistent with prior recommendations directed at improving the IESO load predictor, whose algorithm imputes changes in non-dispatchable load that can induce consumption inefficiency and forecast errors, the Panel recommends that the IESO review its load predictor methodology to determine if it is a source of persistent under-forecasting of demand.

<u>Recommendation 3-2 (Chapter 3 Section 2.5)</u>

In our December 2005 Monitoring Report, the Panel discussed an issue involving Phase Angle Regulators (PARs) between Ontario and Michigan. These PARs, first placed in

[1] Plus adjustments when certain control actions such as voltage reductions and manually constraining-off dispatchable load have been taken

service in March 2005, were intended to limit inadvertent parallel loop flow through Ontario between New York and Michigan in order to increase effective import/export capability on the Michigan and also the New York interfaces. However, the Panel noticed an increase in the amount of import congestion and a reduction in import capability (by about 400 MW) at the Michigan intertie, which coincided with and was the result of placing the Lambton PARs in service. Though the PARs were placed in service, they could not be operated until agreements were negotiated among Hydro One, ITC*Transmission* (ITC), the IESO and the Midwest ISO (MISO). To restore interchange capability, the PARs were removed from service in June 2006.

Since June 2006, many of the Panel's concerns have been resolved. The IESO has indicated that it places a high priority on developing Operating Agreements with MISO, Hydro One and ITC and is targeting implementation and reconnection of the PARs by the spring of 2008.

Hydro One has indicated that the units must be operated in a conservative manner for a number of months until sufficient experience had been gained to allow it to determine if the originally anticipated limits can be achieved in order to maximize the Ontario-Michigan intertie capacity. This is expected to require several months. But even in the interim, the PARs will improve import/export capability substantially.

(1) The IESO should expedite completion of the necessary agreements with Hydro One, the Midwest ISO and* ITC*Transmission for operation of the Phase Angle Regulators on the Michigan intertie. The IESO (and Hydro One) should also complete necessary staff training as soon as possible. Any improvement on the spring 2008 target would have positive efficiency (as well as reliability) effects on the Ontario (and Midwest ISO) system and any slippage would have the opposite effects.

(2) Hydro One should work towards developing ratings that will safeguard the Phase Angle Regulators and provide operationally useful Limited Time Ratings as soon as possible.

Recommendation 3-3 (Chapter 3 Section 3.1)

In previous reports, the Panel has discussed the issue of the volatility of dispatch instructions. Although the IESO has undertaken measures to minimize the effect of this volatility on generators, it has not addressed the root causes of either dispatch volatility or interval-to-interval price volatility.

Market Demand (Ontario demand plus exports) and market supply (available generation plus imports) exhibit abrupt hourly changes for two main reasons: the coordinated change in exports and imports made on the hour and the arrival or departure of hydroelectric generation on the hour. The current fixed one hour bid window combined with the present methodology of scheduling interties is creating inefficiencies.

A potential market design change would be to adopt a 15-minute dispatch algorithm for both generation and imports/exports. We understand that the New York ISO already has a 15 minute dispatch algorithm to allow better scheduling of internal resources. Allowing imports, exports and domestic generation to change on the quarter hour reduces the extent to which domestic generation would be obliged to inefficiently ramp up or down to accommodate changes in imports and exports. Rescheduling within the hour could also provide better response to supply problems that may emerge during the hour.

The MSP recommends the IESO begin investigation of a 15 minute dispatch algorithm to enhance the efficiency of the market.

Recommendation 3-4 (Chapter 3 Section 4.1)

On August 12, 2007, a market participant requested that the IESO constrain on various hydroelectric units for regulatory reasons. In this case, river flows had to be maintained in order to respect agreed water levels. The Market Rules allow variances from dispatch instructions for safety, legal, regulatory and environmental reasons. In the months of August and September 2007, the Market Assessment Unit identified approximately

$150,000 of constrained on payments to a market participant that requested various hydroelectric units be constrained on to maintain required water levels. While such ‘self-induced’ payments may be addressed through discussions leading to voluntary repayments, it would be useful to have rule-based authority to recover such payments.

The IESO should initiate a rule change to allow the recovery of self-induced congestion management settlement credit payments which are made to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons.

<u>Recommendation 3-5 (Chapter 3 Section 4.2)</u>

Import Offer Guarantees (IOG) are intended to assist the reliability of the Ontario market by attracting efficient imports. IOGs are offered to help manage the pricing risk to traders on an hourly basis by paying them based on the higher of their offers and the real-time MCP. Wheel-though transactions, both linked and implied, are not eligible for IOG payments. Such payments are automatically recovered by an IOG offset since there is no net import (i.e., reliability benefit) to Ontario.

Recently, market participants who are business affiliates were identified as importing (and receiving the IOG payment) and exporting in the same hour. This effectively constitutes an implied wheel when the affiliation of the two businesses is considered. If one of these market participants had undertaken both transactions, the IOG payment would have been clawed back through the IOG offset. To date, the amount of money paid to affiliated entities that are importing and exporting power simultaneously has been small. However, it would be appropriate to automatically offset the IOG payments made to a market participant when it is identified as an affiliate in the same manner as for the implied wheel transactions undertaken by a single entity.

The IESO should initiate a rule change to make Intertie Offer Guarantee payments subject to offsets where affiliated market participants are simultaneously importing and exporting.

Recommendation 3-6 (Chapter 3 Section 4.3)

In October of 2004, Hydro One applied and subsequently obtained approval from the Ontario Energy Board for a construction of a new 76-kilometer double circuit 230 kilovolt (kV) transmission line to upgrade the capacity of the Queenston Flow West (QFW) transmission flowgate, as well as upgrades to the Middleport Transformer Station. Increasing the capacity (reducing congestion) of the QFW transmission flowgate will lead to several efficiency gains for the Ontario market including less constrained off generation in the Niagara area, reduced constrained on generation west of QFW, and reduced constrained off/on imports/exports on the New York interties (and the Michigan interties). The projects were expected to increase the rating of the QFW flowgate by 800 MW (44 percent). The projects were to be completed in the summer of 2007, however their completion has been significantly delayed. Hydro One has advised the Panel that although it is not a direct party to the dispute causing the delay, it has been providing input and supporting parties involved in the negotiations. Once the dispute is resolved the Panel anticipates that Hydro One will be ready to complete the project expeditiously.

It is important for the efficiency of the Ontario electricity market that Hydro One attempt to complete the Queenston Flow West transmission expansion as soon as practicable. The ability to fully utilize 'bottled' generation in the Niagara region and maximize economically viable imports with New York (and Michigan) will enhance the efficiency (and reliability) of the Ontario market.

Recommendation 3-7 (Chapter 3 Section 4.4.3)

The Ontario Power Authority (OPA) introduced a Renewable Energy Standard Offer Program (RESOP) in 2006 to help Ontario meet its renewable energy supply targets by providing small renewable energy generating projects (less than 10 MW) with a standard pricing structure and simplified qualifying guidelines. Because of their small size and their connection within LDCs, there are few requirements for these facilities to provide ongoing production status or forecasts. Also because of the intermittent nature of their production, these generators could add uncertainty for the IESO operation and could in some situations lead to production inefficiencies. The Panel understands that the IESO has just initiated a stakeholder consultation to discuss the integration of these and other embedded generators into the reliable operation of the IESO-controlled grid and encourages the IESO to also consider opportunities to reduce potential inefficiencies.

To the extent possible in its stakeholder consultation on embedded generation, the IESO should consider opportunities to reduce inefficiency through the development of the capability for accurate forecasting of embedded generation production, which may require the provision of real-time production and related information (e.g. outages).

Recommendation 3-8 (Chapter 3 Section 4.4.6)

In light of the growing numbers of OPA contracts with energy suppliers in Ontario, we reviewed these contracts from an efficiency perspective. The Panel's view has always been that efficient contract structure is one that motivates generators to offer into the wholesale market at prices that reflect their incremental cost of production and that this helps to ensure efficient dispatch.

Our assessment found that the Clean Energy Supply (CES) type arrangements are the most efficient of the contract structures used by the OPA. Contracts for new supply would be more efficient if they reflected the same structure as the CES contract; an up-front payment of some kind and incentives for hourly decision-making related to the market price. A similar observation may apply for Ontario Electricity Financial Corporation for any new or renewed NUG (New Utility Generator) contracts it might arrange.

The Panel recommends that the Ontario Power Authority structure future contracts to maintain the energy market price as the driver for production decisions (for example, using a strike price structure similar to the payment provisions in the existing Clean Energy Supply contracts).

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

Aside from the Ontario Power Generation (OPG) Rebate, there is no publicly available disaggregation of the Global Adjustment into its various component programs: OPG's baseload generation (prescribed assets), the various Ontario Power Authority (OPA) generation procurement programs and demand management programs, Bruce generation and the NUG contracts. Data such as total monthly payments under each program as well as monthly energy delivered would allow for an assessment of the effectiveness and costs (in total and per MWh of supply or conservation) of these various programs. It could also be beneficial for market participants (and even retail customers) who may want to predict the expected future levels of such payments (which represented approximately $370 million or about $5/MWh for the current six month summer period), for example, when making investment or supply contract decisions. For OPA procurement programs, one possible approach is to aggregate information by program, for example, the Renewable Energy program, the Clean Energy Supply program, each of the corresponding Standard Offer Programs, Demand Management programs and Local Distribution Company energy conservation programs.

(1) The Ontario Power Authority should create more transparency regarding the ongoing monthly payments associated with each of its various procurement programs in order to promote a better understanding of the costs and effectiveness of these programs and to help market participants gain a better understanding of the component costs of the Global Adjustment.

(2) Similarly, the IESO should consider providing aggregate monthly payments associated with Ontario Power Generation's regulated baseload assets, as it currently does for the OPG Rebate.

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Chapter 1: Market Outcomes May 2007 – October 2007

1. *Highlights of Market Indicators*

This Chapter provides an overview of the results of the IESO-administered markets over the period May 1 to October 31 in 2007, with comparisons to the same period a year earlier and in many instances a review of trends since market opening. For ease of reference, the May through October period is sometimes referred to as 'the summer period'. There are four substantive sections summarizing the data on prices, demand, supply and trade. Highlights of each of these are summarized in the subsections that follow.

1.1 Pricing

This section reports on various pricing outcomes. The average Hourly Ontario Energy Price (HOEP) was $45.66/MWh, which is $0.45/MWh or one percent higher than the average HOEP in the same period one year ago. Lower demand and higher hydroelectric and nuclear baseload production reduced the HOEP in May while lower nuclear availability and baseload hydro supply resulted in higher prices in September and October. Furthermore, energy prices were more spread out, with more hours above $70/MWh and more below $20/MWh.

The existence of OPA contracts and regulated prices in Ontario's hybrid markets act to protect consumers from being exposed to paying the HOEP. The actual amount paid by most Ontario loads is more accurately measured by the effective load-weighted HOEP, which increased by $1.20/MWh or 2.3 percent in the summer of 2007 compared to 2006.

In section 2.2, we show that average operating reserve prices differed this summer compared to last. During the on-peak hours, there was a large decline in May operating reserve (OR) prices followed by a dramatic increase in June prices because of changing supply conditions associated with freshet. Off-peak operating reserve prices fell by approximately 50 percent for all OR categories. Changes to the OR requirements, increased OR supply from new entrants, and increased OR activations all contributed to lower OR prices in the off-peak hours this period.

In section 2.3, we show that coal-fired generators continue to set the Market Clearing Price (MCP) most often, although their share fell by 5 percent this summer. Coincidentally, oil/gas generation increased its share by 4 percent.

Section 2.4 reports that there has been little change in the discrepancy between the one-hour ahead and three-hour ahead prices and the HOEP. The section provides an in-depth discussion about the factors that lead to price forecasting errors including forecast error resulting from wind generators. The average absolute difference between offered and delivered MW from wind generation continues to grow as more wind capacity enters the market.

Section 2.5 explores the causes of differences in the HOEP in summer 2007 compared to 2006 by looking at the price effects of different values for key factors like natural gas prices, Ontario load, etc.

Section 2.6 shows hourly uplifts totalled $183 million between May and October 2007, which is 10 percent higher than the previous summer, although the long-term trend continues to suggest both hourly uplift and total uplift are declining.

Average prices and Congestion Management Settlement Credits (CMSC) are reported by zone in section 2.7. Consistent with previous periods, the average zonal price is lowest in the Northwest region at minus $136.65/MWh due to excess hydro supply and low demand forcing generators in the region to bid low (and negative) prices. Constrained off supply/constrained on exports were larger than the same period one year ago by approximately $10 million while constrained on supply/constrained off exports were slightly lower by $0.4 million.

In section 2.8, we compare the frequency of high (>$200/MWh) and low (<$20/MWh) priced hours during the summer months of 2006 and 2007 for both the HOEP and the Richview Shadow Prices. Low priced hours were substantially higher by 182 hours (122 percent) for the HOEP and 108 hours (37 percent) for the Richview Price. There were only 4 hours where the HOEP exceeded $200/MWh and 54 hours for the Richview price at this level.

1.2 Demand

This section presents statistics on Ontario's demand situation for the current summer period. Section 3.1 reports that Ontario and Aggregate (market) Demand declined this summer by 0.65 TWh and 0.39 TWh respectively, although exports increased by over 3 percent. In Section 3.2, we show that wholesale load consumption continued to decline over the last six months. The decline was mainly attributable to declining wholesale load levels in the Northwest.

1.3 Supply

Section 4 reports on the supply conditions in the province by analysing the supply cushion, the average supply curve, outage statistics, and fuel prices during the 2007 summer months. Section 4.1 shows that the average pre-dispatch supply cushion improved to 24.6 percent representing an increase of 2.3 percent compared to last summer while the real-time supply cushion remained the same at 19.7 percent. In section 4.2, we compare the average supply curve this summer compared to last summer and find a small increase in low-priced offers this year, which is mainly due to increased baseload supply.

Energy prices and the supply conditions in the province are sensitive to outages. Section 4.3 presents statistics on planned and forced outages. During the summer of 2007, planned outages showed their typical seasonal variation while forced outage rates were higher during the final three months of the summer, primarily due to frequent outages at two nuclear generating stations.

Section 4.4 discusses changes in fuel prices for the May to October 2006 and 2007 periods. Average monthly natural gas prices (Henry Hub) were higher in the first two months of the summer but lower in the final four months while coal (NYMEX Central Appalachian) prices were lower over all summer months compared to a year ago. We report two additional price series: The Powder River Basin (PWB) coal price and the Union Dawn Hub natural gas price. PWB coal prices were almost 20 percent lower while Dawn gas prices were almost 5 percent higher than last summer.

Finally, section 4.5 presents the results of the net revenue analysis. Similar to previous reports, we find that net revenues earned in the market over the last 12-month period would be insufficient to cover incremental costs.

1.4 Imports and Exports

Section 5 reports on trade outcomes over the current summer period. Section 5.1 shows that total net exports declined by approximately 640 GWh (19 percent) compared to the 2006 summer months. The largest decline occurred during the on-peak hours where net exports fell by 42 percent largely due to increased nuclear outages towards the end of the summer forcing Ontario to become more import dependent. In section 5.2, we observe increasing levels of import and export congestion by 103 hours and 897 hours respectively. Export congested hours to Quebec were 531 hours (431 percent) higher than last summer due to strong competition for energy and a major maintenance procedure that limited the export capabilities of a Quebec intertie.

In the last report, the Panel introduced a revised structural econometric model to analyse the effects of price differences between New York and Ontario on the level of exports to New York. In section 5.3, we update the model by including the summer 2007 months and find that a one percent increase in HOEP will lead to a 4 percent decline in exports while a one percent increase in the New York price will lead to a five percent increase in exports.

In section 5.4, we observe that Ontario remains one the lowest priced areas compared to neighbouring jurisdictions with a six-month average energy price $5/MWh lower than the next lowest priced jurisdiction (MISO). We identify two offsetting effects of the recent appreciation of the Canadian dollar relative to the U.S. dollar: it increases the U.S. cost of buying Ontario energy and; reduces fuel prices for Canadian generators who buy from the U.S. Finally, we report that the level of linked-wheel through transactions increased over the summer 2007 months, especially August 2007 when linked-wheel though transactions totaled 32.9 GWh (approximately 5 percent of imports).

2. *Pricing*

2.1 Ontario Energy Price

Table 1 reports the monthly average Hourly Ontario Energy Price (HOEP) for May to October 2007 compared to the same months in 2006. The average HOEP was $45.66/MWh over the summer months of 2007, which was minimally higher than the same period one year earlier. Over the current six month period, the average HOEP was higher during the on-peak hours but lower during the off-peak hours.

The monthly average HOEP was lower during the first three months relative to a year ago but higher in the last three months, especially September and October where the HOEP increased by 26 percent and 22 percent respectively. The large price differences in September and October from the year before were caused by lower availability of nuclear and baseload hydro supply over the second half of the summer.[2] On the other hand, the price reduction in May was accompanied by somewhat lower demand coupled with higher hydroelectric and nuclear baseload production. The reduction in July corresponded with a large reduction in Ontario demand from a year earlier. Lower coal prices likely put some downward pressure on energy prices over the period, particularly off-peak.

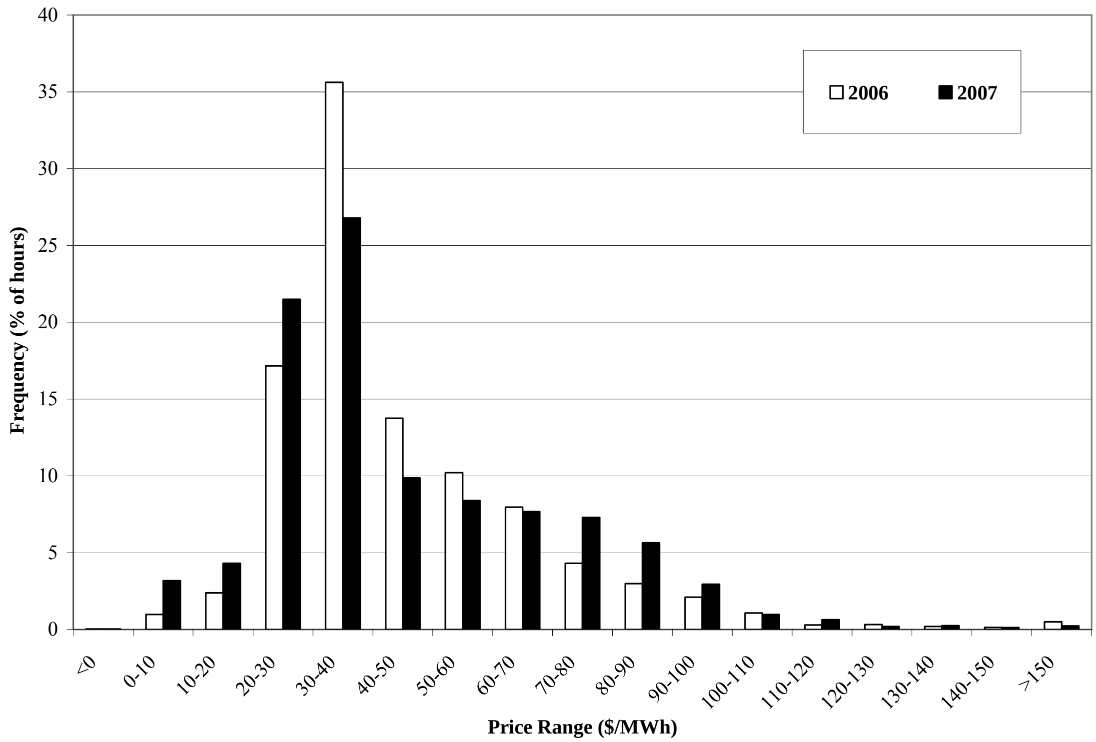
[2] See Tables A-13 and A-14 in the Statistical Appendix

Table 1-1: Average HOEP, On-peak and Off-peak, May – October 2006 & 2007 ($/MWh)

	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2006	2007	% Change	2006	2007	% Change	2006	2007	% Change
May	46.32	38.50	(16.9)	59.18	53.78	(9.1)	34.77	24.77	(28.8)
June	46.08	44.38	(3.7)	56.04	57.32	2.3	37.36	33.06	(11.5)
July	50.52	43.90	(13.1)	63.25	57.70	(8.8)	41.72	32.54	(22.0)
August	52.72	53.62	1.7	65.05	69.80	7.3	41.64	39.10	(6.1)
September	35.42	44.63	26.0	43.85	58.27	32.9	28.67	34.66	20.9
October	40.20	48.91	21.7	49.64	60.19	21.3	32.44	38.77	19.5
Average	45.21	45.66	1.0	56.17	59.51	5.9	36.10	33.82	(6.3)

Figure 1-1 plots the frequency of price outcomes for the HOEP over the 2006 and 2007 summer months. Generally, prices during the summer period were more evenly spread compared to the same period one year ago. There was a noticeable decline in the number of hours where the HOEP fell between $30/MWh and $60/MWh compared to the same period a year ago. The number of hours the HOEP was less than $30/MWh increased by over 370 hours during the summer of 2007 compared to 2006. The frequency of HOEP in the $70-100/MWh range increased from last summer, while the hours above $150/MWh fell from 22 hours to 10 hours. There were four hours during the summer of 2007 where the HOEP was above $200/MWh and a single occurrence of a negative priced event, all of which are examined in more detail in Chapter 2.

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



2.1.1 Load-weighted HOEP

Compared to the average HOEP, the load-weighted HOEP[3] is a more accurate representation of the amount that loads in Ontario pay and what generators receive for their energy (absent Global Adjustment and OPG Rebate considerations) because it reflects the amount of consumption during a given hour. Table 1-2 shows the HOEP and the load-weighted average price for three different customer categories: all loads, dispatchable loads, and other wholesale loads. The table also reports the amount of Operating Reserve (OR) revenue that participating dispatchable loads earned over the period. Dispatchable loads paid $5.53/MWh of consumption less (11 percent) relative to all loads while other wholesale loads paid 7 percent less. If we account for dispatchable load OR revenue, dispatchable loads paid $6.23/MWh (12 percent) less than all loads as a result of consuming less energy at higher prices and more energy at lower prices.

[3] The load-weighted HOEP over the six month period is simply the HOEP weighted by the amount of consumption over the hour.

Table 1-2: Load-Weighted Average HOEP, May – October 2006 & 2007 ($/MWh)

Year	Unweighted HOEP	Load-weighted HOEP[4]			Dispatchable Load OR Revenue
		All Loads	Dispatchable Load	Other Wholesale Loads	
2006	45.21	48.24	43.52	45.37	0.86
2007	45.66	48.89	43.36	45.57	0.70
Difference	0.45	0.65	(0.16)	0.20	(0.16)
% Change	1.0	1.4	(0.4)	0.4	(18.6)

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

Figure 1-2 plots the monthly HOEP along with the Global Adjustment (GA) and OPG Rebate between April 2005 and October 2007.[5] The figure illustrates that the Global Adjustment and OPG Rebate have moderated HOEP volatility over the period. The monthly average effective HOEP has remained relatively stable within the $49-$55/MWh range and generally above the HOEP since the beginning of 2006 which corresponds to the initiation of the Bruce A contract and other contracts such as early movers and Clean Energy Supply (CES) contracts with the Ontario Power Authority (OPA).

[4] Unadjusted – does not include the impact of the Global Adjustment or the OPG Rebate.
[5] April 2005 represents the beginning of the Ontario Power Generation Non-Prescribed Asset Rebate, which was later renamed the OPG Rebate in May 2006.

Figure 1-2: Monthly Average HOEP Adjusted for OPG Rebate and Global Adjustment, April 2005 – October 2007 ($/MWh)

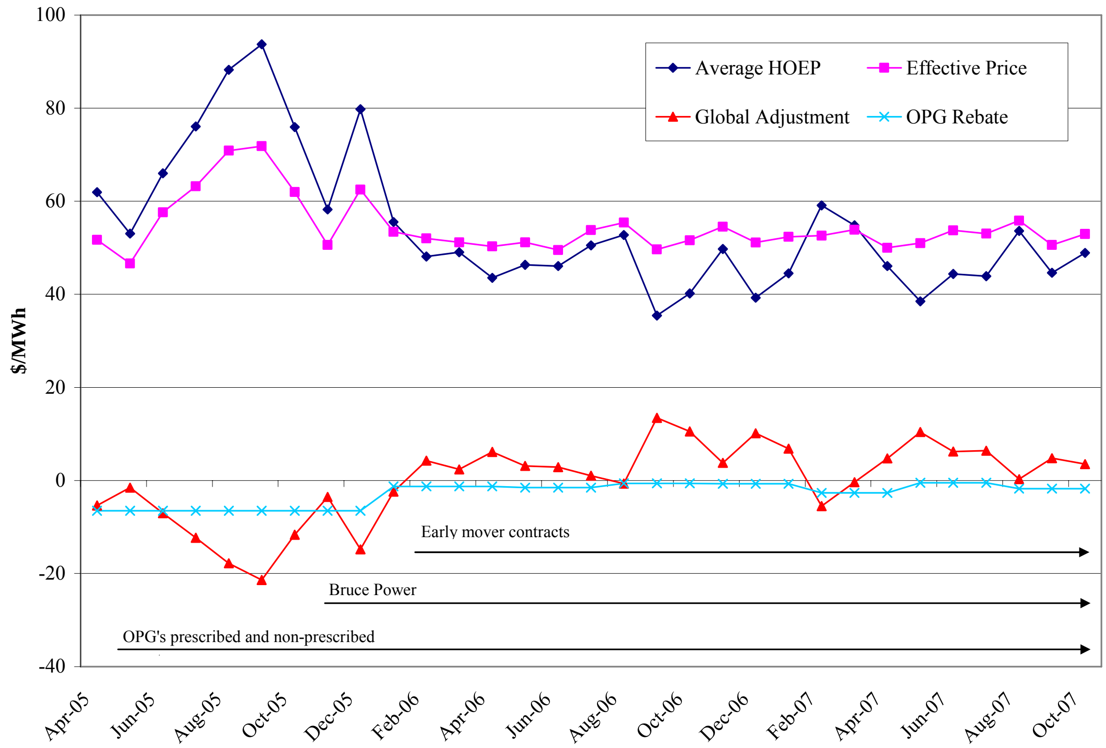


Table 1-3 reports the average six-month HOEP relative to the load-weighted HOEP with and without the Global Adjustment and OPG Rebate over the May to October periods in 2006 and 2007. Although the load-weighted HOEP has increased by only $0.65/MWh, the effective weighted HOEP after being adjusted for Global Adjustment and OPG Rebate has increased by $1.20/MWh, implying the Global Adjustment and OPG Rebate now play a more important role in consumers' final bills.

Table 1-3: Impact of Adjustments on Weighted HOEP, May – October 2006 & 2007 ($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate[6]	Effective Load-Weighted HOEP
2006	45.21	48.24	(3.40)	51.64
2007	45.66	48.89	(3.95)	52.84
Difference ($)	0.45	0.65	(0.55)	1.20
% Change	1.0	1.3	(16.1)	2.3

2.2 Operating Reserve Prices

Tables 1-4 and 1-5 compare average monthly on-peak and off-peak Operating Reserve (OR) prices for the May to October 2006 and 2007 periods for the three OR classes: 10-minute spinning reserve (10S), 10-minute non-spinning reserve (10N), and 30-minute reserve (30R).

There was a noticeable decline in on-peak OR prices in May followed by a large increase in June prices compared to one year ago. The observed price differences may be a result of the peaking hydro units coming online later this spring. As reflected in Table A-25 of the Statistical Appendix, there was less hydro supply in May and more hydro supply in June compared to a year ago. Freshet occurred late this year, resulting in more water in June rather than May. Less water in May resulted in more OR supply and therefore substantially lower prices whereas more water in June resulted in less OR supply and higher prices.

Although on-peak OR prices remained relatively constant year-over-year, off-peak OR prices declined dramatically. Average off-peak OR prices dropped by approximately 50 percent for all categories over the current period and declined or remained the same in all months.

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

There were a few notable events between May and October 2007 that placed downward pressure on OR prices. On May 17, 2007, the IESO reduced the ten-minute non-spinning OR requirement by an additional 50 MW (for a total of 100 MW), through reserve sharing when available from neighbouring areas.[7] We discuss the regional reserve sharing program further in Chapter 3. The effect of the reduced requirement is a lowering of reserve prices. Secondly, in June 2007 a self-scheduling generator with a capacity of 105 MW became dispatchable allowing it to participate in the operating reserve market. Since the middle of June, the unit has provided an average of approximately 20 MW of 10S during the on-peak hours and 30 MW in the off-peak hours, which has increased supply and lowered the clearing price for 10S. Finally, the increase in OR activations in the current period compared to one year ago led to a lower OR requirement, thus putting downward pressure on OR prices. When OR is activated, the IESO is not obligated to immediately replenish the reserve requirement. A lower OR requirement reduces the amount of OR demanded during the intervals after a contingency, which leads to a lower OR clearing price until replenishment occurs. The observed increase in OR activations is discussed later in this section.

Table 1-4: Operating Reserve Prices On-Peak,May – October 2006 & 2007 ($/MWh)

	10S			10N			30R		
	2006	2007	% Change	2006	2007	% Change	2006	2007	% Change
May	6.27	1.96	(68.7)	5.34	1.40	(73.8)	5.34	1.40	(73.8)
June	0.55	4.30	681.8	0.38	2.35	518.4	0.38	2.35	518.4
July	1.78	3.19	79.2	0.44	1.92	336.4	0.44	1.92	336.4
August	3.03	2.82	(6.9)	1.32	0.64	(51.5)	1.32	0.64	(51.5)
September	3.98	2.34	(41.2)	0.21	1.21	476.2	0.21	1.21	476.2
October	2.98	2.05	(31.2)	1.00	1.09	9.0	1.00	1.09	9.0
Average	3.10	2.78	(10.3)	1.45	1.44	(0.7)	1.45	1.44	(0.7)

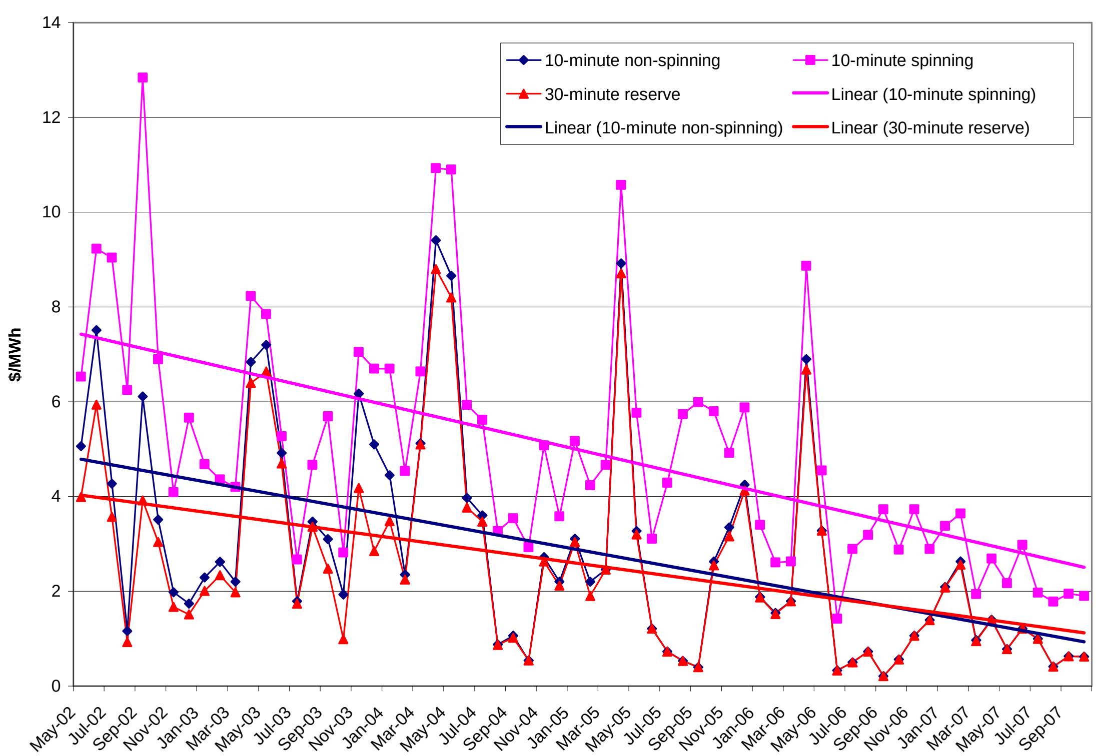
[7] See http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3455 on the IESO website

Table 1-5: Operating Reserve Prices Off-Peak, May – October 2006 & 2007 ($/MWh)

	10S			10N			30R		
	2006	2007	% Change	2006	2007	% Change	2006	2007	% Change
May	3.00	2.36	(21.3)	1.42	0.22	(84.5)	1.42	0.22	(84.5)
June	2.19	1.83	(16.4)	0.29	0.22	(24.1)	0.29	0.22	(24.1)
July	3.65	0.97	(73.4)	0.55	0.24	(56.4)	0.55	0.24	(56.4)
August	3.33	0.84	(74.8)	0.20	0.20	0.0	0.20	0.20	0.0
September	3.52	1.67	(52.6)	0.21	0.20	(4.8)	0.21	0.20	(4.8)
October	2.80	1.77	(36.8)	0.21	0.20	(4.8)	0.21	0.20	(4.8)
Average	3.08	1.57	(49.0)	0.48	0.21	(56.3)	0.48	0.21	(56.3)

Figure 1-3 depicts the monthly average OR prices since market opening. As identified in previous MSP reports, there is an obvious declining long-term trend in all OR price categories since May 2002.

Figure 1-3: Monthly Operating Reserve Prices by OR Class since Market Opening, May 2002 - October 2007 ($/MWh)



Recently, the Board of Directors of the IESO approved a rule change that grants dispatchable loads the opportunity to provide 10-minute spinning reserve.[8] The additional supply available for OR should reduce the OR prices going forward. Secondly, since the OR market is jointly optimized with the energy market, the HOEP may also decline as a result of this new source of supply.

Coincident to the declining OR price trends identified above, Figure 1-4 indicates that the frequency and magnitude of OR activations in Ontario reached record highs over the summer of 2007.[9] In May and June 2007, there were 38 and 37 OR activations respectively, easily eclipsing the previous record of 29 activations set in July 2002. OR activations in May 2007 totalled 13,351 MWh which is approximately 1,000 MWh greater than July 2002, the previous record high month.

8 See http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3800

9 For more information on the IESO's response to contingencies on the system, see the discussion paper presented to the Technical Panel of the IESO titled, "Operating Reserve Activations vs. One-Time Energy Dispatch (OTD)', April 5, 2007 available at http://www.ieso.ca/imoweb/pubs/tp2007/tp199-3c-Paper-ORA-vs-Energy-Dispatch.pdf

Figure 1-4: Monthly Operating Reserve Activations by Frequency and MW since Market Opening,[10] May 2002 - October 2007

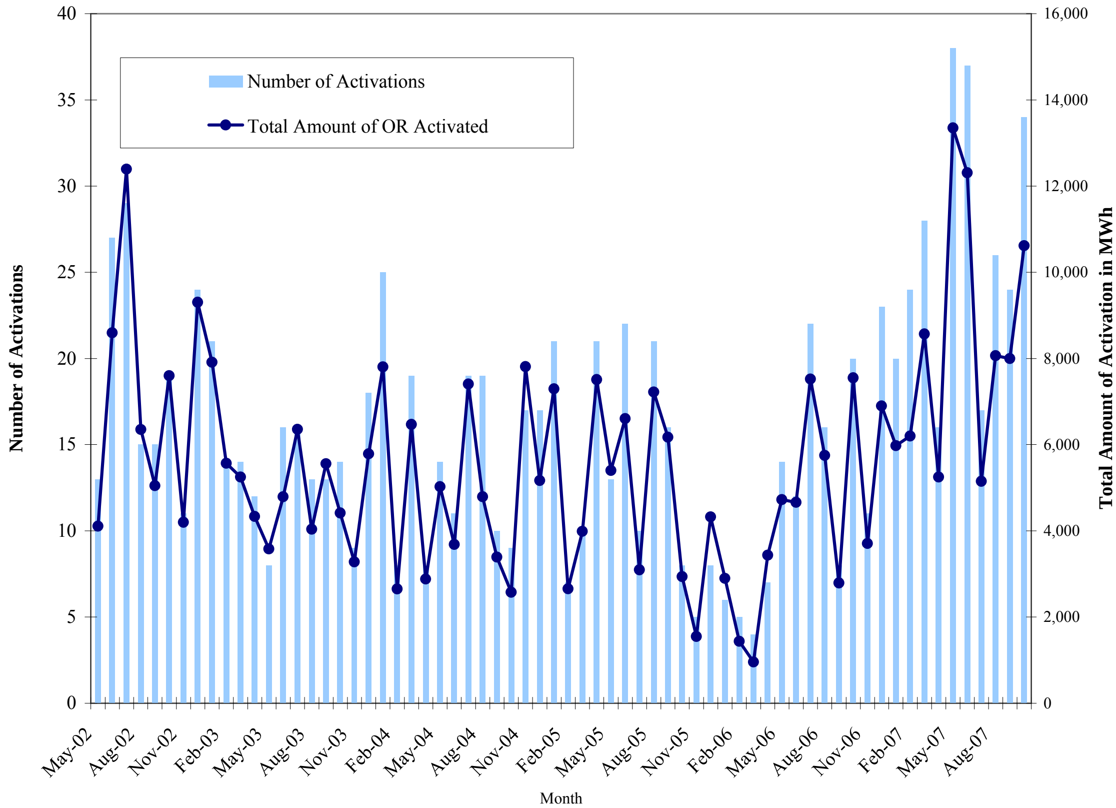
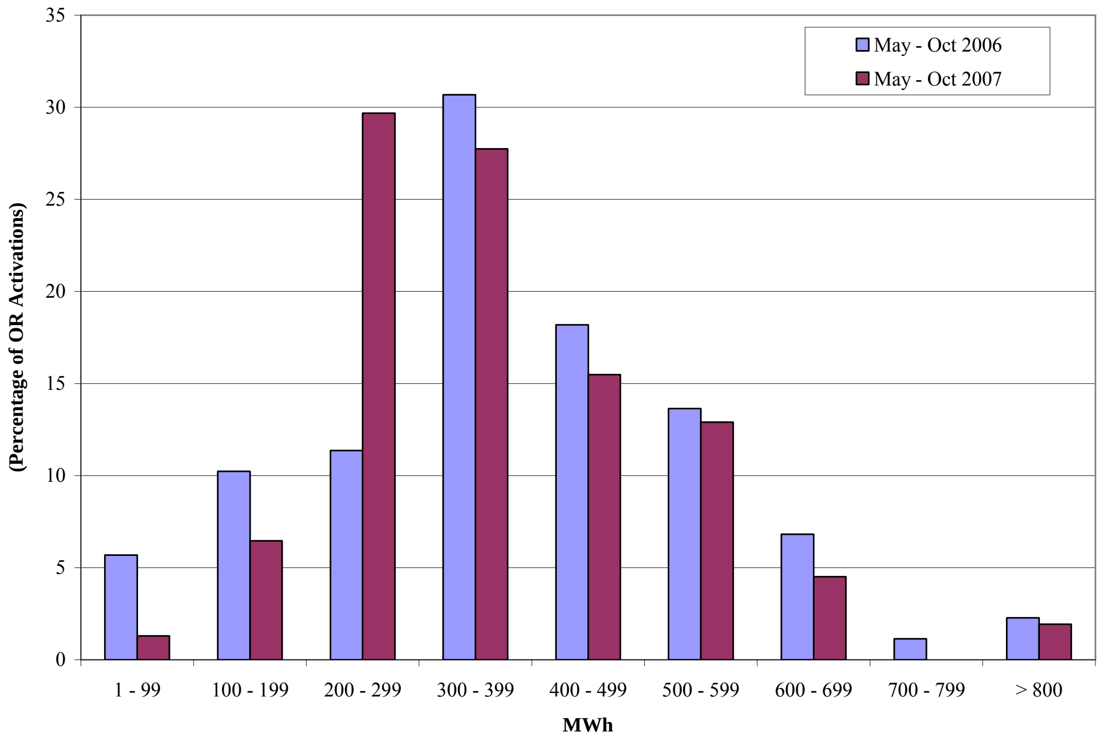


Figure 1-5 plots the percentage of OR activations by 100 MWh increments for the current and previous summer months. The increase in the number of OR activations during the 2007 summer months appears to coincide with a change in the magnitudes of OR activations. Figure 1-5 shows an increase in the percentage of activations within 200 - 299 MWh this summer compared to last summer. On the other hand, the percentage of activations has declined in 2007 for every category above 400 MWh.

[10] MW represents the amount of energy initially activated from the operating reserve and ignores the rate at which the OR is deactivated.

Figure 1-5: OR Activations by 100 MWh Categories, May – October 2006 & 2007 (Percentage of all OR Activations in Period)



The MAU has observed that the increased frequency of OR activations in the two hundred to 299 MW range may be due to generators deviating from their dispatch schedules more frequently than in the past leading to large Area Control Errors (ACE) rather than a significant increase in generators' forced outages.[11] The Panel has requested that the MAU further investigate the issues of increased OR activations.

2.3 Price Setters

Table 1-6 compares the percentage of intervals when each type of generator sets the real-time MCP over the summer months in 2006 and 2007.[12] Coal-fired generators continue to set the MCP most frequently in Ontario, although their share declined by five percent compared to the same period one year ago. Oil/gas-fired generators increased by

[11] Area Control Error means the instantaneous difference between actual and scheduled interchange, taking into account frequency bias (IESO Market Rules, Chapter 11)
[12] Excludes imports because in real-time, imports are unable to set the market clearing price.

4 percent while hydro increased by 1 percent. The shift from coal to oil/gas was largely attributable to higher demand and/or a lower baseload generation supply in August, September, and October 2007. Table 1-9 indicates that coal plants remain the predominant price-setters in off-peak periods, although hydro played an increasingly important role in all months except August and September.

Table 1-6: Average Share of Real-time MCP Set by Resource Type, May – October 2006 & 2007 (% of hours)

	2006	2007	Difference
Coal	59	54	(5)
Nuclear	0	0	0
Oil/Gas	20	24	4
Hydro	21	22	1

Table 1-7 reports the percentage of time each resource type sets the MCP by month over all hours. The frequency that coal set the MCP declined or remained unchanged in every month with the exception of July. The monthly patterns for oil/gas varied considerably.

Table 1-7: Monthly Share of Real-Time MCP set by Resource Type, May – October 2006 & 2007 (% of Hours)

	Coal		Nuclear		Oil/Gas		Hydro	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	63	61	0	0	14	13	23	26
June	61	61	0	0	22	18	17	21
July	52	58	0	0	29	20	20	22
August	57	44	0	0	22	38	22	17
September	56	52	0	0	18	25	26	23
October	62	46	0	0	17	30	21	24
Average	59	54	0	0	20	24	22	22

Tables 1-8 and 1-9 split the hours into on-peak and off-peak periods respectively. Table 1-8 shows that much of oil/gas' share increase seems to have occurred during the on-peak hours where their share rose from 35 percent in 2006 compared to 42 percent for the same months in 2007. The significant increase in oil/gas share is primarily due to the outages at a few nuclear units and a higher Ontario demand in August to October 2007.

Table 1-8: Monthly Share of Real-Time MCP set by Resource Type, On-Peak, May – October 2006 & 2007 (% of Hours)

	Coal		Nuclear		Oil/Gas		Hydro	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	45	49	0	0	26	26	29	25
June	37	47	0	0	39	31	24	22
July	30	38	0	0	48	39	22	23
August	37	15	0	0	34	62	29	23
September	41	32	0	0	32	45	27	23
October	40	26	0	0	32	49	28	26
Average	38	35	0	0	35	42	27	24

Table 1-9: Monthly Share of Real-Time MCP set by Resource Type, Off-Peak, May – October 2006 & 2007 (% of Hours)

	Coal		Nuclear		Oil/Gas		Hydro	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	79	72	0	0	4	1	17	27
June	81	73	0	0	7	6	12	20
July	66	74	0	0	16	5	18	21
August	74	70	0	0	10	18	16	12
September	68	67	0	0	7	11	24	22
October	80	64	0	0	5	13	15	23
Average	75	70	0	0	8	9	17	21

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

Accurate pre-dispatch price signals are essential to decisions by market participants regarding production and consumption. Although a perfect price forecast is unrealistic to expect over all hours, any improvements that can be made will help benefit real-time scheduling efficiency. For this reason, the differences between one-hour ahead and three-hour ahead pre-dispatch prices and HOEP are important statistics to monitor. In future reports, we will continue to monitor the discrepancy between pre-dispatch prices and HOEP as well as examine the consistency of the bias between the two prices.

The three-hour ahead pre-dispatch price has become a very important signal as it is tied to the OPA's Demand Response Program (Phase 1). A more accurate three-hour ahead price certainly improves market efficiency as it can reduce incidents of inefficient curtailment.

Tables 1-10 and 1-11 indicate that the average differences between the one-hour and three-hour ahead pre-dispatch versus real-time prices have remained almost constant relative to the same period one year earlier. However as a percentage of HOEP, the average hourly difference has increased by approximately 4 percent for one-hour ahead and 6 percent for three-hour ahead. This may be due to the increase in the number of low price hours during the summer of 2007. Low-priced hours induce a higher percentage error in an hour for a given absolute forecast difference.

Table 1-10: Measures of Differences Between One-Hour Ahead Pre-Dispatch Prices and HOEP, May – October 2006 & 2007 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	11.94	8.23	1,739.37	71.78	(297.46)	(77.17)	67.55	14.49	29.88	35.18
June	5.12	6.99	44.18	94.35	(66.34)	(331.10)	11.20	21.84	15.04	25.21
July	6.89	5.26	60.33	62.02	(174.98)	(211.39)	13.61	15.91	18.99	22.34
August	9.73	8.16	262.96	74.60	(67.76)	(60.38)	25.64	13.56	19.93	20.05
September	3.82	5.96	34.86	83.01	(67.49)	(68.97)	8.56	12.46	24.74	22.37
October	6.27	8.17	52.09	66.75	(42.27)	(236.65)	10.44	14.99	21.67	30.09
Average	7.30	7.13	365.63	75.42	(119.38)	(164.28)	22.83	15.54	21.71	25.87

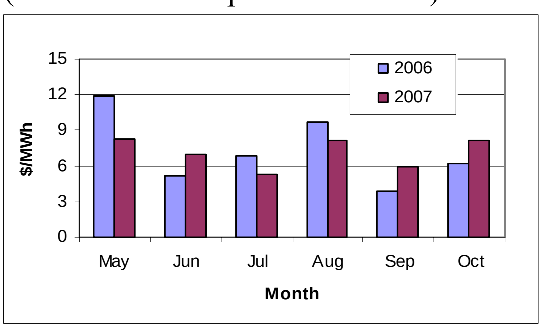
Table 1-11: Measures of Differences Between Three-Hour Ahead Pre-Dispatch Prices and HOEP, May – October 2006 & 2007 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	6.60	7.63	419.55	72.88	(320.42)	(93.58)	30.00	16.11	20.83	30.63
June	4.85	6.83	48.06	99.04	(75.35)	(305.24)	12.76	22.95	14.02	25.54
July	7.51	3.58	114.61	62.49	(126.79)	(215.90)	15.25	16.64	17.92	15.97
August	9.18	7.68	168.10	79.74	(70.41)	(61.26)	27.51	14.90	16.67	19.45
September	2.43	3.91	41.59	60.95	(68.61)	(69.49)	8.99	12.18	17.98	17.71
October	3.86	6.73	62.51	82.25	(42.27)	(234.52)	10.85	15.40	13.59	25.54
Average	5.74	6.06	142.4	76.23	(117.31)	(163.33)	17.56	16.36	16.84	22.47

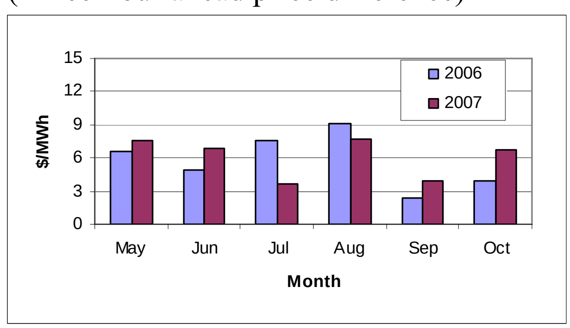
Figure 1-6 graphically represents the average monthly difference between the one and three-hour ahead pre-dispatch versus real-time prices.

Figure 1-6: Average Pre-dispatch Price Differences One and Three-Hour Ahead to Real-Time, May – October 2006 & 2007 ($/MWh)

(One-hour ahead price difference)



(Three-hour ahead price difference)



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

- Demand forecast error;
- Performance of self-schedulers and intermittent generators;
- Failure of scheduled imports and exports; and

- Frequency that imports set the pre-dispatch price.

2.4.1 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 2006 and 2007 summer months. On average, the demand forecast error increased by a very small amount in the current period compared to the previous period for both the one-hour and three-hour ahead measurements.

Table 1-12: Forecast Error in Demand
May – October 2006 & 2007
(%)

	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	
	2006	2007	2006	2007	2006	2007	2006	2007
May	2.03	1.82	1.9	1.66	1.19	1.07	0.96	0.89
June	2.19	2.40	1.95	2.05	1.36	1.59	1.03	1.19
July	2.62	2.34	2.26	2.01	1.80	1.56	1.32	1.14
August	2.35	2.53	2.0	2.15	1.64	1.65	1.15	1.22
September	1.86	2.25	1.67	1.96	1.12	1.40	0.89	1.06
October	1.94	2.15	1.78	1.98	1.16	1.18	0.93	0.99
Average	2.17	2.25	1.93	1.97	1.38	1.41	1.05	1.08

Figure 1-7 plots average one-hour demand forecast error since market opening. As mentioned in previous MSP reports, the long-term trend continues to indicate an improvement in the magnitude of demand forecast error. The Panel is satisfied in the long-term improvements observed since market opening and will not publish this figure in future reports unless we observe a significant change in forecast error.

Figure 1-7: Absolute Average One-Hour Ahead Forecast Error, May 2007 - October 2007 (% of Peak Demand)

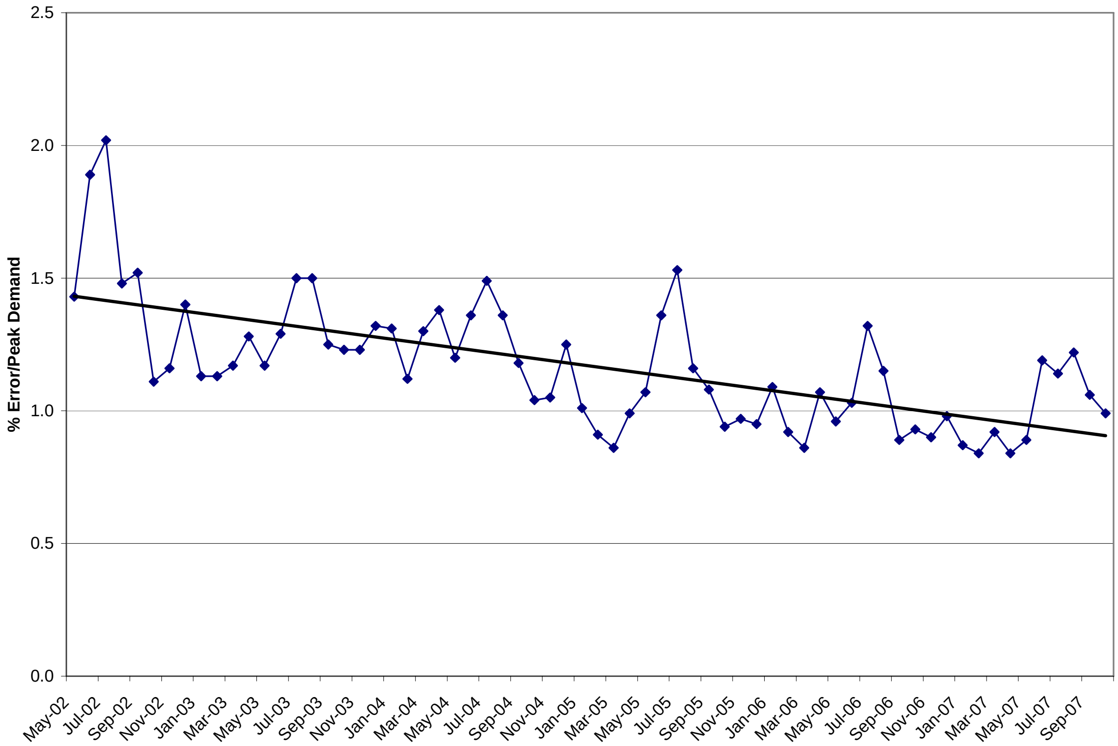
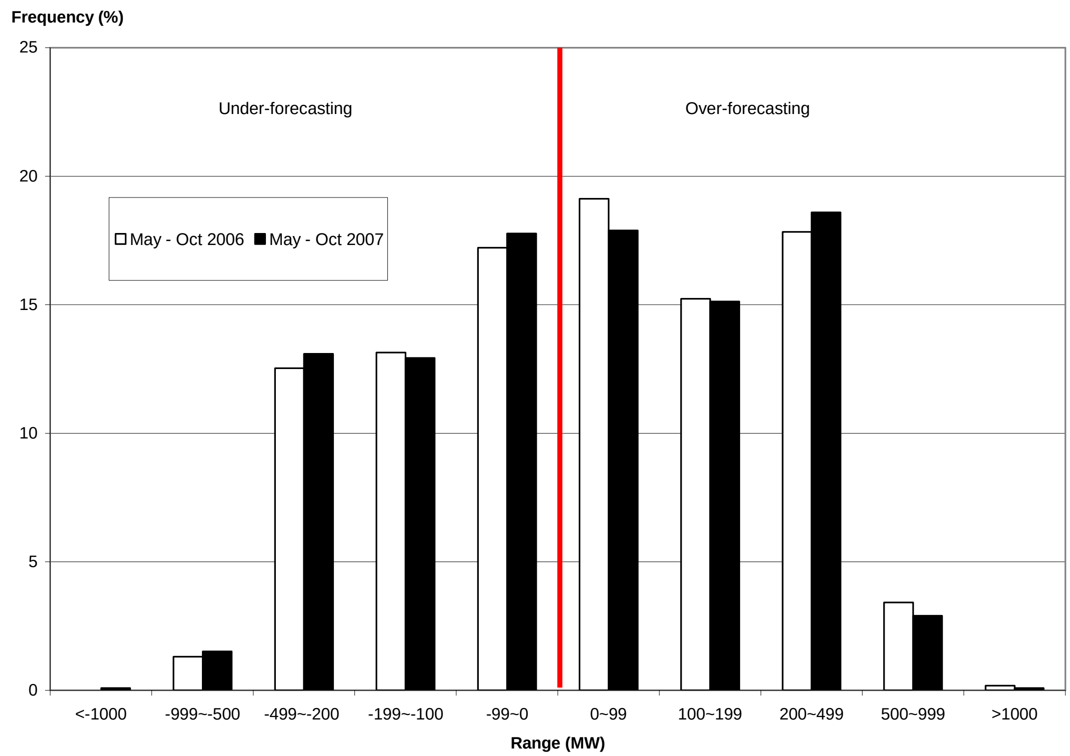


Figure 1-8 divides forecast error events by magnitude and direction. There appears to be a moderate over-forecasting bias during the May to October 2007 months, but slightly less than the bias one year ago.

Figure 1-8: Distribution of Ontario Demand Forecast Error One-Hour Ahead vs. Real-time, May – October 2006 & 2007



2.4.2 Performance of Self-Scheduling and Intermittent Generation

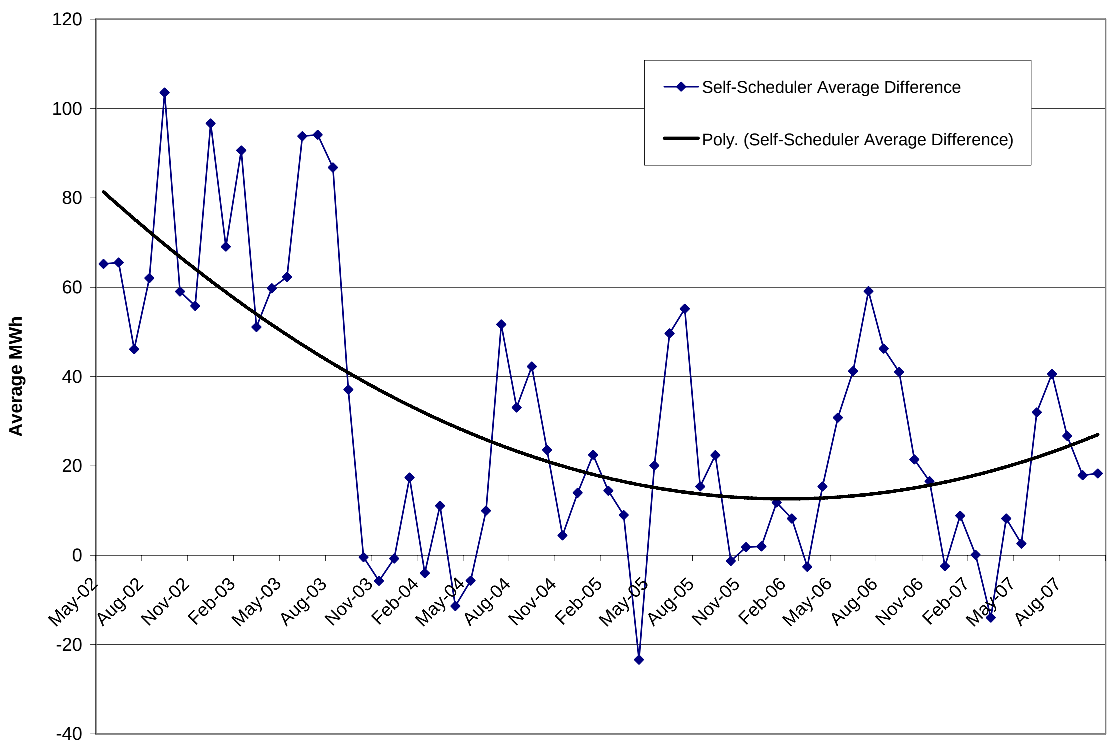
Like the majority of Ontario's generating capacity, self-scheduling and intermittent generators supply energy to the IESO-controlled-grid by submitting forecasts to the IESO indicating the amount of energy they will supply for each hour of the day. However, these units are not held to the strict compliance standards as other generators participating in the IESO-controlled market.[13] The difference between what this group of generators schedules and produces leads to discrepancies between pre-dispatch and real-time prices.

Figure 1-9 plots the monthly average difference between what self-scheduling and intermittent generators offered to produce and what they actually produced since market opening. Since the beginning of 2006, the monthly average differences have been quite

[13] For more details on monitoring standards for intermittent generators, see the slides from the presentation titled "Compliance Assessment of Intermittent Generators" made to the Wind Power Integration Working Group (August 20, 2007) and available at http://www.ieso.ca/imoweb/pubs/consult/se29/se29-20070820-Item6_Compliance_requirements.pdf

volatile. Over the last 12 months, the monthly average difference between delivered and offered energy reached a maximum of 40 MWh in July 2007, which represents the lowest error in July since market opening. Tables A-13 and A-14 in the Statistical Appendix report that hourly self-scheduler supply averaged approximately 700 MW during the off-peak hours and 800 MW during the on-peak hours over the summer of 2007. Therefore, average hourly error made up approximately 5 and 6 percent of average hourly self-scheduler supply for the on-peak and off-peak periods respectively. Comparing the last six months with the year earlier, the differences between offered and delivered have narrowed by over 23 MW (40 percent) on average. This better forecast of supply would tend to lower the pre-dispatch price and narrow the gap between the pre-dispatch price and the HOEP, but the effect of narrowing the difference year-over-year would be small.

Figure 1-9: Average Difference between Self-Schedulers' Offered and Delivered Energy, May 2002 - October 2007 (MWh)



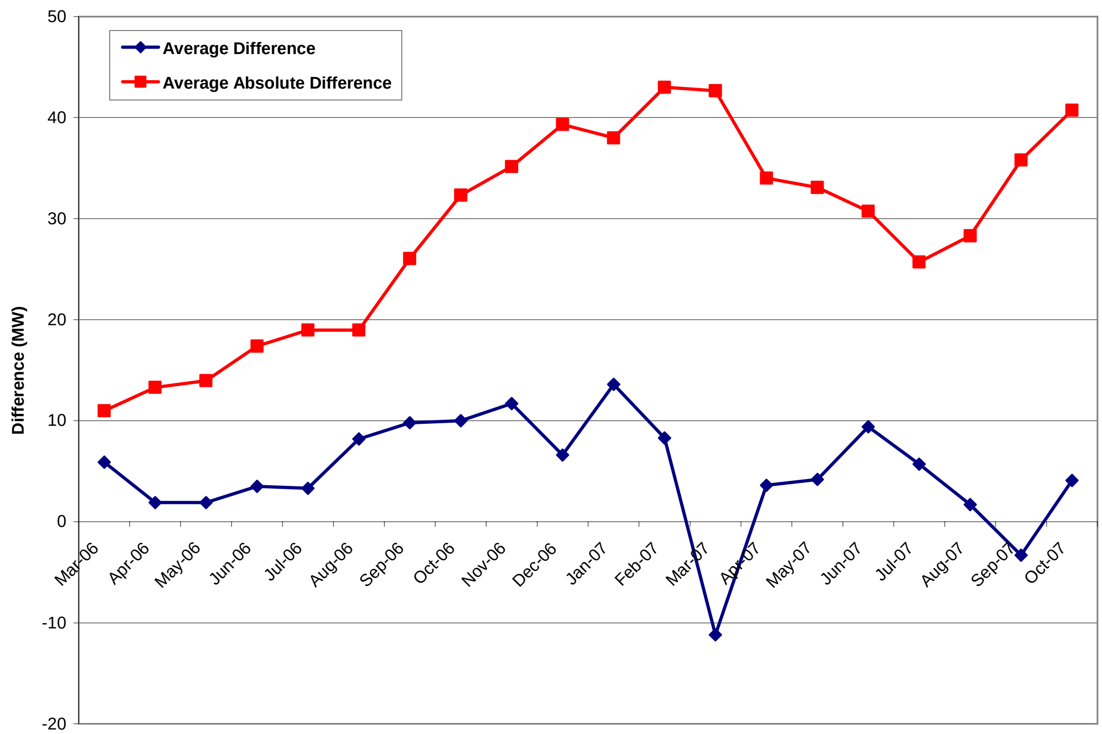
2.4.3 Performance of Wind-Power Generation

Figure 1-10 graphs the average and the absolute average difference[14] between the amounts of energy that wind generators forecast one-hour ahead and what they actually supplied since March 2006.[15] The average difference fell within 5 MW or less in four of the six months during the current period. The average error was positive for all months in the summer 2007 period excluding September, which indicates that on average, wind generators forecasted more energy output one-hour ahead than they delivered to the market.

In this report, we plot the average difference along with the absolute average difference because it eliminates the effect of positive and negative errors cancelling each other out within any given month. Although the average error appears to fluctuate around zero, the average absolute error seems to be rising since early 2006 when the majority of wind generators began producing energy.

[14] The average offsets positive and negative differences, whereas the absolute average does not.
[15] A significant portion of Ontario's wind generation procured by the OPA came online in early 2006.

Figure 1-10: Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy, March 2006 - October 2007 (MWh)



In Figure 1-11, we normalize average error and absolute error by total wind generation capacity to control for the influence of capacity that has entered the market since early 2006. Although absolute error is increasing, the ratio of absolute error to wind capacity seems stable around 10 percent. The implication is that the observed absolute difference between forecasted MWh and delivered MWh from wind generation is becoming larger due to increased wind generation entering the market.

Figure 1-11: Normalized Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy, March 2006 - October 2007 (Difference/Capacity)

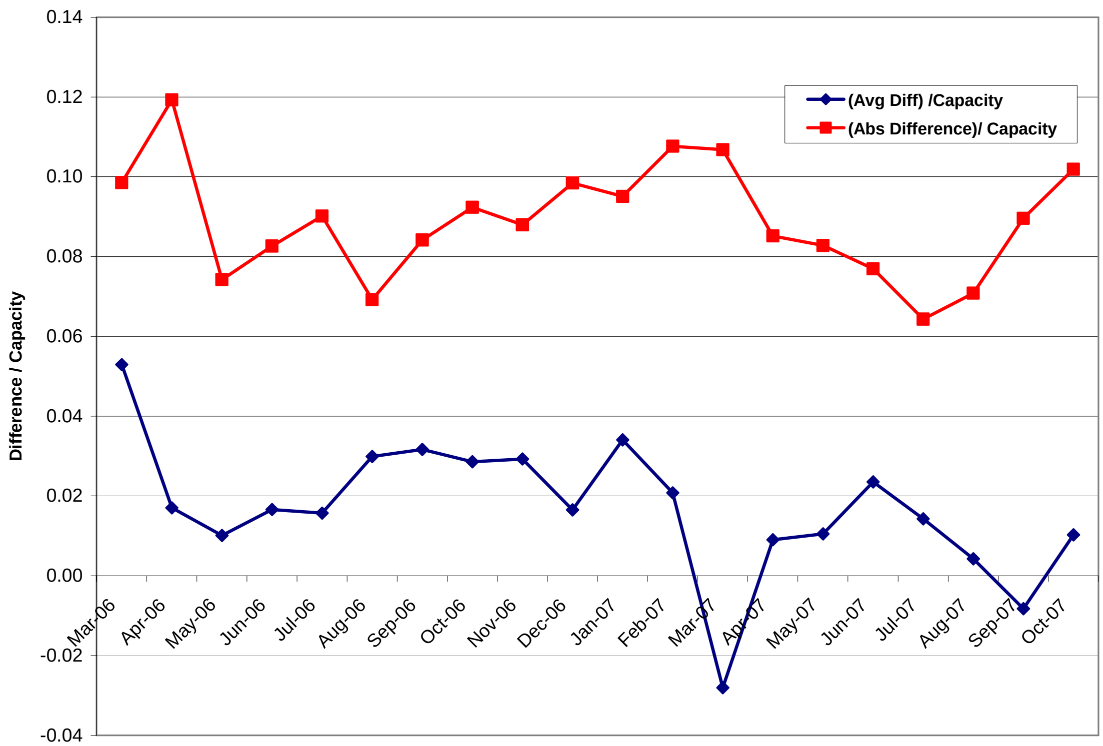
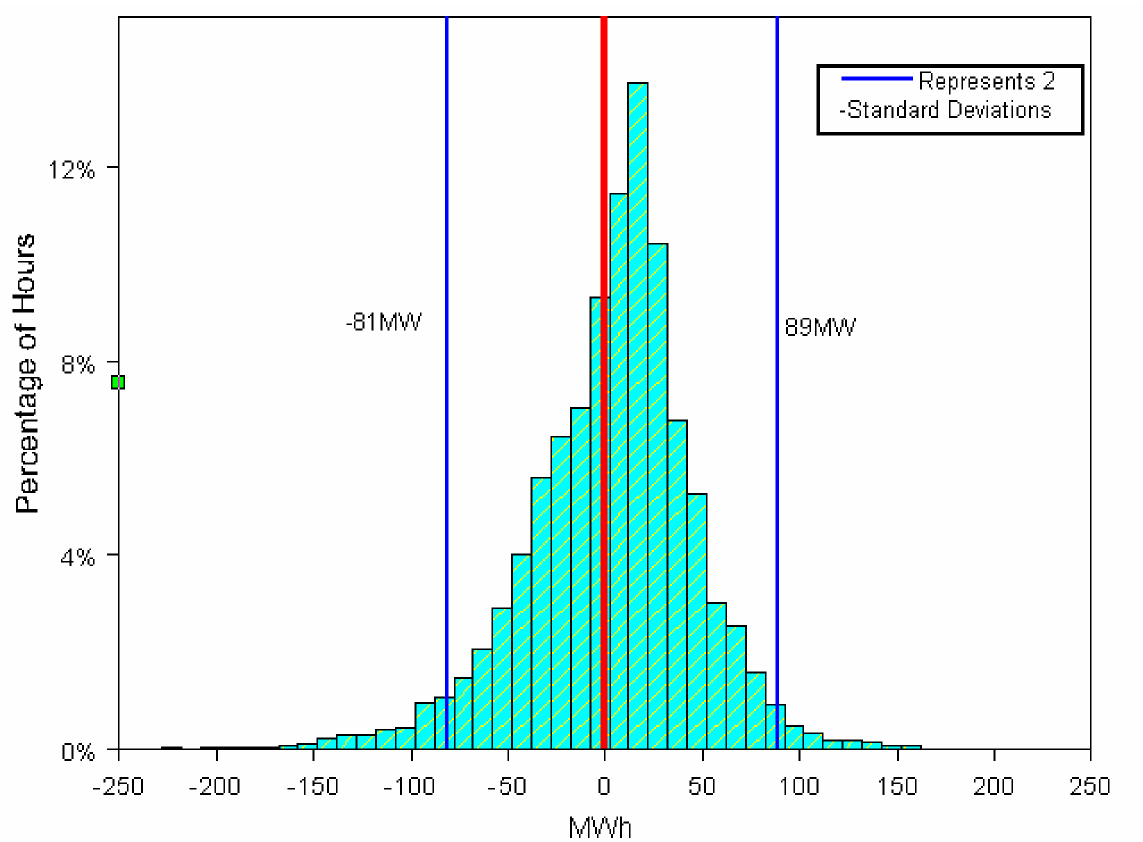


Figure 1-12 below depicts the distribution of forecast error for wind generators during the period May to October 2007. A positive number indicates that these generators over-forecast their output level one-hour ahead, while a negative number indicates that they under-forecast their output level one-hour ahead. On average, these generators slightly over-forecast their offered output although the error range is quite high. The lowest under-forecast amount was 228 MW while the highest over-forecast amount totaled 159 MW. Given that the total wind-power generation capacity is about 400 MW, 228 MW represents over half of Ontario's available wind capacity and constituted an overall forecast error equivalent to 2 percent of scheduled supply during the hour in question. As more and more wind generators enter the market, the magnitude of forecast errors may significantly increase.

Figure 1-12: Wind Generation Forecast Error Distribution One-hour Ahead Pre-dispatch vs. Real-time, May 2007 - October 2007 (Percentage of Hours in 10 MWh Ranges)



A large discrepancy between the forecasted and actual output imposes a reliability risk on the system. If these generators significantly overstate their capability, the IESO may dispatch fewer fossil generators or fewer imports in pre-dispatch. In real-time, when wind generators produce less energy than expected and other available resources are not dispatched, system reliability can be at risk. A large discrepancy can also lead to adverse consequences on market prices and efficiency in the market. In pre-dispatch, the IESO dispatches other generators, imports and/or exports based on the forecasts they receive from wind generators. When wind generators supply less energy than offered, the opportunity to dispatch cheaper imports is foregone and the IESO is forced to schedule and dispatch more expensive generation. In contrast, an over-supply by wind generators means that excess energy was scheduled when it was not required. Both of these situations result in negative market efficiency implications and distort the Market Clearing Price.[16]

In Chapter 2, we illustrate an example where a single wind generator significantly under-forecasted its output and as a result, partially contributed to a negative HOEP of minus $0.40/MWh.[17]

> ***Recommendation 1-1:***
> ***The Panel encourages the IESO to continue to review the forecasting process with wind generators and determine methods to reduce forecast errors. Such generators should have incentives (positive or negative) to encourage accurate forecasting.***

2.4.4 Real-Time Failed Intertie Transactions

Failed import and export transactions are a major source of the differences between pre-dispatch prices and HOEP. In real-time, import failures represent a loss of supply while export failures represent a decline in demand, both of which result in discrepancies between pre-dispatch and real-time prices.

Tables 1-13 and 1-14 compare the number of incidents and rates of import and export failures over the 2006 and 2007 summer months. The frequency of failed exports measured by the number of incidents and the failure rate declined moderately this period. The number of import failures increased 15 percent and the average monthly import failure rate increased 4 percent relative to the same period one year ago, with failure rates higher in three months and lower in the other three months. However, because imports increased by more than 30 percent in this period, the overall import failure rate declined about 5 percent. This is measured as the ratio of total failed imports for the period measured in MWh (rather than averaging monthly values) to total imports.

[16] The IESO has set up a working group to address some of the challenges that wind generators and the IESO will face as more wind projects enter the market including examining wind-power forecasting options. For more information, see the IESO's Wind Power Integration in Ontario (SE-29) webpage available at: http://www.ieso.ca/imoweb/consult/consult_se29.asp
[17] See Chapter 2, section 2.2.1.

Table 1-13: Incidents and Average Magnitude of Failed Exports from Ontario, May – October 2006 & 2007

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)***	
	2006	2007	2006	2007	2006	2007	2006	2007
May	564	522	1,136	938	318	202	13.03	8.87
June	324	382	817	733	176	167	5.87	5.76
July	354	350	850	1,079	201	175	6.47	4.51
August	399	373	914	900	187	163	5.8	5.15
September	422	397	788	1,071	192	208	8.88	8.20
October	412	389	874	898	185	195	7.25	7.51
Total	2,475	2,413	N/A	N/A	N/A	N/A	N/A	N/A
Average	413	402	897	937	210	185	7.88	6.67

* The incidents with less than 1 MW are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled exports MWh in the unconstrained sequence in a month

Table 1-14: Incidents and Average Magnitude of Failed Imports to Ontario, May – October 2006 & 2007

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)***	
	2006	2007	2006	2007	2006	2007	2006	2007
May	121	192	818	453	135	135	3.10	6.25
June	187	148	848	400	153	95	4.58	2.89
July	207	112	1,020	700	123	123	4.25	2.75
August	171	207	405	546	113	118	4.53	3.53
September	54	155	300	525	76	146	1.12	2.54
October	109	172	240	607	69	116	2.08	2.44
Total	849	986	N/A	N/A	N/A	N/A	N/A	N/A
Average	142	164	605	539	112	122	3.28	3.40

* The incidents with less than 1 MW are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled imports MWh in the unconstrained sequence in a month

It is difficult to link these changes in the failure rates to the observed changes in the accuracy of the HOEP forecasts. Export failures imply a higher demand in pre-dispatch than in real-time. Reduced failures could imply reduced differences between pre-dispatch and real-time market demand and therefore reduced differences between pre-dispatch prices and HOEP. Increased import failures could also increase demand for domestic generation and thus HOEP, which would tend to reduce the gap between the pre-dispatch price and the HOEP. This is roughly consistent with the observed decline in the average pre-dispatch to HOEP difference in Table 1-10.

Figure 1-13 plots the percentage of monthly export failures to total exports by the cause of the failure. Failures are separated into those under the market participant's control and those under the neighbouring ISOs' control. The percentage of total export failures not within the market participant's control reached a high of almost 8 percent of total exports in May 2007 and a low of about 2.3 percent in August 2007. The export failure rate under the market participant's control was generally below 3 percent since the implementation of the Intertie Failure Charge in June 2006, but increased to around 5 percent in September and October 2007.

Figure 1-13: Monthly Export Failures as a Percentage ofTotal Exports by Cause, January 2005 - October 2007
(%)

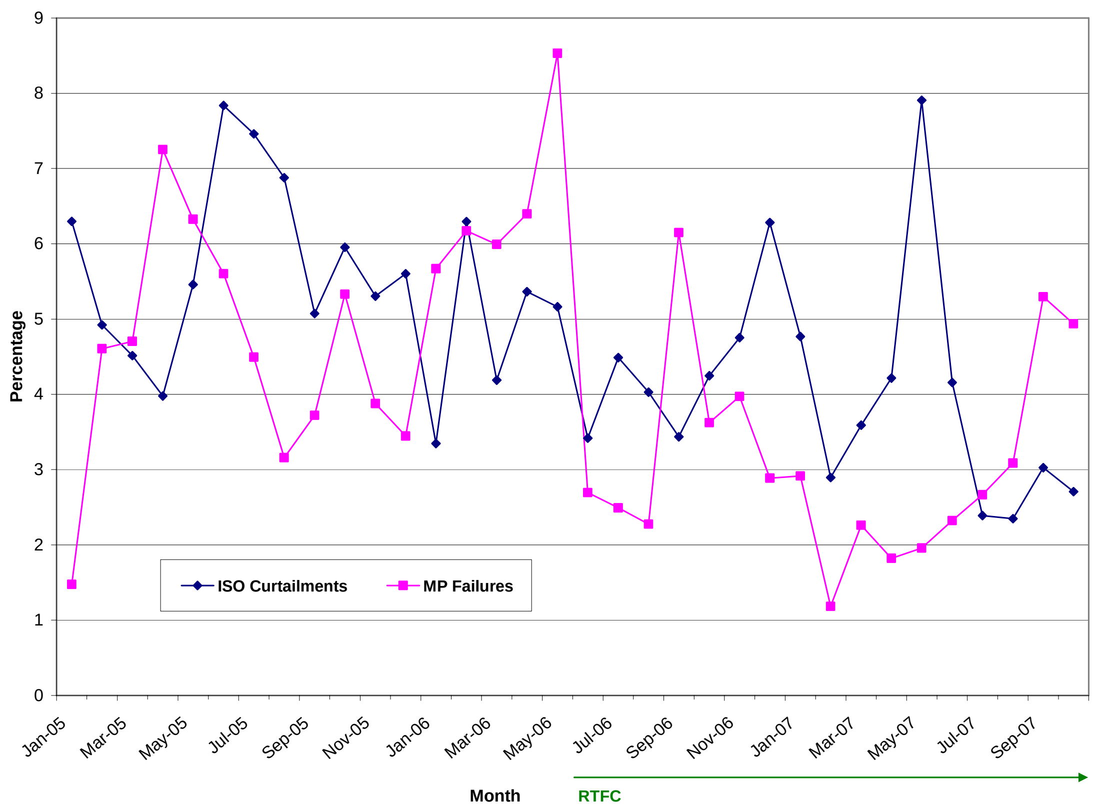


Figure 1-14 plots the percentage of monthly import failures to total imports by cause. Since the introduction of the Intertie Failure Charge in June 2006, the total import failures within the market participant's control as a percentage of total imports has remained at 2 percent or less with the exception of May 2007 where the percentage increased above 4 percent. Failures under the ISOs' control peaked in August 2007 at almost 4.5 percent.

Figure 1-14: Monthly Import Failures as a Percentage of Total Imports by Cause, January 2005 - October 2007
(%)

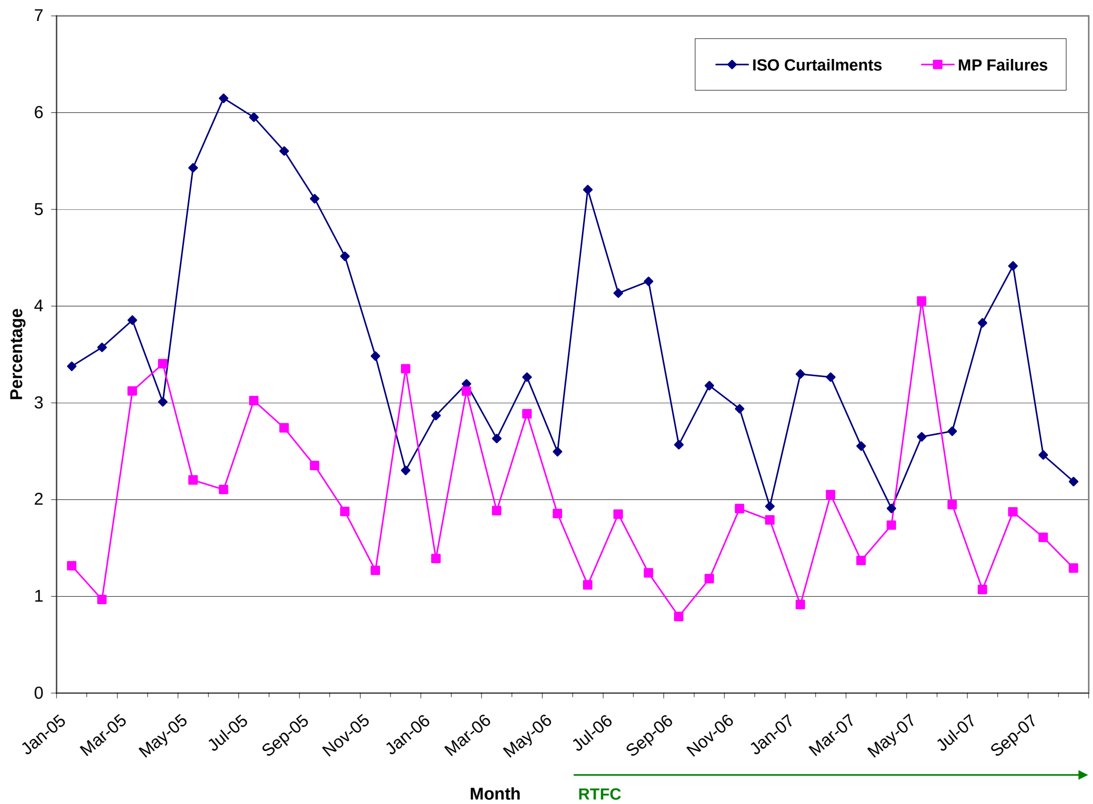


Table 1-15 reports average monthly export failures by intertie and cause for the period November 2006 to October 2007. New York destined export failures make up the majority of total export failures for both causes. For example, approximately 86 percent of export failures under the ISOs' control and over 94 percent of export failures under the participant's control were destined for New York.

Table 1-15: Average Monthly Export Failures by Intertie and Cause, November 2006 – October 2007 (GWh and % Failures)

	Average Monthly Exports (GWh)	Failures (ISO Controlled)		Failures (Participant Controlled)	
		GWh	%	GWh	%
NYISO	715	34.2	86	26.6	94
MISO	173	2.3	6	1.3	4
Manitoba	20	0.7	2	0.3	1
Minnesota	15	0.5	1	0.2	1
Quebec	75	2.1	5	0.1	0
Total	998	39.8	100	28.4	100

Table 1-16 reports average monthly import failures by intertie and cause for the period November 2006 to October 2007. Average monthly MISO imports totalled 317 GWh, or 56 percent of total imports over the last year. Therefore it is not surprising that ISO controlled import failures were the highest in the MISO region and proportional to their imported energy volume at 57 percent of total ISO controlled import failures. However, participant controlled import failures were not proportional to import volumes over the interties. For example, average monthly import failures from New York under the participant's control totalled 6 GWh over the past year representing 60 percent of all participant controlled failures.

Table 1-16: Average Monthly Import Failures by Intertie and Cause, November 2006 – October 2007 (GWh and % Failures)

	Average Monthly Imports (GWh)	Failures (ISO Controlled)		Failures (Participant Controlled)	
		GWh	%	GWh	%
NYISO	75	1.2	7	6.0	60
MISO	317	8.8	57	3.6	37
Manitoba	47	2.0	13	0.1	1
Minnesota	21	0.7	5	0.0	0
Quebec	110	2.8	18	0.2	2
Total	570	15.5	100	10.0	100

2.4.5 Imports Setting Pre-dispatch Price

In the last report, the Panel identified a fourth factor that leads to discrepancies between pre-dispatch and real-time prices; the frequency of imports setting the pre-dispatch market clearing price. In pre-dispatch, imports can set the Market Clearing Price. However in real-time, they cannot be the marginal resource as they are moved to the bottom of the offer stack. Holding everything else constant, the real-time market clearing price may potentially decline compared to the pre-dispatch price during hours when an import is the marginal resource in the pre-dispatch schedule.[18] Therefore, price forecast error measurements would be expected to be higher during months when imports set the pre-dispatch price most frequently.

Table 1-17 shows the frequency of imports setting the pre-dispatch price for the May to October 2006 and 2007 periods by month. During the summer of 2007, imports set the pre-dispatch price 46 hours less frequently than the previous summer, which represents a decrease of approximately one percent relative to the hours in the period. Consistent with the results reported in Table 1-10, the lower incidence of imports setting the pre-dispatch price, the less of a tendency for real-time prices to fall.

Table 1-17: Frequency of Imports Setting the Pre-Dispatch Price, May – October 2006 & 2007 (Number of Hours and % of Hours)

	2006		2007		Difference	
	Hours	%	Hours	%	Hours	% Change
May	250	33.6	272	36.6	22	3.0
June	281	39.0	212	29.4	(69)	(9.6)
July	245	32.9	188	25.3	(57)	(7.6)
August	201	27.0	230	30.9	29	3.9
September	186	25.8	191	26.5	5	0.7
October	216	29.0	240	32.3	24	3.3
Total	1,379	31.2	1,333	30.2	(46)	(1.0)

[18] For more detail about how imports setting the pre-dispatch price can lead to price forecast error, refer to the Section 2.4.5 beginning on page 30 of the August 2007 MSP Report.

2.5 Analyzing Year-Over-Year Changes in the HOEP

In the June 2006 MSP Report, the MAU under the direction of the Panel introduced a simple reduced form econometric model to analyse monthly changes in the HOEP. Originally, the model was estimated using monthly data between January 2004 and April 2006. In the last MSP report, the model specification was changed to alleviate correlation concerns between two explanatory variables; the natural gas price and the New York price. In the revised model, New York integrated load was substituted for the New York price. In this report, we re-estimated the model using monthly data between January 2003 and October 2007 resulting in a total of 58 monthly observations.

Table 1-18 reports the estimation results for the on-peak and off-peak periods. The monthly average HOEP is the dependent variable and the independent variables include nuclear and self-scheduler production, Ontario demand, the natural gas price measured by the average Henry Hub spot market price, New York load, and monthly fixed effects. All explanatory variables in the model are significant and intuitive. The estimated coefficients suggest that holding all else equal, increases in nuclear and self-scheduler supply decreases the HOEP while increases in Ontario and New York demand and the price of natural gas increases the HOEP.

Table 1-18: Estimation Results of the Updated Econometric Model,[19] January 2003 - October 2007

Variable	On-peak Model		Off-peak Model	
	Coefficient	P-value	Coefficient	P-value
Constant	-26.38	0.00	-19.45	0.00
LOG(Nuclear Output)	-0.74	0.00	-0.65	0.00
LOG(Self Scheduler output)	-0.19	0.03	-0.24	0.13
LOG(Ontario Demand)	1.50	0.00	1.67	0.00
LOG(New York Demand)	2.24	0.00	1.37	0.04
LOG(Natural Gas Price)	0.65	0.00	0.55	0.00
Model Diagnostics				
R-squared	0.91		0.82	
Adjusted R-squared	0.88		0.75	
LM test of Serial Correlation	Absent		Absent	
JB test of normality of residuals	Normal		Normal	
Number of observations	58		58	

Table 1-19 shows the results of the decomposition analysis. The analysis attempts to quantify what the monthly average HOEP would have been in 2006 if the explanatory variables observed in 2007 were used in place of the corresponding 2006 values. To isolate the change in HOEP, the replacement procedure is performed one variable at a time. For example, if we replace July 2006 Ontario Demand with the observed July 2007 amount, all else held constant, the 2006 HOEP would have been $5.53/MWh higher. The table also reports the actual average HOEP for each month in the summer of 2006 and the predicted price or ‘calibrated HOEP’, which is the price that the model ‘predicts’ for that month using the actual values of the independent variables which were observed for that month last year. A small gap between the actual and calibrated HOEP, as can be seen in the period averages and in many of the individual months for both on-peak and off-peak hours, suggests the model is reasonably accurate and has captured most of the factors influencing price.

[19] The P-Value (probability value) in the table indicates the probability, under the null hypothesis (that the coefficient equals zero) of obtaining a value for the test statistic (in absolute value) that exceeds the value of the statistic that is computed from the sample. A p-value close to zero leads to rejection of the null hypothesis implying that the coefficient is statistically significant in the model.

The estimates from the decomposition analysis suggest that the HOEP is sensitive to changes in the price of natural gas. The results in Table 1-19 show that if 2006 natural gas prices were replaced by the 2007 values, there would have been a large decline in the HOEP in May and June. On the other hand, there would have been $7.64/MWh increase in the HOEP in August, which is consistent with the 17 percent decline in the natural gas price in August 2007 relative to 2006. Another interesting result is if nuclear output in September and October 2006 were replaced by 2007 nuclear output in those months, the HOEP would have declined by $3.12/MWh and $2.66/MWh respectively consistent with higher nuclear forced outage rates in September and October 2007 relative to one year ago as reported in section 4.3.2.

Table 1-19: Price Effects of Setting 2006 On-Peak and Off-Peak Factors at 2007 Levels ($/MWh)

	Month	Nuclear	Natural Gas Price	NY Load	Self	Ontario Load	Actual HOEP	Calibrated HOEP
All Hours	**May**	2.08	-5.62	-2.77	0.58	-1.27	38.50	45.56
	June	-0.18	-3.78	-2.21	-1.33	-1.08	44.38	50.30
	July	-1.53	1.62	4.16	-1.32	5.53	43.90	43.61
	August	-5.37	7.64	-0.87	-1.33	-1.08	53.62	55.56
	September	-3.12	-1.09	-6.13	-1.80	-2.49	44.63	46.69
	October	-2.66	-0.36	-4.54	-1.01	0.59	48.91	45.76
	Average	**-1.80**	**-0.26**	**-2.06**	**-1.03**	**0.03**	**45.66**	**47.91**
Off-peak Hours	**May**	1.12	-2.97	-0.53	0.37	-0.62	24.02	29.24
	June	-0.09	-2.00	0.01	-1.10	-0.22	27.22	32.44
	July	-0.87	0.86	4.20	-1.08	3.38	27.65	28.63
	August	-2.97	3.99	0.87	-0.78	-0.31	35.25	36.08
	September	-1.90	-0.61	-1.94	-1.21	-1.18	29.53	31.94
	October	-1.53	-0.20	-0.90	-0.75	0.25	32.25	31.08
	Average	**-1.04**	**-0.15**	**0.29**	**-0.76**	**0.22**	**29.32**	**31.57**
On-peak Hours	**May**	2.43	-6.59	-1.19	0.74	-1.46	48.84	55.11
	June	-0.23	-4.35	0.61	-1.39	-1.68	56.64	59.90
	July	-1.69	1.82	11.74	-1.40	6.43	55.51	50.56
	August	-6.16	8.76	2.58	-1.71	-1.62	66.75	66.02
	September	-3.43	-1.24	-6.70	-2.21	-3.30	55.42	54.92
	October	-2.98	-0.42	-4.75	-1.21	0.19	60.80	55.57
	Average	**-2.01**	**-0.34**	**0.38**	**-1.20**	**-0.24**	**57.33**	**57.01**

2.6 Hourly Uplift and Components

Table 1-20 reports total hourly uplift charges by component for May to October 2006 and 2007.[20] Uplift payments paid by Ontario consumers and each participant's share vary depending on the energy they consume each month. Total hourly uplift remained relatively constant between summer 2006 and 2007. Hourly uplift increased from $167 million in 2006 to $183 million in 2007 representing an increase of 10 percent. This change is mostly the result of a $10 million increase in Congestion Management Settlement Credit (CMSC) payments along with a $5 million increase in Import Offer Guarantee (IOG) payments. As a percentage of total cost paid by consumers, total uplift represented four percent of total cost paid by consumers of the current six month period.[21]

Table 1-20: Monthly Total Hourly Uplift Charge,
May – October 2006 & 2007
($ million)

	Total Hourly Uplift		**IOG***		**CMSC**		**Operating Reserve**		**Losses**	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	36	24	4	3	15	10	3	1	14	11
June	28	39	2	3	13	21	1	1	13	14
July	32	26	2	2	12	9	1	1	17	14
August	37	36	4	3	16	15	1	1	16	18
September	15	30	1	5	5	12	1	1	8	12
October	19	28	2	4	6	10	1	1	10	13
Total	167	183	15	20	67	77	8	6	78	82

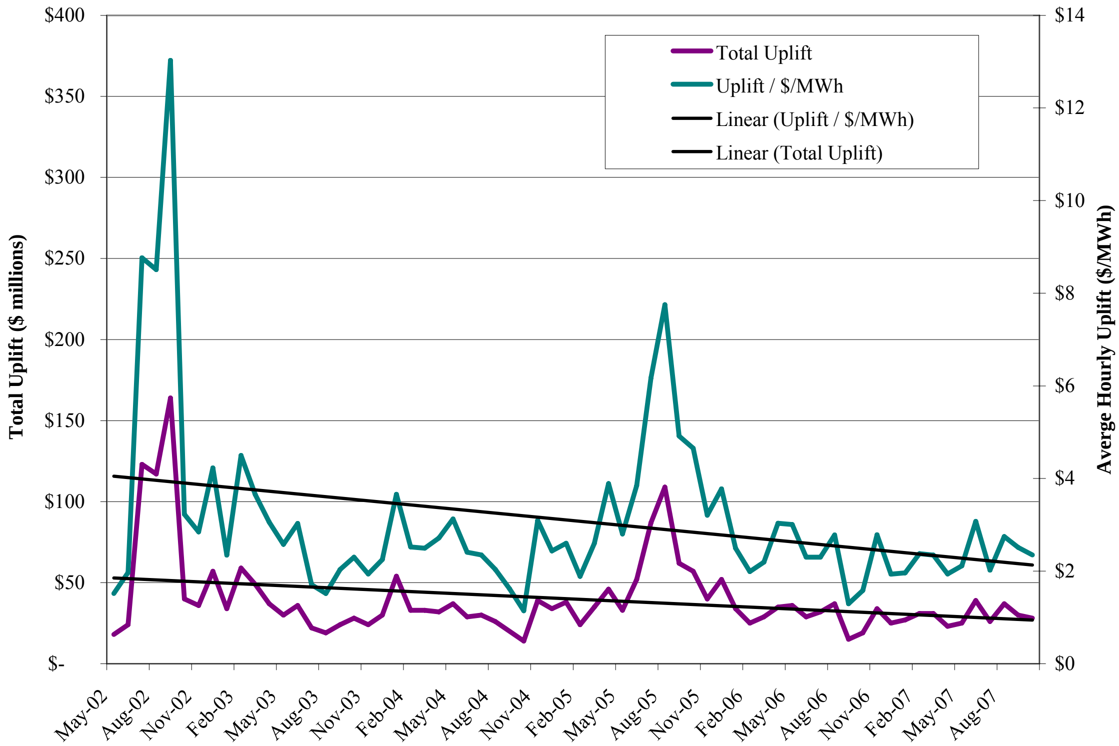
* Includes Day Ahead IOG as of June 2006 and onwards

The long-term trend in hourly uplift charges as illustrated in Figure 1-15 indicates that both total and average hourly uplift payments are declining, although the trend appears to have levelled off since early 2006.

[20] Reported uplift does not include non-market related adjustments described in Section 2.1.2

[21] This was calculated by dividing total uplift by total Market Demand (adjusted using an assumed 3 percent loss factor) over the May to October 2007 months, which resulted in an average uplift of approximately $2.30/MWh. When compared to the average HOEP in the period and accounting for the Global Adjustment, we find that approximately 4 percent of the total cost paid by consumers for energy is in the form of uplift.

Figure 1-15: Total Hourly Market Uplift and Average Hourly Market Uplift since Market Opening May 2002 – October 2007 ($ millions and $/MWh)



2.7 Internal Zone Prices and CMSC Payments

Average nodal prices for the 10 internal zones are shown in Table 1-21 for each six month period for the last 2 ½ years.[22] For most zones other than the Northwest, Northeast, and Niagara, the table shows that current internal zone prices are roughly the same as those over the previous year, being about 5 percent higher than those a year earlier but 2 percent lower than the prices 6 month earlier. These price movements are slightly greater than the change in the average Richview nodal price: the current Richview price was 1 percent below and 1.9 percent above the previous periods respectively. Similar prices across these zones suggest that both congestion and losses are relatively small factors. The small changes in zonal prices relative to changes in the

[22] 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

Richview price indicate only minor shifts in congestion across the last year. For the Northwest, Northeast, and Niagara zones, increased congestion has induced more significant changes in zonal prices.

Table 1-21: Internal Zonal Prices,[23] May 2005 - October 2007 ($/MWh)

Zone	May05-Oct05	Nov05-Apr06	May06-Oct06	Nov06-Apr07	May07-Oct07
Bruce	94.93	66.95	49.67	55.37	53.80
East	100.09	68.01	51.15	55.49	54.42
Essa	96.43	64.51	49.69	52.71	52.16
Northeast	82.22	60.78	44.21	47.67	42.38
Niagara	96.65	70.65	53.24	55.41	52.29
Northwest	33.17	34.43	23.53	36.98	(136.65)
Ottawa	107.22	71.48	53.56	57.01	56.03
Southwest	98.49	68.41	52.36	56.04	54.50
Toronto	106.18	70.08	53.44	57.22	56.36
Western	100.82	69.41	53.59	56.54	55.23
Average	91.62	64.47	48.44	51.02	23.30
Richview	102.00	70.58	55.00	56.63	56.04

For the first time, we are observing Northwest zonal prices which are consistently negative over the period of review, averaging about minus $137/MWh compared with the previous periods in Table 1-21 showing averages between $24/MWh and $37/MWh. Several factors contributed to this dramatic shift in price. First, as reported later, demand in the Northwest has continued to fall. At the same time energy supply, primarily hydroelectric energy, was abundant in the Northwest as well as in Manitoba. This excess supply over demand induced high flows towards the Northeast and from there southward from this part of the province, resulting in congestion at one of several possible locations in the Northwest in roughly half of all hours in the period.[24] Coincident with this congestion, hydroelectric generation in the Northwest was being offered at lower and lower prices over the summer in an attempt to get this energy scheduled so as to minimize the spillage of water. Thus when congestion did occur it led to very low nodal

[23] All nodal and zonal prices have been modified to +$2000 (or -$2000) when the raw value was higher (or lower).

[24] Some of the congestion identified was due to flows westward through the zone or out of the zone (i.e. exports) primarily in May. As the summer progressed flows east increased to the point where there was congestion almost 80 percent of the time in August. This diminished only slightly in September and October.

prices across the Northwest. Over the period the impact of the increasing congestion and the changing energy prices led to the congestion component of the nodal price steadily growing, from near zero in May, to roughly minus $400/MWh in September and October. While generators may offer at negative prices in order to operate, they nevertheless receive the HOEP.

The Northeast zone price averaged $42.38/MWh in the period, somewhat lower than each of the two previous periods. This is indicative of somewhat higher levels of congestion than in previous periods. This is induced partly by the greater level of hydroelectric resources available in the Northeast, partly by flows from the Northwest and outages to the major transmission lines in the Northeast.

Niagara zone prices at $52.29/MWh are also lower than in previous periods. This is also indicative of increased congestion in the Niagara area induced to a large extent by loop flows.

Figure 1-16 shows graphically the average zonal prices for the last six months.

Figure 1-16: Average Internal Zonal Prices, May 2007 – October 2007 ($/MWh)

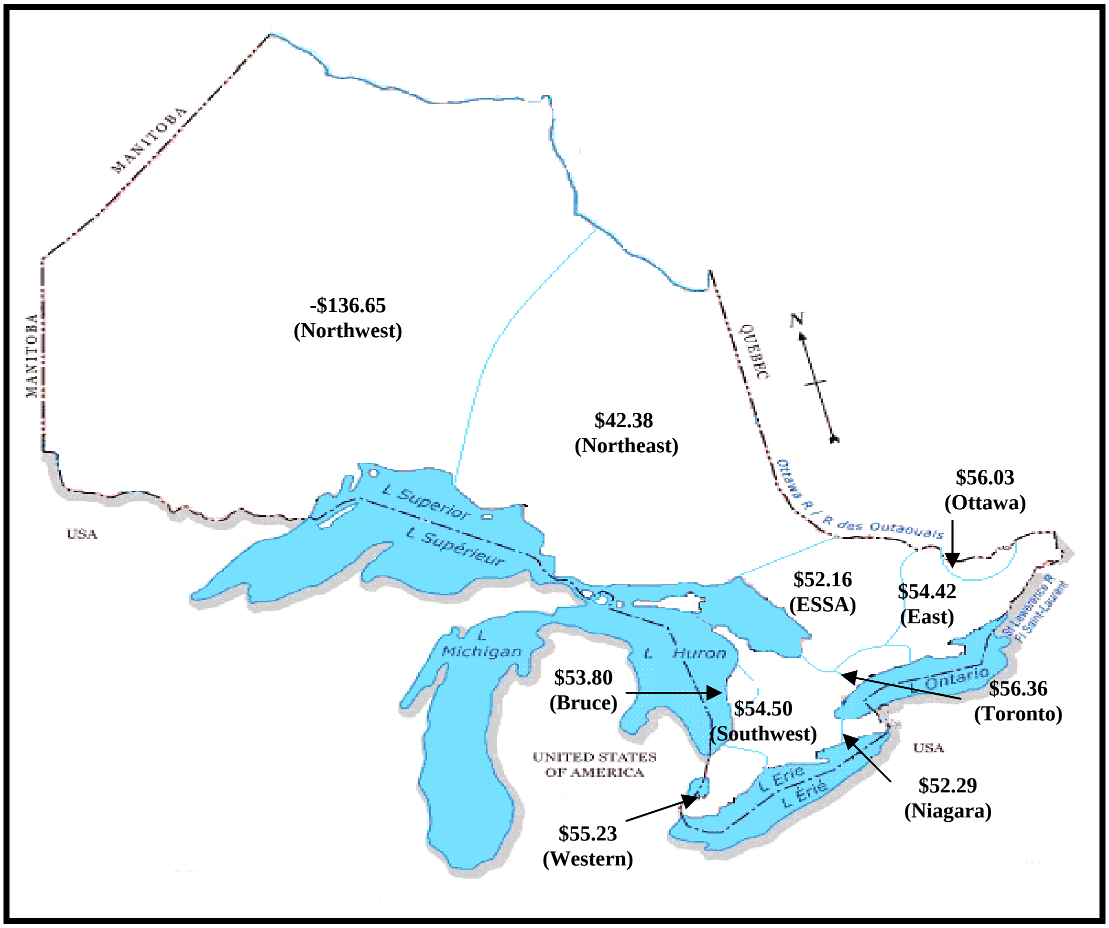
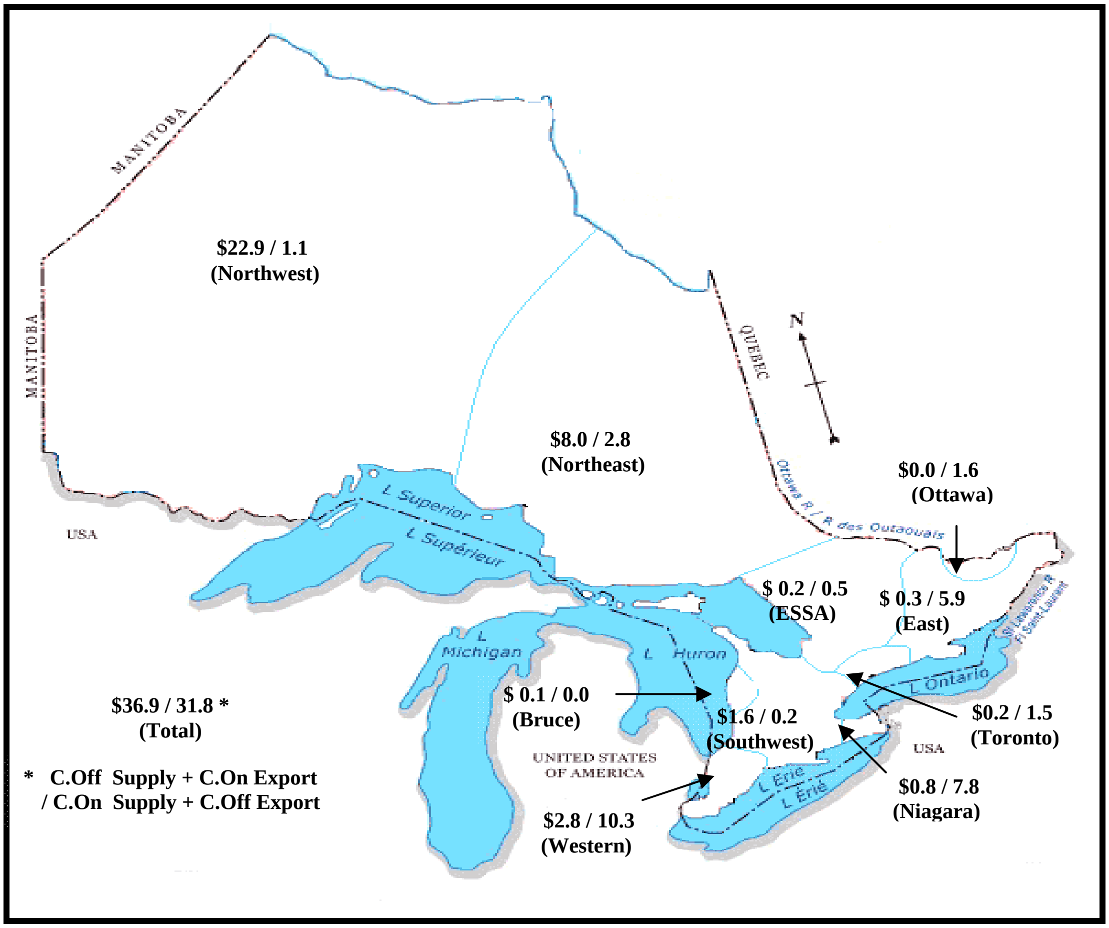


Figure 1-17 shows two sets of CMSC payments for each internal zone for the 6 month period ending October 2007. The first value is the sum of CMSC payments for constrained off generation and imports, plus constrained on exports. The second value is the sum of CMSC payments for constrained on generation and imports, plus constrained off exports. CMSC for imports and exports is attributed only to the zone to which the intertie is connected. The first value is generally indicative of bottling of lower cost supply in an area while the second value corresponds to needing to schedule more costly generation in the constrained schedule in the zone. Dispatchable load CMSC is omitted since it is primarily self-induced; that is, caused by conditions at the load rather than system conditions.

Figure 1-17: Total CMSC Payments by Internal Zone, May 2007 - October 2007 ($ millions)



In aggregate across all zones, the total of these CMSC payments are larger than for the period 12 months ago. CMSC payments for constrained off supply plus constrained on exports has increased over $10 million or 40 percent, while constrained on supply plus constrained off exports has decreased by about $0.4 million or 1 percent. Comparing the results in Figure 1-17 with those from the period one year ago, the largest increase has been in the Northwest where CMSC paid for constrained off supply has jumped by over $10 million to $22.9 million with a further increase of almost $5 million occurring in the Northeast. Other areas in the province tended to exhibit lower payments amounting to $5 million less in aggregate for constrained off supply. In spite of more constrained off energy in these Northern areas, there was a small decrease in CMSC paid for constrained on supply and constrained off exports across the province. The largest reductions were in the Northeast and East zones.

The largest changes in CMSC payments have been induced for much the same reasons as the changes in nodal prices, primarily due to increased supply in the North, coupled with transmission limitations preventing the energy flowing south. Much of the CMSC payments in the Niagara and Western zones were induced by loop flows, which caused Queenston Flow West (QFW) limitations for flows into Ontario from New York and flows out of Ontario at Michigan. Another factor which would be expected to affect CMSC payments is the movement from the 12 times to 3 times ramp rate in the unconstrained schedule, which took place on September 12, 2007. Directionally, the transition from 12 times to 3 times ramp should reduce both constrained on and constrained off CMSC payments going forward. However, it is difficult to observe this clearly with six weeks of data.

2.8 A Comparison of High and Low HOEP and Richview Nodal Price

Table 1-22 shows that the number of hours with a low HOEP or Richview nodal price increased dramatically in the summer of 2007 compared to 2006. The number of hours when the HOEP fell below $20/MWh more than doubled from 149 hours in 2006 to 331 in 2007. For both HOEP and Richview price, the frequency of high-priced hours over the period is largely unchanged.

The majority of the low-priced hours occurred in May, June, and July 2007. The most dramatic monthly increase occurred in May where the number of hours the HOEP and Richview prices fell below $20/MWh increased from 17 hours to 115 hours for HOEP and from 37 hours to 135 hours for the Richview price. Increased nuclear and baseload hydroelectric supply (as observed in Statistical Appendix Tables A-13 and A-14) and lower demand were both contributing factors in the observed increase in low-priced hours in May. The only month with fewer low HOEP hours was September which experienced both notably higher demands and less low-cost energy.

Table 1-22: Hours with a Low HOEP or Richview Nodal Price, May – October 2006 & 2007 (Number of Hours)

	Number of Hours with HOEP <$20/MWh			Number of Hours with Richview Price <$20/MWh		
	2006	2007	% Change	2006	2007	% Change
May	17	115	576.5	37	135	264.9
June	14	67	378.6	25	69	176.0
July	30	57	90.0	40	73	82.5
August	4	11	175.0	35	22	(37.1)
September	63	45	(28.6)	101	70	(30.7)
October	21	36	71.4	53	30	(43.4)
Total	149	331	122.1	291	399	37.1

The frequency of hours when the HOEP and Richview nodal prices were above $200/MWh remained relatively stable this period compared to the same period last year as shown in Table 1-23. High-priced HOEP hours declined from six hours to four hours while the Richview price eclipsed $200/MWh in 54 hours this summer compared to 51 hours last summer. The frequency of high Richview price hours continues to be notably higher than the frequency of high HOEP hours for reasons which are discussed in Chapter 3.

Table 1-23: Hours with a High HOEP or Richview Nodal Price, May – October 2006 & 2007 (Number of Hours)

	Number of Hours with HOEP >$200/MWh			Number of Hours with Richview Price >$200/MWh		
	2006	2007	% Change	2006	2007	% Change
May	3	0	(100.0)	19	0	(100.0)
June	0	2	N/A	5	25	400.0
July	1	1	0.0	8	3	(62.5)
August	2	0	(100.0)	18	13	(27.8)
September	0	0	N/A	0	6	N/A
October	0	1	N/A	1	7	600.0
Total	6	4	(33.3)	51	54	5.9

3. *Demand*

3.1 Aggregate Consumption

As illustrated in Table 1-24, total Ontario and total Market (Ontario plus exports) Demand declined this summer compared to last summer by 0.65 TWh and 0.39 TWh respectively, although exports increased by 0.23 TWh.

There was a noticeable decline in demand in July 2007 compared to July 2006. In July, Ontario Demand declined by over 1.04 TWh, or 7.5 percent and Market Demand fell by 0.77 TWh, representing a decline of greater than 5 percent. An important factor that contributed to July's decline in demand was cooler weather. Tables A-2 and A-3 of the Statistical Appendix show that weather conditions in July were on average 2°C cooler than the year before and the number of days when the temperature rose above 30°C declined from nine days to four days. Contrasting the trend to lower demand, September saw higher demands, both domestic and export, primarily as the result of 2.5°C higher temperatures and four more days with temperatures above 30°C.

Table 1-24: Monthly Energy Demand, Market Schedule, May – October 2006 & 2007 (TWh)

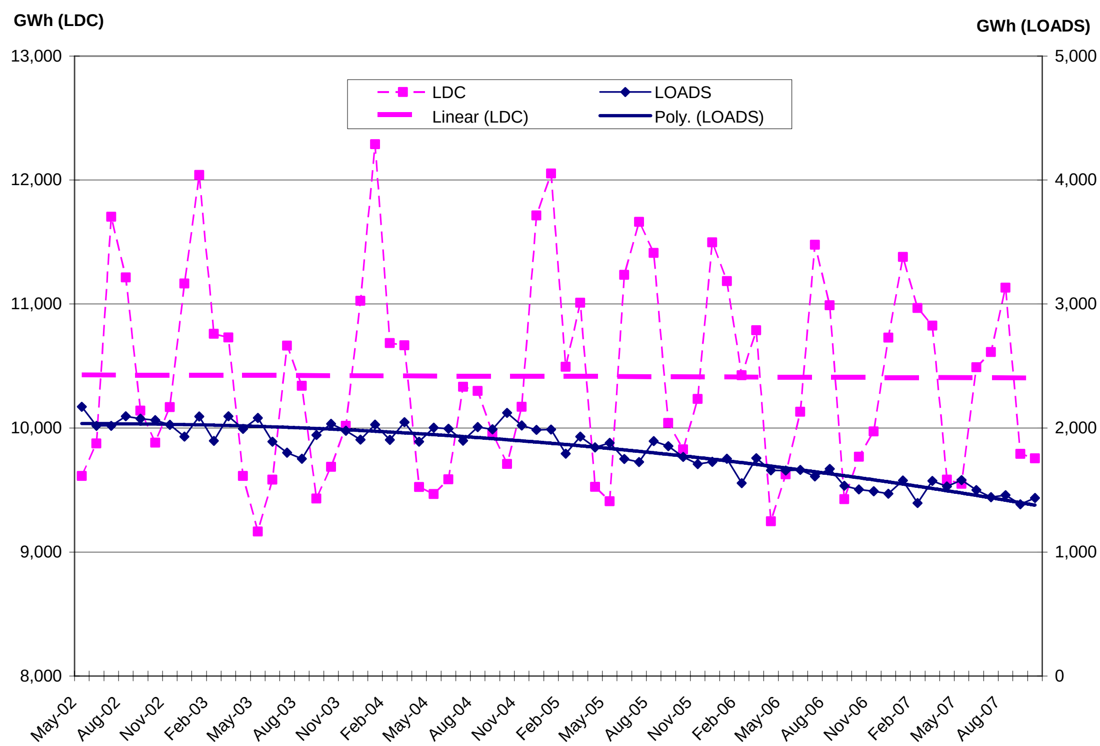
	Ontario Demand*			Exports			Total Market Demand		
	2006	**2007**	**% Change**	**2006**	**2007**	**% Change**	**2006**	**2007**	**% Change**
May	11.99	11.83	(1.3)	1.20	1.08	(10.0)	13.19	12.91	(2.1)
June	12.59	12.69	0.8	0.91	1.04	14.3	13.50	13.74	1.8
July	13.89	12.85	(7.5)	1.03	1.30	26.2	14.92	14.15	(5.2)
August	13.32	13.47	1.1	1.21	1.12	(7.4)	14.53	14.60	0.5
September	11.58	11.95	3.2	0.83	0.92	10.8	12.41	12.88	3.8
October	11.99	11.92	(0.6)	0.98	0.93	(5.1)	12.97	12.85	(0.9)
Total	75.36	74.71	(0.9)	6.16	6.39	3.7	81.52	81.13	(0.5)
Average	12.57	12.45	(0.9)	1.03	1.07	3.4	13.59	13.52	(0.5)

* Non-dispatchable loads plus dispatchable loads

3.2 Wholesale and LDC Consumption

Figure 1-18 separates energy consumption by Local Distribution Companies (LDCs) and other wholesale loads since the market opened in May 2002. Wholesale load consumption has significantly declined since market opening. On average since January 2005, wholesale load has declined by approximately 600 GWh (30 percent). LDC consumption has remained relatively consistent, and Figure 1-18 suggests that month-to-month volatility has declined. That is, seasonal swings in consumption have not been as dramatic as observed during the early years of the market. As might be expected, this pattern appears to be closely tied to monthly temperatures, with the winter peak monthly consumption driven by January or December temperatures and summer peak consumption driven by July or August average temperatures.[25]

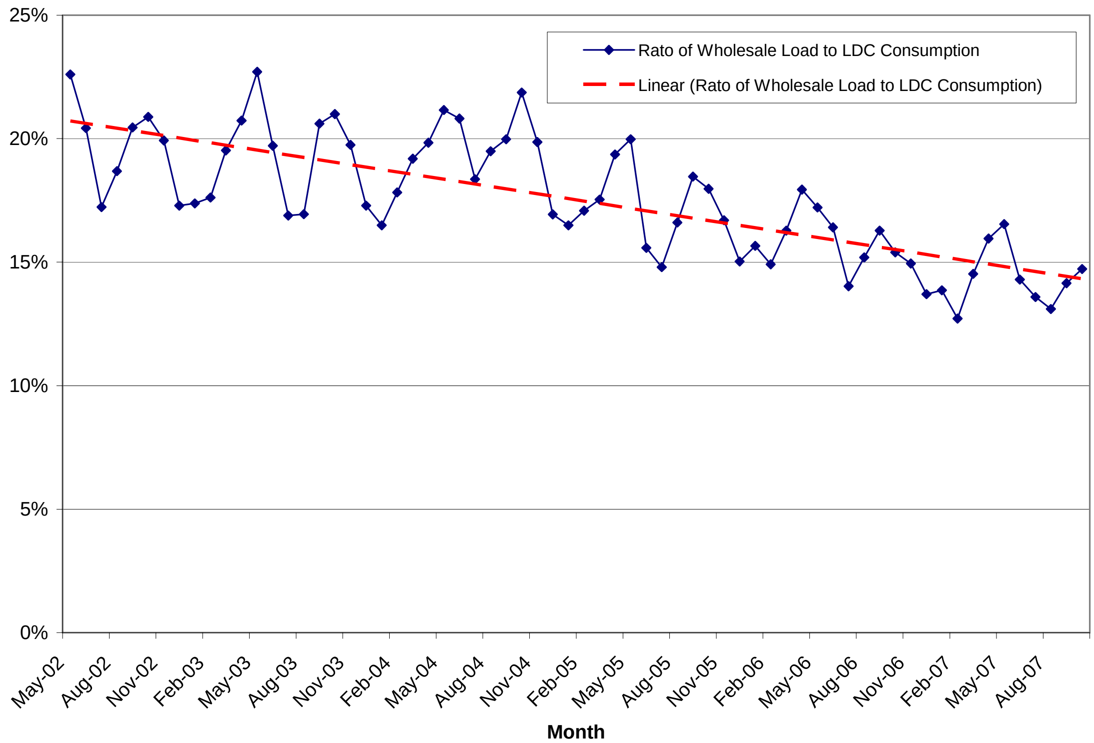
Figure 1-18: Monthly Total Energy Consumption, LDC vs. Wholesale Loads, May 2002 – October 2007 (GWh)



[25] See Statistical Appendix, Table A-2.

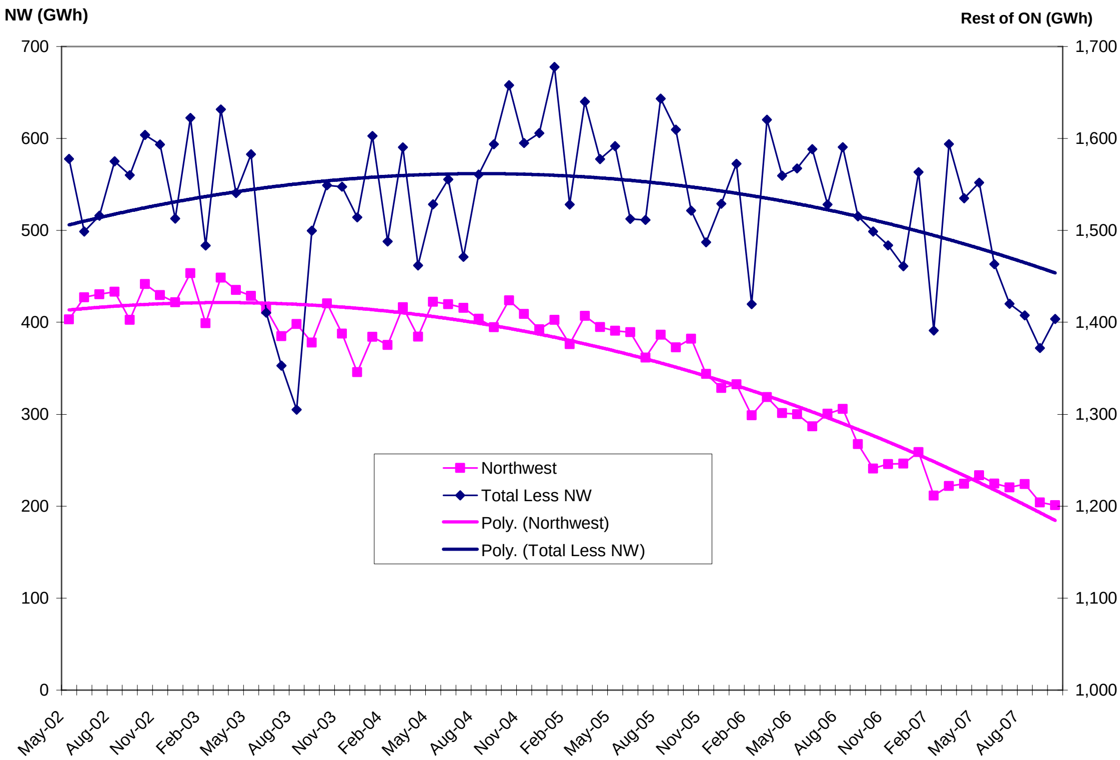
Figure 1-19 reports the ratio of wholesale load to LDC consumption on a monthly basis since market opening. Consistent with the decline in wholesale load, there is a long-term declining trend in the ratio between wholesale load to LDC consumption.

Figure 1-19: Ratio of Wholesale Load to LDC Consumption, May 2002 – October 2007 (%)



In Figure 1-20, monthly wholesale load in the Northwest is isolated from the rest of Ontario and polynomial trend lines are included to help identify long term trends. The previous MSP report identified a large decline in wholesale load in the Northwest beginning in early 2005. This trend continued through the summer months of 2007. There also appears to be a slight decline in wholesale load in the rest of the province. In September 2007, monthly wholesale load in Ontario excluding the Northwest totalled 1,372 GWh, representing the lowest monthly total since the summer months of 2003.

Figure 1-20: Total Monthly Wholesale Load Northwest and the Rest of Ontario, May 2002 – October 2007[26] (GWh)



4. *Supply*

4.1 Supply Conditions and the Supply Cushion

The supply cushion is an important market and reliability measure that represents the amount of excess supply available for dispatch in a given hour. Tables 1-25 and 1-26 report the pre-dispatch and real-time domestic supply cushion statistics for all months between May and October 2006 and 2007.

In pre-dispatch, the average supply cushion increased by 2.3 percent and grew in all months in 2007 relative to the same months in 2006 with the exception of October. For most months, both the number of hours with a negative pre-dispatch supply cushion and

[26] The low value for total load in August 2003 is due to the blackout that month.

supply cushion less than 10 percent declined relative to last summer. This implies that there was almost always sufficient generation to meet the Ontario demand. One major factor which led to an improved pre-dispatch supply cushion was moderate weather conditions this summer causing reduced demand.

Table 1-25: Pre-Dispatch Domestic Supply Cushion, May – October 2006 & 2007 (% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2006	2007	2006	%	2007	%	2006	%	2007	%
May	20.0	25.4	34	4.6	0	0.0	161	21.6	34	4.6
June	22.4	23.1	2	0.3	2	0.3	146	20.3	126	17.5
July	22.8	25.7	1	0.1	0	0.0	147	19.8	68	9.1
August	24.3	27.6	10	1.3	4	0.5	80	10.8	56	7.5
September	23.9	25.6	0	0.0	8	1.1	71	9.9	47	6.5
October	20.4	19.9	3	0.4	0	0.0	106	14.2	147	19.8
Total	22.3	24.6	50	1.1	14	0.3	711	16.1	478	10.8

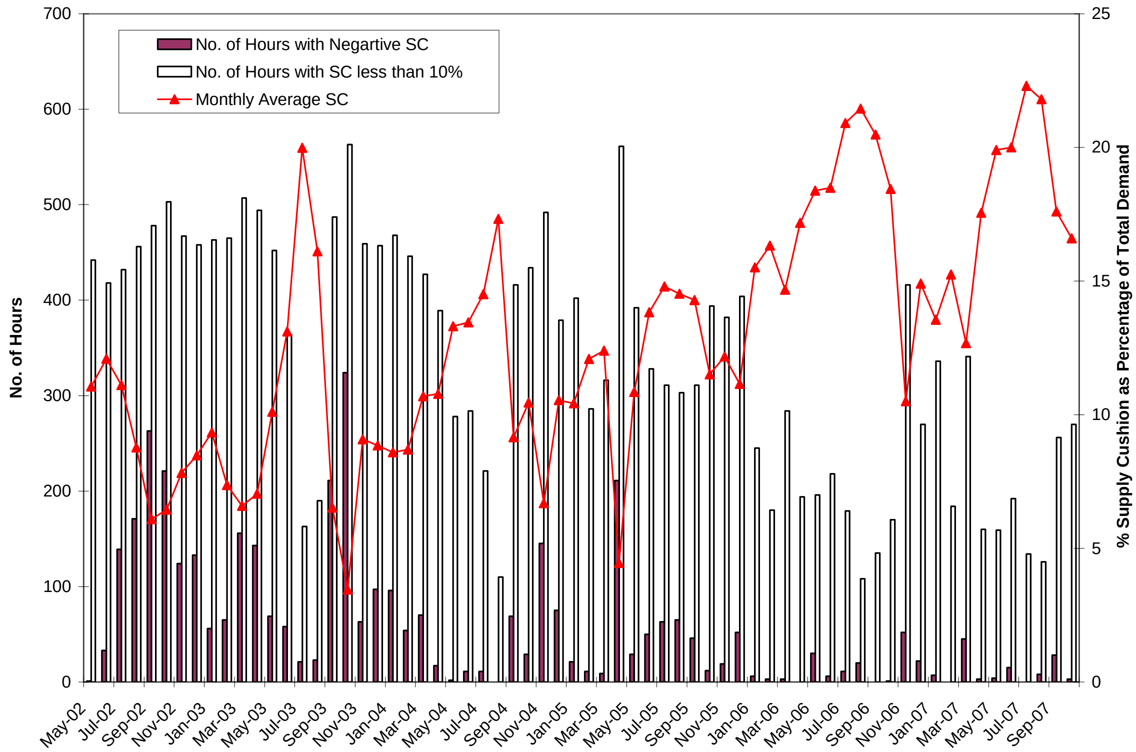
Table 1-26 shows that on average, the real-time domestic supply cushion remained the same at 19.7 percent when comparing the summer months of 2006 and 2007. The number of hours with a negative supply cushion declined moderately, however the number of hours less than 10 percent increased by 131 hours.

Table 1-26: Real-time Domestic Supply Cushion, May – October 2006 & 2007 (% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2006	2007	2006	%	2007	%	2006	%	2007	%
May	18.4	19.9	30	4.0	4	0.5	196	26.3	159	21.4
June	18.5	20.0	6	0.8	15	2.1	218	30.3	192	26.7
July	20.9	22.3	11	1.5	0	0.0	179	24.1	134	18.0
August	21.5	21.8	20	2.7	8	1.1	108	14.5	126	16.9
September	20.5	17.6	0	0.0	28	3.9	135	18.8	256	35.6
October	18.4	16.6	1	0.1	3	0.4	170	22.9	270	36.3
Total	19.7	19.7	68	1.5	58	1.3	1,006	22.8	1,137	25.7

Figure 1-21 plots the average monthly real-time domestic supply cushion statistics since market opening. The monthly average supply cushion reached its highest level during the summer of 2007 when it reached an all-time high of 22.3 percent in July. Furthermore, instances of a negative supply cushion are much less frequent compared to the beginning of market opening, suggesting that the reliability conditions in the province are gradually improving.

Figure 1-21: Monthly Real-time Domestic Supply Cushion Statistics, May 2002 – October 2007 (% and Number of Hours under Certain Levels)



4.2 Supply Curves

Figure 1-22 plots the average domestic offer curve for the summer months this year compared to last year. There was little increase in Ontario's total generating capacity this summer relative to last, which is reflected in the small change in total offered MW. The section of the offer curves below $0/MWh suggests that more baseload generators are offering minus $2,000/MWh (approximately 300 MW) rather than between minus $500/MWh and $0/MWh.

Figure 1-22: Average Domestic Offer Curve, May – October 2006 & 2007 ($/MWh)

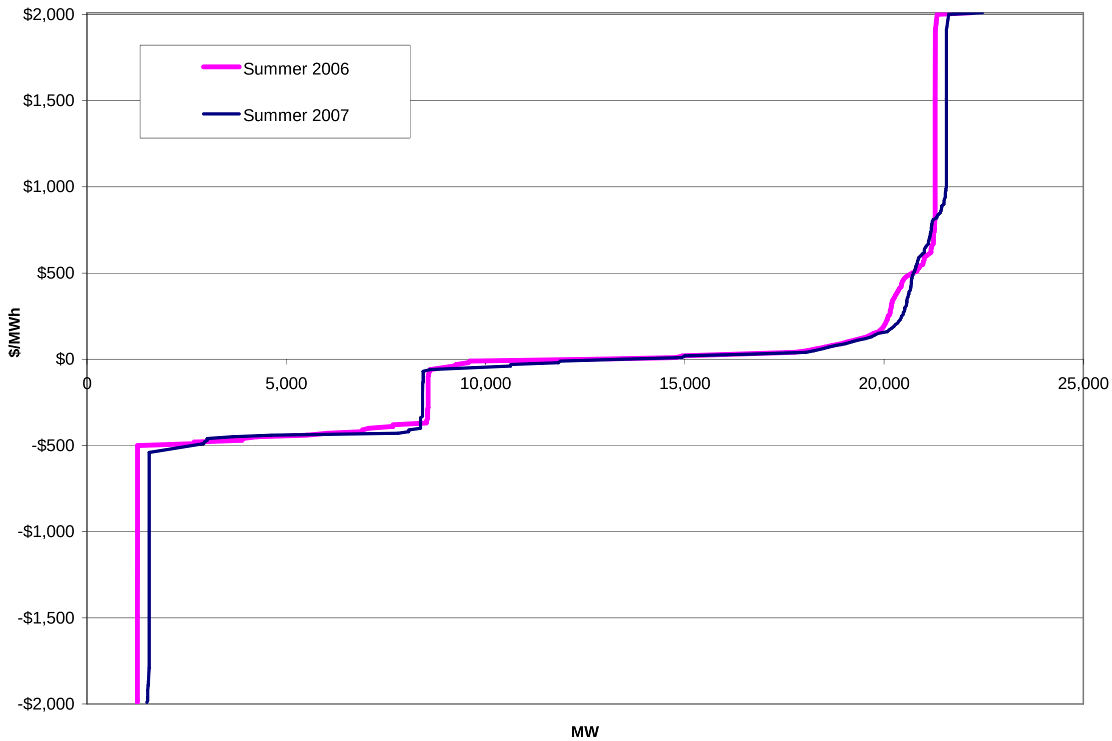


Table 1-27 reports the average hourly market schedule and Ontario demand for the period May to October 2006 and 2007 by baseload generation type. Over the six month period, hourly baseload production in the market schedule marginally declined from 16.5 GW to 16.4 GW. Scheduled nuclear supply declined by on average 0.4 GW per month compared to the summer of 2006 mainly due to an increase in nuclear outages from July onwards.

Table 1-27: Average Hourly Market Schedules by Baseload Generation Type and Ontario Demand, May – October 2006 & 2007 (GW)

	Nuclear		Baseload Hydro		Self-Scheduling Supply		Ontario Demand (Non-Dispatchable Load)	
	2006	2007	2006	2007	2006	2007	2006	2007
May	8.8	9.4	2.0	2.2	0.8	0.8	15.5	15.4
June	9.4	9.4	1.9	2.0	0.9	0.8	16.9	17.1
July	10.2	9.7	2.1	1.9	0.8	0.7	18.1	16.8
August	10.8	9.5	2.0	1.8	0.8	0.7	17.4	17.6
September	9.6	8.7	2.0	1.8	0.9	0.7	15.6	16.1
October	8.9	8.2	2.1	2.0	0.9	0.9	15.6	15.5
Average	9.6	9.2	2.0	2.0	0.9	0.8	16.5	16.4

4.3 Outages

Managing planned outages and minimizing forced outages allows generators to maximize their output, increase revenues, and improves the supply situation in the province. Market Clearing Prices are sensitive to both planned and forced outages since supply is removed from the market. Planned outages are usually taken during the low demand periods in spring and fall. Forced outages are unexpected and therefore a challenge for a system operator to accommodate and the generator owners to manage. In this section, we report nuclear and coal outage rates, since outages to these inframarginal resources tend to have a significant effect on price. Given that a significant amount of gas-fired generation will enter the market over the next few years, we will consider reporting outage rates for this group in future reports.[27]

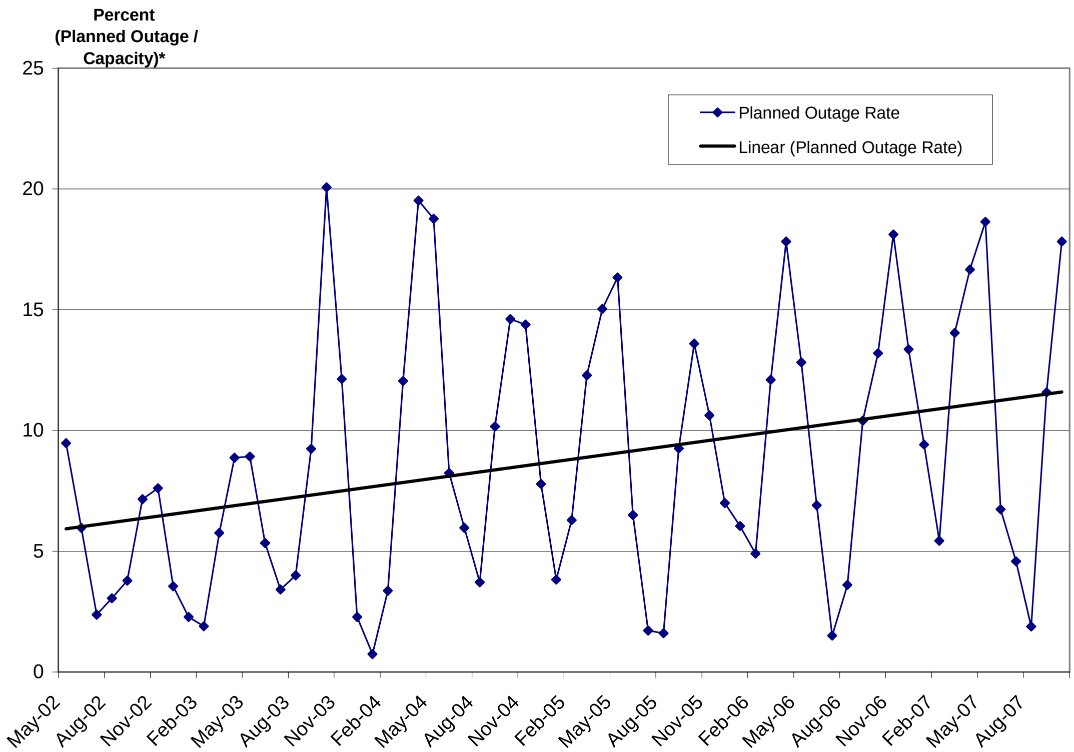
4.3.1 Planned Outages

Figures 1-23 plots the monthly planned outages as a percentage of capacity. Planned outages show a great deal of seasonal variation since they are most often taken during the spring and fall, which represent the low demand periods of the year. Since market opening, the long term trend line appears to be moving upward but this seems to be

[27] See http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=236 for a list of operating and new natural gas-fired generation projects under contract with the OPA along with projected start dates.

influenced by lower planned outage levels during the first year of the market. Since late 2003, the long-term trend appears relatively flat with typical seasonal variations.

Figure 1-23: Planned Outages Relative to Capacity,*
May 2002 - October 2007
(% of Capacity)

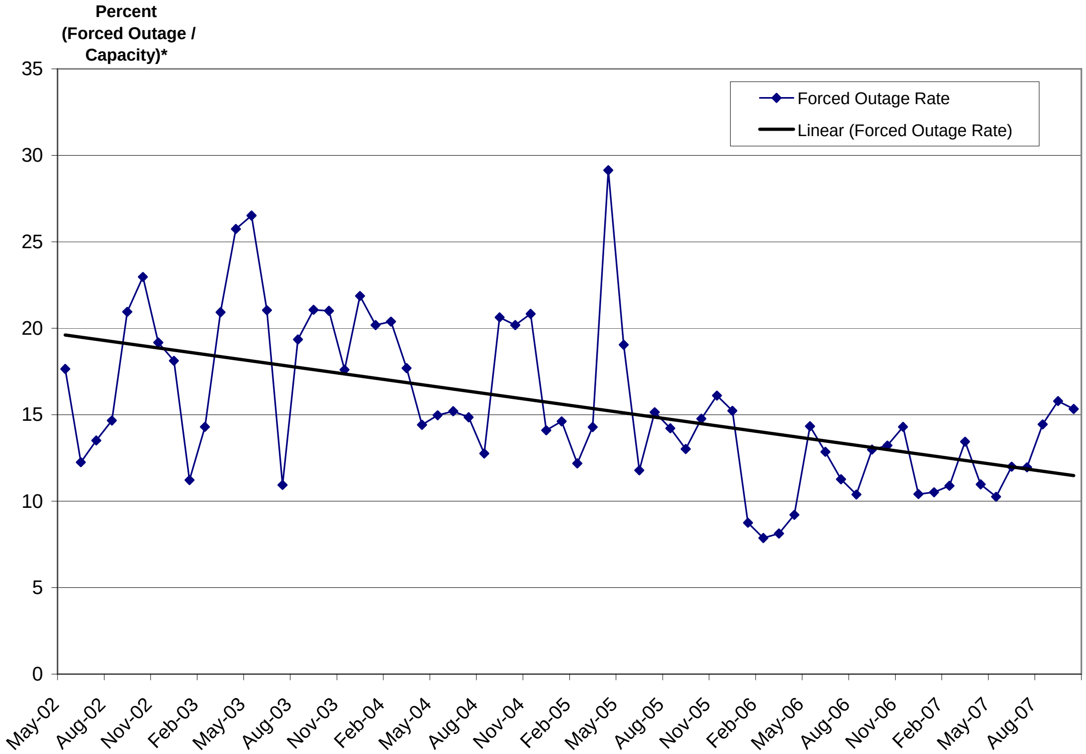


** Nuclear and Coal-fired units only*

4.3.2 Forced Outages

Figure 1-24 plots forced outages as a percentage of capacity between May 2002 and October 2007. The long-term trend in forced outages appears to be declining relative to capacity and is approaching 10 percent. However, forced outage rates rose above the 15 percent level in September and October (a level not seen since 2005). Future observations will confirm if the increase is sustainable.

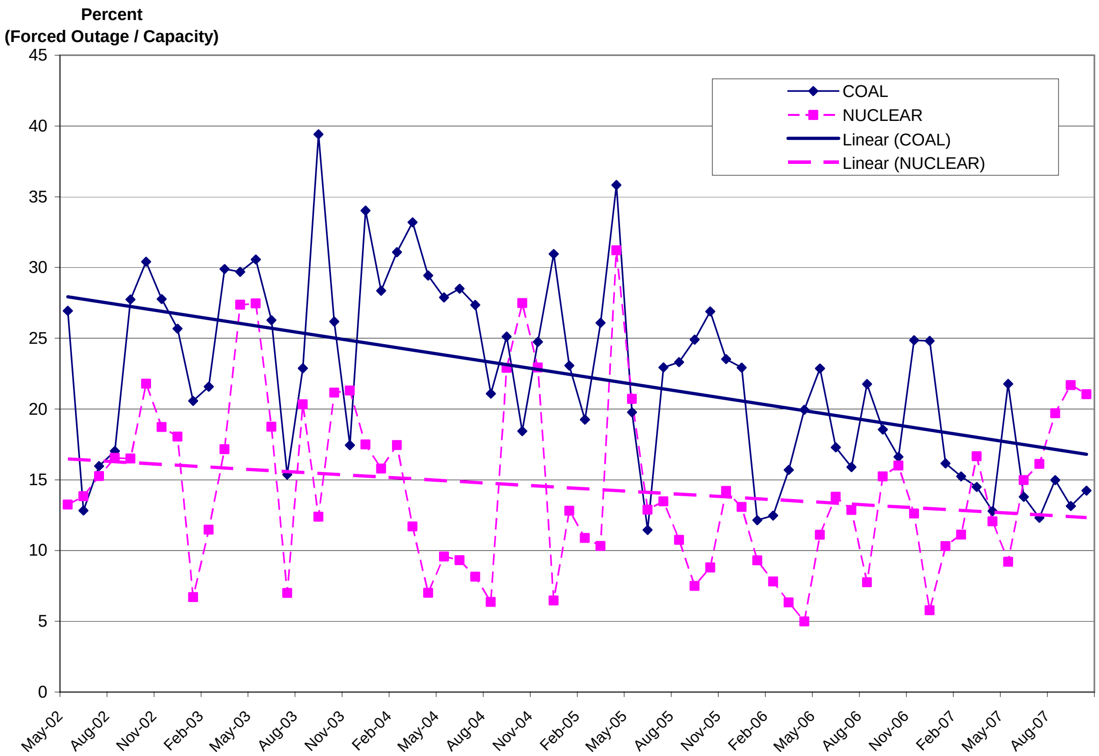
Figure 1-24: Forced Outages Relative to Capacity,*
May 2002 - October 2007
(% of Capacity)



** Nuclear and Coal-fired units only*

Figure 1-25 separates forced outage rates by fuel type since market opening and includes linear trend lines to help isolate long term trends. Although coal-fired generator outages were relatively low compared to previous years, nuclear outages increased to 20 percent or higher in August, September, and October 2007. Nuclear outage rates have not been above 20 percent since the spring of 2005. These high rates resulted from frequent outages at two nuclear generating stations from July onwards.

Figure 1-25: Forced Outages Relative to Total Capacity by Fuel Type, May 2002 - October 2007 (% of Capacity)



4.4 Changes in Fuel Prices

Table 1-28 shows the monthly average spot market prices this summer relative to summer 2006 for both natural gas and coal. The average natural gas price is measured by the Henry Hub spot price and then converted to Canadian dollars.[28 29] The coal price is evaluated using the NYMEX over-the-counter price for Central Appalachian region coal converted to Canadian dollars.

In May and June 2007, natural gas prices were approximately 21 percent and 13 percent higher than the same months in 2006. Although natural gas prices began the summer much higher in 2007 compared to 2006, gas prices fell in the final four months. The

[28] The Henry Hub is located in Southern Louisiana and is routinely used as the reference price for most of the domestic gas destined for the East.

[29] The Bank of Canada nominal noon exchange rate was used to convert commodity prices into Canadian dollars. Between May 2007 and October 2007, the Canadian dollar appreciated by approximately 13 percent to an average monthly rate of $1 CAD =$ 1.02 USD in October.

largest monthly decline occurred in August when the average gas price fell over 17 percent this year compared to last. NYMEX OTC Central Appalachian coal prices were on average, $0.25/MMBtu or approximately 12 percent lower in the last six months compared to one year ago. Much of the observed decline in both coal and natural gas prices is due to the strengthening Canadian dollar relative to the U.S dollar. The impact of exchange rates is discussed in more detail in section 5.4.2.

Table 1-28: Average Monthly Fuel Prices , May – October 2006 & 2007 ($CDN/MMBtu)

	Coal Price (NYMEX OTC Central Appalachian)			Natural Gas Price (Henry Hub Spot)		
	2006	**2007**	**% increase**	**2006**	**2007**	**% increase**
May	2.36	2.00	(15.3)	6.92	8.39	21.2
June	2.32	2.07	(10.8)	6.94	7.82	12.7
July	2.18	1.93	(11.5)	6.91	6.54	(5.4)
August	2.22	1.90	(14.4)	8.03	6.64	(17.3)
September	2.12	1.88	(11.3)	5.62	5.61	(0.2)
October	2.02	1.89	(6.4)	6.66	6.56	(1.5)
Average	2.20	1.95	(11.7)	6.85	6.93	1.2

In the past, the Panel has used the Central Appalachian coal price and the Henry Hub natural gas price exclusively to measure average monthly fuel prices. Table 1-29 reports two additional fuel price series for the May to October 2006 and 2007 months which can help identify trends in fuel prices and may represent an improvement when measuring fuel prices: the Powder River Basin coal price and the Union Dawn Hub natural gas price. The Powder River Basin, which is located in southeast Manitoba and northeast Wyoming, represents a relatively cheap source of coal used by a large portion of Ontario’s fossil generating fleet. The Union Dawn Hub is Canada’s largest underground natural gas storage facility located in near Sarnia, Ontario. Although the Henry Hub and Union Dawn Hub gas prices are similar in many hours, differences that reflect transportation constraints do occur. Dawn prices may be more applicable to generators in Ontario, but somewhat less so for those in the U.S. For future analysis (including the various econometric models available), we will consider how the additional fuel price data should be used.

Table 1-29: Average Monthly Fuel Prices, May – October 2006 & 2007 ($CDN/MMBtu)

	Coal Price (Powder River Basin)			Natural Gas Price (Union Dawn Hub)		
	2006	**2007**	**% Change**	**2006**	**2007**	**% Change**
May	0.84	0.55	(34.8)	7.14	8.76	22.7
June	0.79	0.56	(29.5)	7.02	8.07	15.0
July	0.76	0.57	(25.2)	6.85	6.77	(1.1)
August	0.71	0.63	(11.7)	7.84	6.54	(16.6)
September	0.63	0.62	(1.7)	5.71	6.31	10.6
October	0.65	0.60	(8.5)	6.78	6.82	0.5
Average	0.73	0.59	(19.7)	6.89	7.21	4.7

Figures 1-26 and 1-27 plot the monthly average natural gas and coal prices with the on-peak and off-peak HOEP prices. Over the summer months in 2007, movements in the HOEP appear to coincide with movements in the price of natural gas, which is consistent with the long-term relationship between the two variables. Coal prices do not show the same long-term relationship with the HOEP. Nevertheless, the observed 12 to 20 percent drop in coal price in Canadian dollars is likely one of the factors influencing Ontario prices. Off peak energy prices dropped on average just over 6 percent relative to the previous year, which was likely influenced by lower coal prices which were on the margin 70 percent of the time off peak. On peak coal was on the margin half that much. The downward pressure from coal price on market price was offset by poorer baseload generation performance.

Figure 1-26: Henry Hub Natural Gas Spot Price and HOEP, May 2002 - October 2007 ($/MWh and $/MMBtu)

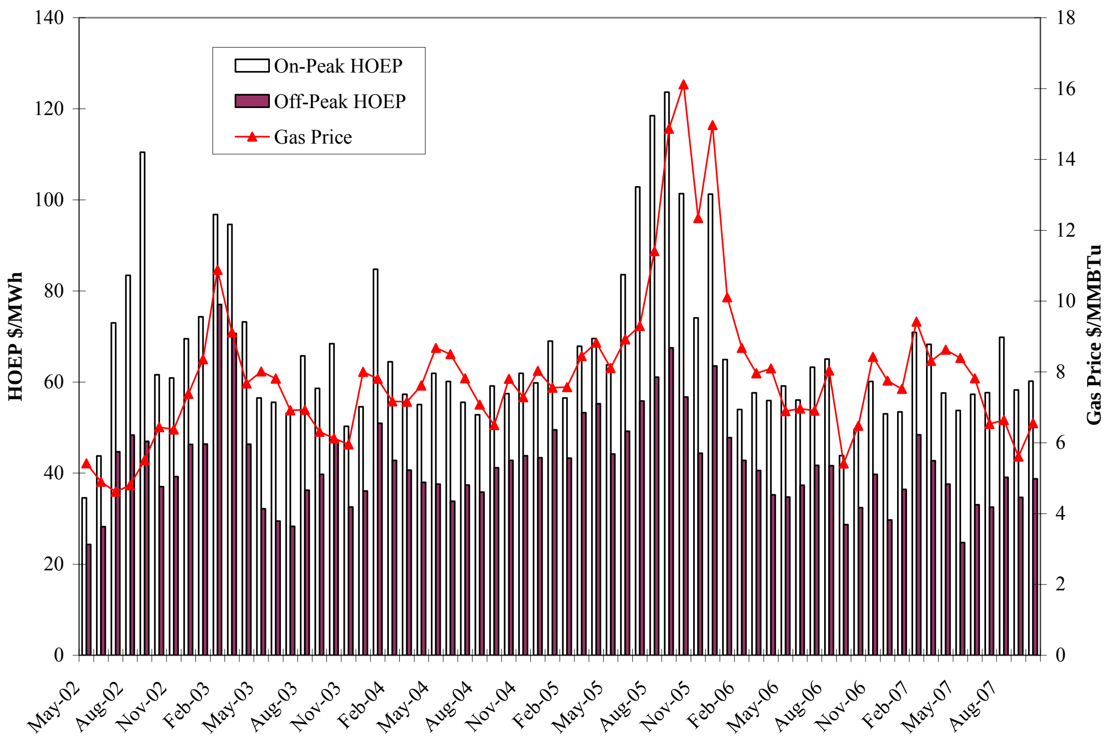


Figure 1-27: NYMEX OTC Central Appalachian Coal Price and HOEP, May 2002 - October 2007 ($/MWh and $/MMBtu)

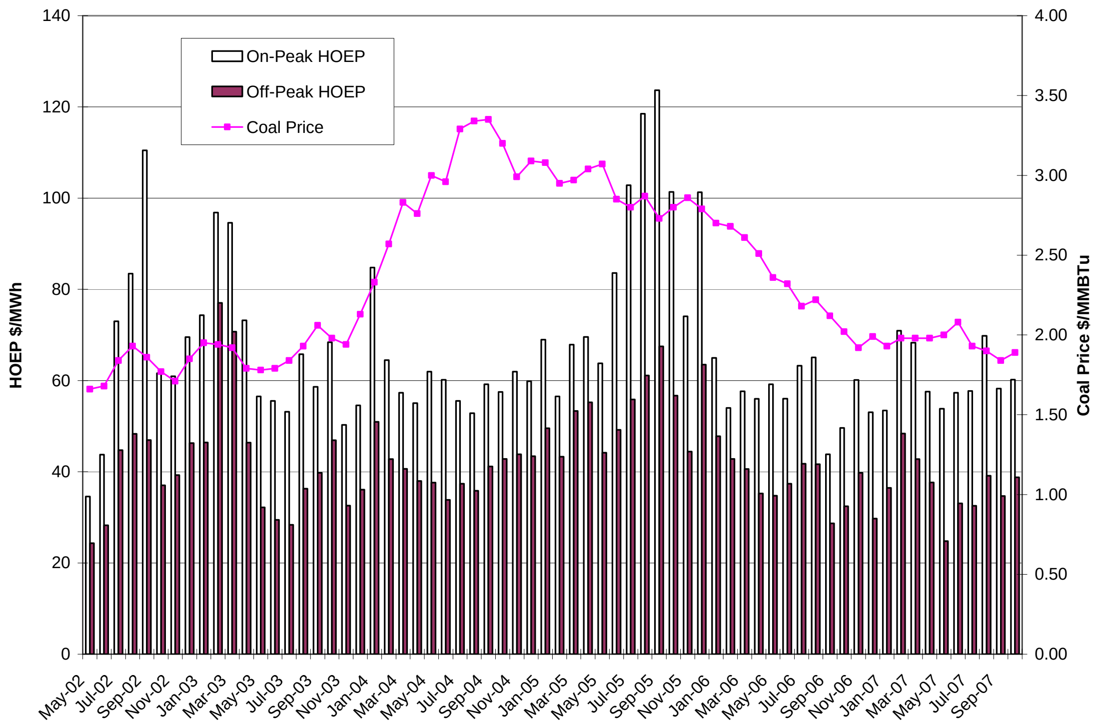
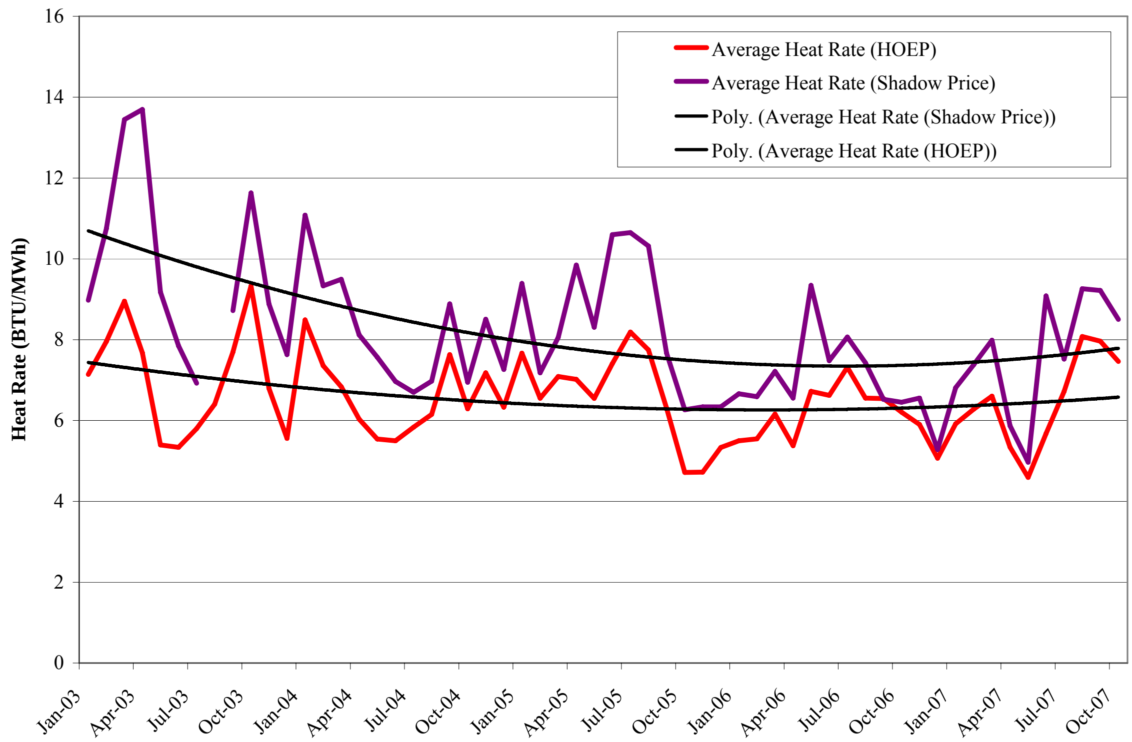


Figure 1-28 plots the estimated system heat rate since January 2003. The system heat rate is derived by dividing the observed monthly average price by the average Canadian dollar equivalent of the Henry Hub gas price (i.e. implicitly assuming gas is always the marginal fuel source). This estimated heat rate is useful for two 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 be 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 type of gas-fired generator can be potentially scheduled in the market and thus able to recover their incremental costs. A high system heat rate indicates that less efficient generators are being scheduled by the system and these units have an opportunity to recover incremental costs. A low system heat rate indicates that more efficient generators are needed and only these generators have an opportunity to recover incremental costs.

Figure 1-28 shows that in the early years of the market, a relatively less efficient generator could cover incremental costs since market prices were relatively favourable to generators. However in later years, only the most efficient generators were able to cover incremental costs. For example before mid 2005, a gas-fired generator with a heat rate of 7,000 MMBtu could make sufficient revenue to recover its incremental costs while after mid 2005, only generators with a heat rate of 6,000 MMBtu could recover their incremental costs. Taking into account CMSC payments by using the Richview shadow price in the heat rate calculation, a generator with a heat rate above 8,000 MMBtu could recover its incremental costs before mid 2005, while only generators with a heat rate of about 7,000 MMBtu could break even after mid 2005.

The system heat rate data is consistent with our net revenue analysis in this report and in previous reports. Apart from the first year the market opened, the HOEP levels have been low enough not to allow a typical gas-fired generator with a standard heat rate of 7,000 MMBtu to recover its costs without a contract.

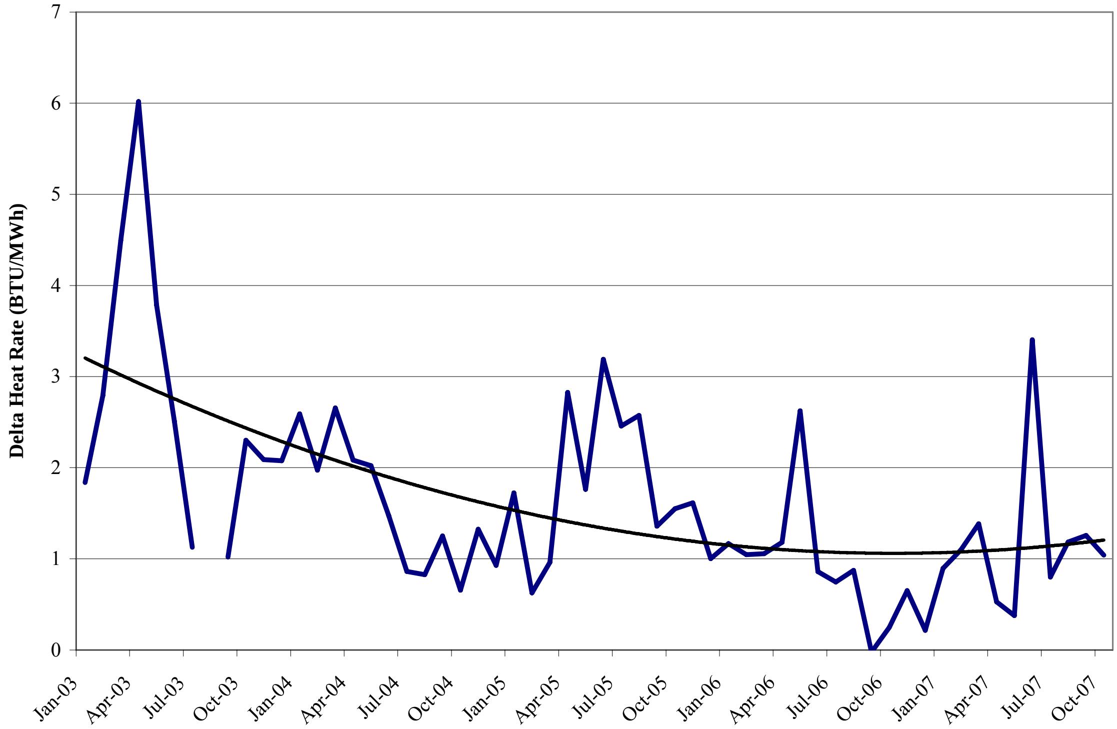
Figure 1-28: Estimated Monthly Average System Heat Rate since Market Opening using HOEP and Shadow Price, January 2003 - October 2007 (Btu/MWh)



The gap (or delta) between the unconstrained (measured using the HOEP) and constrained (measured using the Richview Shadow Price) heat rates is shown in Figure 1-29. The gap between the two has been declining since early 2003, although there was a large increase in the delta during June 2007.[30] The narrowing gap implies a lower CMSC to generators and the HOEP has been becoming a more and more important signal to market participants and potential investment. The narrowing delta mirrors an apparent convergence between the HOEP and the Richview shadow price, as will be discussed in Chapter 3.

[30] The large gap in June 2007 was due to higher Richview Shadow prices caused by a few factors: 1) an outage in a major transmission line (D501P) that limited hydro power in north to flow south in the early part of the month, 2) a derating of the QFW transmission line on June 11th that limited power production at the Beck generating station, and 3) events on June 12th, which are discussed in more detail in Chapter 2.

Figure 1-29: Delta Heat Rate (Constrained less Unconstrained Schedules), January 2003 to October 2007 (Btu/MWh)



4.5 Net Revenue Analysis

Similar to previous MSP reports, we use a standardized model developed by the Federal Energy Regulatory Commission of the United States (FERC) to help 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.[31]

Table 1-30 reports estimated net revenues for two types of generators; an efficient combined cycle plant with a heat rate of 7,000 Btu/KWh and a less efficient combustion turbine plant with a heat rate of 10,500 Btu/KWh. The assumed variable operating and maintenance (O&M) costs are $1.1/MWh for the combined cycle and $3.3/MWh for the

[31] For details, see FERC 2004 State of the Markets Report, Docket MO05-4-000.

combustion turbine unit along with an assumed 5 percent outage rate for both.[32] Revenues are examined on an annual basis using the November to October period.

The amount of net revenue available to new generation during May – October 2007 continues to be insufficient to induce new investment in Ontario in the absence of guarantees and subsidies.[33] Estimated net revenues over the November 2006 to October 2007 period were $61,257 for the combined-cycle unit and $15,151 for the combustion. These net revenues are well below the estimated FERC requirement of US$80,000-90,000/MW-year for a combined cycle unit and US$60,000-70,000/MW-year for a combustion-turbine unit to meet all debt and equity requirements.[34]

Table 1-30: Yearly Estimated Net Revenue Analysis for Two Generator Types, November 2002 - October 2007 ($/MWh)

Generator Type	7,000 Btu/KWh of Combined-cycle with variable O&M cost of $1.10/MWh	10,500 Btu/KWh of Combustion turbine with variable O&M cost of $3.30/MWh
Nov 2002 – Oct 2003	$111,467	$31,695
Nov 2003 - Oct 2004	$52,987	$11,128
Nov 2004 – Oct 2005	$95,181	$28,064
Nov 2005 - Oct 2006	$45,093	$10,181
Nov 2006 – Oct 2007	$61,257	$15,151
Average	$73,197	$19,244

5. *Imports and Exports*

5.1 Overview

Table 1-31 reports monthly net exports for on-peak, off-peak, and all hours over the last two summer periods. Total net exports declined by approximately 640 GWh in the

[32] FERC assumes US$1/MWh for the more efficient combined cycle unit and US$3/MWh for the less efficient combustion turbine. To translate the numbers to Canadian dollars, we presume an exchange rate of US$1=CND$1.1, which is close to the average over the last twelve months (although there has been a dramatic appreciation in the $CDN relative to the $US since September 2007) and consistent with the calculations performed in previous MSP reports.

[33] Net revenue is earned on the portion of revenue above the generator's assumed strike price. The generator is assumed to be online in all hours when the HOEP is larger than the strike price.

[34] The FERC numbers reported represent the best estimates of what is required to cover all costs associated with constructing and operating a new gas-fired generation unit by efficiency type.

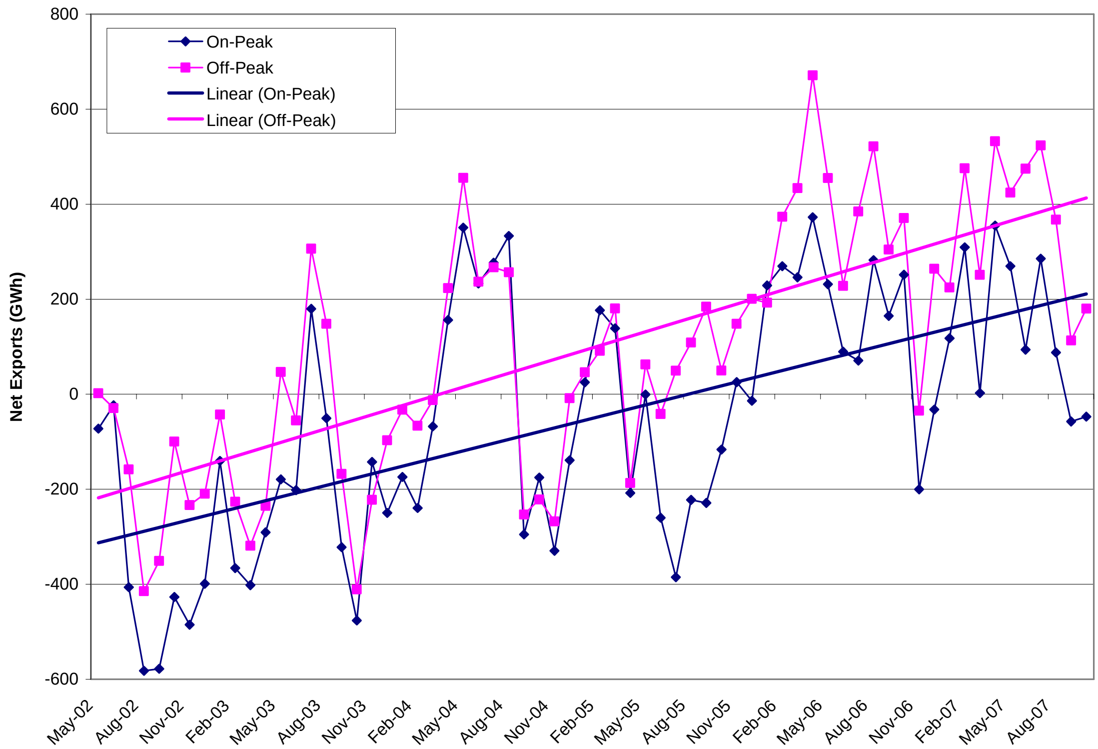
summer of 2007 compared to 2006. The majority of the decline occurred during the on-peak hours and were due to increased imports. Net exports increased during the first three summer months compared to 2006 and declined in the later three months coinciding with the rapid appreciation of the Canadian dollar relative to its US counterpart (as described more fully in section 5.4.2 below).

Table 1-31: Net Exports from Ontario On-Peak and Off-Peak, May – October 2006 & 2007 (GWh)

	Off-Peak			On-Peak			Total		
	2006	**2007**	**% Change**	**2006**	**2007**	**% Change**	**2006**	**2007**	**% Change**
May	455	424	(6.8)	231	270	16.9	686	694	1.2
June	227	475	109.3	90	94	4.4	318	568	78.6
July	384	524	36.5	71	285	301.4	455	809	77.8
August	522	367	(29.7)	282	88	(68.8)	804	455	(43.4)
September	305	113	(63.0)	165	(58)	(135.2)	469	55	(88.3)
October	371	180	(51.5)	252	(47)	(118.7)	623	133	(78.7)
Total	2,264	2,083	(8.0)	1,091	632	(42.1)	3,355	2,714	(19.1)
Average	377	347	(8.0)	182	105	(42.3)	559	452	(19.1)

Figure 1-30 plots the long-term trends in on-peak and off-peak net exports. Although Ontario was typically a net importer when the market first opened due to the tight supply conditions, net exports have been gradually increasing, although on-peak net exports fell below zero (i.e. represented net imports) over the last two months of the current summer period. This was mainly due to increased nuclear outages at the end of the summer forcing Ontario to be more dependent on imports.

Figure 1-30: Net Exports, On-peak and Off-peak, May 2002 - October 2007 (GWh)



5.2 Congestion

Tables 1-32 and 1-33 report the number of occurrences of import and export congestion by month for the May to October 2006 and 2007 periods. Total import congestion increased this summer from 676 hours in 2006 to 769 hours in 2007 representing an increase of 14 percent. Export congestion hours increased dramatically from 753 hours in 2006 to 1,650 in 2007.

Examining the monthly import and export congestion values indicates that, as would be expected, the frequency of congested hours and the direction of flows appear to correspond to the substantial appreciation of the Canadian/US dollar exchange rate towards the end of the current period.

Import congestion in total started the period quite low, being much lower than the previous year's frequency in May and June. As the period progressed and the Canadian dollar appreciated against the US dollar, congestion frequency grew, exceeding the previous year's values with the frequency for October 2007 nine times larger than in October 2006. The most significant changes in import congestion occurred at the Michigan and Minnesota interties. Import congestion decreased during the first 3 or 4 months of the period and dramatically increased during the last three months, coinciding with the appreciating dollar.

Similarly, as shown in Table 1-33, the current six-month period saw export congested hours increase relative to last year. This was due almost entirely to increases in exports to the US in the first three months across all interfaces.[35] However consistent with the appreciating Canadian dollar, export congestion declined relative to these first few months on all interties and fell below last year's values during September and October.

Table 1-32: Import Congestion in the Market Schedule, May – October 2006 & 2007 (Number of Hours)

	NY to ON		MI to ON		MB to ON		MN to ON		QC to ON		Total	
	2006	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
May	8	4	19	0	0	2	112	1	8	2	147	9
June	0	0	33	1	9	11	243	8	0	16	285	36
July	0	0	0	3	2	2	4	29	43	26	49	60
August	1	11	0	5	4	8	46	123	4	6	55	153
September	0	0	0	122	3	7	95	14	2	0	100	143
October	0	0	8	64	0	6	26	297	6	1	40	368
Total	9	15	60	195	18	36	526	472	63	51	676	769

[35] It is important to note that many exports we report as heading to Quebec are in fact wheel-though transactions to the U.S.

Table 1-33: Export Congestion in the Market Schedule,
May – October 2006 & 2007
(Number of Hours)

	ON to NY		ON to MI		ON to MB		ON to MN		ON to QC		Total	
	2006	2007	2006	2007	2006	2007	2006	2007	2006	2007	2006	2007
May	66	32	2	39	0	1	2	26	16	321	86	419
June	10	149	0	11	0	0	2	4	10	92	22	256
July	37	247	0	5	0	0	10	108	2	159	49	519
August	194	146	5	14	0	0	15	35	0	34	214	229
September	163	83	0	3	0	0	16	0	45	41	224	127
October	105	91	0	1	0	0	3	1	50	7	158	100
Total	575	748	7	73	0	1	48	174	123	654	753	1,650

Figures 1-31 and 1-32 presents import and export congested hours respectively as a percentage of total congested hours by intertie over the 2007 summer months. Figure 1-31 shows that majority of import congestion (61 percent) occurred over the Minnesota intertie. In many hours, imports from Manitoba are unable to enter the province due to excess supply in the Northwest. Transmission constraints limit the amount of energy that can be moved from the Northwest to the rest of the province, which is reflected in the negative shadow price observed in Table 1-21. On the other hand, the majority of the export-congested hours during the summer were destined to New York and Quebec (85 percent combined). Export-congested hours to Quebec were abnormally high during the first half of the summer for two reasons. First, with attractive off-peak prices in Ontario (especially May), there was strong competition for energy leading to the tie being congested. Secondly, there was a transformer refurbishment procedure performed on H4Z forcing the line to be export limited to 40 MW (down from 85 MW) and therefore vulnerable to congestion.

Figure 1-31: Import Congestion in the Market Schedule by Intertie, May 2007 – October 2007 (Percentage of Congested Hours)

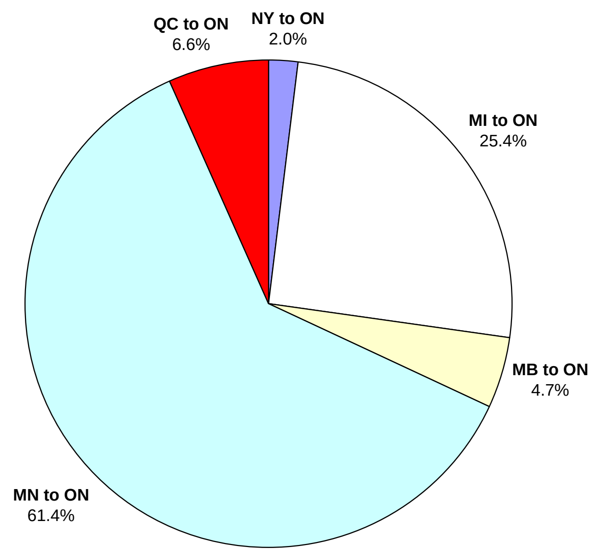
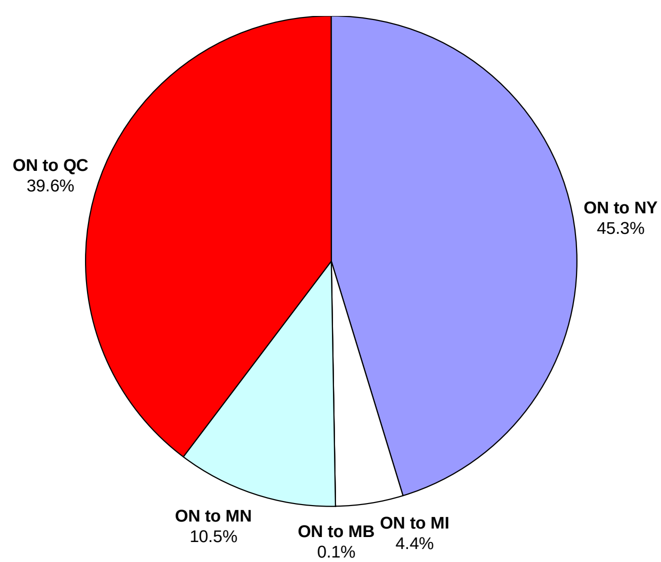


Figure 1-32: Export Congestion in the Market Schedule by Intertie, May 2007 – October 2007 (Percentage of Congested Hours)



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

In the last report, the Panel introduced a revised econometric model to analyse the determinants of the volume of export flows between Ontario and New York, which continues to be our largest export destination.[36] Developed by the IESO, the reduced form structural model tests the hypothesis that exports from Ontario to New York are an increasing function of the differential between the New York and Ontario energy prices, after controlling for seasonal and other factors that vary from month to month and over time.[37]

We re-estimate the model using monthly data covering the period January 2003 to October 2007 (58 observations) and provide separate estimates for the on-peak and off-peak hours. Coefficient estimates are reported in Table 1-34. The results indicate that the differential between the Ontario and New York prices is influential on the level of exports from Ontario to New York. Both the HOEP and New York prices have the expected coefficient signs; a negative sign for the coefficient associated with the HOEP and a positive sign for the New York price coefficient.

[36] Between May and October 2007, over 70 percent of exports were destined for New York.
[37] The model is estimated using the two-stage least squares method. First stage instruments include Ontario non-dispatchable demand, nuclear output, self-scheduler output, New York load and the price of natural gas.

Table 1-34: Export Model Estimation Results, January 2003 – October 2007

Variable	All Hours		On-peak		Off-peak	
	Coef.	**S.E.**	**Coef.**	**S.E.**	**Coef.**	**S.E.**
Constant	3.94	0.00	2.21	0.05	5.12	0.00
Log(HOEP)	-4.27	0.00	-6.58	0.00	-2.18	0.06
Log(New York Price)	4.74	0.00	7.43	0.00	2.46	0.02
January	0.22	0.18	0.27	0.24	-0.02	0.86
February	0.19	0.32	0.02	0.95	0.12	0.32
March	0.13	0.38	-0.01	0.96	0.04	0.80
April	-0.01	0.97	-0.04	0.89	-0.19	0.20
May	0.22	0.28	0.13	0.65	0.07	0.73
June	0.35	0.07	0.54	0.03	-0.02	0.91
July	0.10	0.51	0.29	0.29	-0.22	0.40
August	-0.11	0.64	-0.18	0.56	-0.27	0.36
September	0.04	0.74	-0.11	0.73	-0.23	0.11
October	-0.34	0.19	-0.22	0.45	-0.58	0.05
November	-0.01	0.96	-0.05	0.76	-0.15	0.33
Time Trend	0.01	0.15	0.01	0.34	0.01	0.03
Model Diagnostics						
Correlation between actual and fitted values	0.79		0.78		0.73	
Number of observations	58		58		58	

The model is estimated in logarithmic form so the coefficient estimates can be interpreted as elasticities. The elasticity of exports with respect to the HOEP over all hours is estimated as minus 4.27, implying a one percent increase in the HOEP leads to a 4.27 percent decline in exports to New York (and vice versa), all other things held constant. Alternatively, the coefficient estimate for the New York price over all hours is 4.74, meaning a one percent increase in the New York price will lead to a 4.74 percent increase in exports destined for New York. Coefficient estimates for the on-peak and off-peak hours show that exports are more responsive to changes during the on-peak hours given the larger magnitude of the estimates.

5.4 Wholesale Electricity Prices in Neighbouring Markets

5.4.1 Price Comparisons

In the last Panel report we observed that for the first time prices in Ontario dropped below those of all neighbouring markets, although marginal costs (as represented by the Richview shadow price) suggested that Ontario production costs were not the lowest.

In Table 1-35 we observe once again that the six-month average HOEP prices for Ontario are lower than market prices in the 4 main nearby markets, in both off-peak and on-peak periods and in aggregate. Up to about one year ago MISO exhibited the lowest prices relative to all surrounding jurisdictions. However in the current period, MISO prices are about 10 percent higher than in Ontario. PJM's prices were the highest, about 50 percent above Ontario prices on average.

Table 1-35: Average HOEP Relative to Neighbouring Market Prices, May 2007 - October 2007 ($CDN/MWh)

	Off-Peak	On-peak	Total
Ontario	33.82	59.51	45.66
MISO	36.27	68.64	50.95
New England	57.26	75.90	65.72
New York	40.86	67.81	53.12
PJM	51.13	84.61	66.02
Average	43.87	71.29	56.29

Figures 1-33 to 1-35 compare the Ontario HOEP with the appropriate zonal prices in neighbouring jurisdictions on a monthly basis between May and October 2007 for all hours, on-peak hours, and off-peak hours respectively. Ontario tends to be the lowest price market in almost all months. However, MISO had lower prices on-peak in September and October, and off-peak in June, July, and September. New York prices were lower only in the May off-peak period.

Figure 1-33: Average Monthly HOEP Relative to Neighbouring Market Prices, May 2007 – October 2007 ($CDN/MWh)

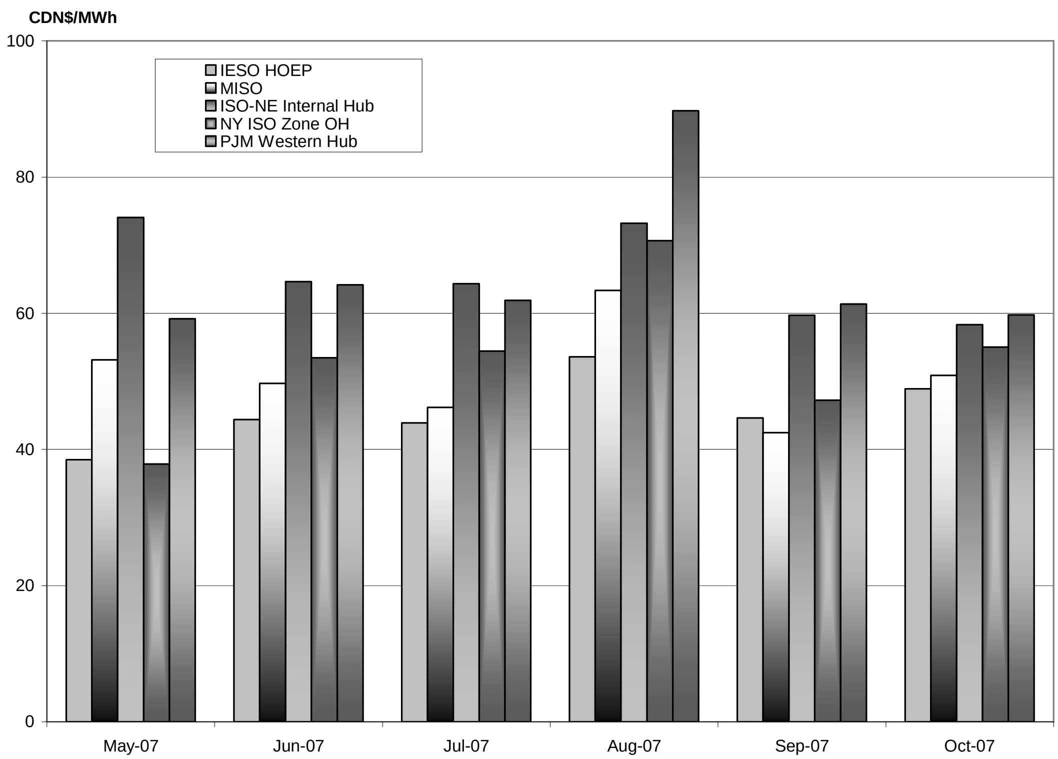


Figure 1-34: Average Monthly HOEP Relative to Neighbouring Market Prices, On-Peak,
May 2007 – October 2007
($CDN/MWh)

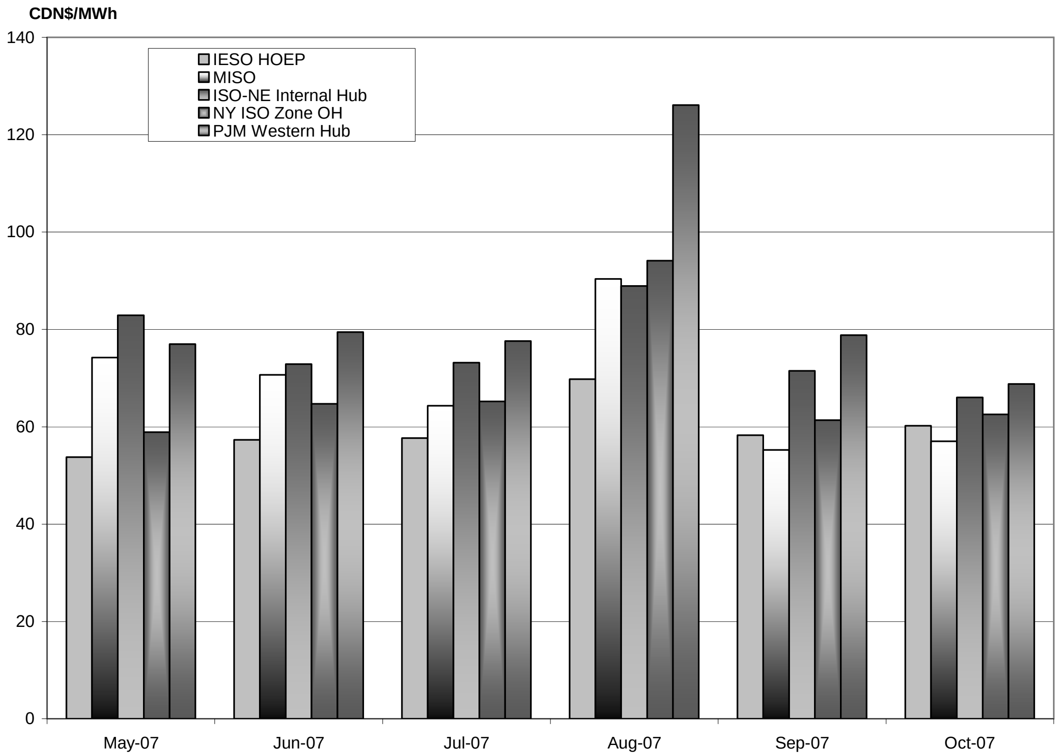


Figure 1-35: Average Monthly HOEP Relative to Neighbouring Market Prices, Off-Peak, May 2007 – October 2007 ($CDN/MWh)

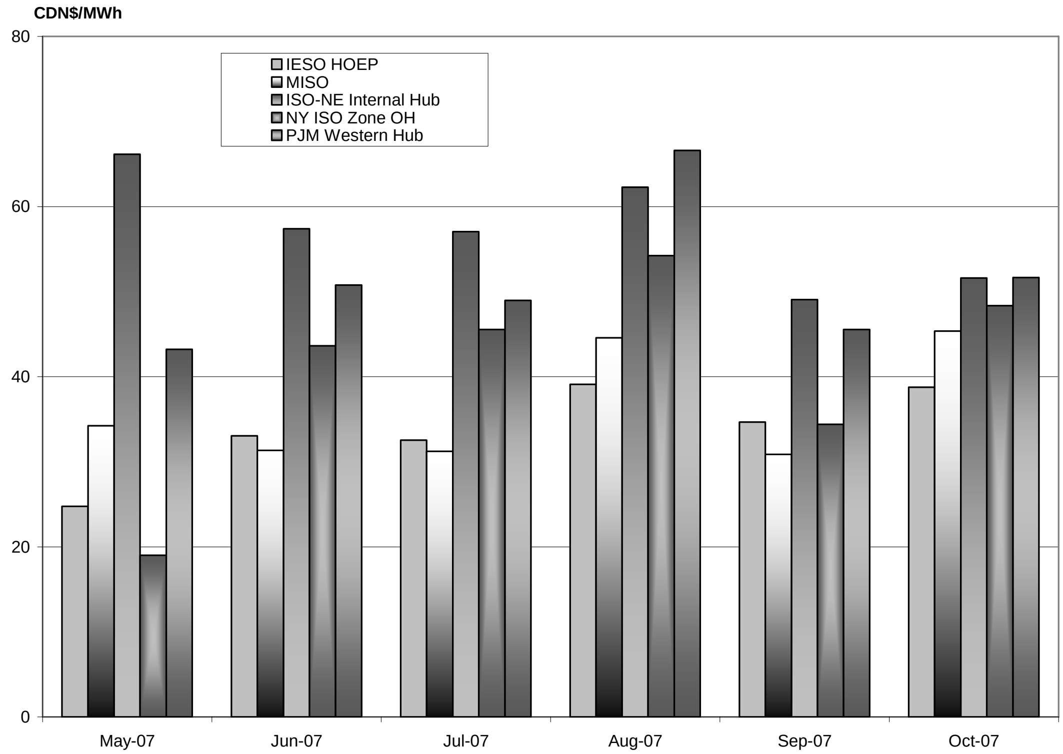
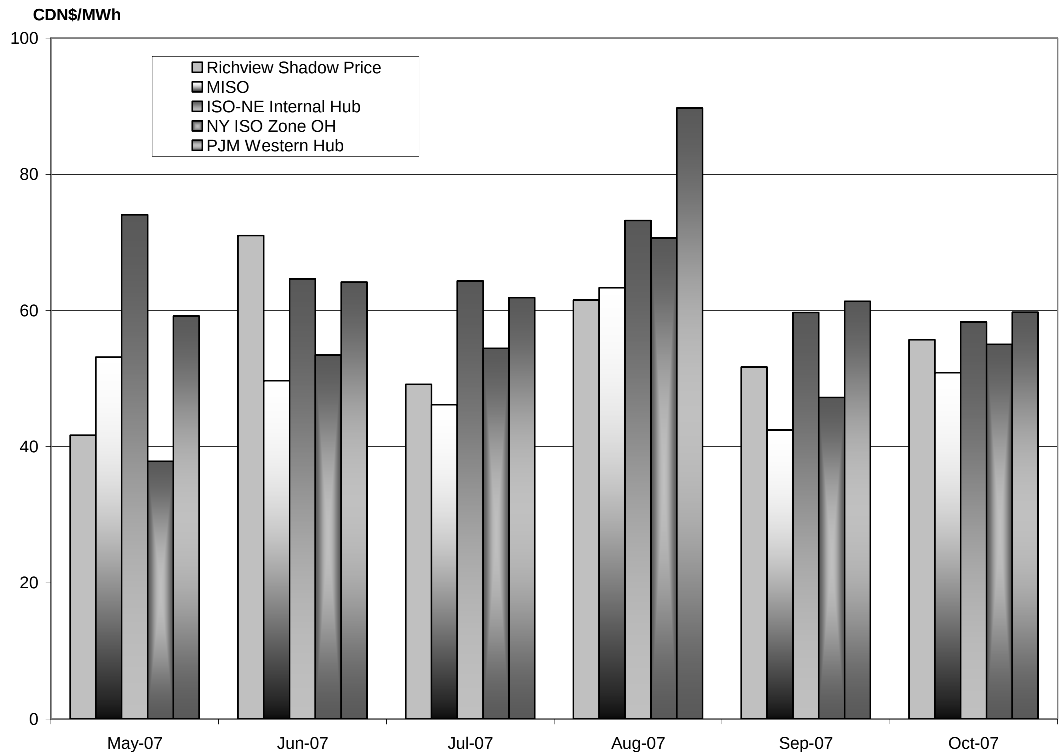


Figure 1-36 compares Richview shadow prices to neighbouring market prices, similar to Figure 1-33. However, because of the higher shadow prices, Ontario's marginal production costs appear to be more expensive than MISO for four months (June, July, September, and October) and more expensive than New York for four months (May, June September, and October). By this measure Ontario is one of the lower production cost markets, but not the lowest in any month of the period.

Figure 1-36: Average Richview Shadow Price Relative to Neighbouring Markets, May 2007 – October 2007 ($CDN/MWh)

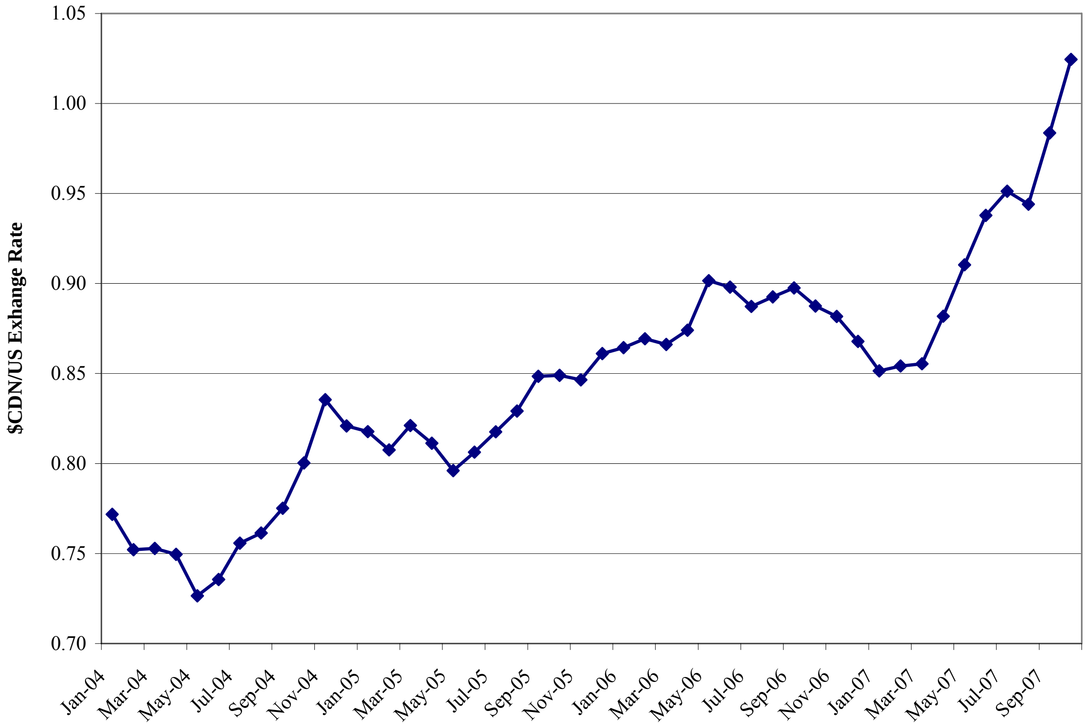


5.4.2 Exchange Rate Effects and Trade Flows

As discussed earlier in the Chapter, there has been a substantial appreciation in the Canadian dollar relative to the US dollar over the past summer and especially in September and October. Figure 1-37 illustrates the increase in the monthly average Canadian/US dollar exchange rate since January 2004.[38] The figure shows a gradual appreciation of the Canadian dollar since early 2004. More recently, between January and October 2007 the average monthly Canadian /US dollar exchange rate increased from approximately $0.85 to $1.02 or 20 percent. Similarly, the exchange rate has increased by approximately 13 percent since May 2007, which represents the first month of the current summer period. The average exchange rate for the six-month summer period has increased from $0.89 to $0.96, or 8 percent.

[38] The monthly exchange rate is calculated by averaging the Bank of Canada's daily noon spot rate available at http://www.bank-banque-canada.ca/en/rates/exchange.html.

Figure 1-37: Monthly Average $CDN/US Exchange Rate, January 2004 – October 2007



In addressing the question of whether this change in the exchange rate has affected imports and exports, the Panel has noted there are two factors to consider: the direct impact on traders transacting between two jurisdictions with different currencies; and the indirect impact of fuel prices in Ontario relative to the US energy markets.

Consider first what traders would experience from an increase in the exchange rate assuming the market energy prices in the local currencies had not changed last year to this year. Taking an on-peak example, if the US energy price were US$62.30/MWh and the Ontario price were CDN$70/MWh in both years, at a $0.89 exchange rate, the Ontario price would be equivalent to the US price. There would be little motivation for any trade. As the exchange rate increased to $0.96, the Ontario price would now be US$67.20/MWh, which is significantly higher that the US energy price (given both are assumed unchanged). At these average prices, there is more opportunity for trade, primarily imports to Ontario. Therefore, a change in the exchange rate creates arbitrage opportunities for export and import transactions.

However, the exchange rate should also affect energy prices in the two countries. Generators that rely on natural gas to produce energy are very sensitive to large changes in the price of natural gas. Table 1-36 reports the monthly average Henry Hub spot market price for the May to October 2006 and 2007 periods in both US and Canadian dollars. Table 1-37 reports similar Canadian and US dollar prices for Central Appalachian coal.

Table 1-36: $CDN and $US Henry Hub Spot Market Price Comparison, May – October 2006 & 2007 ($/MMBtu)

	$CND			$USD			Exchange Rate		
	2006	2007	% Change	2006	2007	% Change	2006	2007	% Change
May	6.92	8.39	21.2	6.21	7.64	23.0	0.90	0.91	1.0
June	6.94	7.82	12.7	6.26	7.34	17.3	0.90	0.94	4.4
July	6.91	6.54	(5.4)	6.12	6.22	1.6	0.89	0.95	7.2
August	8.03	6.64	(17.3)	7.17	6.27	(12.6)	0.89	0.94	5.8
September	5.62	5.61	(0.2)	4.86	5.44	11.9	0.90	0.98	9.6
October	6.66	6.56	(1.5)	5.75	6.72	16.9	0.89	1.02	15.4
Average	6.85	6.93	1.2	6.06	6.61	9.0	0.89	0.96	7.2

Table 1-37: $CDN and $US NYMEX OTC CAPP Coal Market Price Comparison, May – October 2006 & 2007 ($/MMBtu)

	in $CND			in $USD			Exchange Rate		
	2006	2007	% Change	2006	2007	% Change	2006	2007	% Change
May	2.36	2.00	(15.3)	2.13	1.82	(14.6)	0.90	0.91	1.0
June	2.32	2.07	(10.8)	2.08	1.94	(6.7)	0.90	0.94	4.4
July	2.18	1.93	(11.5)	1.94	1.84	(5.2)	0.89	0.95	7.2
August	2.22	1.90	(14.4)	1.98	1.79	(9.6)	0.89	0.94	5.8
September	2.12	1.88	(11.3)	1.9	1.81	(4.7)	0.90	0.98	9.6
October	2.02	1.89	(6.4)	1.79	1.94	8.4	0.89	1.02	15.4
Average	2.20	1.95	(11.7)	1.97	1.86	(5.8)	0.89	0.96	7.2

These data demonstrate gas prices barely increased on average in Ontario while they increased 9 percent in US dollars. Similarly US coal price dropped almost 6 percent but the price in Ontario went down 12 percent. This means that Ontario generators have seen lower or stable input costs, while US generators have seen price increases for natural gas and smaller price reductions for coal. In other words, when the Canadian dollar is strong it takes 'less Canadian dollars' to get to the same fuel as the weaker US dollar.

If fuel price were the only factor affecting market price, then US market prices would have risen somewhat in US dollars to reflect increasing fuel prices (with possibly some off-peak moderation in price based on coal prices) while Ontario prices should have remained stable or fallen in Canadian dollars.

Exchange rate has two offsetting effects. It increases the US cost of purchasing Ontario energy (or increases the value of selling into Ontario), but it would also tend to reduce the Ontario market prices relative to the US markets because the fuel costs are lower, theoretically by the same amount, all else held constant.

Market prices are driven by other factors as well, and we would not expect spot fuel price changes or exchange rate fluctuations to change offer prices on a direct pro-rata basis either immediately or over time. But the tendency for the exchange rate alone as a driver to increase imports and reduce exports would seem to be muted by the compensating impact on fuel price and in turn market price.

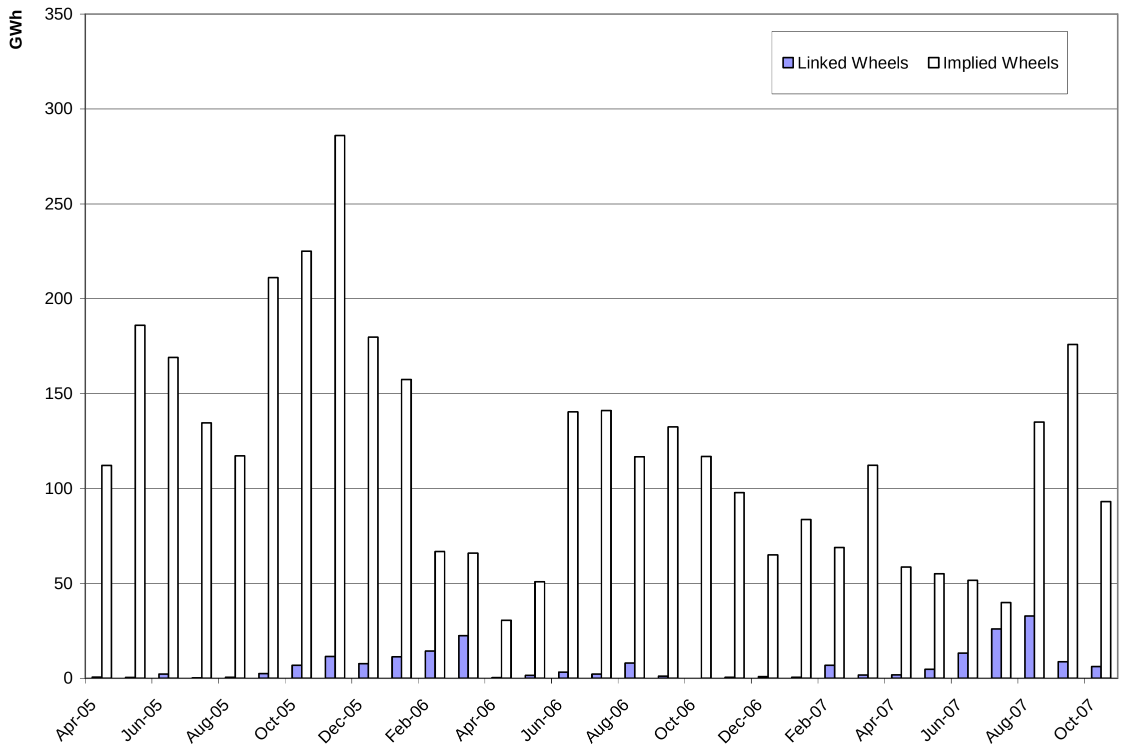
5.4.3 Linked Wheel-through Transactions

A wheel-through transaction occurs when a market participant moves energy from one jurisdiction to another through the IESO-controlled transmission grid. These can be implied wheels, with no identified relationship between an import and export, or a market participant can specifically identify the transaction as a "linked wheel" through the NERC eTag. If either leg of the linked wheel is prevented from flowing, the other leg must also be cut. Ontario receives a fixed $/MWh payment on the export side of a linked-wheel transaction in order to compensate for using the province's transmission infrastructure.

Figure 1-38 below shows the total monthly volume of linked wheel-through transactions and implied-wheel through transactions since April 2005.[39] The total monthly quantity of linked wheel-through transactions through Ontario has historically been below 15 GWh prior to the summer of 2007 and in many months below 5 GWh. Between June and August 2007, linked wheeled-transaction quantities dramatically increased and reached a peak monthly total of 32.9 GWh in August. Traders appear to have identified arbitrage opportunities between other jurisdictions that require them to move energy through Ontario to fulfill their delivery obligations.

[39] This start date was chosen because on April 1, 2005, the Midwest ISO launched its Midwest Energy Markets and began centrally dispatching wholesale electricity and transmission service throughout the jurisdiction.

Figure 1-38: Quantity of Linked and Implied Wheel-through Transactions,April 2005 – August 2007 (GWh)



Although the quantity of linked wheel-through transactions has increased over the past few months, they make up a small proportion of total Ontario imports and exports. For example, during the peak month of August 2007, linked wheel-through transactions accounted for 5.4 percent of total imports and 3.1 percent of total exports.

Chapter 2: Analysis of Market Outcomes

1. *Introduction*

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

The MAU monitors high and low priced hours and any other events that appear to be anomalous, even though they may not meet bright-line price tests, and reports its findings to the Panel. The Panel believes the explanation of these types of events provides transparency on why certain outcomes occur in the market and leads to learning by all market participants.

On a daily basis, the MAU reviews the previous day, not only to discern anomalous events but also to review:

- apparent changes in bid strategies;
- the impact of forced outages and extended planned outages;
- import/export arbitrage opportunities;
- the appropriateness of uplift payments; and
- the application of IESO procedures.

In addition to identifying anomalous events, such reviews may lead to identification of inappropriate market incentives that lead to inefficiencies.

The MAU reviews all high priced hours to identify the critical factors leading to the high prices and reports its findings to the Panel. For the purpose of this report, high priced hours are defined as all hours in which the HOEP was greater than $200/MWh or in which the hourly uplift exceeded the HOEP. In addition, the MAU reviews all low priced hours and reports its findings to the Panel. For the purpose of this review, a low priced hour is defined as any hour in which the HOEP was less than $20/MWh.[40]

With respect to high priced hours, there were four hours during the review period May 2007 through October 2007 in which 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. There were also three hours during the review period in which the hourly uplift exceeded the HOEP. The Panel has observed that the increasing frequency with which uplift exceeds the HOEP is not because the uplift is unusually high but because the HOEP is very low. This raises the question of whether the observation that the uplift exceeds the HOEP remains a useful indicator of uplift anomalies. The Panel has asked the MAU to explore the possibility of developing a more useful indicator of anomalous uplifts.

In this review period there were 331 hours in which the HOEP was less than $20/MWh including one hour in which 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 its review and analysis of high-priced and low-priced hours and other anomalous events, the MAU did not find any event which suggested that there was gaming or abuse of market power by any market participant Nevertheless, we do have recommendations for the IESO and Hydro One which are intended to improve market efficiency.

2. *Anomalous HOEP*

2.1 Analysis of High Priced Hours

The MAU regularly reviews all hours where the HOEP exceeds $200/MWh and where the hourly uplift exceeds the HOEP. The objective of this review is to understand the underlying causes that led to these prices and determine whether any further analysis of

[40] $200/MWh is typically an upper bound for the cost of a fossil generation unit. $20/MWh is a lower bound for the cost of a fossil unit.

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 and the total number of hours with an uplift greater than the HOEP from May to October 2007, with comparative data for the same period in 2006. The number of hours with HOEP greater than $200/MWh was smaller in 2007 than in 2006, while the number of hours with an uplift exceeding the HOEP remained the same. In both periods, the total number of high-priced hours is quite low, representing close to 0.1 percent of total hours of operation. This frequency of high-priced hours is a marked decrease from the period just after market opening, when high-priced hours represented almost 1.3 percent of total hours in first six months.

Hours when uplift exceeds HOEP are of potential concern because uplift is calculated after the fact and is thus less transparent to the market. That is, potentially price-responsive loads do not see the uplift and, because it can be volatile at times, cannot take it into account when making their consumption decisions. The greater uplift is relative to the HOEP, the less accurate is the HOEP as a signal of the incremental cost of supply or the incremental value of consumption. Hours in which the uplift is well in excess of its usual magnitude may also imply problems in market design or operation and thus merit further examination.

Table 2-1: Hours with a High HOEP and Uplift greater than HOEP, May - October, 2006 & 2007 (Number of Hours)

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

In our previous reports, we noted that a HOEP greater than $200/MWh typically occurs in hours when one or more of the following occurs:

- real-time demand is much higher than the pre-dispatch forecasts 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.

2.1.1 June 8, 2007 HE 12

Prices

The HOEP in this hour reached $204.72/MWh. Table 2-2 shows the real-time energy and OR prices and the one-hour ahead pre-dispatch prices for HE 11 – 13. While pre-dispatch prices were moderate, the real-time MCP began to increase late in HE 11 and near the end of HE 12 was as high as $350/MWh.[41] At the same time, the real-time OR

[41] The Richview nodal price reached $1,299.90 when the MCP peaked.

prices jumped and stayed at or above $30/MWh. The 10 minute spinning reserve price peaked at $104.51/MWh just before the end of HE 12 when the MCP was at its highest. The interval prices and HOEP fell to about $135/MWh in HE 13, which was still roughly $54/MWh higher than the pre-dispatch run had projected.

Table 2-2: Real-Time and One-Hour Ahead Pre-dispatch Prices, Energy and OR, June 8, 2007, HE 11 to HE 13

($/MWh)

Delivery Hour	Interval	Pre-dispatch				Real-Time				Difference in MCP
		10N	10S	30R	MCP	10N	10S	30R	MCP	
11	1	0.43	0.43	0.43	72.42	0.43	0.43	0.43	70.36	-2.06
11	2	0.43	0.43	0.43	72.42	0.43	0.43	0.43	72.42	0.00
11	3	0.43	0.43	0.43	72.42	0.43	0.43	0.43	72.42	0.00
11	4	0.43	0.43	0.43	72.42	0.43	0.43	0.43	72.42	0.00
11	5	0.43	0.43	0.43	72.42	0.43	0.43	0.43	76.12	3.70
11	6	0.43	0.43	0.43	72.42	0.43	0.43	0.43	76.12	3.70
11	7	0.43	0.43	0.43	72.42	0.44	0.44	0.44	76.24	3.82
11	8	0.43	0.43	0.43	72.42	0.44	0.44	0.44	76.24	3.82
11	9	0.43	0.43	0.43	72.42	2.00	2.00	2.00	86.68	14.26
11	10	0.43	0.43	0.43	72.42	22.53	22.53	22.53	107.33	34.91
11	11	0.43	0.43	0.43	72.42	29.95	29.95	29.95	120.26	47.84
11	12	0.43	0.43	0.43	72.42	22.53	22.53	22.53	107.33	34.91
12	1	0.43	4.88	0.43	73.00	30.00	45.01	30.00	127.13	54.13
12	2	0.43	4.88	0.43	73.00	30.00	45.01	30.00	154.66	81.66
12	3	0.43	4.88	0.43	73.00	30.00	45.01	30.00	140.00	67.00
12	4	0.43	4.88	0.43	73.00	30.10	45.11	30.00	154.78	81.78
12	5	0.43	4.88	0.43	73.00	30.00	45.01	30.00	154.66	81.66
12	6	0.43	4.88	0.43	73.00	30.01	45.01	30.00	154.67	81.67
12	7	0.43	4.88	0.43	73.00	30.10	45.11	30.00	154.78	81.78
12	8	0.43	4.88	0.43	73.00	75.00	91.83	74.90	241.95	168.95
12	9	0.43	4.88	0.43	73.00	75.00	91.83	74.90	241.95	168.95
12	10	0.43	4.88	0.43	73.00	75.00	104.51	74.90	350.12	277.12
12	11	0.43	4.88	0.43	73.00	75.00	104.51	74.90	350.12	277.12
12	12	0.43	4.88	0.43	73.00	75.00	91.83	74.90	231.83	158.83
13	1	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.68	53.68
13	2	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80
13	3	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.68	53.68
13	4	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.68	53.68
13	5	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80
13	6	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80
13	7	0.43	12.88	0.43	81.00	30.00	45.01	30.00	124.80	43.80
13	8	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80
13	9	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80
13	10	0.43	12.88	0.43	81.00	30.00	45.01	30.00	145.12	64.12
13	11	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80
13	12	0.43	12.88	0.43	81.00	30.00	45.01	30.00	134.80	53.80

Day-ahead Conditions

June 8 was expected to be a normal day with a peak demand of about 21,000 MW in HE 15. For HE 12, the forecast demand was about 20,600 MW. The Day-Ahead Commitment Process (DACP) scheduled most of the available fossil units to meet the anticipated peak demand. No imports were scheduled in DACP since the domestic supply was economic and sufficient to satisfy the forecast Ontario demand.

Baseload supply was significantly affected by long-term planned and forced outages of several nuclear and fossil units. In total, the unavailable baseload capacity amounted to as much as 3,900 MW. These outages were all known day-ahead and were expected to continue on June 8^{th}.

Final Pre-dispatch Conditions

In the final pre-dispatch run, the one-hour ahead Ontario demand for HE 12 was forecast at 21,300 MW, with a projected price of $73/MWh. The one-hour ahead forecast was about 700 MW heavier than forecast day-ahead. There were 1,120 MW of exports and 801 MW of imports scheduled in the unconstrained schedule. The pre-dispatch schedule had 936 MW being offered between $73/MWh and $350/MWh. The majority of these offers were from peaking hydro units, which were also supplying operating reserve. The pre-dispatch supply cushion was 3.4 percent.

With the absence of 3,900 MW of inframarginal supply in pre-dispatch, the pre-dispatch price reflected the cost of gas-fired generation which set the price. The small supply cushion and the moderate pre-dispatch price imply that the offer curve was very steep on the right side of the demand curve. Under these conditions, a small forced outage (including an import failure) or a slight under-forecast of demand could lead to a spike in the real-time price.

<u>Real-time conditions</u>

After the final pre-dispatch run, 126 MW of imports from Michigan failed due to security problems in MISO. As well, at 10:38 (HE 11 Interval 8), a baseload fossil-fired generator was derated by 85 MW. The total loss of supply amounted to 211 MW.

In real-time, demand came in heavier than expected. Average demand in HE 12 was 21,655 MW while peak demand in the hour occurred in interval 11 and totalled 21,833 MW, or 533 MW (2.5 percent) greater than forecast one hour earlier (which was about 1,200 MW (5.8 percent) greater than forecast day-ahead).

In total, the excess of actual over expected demand plus the lost supply (including failed imports) amounted to 744 MW in the hour, implying the DSO needed to dispatch more peaking generation to meet the demand. The real-time supply cushion dropped to -0.9 percent, implying that CAOR was being used to provide operating reserve.[42] In fact, CAOR was scheduled in all intervals to supply between 200 MW and 500 MW of ten minute non-spinning and 30 minute reserve and CAOR set the operating reserve prices.

The effect of demand coming in heavy and supply being lost was to push the HOEP to $204.72/MWh for the hour. There is no indication that the import failure and the loss in domestic supply involved inappropriate behaviour.

2.1.2 <u>June 12, 2007</u>

On this day, HOEP peaked at $436.53/MWh in HE 15. Besides the high price in the hour, the day of June 12 is itself of interest because the IESO used almost all the available tools to maintain reliability including:

- cutting exports;
- purchasing emergency energy;
- curtailing dispatchable loads;

[42] The real-time supply cushion does not include CAOR as a resource as it is not a real generation resource and does not help system reliability. Including CAOR as supply would gradually increase the supply cushion as more CAOR is introduced which would distort the true supply/demand situation in the marketplace. Therefore, a negative real-time supply cushion means there are fewer resources than the Ontario demand plus operating reserve, indicating the CAOR is used to provide OR.

- activating OR; and
- making a 5 percent voltage cut.

The CMSC for the day amounted to $3 million, in contrast with $0.2 million - $0.5 million in a normal weekday.

2.1.2.1 June 12, 2007: Events of the day

Day-Ahead Conditions

Going into June 12th, there were 4,400 MW of inframarginal nuclear and fossil generation on planned or forced outages.

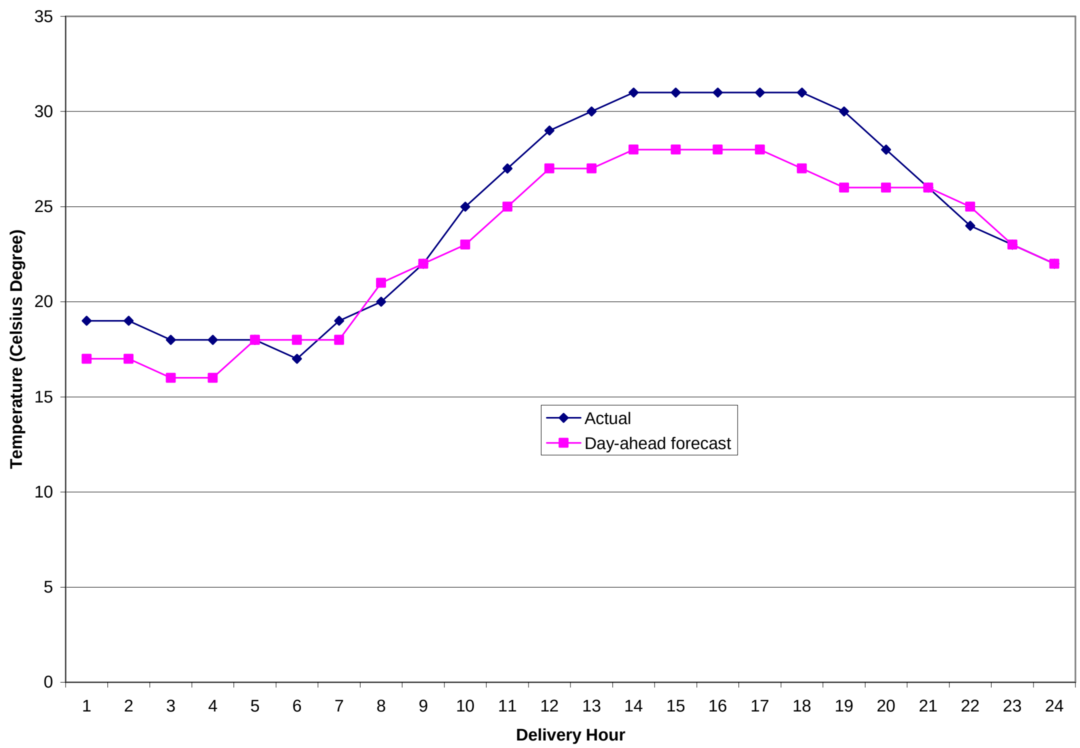
The Ontario demand forecast for the day at the time of the DACP run (June 11, 2007 HE 15 for June 12, 2007) was moderate with a daily peak demand of 21,796 MW expected in HE 16. The forecast (peak) demand for HE 15 was 21,569 MW, with a price projected at about $120/MWh. The IESO scheduled 3,540 MWh of imports, from a total of 10,000 MWh offered, as well as 5,500 MWh from 22 dispatchable coal and gas-fired generators for the peak hour by providing DA-IOG or DA-GCG guarantees through the DACP. All generators and imports that had been scheduled in the DACP showed up on time, unless otherwise approved by the IESO to withdraw from the DACP.

Real-Time Conditions

While the DACP predicted a ‘normal’ day with sufficient supply, the real-time demand in peak hours turned out to be 1,000 to 1,500 MW higher than expected day-ahead. The peak Ontario demand of 23,273 MW in HE 16 was about 1,500 MW (or 6.78 percent) higher than forecast day-ahead. It appears that the reason for this is that the temperature on the day was significantly under-forecast day ahead and revisions were too little and too late. Beginning in HE 8, the demand grew much faster than expected as the temperature continued to increase. Figure 2-1 shows the comparison of hourly actual and forecast day-ahead temperature. For the afternoon peak hours, the temperature was 3ºC to

4ºC under-forecast, which is equivalent to a demand under-forecast of about 1,200 MW to 1,600 MW.

Figure 2-1: Temperature: Day-ahead Forecast vs. Actual for June 12, 2007 (Degrees Celsius)

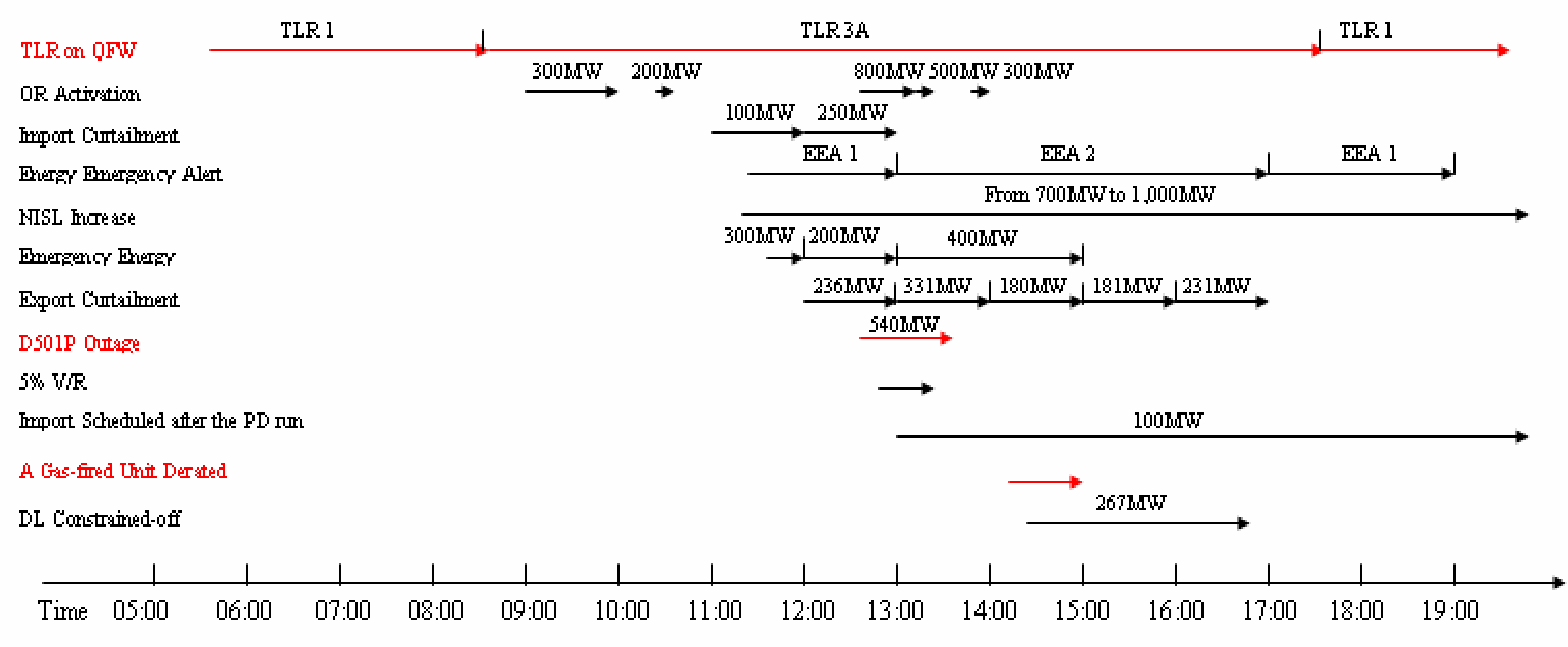


<u>Supply Changes and IESO Responses</u>

On the supply side, the B31L line (one of the main interfaces with Quebec) was de-rated from 390 MW to 200 MW for HE 11 to HE 13 due to transmission limitations in Quebec. This reduced the availability of imports and emergency energy from Quebec. In addition, 50 MW of imports on the P33C line that were scheduled in the DACP were curtailed in HE 15 by HQ for its own security.

The IESO took a series of control actions to deal with the unexpectedly high-demand. These actions are explained below and also summarized in Figure 2-2.

Figure 2-2: Major Events and the IESO's Actions, June 12, 2007



Beginning in the early morning (at 05:35), a TLR 1[43] (Transmission Loading Relief) was issued by the IESO on the Queenston Flow West (QFW) flowgate.[44] QFW normally carries the power produced by Ontario's Niagara area generation, imports and inadvertent loop flows, the latter often referred to as Lake Erie Circulation (LEC). LEC can be clockwise or counter-clockwise, although in recent years it has most often been counter-clockwise. On June 12 a large counter-clockwise loop-flow, which ranged from 600 to 800 MW in peak hours, consumed a large proportion of QFW capability leading to it becoming overloaded and the IESO declaring a TLR 3A from 08:32 until 17:26 in the evening.[45] As a result of the high LEC, the power flow from the Beck and Nanticoke generation toward Hamilton and Toronto was constrained down by up to 400 MW for the TLR 3A period. Also, 100-250 MW of imports from Michigan were cut (in HE 12 and HE 13) because the additional imports would have further increased the counter-clockwise LEC. In general, about 30 percent of these imports flow to Ontario through the Niagara ties.

Due to the congestion on the QFW flowgate, the 100 MW of RRS (Regional Reserve Sharing) with New York, PJM and New England was also unavailable. The IESO subsequently increased its OR requirement from 1,318 MW to 1,418 MW for the period HE 14 to HE 24.

At 10:18 (HE 11 interval 4), the IESO requested a market participant to start a gas-fired generator as soon as possible for reliability, even though withdrawal of the unit from its DACP schedule had been approved earlier in the day. The unit was in service and synchronized three hours later.

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[43] A TLR 1 is a notice to neighbouring ISOs and market participants that there is a potential that the designated interface may, at some point in the future, be above its operating limit.

[44] The QFW transmission Flowgate (often called an Interface) consists of a set of five 230kV transmission circuits (Q23BM, Q24BM, Q25BM, Q29BM and Q30M) from the Queenston area on the Niagara River to major transmission stations at Middleport and Hamilton. QFW, with a normal rating of about 1,800 MW, was de-rated by 400 MW from HE 7 on June 11, 2007 for a planned outage of Q29BM. At 12:01 (HE 13 interval 1) on June 12, the IESO recalled the Q29BM outage for adequacy concerns, and the line was restored to service at 16:53 (HE 17 interval 11).

[45] A TLR 3 is a notice to the other ISOs and the market that QFW flowgate is over its operating limit and transmission services will be re-allocated to continue to allow transactions with higher transmission priority to continue to flow. For details on how the TLR levels are determined, see the NERC procedures: ftp://www.nerc.com/pub/sys/all_updl/docs/ferc/TLRFiling-2-05.pdf.

At 10:41 (HE 11 interval 9), the Multi Interval Optimizer (MIO is the constrained version of the DSO) indicated both a 10S and a total OR deficiency as internal generation normally providing OR was being dispatched for energy. After having assessed the power flow on the QFW interface, the IESO determined that there was still room for a slight increase in power flow up to its stability limit and subsequently requested emergency energy from MISO to allow it to eliminate the OR shortfall for HE 12. Hence, 300 MW of emergency energy flowed from Michigan to Ontario from 11:40 to 12:00.

At 11:26 (HE 12 interval 6), the IESO declared EEA 1 (Energy Emergency Alert – Level 1) as demand continued to run heavier than forecast and it was waiting for available generation to come online.[46] As a result of the declaration of EEA 1, the IESO, following its standard operating procedures, increased the Net Interchange Scheduling Limit (NISL) from the standard 700 MW level to 1000 MW to allow more imports to flow in. The IESO also started to curtail 236 MW of exports and scheduled an additional 100 MW of imports from Quebec for local requirements in the Ottawa area after the pre-dispatch run.

At 11:45 (HE 12 interval 9), an additional 200 MW of emergency energy was bought from MISO for HE 13, based on the adequacy assessment for that hour.

At 12:42 (HE 13 interval 9), a 500 kV transmission line (D501P) that links the hydroelectric generation in the northeast to the south tripped. This caused a loss of about 800 MW of supply. In response to this event, the IESO immediately activated 800 MW of OR, curtailed 331 MW of exports and purchased 400 MW of emergency energy for the coming hour, HE 14. Because OR was activated, the IESO reduced the OR requirement by 800 MW. The OR requirement was restored to 1318 MW at 13:16 (HE 14 interval 4).

[46] Following the NERC Reliability Standard (EOP-002 Attachment 1), the IESO will issue EEA 1 when the IESO control area has or expects to have all available resources in use, and EEA 2 when it has or is about to initiate load management procedures such as voltage reduction and/or load curtailment (see IESO Market Manual 7 Appendix E.1)

Although the IESO's actions followed the NPCC standard, which allows up to 105 minutes for replenishment of OR after a contingency,[47] the reduction in the OR requirement for 34 minutes during this shortage condition had the effect of depressing both the HOEP and OR prices during this period.[48] As Table 2-5 in the later part of this section shows, the HOEP would have been \$0.02/MWh higher in HE 13 and \$1.93/MWh higher in HE 14.

The loss of the 500 kV transmission line highlights the inconsistent treatment of generation outages and transmission outages. As was discussed in our December 2006 report, when a transmission outage affects system reliability, the lost supply remains in the unconstrained schedule and thus has no impact on the market price. In contrast, when a generator has an outage, the lost supply is removed from the unconstrained schedule and thus may increase the market price in a manner which reflects the scarcity of the available resources. In the current case, the loss of D501P represented an inability to access 800 MW of hydro generation in the north, but had no impact on the market price. Although it might be logical to treat a transmission outage that causes loss of resources in the same way as a generation outage, transmission limitations are regularly only reflected in the IESO's constrained schedule. However, in this situation there has been an OR reduction of 800 MW in both constrained and unconstrained schedules, corresponding to the loss of generation, even though the generation is still available in the unconstrained schedule. This type of double counting means, all else equal, that not only would the market price not increase to reflect the loss but it would actually drop because of the reduced OR demand.

At 12:43 (HE 13 interval 9), the IESO implemented a 5 percent province-wide voltage reduction, except in the Niagara area which was congested. A reduction of load in this area would have increased the QFW congestion. The 5 percent voltage reduction lowered

[47] The NPCC A-6 Criteria allows restoration of 10 minute OR within 90 minutes of a shortfall without a contingency and 105 minutes with a reportable contingency from the start of the shortfall.
[48] In our previous monitoring report, July 2007, we recommended replenishing OR as quickly as possible. The IESO is planning to stakeholder the discussion of this issue.

Ontario demand by about 540 MW. As previously recommended by the Panel, this reduction was added back into the unconstrained schedule to avoid an artificial depression of prices during this period of scarcity.[49]

At 13:02 (HE 14 interval 1), the IESO declared an EEA 2.[50]

The voltage reduction was terminated at 13:24 (HE 14 interval 5) as D501P came back into service. However, as supply was still tight, export curtailment and emergency purchases continued.

As demand continued to run heavier than expected, at 14:20 (HE 15 interval 4) the IESO determined there would be adequacy problems in the afternoon peak hours. It therefore manually constrained off 60 percent of the dispatchable load (267 MW) for HE 15 to HE 17. These MW still appeared in the unconstrained sequence which again avoided an artificial depression of prices during a period of scarcity. In total, the IESO paid $766,000 in constrained-off payments to these dispatchable loads.

As an indication of how 'tight' the constrained system was, from HE 10 interval 11 on and off through to HE 14 interval 5, CAOR was being used by the constrained schedule for energy, implying a potential need for export curtailment or voltage cuts. Beginning in HE 13 interval 9 through to HE 14 interval 5, and with D501P forced out of service, 545 MW of CAOR was being dispatched in the constrained schedule.

At 17:01 (HE 18 interval 1) the EEA was reduced to level 1 from level 2. It was withdrawn at 18:59 (HE 19 interval 12).

[49] See our June 2004 Report (pp 47-51) and June 2005 Report (pp 60-66). The IESO implemented the new procedures for the treatment of voltage reduction on August 11, 2005.
[50] NERC Reliability Standard (EOP-002 Attachment 1).

2.1.2.2 June 12, 2007 HE 15

Summary Information

In this hour the HOEP spiked to $436.53/MWh, the highest HOEP to date in 2007. Table 2-3 below provides summary information for the hour. The sudden increase in MCP coincided with the forced derating of a fossil unit.

Table 2-3: Interval Summary Information, June 12, 2007, HE 15 (MWh and $/MWh)

Hour	Interval	DA Peak Demand (MWh)	PD Peak Demand (MWh)	RT Actual Demand (MWh)	MCP ($/MWh)	Failed Imports (MWh)	Curtailed Exports (MWh)	A Gas-Fired Unit Market Schedule (MWh)
15	**1**	21,569	22,086	22,534	154.22	156	175	217
15	**2**	21,569	22,086	22,636	135.35	156	175	510
15	**3**	21,569	22,086	22,673	135.35	156	175	525
15	**4**	21,569	22,086	22,743	135.35	156	175	525
15	**5**	21,569	22,086	22,676	135.23	156	175	525
15	**6**	21,569	22,086	22,689	544.37	156	175	18
15	**7**	21,569	22,086	22,771	599.99	156	175	18
15	**8**	21,569	22,086	22,751	574.62	156	175	18
15	**9**	21,569	22,086	22,873	622.06	156	175	18
15	**10**	21,569	22,086	22,951	779.78	156	175	18
15	**11**	21,569	22,086	22,873	622.06	156	175	18
15	**12**	21,569	22,086	22,955	799.99	156	175	18
Average		21,569	22,086	22,760	436.53	156	175	202

Final Pre-dispatch Conditions

The pre-dispatch peak demand for HE 15 was forecast at 22,086 MW with a projected price at $105.43/MWh. Net imports of 332 MW were scheduled in the unconstrained sequence. The pre-dispatch supply cushion was 3.1 percent, implying very tight supply.

Real-time Conditions

In real-time, the average demand in HE 15 came in at 22,760 MW, with a peak demand of 22,955 MW. The peak demand was 869 MW or 4 percent more than expected one-hour ahead while 156 MW of imports failed due to external security issues in Quebec.

To respond to the tight supply conditions, the IESO curtailed 175 MW of exports to Michigan before real-time for 'adequacy'. The real-time supply cushion dropped to -2.4 percent. As an illustration of how much tighter conditions were in the constrained schedule, the IESO constrained off a large portion of the dispatchable load (from HE 15 interval 4 to HE 17 interval 10).

As noted above, at 10:18 the IESO requested a gas-fired unit to start up as soon as possible. When this unit is started from the cold state, it takes four hours to warm up and another period of operation at a low output level. The usual practice is for the operator to send an outage slip to the IESO, indicating the time and the output level that the unit must stay at when it starts up. Due to the 12 times ramp rate effect, as soon as the unit is synchronized into the system, it is deemed to have ramped up almost immediately to its maximum capacity in the market schedule.

As Table 2-4 below shows, as soon as the unit was synchronized in interval 1, its unconstrained schedule appeared as 217 MW (12 times ramp effect) although it was scheduled for 0 MW in the constrained sequence. Conversely, when it is derated, it is deemed in the market schedule to have ramped down immediately to the derated level, in this case from 525 MW to 18 MW. In the current case, when the derating was implemented, the MCP simultaneously jumped to above $500/MWh as a result of loss of 507 MW of inframarginal supply in the unconstrained sequence.

The effect of using 12 times ramp rate multiplier can be compared to other alternatives such as three and one times ramp rate multiplier. As Table 2-4 shows, had a three times ramp rate been used, the unit could have been ramped up to 292 MW in five intervals (implying a 200~400 MW reduction in phantom supply, that is, supply in the market schedule that physically cannot be accessed) and the MCP would have been $20~$80/MWh higher when the 200~400 MW of phantom supply were unavailable. Had one times ramp rate been used, the market schedule for the unit would have been up to only 75 MW in five intervals (implying a 450 MW reduction in phantom supply), and the MCP would have been $60~$200/MWh higher. The reduction of the ramp multiplier from twelve to three on September 12, 2007 should reduce the incidence of large swings in phantom capacity in the future.

Table 2-4: Market Schedule and MCP under Different Ramp Rate Multipliers, June 12, 2007, HE 15 (MWh and $/MWh)

			12-times Ramp Rate		3-times Ramp Rate		1-times Ramp Rate	
Hour	**Interval**	**Constrained schedule**	**MCP ($/MWh)**	**Market Schedule (MW)**	**MCP ($/MWh)**	**Market Schedule (MW)**	**MCP ($/MWh)**	**Market Schedule (MW)**
15	**1**	0	155.00	217	211.13	45	220.33	15
15	**2**	28	145.22	510	226.99	90	350.12	30
15	**3**	43	135.35	525	211.13	142	350.12	45
15	**4**	58	135.35	525	155.45	217	350.12	60
15	**5**	68	135.23	525	154.22	292	220.33	75
15	**6**	18	375.12	18	375.12	18	375.12	18
15	**7**	18	599.99	18	599.99	18	599.99	18
15	**8**	18	562.50	18	562.50	18	562.50	18
15	**9**	18	622.06	18	622.06	18	622.06	18
15	**10**	18	779.78	18	779.78	18	779.78	18
15	**11**	18	622.06	18	622.06	18	622.06	18
15	**12**	18	799.99	18	799.99	18	799.99	18
Average		27	422.30	202	443	76	487.71	29

Of interest is that the simulated MCP is exactly the same under different ramp rate multipliers after the unit is derated. The reason for this is that almost all fossil resources were fully utilized and a change in the multiplier has no impact on their schedules. Hydro units have a very large ramp rate and the change in the ramp rate multiplier has no effect on their market schedules. As a result, the change in the multiplier has no impact on the MCP for those intervals after the unit was derated.

2.1.2.3 Assessment of June 12, 2007

The under-forecast of the temperature and thus of demand was the primary cause for the need for control actions by the IESO on June 12th but failed imports, the outage at D501P and a derated generator aggravated a tight supply condition. To respond to the unexpectedly large demand in real-time that was compounded by supply issues, the IESO took almost all available control actions to maintain system reliability. These actions, and their market impacts, included:

- purchasing emergency energy (which was included as part of the demand in the market[51] and had no effect of suppressing the market price);
- reducing the system voltage by 5 percent (an estimated reduction in demand from the voltage reduction was added back into the market schedules and thus provided correct price signals);
- manually constraining-off a dispatchable load (which was not removed from the market schedules and had no effect of suppressing the market price);
- activating operating reserve and reducing OR requirements (which lowered the total demand and thus had an effect of suppressing the market price); and
- recalling exports in real-time for 'adequacy' (which were taken out of the market demand and suppressed the market price[52])

While these actions collectively helped to keep the lights on, the last two actions likely had an adverse impact on efficiency and future hour system reliability as they artificially suppressed the HOEP signal in several hours and thus perhaps discouraged potentially economic imports and domestic supply, and encouraged potentially uneconomic exports.

The Impact of OR Requirement Reduction

To see how the delayed OR replenishment affected the HOEP, the MAU ran a simulation with immediate OR replenishment for those hours in which OR was activated and the OR requirement was reduced. In order to control modelling error this simulation was compared to simulated actual conditions. The simulation results are summarized in Table 2-5 below. Our observations are:

- the OR reduction had a very limited impact on the prices in HE 10 and HE 11 because the OR amount involved was small,

[51] Market Rule Amendment MR – 000296 allows the IESO to increase or decrease the market demand to offset the impact of control actions such as emergency energy purchase, dispatchable load curtailment, and voltage reduction.
[52] A recalled export is taken away from the market demand in the unconstrained sequence only if it is for 'adequacy'. A recalled export for 'security' (e.g. TLRi) has no effect on the market price. The curtailment of exports has the unintended consequence of hedging the risk to exporters by cutting them when prices are rising so that exporters can avoid a potentially high price.

- the price impact in HE 13 was still small although 266 MW of OR was activated. The reason for this is that the energy demand was moderate in HE 13 hour and there were still a lot of peak hydro supplying OR.
- the OR reduction had a noticeable impact in HE 14, where both the HOEP and the OR prices would have been almost $2/MWh higher had the OR requirement not been reduced. The reason for such a larger impact is that the demand was 400 MW greater than in HE 13, and some peaking hydro units were dispatched for energy and thus could not provide cheap OR.

Table 2-5: Price Impact of Delayed OR Replenishment, June 12, 2007, HE 10 to HE 14 (MW and $/MWh)

	'Simulated' Actual				If OR had not been Reduced				Integrated OR Activation (MW)	HOEP Difference
Hour	10N	10S	30R	HOEP	10N	10S	30R	HOEP		
10	0.28	2.34	0.28	90.01	0.31	2.34	0.31	90.01	75	0.00
11	0.41	3.37	0.41	96.30	0.42	3.37	0.42	96.30	17	0.00
13	0.22	0.22	0.22	101.31	0.32	0.32	0.32	101.34	266	0.02
14	12.80	12.96	12.80	127.67	14.78	14.94	14.78	129.60	185	1.93

<u>The Impact of Export Curtailment for Adequacy</u>

The IESO may curtail an export for 'security' or 'adequacy' after the final pre-dispatch run. 'Security' is designated if the curtailment of the export is directly due to an internal transmission limitation or transmission limitation on an intertie. 'Adequacy' is used when Ontario faces a resource shortfall which is not recognized by the hour-ahead pre-dispatch sequence. A 'security' designation is used rather than 'adequacy' if the resource shortfall is expected to last beyond the next hour so that the pre-dispatch sequence can recognize it.

When exports are curtailed for 'adequacy', the IESO removes them from both the constrained and unconstrained sequence.[53] This manual action has the effect of a sudden loss of demand in both sequences. As a result, the market price is suppressed by the

[53] See the IESO Market Manual 4 Appendix C

operator's control action, at a time when the market is unable to fully meet demand. Market participants are not compensated for the curtailment in this situation.[54]

In contrast, an export recalled for 'security' is not removed from demand in the unconstrained sequence and hence does not artificially suppress the market price. Market participants are compensated or charged for being constrained off through the CMSC mechanism.

Exporters understand that in periods where demand outstrips supply and IESO control actions must be taken (periods of concern for 'adequacy'), the IESO will curtail the export and remove it from both schedules. In other words in periods where the HOEP may be extremely high the price risk to the exporter is hedged by the IESO's control actions. Curtailing the export for 'security' removes it from the constrained schedule only, which continues to keep the price risk where it is supposed to be, in the hands of the exporter. Removing exports from the market schedule with the resulting lower HOEP may also have the effect of sending a signal to continue seeking exports from the IESO in the next hours in spite of the potential scarcity situation.

To see how the export curtailment affected the HOEP on the day, the MAU ran a simulation in which the unconstrained sequence retained the exports. Had the exports that were curtailed for 'adequacy' in HE 13 to 17 been included in the market demand, the simulated HOEP would have indicated a more severe shortage condition. The estimated energy price was $335/MWh, the 10N and 30R OR prices at $127/MWh and the 10S at $190/MWh, which were much higher than the actual price, as can be seen in Table 2-6 below.

[54] If they were constrained off for 'security', instead, they might face a negative CMSC, i.e. they would have to pay for the difference between the HOEP and their offer price times their market schedule although they have actually exported nothing.

Table 2-6: The Price Impact of Export Curtailment, June 12, 2007, HE 13 to HE 17 ($/MWh)

Delivery Hour	Simulated Actual[55]				Had Export Curtailment Had No Impact on Market demand				HOEP Difference
	10N	10S	30R	HOEP	10N	10S	30R	HOEP	
13	0.22	0.22	0.22	101.31	0.23	0.23	0.23	104.81	3.50
14	12.80	12.96	12.80	127.67	40.65	50.32	40.60	232.88	105.21
15	70.85	205.58	70.78	422.30	509.34	733.02	509.26	907.48	485.18
16	47.35	49.34	47.29	185.88	64.59	146.60	64.53	308.26	122.38
17	4.79	4.79	4.79	104.10	18.98	18.98	18.98	123.31	19.20
Average	27.20	54.58	27.17	188.25	126.76	189.83	126.72	335.35	147.09

As Table 2-6 indicates, the HOEP would have been substantially higher in HE 14 through HE 16 if those curtailed exports had not been subtracted from market demand in the market schedule. In other words, the IESO's control actions had an effect of suppressing the market price to a level that failed to correctly reflect the true tight supply condition. Higher prices would have provided market participants with appropriate signals and incentives to respond in a timely manner to the scarcity situation. For most participants, although they are unable to respond to the real-time price within the two hour offer/bid window, they can do so in future hours if they expect a high real-time price to continue.

One solution to this situation is to leave exports in the market schedule which would lead to a higher price and a signal for the market to respond when there are adequacy problems. But it should be noted that part of the problem with the treatment of these exports is the inability to reschedule imports or exports during the hour. In Chapter 3 the Panel assesses some of the benefits of 15 minute scheduling. If schedules were determined every 15 minutes, imports and exports could be re-scheduled shortly after an adequacy (or security) situation emerged, to help respond to the scarcity.

[55] The 'actual' MCP or HOEP is simulated and slightly different from the actual outcome from the DSO in this case because the simulation tool has a different converging algorithm and some input information is slightly different from that actually used by the DSO. In the majority of cases, the simulation tool generates almost identical results as the DSO.

<u>Recommendation 2-1</u>

Export curtailment due to 'adequacy' has an effect of suppressing the market price during times of serious scarcity since the curtailed amount is removed from the market schedule, thus distorting the market price signal. The Panel recommends that the IESO not remove the curtailed amount due to 'adequacy' from the market schedule.

2.1.3 <u>July 17, 2007 HE 10</u>

<u>Prices</u>

On July 17 the HOEP reached $271.40/MWh in HE 10, with a maximum MCP of $652/MWh in interval 12. Table 2-7 below lists the interval MCP and the pre-dispatch price during both HE 10 and 11 on July 17, 2007. Between the second and third intervals in HE 10, the real-time MCP suddenly jumped from $57.44/MWh to $192.58/MWh and then continued to move up to $652.33/MWh in interval 12. The MCP was back to $67/MWh by interval 1 of HE 11.

Table 2-7: Pre-dispatch and Real-Time Prices, July 17, 2007, HE 10 and HE 11 ($/MWh)

Delivery Hour	Interval	PD MCP	RT MCP	Difference
10	**1**	60.01	57.25	-2.76
10	**2**	60.01	57.44	-2.57
10	**3**	60.01	192.58	132.57
10	**4**	60.01	226.2	166.19
10	**5**	60.01	226.43	166.42
10	**6**	60.01	226.43	166.42
10	**7**	60.01	226.44	166.43
10	**8**	60.01	226.43	166.42
10	**9**	60.01	245.22	185.21
10	**10**	60.01	350.12	290.11
10	**11**	60.01	569.95	509.94
10	**12**	60.01	652.33	592.32
Average		**60.01**	**271.40**	**211.39**
11	**1**	61.00	66.79	5.79
11	**2**	61.00	72.15	11.15
11	**3**	61.00	72.15	11.15
11	**4**	61.00	72.15	11.15
11	**5**	61.00	74.25	13.25
11	**6**	61.00	72.15	11.15
11	**7**	61.00	72.15	11.15
11	**8**	61.00	94.05	33.05
11	**9**	61.00	94.05	33.05
11	**10**	61.00	94.05	33.05
11	**11**	61.00	94.05	33.05
11	**12**	61.00	94.05	33.05
Average		**61.00**	**81.00**	**20.00**

Day-ahead Conditions

Demand was expected to be normal day-ahead with a peak demand of 20,255 MW in HE 17. The peak demand for HE 10 was forecast at 18,964 MW. The DACP scheduled 15 fossil units (with a total capacity of 5,460 MW) online for peak hours. There were no imports scheduled as Ontario generation was sufficient and more economic.

Final Pre-dispatch Conditions

In the final pre-dispatch run, the forecast hour-ahead demand for HE 10 was 19,024 MW, with a projected price of $60.01/MWh. There were 2,404 MW of exports and 295 MW of imports scheduled. The pre-dispatch schedule indicated that approximately 1,700 MW was being offered between $61/MWh and $652/MWh. The majority of these offers were from peaking hydro units which were scheduled to supply 960 MW of OR, implying the remaining 840 MW of offers was available for energy. The pre-dispatch supply cushion was 6.6 percent.

Real-time Conditions

Real-time demand came in heavier than expected. The average demand in HE 10 was 19,185 MW and the peak demand in the hour which occurred in interval 12 was 19,464 MW, or 440 MW (2.3 percent) greater than had been expected one hour earlier.

Starting in interval 3, three fossil-fired generators were de-rated due either to technical problems or to environmental concerns. This resulted in a loss of up to 360 MW of inframarginal supply.

Another unit that had been scheduled for 88 MW in pre-dispatch failed to show up in real-time. The reason this occurred is that this unit was unintentionally offered at a low price two hours ahead and it was picked up by the pre-dispatch sequence although it was not ready for synchronization. The unit owner subsequently took all necessary actions to communicate with the IESO, and there was no breach of Market Rules.

As well, 50 MW of exports failed on the Michigan interface due to a missing E-tag, which partially offset the effect of lost supply and increased demand.

The effect of these losses in supply was to reduce the real-time supply cushion to -0.5 percent.

Assessment

The price spike was due to an under-forecast of demand (440 MW) combined with a series of deratings of typically inframarginal generators (360 MW). The real-time market thus required up to 890 MW from peaking units to fill the gap. There were no control actions that distorted the market price.

The MCP in HE 11 interval 1 dropped to $66.79/MWh, which is in a sharp contrast to the $652.33/MWh MCP in the previous interval. The collapse of the MCP was primarily due to the synchronization of the fossil-fired generator which had failed to show up earlier. The effect of the 12 times ramp rate assumption was to treat this unit as if it had ramped up almost to full capacity in the unconstrained sequence as soon as it was synchronized. This sudden, large and artificial increase in inframarginal supply instantaneously suppressed the MCP.

In addition to the synchronization of the coal-fired generator, the IESO activated 400 MW of OR for intervals 1 and 2 of HE 11 as the Area Control Error (ACE) was near -400 MW.[56] The activation of OR led to a reduction of 400 MW in the OR requirement, which further added a downward pressure on the MCP.

2.1.4 October 24, 2007 HE 18

The HOEP reached $297.52/MWh in HE 18, with a maximum MCP of $622.79/MWh. The projected one-hour ahead price was only $60.87/MWh.

Table 2-8 below lists the interval MCPs and the pre-dispatch prices in HE 18. In the first three intervals, the MCP was quickly decreasing from $104.72/MWh to $69.98/MWh, which is a typical pricing pattern for this hour since the implementation of 3 times ramp rate. The MCP stayed at $100-$200/MWh for four intervals in the middle of the hour, and then suddenly jumped above $430/MWh from interval 8 onwards.

[56] ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effect of frequency bias. The IESO typically re-dispatches generators to restore the ACE. If the IESO feels that the re-dispatching cannot solve the issue (usually when a negative ACE is greater than 200 MW), it may activate operating reserve.

Table 2-8: Real-Time and One Hour Ahead Pre-dispatch Prices, October 24, 2007, HE 18 and HE 19 ($/MWh)

Delivery Hour	Interval	Real-time MCP	One-Hour Ahead Pre-dispatch Price	Difference
18	**1**	104.72	60.87	43.85
18	**2**	94.72	60.87	33.85
18	**3**	69.98	60.87	9.11
18	**4**	110.36	60.87	49.49
18	**5**	126.90	60.87	66.03
18	**6**	142.66	60.87	81.79
18	**7**	190.30	60.87	129.43
18	**8**	430.00	60.87	369.13
18	**9**	530.00	60.87	469.13
18	**10**	622.79	60.87	561.92
18	**11**	525.05	60.87	464.18
18	**12**	622.79	60.87	561.92
19	**1**	115.48	99.00	16.48
19	**2**	68.66	99.00	-30.34
19	**3**	61.12	99.00	-37.88
19	**4**	61.12	99.00	-37.88
19	**5**	61.12	99.00	-37.88
19	**6**	61.12	99.00	-37.88
19	**7**	65.86	99.00	-33.14
19	**8**	68.66	99.00	-30.34
19	**9**	68.66	99.00	-30.34
19	**10**	59.54	99.00	-39.46
19	**11**	61.12	99.00	-37.88
19	**12**	59.54	99.00	-39.46

The real-time MCP in HE 19 fell to about $60/MWh after the first interval and the HOEP was only $67.67/MWh.

Pre-dispatch Conditions

In pre-dispatch, the forecast one hour ahead peak demand was 18,456 MW, with a projected price of $60.87/MWh. There were 1,777 MW of exports and 1,800 MW of imports scheduled, implying the Ontario market was very liquid for the hour. The pre-dispatch supply indicated that approximately 900 MW were being offered between $61/MWh and $622/MWh by domestic generators. The majority of these offers were from peaking hydro units. They were scheduled to supply about 300 MW of OR, implying that the remaining 600 MW was available for energy. The pre-dispatch supply cushion was 5.5 percent.

Real-time Conditions

Real-time demand came in almost the same as expected. The average demand in HE 18 was 18,229 MW and the peak demand in the hour occurred in interval 10 was 18,520 MW, or only 60 MW (0.3 percent) greater than expected one hour earlier. The real-time supply cushion was only -2.2 percent, however, implying CAOR was used to provide operating reserve. CAOR set the OR prices for most intervals in the hour.

Assessment

The price spike was driven almost entirely by an error in the offers of a gas-fired generator. The generator was shut down in the middle of HE 16 as scheduled. At the time it was shut down its operator intended to remove the offers that had been made for HE 17 and 18 in the offer/bid window. These offers were not, in fact, removed and the DSO picked them up in the final pre-dispatch run and dispatched the generator in both the constrained and unconstrained sequences and in both hours.

In real-time, however, the generator involved could not be dispatched as its breakers were open. The DSO thus had to turn to more other expensive internal generators along the offer stack. At the same time, the few coal-fired generators online were in the middle of ramping down and could not ramp back up fast enough to offset the absence of the gas-fired generator.

To add to an already tight situation, 100 MW of imports from MISO failed due to ramp rate limitations in Michigan. The real-time supply cushion was reduced to -2.2 percent as a result of the unavailability of the gas-fired generator, the ramping down of several coal-fired units and the 100 MW import failure. As a consequence, the real-time HOEP spiked to $297.25/MWh.

The MAU ran a simulation of assuming the offers of the gas-fired generator had been properly dealt with. The comparison of the simulation results is listed in Table 2-9. Had the offers been correctly removed, the DSO would have scheduled 2,033 MW of imports and 1,633 MW of exports in the pre-dispatch sequence for HE 18, with a pre-dispatch price at $85/MWh. The additional imports (233 MW) would have come from Quebec, and the reduced exports (144 MW) would have been on the New York interface. That is, the pre-dispatch sequence would have scheduled 377 MW more in net imports. If all those additional net imports were available in real-time, the HOEP would have been $82.22/MWh, or $211.86/MWh lower than the 'actual' HOEP.

We understand that the error in the offers for HE 17 and HE 18 is under investigation by the IESO's Compliance Unit for a possible breach of the Market Rules.

Table 2-9: Net Imports and 'Actual' and Simulated Prices, July 17, 2007 HE 18 (MWh and $/MWh)

Delivery Hour	Interval	Simulated 'Actual'			Simulated			MCP Difference (Simulated-Actual)
		RT MCP ($/MWh)	PD Price ($/MWh)	Net Import (MWh)	RT MCP ($/MWh)	PD Price ($/MWh)	Net Import (MWh)	
18	**1**	104.72	60.87	23	33.45	85.00	400	-71.27
18	**2**	94.72	60.87	23	33.77	85.00	400	-60.95
18	**3**	69.98	60.87	23	33.77	85.00	400	-36.21
18	**4**	110.36	60.87	23	34.70	85.00	400	-75.66
18	**5**	120.48	60.87	23	35.64	85.00	400	-84.84
18	**6**	142.66	60.87	23	65.85	85.00	400	-76.81
18	**7**	190.30	60.87	23	65.85	85.00	400	-124.45
18	**8**	400.00	60.87	23	131.90	85.00	400	-268.10
18	**9**	525.05	60.87	23	134.44	85.00	400	-390.61
18	**10**	622.79	60.87	23	142.66	85.00	400	-480.13
18	**11**	525.05	60.87	23	131.90	85.00	400	-393.15
18	**12**	622.79	60.87	23	142.66	85.00	400	-480.13
Average		**294.07**	**60.87**	**23**	**82.22**	**85.00**	**400**	**-211.86**

2.1.5 <u>Uplift Greater than HOEP</u>

There were three hours in 2007 in which the uplift was greater than the HOEP: May 12 HE 3, September 16 HE 3, and September 18 HE 1. These events all took place during the overnight hours where HOEP tends to be lower. For two of the events uplift was not large, rather HOEP was quite low.

On May 12 HE 3, the relatively high uplift ($6.36/MWh) was due to a large constrained-off payment to a dispatchable load, which was subsequently reversed by the IESO as the constrained-off was induced by the load itself. The IESO practice is to calculate the CMSC hourly based on real-time unconstrained and constrained schedules. But at the end of each month, the IESO may recover those payments to dispatchable loads if they are induced by participants themselves. The HOEP was $5.72/MWh, because the Ontario demand was only 12,393 MW and there was a lot of baseload supply.

On September 16 HE 3, the uplift charge of $1.08/MWh was in the normal range, but the HOEP was only $0.39/MWh because the Ontario demand was as low as 12,000 MW and failed exports to New York were 1,071 MW.

On September 18 HE 1, the HOEP was negative with an uplift charge $2.12/MWh. We will discuss the negative priced hour in the next section.

None of these hours raise any concerns regarding the operation of the market.

2.2 Analysis of Low-priced Hours

A ‘low-priced hour’ is arbitrarily defined for monitoring purposes as any hour in which the HOEP was less than $20/MWh. As Table 2-10 below indicates, there were 331 hours during the period May - October 2007 for which the HOEP was less than $20/MWh. During the same months a year earlier, there were 149 low priced hours. The lowest HOEP in the review period, -$0.40/MWh, occurred on September 18, 2007 in HE 1 and was the only negative HOEP in the period. Section 2.2.1 reviews this hour.

Table 2-10: Number of Hours with HOEP Less $20/MWh, May 2002 – October 2007 (Number of Hours and Percentage of Total Hours)

Time Period	HOEP < $20/MWh		HOEP < $0/MWh
	Number of Hours	% of Total Hours	Number of Hours
May 2002 to October 2002	162	3.7	0
May 2003 to October 2003	78	1.8	0
May 2004 to October 2004	314	7.1	0
May 2005 to October 2005	52	1.2	0
May 2006 to October 2006	149	3.4	1
May 2007 to October 2007	331	7.5	1

The MAU has found that, in general, a HOEP below $20/MWh occurs in hours when one or both of the following occurs:

- Ontario demand is less than 15,000 MW. This typically occurs in the overnight hours, on holidays or during the spring/fall seasons.
- Normal baseload supply is augmented by the supply from a number of hydroelectric facilities that are usually 'run-of-river' facilities, which have an abundance of water. This occurs most frequently during the freshet period such as in April, May and June but it can occur at other times.

While these are the primary factors that contribute to a HOEP being less than $20/MWh, demand forecast errors and failed export transactions can also place significant downward pressure on the HOEP, resulting in HOEP being much lower than pre-dispatch.

<u>Occurrences of Low Priced Hours May – October 2007</u>

The MAU's review of these low priced hours between May – October 2007 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 as low as 13,000 MW, baseload generation may be sufficient to meet it, leading to very low prices.

Table 2-11 summarises the average key data on low-price hours by month and Table A-51 in the Statistical Appendix has detailed hourly statistics on these hours.

Table 2-11: Key Data (Monthly Average) for Low Priced Hours, May – October 2007 (MW and $/MWh)

Delivery Month	Failed Net Exports (MW)	Real-time Demand (MW)	Pre-dispatch Demand (MW)	Demand Over-forecast (MW)	HOEP $/MWh	Pre-dispatch Price $/MWh	Difference (RT-Pre-dispatch) $/MWh
May	199	13,151	13,323	172	11.80	19.23	-7.43
June	124	13,596	13,903	307	13.06	19.29	-6.23
July	107	13,236	13,519	283	12.57	20.19	-7.62
August	158	13,196	13,524	328	10.14	21.10	-10.96
September	256	12,822	12,952	130	9.95	22.41	-12.46
October	261	12,818	13,111	293	9.96	24.77	-14.81
Average	181	13,176	13,407	231	11.68	20.50	-8.82

2.2.1 September 18, 2007 HE 1

The HOEP in this hour was -$0.40/MWh. Table 2-12 below lists the real-time MCPs and the pre-dispatch prices for the hour. The MCP reached a low of - $ 4.06/MWh in interval 12.

Table 2-12: MCP Prices by Interval, September 18, 2007, HE 1, ($/MWh)

Delivery Hour	Interval	RT MCP	PD Price	Difference (RT-PD)
1	1	-0.1	25.35	-25.45
1	2	-0.1	25.35	-25.45
1	3	1.0	25.35	-24.35
1	4	0.0	25.35	-25.35
1	5	-0.1	25.35	-25.45
1	6	-0.1	25.35	-25.45
1	7	-0.1	25.35	-25.45
1	8	-0.2	25.35	-25.55
1	9	-0.2	25.35	-25.55
1	10	-0.4	25.35	-25.75
1	11	-0.4	25.35	-25.75
1	12	-4.06	25.35	-29.41
Average		-0.40	25.35	-25.75

Pre-dispatch Market Conditions

The pre-dispatch peak demand for HE 1 was forecast at 13,812 MW with a projected price at $25.35/MWh. There were 1,637 MW of offers at prices between -$0.40/MWh and $25.35/MWh, of which about 1,200 MW were offered by baseload hydro generators who were also providing a significant amount of OR. The pre-dispatch total supply cushion was 44.3 percent.

Real-time Market Conditions

The real-time demand for the hour averaged 13,420 MW, with a peak demand of 13,564 MW which is 248 MW (or 1.8 percent) less than forecast hour-ahead. Failed exports amounted to 731 MW, all of which were under the control of the market participants involved and thus subject to an automatic settlement charge.[57] Self-scheduling and intermittent generators also produced 140 MW more than was projected, which put further downward pressure on the real-time price. These three factors caused the HOEP to drop to -$0.40/MWh. The real-time total supply cushion slipped slightly to 40.4 percent, as a few fossil-fired units were either shutting or ramping down to their minimum loading point, which tended to reduce the real-time supply cushion.

Assessment

The MCPs were set by a run-of-the-river hydro unit which received a fixed contract price of $33/MWh for its output. For this generator, offering a negative price minimizes the possibility of spilling water and ensures that the unit is likely to be scheduled and receive its contract price.

The Global Adjustment for the hour was $3.52/MWh, and the OPG Rebate $1.76/MWh. The net result is that consumers paid or will pay $1.36/MWh, although the wholesale price was -$0.40/MWh. Exporters were actually paid $0.40/MWh for the 815 MW which was exported.

[57] Exporters paid a real-time failure charge of about $16,909 (about $32/MWh) for these failed exports.

The negative HOEP was the result of 1119 MW of net change from pre-dispatch arising from the following sources:

- 731 MW of failed exports
- 248 MW lower than expected Ontario demand
- 140 MW of self-scheduler production in excess of forecast

The over-forecast of demand led to an additional 217 MW of imports being purchased from Michigan. These imports were offered at $25/MWh, slightly below the pre-dispatch price of $25.35/MWh, and were guaranteed a RT-IOG payment of $5,512. These imports were not required in real-time, but because imports accepted in pre-dispatch are put at the bottom of the supply stack in real-time, this had the effect of suppressing the HOEP. As we suggested in our previous report, it would be useful for the IESO to review the costs and benefits of the IOGs in off-peak hours.[58]

The large amount of failed exports on the Michigan interface had a run-on effect of suppressing the HOEP in the following hour as well. The Net Interchange Scheduling Limit ('NISL', which is preset at 700 MW) was binding for HE 2 as a result of the export failure in HE 1, which limited the maximum amount of net exports in HE 2. Had the NISL not been binding, a greater market demand in HE 2 and thus a higher real-time price would have resulted.

Although the binding NISL was a direct consequence of the export failure in the previous hour, the limitation of exports could have been relaxed if a high NISL were applied. As we indicated in our previous report, it would be useful for the IESO to review whether the default NISL setting of 700 MW could be raised.[59]

The majority of the energy in HE 1 was provided by baseload, self-scheduling and intermittent generators. Apparently some self-scheduling and intermittent generators were induced online by their fixed-price NUG contracts. Because most of these

[58] See our July 2007 Report, pp. 124-127, Recommendation 3-4.
[59] See our July 2007 Report, pp.97-100, Recommendation 2-2.

generators are paid a fixed price based on their actual output, they may generate power when the HOEP is lower than their incremental cost and thus displace more economic resources.

Fossil generators being online overnight were mainly driven by economics as they can avoid a restart-up during the load pick-up period in later hours by staying at their minimum level; some fossil units were in the middle of ramping down to their minimum.

The low price was further depressed by the over-generation of self scheduling and intermittent generators. The vast majority of the over-generation was from a wind generator that was projected to produce only 60 MW, but actually generated 178 MW. As more and more wind-power generators come online in future, the forecast error from these generators will have a significant impact on both market efficiency (and system reliability). The Panel will continue to monitor these new resources for their impact on efficiency.

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Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. *Introduction*

This Chapter summarises changes in the marketplace since our last report. It also updates the status and analyses of issues raised in previous reports as well as discussing new issues that have arisen during the review period.

Section 2 identifies material changes that have occurred in the market since our last report as well as providing additional analysis of matters raised in earlier reports:

- the replacement of the twelve times ramp rate assumption with a three times ramp rate assumption in the unconstrained pricing sequence;
- the implementation of a further 50 MW tranche of regionally shared Operating Reserve;
- the causes of the observed convergence of the Richview (nodal) price with the HOEP;
- an event that illustrates an inefficiency of the OPA's demand response program Phase I;
- the Lambton phase shifter (PARs) issue that was identified in our December 2005 report.

Previous Panel reports have identified market participants' concerns with regard to dispatch issues and described some of the measures the IESO has undertaken to address these issues. In the past, there has been discussion of the possibility of moving from hourly to 15 minute dispatch as a further remedial measure. In section 3 the Panel discusses some of the possible efficiency gains that may be obtained from 15 minute dispatch.

In section 4, we comment on some new issues. First, there are some CMSC payments made for legal, regulatory and environmental reasons that are probably unwarranted. Second, there are instances of Intertie Offer Guarantee (IOG) payments that would not be made if the IOG excluded implied wheeling by affiliated entities just as excludes implied wheeling by a single market participant. Finally, the Panel examines the efficiency implications of the various public agency contracts that have been struck with the advent of the hybrid market and provides guidance on contract structures that could promote efficiency.

2. *Material Changes to the Marketplace since the Previous Report*

2.1 Reduction in the Ramp Rate Multiplier in the Unconstrained Sequence

In previous reports, we have described how the unconstrained sequence (i.e. the market schedule) derives dispatch schedules and the corresponding energy prices based on the assumptions that generation can ramp at twelve times its actual capability as specified in its offer and that potential transmission limits are not binding.[60] The Panel has noted how this has led to market prices that are inconsistent with actual generator capabilities and dispatches leading to inefficiencies in the marketplace. The Panel has previously recommended using the actual (one times) ramp in the market schedule.[61]

In January 2007 the IESO approved a Market Rule change to be implemented in February 2007 which specified that the ramp multiplier should be reduced from twelve to three times.[62] Challenge to this rule change by the Association of Major Power Consumers of Ontario (AMPCO) at the OEB was unsuccessful[63] and a subsequent appeal to the Divisional Court was abandoned. As a result, the IESO implemented the three times ramp multiplier in the market (real-time) schedule on September 12, 2007. With only 49 days of market data available during this reporting period, it is difficult to attribute any changes in market prices or in market participants' behaviour to the change in the ramp rate multiplier. We have asked the

[60] For details, see our December 2003 monitoring report (page 112) and December 2004 report (page 63).
[61] See our December 2003 report, page 112.
[62] Market Rule Amendment MR – 00331, see: www.ieso.ca
[63] See OEB order EB-2007-0040 dated April 10, 2007.

MAU to continue monitoring the matter and report to us when more data are available.

In this section, we provide some initial observations. Figure 3-1 below depicts the normalized MCP – the ratio of the interval MCP to the HOEP for the hour -- for the period September 12 to October 31, 2007 and for the same period in 2006. This index shows how the MCP can deviate from its associated HOEP: the further away the index is from unity, the more divergent is the MCP from the associated HOEP. We chose 2006 as the representative benchmark period as it is similar in structure to earlier years.[64] It appears that the divergence between the MCP and the associated HOEP has increased since the implementation of the three times ramp rate multiplier and that this divergence is more prominent in the evening hours. For example, from HE 21 to 24, the MCP in the first interval is much higher relative to the HOEP while in subsequent intervals it is lower.[65]

[64] We also looked at the same period in 2003 to 2005. Except in 2005, the index shows essentially the same pattern and magnitude as in 2006. The highly volatile MCP in 2005 was likely induced by the dry weather which significantly reduced the availability of water and thus the system had relied more on fossil units that have a much slower ramp rate than hydro units.
[65] Although it is difficult to see because of the scale used in Figure 3-1, the high points for each of HE 21-24 are in the first intervals. Figure 3-2 also shows the dramatic price changes between interval 12 and interval 1 for these same hours.

Figure 3-1: Average Interval MCP Relative to Average HOEP by Hour, September 12 - October 31, 2006 and 2007

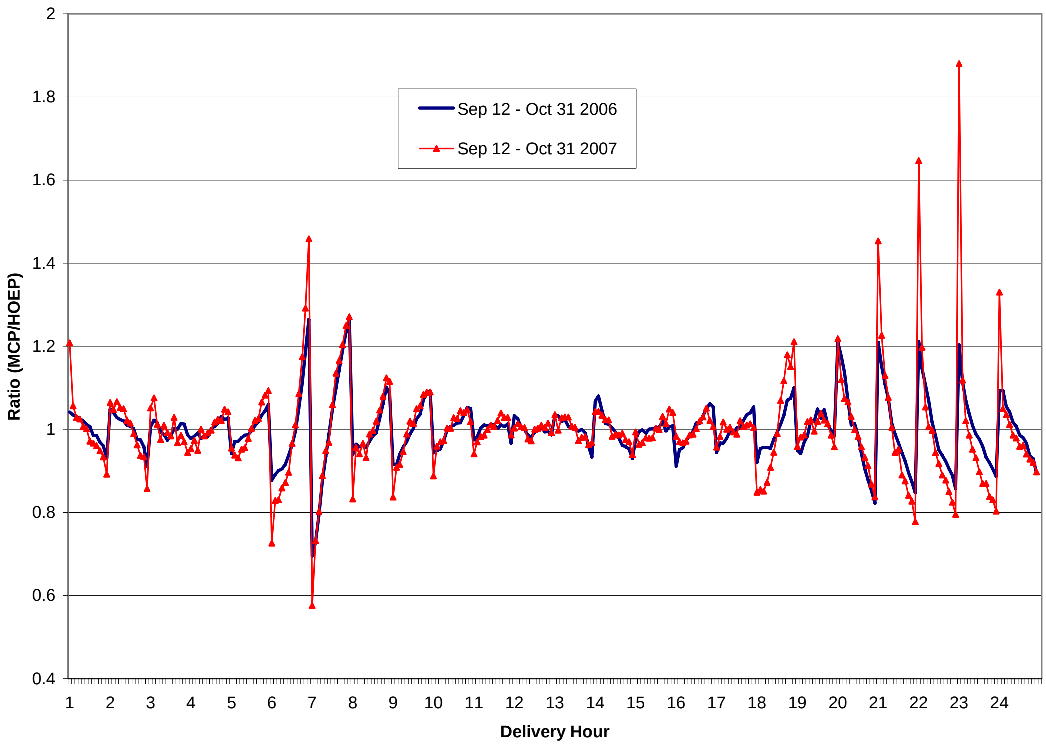


Table 3-1 below lists summary statistics for the pre-dispatch and real-time MCPs for the periods we are comparing. Presumably, the pre-dispatch MCP (which is an hourly price) is not directly affected by the change in the assumed ramp rate for real-time. Real-time MCP (rather than HOEP) is used as it is most likely affected by the change in ramp rate multiplier. A comparison of the two prices should provide important information on how the change in the ramp rate multiplier has affected the real-time price. To measure the volatility of these prices we use the coefficient of variation (COV), which is the standard deviation divided by the average for a set of observations. To check for changes in volatility, we do before-and-after comparisons of the respective COVs of the pre-dispatch and real-time MCPs and before-and-after comparisons of the respective COVs of the absolute hour-to-hour changes in the pre-dispatch and real-time MCPs. It appears that both the MCP and the change in MCP have been somewhat more volatile since the implementation of the three times ramp rate multiplier. For example, the coefficient of variation of the real-time MCP for 2007 was 0.54, in contrast to 0.41 for 2006 (or a 32 percent increase). The average absolute interval-to-interval change in the real-time MCP was \$3.67/MWh for 2007 versus \$1.86/MWh for the same 49 days in 2006 (or a 5 percent increase). In contrast to the increase in the real-time price volatility, the COV of the pre-dispatch price has increased only by 14 percent and the volatility of absolute change in the pre-dispatch price by 4 percent.

Table 3-1: Summary Statistics: Pre-dispatch & Real-time, September 12 – October 31, 2006 and 2007

	PD MCP		Absolute Change in PD MCP		RT MCP		Absolute Change in RT MCP	
	2006	2007	2006	2007	2006	2007	2006	2007
Average $/MWh	44.32	53.98	4.96	6.46	39.09	46.83	1.86	3.67
Standard Deviation $/MWh	15.31	21.55	5.65	7.63	15.99	25.19	4.67	9.67
Coefficient of Variation (COV)	0.35	0.40	1.14	1.18	0.41	0.54	2.51	2.63
Percentage Changes in COV %		14		4		32		5

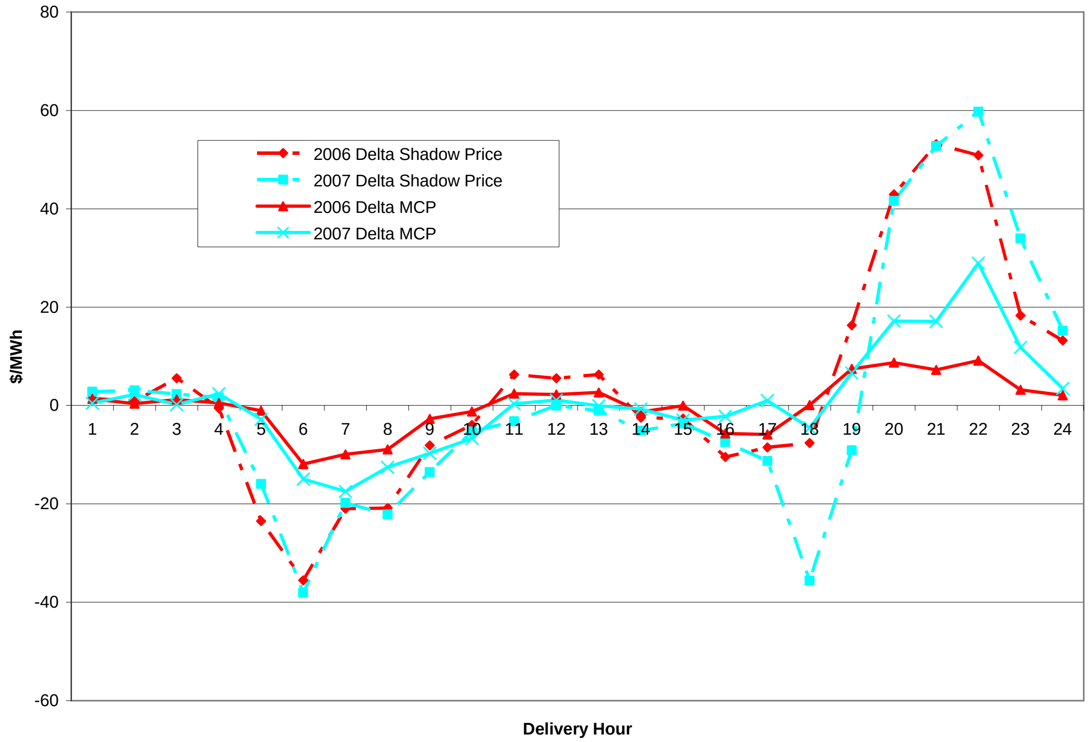
Along with a more volatile real-time price in 2007, the average real-time MCP (equivalent to an average HOEP) also increased from \$39.09/MWh to \$46.83/MWh, or by \$7.74/MWh. The Panel believes that this price difference was driven largely by fundamentals of supply and demand in the marketplace. In fact, the pre-dispatch price also increased from \$44.32/MWh to \$53.98/MWh, or by \$9.66/MWh, more than the increase in the real-time price. One can also see from Chapter 1 that the Ontario price was closely following the trend of the prices in external markets.

As shown in Figure 3-1 above, the most obvious change in interval to interval prices appears to be occurring between interval 1 of a given hour and interval 12 of the preceding hour. Between these two intervals (in other words, between the two adjacent hours), market supply and demand conditions can differ sharply as peaking hydroelectric generators and importers and exporters enter or exit the market on the hour as load grows in the morning and as it declines in the evening.[66] The sudden change in the supply/demand balance on the hour requires fossil generators to ramp down quickly at the beginning of each hour in the morning to accommodate the sudden arrival of imports and peaking hydro and/or the sudden departure of exports, and to ramp up quickly at the beginning of each hour in the evening. As a result, the interval MCP at the beginning of the hour can be noticeably less than the MCP at the end of the previous hour in the morning with the reverse being true of the evening. The use of three times ramp rate multiplier rather than twelve times ramp rate multiplier in the market schedule further amplifies the effect on the MCP of the sudden change in the supply/demand balance on the hour. This comes closer to accurate price signals, although there is still a fictitious assumption that such changes occur three times faster than the actual capability.

Figure 3-2 below provides a comparison of the price change from interval 12 to interval 1 for both the unconstrained and constrained sequences. The price for the constrained sequence is the Richview shadow price. What is apparent is that the reduction of the assumed ramp rate multiplier from twelve to three in the unconstrained sequence has tended to bring the interval price pattern in the unconstrained sequence more into line with the constrained sequence which uses the actual ramp rate.

[66] This is explained in greater detail in section 3.1, our review of dispatch volatility.

Figure 3-2: Average Changes in Prices between Intervals 12 and 1, Unconstrained and Constrained (Richview) Sequences, September 12 - October 31, 2006/2007



2.2 A Further 50 MW of Regional Operating Reserve is Introduced to the Ontario Market

On January 4, 2006 the Northeast Power Coordinating Council (NPCC)[67] authorised a Regional Reserve Sharing Program (RRS) for up to 50 MW of reserve energy for up to 60 minutes. The IESO implemented the RRS program on January 4, 2006 and

[67] NPCC, following the rules and standard of the NERC, develops regionally-specific reliability criteria and standards. NPCC includes New York State, the six New England States, and the Ontario, Québec, and the Maritime Provinces.

correspondingly lowered its reserve requirements from a normal level of 1418 MW to 1368 MW.[68] We commented on this development in our May 2006 report.

On April 27, 2007, the NPCC approved a further 50 MW of regional reserve sharing. On May 17, 2007, the IESO implemented this second tranche of 50 MW of RRS, lowering its normal reserve requirements further down to 1318 MW. The Panel welcomes developments, such as the reserve sharing program, that allow the IESO to maintain the same system reliability standard at a lower cost. The reduction in the value of the resources required to maintain reliability represents an efficiency gain. An estimate of the magnitude of this efficiency gain is reported below.

To estimate the efficiency gain resulting from the reduction in the OR requirement from 1,368 MW to 1,318 MW, the MAU ran a simulation for the period since the reduction, assuming the 50 MW OR reduction had not occurred.[69] Table 3-2 below shows the estimated efficiency gains and price effect by month. Everything being equal, the energy price would have been \$0.07/MWh higher than the current price and the OR prices \$0.14/MWh to \$0.17/MWh higher. The efficiency gain is equal to the cost of the additional OR that would have been required if the OR

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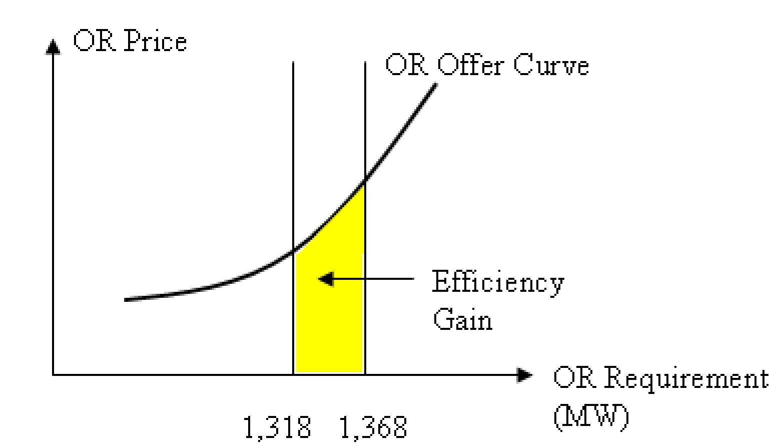
[68] Market Rule Amendment MR 00299, see www.ieso.ca

[69] The simulation mimics the unconstrained sequence and ignores all constraints that exist in the constrained sequence. As a result, the estimated efficiency gains may understate the true efficiency gains in the constrained sequence. The estimated efficiency gain is essentially the avoided cost of providing the 50 MW of OR, which is the shaded (yellow) area in the



following graph.
Note, due to the joint optimization of the DSO, there may be efficiency gains on the energy side as well even though there is no change in energy demand, although the gains may be very small. The efficiency gains reported in Table 3-2 are the total cost savings in both the energy and OR markets, as derived from the reported total costs in the simulations.

requirement had not been reduced. The total efficiency gain amounted to $119,000 for less than six months, with a relatively large gain in the freshet period (usually from May to July) when hydro units are typically supplying energy and hence are unavailable to provide Operating Reserve. In this period, the OR price tends to be higher. In other words, the efficiency gain is highly related to the OR prices, especially the 10 minute non-spinning reserve price, as one might have expected.

Table 3-2: Estimated Efficiency Gains 50 MW Regional Reserve Sharing by Month, May to October 2007

	Price Change Had the OR Requirement not Been Reduced ($/MWh)				Efficiency Gains $ (000)
	Energy	10S	10N	30R	
May-07*	0.05	-0.04	0.05	0.09	7
07-Jun	0.06	0.09	0.15	0.15	24
07-Jul	0.13	0.39	0.39	0.38	42
07-Aug	0.05	0.1	0.1	0.09	15
07-Sep	0.03	0.09	0.1	0.09	14
07-Oct	0.03	0.13	0.14	0.13	17
Total					119
Average	0.07	0.14	0.16	0.17	

*from May 17 to 31

During this period, the total 100 MW RRS has been used to offset total 10 minute and total OR requirements (reducing the need for non-spin OR resources). The Panel is aware that the IESO had been considering shifting the OR reduction discussed above to offset 10 minute spinning reserve as well. To support that discussion the IESO undertook a study based on the same methodology as we have used here which concluded that the cost saving to the market could amount to $20,000 per year.[70] We support this further initiative. It is to be implemented early in 2008.[71]

[70] See "Drafted Cost-Benefit Analysis" for Market Rule Amendment MR-00332, presented to the Technical Panel on July 24, 2007. available at: http://www.ieso.ca/imoweb/amendments/tp_meetings.asp
[71] The IESO Board of Directors approved the rule amendment on September 7, 2007, and the new rule came into effect on December 12, 2007 (IESO's "Participant News" dated September 13, 2007). The new OR requirement will take effect in early 2008 when the IESO completes all necessary tool changes.

2.3 The Convergence of the Uniform Price and the Richview Shadow Price

Factors Affecting Convergence

As the Panel has observed on numerous occasions, the uniform price regime in the Ontario market results in some inefficiencies.[72] A manifestation of this is the gap between the HOEP, which is the base price (prior to uplifts) that loads pay and generators receive in the spot market, and the incremental cost of providing energy to meet the last MW of demand which the Panel has traditionally viewed as being represented by the Richview nodal price (also referred to as the 'Richview shadow price' or 'Richview price').[73]

A convergence between the HOEP and the Richview price could be taken to imply that there has been a reduction in the inefficiencies associated with the uniform pricing regime. This depends on the reason for the convergence. One possibility is that the sources of bias or inefficiency in the HOEP have been reduced and this has brought it closer to the Richview price. Another possibility is that there may be biases in the Richview price that have brought it closer to the HOEP. In the latter case, convergence would not imply an efficiency improvement. In this section we attempt to address this question with an analysis of the causes of the observed convergence of the HOEP and the Richview price.

Over the years since market opening, the Panel has made various recommendations and the IESO has taken numerous steps to remove sources of bias in both the HOEP and in nodal prices including the Richview price. The reforms that have been introduced include:

1. Adding up to 800MW of CAOR for Operating Reserve and thus eliminating the IESO's control actions of reducing reserve requirements and suppressing the HOEP during shortage conditions;

[72] See especially our December 2006 and July 2007 monitoring reports.
[73] Richview is generally representative of the incremental cost, although there would be regional variations based on local supply and demand conditions relative to grid constraints. Richview is close to the major load centre in Ontario, and from Table 1-21 in Chapter 1 it can be seen that this price is close to zonal prices in much of Southern Ontario, especially the Toronto zonal price. For a further explanation, see also the Panel's monitoring report, Dec 2006, p. 91.

2. Reducing demand forecast errors;
3. Reducing transaction failures by imposing the Intertie Failure Charges;
4. Working with self-scheduling and intermittent generators to reduce their forecast errors;
5. Not subtracting emergency energy purchases from the market demand and adding an equivalent amount of demand reduction from voltage reduction to the market demand, thus reducing counter-intuitive price impacts during scarcity conditions;
6. Introducing the MIO (Multi-Interval Optimization) in the constrained sequence and thus removing some inefficiently high shadow prices; and
7. Lowering the ramp rate multiplier in the unconstrained sequence from 12 to 3.

Table 3-3 below summarizes our assessment of the effect of the above actions on either the Richview shadow price or the HOEP, or both. In brief, the changes in procedures regarding emergency energy purchases and voltage reductions have improved the fidelity of the HOEP, the implementation of MIO has led to a more efficient Richview shadow price, and other changes have improved both price signals.

Table 3-3: Effect of Actions on Quality of Price Signals

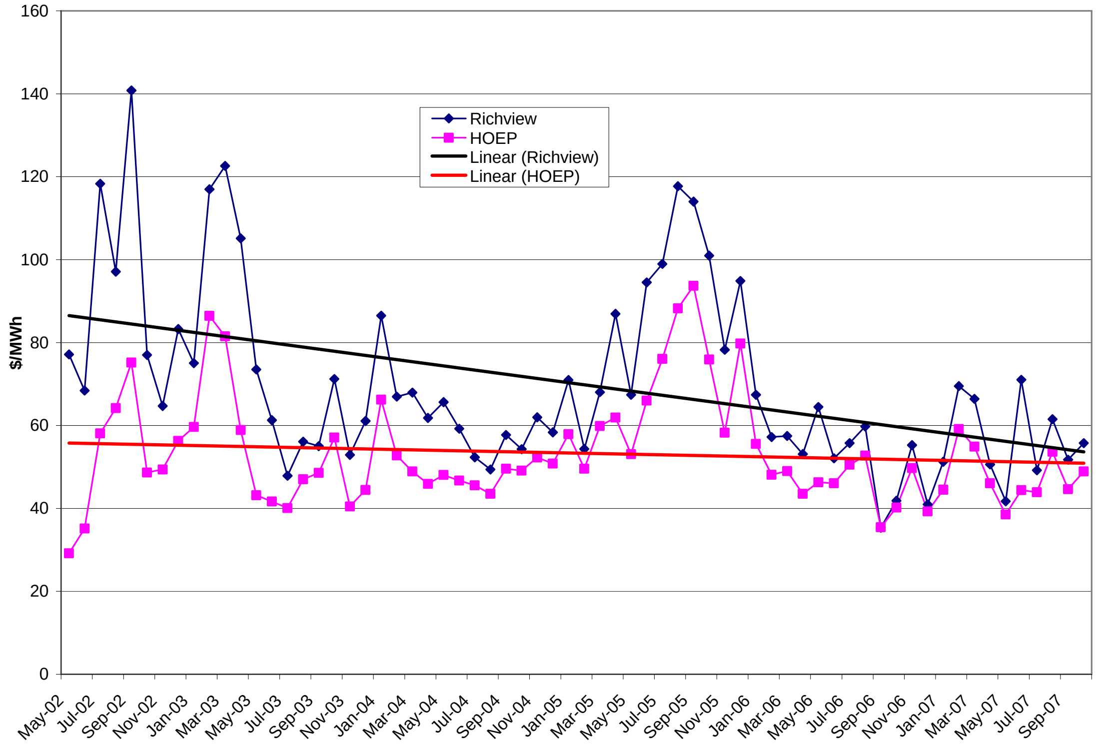
Action	Date Introduced	Richview Price	HOEP
CAOR	Aug. 2003 (400 MW), Aug. 2005 (+400 MW)	Improved	Improved
Reduced Forecast Error	On-going	Improved	Improved
Intertie Failure Charge	June 2006	Improved	Improved
Self-Scheduling Error Reduced	On-going	Improved	Improved
Emergency Energy & Voltage Reduction Added to Market Demand	Aug. 2005	None	Improved
MIO	June 2004	Improved	None
3 Times Ramp Rate	Sept. 2007	None	Improved

As well, the market has experienced improved supply conditions as shown by the increase in the supply cushion since market opening (see the data in Chapter 1). An implication of the increase in the supply cushion is that the market is operating on the flatter portion of the offer curve in both the constrained and unconstrained schedules and this should have the effect of reducing the gap between the Richview (constrained) price and the (unconstrained) HOEP.

Convergence Trend

Possibly as a result of the reforms introduced by the IESO and the increase in the supply cushion, the Richview nodal price and the HOEP have been converging. This is illustrated in Figure 3-3 below.

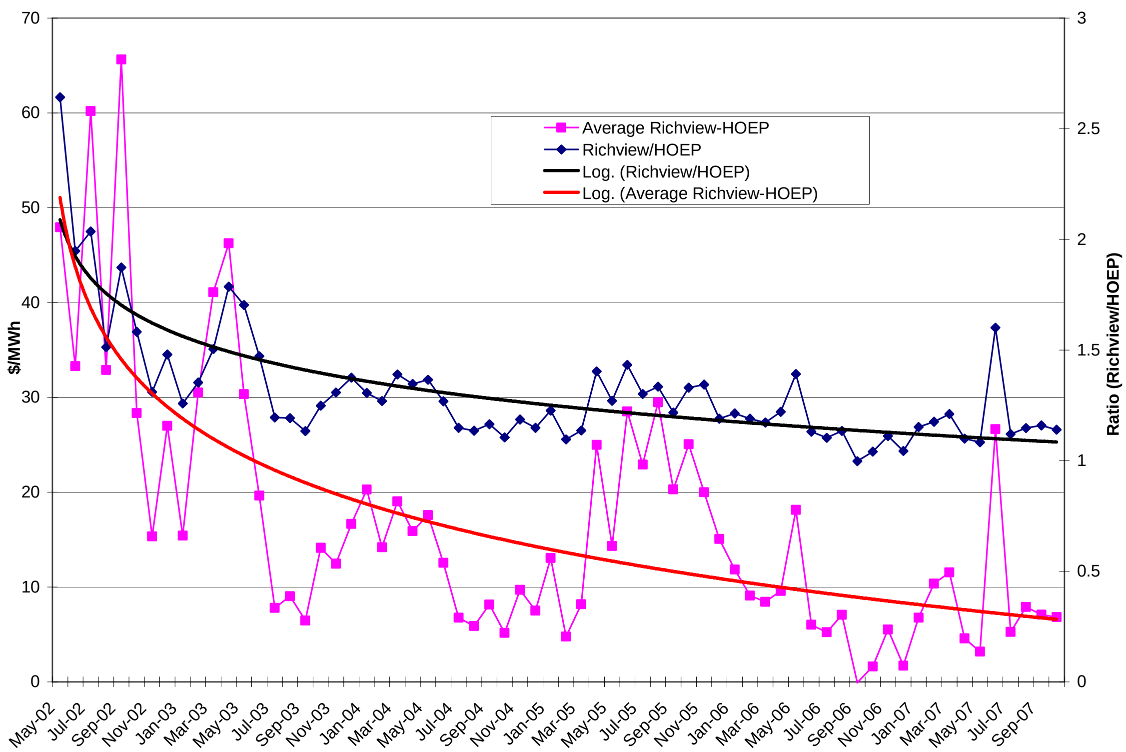
Figure 3-3: Monthly Average HOEP and Richview Shadow Price, May 2002 – October 2007



Convergence is also apparent in Figure 3-4 below which depicts both the monthly average difference between the Richview price and the HOEP, and the ratio of the Richview price to the HOEP.[74] Both the price gap and the ratio have decreased over time. The conclusion that the Richview price and the HOEP have converged is also supported by statistical analysis.[75]

[74] Like the HOEP, the Richview price is capped between $2,000 and -$2,000. Blackout period (from August 14 to 21) was excluded.
[75] Statistical (unit root) tests support this conclusion. The test model is the Augmented Dickey-Fuller test, which is detailed in our December 2004 report (page 68-69). This test is updated in this report.

Figure 3-4: Monthly Average Difference between the Richview Nodal Price & the HOEP, May 2002-October 2007



One interpretation of the convergence of the HOEP and the Richview price is that the artificial gap between the HOEP and the cost of producing power is smaller, thus reducing the inefficiencies resulting from the use of the HOEP as the market price. Another interpretation is that if the Richview price has been pushed down toward the HOEP by system operator control actions, the narrowing of the gap may not indicate any efficiency improvement in the market. In essence, convergence may be due to the HOEP becoming a more efficient price or Richview becoming a less efficient price or both. The purpose of the analysis reported below is to determine the major causes of the convergence of the HOEP with the Richview price.

In our December 2006 report, we identified some factors that could lead to the Richview price being lower than the HOEP. The factors identified in that report included demand forecast error, constrained off (net) exports, and the high minimum loading point of manually constrained on generation.

In this report we include two of these with other potentially important factors and undertake an econometric analysis to estimate their respective effects. The factors considered are:

- Transmission congestion from the northwest;
- Demand forecast error;
- Manually constrained on generation;
- Constrained off (net) exports; and
- Changes in the real-time supply cushion.

Transmission Congestion from the Northwest

The constrained sequence takes account of all transmission limits internal to Ontario and at the interties with other systems. In contrast, internal transmission limits are ignored in the unconstrained sequence. The most important source of transmission congestion is from the northwest area of Ontario to southern Ontario. Northwestern Ontario normally tends to have excess capacity that is bottled in the area due to transmission limitations. This bottled capacity is treated as being available to the market in the unconstrained schedule thereby imparting a downward bias to the HOEP. Any easing of transmission congestion or reduction in supply in the northwest would reduce this downward bias.

Figure 3-5 plots the total number of hours with significant transmission congestion between the northwest, northeast and all other zones and the Richview bus. A few large generators in each zone are chosen for purposes of this calculation, and the transmission is considered to be congested if the Richview price is at least 20 percent higher than the loss-adjusted average nodal price.[76] It can be seen that most

[76] The difference between the Richview price and a reference price at a node can be decomposed into two components – a loss and a congestion component. A detailed decomposition technique is demonstrated in the Panel's December 2006 report. The 20 percent price difference threshold is intended to distinguish incidents of significant congestion.

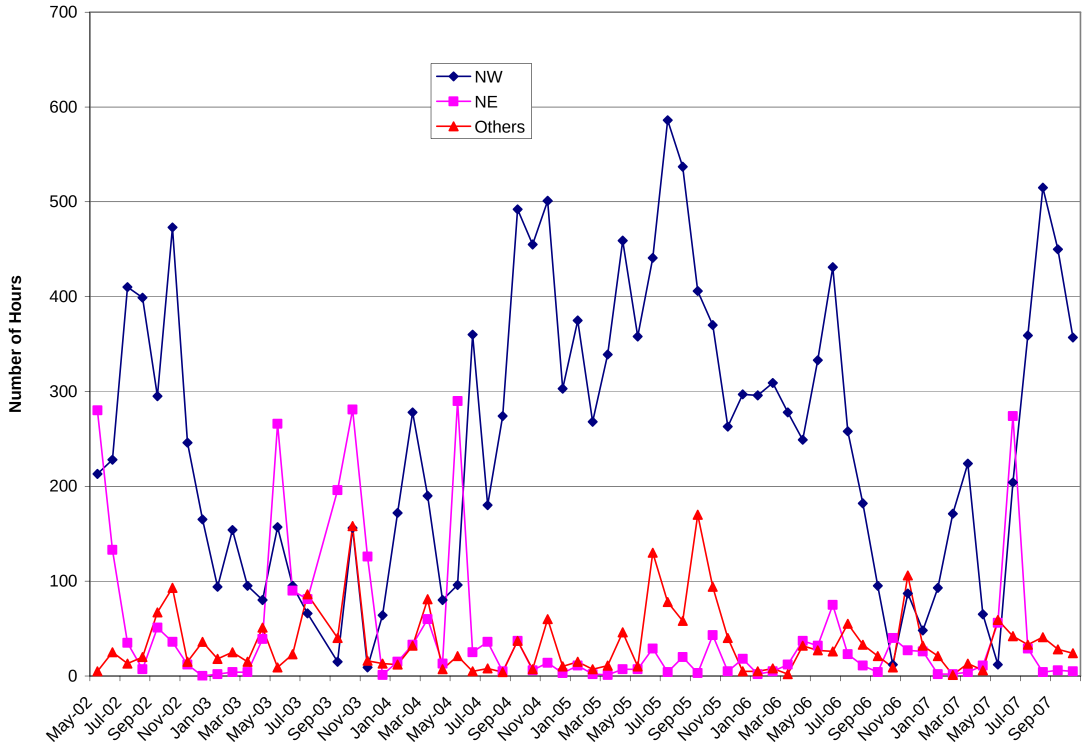
congestion occurs on the tie from the northwest area to the south. Although such congestion has been decreasing since the summer of 2005, it increased again in July to October 2007. The main reasons for the decrease in congestion before July 2007 are:

- fossil-fuelled generation in the northwest was staying off-line much more frequently; and
- there was less rainfall and thus less water available for hydro stations in the northwest to produce energy.

The increase in congestion in July to October 2007 was coincident with the increased availability of water in northwest.

In essence, between the summer of 2005 and June 2007, there was a reduction in the amount of bottled generation in the northwest, implying less phantom generation in the unconstrained schedule and therefore a reduction in the downward bias of the HOEP.

Figure 3-5: Number of Hours per Month with Significant Congestion from Various Zones to the Richview Bus, May 2002 - October 2007



Demand Forecast Error

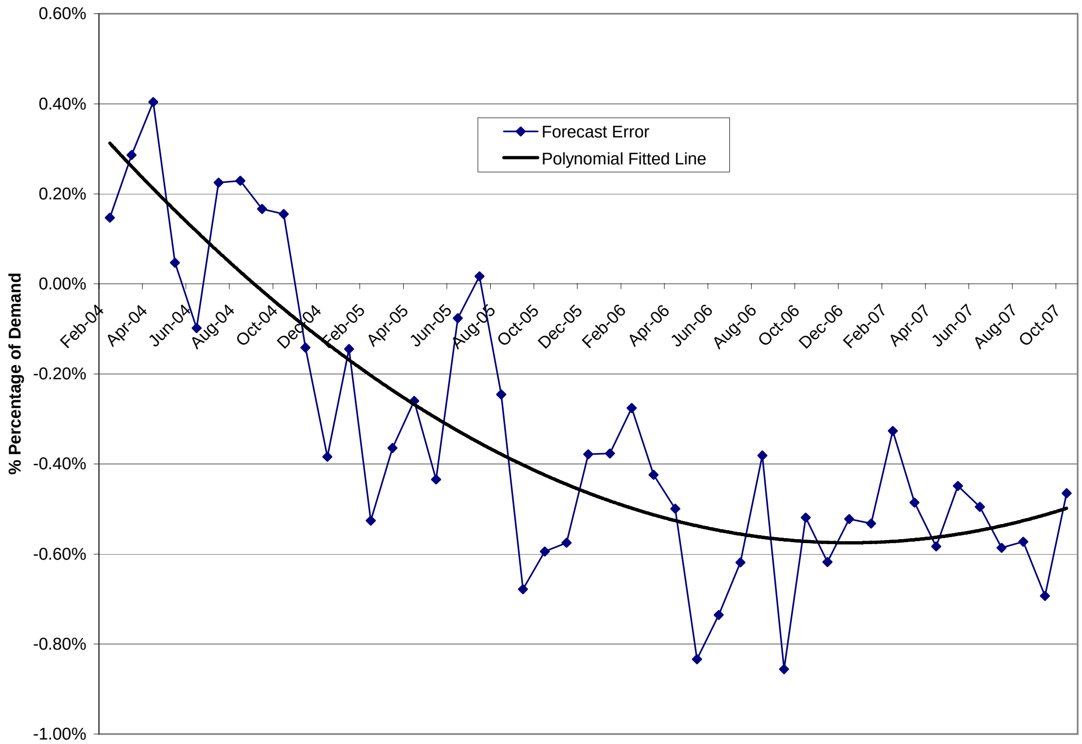
The constrained sequence uses a ten-minute-ahead demand forecast, while the unconstrained sequence uses actual demand (plus adjustments when certain control actions such as voltage reductions have been taken).

Figure 3-6 plots the monthly deviation between the forecast demand used for calculating the Richview shadow price and the adjusted actual demand used for calculating the MCP and the HOEP.[77] The data are available from February 2004 onward. It is apparent that demand was increasingly under-forecast from late 2004 through late 2006 but the discrepancy between forecast and actual demand has been

[77] The demand forecast for calculating the shadow price is an average demand while the demand for calculating the MCP is a snap shot demand at the time when the unconstrained sequence runs. The demand used for the MCP calculation may be adjusted if there is a voltage reduction.

roughly stable since late 2006. The under-forecast of demand in the constrained sequence biases the Richview price (and all other nodal prices) downward.

Figure 3-6: Demand Forecast Error, February 2004 – October 2007



It appears that the demand was persistently under-forecast since early 2005. In our July 2007 report, the Panel noticed that the consumption deviation of dispatchable load can be a source of forecast error because the IESO's forecast model counts the deviation as a portion of forecast demand of non-dispatchable load.[78, 79] We have asked the MAU to continue monitoring the forecast error.

Recommendation 3-1:

Consistent with prior recommendations directed at improving the IESO load predictor, whose algorithm imputes changes in non-dispatchable load that can induce consumption inefficiency and

[78] MSP monitoring report, July 2007, pp. 100-106
[79] To a minor degree historically but more so in future, there are other causes of forecast errors including RESOP projects that are located behind the LDC meters and proposed CESOP projects, as will be discussed in section 4.4 of this Chapter.

forecast errors, the Panel recommends that the IESO review its load predictor methodology to determine if it is a source of persistent under-forecasting of demand.

Manually Constrained On Generation

Generation is said to be manually constrained on when it is constrained on by the IESO control room rather than by the dispatch algorithm. When generation is constrained on manually, the additional supply involved is added to the bottom of the constrained offer stack, shifting it to the right. This lowers the nodal prices, including the Richview price. Manually constrained on generation is not included in the market (unconstrained) schedule and it does not affect the HOEP.

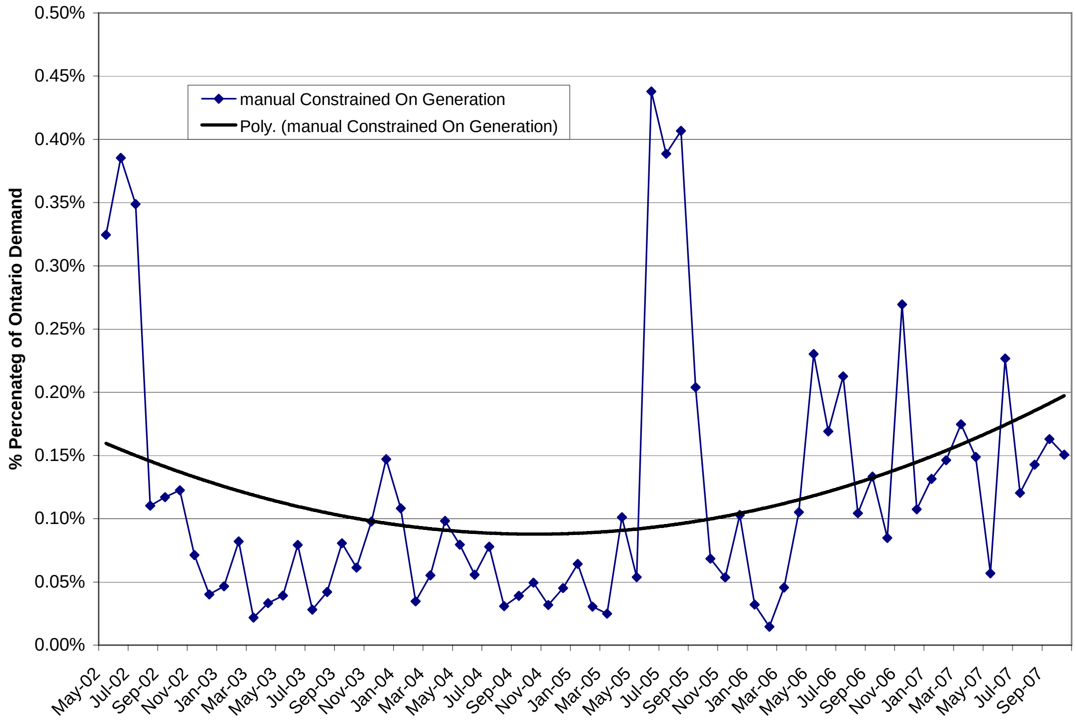
Fossil generation is constrained on manually for a variety of reasons. First, fossil units have a minimum run-time (MRT). At times, in order to keep a unit online for the required period, the IESO must manually constrain it on during hours when it is not otherwise selected based on its offer prices. A second reason is that a fossil generator usually has a minimum loading point (MLP). The unit cannot operate stably at output levels below the MLP without shutting-down. At times, in order to keep the unit on-line the IESO must constrain it on to the MLP during hours where it is not selected based on its offers. A third reason is fossil generators have a long lead time in order to start. If the IESO expects the market will not solve its reliability concerns in future hours, it may constrain a generator on even if the unit is offering above the relevant nodal price.

The IESO use of manually constrained on generation has increased over the last couple of years with the addition of new gas-fired generation facilities. This type of generation has a long MRT and a high MLP. For example, for a 500 MW coal-fired generator the MLP is in the order of 20 percent of its capacity (100 MW) while for a similar sized gas-fired generator the MLP is 75 percent of its capacity (375 MW). If the IESO constrains on a gas-fired generator, this generator is forced to produce at a fixed level or a minimum level regardless of its offer price. In other words, the

DSO puts this constrained energy at the bottom of the supply stack when it calculates the nodal price, which is equivalent to a rightward shift in the offer curve. An observation is that due to the physical characteristics of this gas-fired generation this high variable cost generation is being treated as if it were low variable cost generation. This lowers the Richview price when measured against the HOEP. This downward trend may have increased over time because of the increase in the MLP and MRT of the generation fleet and also because the introduction of programs such as SGOL and DACP increases the frequency with which generation is manually constrained on.

Figure 3-7 plots monthly total constrained on energy due to manual actions relative to the total Ontario demand. One can see that the IESO has been increasing its use of manual actions, which tends to lower the Richview price in relation to the HOEP. The marked increase in manually constrained on generation in 2006 coincides with the inception of the DACP.

Figure 3-7: Manually Constrained on Energy Relative to the Ontario Demand, May 2002 – October 2007

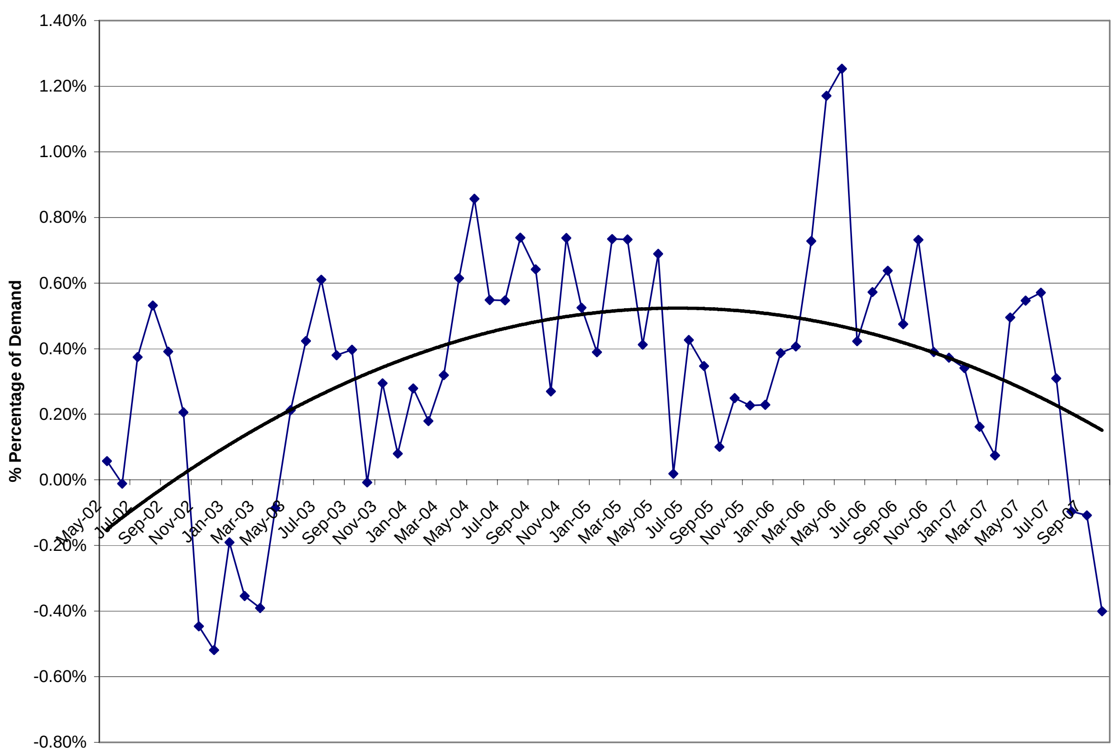


<u>Constrained off Net Exports</u>

With the improved domestic supply/demand balance, Ontario has become a net exporter (as can be seen from the data in Chapter 1). The major export markets are New York and Michigan. The export capability of the interfaces with these markets is partially a function of what is called Lake Erie Circulation (LEC or loop flow). Loop flow has the effect of reducing transmission capacity on the interties, but can also reduce the availability of transmission within Ontario even more, with the result that some exports that cannot be supported by internal transmission are still scheduled in the unconstrained sequence. These exports in the unconstrained schedule but not in the constrained sequence are constrained off exports. Constrained off exports appear in the unconstrained (market) schedule with the result that this demand is overstated and the HOEP is biased upwards.

Figure 3-8 below plots monthly total constrained off (net) exports. A positive number indicates that there are more (net) exports in the unconstrained sequence than in the constrained sequence, implying a higher demand in the unconstrained sequence and thus a higher HOEP. Constrained off exports increased relative to total demand until mid-2006 after which they have been decreasing. With more constrained off exports HOEP is thus higher relative to the Richview shadow price, while fewer constrained-off exports reduce HOEP relative to the Richview shadow price. The generally increasing level of constrained-off net exports should have had an effect of narrowing the gap between the Richview price and the HOEP, since HOEP was lower to start with and it moves upward relative to the shadow prices, because of the higher relative demand. The more recent reduction in the level of constrained-off exports tends to remove some phantom demand in the unconstrained sequence and thus bring down the HOEP relative to shadow prices, widening the gap between the Richview and the HOEP.

Figure 3-8: Monthly Constrained off Net Exports, May 2002 – October 2007



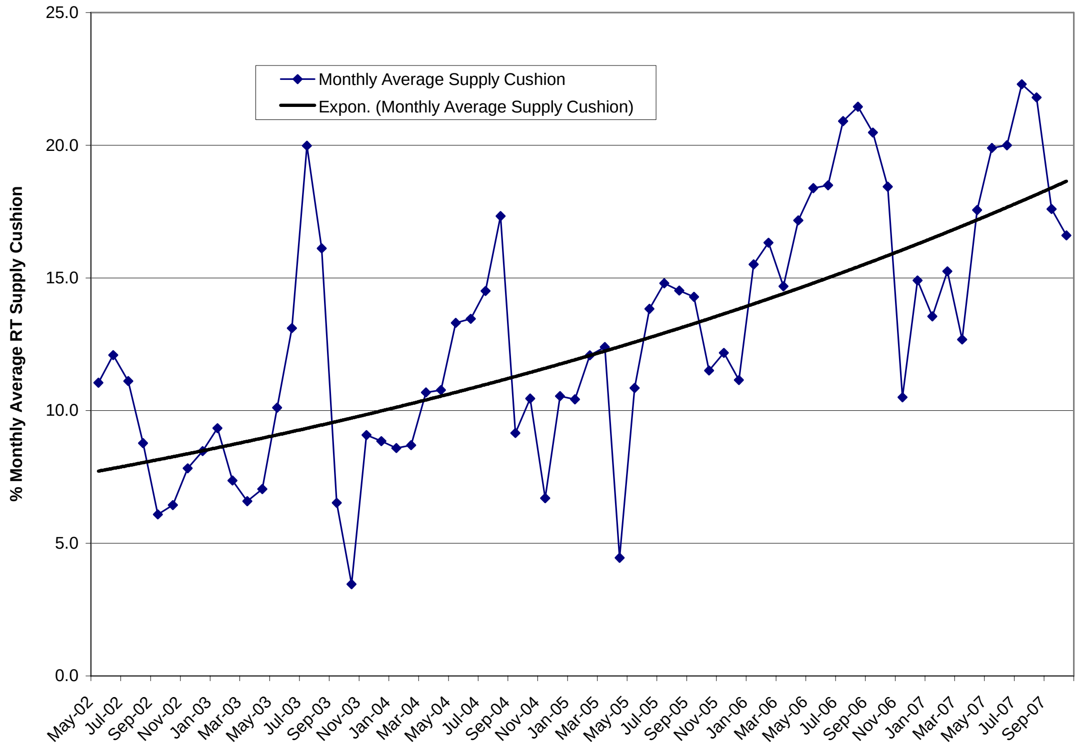
Real-Time Domestic Supply Cushion

The real-time domestic supply cushion is an indicator of the demand and supply balance in real-time.[80] As noted in Chapter 1, the supply cushion measures the excess of available generating capacity over total demand (energy plus the OR requirement).[81] A bigger supply cushion implies a greater ability to respond to demand or supply disturbances in both the constrained and unconstrained sequences. This tends to not only smooth price spikes in both sequences, but also to narrow the gap between the Richview price and the HOEP because a spike in the HOEP is often associated with a proportionately greater spike in the Richview price due to transmission constraints.

Figure 3-9 below charts the monthly average domestic supply cushion from May 2002 to October 2007. It is apparent that the supply cushion has been increasing over time, implying an improved supply/demand balance. This would have helped to reduce the gap between the Richview shadow price and the HOEP.

[80]To see how the Panel constructs the supply cushion, refer to our April 2007 report, page 79-82.
[81] Note the supply cushion does not include the offers from a fossil generator that is offline. Therefore an increased supply cushion can be a result of either improved fundamentals of supply/demand condition, or simply fossil generators that stay online more frequently and/or for a longer period of time. As the Panel noted in its April 2007 report, the SGOL and DACP programs may have induced some gas-fired generators to stay online longer or come online more frequently than required and thus improved the supply cushion.

Figure 3-9: Average Monthly Real-Time Domestic Supply Cushion, May 2002 - October 2007



Relative Effects of the Factors Contributing to Convergence: An Econometric Decomposition

The Panel have been working with the MAU (supported by the IESO) on an econometric model of the difference between the Richview nodal price and HOEP to help explain the price convergence we have noted over the past few years. The technique used is an Oaxaca decomposition, which can provide insights on how much the price gap has changed as result of changes in the explanatory variables, as well as the sensitivity of the price gap to these variables from one year to the next. Appendix 3.1 at the end of this Chapter provides the details on this decomposition technique and its results.

The decomposition allows year-to-year comparisons. For illustration simplicity, we only report and compare 2004 with 2007 results, for off-peak and on-peak. 2004 was chosen as the earliest date with sufficiently full and accurate data. The decomposition employed the five explanatory variables discussed earlier in this section.

In the off-peak period, the gap between the Richview price and the HOEP narrowed by $2.66/MWh (from $7.70/MWh in 2004 to $5.04/MWh in 2007). The decomposition analysis shows that, to the extent that variation in the price gap can be explained by the selected variables, the narrowing of the Richview nodal price and HOEP gap between 2004 and 2007 is largely attributable to the supply cushion variable and, to a lesser degree, the demand forecast error variable. The increase in the supply cushion reduced the amount by which HOEP was lower than the Richview price, while increasing the under-forecast of demand in the constrained schedule suppressed the Richview price. The improved supply cushion implies a reduction in the price difference of between $3.48/MWh and $7.39/MWh, and the increased demand under-forecast by between $0.49/MWh and $4.18/MWh.

In the on-peak period, the price gap narrowed by $2.3/MWh, from $16.34/MWh in 2004 to $14.00/MWh in 2007. The improved supply cushion and increasing demand under-forecast were the most important explanatory variables leading to the change although the importance of each is less certain than for the off-peak analysis because of the smaller identified effects in 2004. The supply cushion reduced the gap by between $2.60/MWh and 4.63/MWh, and the demand under-forecast by between $0 and $15.14/MWh.

However, the on-peak model also shows a very large change, $15.49/MWh, in the constant terms between the two years. This implies that some other important factors were not captured by the model, which appears to have had an effect of increasing the difference in the two prices. The change may also indicate that a linear structural model is not adequate for representing the underlying process.

The possibility that other important factors have been omitted or that the structure of the model is not sufficiently accurate is also demonstrated (in the Appendix) by large changes in the coefficients of many of the variables between 2004 and 2007. Changes in these coefficients combined with the changes in the constant term imply almost as large changes in the Richview nodal price and HOEP difference as the explanatory variables themselves.

In both the off-peak and on-peak analyses, the other variables (congestion between the northwest and the south, manually constrained on generation, and constrained-off net exports) had limited effect on the gap between the two prices in the two comparable years.

The optimization processes which determine the Richview nodal price and HOEP are complex and non-linear, and thus the effects of the factors studied above on the price convergence should be complex and non-linear. The large difference in the marginal effects due to coefficient changes from year-to-year suggests that either the linear approximation is not a good approach for modeling this non-linear process, or parameters not modeled have significantly changed and affected the prices and price differences.

This econometric decomposition, although not perfect, does provide some insights, for example that of the factors considered, the improved supply cushion and demand under-forecast had the largest impact on the convergence of the two prices. However, our analysis shows that the determinants of the gap between the Richview price and the HOEP vary significantly over time.

2.4 An Inefficient Demand Response Event

In its December 2006 report, the Panel discussed the issue of demand response programs in the Ontario market. In the Panel's view, conservation should not mean simply using less electrical energy. Conservation is properly defined as efficient use and stewardship of resources in general.

The MAU observed an event in early November of 2007 that highlighted an inefficiency in one of the current demand response programs. The Panel felt it would be worthwhile including this event in this report rather than its normal reporting cycle of November 2007 to April 2008 which would be six months hence.

The Ontario Power Authority (OPA) implemented a Demand Response Program Phase I (DR1) on June 23, 2006, having about 270 MW registered capacity as of December 2006.[82] The maximum curtailment in a single hour to the end of 2006 was estimated as 140 MW.

The key components of DR1 are as follows:

1. The program requires eligible participants to have a demand response capability between 0.5 MW and 100 MW.
2. Each month, participants submit a strike price at which they are willing to curtail consumption. The strike price must be equal to or exceed the floor price provided by the OPA for the contract period. The floor price was $80/MWh for November 2007.[83]
3. If the IESO three-hour ahead price hits the strike price, a program participant may indicate to the OPA that it will reduce its consumption for that hour and up to two hours after the event.
4. The OPA will pay the participant an amount equal to the verified demand reduction times the strike price for each eligible hour. The verified demand reduction for an hour is measured against a baseline demand. The baseline demand is measured on an hourly basis as the average of the ten highest consumption levels for the given delivery hour in the past eleven days or through an alternative approach proposed by market participants and approved by the OPA.

[82] See "Review of Phase One of the Demand Response Program" by Price Watch House Cooper dated at March 30, 2007. www.powerauthority.on.ca/
[83] The OPA updates the floor price monthly on its website: www.powerauthority.on.ca

On November 7, 2007 a major north-south transmission line in the Northeast part of the province was out of service for planned maintenance, resulting in over 700 MW of hydroelectric generation being bottled in the zone. A DR1 load located in the Northeast (the congested zone), was activated by the load under OPA's Demand Response program in HE 18 to 23 of November 7, curtailing 50 MW of consumption.[84] In response to the reduction in the DR1 load in this congested area, the IESO had to constrain down an additional 50 MW of hydroelectric generation.

For HE 18, the three-hour ahead price, at $85.76/MWh, was above the OPA's published floor price of $80/MWh. That the DR1 load chose to activate the program implies that its contract price must be somewhere between $80/MWh and $85.76/MWh. The load notified the IESO at 16:45 (HE 17 Interval 9) after the final pre-dispatch schedule for HE 18. The load reduction lasted from hours 18 through 23, implying the DR activation was in effect in those hours. (Note that the three hour ahead prices for the six hours were all above $80/MWh, the OPA's floor price).[85]

Table 3-4 below lists the unconstrained prices, estimated shadow prices, as well as estimated efficiency losses and constrained off payments due to the activation of the DR1 load. Although the three-hour ahead pre-dispatch price in all six hours was above $80/MWh, the HOEP was well below $80/MWh except in HE 19. The shadow prices in the Northeast (Marginal Cost Column) are estimated as the IESO manually constrained down the units in the area due to the transmission outage and thus the shadow prices produced by the DSO are not an accurate indicator of the actual marginal production cost. Based on actual schedules and offer prices at the time, we estimated that the true shadow prices should be close to $3/MWh, which is well below the OPA's floor price. Given that the implied consumption value to the

[84] Market Manual 7.1 section 3.3.4 requires a wholesale load to notify the IESO if it is going to deviate from its routine consumption by more than 50 MW in north (north of ESSA in Barrie) or by more than 100 MW in the south (south of ESSA). A load, however, is not required to report the reasons for the deviation. The current case caught the Panel's attention as the consumers happened to notify the IESO that the load curtailment was due to the OPA's DR1.
[85] In general, the Panel has no information on whether or not a load curtailment is due to the OPA's DR program or the load's own consumption interruption. This information is strictly confidential between the OPA and the market participant. Based on the three-hour ahead prices and the load's consumption, we believe it reasonable to assume the consumption reduction in all these hours was due to DR1.

DR1 load is $160/MWh,[86] total efficiency loss (i.e. reduced consumption times the difference between the marginal value and marginal cost, $160/MWh and $3/MWh respectively) in these hours amounted to $48,000.

Table 3-4: Prices, Implied Value, and Efficiency Loss, November 7, 2007

	3 hr ahead price $/MWh	HOEP $/MWh	Marginal Cost in North $/MWh	Contract Price $/MWh	Implied Value to Consumer $/MWh	Efficiency Loss to Market $(000)	Constrained off to Hydro Unit $(000)
18	87.56	54.71	3	80	160	8	3
19	99.29	96.11	3	80	160	8	5
20	83.99	62.96	3	80	160	8	3
21	87.56	48.83	3	80	160	8	2
22	87.56	41.97	3	80	160	8	2
23	83.41	35.66	3	80	160	8	2
Total						48	17

In the six hours (from HE 18 to 23), we assume the DR1 load was paid $24,000 (50MW*$80/MWh*6hrs) for reducing consumption and the hydroelectric generator was paid a constrained off payment of about $17,000 for reducing production. These payments, totalling $41,000, are paid by other consumers.

Although the DR1 is structured to invite efficient bids (i.e. the strike price is intended to reflect the preferences of individual loads), inefficiency remains because the value of consumption foregone by loads is roughly twice the avoided cost of generation.

Given the implied value of consumption to a load, activation of a DR program is very likely inefficient. In the case of November 07, 2007, the activation led to an efficiency loss as high as $48,000, which is almost exactly equal to the lost value of

[86] The implied consumption value is equal to the HOEP the load avoided (projected to be $80/MWh) and the price it was paid (we assume $80/MWh). For the load to be willing to forego consumption, its profit when consuming (approximately Value – HOEP) must be no more than its profit not consuming (the payment it receives from OPA = Strike Price), or Value – HOEP = Strike Price. If a load has a higher strike price, its implied consumption value is higher, which is equal to twice its strike price, since the projected HOEP is approximately equal to its strike price..

consumption (because of the low incremental cost) and twice the payment to the load for its reduced consumption.

The case is a concrete illustration for market participants of our earlier comments in the December 2006 report:

> "If demand response programs are deemed to be required they should be designed so as to enable customers to: (i) curtail their consumption of a service (or have it curtailed on their behalf) when the value customers derive from the service is less than the incremental cost of providing it and; (ii) consume when the value they derive from the service exceeds the incremental cost of providing it. Incentive programmes that induce customers to curtail consumption at times when the value they derive from the service is greater than the incremental cost of providing do not conserve resources in the true sense of the word."[87]

In our analyses and comments the Panel focuses on the efficiency implications for the market, although in a broader context there may be other public policy goals relevant to the discussion of these programs.

2.5 The Effect of Phase Shifters on the Michigan Interface

In our December 2005 monitoring report, the Panel discussed an issue involving Phase Angle Regulators (PARs) between Ontario and Michigan: two at Ontario's Lambton Generating Station and one at ITC*Transmission*'s (ITC) Bunce Creek station in Michigan. PARs (commonly referred to as Phase Shifters), are specialized transformers which are designed to allow operators to control the amount of power flowing on an interface within certain limits. In this case the PARs, designed to allow control of up to 500 MW in either direction,[88] were intended to limit the inadvertent parallel flow (Loop Flow)[89] of power through Ontario between New York and Michigan (commonly referred to as 'Lake Erie Circulation' (LEC))

[87] See our December 2006 report at page 140.
[88] For example, if LEC was measured to be 700 MW, the PARs could reduce this parallel flow to 200 MW, thus enabling increased import or export transactions by allowing transmission capacity to be more usefully employed.
[89] Loop flows are discussed in more detail in our December 2006 monitoring report, pp 113 – 117.

and thus increase effective import/export capability on the Michigan and also the New York interfaces. High LEC can cause congestion on Ontario's transmission system which may affect market efficiency and also reliability.

During the Panel's 2005 monitoring activities, the MAU brought to our attention that there had been an upward trend in the number of hours in which import congestion occurred and a reduction in the average import capacity of about 400 MW at the Michigan interface. This coincided with and was the result of placing the Lambton PARs in service.

Several of the issues identified in our December 2005 Report have been resolved:

1. Hydro One has restored circuit B3N to service following successful re-negotiation of a right-of-way easement with the local First Nations band.

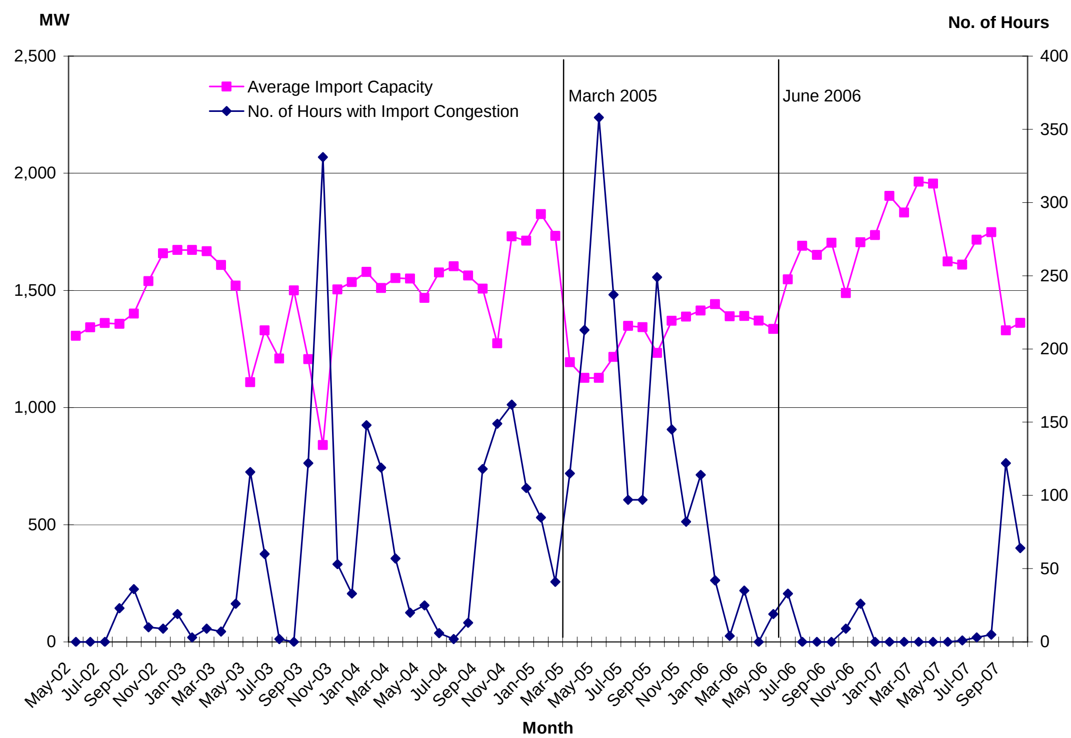
2. Once the above B3N issue was resolved, ITC ordered new PARs for this circuit and these are expected to be in-service in mid-2009.

3. Because the PARs limited import capability, the IESO and Hydro One worked together to bypass them in early June 2006 following Hydro One's confirmation that this was technically feasible and an operational procedure was developed to enable the PARs to be returned to service within 30 minutes in an emergency. The bypass restored interchange capacity to previous levels as shown in Figure 3.10.

   The lower import capability in September and October 2007 was due to a planned outage of transmission line L4D to facilitate system enhancements and expansion in Lambton area, particularly the connection of the new Sarnia Greenfield and St. Clair generators. This outage reduced the import capability by about 400 MW until the line was returned to service in mid November 2007.

4. Hydro One has signed an Interconnection Facilities Agreement (IFA) with ITC and the companies are developing a Standard Operating Procedure (SOP) which we understand is expected to be completed by year-end 2007. Hydro One advised the Panel that the SOP is expected to cover Limited Time Ratings (LTR) for all PARs at Lambton and Bunce Creek and to allow these PARs to be operated to control power flows as designed.

Figure 3-10: Monthly Average Import Capability and Number of Hours with Import Congestion on the Michigan Interface, May 2002 - October 2007



As noted in our earlier monitoring reports, the manufacturer of the PARs has provided Hydro One with Continuous Ratings and 15 minute Limited Time Ratings. This 15 minute LTR has little utility from an operations perspective due to MISO's inability to re-position their system to limit power flows within 15 minutes. NERC standards require the ISOs to be able to do so as soon as possible following a contingency, but within 30 minutes at the most. The 15 minute rating thus only indicates (from the manufacturers perspective) that a higher than ‘continuous’ rating is feasible for the PARs for short periods in contingency situations.

Hydro One advised that it recognizes the importance of the PARs to enable efficient market operation and their contribution to reliability in both Ontario and Michigan. However, they are concerned about the risk to the equipment of extending operating ranges, particularly given the failures of all the original phase shifters as they were being commissioned into service. This concern has led to a conservative operating philosophy which is reflected in Hydro One’s IFA with ITC. The IFA calls for a relatively wide 300 MW ‘dead band’ within which the tap changers[90] will be not be operated. This dead band will only be reduced based on operating experience.

Consistent with this concern, Hydro One has expressed its reluctance to modify any operating parameters until sufficient experience has been gained to verify the PARs’ condition and performance under normal operating conditions. This will entail operating the PARs over both a reasonable period of time (likely a number of months) as well as under a variety of conditions including relatively heavy loading and substantial tap changer operations

Once this operating experience has been obtained, Hydro One is willing to undertake the necessary studies related to moving to a 30 minute LTR. Hydro One also indicated that it is waiting for IESO to complete its necessary agreements with the Michigan parties and indicate its readiness to terminate the previous interconnection agreement, and that all parties have trained staff in place to operate the PARs. The sooner these agreements are in place, the sooner this operating experience can be gained.

[90] Tap changers are the electro-mechanical devices that regulate the degree to which the PARs control power flows over the inter-connections.

The IESO has advised the Panel that it and Hydro One have agreed that a clear and unambiguous understanding of the terms of the IFA and SOP is required in their Operating Agreement. Therefore, IESO has placed a high priority on resolving outstanding issues and completing its agreements with Hydro One, ITC and MISO. These involve modifying an Operating Instruction with MISO, ensuring that the operating staffs of all four parties are trained in the intricacies of the revised interconnection and finally, terminating an old interconnection agreement with MISO's predecessors. The IESO expects that completion of these items will allow normal operation of the existing PARS by the end of the first quarter of 2008, i.e. ahead of next summer's peak period. When the B3N PAR is placed in service by ITC in mid-2009, control of Lake Erie Circulation will be fully operational and full import capability of about 2,500 MW realized over the Michigan ties. Also, even before the B3N Pars are in service, import capability will be enhanced with the Lambton PARs operational.

While we understand and respect Hydro One's concerns for the safety of the PARs, we continue to urge Hydro One to develop appropriate LTRs for these units as soon as possible. Hydro One has noted that the sooner that the IESO completes its necessary agreements with the Michigan parties and indicates its readiness to terminate the previous interconnection agreement, and that all parties have trained staff in place to actually operate the PARs, the sooner operating experience can be gained to allow determination of the feasibility of establishing a 30 minute LTR. Because the increased LEC has become a large issue to the system reliability and market efficiency, full functioning of these PARs will significantly reduce the loop-flow and bring a significant benefit to the Ontario and US markets.

Recommendation 3-2

(1) The IESO should expedite completion of the necessary agreements with Hydro One, the Midwest ISO and ITCTransmission for operation of the Phase Angle Regulators on the Michigan intertie. The IESO

(and Hydro One) should also complete necessary staff training as soon as possible. Any improvement on the spring 2008 target date would have positive efficiency (as well as reliability) effects on the Ontario (and Midwest ISO) system and any slippage would have the opposite effects.

(2) Hydro One should work towards developing ratings that will safeguard the Phase Angle Regulators and provide operationally useful Limited Time Ratings as soon as possible.

3. *New Matters*

3.1 Dispatch issues

Several previous Panel reports have discussed the issue of the volatility of dispatch instructions and over the past several years the IESO has undertaken measures to minimize the effect of this volatility on generators.

These IESO measures include:

1. an increase in the generator compliance dead band to 15 MW from 10 MW on May 8, 2006;
2. compliance aggregation for hydroelectric generators which allows substitution of production by a facility with a similar grid effect, June 7 2006;
3. replacement offers, August 19, 2006;
4. fossil units with symmetrical ramp rates,[91] Fall 2006; and
5. fossil units with non-symmetrical ramp rates, December 2007.

Many of these measures were discussed in the Panel's report of December 2006.[92] These measures are designed to reduce the inefficiencies associated with volatile

[91] Specified fossil units can substitute energy for each other, with certain restrictions, including the requirement that their ramping-up and ramping-down capabilities are the same (i.e. symmetrical) in corresponding production ranges.
[92] More detailed explanations can also be found on the IESO website at Stakeholder Engagement Plan 9 www.ieso.ca

dispatch both in the short-term (inefficient fuel conversion) as well as the longer term where volatility increases maintenance costs and outages.

These measures do not address the root causes of either dispatch volatility or interval to interval price volatility. Dispatch volatility arises as a result of:

.

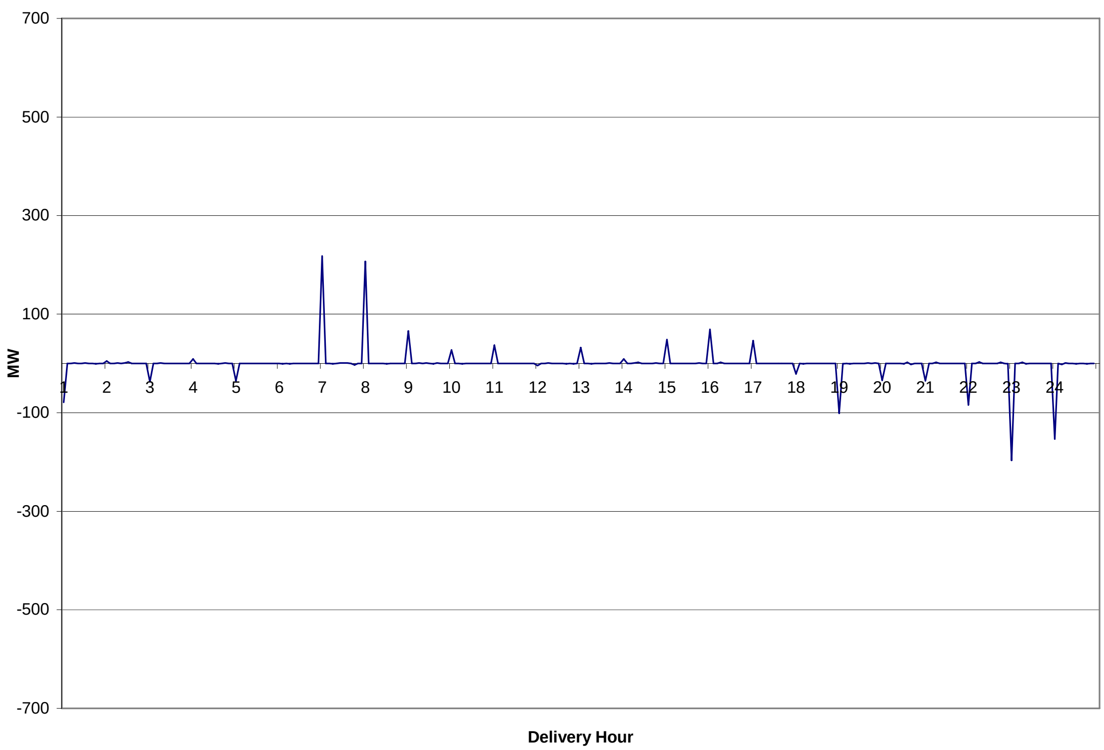
1. interval to interval changes in the Ontario demand;
2. deviations by generators and dispatchable loads from their dispatch instructions (whether or not this constitutes non-compliance);
3. deratings and forced outages of generators;
4. deratings and forced outages of transmission facilities, changes in flow limits or externally-induced loop flows;
5. cross-hour changes in generator offers (especially by peaking hydro generators); and
6. cross-hour changes in import and export offers.

Normally, Ontario demand is characterized by fairly smooth interval-by-interval increase and decrease of load across the day. In contrast, market demand, which is a combination of Ontario demand and the hourly change in demand and supply on the inter-ties, exhibits abrupt hourly changes. The hourly change in intertie demand/supply is not a reflection of changes in demand in other markets. Rather, it is a consequence of the design of the institutions linking Ontario with other markets. The limitations of these linking institutions are commonly referred to as 'seams issues'. One of these limitations is that decisions regarding imports and exports must be made far enough ahead of the hour to allow the various ISOs to co-ordinate intertie flows. These decisions are made hour-ahead and, once chosen, become non-dispatchable.

The coordinated change in net imports is made on the hour. In response to changes in net imports, marginal domestic generators must either increase or decrease their output rapidly over a ten minute time period. In recognition of the limited capability of internal generation to be ramped to accommodate changes in net imports, the IESO maintains a Net Interchange Scheduling Limit (NISL) of 700 MW. The purpose of the NISL is to limit intertie schedule changes to a maximum of 700 MW between hours.

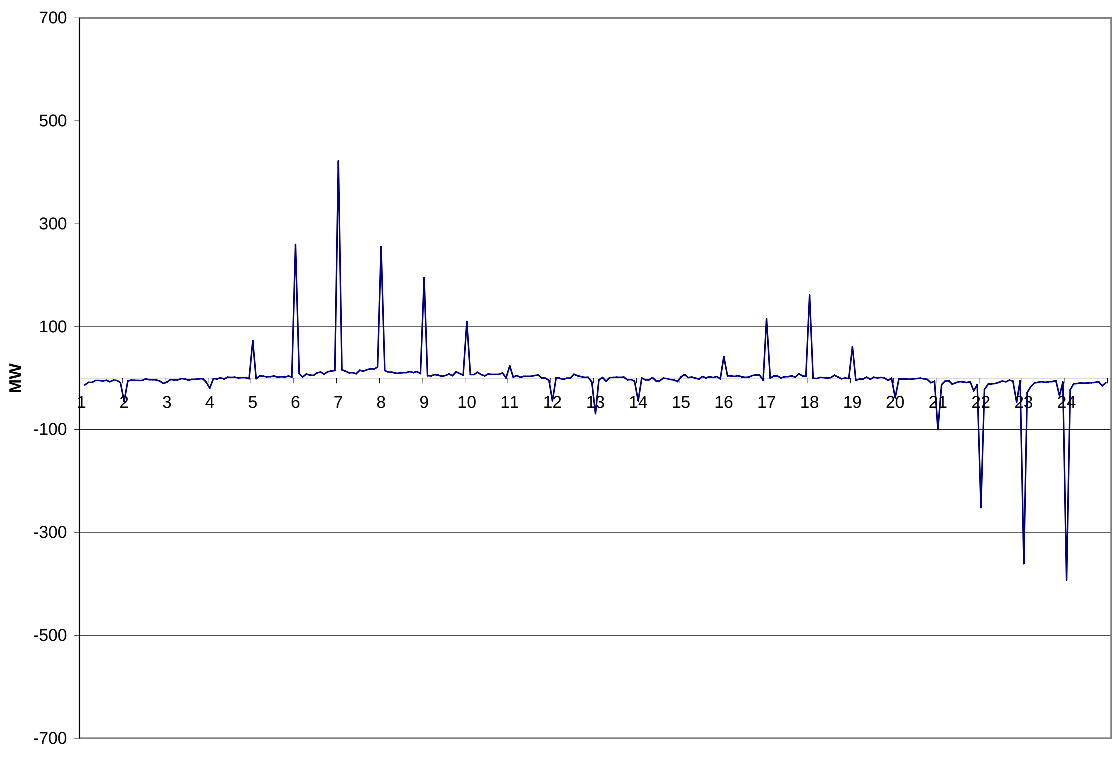
Figure 3-11 below shows the average interval to interval change in net imports from October 1, 2006 through September 30, 2007. Typically, these changes happen on the hour. It is apparent that there are abrupt changes in net imports in the morning ramp hours of HE 7 and HE 8 when exports decline and imports increase as prices rise across the day, leading to a net import increase of 200 MW on average. Again, in the evening hours as exports typically increase and imports decrease, we see a net export increase of roughly 150 MW hourly.

Figure 3-11: Average Net Import Change across Intervals, November 2006 - October 2007



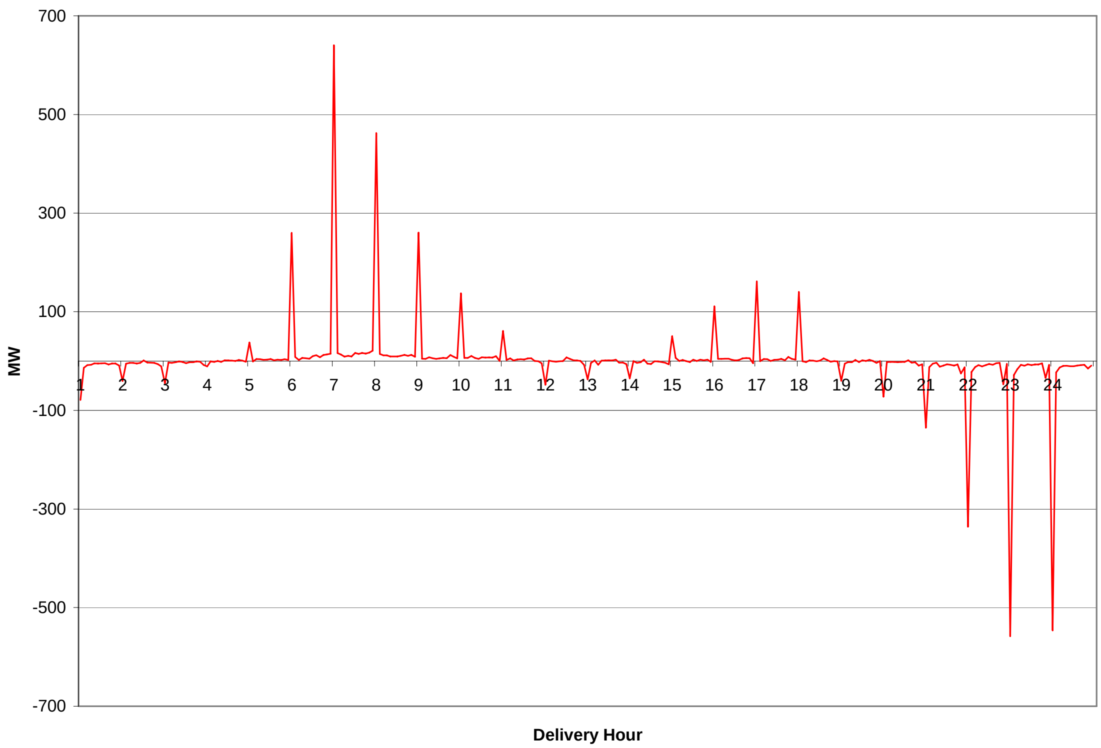
A further source of volatility comes from the abrupt arrival or departure of hydroelectric generators on the hour. Hydroelectric generators wishing to be assured of either running or not running during a particular hour tend to offer either well into the money or well out of it. This implies that there will be a large swing on the hour as hydroelectric generators enter the market in the morning, leave it in the afternoon, return for the evening peak and leave again in the late evening. This is in fact what is observed in Figure 3-12 below.

Figure 3-12: Average Net Change of Hydroelectric Resources across Intervals, November 2006 - October 2007



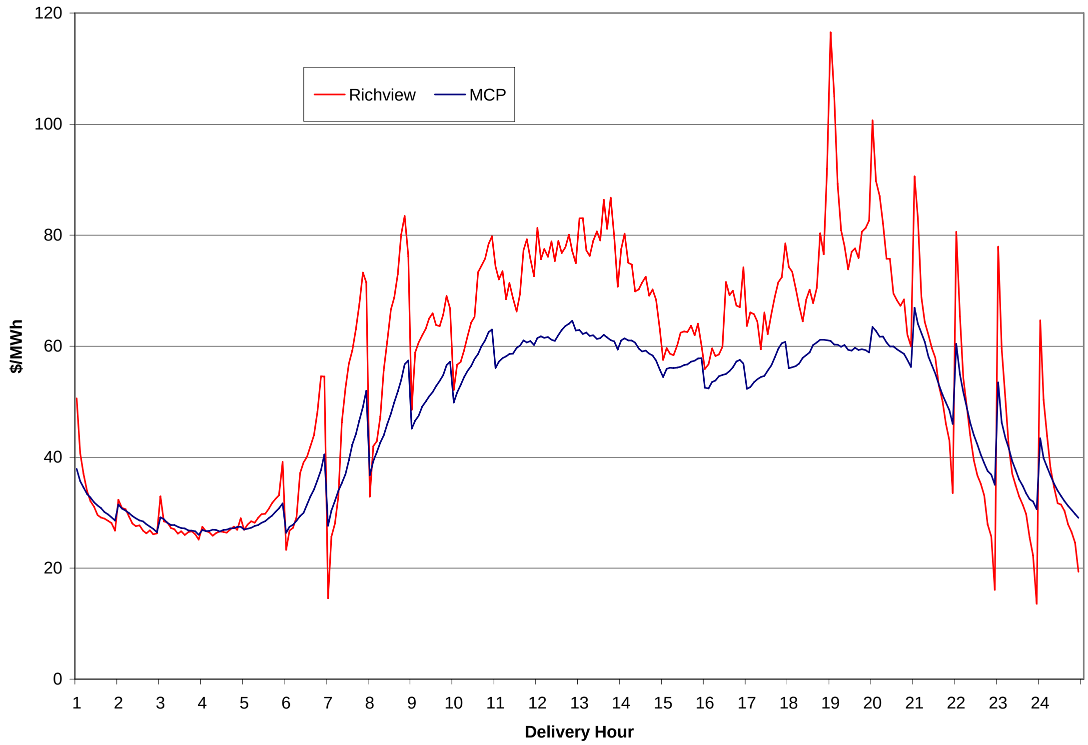
The combined effect of the change in net imports with the change in inframarginal hydroelectric output on the hour is illustrated in Figure 3-13. In the morning, the decrease in net exports and increase in inframarginal hydroelectric supply on the hour forces marginal generators to ramp down suddenly during the first two intervals of each hour to accommodate these changes and then ramp back up as demand builds across the hour. For example, on average over the past year, marginal generators were required to ramp down by close to 700 MW in total within the first and second intervals of the start of Hour 7 to accommodate the increase in net imports and inframarginal hydroelectric supply that occurred at the beginning of the hour. At night, marginal generators must ramp up for a few intervals each hour in order to accommodate the decrease in net imports and hydroelectric supply on the hour and then quickly return to reducing output to match the declining load.

Figure 3-13: Average Total Net Change in Hydroelectric Resources and Net Imports, November 2006 - October 2007



The price effects of abrupt changes in the supply/demand balance on the hour are illustrated in Figure 3-14. The figure shows that there are relatively large changes in the Richview nodal price on the hour, which is due to the fact that there is a steeper offer curve in the constrained sequence mainly as a result of transmission constraints and ramp capability. In the morning the interval price plummets on the hour as net imports and hydroelectric generation abruptly increase.[93] The interval price then recovers over the hour only to plummet again at the beginning of the next hour. The reverse is true at night.

Figure 3-14: Average MCP and Richview Shadow Price by Interval, November 2006 - October 2007



Looking at the change in price from interval to interval averaged across the year it is quite clear that the present fixed one hour bid window in combination with the present methodology of scheduling transactions over the interties is creating inefficiencies at times. Changes in institutional design that could smooth the transitions that are presently massed on the hour could reduce these inefficiencies. There would be less need to quickly ramp down relatively inexpensive generation in the morning and then within a few minutes begin to reload it. Similarly, there would be less need to ramp up more expensive generation for short periods of time

[93] Because of their quick ramping capability hydroelectric units can ramp to their full output in the first interval of the hour. This contrasts with much slower ramping fossil units which could take many intervals or even hours to reach their full economic production.

in the evening to accommodate on-the-hour departures of peaking hydro and imports.

A possible change in market design would be to move towards a 15-minute dispatch for generators and imports / exports. One option for this new algorithm would be to allow participants to offer or bid in 15 minute increments and be pre-dispatched every 15 minutes, instead of hourly. This is the approach currently used by New York for its internal generation. In the case of MISO and PJM, generators must offer hourly while imports and exports are scheduled for an hour but can transit between markets on the quarter hour, depending on ramp availability. Allowing imports and exports to change on the quarter hour reduces the extent to which domestic generation is obliged to ramp up or down to accommodate changes in exports and imports.

Preliminary discussions with hydroelectric generators also indicate that being allowed to bid at intervals that are more frequent than an hour would allow them to refine their offers so that they are potentially marginal for parts of an hour rather than bidding deep into the money for the entire hour. This would enable them to avoid the low price intervals in an hour.

One source of efficiency gains from 15 minute dispatch is from avoiding imports for the low demand intervals in an hour. The MAU has estimated the potential efficiency gains from this source for the period November 2006 to October 2007. It is equal to the amount of avoided imports times the difference between the import offer price and the adjusted Richview shadow price. This calculation is described in detail in Appendix 3.2 to this Chapter.

Table 3-5 below summarizes the monthly efficiency gains, average daily demand ratio, and real-time IOG payment. The average daily demand ratio is the average of the daily highest Ontario demand relative to the daily lowest demand. In total, the efficiency gains from re-dispatching imports can amount up to $8.32 million yearly, which is about one-third of the real-time IOG payment.

Table 3-5: Efficiency Gains, Average Daily Demand Ratio, & Real-Time IOG Payment, November 2006 – October 2007

Month	Efficiency Loss ($ Millions)	Average Daily Demand Ratio	RT IOG* ($ Millions)
Nov-06	0.57	1.42	3.69
Dec-06	0.72	1.42	2.64
Jan-07	0.47	1.37	2.57
Feb-07	0.80	1.30	4.30
Mar-07	0.85	1.30	4.70
Apr-07	1.00	1.32	2.44
May-07	0.96	1.38	2.49
Jun-07**	1.00	1.48	2.35
Jul-07	0.65	1.47	1.58
Aug-07	0.95	1.46	2.42
Sep-07	1.04	1.43	1.85
Oct-07	0.60	1.41	2.71
Total	8.32	1.39	27.41

* IOG reversals are not adjusted

** June 12, 2007 is excluded as the Richview shadow price was significantly distorted by the IESO's control actions.

One might expect that even greater efficiency gains could be realized, the larger are the demand changes in an hour as more expensive imports are not needed to meet the demand in the low demand intervals. This is generally not true as shown in Table 3-5 above. For example, the average daily ratio for March 2007 was 1.30, the lowest in all months, but the estimated efficiency gains reached $0.85 million, the sixth highest. The reason for this is that the efficiency gains also depend on the amount of marginal imports and their offer structures. If marginal imports are small in a month, the estimated efficiency gains will be small.

Although these estimates may overstate the efficiency gains arising from the re-dispatch of imports,[94] moving to 15 minute dispatch is also likely to yield efficiency

[94] The overstatement of efficiency gains come from the fact that the prices for low demand intervals should be lower compared to an average price for the hour and thus more exports are expected. The increase in exports will drive up the

gains from more efficiently dispatching both fossil and peaking hydro generators. For example, peaking hydro may be scheduled for the peak demand intervals in an hour only thus conserving valuable energy for later high-demand hours.

<u>Recommendation 3-3</u>

The MSP recommends the IESO begin investigation of a 15 minute dispatch algorithm to enhance the efficiency of the market.

4. *New Items to Report*

4.1 Self-Induced CMSC Payments made for Safety, Legal, Regulatory or Environmental Purposes

At 00:08 on August 12, 2007, a market participant requested that the IESO constrain on various hydroelectric units due to regulatory reasons, when river flows had to be maintained in order to respect agreed water levels. At the time, the units were offered at over \$500/MWh. The IESO constrained on these generators at 51 MW beginning in HE 1 Interval 5. As a result of this action, the market participant received approximately \$16,000 in constrained on payments for the hour as part of the normal settlement process.

The present policy of the IESO control room is to accept generators not following dispatch for safety, legal, regulatory and environmental reasons.[95] In order for the IESO to achieve subsequent accurate dispatch schedules (for all units), the control room must constrain the generator to the output that it requires. Effectively, the resulting constraint payments (on or off) are self-induced (i.e. caused by conditions at the plant, not conditions on the grid).

estimated new Richview shadow price and thus narrow the gap between the import offer price and new Richview shadow price. In other words, the estimated efficiency gains based on the gap should be smaller.

[95] Chapter 7 section 7.5.3 of the Market Rules does not require a market participant to comply with a dispatch instruction that would "endanger the safety of any person, damage equipment, or violate any applicable law". This is interpreted to include regulatory or environmental concerns. In this report we refer to these collectively as "safety, legal, regulatory or environmental" reasons.

In the months of August and September 2007, the MAU has identified approximately $150,000 of these types of constrained on payments to this market participant under similar conditions.[96] While there is no formal rule or process available for the recovery of these funds, discussions are under way between the IESO and the market participant for a voluntary repayment of these funds. It is understood this voluntary re-payment will occur.

In an early Market Surveillance Panel Report, on the subject of "Constrained Off Payments and Other Issues in the Management of Congestion" it was recommended that:

> the [IESO] initiate a rule change which does not require the [IESO] to make such payments in the first place or authorizes the [IESO] to completely recover self-induced constrained off CMSC payments to generation or dispatchable load.[97]

As a result, Market Rule changes were put into place to enable the recovery of self-induced dispatchable load CMSC payments.[98] At that time, discussions had taken place with market participants regarding similar self-induced payments for generators, but the IESO concluded that a general solution was too difficult to implement. With a narrower focus on generator self-induced payments for safety, legal, environmental and regulatory requirements, a rule change should now be easier to undertake.

[96] Only a sample of the events from May to October 2007 is included in this estimate since these were more readily available. To develop complete figures for the period it would be necessary to review the control room's logs for each day, identify the likely cases and determine how much CMSC was paid for each.
[97] Market Surveillance Panel Report, July 3, 2003; p. 6.
[98] See Section 3.5.1A in Chapter 9 of the Market Rules.

<u>Recommendation 3-4</u>

The IESO should initiate a rule change to allow the recovery of self-induced congestion management settlement credit payments which are made to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons.

4.2 IOG payments made to Affiliates

An Intertie Offer Guarantee (IOG) is a payment made by loads to improve the incentives for traders to enter the IESO-administered market as importers of energy from neighbouring markets. This is intended to assist the reliability of the Ontario market. However, IOG payments create the potential for gaming opportunities in the market that provide no net reliability improvements, as explained below. Rule changes were made in August 2002 to limit some of the perverse effects of the IOG payments.[99]

In June 2007, it was observed that two affiliate organizations were in a position to benefit in a manner consistent with an implied wheel. A second example of a group of such transactions taking place over several months in 2007 by two other affiliated entities, was also identified. Had these simultaneous import and export transactions been undertaken by the parent company, the IOG payment would have been offset.[100]

<u>Introduction</u>

Imports are important for the reliable operation of the Ontario market. It is recognized that trading between distinct energy markets with volatile pricing on both sides requires traders to manage significant risks. Such risks may discourage potential beneficial transactions. To help traders manage that risk, and hence

[99] See Market Rule Amendment Proposal MR-00204-R00 for the rationale for the rule changes http://www.ieso.ca/imoweb/pubs/mr/ua/mr_00204_r0i.pdf.
[100] According to section 3.8A.3.1 of Chapter 9 of the Market Rules.

increase their incentives to participate in the market, IOG payments were offered. These payments guarantee that, in the event that an import is scheduled, and the market price falls below the importer's offer price, they will be paid based on their offer and not on the real-time MCP. The guarantee also reduces the likelihood of imports failing in real-time as a result of changing market conditions, improving certainty of supply for the IESO.

Some transactions were excluded from IOG payments shortly after the market was opened, as they were deemed to not provide a reliability improvement. These transactions are referred to as implied wheel transactions. Implied wheel transactions occur between two markets that require power to flow through Ontario from the source market to the destination market. As Ontario is not the final destination of the energy, no increase in system reliability is gained by the simultaneous importing and exporting of energy. The subsequent payment of the IOGs for such transactions would be an unwarranted burden on loads in Ontario. Implied wheel transactions are not prohibited by the rules; rather the implementation of the IOG offset rules for an implied wheel transaction prevents the trader from benefiting from the IOG.

Without the IOG offset, traders could make use of 'implied wheels' and game the IOG payment, increasing profit without providing any benefit to the market. By transferring energy through the market with two distinct transactions at the same time, the IOG payment on the import allowed for the potential to arbitrage between real-time and pre-dispatch prices. Substantial profits were possible whilst there may have been no real net flow of energy between markets at all. The Market Rules were urgently amended in July 2002 to prevent the payment of IOGs in such situations.[101]

The amendment to the rules also included removing the eligibility of a market participant to receive IOG payments when the MAU determines that the recipient has an agreement or arrangement to share the IOG payment with another

[101] MR-00204-R00, op. cit.

participant.[102] The evidentiary burden upon the MAU to demonstrate that an agreement to share IOG payments exists is significant. If demonstrated, however, the IESO can recover those payments which were subject to that agreement through an IOG offset.

In July 2002 there were only hour-ahead transactions, but when the day-ahead commitment process was introduced in June 2006 the IOG offset was not extended to day-ahead import offer guarantees (DA-IOG) for imports where the importer took verifiable day-ahead actions to firm up the transaction.

<u>First Example</u>

Recently two affiliated market participants were identified as importing (and receiving the IOG payment) and exporting respectively in the same hour. These transactions effectively constitute an implied wheel when the affiliation of the two businesses is considered. Because there is no net import to the IESO, a reliability benefit commensurate with the IOG Payment was not delivered by the overall economic enterprise, the eventual beneficiary of the payment. Had either one of these legal entities undertaken both transactions itself, the IOG payments would have been offset automatically in the settlement process.

The size of the IOG payments related to such transactions are small even when investigated over the time during which the two affiliates have both been operating in Ontario. Table 3-6 below highlights the IOG payments made to the importing affiliate since its registration, the amounts that occurred at times when the other affiliate was exporting, and an estimate of the total potential IOG offset if the simultaneous transactions has been treated as implied wheels.

[102] According to section 3.8A.3.2 of Chapter 9 of the Market Rules. There has been no application of this rule to date.

Table 3-6: IOG Payments since Registration, Amounts that Accrued at Times of Affiliate Export & an Estimate of Potential IOG Offset

Total IOG Payments	IOG Payments when affiliate exporting	Estimate of Potential Offset[103]
$334,492	$41,771	$20,692
	12%	6%

Second Example

Further investigation of other known affiliate relationships revealed that two other affiliated entities are also periodically importing and exporting at the same time.

When investigated from January 1, 2007, the size of the potential offset is also small. Table 3-7 below highlights the IOG payments made to the importing affiliate, the amounts that occurred at times when the other affiliate was exporting, and an estimate of the total potential IOG offset.

Table 3-7: IOG Payments since January 2007, Amounts that Accrued at Times of Affiliate Export & an Estimate of Potential IOG Offset

Total IOG Payments	IOG Payments when Exporting	Estimate of Potential Offset
$300,678	$65,664	$60,912
	22%	20%

These events again identify some shortcomings of the IOG payments.

[103] In hours where there are simultaneous imports and exports, the export can be smaller. This leads to a partial recovery of the IOG in a given hour.

In the absence of the removal of IOG payments, it is clear that parent companies have benefited from IOG payments at times when they were wheeling energy across their portfolio, without providing a reliability benefit (or taking on the market price risks usually associated with import transactions).

We noted earlier an existing Market Rule that allows IOG offsets if the MAU finds there is an agreement or arrangement between two entities to share the IOG. However, the IESO does not consider affiliation alone as a sufficient basis for application of this rule. Moreover, based on the small size of the payments and the somewhat random nature of simultaneous imports and exports, it does ***not*** appear that this was a coordinated, intentional attempt to game the IOG payment through an agreement or arrangement in either of the above examples.

To prevent further accumulation of IOG payments that do not provide the intended reliability benefits, and to close what appears to be an unintended loop hole that would allow the gaming of IOG payments by affiliates, it would be appropriate to automatically offset the IOG payments made to a participant when it is identified that an affiliate business is exporting energy at the same time. In formulating such a rule change it will be important to confirm whether affiliation as currently defined in the rules[104] is a sufficient threshold to restrict potential gaming of the offsets.

Recommendation 3-5

> ***The IESO should initiate a rule change to make Intertie Offer Guarantee payments subject to offsets where affiliated market participants are simultaneously importing and exporting.***

[104] The Market Rules Chapter 11 defines

> "affiliate, with respect to a corporation, has the meaning ascribed thereto in the Business Corporations Act (Ontario)"

4.3 The Effect of a Delay in a Transmission Upgrade

On October 29, 2004, Hydro One submitted an application to, and subsequently obtained approval from, the Ontario Energy Board for a construction of a new 76-kilometer double circuit 230 kilovolt (kV) transmission line to upgrade the capacity of the Queenston Flow West (QFW) transmission flowgate, as well as upgrades to Middleport Transformer Station. The projects were expected to increase the rating of the QFW flowgate by roughly 800 MW from its current level of 1800 MW to 2600 MW (or a 44 percent increase). These upgrades were expected to be finished in the summer of 2007. The Panel understands that completion of these projects has been significantly delayed.

When this new line is in placed in service, it is expected that, based on historical loading patterns, the QFW flowgate will almost never be congested. The elimination of congestion on the QFW flowgate would lead to significant efficiency gains to the Ontario market. These efficiency gains include reduced constrained off generation in Niagara area, reduced constrained on generation west of the QFW flowgate, and reduced constrained off/on imports/export on either the New York interface or the Michigan interface. The MAU estimated that from the constrained off generation in the Niagara area alone the efficiency gain can be almost $3 million per year, as shown in Table 3-8.[105]

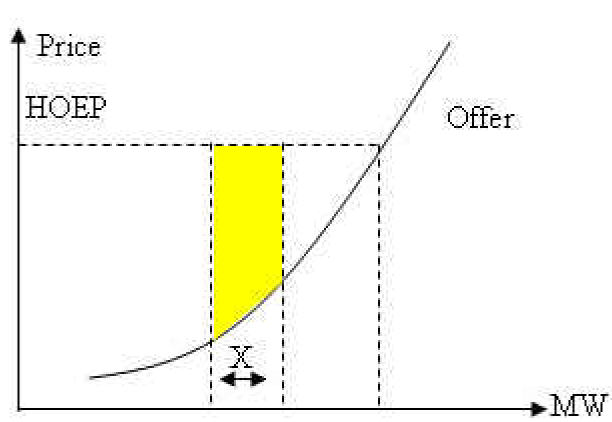
[105] The efficiency gain of reducing constrained off generation is equivalent to the constrained off payment to the generators, which is illustrated in following graph. If there were no congestion on the QFW interface, the offered X MW could have been utilized and the yellow area is the lost producer surplus (note consumer surplus is irrelevant in this case as all consumption is met by constraining on other generators).

Table 3-8: Constrained Off Payments to Generators in Niagara Area, November 2006 - October 2007

	Constrained off Payment ($ thousand)
Nov-06	572
Dec-06	330
Jan-07	229
Feb-07	133
Mar-07	211
Apr-07	211
May-07	359
Jun-07	226
Jul-07	101
Aug-07	134
Sep-07	193
Oct-07	268
Total	2,969

With the upgrades completed, IESO staff estimate that the import capability on the New York interface may increase by as much as 350 MW. The number is an estimate based on the transmission capability within the New York state.

The improved import capability on the Michigan interface can be as high as 800 MW. The 800 MW is estimated based the LEC pattern: typically, every 100 MW import from Michigan tends to result in 30 MW flow through New York with the remaining 70 MW flowing directly over the Michigan ties. Thus when a



transmission line within New York is congested, this also limits import capability from Michigan. The improved import/export capability should significantly relieve system strain on days such as June 12, 2007 and improve market efficiency.

Prior to the work stoppage Hydro One had carried out an extensive consultation process with the stakeholders and was well on its way to completing the transmission project. Since the work stoppage is the result of a dispute between parties other than Hydro One, the Panel understands that Hydro One is not a direct party to the dispute and is precluded from participating directly in the negotiations aimed at resolving the dispute. Nevertheless, Hydro One can continue providing input and support to the parties involved in the negotiations. Once the dispute is resolved, the Panel anticipates that Hydro One will be ready to complete the project expeditiously.[106]

Recommendation 3-6

> ***It is important for the efficiency of the Ontario electricity market that Hydro One attempt to complete the Queenston Flow West transmission expansion as soon as practicable. The ability to fully utilize 'bottled' generation in the Niagara region and maximize economically viable imports with New York (and Michigan) will enhance the efficiency (and reliability) of the Ontario market.***

4.4 Efficiency Implications of Public Agency Contracts

In late 2004, the Ontario Power Authority (OPA) was created by the Government of Ontario for the stated purpose of developing a reliable and sustainable electricity system for the future. Since then, the OPA has announced a number of supply procurement programs through a Request for Proposals (RFP) process, along with

[106] Hydro One has explained to the Panel that only 5 weeks of further installation work is needed.

new contractual arrangements with existing generators. It appears that new generation in Ontario will continue to develop through the provincial government procurement process for the foreseeable future. These initiatives have important implications for the role the competitive spot market plays in Ontario.

The Panel's view is that an efficient contract structure is one that motivates generators to offer supply into the wholesale market at prices that reflect their incremental cost of production and that this helps to ensure efficient dispatch. In this section, we review and summarizes various OPA supply procurement programs including CES Contracts/Early Movers, the Bruce A contract, and the Renewable Energy and Clean Energy Standard Offer Programs, as well as the IESO's Lennox Reliability Must Run contract.[107]

Table 3-9 summarizes the amount of installed capacity by contract type as of September 2007. In aggregate, these contract arrangements currently make up approximately 18 percent of Ontario's total production capacity.

[107] Although the Lennox RMR contract is currently an agreement between the IESO and OPG, the intention is that the OPA will eventually replace the IESO in these contracts. The latest one-year contract, dated October 1, 2007, is awaiting OEB approval, According to the Integrated Power System Plan (IPSP) released August 29, 2007, the IESO is unlikely to require Lennox for local area supply in the future and will therefore be unable to secure its capacity under the existing RMR contract terms. At that time, a contractual arrangement with the OPA would be required to avoid the units shutting down. See Exhibit D, Tab 9, Schedule 1, Attachment 1 of the IPSP for details at: http://www.powerauthority.on.ca/Storage/50/4562_D-8-1_Att_1.pdf

Table 3-9: Installed Capacity by Contract Type as of October 2007

Contract Type	Total Installed Capacity (MW)	Percentage of Ontario Capacity[108]
OPA Clean Energy Supply/Early Movers Contracts	1,264	4.1
OPA Bruce A Contract (Units 1 and 2)	1,500	4.8
OPA Clean Energy Standard Offer Program[109]	N/A	N/A
OPA Renewable Energy Standard Offer Program	628[110]	2.0
Lennox Reliability Must Run Contract	2,140	6.9
Total	5,532	17.8

In the Panel's opinion, the CES Contracts and Early Movers Contracts entered into by the OPA are designed in a way that maintains dispatch efficiency. The other contracts can be categorized as true fixed-price contracts or variations thereon. Contracts that pay fixed prices can lead to externalities where a generator has a financial incentive to run even if the market price is lower than its incremental cost. This could lead to an efficiency loss because a lower cost supplier may be displaced and the market price may be less than the incremental cost of generation. The Panel continues to urge the OPA to utilize the real-time Market Clearing Price as a signal for supply in order to promote dispatch efficiency.

We also note that there may be a number of 'non-utility generation' (NUG) contracts arranged 15 to 20 years ago and currently administered by Ontario

[108] There is approximately 31,000 MW of installed generation in Ontario's electricity market as stated on IESO website at http://www.ieso.ca/imoweb/media/md_supply.asp
[109] The Clean Energy Standard Offer Program has not been finalized and launched. For details on the anticipated program design, see the OPA's final recommendations at http://www.powerauthority.on.ca/Storage/44/3973_CESOP_Final_Recommendations.pdf
[110] Installed capacity up to and including September 2007. See the September 2007 Progress Report on the OPA's Standard Offer Program website at: http://www.powerauthority.on.ca/SOP/Storage/52/4814_RESOP_Sept._2007_report.pdf

Electricity Financial Corporation, that may be coming to the end of the contract life. We do not know details of these contracts, but would suggest that conclusions below regarding efficient contract structures for OPA might also apply to any new or renewed OEFC contracts.

4.4.1 OPA Clean Energy Supply and Early Mover's Contracts[111]

In early 2004, a Request for Proposals (RFP) was issued by the government of Ontario for 2,500 MW of clean energy and demand-side projects. The successful Clean Energy Supply (CES) projects were announced in the spring of 2005 and led to 1,945 MW of new generation in the province. On June 15, 2005, the Ontario Power Authority (OPA) was directed by the Ontario Minister of Energy to develop contracts for certain power generation projects that would not otherwise have qualified for the CES RFP and they were named the 'Early Movers'. There have been five Early Movers contracts executed since the beginning of 2006. These contracts are quite similar to the standard CES contract.

Generators under the CES/Early Movers contracts are motivated to offer at their incremental cost. When the Market Clearing Price is higher than the calculated unit strike price, the unit is deemed to produce energy, otherwise they are penalized an amount based on the foregone output which is ultimately removed from their monthly revenue requirement.[112] This promotes efficient dispatch.[113]

Efficient contract structures should motivate generators to reduce both their fixed and variable operating costs. The CES/Early Movers contracts do motivate generators to reduce both fixed and variable costs since the generator receives a

[111] The CES pro-forma contract is available on the Ontario Electricity RFP Website at http://www.ontarioelectricityrfp.ca/Docs/ConsolidatedCESContract.pdf
[112] Actual rules for deeming units are more complicated, and there is an allowance for start-up costs.
[113] Due to the SGOL and day-ahead cost guarantees available to generators participating in the IESO-administered market, such a generator may be motivated to offer its minimum production amount below cost, while offering incremental energy above that at cost. This is a no-cost strategy for the generator to reduce its risk of not being online when it may be deemed to be generating. This is a general function of the design of the DA-GCG and SGOL programs, not a peculiarity of the CES or Early Movers contracts. In our July 2007 report, we recommended that the IESO review its DA-GCG and SGOL guarantee programs due to inefficiencies created. For more information, see Recommendation 3-3 on page 123 of the July 2007 MSP Report.

fixed pre-determined payment to cover all operating and maintenance (O&M) costs. Every dollar saved by reducing costs is realized by the generator and in turn increases its profits.

Most generating facilities in Ontario are required to take periodic planned outages for maintenance, upgrade, or safety reasons. The frequency of these outages depends on generation technology and the age of the equipment, as well as the owner's maintenance strategy. An efficient contract structure should motivate a generator to take planned outages during the low demand hours and days of the year. In the CES/Early Movers contracts, there is no reference of the way planned outages are accounted for in the calculation of the monthly Contingent Support Payment (CSP) and the Revenue Sharing Payment (RSP). This may motivate the generator to minimize planned outages in order to reduce the risk of not being on line when required.

Forced outages (or deratings) are unanticipated in nature. Within the CES/Early Movers contracts, all forced outages (or forced deratings) fall under the definition of "Force Majeure" meaning the generators are excused of any obligations to produce.[114] This creates an incentive for these facilities to employ a maintenance strategy that reduces (or eliminates) preventive maintenance through planned outages and simply deals with maintenance issues when they bring about forced outages.[115]

Generators under the CES/Early Movers contracts are deemed to produce when the Market Clearing Price is higher than their strike price (estimated cost of production) and are penalized if they are not online during those hours.[116] The benefit of this structure is that it acts as a motivator for the generator to operate when prices are

[114] The hours are ignored for the purposes of the CSP and RSP calculations set out in Exhibit J of the contract.
[115] Generators must examine all risk and revenue factors when considering a maintenance strategy.
[116] Actual deeming rules are more complicated, accounting for pre-dispatch and HOEP prices. In addition there is an adjustment for start-up costs.

higher than their cost, which is generally efficient. Therefore, much of the financial risk is in the hands of the generators, and thus will also tend to promote efficiency.

Since the derivation of the strike price accounts for fuel prices, this basically removes the risk of fuel price fluctuations to the generators. The implication of this structure is that the CES generators do not have an incentive to minimize fuel costs.

4.4.2 OPA Bruce A Contract[117]

On October 17, 2005, the Ontario government announced that it had reached an agreement with Bruce Power for the refurbishment of Bruce A Units 1 and 2 at the Bruce Nuclear facility representing 1,500 MW of new baseload capacity through 2036.[118] The agreement also stated that Bruce Unit 3 would be refurbished once it reached the end of its operational life and only Unit 4's steam generators would be replaced.

On August 29, 2007, the Ontario Power Authority confirmed the expansion of the agreement to include the full refurbishment of Unit 4, rather than only replacing the steam generators. The replacement of the fuel channels will lengthen the operational life of Unit 4 to 2036 and add 750 MW of refurbished nuclear power, increasing the total refurbished nuclear capacity under contract to 3,000 MW.

The Bruce A contract with the OPA is designed to maximize the output of the units. Bruce A units are paid a fixed rate for each MWh of production. For this reason, the units are not motivated to offer at incremental cost. In order to maximize revenues, the units are motivated to offer at a level that guarantees they are dispatched. Since the Bruce A generating units are inframarginal, the efficiency implications of their bidding strategy should be quite small.

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[117] The Bruce Power Refurbishment Implementation Agreement is publicly available on the Ministry of Energy's website at http://www.energy.gov.on.ca/english/pdf/electricity/bruce_power_refurbishment_implementation_agreement.pdf

[118] See the News Release from October 17, 2005 on the Ministry of Energy's website for more details: http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&body=yes&news_id=110

An efficiency benefit from this type of arrangement is that these units are motivated to minimize the amount of time they spend on outage as well as reduce costs, since all of the cost savings will benefit the generator through higher profits.[119]

4.4.3 OPA Renewable Energy Standard Offer Program[120]

Implemented in November 2006, the Renewable Energy Standard Offer Program (RESOP) was designed to help Ontario meet its renewable energy supply targets by providing small renewable energy generating projects (less than 10 MW) with a standard pricing structure and simplified qualifying guidelines. Eligible renewable energy sources include wind, hydroelectric, solar and biomass.[121]

A potentially inefficient component of the RESOP contract structure is that participating generating projects receive a fixed-price for their electricity production. Generators receive $110/MWh for electricity with 20 percent of the base rate indexed annually for inflation.[122] The RESOP contract structure motivates the participating generators to maximize production regardless of the time of day or period of the year. As a result, RESOP generating units may potentially displace cheaper sources of electricity.

For renewable energy with very low incremental production costs (which applies to all except possibly some sources of biomass), it would be efficient to run these under most circumstances. The main exception occurs when they induce significant costs to other generation that must change their output due to transmission limitations. As a result, in practice there are likely no significant negative

[119] We are advised by Bruce Power that Ontario consumers also benefit from any cost savings as a result of a cost sharing arrangement incorporated in the contract. We have not had an opportunity to review this provision.
[120] The OPA Renewable Energy Standard Offer Program contract is publicly available on the OPA's website at http://www.powerauthority.on.ca/Storage/32/2793_RESOP_Contract_Version_2.0.pdf
[121] For eligibility and contract details, see http://www.powerauthority.on.ca/sop/Storage/44/3985_SOPInformationBrochure.pdf
[122] Excludes Solar PV generators who receive $420/MWh over the life of the contract

efficiency implications except for some types of biomass or for wind in transmission congested areas such as near the Bruce generating facility.

RESOP generating units have little incentive to store energy in order to produce during the on-peak hours of the day. Generally, the electricity is provided as the fuel becomes available.

Participating generators have appropriate incentives to minimize production costs under the RESOP contracts. All cost savings will benefit the generator through increased profits.

There are some cost risks to both the RESOP generators and the consumers of Ontario. RESOP generators are at risk of not covering their investment costs if they are unable to produce enough electricity due to prolonged outages or insufficient fuel (wind). In such cases, risk is assigned to the party that can best deal with it, the generator owner. For consumers, the main implication is that the fixed-price of $110/MWh is likely to be higher than the average HOEP, with the resulting difference being factored into and increasing the Global Adjustment.

It is expected that most of the RESOP generators will be embedded within LDCs and may place an externality on other market participants. The present calculation of transmission charges for LDCs is based on their net withdrawal from the Grid. The RESOPs are generating behind the LDC meter and as a result the LDC avoids uplift charges in respect of the RESOP volumes. As such volumes increase, total market uplift will be paid by a smaller load base.

There are some further implications from RESOP projects due to their size, the intermittent nature of their operation, and the number of projects across the province. Since RESOP facilities are not dispatchable and likely connected to an LDC rather than directly to the IESO grid, there are few requirements for these facilities to provide ongoing production status or forecasts. This adds uncertainty for the IESO operators because the only indication they may have that RESOP generators are changing output is through changes in observed demand. We understand that it was originally anticipated that this would not be a significant concern because these are small projects which are spread over the province, making abrupt changes in aggregate output less of a risk.

In addition, we note from OPA reports,[123] that there are several groupings of 10 MW projects which appear to be part of a much larger overall Wind Farm or Solar Group, which if treated as a single project would be subject to a system impact assessment by the IESO. It is our understanding that over 2,000 MW of RESOP generation has applied for contracts.[124] Changes in production for this generation will appear as changes in demand from LDCs, and would contribute to an additional component of demand forecast error. Significant and abrupt changes in demand could lead to the IESO having to constrain on slow starting dispatchable generation (fossil units) at minimum load levels in order to meet load variation due to uncertain RESOP generation volumes. In congested areas, the IESO may have to reserve some transmission capability because of the large uncertainty in the magnitude of power flows caused by this intermittent generation. There may be other operational responses but constraining on generation and/or limiting transmission capability generally would not be efficient.

The Panel understands that the IESO has just initiated a stakeholder consultation to discuss the integration of these and other embedded generators into the reliable operation of the IESO-controlled grid.[125] Due to the scale of the projects and the intermittent nature of the output (as illustrated in Chapter 1 section 2.4.3 on the performance of wind generation) and their possible effect on efficiency, to the extent possible in its consultation, the IESO should consider opportunities to reduce potential inefficiencies. This may include ways by which these generators could

[123] http://www.powerauthority.on.ca/sop/Storage/56/5161_RESOP_Nov._2007_report.pdf
[124] This does not necessarily mean all 2000 MW will be contracted or eventually built. As of November 2007, there were some 842 MW of executed contracts under the RESOP.
[125] See IESO consultation on Embedded Generation: http://www.ieso.ca/imoweb/consult/consult_se57.asp

provide the IESO with better information on actual and forecast production including outage plans.[126]

Recommendation 3-7

To the extent possible in its stakeholder consultation on embedded generation, the IESO should consider opportunities to reduce inefficiency through the development of the capability for accurate forecasting of embedded generation production, which may require the provision of real-time production and related information (e.g. outages).

4.4.4 Proposed OPA Clean Energy Standard Offer Program[127]

The proposed Clean Energy Standard Offer Program (CESOP) is intended to support the introduction of small (less than 10 MW) generation including combined heat and power and electricity generated as by-product fuels that would otherwise be under-utilized. The program is now expected to launch in the spring of 2008 after further review.

Under the presently proposed design, generators that participate in the CESOP would be encouraged to run during the prime-peak periods and mid-peak periods as specified by a CESOP rate schedule. The proposed agreement states that during the high peak hours, generators would receive HOEP plus $81/MWh for energy and during the mid peak hours, generators would receive HOEP plus $43.20/MWh. For the remaining hours, the generator will be motivated to produce when the HOEP is greater than their incremental cost of production since they only receive the HOEP for energy generated. The rates are intended to reflect the flexibility and reliability of distributed generation to the integrated power system and promote energy production during the high-demand hours during the year.

[126] Martin Merritt, the Market Surveillance Administrator for Alberta has discussed similar concerns with the proposed scale of wind projects in Alberta. See " Power Luncheon: Alberta's Power Market 12 Years After Inception", September 2007 available at http://www.albertamsa.ca/files/BMO_Nesbitt_Sept_2007(w_notes).pdf
[127] The OPA's final recommendations on the Clean Energy Standard Offer Program can be found at http://www.powerauthority.on.ca/Storage/44/3973_CESOP_Final_Recommendations.pdf

Under the proposed design, generators participating in the CESOP would be efficiently motivated by the fixed rate schedule to reduce their operating costs and maximize their availability during on-peak hours due to the nature of the fixed rate schedule. However, at lower load levels or periods with more than enough low cost generation, the fixed rate schedule would be expected to lead to inefficiencies. The primary inefficiency of this contract structure is that generators may choose to operate when market prices are lower than their incremental costs in order to receive the fixed rate schedule.

The proposed CESOP contract design would also place an externality on other market participants. The OPA has projected that most potential applicants will be loads including greenhouses, hospitals, universities, industrial facilities, and natural gas pressure regulating stations. If this projection holds true and most CESOP generators have an embedded load attached, they have the ability to generate 'behind the meter'. Thus the attached load avoids uplift charges. When these generators produce behind the meter, it places an increased uplift burden on all other consumers, as the existing total uplift amounts will be shared by the lower volumes of the fewer remaining loads.

This uplift issue should be seen in context. First, other generation (existing and projected) that is embedded behind a load (e.g., CTU or combined cycle generators on-site at an industrial plant), also avoids uplift. Even generation not associated with a specific load will also have this effect (including RESOP generation), since it reduces the LDCs net demand and therefore uplift charges decline for consumers that fall within the LDC. In such cases, the reduced uplifts are experienced by all the load in the LDC, not just the load with a generator.

Not all uplifts are avoidable. LDCs will continue to be responsible for identifying embedded generation for the purpose of the Debt Retirement Charge (DRC). DRC applies to the gross demand, not demand net of generation. So even for CESOP (and RESOP) projects, the generation will be tracked and accounted for under the DRC.

Even though other embedded generation is netted against load, there is a potential for a much larger portfolio of such generation to be built in the future under CESOP as well as RESOP and potentially other programs, with an increasingly significant effect on the uplift paid by the remaining loads.

As mentioned, it is our understanding that OPA is further reviewing the proposed structure of the CESOP contract.

4.4.5 Lennox Reliability Must Run Contract[128]

Although the Reliability Must Run (RMR) contract is an agreement between the IESO and OPG, we review its efficiency implications partly for completeness of a review of different contract structures in Ontario.

The Panel had briefly reviewed some aspects of the contract in an earlier report[129] and we expand somewhat on that analysis here. The Panel notes that versions of this contract have been reviewed and approved by both the IESO Board and the OEB.[130] However, as explained below, our overall view is that the contract does not always rely on financial drivers to achieve efficient outcomes, although it has built in a variety of contractual terms that may encourage some efficient behaviours.

Lennox is a 2,140 MW dual-fuelled (oil and natural gas) generating station located near Kingston, Ontario. Lennox is owned by Ontario Power Generation (OPG) and is operated as a peaking resource. After the IESO identified reliability concerns

[128] For a copy of the latest Lennox contract, see http://www.opg.com/about/reg/filings/files/Regulatory%20Documents/Lennox%20RMR%20Appendix%201.pdf

[129] MSP Monitoring Report, June 2006, p.116 and pp.120-121. The Report addresses the possible incentives for inefficient bidding and offsetting lower incremental cost plant, but notes “the contract seeks to limit the potential for these excursions to special circumstances”.

[130] The OEB Decision (EB-2005-0490) March 13, 2006 deals with some of the issues the Panel identifies here and concludes “that the financial provisions of the RMR Contract are reasonable and that the RMR Contract does not contain incentives for OPG to alter its offer behaviour”. With regard to recovery of 100 percent of the fixed and variable costs, the OEB stated “the cost-based financial structure of the contract is appropriate for reliability must-run contracts”.

with the proposed closure of Lennox, the IESO and OPG entered into a one year RMR contract beginning October 1, 2005. The agreement has been renewed each year with the latest contract beginning October 1, 2007. It is the only RMR contract in Ontario. [131]

The contract specifies that the generation units must run when the IESO requires them for reliability purposes. The generator may also run the units at other times if it makes offers that are selected. Under the contract, the generator receives a monthly payment to cover all fixed and variable costs associated with running the plant,[132] not just during those periods when specifically required by the IESO. As a RMR contract, this degree of cost recovery may be justified but we observe that it provides little incentive to the generator to reduce costs. OPG has expressed to the Panel that the contract does motivate them to reduce costs, by virtue of the various audit and review provisions granted to the IESO under the terms of the contract. Although OPG may be separately motivated to reduce its costs, the Panel does not regard the audit and review provisions of the contract alone as a significant incentive for OPG to actively seek efficient cost reductions.

Under this RMR contract the generator does not have a significant financial driver to offer production at incremental cost. There are non-financial terms which guide the generators behaviour, although these are subject to some interpretation.[133] When required by the IESO, the generator is to provide offers that allow the units to be selected in the dispatch schedule. As an additional financial incentive, the generator receives 5 percent of all revenues earned from the units' energy production. This premium provides a small incentive to be on-line during the high priced hours of the day. This could also constitute an inefficient incentive for the generator to stay online overnight - when it would not be efficient for the market -

[131] In the June 2006 Monitoring Report p.121, the Panel identified the potential inefficient driver in the Lennox RMR contract associated with payments based on incremental cost plus a portion of the MCP.
[132] A small portion of fixed costs, about 5 percent, are not specifically identified in the contract, and payment for these was set at the initial estimated value, about $1.5 million.
[133] These are: "consistent with good utility practice", to act in a "commercially reasonable manner", and other than in exceptional circumstances "offer a unit economically over a sustained period of time based on its costs". OPG has advised that it considers these provisions to mean offering at incremental costs, although, the Panel notes that the contract does not specifically require this.

in order to minimize start up risk the next day, and receive 5 percent of the smaller off-peak prices. However, the Panel has not observed such behaviour.

There are performance standards in the RMR contract which provide a small financial incentive for the generator to maximize the availability of the units, based on seasonal target rates of forced unavailability. This encourages the units to be available most of the time, when needed for reliability, but is not directly linked to actual market conditions or prices.

4.4.6 Summary

Efficient contract structures are critical in setting proper incentives for generators to respond in efficient ways. The CES type arrangements are the most efficient of the contract structures used by the OPA. These contracts recognize the marginal cost of a unit and place the focus on the MCP as the driver for offer decisions. Contracts for other types of supply would be more beneficial to market efficiency if they reflected a similar structure as the CES contract; an up-front payment of some kind and incentives for hourly decision-making related to the MCP. Standard Offer Programs for energy sources that have minimal incremental costs are unlikely in practice to cause much inefficiencies when they produce (unless they force hydro to spill or nuclear to reduce production for a few hours or days). However, the generators operating under such contracts have only limited drivers to take outages when the energy is least valuable and therefore could benefit from a market-price based signal.

Similar to the CES contracts, a possible structure for CESOP (or future RESOP) contracts would be to provide an up-front payment, ideally linked to some annual or perhaps quarterly performance requirements, with actual production paid based on HOEP. There are variations on this to remove some of the risks to the producers or loads who are paying for these.

This type of structure is quite flexible and applicable over many generator types. Generators in the SOP are self-scheduled or intermittent. The above structure allows them to continue to make production or outage decisions in reference to expected market prices. Contracts for units which in practice run flat (e.g. nuclear) may use performance-related fixed payments, with HOEP-related hourly payments. This maintains an incentive to maximize production and take outages when prices are lowest. Finally, there appears to be no reason why a contract for Lennox, if desired by both OPA and OPG once it is no longer needed as a RMR supply, should have a structure different from the CES contract.

Recommendation 3-8

The Panel recommends that the Ontario Power Authority structure future contracts to maintain the energy market price as the driver for production decisions (for example, using a strike price structure similar to the payment provisions in the existing Clean Energy Supply contracts).

Table 3-10: Contract Efficiency Comparison

	Early Movers / CES	Bruce A	Lennox RMR	Renewable Energy Standard Offer Program	Proposed Clean Energy Standard Offer Program
Is the generator motivated to offer at its incremental cost?	Yes, when the MCP > Strike Price, the unit is deemed to produce (and if it does not, they are penalized).	No. Bruce A generating units are motivated to offer to guarantee they are selected in the dispatch schedule.	There are no financial drivers, but, contracts terms indicate such behaviour.	Offers are not submitted by these generators.	Offers are not submitted by these generators.
Is the generator motivated to reduce its costs both fixed and variable?	Yes, the generator receives a fixed pre-determined payment to cover all O&M costs for the life of the contract so money saved is profit for the generator.	Yes, Bruce keeps all realized cost savings (see footnote in the text).	Not directly, since costs are covered monthly. There may be some weak drivers, more related to IESO audit and review, which would ensure reasonable costs.	Yes, since they are paid a fixed amount for each MWh produced. All cost savings are kept by the RESOP generator.	Yes, since they are paid based on a fixed rate schedule for each MWh produced. All cost savings are kept by the CESOP generator.
Is the generator motivated to maximize its availability (minimize its outages and deratings)?	Yes and no. A facility has an incentive to plan outages at times it is not needed by the system. However, there may be an incentive to go on “forced outage” rather than “planned outage” due to the favourable treatment of forced outages.	Yes, Bruce A is paid for each MWh produced.	On a plant basis, there are some drivers to minimize forced outages.	Yes. The rate schedule motivates them to maximize their availability.	Yes. The rate schedule motivates them to maximize their availability.
Is the generator motivated to schedule / plan its outages in the most efficient time period?	Yes, They would want to avoid most risky time periods, i.e. if contract expects them to run, which is consistent with finding most efficient period for outages.	No, although there is an incentive to minimize outages, as noted above.	The IESO may require them for reliability at other times. There is no direct financial incentive, but there are various contract requirements to act in a “commercially reasonable manner”, and “consistent with good utility practice”.	No, payment to the generator is strictly based on output regardless of when that output is produced.	Yes. The rate schedule motivates them to schedule outages during the low demand hours and days when contract payments do not apply
Is the generator motivated to provide OR and other ancillary services?	Yes, Ancillary Payments are kept by the generator.	Yes, Ancillary Payments are kept by the Generator	Yes, “consistent with good utility practice”. However, compensation could be marginally less since the generator maintains 5 percent of market revenue, which may be less for OR.	No. The generator assigns to the OPA all rights to the Related Products (includes all ancillary services).	This level of detail not yet available.
Is the generator motivated to provide ramp and dispatch capability?	Yes, rising prices will motivate these generators to be online.	No, the generator is only motivated to maximize output.	This should be “consistent with good utility practice” and the 5 percent MCP premium acts as a small financial incentive to do so. They can also be required to provide ramp and dispatch capability when needed by the IESO.	No	No, they only have an incentive to produce according to the payment schedule set out in the CESOP contract.

	Early Movers / CES	Bruce A	Lennox RMR	Renewable Energy Standard Offer Program	Proposed Clean Energy Standard Offer Program
Is the generator motivated to provide energy during the peak hours of the day?	Yes. The generator is penalized if they are not online during hours when Market Clearing Prices are above their strike price	Yes, the units are motivated to maximize output over all hours of the day given they receive a fixed amount per MWh generated.	Yes, this would be "consistent with good utility practice". They must do so if requested by the IESO for reliability reasons, and are financially motivated in order to receive 5 percent of revenues earned from the energy market (small incentive to be online during high-priced hours).	Due to the inherent characteristics of the RESOP generators, time-shifting production could be prohibitively costly and inefficient.	Yes, but only during peak demand months specified in the rate schedule.
Are the contracts tailored to promote generators to participate in the market?	Yes, fixed costs are essentially covered and the generators are required to run when prices are higher than the generator's strike price.	Yes, the Bruce A contract promotes participation by rewarding the generator for producing as much as possible.	This is required "consistent with good utility practice". The 5 percent MCP premium acts as a very small incentive to participate.	Yes, these generators want to produce as much as possible in order to recover costs.	The program promotes generation during the high and mid peak hours and days of the year.
Do the contracts establish externalities on others?	No. If these generators operate in periods where they do not cover their costs there is no compensation from the Contract.	Yes, there is no incentive to shutdown when energy prices fall below their costs. They may displace cheaper-priced generation.	Yes, generator can operate and recover its costs plus 5 percent of revenues no matter what the energy price. However, consumers recover 95 percent of market revenues.	Yes, if they have an embedded load attached, they may be motivated to generate behind the meter to avoid uplift charges, resulting in total uplift being shared by all other participants.	Yes, if they have an embedded load attached, they may be motivated to generate behind the meter to avoid uplift charges, resulting in total uplift being shared by all other participants.
Are risks assigned to those who can best deal with them?	Yes, if the generators don't produce when MCP > Strike Price, implied deemed payments will be clawed back. The calculation of the strike price accounts for fuel prices so the consumers hold fuel price risk.	Yes and No. Volume risk sits with the Generator. Fuel price risk sits with the Load.	No. The generator bears no volume or fuel price risk.	No. The generator must produce enough to cover costs. The price risk is on the consumers.	No. the generator must produce enough to cover costs. The price risk is on the consumers. Fuel risk is shared by generator and consumers though the fixed spark spread.
Are the contracts transferable to a DAM type construct and LMP?	Yes. The contracts reference the possibility of evolution to both DAM and similarly LMP, and the conversion of the contract pricing from HOEP to DAM or LMP pricing.	Yes, the contract addresses the potential introduction of both LMP and day-ahead prices.	There are no financial drivers, but, contracts terms indicate such behaviour.	No mention in Contract.	No mention in preliminary documentation.

Chapter 3 Appendix

Appendix 3.1: An Econometric Decomposition of the Relative Effects of the Factors Contributing to Convergence of the Richview Price and the HOEP

The decomposition technique we use is an Oaxaca decomposition.[134] The same regression equation is estimated for each year or period we wish to compare:

$$Diff_i = \alpha_i + \beta_i X_i + U_i \,, \qquad (1)$$

where $Diff$ is the average hourly difference between the Richview nodal price and the HOEP, i is a year or period indicator, α and β are parameters, X is a vector of independent variables, and U is the residual term.

The mean variation in the price difference over n years can then be rewritten as:

$$\overline{Diff_i} - \overline{Diff_{i-n}} = \beta_i[\overline{X}_i - \overline{X}_{i-n}] + [\alpha_i - \alpha_{i-n}] + [\beta_i - \beta_{i-n}]\overline{X}_{i-n} \quad (2)$$

Or

$$\overline{Diff_i} - \overline{Diff_{i-n}} = \beta_{i-n}[\overline{X}_i - \overline{X}_{i-n}] + [\alpha_i - \alpha_{i-n}] + [\beta_i - \beta_{i-n}]\overline{X}_i \quad (3)$$

The variation in the price difference between period *i* and period *i-n* has two components in both equations: explained variation (the first term) and unexplained variation (the last two terms). The explained variation comes from the change in the explanatory variables in the regression model between period *i* and period *i-n*; the unexplained variation comes from the changes in the estimates of the regression coefficients (α and β) between periods.

The analysis reported here is of the determinants of the change in the average hourly on-peak and off-peak Richview-HOEP price differentials between the period February to October, 2004 and the same period in 2007. February to October, 2004 is chosen as the base period as this is the earliest period for which we have accurate forecast data. All variables are hourly averages for on-peak and off-peak hours respectively.

[134] The Oaxaca decomposition is widely used in labour economics, to identify the degree of wage discrimination between different groups of employees.

Appendix Table 3-1 and 3-2 below report the regression results and the decomposition. The independent variables (i.e. regressors) include hourly averages of those factors discussed in Section 2.3:

- a binary indicator of congestion between the northwest and the south (1 for congestion and 0 for non-congestion),
- the average hourly 10-minute demand forecast error,
- the average hourly amount of manually constrained on generation,
- the average hourly amount of constrained off net exports, and
- the average hourly real-time supply cushion.

On the top of each table are the yearly average Richview nodal price and HOEP, their difference, and the change in the difference. In the middle of each table are the average magnitudes of each explanatory variable and the explained variation based on either 2007 or 2004 coefficients. Both sets of coefficients are used for comparison as the coefficients for each year might be very different and thus the explained variation could be very different. At the bottom of each table are the estimated coefficients and the unexplained variation. Our primary interest is in the contributions of the explanatory variables to variation in the price differences.

For example, from Appendix Table 3-1, the actual off-peak price difference in 2004/2007 narrowed by \$2.66/MWh (from \$7.70/MWh in 2004 to \$5.04/MWh in 2007). Changes in the explanatory variables contributed to these 2004 to 2007 differences as follows:

- Over the period 2004-2007, congestion from the northwest to the south increased slightly and this widened the gap between the Richview price and the HOEP by \$0.07/MWh because of the downward effect of the phantom supply in northwest on the HOEP. The effect of using the 2004 or 2007 coefficient is the same.
- The extent to which demand was under-forecast in the constrained schedule increased over the period 2004 – 2007. This suppressed the Richview price and narrowed the gap with the HOEP by \$4.18/MWh if the 2007 coefficient is used, or \$0.49/MWh if the 2004 coefficient is used.

- The increase in manually constrained on generation and the decrease in constrained off net exports each had a relatively little effect, whether the 2004 or 2007 coefficients are applied.
- The increase in the real-time supply cushion over the period 2004 – 2007 reduced the relative severity of price spikes in the constrained schedule thereby reducing the amount by which HOEP was lower than Richview. This decreased the gap by \$3.48/MWh if the 2007 coefficient is applied, or \$7.39/MWh if the 2004 coefficient is applied. The effect of the supply cushion is prominent among all variables of study, whether the 2004 or 2007 coefficient is applied.

The implication of the decomposition analysis for off-peak periods is that, to the extent that variation in the gap between the Richview nodal price and the HOEP can be explained by the five variables identified, the reduction of this gap between 2004 and 2007 is largely attributable to an increase in the supply cushion (which reduced the amount by which HOEP was lower than the Richview price) and likely to under-forecasting demand in the constrained schedule (which suppressed the Richview price).

Appendix Table 3-1: Contributions to Off-Peak Price Differences, February – October, 2004 vs. 2007

	2004	2007		2007 - 2004 ($/MWh)	
Richview ($/MWh)	46.6	41.64		4.96	
HOEP ($/MWh)	38.9	36.6		2.30	
Difference ($/MWh)	7.7	5.04		**-2.66**	
Average values				Using 2007 Coefficient	Using 2004 Coefficient
Northwest-South Congestion	0.267	0.278	**Regressors**	0.07	0.07
Demand Forecast Error (MWh)	22	-101		-4.18	-0.49
Manual Constrained on generation (MWh)	9	16		-0.02	0.23
Constrained on net export (MWh)	94	78		0.13	0.32
Supply Cushion (%)	15.587	25.144		-3.48	-7.39
Subtotal				**-7.48**	**-7.25**
Estimated Coefficients					
Constant	19.438	16.476	**Coefficients**	-2.96	-2.96
Northwest-South Congestion	6.781	6.402		-0.10	-0.11
Demand Forecast Error	0.004	0.034		0.66	-3.03
Manual Constrained on generation	0.033	-0.003		-0.32	-0.58
Constrained off net export	-0.020	-0.008		1.13	0.94
Supply Cushion	-0.773	-0.364		6.38	10.28
Subtotal				**4.78**	**4.55**
Total ($/MWh)	**-2.71**				**-2.71**

Regarding the implications of the different coefficients in the two years, the changed coefficient for the supply cushion variable dominates the unexplained portion of the difference between the Richview prices and HOEP. For example, the change to the supply cushion coefficient accounts for an increased price gap of $6.38/MWh using the 2004 supply cushion value or $10.28/MWh using the 2007 supply cushion. The former value is based on the 2004 average value of the supply cushion multiplied by the difference in the coefficients between the two years. The latter value uses the 2007 average supply cushion multiplied by the change in the coefficients.

According to Appendix Table 3-2 for the on-peak decomposition, the on-peak price gap decreased by $2.3/MWh, from $16.34/MWh in 2004 to $14.00/MWh. Changes in the explanatory variables contributed to these 2004 to 2007 differences as follows:

- The demand forecast error contributed a $15.14/MWh reduction (using the 2007 coefficient) or $0/MWh (using the 2004 coefficient) to the Richview-HOEP gap. Based on the 2007 coefficients, this variable affected the price difference most, while using the 2004 coefficients, this variable had a negligible effect on the price difference.
- The supply cushion variable change reduced the gap by $4.63/MWh (using the 2007 coefficient) or $2.60/MWh (using the 2004 coefficient).
- Effects of all other explanatory variables were minimal.[135]

[135] The manual constrained on generation increased by 25 MW from 11 MW in 2004 to 36 MW in 2007, but has counterintuitive effect of increasing the gap by $0.23/MWh or $0.31/MWh. The counterintuitive effect was induced by a few outliers in which there was large constrained on generation associated with a large Richview price.

Appendix Table 3-2: Contributions to On-Peak Price Differences, February – October, 2004 vs. 2007

	2004	2007		2007 - 2004 ($/MWh)	
Richview ($/MWh)	74.43	75.57		1.14	
HOEP ($/MWh)	58.09	61.57		3.48	
Difference ($/MWh)	16.34	14.00		**-2.34**	
Average values				2007 Coefficient	2004 Coefficient
Northwest-South Congestion	0.49	0.46	Regressors	-0.44	-0.13
Demand Forecast Error (MWh)	49	-74		-15.14	0.00
Manual Constrained on generation (MWh)	11	36		0.23	0.31
Constrained off net export (MWh)	140	142		-0.04	0.00
Supply Cushion (%)	7.966	10.182		-4.63	-2.60
Subtotal ($/MWh)				**-20.03**	**-2.43**
Estimated Coefficients					
Constant	23.057	38.546	Coefficients	15.49	15.49
Northwest-South Congestion	5.464	18.519		6.33	6.02
Demand Forecast Error	0.000	0.123		6.04	-9.10
Manual Constrained on generation	0.012	0.009		-0.03	-0.11
Constrained off net export	0.000	-0.021		-2.94	-2.98
Supply Cushion	-1.175	-2.089		-7.28	-9.31
Subtotal ($/MWh)				**17.61**	**-0.01**
Total ($/MWh)	**-2.42**				**-2.42**

There are also large changes in the coefficients of the variables (except manual constrained on generation) which, together with the $15.49/MWh change in the constant term, imply an effect on the price gap almost as large as the changes in the variables themselves. The shifted coefficient of the Northwest-south congestion variable increased the gap by about $6/MWh. The change in the coefficient for the demand forecast error using the 2004 average value of the variable (representing an over-forecast) had an apparent similar effect on the price gap , while the 2007 value of the variable (representing an under-forecast) appears to have reduced the gap by $9.10/MWh. The changed coefficients for the constrained off net export and supply cushion variables appear to have reduced the price gap by about $3/MWh to $9/MWh.

As noted above, there is a large change in the constant term, but both the 2004 and 2007 constant terms are quite large in themselves, \$23/MWh and \$39/MWh respectively. This implies that there may be important explanatory variables that the model has not captured. These large values may also be indicating that the linear model assumed for the decomposition is not sufficiently representative of what may be a non-linear relationship in the variables. The large size of the constant terms for the off-peak results leads to a similar conclusion.

Summary

In general, our analysis shows that the determinants of the gap between the Richview price and the HOEP vary in importance over time. As a consequence, the explanation for the convergence or divergence of the Richview price and the HOEP over a particular time period depends on the time period chosen. As far as the reduction in the gap between the Richview price and the HOEP between 2004 and 2007 is concerned, this appears to be most sensitive to the increase in the supply cushion and the increased under-forecast of demand in the constrained schedule. Changes in congestion between the northwest and the south, in manually constrained on generation, and in constrained off net exports respectively had a limited effect on the gap between the two prices.

However, the decomposition also demonstrates that coefficients of the variables can change significantly between years, and combined with the constant term, suggest that the unexplained variations of the price gap in the model may be almost as large as the explained variations. This indicates that there may be important variables the decomposition has not modeled. Alternately, the decomposition may be using a linear model to represent a non-linear process.

Appendix 3.2: Quantifying Efficiency Gains of Moving to 15-minute Dispatch

We use a static approach to estimate the efficiency gains of moving from one hour to 15 minute pre-dispatch. In other words, we assume offers and bids from all resources to be the same as they were and proxy the potential efficiency gains had the 15 minute pre-dispatch been used.

We assume the offers are still hourly offers. That is, an offer is valid for the whole hour. 15 minute dispatch divides an hour of 12 intervals into four blocks: interval 1-3, 4-6, 7-9 and 10-12. When demand is ramping up within an hour, interval 10-12 has the peak demand, while when demand is ramping down, interval 1-3 has the peak demand.

The efficiency implication of the 15 minute pre-dispatch is highlighted in Appendix Figure 1. Assume this is an hour with demand ramping up.[136] Thus the demand in interval 10-12 is the peak demand for the hour, which is greater than the demand in interval 7-9 as well as in interval 1-3 and 4-6. PD Offer Stack represents the actual offers from all resources: solid black lines represent domestic generator offers and the red line is an import. The import is scheduled based on the peak demand for the hour.

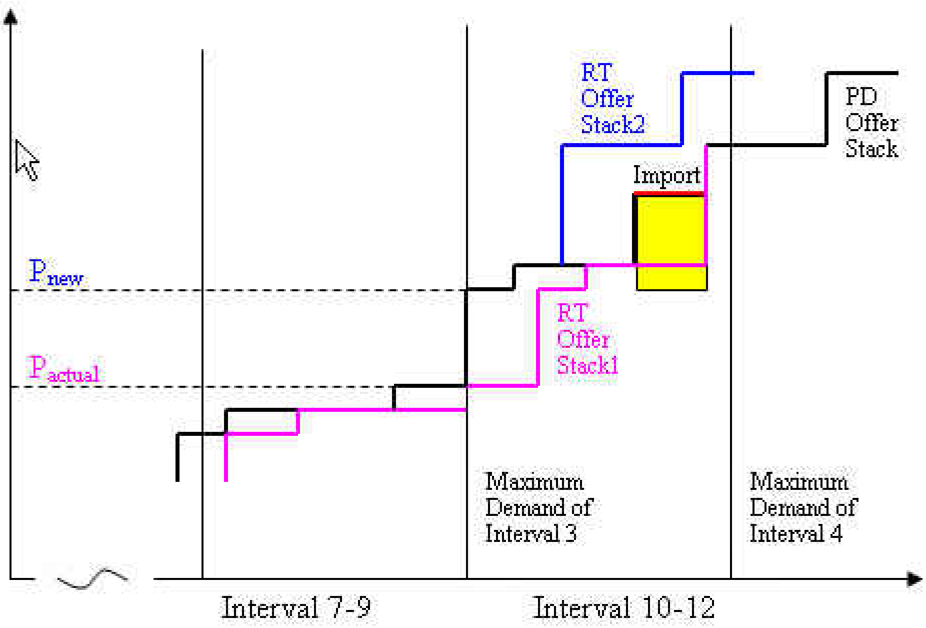
Imports cannot set the real-time price. Their offers are re-stacked at the bottom of the supply stack in real-time. The pink line represents the real-time offer curve, and the real-time price is set at P_{actual}.

Apparently the scheduled import is efficient for interval 10-12 in which the demand is the highest, but inefficient for interval 7-9 as well as for interval 1-3 and 4-6 because cheaper domestic generation can be sufficient to meet the demand. Had the import not been scheduled for interval 7-9, the supply stack would have been the same as the PD Offer Stack in the first part but steep in the second part, as shown in the blue lines. The new real-time price would be $P_{new.}$

[136] The analysis for situations with demand ramping down is analogous.

The efficiency gains of having the import not dispatched for interval 7-9 is the imported MW times the difference between its offer and the new price, which is represented by the yellow rectangle.

Appendix Figure 1: Estimation of Efficiency Gains of Moving from One Hour to 15 Minute Pre-dispatch



Because actual dispatch efficiency depends on the outcomes from the constrained sequence, we estimate the efficiency gains based the constrained sequence. Our estimation approach is as follows.

1. Based on the one-hour ahead pre-dispatch demand, we identify the interval with the highest demand within each interval block (i.e. every 15 minute period). The pre-dispatch demand is used since the 15 minute pre-dispatch is also based on the forecast demand.

2. We restack the offer curve for each interval with the highest demand within a 15 minute block except the interval with the highest demand within the hour. The

peak interval with the hour is excluded as there is presumably no efficiency gain for this 15 minute block.

a. If a unit is dispatched for operating reserve, an equivalent portion is reduced from the highest to lowest offer price. This eliminates potential double counting effect on energy supply.
b. All dispatched energy at generation units is removed from the supply curve as they are irrelevant to the calculation.[137] This can also eliminate the effect of out-of-merit dispatch as a result of manual actions by the operator.
c. If an import is manually constrained on, the import is not counted into the offer stack as manual actions are typically taken when there is security of adequacy problems.

3. We match the Richview nodal price with the rebuilt offer stack and identify the marginal unit. Then we sequentially remove the scheduled imports from the highest offer to the lowest offer and approximate a new Richview nodal price. The removal process goes on until the last removed import will lead to a new price greater than its offer price. The final estimated price should be below the offer price of all removed imports, i.e. all avoidable imports.

4. We then calculate the potential efficiency gains of having not scheduled those avoidable imports.

There are a few caveats in this analysis. First, we assume no behavioural change and thus may overstate the efficiency gains. For example, had few imports scheduled for low-demand intervals, the price should be higher for those intervals. In response to the expected higher price, some exports may not have offered and thus been selected. This will push the price up. The static approach of assuming no response overstates the likely price effect and thus the efficiency gains from the change in dispatch interval. Second, our estimation of focusing on imports only tends to understate the efficiency gains from

[137] Removing imports from the schedule can only lead to more generation rather than less.

smoothing the dispatch of fossil units and hydro units. It is expected that the import/export change between every 15 minute interval is smaller than the change from hour to hour, which can reduce the cycling of fossil generators and lower wear and tear costs.[138] The smoothing in demand growth can also reduce the need for hydro generators to provide ramp capability and thus preserve energy for high valued hours.

[138] The Independent Market Advisor to the New York ISO observed that since the 15 minute dispatch was implemented, the hour-ahead and real-time price has been convergent. The improved convergence improved the scheduling of non-dispatchable resources and imports and the commitment pf peaking units. For details, see '2004 State of the Market Report, New York ISO' by Potomac Economics, Ltd., July 2005.

Chapter 4: The State of the IESO-Administered Markets

1. *General Assessment*

This is our 11th semi-annual monitoring report on the IESO-administered markets covering the summer period May to October 2007. As in our previous reports we conclude that the market has operated well according to the parameters set for it.

The average monthly HOEP, May to October 2007, was slightly higher (by 1 percent), than the HOEP corresponding to the period a year ago, and represents a levelling out of the trend towards lower prices we have seen since the market began operating. Market-related uplift payments for congestion, supply guarantees and other matters were also marginally higher than the corresponding period a year ago, primarily as the result of more congestion particularly in the northwest.

Lower prices have been the natural outcome of the increased energy supplies seen in Ontario since market opening. However, with little new generation being added over the last year and slightly lower production from nuclear generation, there was less downward pressure on market prices in the period relative to last year. In fact, less available low cost energy pushed up prices in the latter months of the period, particularly on-peak. Export demand was up but overall market demand was lower, primarily due to the continued decrease in wholesale load.

Higher exchange rates for Canadian currency over the period tended to offset higher U.S. gas prices. The exchange rates, combined with already lower US coal prices produced significantly lower Ontario prices for coal.

Generally, on-peak prices were higher and off-peak prices lower compared to the same period last year, and consistent with this, energy prices were more spread out, with more hours above $70/MWh and more below $20/MWh. Lower coal prices likely contributed to some of the reduction in the off-peak prices since coal-fired generators were usually the marginal units in these hours.

There were only 4 hours with HOEP over $200/MWh, compared with six last year. Even though there was a higher frequency of prices below $20/MWh, there was only one hour with negative HOEP, the same as last year. Our review of these and other anomalous hours led us to conclude that the price movements in these hours were consistent with the supply/demand conditions prevailing at the time. As is customary, the MAU communicated with market participants from time to time to review and understand market behaviour. We found no evidence of gaming or abuse of market power during the review period.[139]

The rest of the Chapter is organized as follows: section 2 summarizes findings from Chapter 3 of our review of generation contracts and a demand response event in the period. Section 3 provides a status report of actions by the IESO in response to previous Panel recommendations. Finally, section 4 excerpts and lists the various recommendations made in the body of our report.

2. *Efficiency Implications of Public Agency Contract Arrangements*

In Chapter 3 we reviewed the implications for dispatch efficiency in the IESO-administered market of existing public agency generation contracts and an event involving a load participating in the Ontario Power Authority's (OPA) Demand Response Program DR1.

The generation contracts reviewed included the Reliability Must Run contract struck by the IESO, and several of OPA's generation procurement programs, such as the Bruce A energy contract, two forms of Standard Offer Programs (SOPs), and the Clean Energy Supply (CES) program (whose contract structure acted as a reference for the Early Movers contracts).

[139] 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.

From that review we observed that the CES contract arrangements were 'efficiency friendly' by many measures, whereas the other contracts (noted above) did not provide as clear efficiency drivers to the generators. This is primarily due to the CES contract using a strike price based on the generator's marginal cost and (in simple terms) deeming the generation to be producing when market prices reach the strike price.

In the case of low cost energy (Renewable Energy SOP and Bruce A contract), though efficiency drivers are weak, the contracts can still lead to efficient outcomes, except on occasions when there may be a surplus of low-cost energy, or in the event that outages may be planned without reference to daily or seasonal market prices as a driver. We also noted that the limited information the IESO may have about actual and projected production for RESOP facilities is likely to increase operational uncertainty, by increasing demand forecast error since most SOP projects would be connected within an LDC. This may not have a large impact over the province as a whole, given the small total volumes currently generated under such contracts and diversity of production across the province. However, it will be larger in future and could become quite significant locally where transmission may be limiting. This has the potential to lead at times to inefficient utilization of local transmission because of the uncertainty of RESOP production.[140] For example in a transmission congested area such as the Northwest abrupt upward changes in RESOP production could overload local transmission therefore at times it may be necessary for the IESO to increase the transmission buffer. There may be operational alternatives for dealing with this issue and the Panel understands that the IESO has just initiated a stakeholder consultation to discuss the integration of RESOP and other embedded generators into the reliable operation of the IESO-controlled grid.[141] We are recommending the IESO consider opportunities arising from this consultation for minimizing inefficiencies that may be associated with embedded generation projects. (See Recommendation 3-7 in section 4.)

[140] OPA has the ability to limit projects in certain areas of the province where transmission may be restrictive.
[141] http://www.ieso.ca/imoweb/consult/consult_se57.asp

While the proposed Clean Energy SOP is under review by OPA the Panel would like to point out issues with the initial draft of the CESOP that should be reviewed. The large hourly payments associated with the proposed CESOP may lead to these suppliers replacing lower cost Ontario generation or imports in the market. The potential magnitude of total CESOP projects underscores a further issue. Because this generation is typically expected to be coupled with a load, by netting this generation against load, uplifts payments by this load are reduced (with the exception of the Debt Retirement Charges which are based on gross demand). The consequence of this is that the fixed costs of uplift are spread over a smaller load base, thus increasing the separation between HOEP and the total cost of consumption for most loads. This impact on uplift is not unique to CESOP generation, but it could increase significantly as more embedded generation facilities come online.

Finally, as we have reported before, we found the IESO's Reliability Must Run contract for OPG's Lennox facility does not always rely on financial incentives to achieve efficient outcomes, rather it has a variety of contractual terms that may encourage efficient behaviour subject to the appropriate interpretation.

We also reported an event in which a load in OPA's Demand Response Program DR1 was induced by projected market prices above $80/MWh to reduce consumption, although doing so led to the IESO having to reduce lower cost hydroelectric generation. The value of the reduced consumption was estimated at about $160/MWh while the cost of the marginal supply was estimated at $3/MWh. Not consuming in this situation was obviously inefficient and led to other loads paying total uplifts to the DR1 load and the generator roughly equivalent to the efficiency loss. It is not clear how often such events occur, partly because of a lack of information about use of the program. However, any scheme that pays a load to reduce consumption can be expected to induce a significant proportion of inefficient outcomes, even when there are no transmission limits.[142]

[142] Excluding consideration of any benefits associated with other public policy goals, efficiency loss is the value of consumption less the incremental cost of generation. With value roughly two times HOEP and incremental cost roughly equal to HOEP (absent transmission limits and large transmission losses), the efficiency loss is often close to HOEP. For the event above, the efficiency loss was much greater because congestion induced a much lower incremental cost for generation.

There is a common shortcoming of several of the generation contract arrangements and the DR1 scheme, namely that the MCP signal to these facilities is being distorted. Some generators do not see this signal at all, or receive a premium well above MCP. Under DR1, the signal to the load is roughly two times MCP. For future programs, or to the extent that payments under existing programs can be modified, there would be greater efficiency gains to the market if these programs focused on an undiluted MCP as the driver.[143]

In Chapter 3 and in our previous report we recommended that OPA employ a contract structure which uses the energy market price as the hourly payment or driver, such as the CES contract.[144] With regard to Demand Response programs, we have previously recommended such programs be designed to motivate consumers not to consume only when their value is less than the cost of supply.[145]

As we noted in Chapter 1, load-weighted HOEP has increased by $0.65/MWh, but the effective weighted HOEP after being adjusted for the Global Adjustment (GA) and OPG Rebate has increased by $1.20/MWh. This implies that additional costs have been added to the GA.[146] This data indicates a trend toward increasing payments by consumers as the result of the changing Global Adjustment. As OPA procures more resources, both generation and demand response, the size of this uplift charge is expected to grow. About 3200 MW of generation contracted by OPA is expected to be installed in 2008 with another 3400 MW (approximately) expected in the following two years, much more than the roughly 1700 MW of generation currently contracted by OPA. This does not include Standard Offer Program generation.[147]

[143] The most accurate driver and signal for efficiency would be the shadow price at each location. MCP or HOEP diverge from shadow prices, but less so most of the time than the price drivers in many of the existing contracts.

[144] "To realize all of the benefits of the wholesale market, however, future supply contracts should include terms and conditions that induce new generation to offer into the wholesale market at prices that reflect their incremental cost of production. This will help to ensure efficient dispatch." - December 2006 Monitoring Report, p.150.

[145] Ibid. p.140

[146] The Global Adjustment is affected by HOEP, the capacity contracted and any strike prices in the contracts. Normally when average HOEP increases, GA should decrease. So the increase in GA this year in spite of slightly increasing HOEP is indicative of marginally more contracted capacity. We also note that new OPA resources being contracted tend to be at prices above current HOEP, so would tend to increase the GA.

[147] See http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=123; These figures include the planned 1500 MW of refurbishment at Bruce, but not Bruce 1 or Bruce 2 capacity. See also OPA; "A Progress Report on Renewable Energy Standard Offer

Aside from the OPG Rebate figure, there is no publicly available disaggregation of the Global Adjustment into its various components: OPG's baseload generation (prescribed assets), the various OPA generation procurement and demand management programs, Bruce generation or the NUG contracts. Data such as total monthly payments under each program as well as monthly energy delivered would be useful for an assessment of the effectiveness or cost of these various programs. Disaggregation could also be helpful for market participants or even retail customers who may try to forecast how these payments may increase in the future and could be useful for making investment or supply contract decisions. The Global Adjustment alone for the recent summer period represented an aggregate charge to Ontario consumers of approximately $370 million or about $5/MWh of Ontario consumption in the period.

Recommendation 4-1

(1)The Ontario Power Authority should create more transparency regarding the ongoing monthly payments and energy delivered for each of its various procurement programs in order to promote a better understanding of the costs and effectiveness of these programs and to help market participants gain a better understanding of the component costs of the Global Adjustment.

(2) Similarly, the IESO should consider providing aggregate monthly payments associated with Ontario Power Generation's regulated baseload assets, as it currently does for the OPG Rebate.

3. *IESO Responses to Previous Panel Recommendations*

Many of the recommendations in Panel's reports are directed toward the IESO. In November 2006 the IESO began to formally report on the status of actions it has taken in

Program November 2007" .There are some 842 MW of energy under 228 executed RESOP Contracts, with another 78 applications in process. Based on information from OPA, this represents about 100 MW in 2007, another 300 MW in 2008 and some 400 MW in 2009 and 2010 combined.

response to these recommendations. The IESO posts this information on its Web site, as well as discussing the recommendations and actions with its Stakeholder Advisory Committee (SAC).[148]

The current version of the status document covers recommendations going back several years. In this section we review the status of the recommendations from our last monitoring report, released in August 2007. The IESO responses to these are summarized in Table 4-1 below.

[148] See "IESO Response to MSP Recommendations" at http://www.ieso.ca/imoweb/marketSurveil/surveil.asp

Table 4-1: Summary of IESO Responses to Recommendations in Previous Market Surveillance Panel Reports

Recommendation Number & IESO Status	Subject	Summary of Action
1-1 (1)[149] **Closed**	Intertie Failures	"… a proposal has been made to the Inter-Jurisdictional Trading Sub-committee that would result in a majority of these failures being classified as within the market participant's control and subject to the various failure charges."
2-1 (2) **In Progress** Target: 2008/03/31	Time Lags for Replenishing OR	"… the IESO has begun a review of the operating reserve adjustment policy. As part of this review the IESO will respond to the MSP's question regarding the appropriateness of any OR reductions."
2-2 (3) **In Progress** Target: 2008/06/30	Increasing Net Interchange Scheduling Limit	"… IESO … will undertake to review the frequency and impact of a binding 700 MW limit. The IESO's review will consider the appropriate balance between too low a NISL that … may affect efficient trade and too high a NISL limit that … can have negative effects on the operation of the grid and can also interfere with issues of price fidelity and market efficiency."
2-3 (4) **In Progress**	Load Predictor Tool	"The IESO accepts this recommendation and will initiate a review of the dispatchable load treatment and determine based on frequency, impact, priority and cost what future actions should be taken."
3-1 (5) **Closed**	Efficient use of Dispatchable Loads' OR Capability	"…as of August the OPA contract provisions now allow for the continued offering of OR by dispatchable loads that have not been dispatched by an OPA program."
3-2 (6) **In Progress** Target: 2008/05/31	DACP and Generator Cost Guarantees	"The IESO is in the midst of an assessment of possible improvements to day-ahead mechanisms. This review will include possibilities ranging from DACP enhancements that could include three-part bidding and 24-hour optimization, to a more complete day-ahead market design."
3-3 (7) **Closed**	SGOL and DA-GCG Interface	"This recommendation will be tracked under Recommendation 6 above."
3-4 (8) **In Progress**	RT-IOG and DA-IOG in Off-Peak Hours	"This issue was identified by the Market Pricing WG in 2004 and reviewed in 2005. … This remains an issue on the list of pricing issues to be addressed by the Market Pricing WG."
3-5 (9) **In Progress**	Energy Exports through Segregated Mode of Operation	"This work was initiated sometime ago and we have met with OPG and are working through the concept."
3-6 (10) **Closed**	Locational Pricing Analysis	"Following a review of locational pricing undertaken by the Market Pricing WG in late 2006, the Stakeholder Advisory Committee (SAC) recommended to the IESO Board, which was accepted by the Board, that the IESO continue to learn about Locational Pricing, but at a measured pace. The 2006 analysis identified several factors that make a direct comparison of historic constrained shadow prices and HOEP problematic. IT changes are in progress that will improve the accuracy of the existing shadow prices[150] and the IESO continues to develop its capability to analyze behavioural responses to market changes."

[149] Recommendations are labelled according to the numbering in our monitoring report, e.g. "1-1", as well as according to the chronological numbering used in the IESO Report e.g. "(1)".
[150] Information technology changes completed or underway include new loss factors, publishing intertie shadow prices and identifying when NISL is limiting.

Given the few months since our recommendations were made public, the IESO has made valuable progress in several areas. There are specific targets dates on some of the actions described, although a few actions "In Progress" are open-ended with no indication when the issues might be considered. Four items are shown as "closed": the resolution for number 1-1 (1) is imminent; number 3-1 (5) has been successfully dealt with; number 3-3 (7) has been combined with another "In Progress" item; and 3-6 (10) appears to be closed only in the sense that some initial exploratory activities have been identified and are underway. We will continue to monitor market developments in relation to unimplemented panel recommendations to the IESO.

4. *Summary of Recommendations*

The following recommendations arise from the analysis in this report. They focus on issues of price fidelity and market efficiency, although we expect that several may also enhance reliability.

Recommendation 1-1 (Chapter 1 Section 2.4.3)

The Panel encourages the IESO to continue to review the forecasting process with wind generators and determine methods to reduce forecast errors. Such generators should have incentives (positive or negative) to encourage accurate forecasting.

Recommendation 2-1 (Chapter 2 Section 2.1.2.3)

Export curtailment due to 'adequacy' has an effect of suppressing the market price during times of serious scarcity since the curtailed amount is removed from the market schedule, thus distorting the market price signal. The Panel recommends that the IESO not remove the curtailed amount due to 'adequacy' from the market schedule.

Recommendation 3-1 (Chapter 3 Section 2.3)

Consistent with prior recommendations directed at improving the IESO load predictor, whose algorithm imputes changes in non-dispatchable load that can induce consumption inefficiency and forecast errors, the Panel recommends that the IESO review its load predictor methodology to determine if it is a source of persistent under-forecasting of demand.

Recommendation 3-2 (Chapter 3 Section 2.5)

(1) The IESO should expedite completion of the necessary agreements with Hydro One, the Midwest ISO and ITC*Transmission for operation of the Phase Angle Regulators on the Michigan intertie. The IESO (and Hydro One) should also complete necessary staff training as soon as possible. Any improvement on the spring 2008 implementation target would have positive efficiency (as well as reliability) effects on the Ontario (and Midwest ISO) system and any slippage would have the opposite effects.*

(2) Hydro One should work towards developing ratings that will safeguard the Phase Angle Regulators and provide operationally useful Limited Time Ratings as soon as possible.

Recommendation 3-3 (Chapter 3 Section 3.1)

The MSP recommends the IESO begin investigation of a 15 minute dispatch algorithm to enhance the efficiency of the market.

Recommendation 3-4 (Chapter 3 Section 4.1)

The IESO should initiate a rule change to allow the recovery of self-induced congestion management settlement credit payments which are made to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons.

Recommendation 3-5 (Chapter 3 Section 4.2)

The IESO should initiate a rule change to make Intertie Offer Guarantee payments subject to offsets where affiliated market participants are simultaneously importing and exporting.

Recommendation 3-6 (Chapter 3 Section 4.3)

It is important for the efficiency of the Ontario electricity market that Hydro One attempt to complete the Queenston Flow West transmission expansion as soon as practicable. The ability to fully utilize 'bottled' generation in the Niagara region and maximize economically viable imports with New York (and Michigan) will enhance the efficiency (and reliability) of the Ontario market.

Recommendation 3-7 (Chapter 3 Section 4.4.3)

To the extent possible in its stakeholder consultation on embedded generation, the IESO should consider opportunities to reduce inefficiency through the development of the capability for accurate forecasting of embedded generation production, which may require the provision of real-time production and related information (e.g. outages).

Recommendation 3-8 (Chapter 3 Section 4.4.6)

The Panel recommends that the Ontario Power Authority structure future contracts to maintain the energy market price as the driver for production decisions (for example, using a strike price structure similar to the payment provisions in the existing Clean Energy Supply contracts).

Recommendation 4-1 (Chapter 4 Section 2)

(1) The Ontario Power Authority should create more transparency regarding the ongoing monthly payments and energy delivered for each of its various procurement programs in order to promote a better understanding of the costs and effectiveness of these programs and to help market participants gain a better understanding of the component costs of the Global Adjustment.

(2) Similarly, the IESO should consider providing aggregate monthly payments associated with Ontario Power Generation's regulated baseload assets, as it currently does for the OPG Rebate.

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 2007 – October 2007

PUBLIC

2007

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 2006 – October 2007 (TWh)*

	Ontario Demand		Exports		Total Market Demand	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	11.99	11.83	1.20	1.08	13.18	12.91
Jun	12.59	12.69	0.91	1.04	13.51	13.74
Jul	13.89	12.85	1.03	1.30	14.92	14.15
Aug	13.32	13.47	1.21	1.12	14.53	14.60
Sep	11.58	11.95	0.83	0.92	12.41	12.88
Oct	11.99	11.92	0.98	0.93	12.97	12.85
Nov	12.22	N/A	0.53	N/A	12.75	N/A
Dec	12.92	N/A	0.67	N/A	13.58	N/A
Jan	13.79	N/A	0.78	N/A	14.57	N/A
Feb	13.04	N/A	1.19	N/A	14.24	N/A
Mar	13.21	N/A	0.91	N/A	14.12	N/A
Apr	11.86	N/A	1.16	N/A	13.02	N/A
May – Oct	75.36	74.71	6.16	6.39	81.52	81.13
Nov - Apr	77.04	N/A	5.24	N/A	82.28	N/A
May - Apr	152.40	N/A	11.40	N/A	163.80	N/A

* Data includes dispatchable loads

Table A-2: Average Monthly Temperature*, March 2002 - October 2007*
(°Celsius)

	2002	2003	2004	2005	2006	2007
Jan	N/A	(7.68)	(9.13)	(6.78)	0.30	(2.65)
Feb	N/A	(7.02)	(3.29)	(3.60)	(3.56)	(7.99)
Mar	0.39	(0.57)	2.26	(1.29)	1.21	0.59
Apr	7.27	5.53	6.88	8.18	8.36	6.29
May	11.21	12.23	13.31	12.14	14.59	14.77
Jun	19.18	18.53	17.78	22.54	19.76	20.84
Jul	24.14	21.71	20.65	24.09	23.50	21.42
Aug	22.63	21.85	19.57	22.53	21.22	22.27
Sep	20.09	17.12	18.40	18.33	15.79	18.34
Oct	9.16	9.04	10.85	11.01	9.07	14.11
Nov	3.18	4.91	5.29	5.06	5.25	N/A
Dec	(1.82)	(0.03)	(2.54)	(3.13)	1.94	N/A

* Temperature is calculated at Toronto Pearson International Airport

Table A-3: Number of Days Temperature Exceeded 30°C, March 2002 - October 2007*

	2002	2003	2004	2005	2006	2007
Jan	N/A	0	0	0	0	0
Feb	N/A	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	2	1
Jun	5	4	2	9	3	6
Jul	16	4	1	11	9	4
Aug	8	4	0	7	3	8
Sep	4	0	0	2	0	4
Oct	0	0	0	0	0	1
Nov	0	0	0	0	0	N/A
Dec	0	0	0	0	0	N/A

* Temperature is calculated at Toronto Pearson International Airport

Table A-4: Outages, May 2006 - October 2007*
(TWh)

	Total Outage		Planned Outage		Forced Outage	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	5.06	5.49	2.63	3.63	2.43	1.86
Jun	3.89	3.58	1.51	1.35	2.37	2.23
Jul	2.82	3.34	0.40	0.94	2.42	2.40
Aug	3.22	3.61	0.96	0.46	2.26	3.15
Sep	4.82	5.48	2.46	2.42	2.36	3.06
Oct	5.34	6.53	2.93	3.77	2.41	2.76
Nov	5.75	N/A	3.34	N/A	2.41	N/A
Dec	4.37	N/A	2.47	N/A	1.90	N/A
Jan	3.74	N/A	1.83	N/A	1.90	N/A
Feb	3.03	N/A	1.13	N/A	1.89	N/A
Mar	5.17	N/A	2.86	N/A	2.32	N/A
Apr	4.99	N/A	3.11	N/A	1.88	N/A
May – Oct	25.15	28.03	10.89	12.57	14.25	15.46
Nov - Apr	27.05	N/A	14.74	N/A	12.30	N/A
May - Apr	52.20	N/A	25.63	N/A	26.55	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 2006 - October 2007
($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	46.32	38.50	59.18	53.78	34.77	24.77
Jun	46.08	44.38	56.04	57.32	37.36	33.06
Jul	50.52	43.90	63.25	57.70	41.72	32.54
Aug	52.72	53.62	65.05	69.80	41.64	39.10
Sep	35.42	44.63	43.85	58.27	28.67	34.66
Oct	40.20	48.91	49.64	60.19	32.44	38.77
Nov	49.71	N/A	60.13	N/A	39.75	N/A
Dec	39.25	N/A	53.06	N/A	29.71	N/A
Jan	44.48	N/A	53.44	N/A	36.43	N/A
Feb	59.12	N/A	70.93	N/A	48.39	N/A
Mar	54.85	N/A	68.31	N/A	42.76	N/A
Apr	46.05	N/A	57.58	N/A	37.63	N/A
May – Oct	45.21	45.66	56.17	59.51	36.10	33.82
Nov - Apr	48.91	N/A	60.58	N/A	39.10	N/A
May - Apr	47.06	N/A	58.37	N/A	37.60	N/A

Table A-6: Average Richview Slack Bus Price, On and Off-Peak, May 2006 - October 2007 ($/MWh)

	Average Richview Slack Bus Price		Average On-Peak Richview Slack Bus Price		Average Off-Peak Richview Slack Bus Price	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	64.45	41.69	96.58	57.84	35.60	27.18
Jun	52.09	71.03	61.00	103.80	44.29	42.38
Jul	55.71	49.16	68.17	66.92	47.11	34.54
Aug	59.78	61.53	73.72	82.04	47.26	43.10
Sep	35.32	51.71	44.01	71.36	28.38	37.35
Oct	41.83	55.73	50.96	68.24	34.32	44.49
Nov	55.24	N/A	68.11	N/A	42.93	N/A
Dec	40.97	N/A	56.03	N/A	30.57	N/A
Jan	51.24	N/A	61.90	N/A	41.67	N/A
Feb	69.49	N/A	83.83	N/A	56.45	N/A
Mar	66.40	N/A	86.19	N/A	48.64	N/A
Apr	50.63	N/A	60.15	N/A	43.67	N/A
May – Oct	51.53	55.14	65.74	75.03	39.49	38.17
Nov - Apr	55.66	N/A	69.37	N/A	43.99	N/A
May - Apr	53.60	N/A	67.55	N/A	41.74	N/A

Table A-7: Ontario Consumption by Market Segmentation,
May 2006 - October 2007
(TWh)

	LDC's		Wholesale Loads		Generation		Metered Energy Consumption		Transmission Losses		Total Energy Consumption	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	9.63	9.55	1.66	1.58	0.18	0.20	11.46	11.33	0.47	0.49	11.93	11.82
Jun	10.13	10.49	1.66	1.50	0.19	0.19	11.99	12.18	0.56	0.51	12.54	12.69
Jul	11.48	10.61	1.61	1.44	0.19	0.19	13.27	12.24	0.58	0.60	13.85	12.84
Aug	10.99	11.13	1.67	1.46	0.16	0.20	12.82	12.79	0.49	0.66	13.31	13.45
Sep	9.43	9.79	1.53	1.38	0.16	0.18	11.12	11.36	0.40	0.56	11.52	11.92
Oct	9.77	9.75	1.50	1.44	0.15	0.15	11.42	11.33	0.54	0.58	11.96	11.91
Nov	9.97	N/A	1.49	N/A	0.16	N/A	11.63	N/A	0.55	N/A	12.18	N/A
Dec	10.73	N/A	1.47	N/A	0.16	N/A	12.36	N/A	0.52	N/A	12.88	N/A
Jan	11.38	N/A	1.58	N/A	0.16	N/A	13.12	N/A	0.64	N/A	13.76	N/A
Feb	10.97	N/A	1.40	N/A	0.14	N/A	12.51	N/A	0.53	N/A	13.04	N/A
Mar	10.83	N/A	1.57	N/A	0.18	N/A	12.58	N/A	0.62	N/A	13.19	N/A
Apr	9.60	N/A	1.53	N/A	0.17	N/A	11.30	N/A	0.53	N/A	11.83	N/A
May – Oct	61.43	61.32	9.63	8.80	1.03	1.11	72.08	71.23	3.04	3.40	75.11	74.63
Nov - Apr	63.48	N/A	9.04	N/A	0.97	N/A	73.50	N/A	3.39	N/A	76.88	N/A
May - Apr	124.91	N/A	18.67	N/A	2.00	N/A	145.58	N/A	6.43	N/A	151.99	N/A

Table A-8: Frequency Distribution of HOEP, May 2006 - October 2007
(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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.67	6.59	1.61	9.01	12.77	26.61	**40.73**	**27.55**	16.26	6.72	10.48	5.65	7.26	5.11	7.39	10.75	2.42	2.02	0.40	0.00
Jun	0.42	3.19	1.53	6.11	9.44	26.11	**39.03**	**27.36**	13.61	7.08	14.44	6.39	10.69	9.17	10.28	10.00	0.56	4.31	0.00	0.28
Jul	0.54	2.82	3.49	4.84	10.89	24.19	**33.87**	**27.96**	12.37	9.01	8.74	8.74	7.93	6.59	18.95	13.98	3.09	1.75	0.13	0.13
Aug	0.13	0.81	0.40	0.67	19.22	14.52	**30.38**	27.55	8.47	10.35	9.01	7.93	12.37	6.99	12.10	**28.09**	7.66	3.09	0.27	0.00
Sep	3.33	3.06	5.42	3.19	28.61	20.42	**31.67**	**26.94**	16.81	13.61	9.58	11.25	2.64	6.53	1.67	13.33	0.28	1.67	0.00	0.00
Oct	0.94	2.69	1.88	2.15	22.72	17.61	**37.77**	**22.98**	14.78	12.37	9.14	10.62	7.12	11.69	5.51	18.82	0.13	0.94	0.00	0.13
Nov	0.97	N/A	2.50	N/A	11.25	N/A	**33.33**	N/A	11.81	N/A	8.89	N/A	9.17	N/A	19.72	N/A	19.72	N/A	0.00	N/A
Dec	6.32	N/A	7.53	N/A	18.01	N/A	**36.69**	N/A	9.81	N/A	5.65	N/A	5.11	N/A	8.33	N/A	8.33	N/A	0.00	N/A
Jan	1.08	N/A	1.34	N/A	9.68	N/A	**43.15**	N/A	15.32	N/A	10.08	N/A	7.26	N/A	11.29	N/A	11.29	N/A	0.00	N/A
Feb	0.00	N/A	0.00	N/A	0.15	N/A	**31.99**	N/A	13.54	N/A	11.01	N/A	12.50	N/A	26.04	N/A	26.04	N/A	0.00	N/A
Mar	0.00	N/A	0.00	N/A	5.78	N/A	**37.10**	N/A	9.68	N/A	10.62	N/A	8.06	N/A	22.18	N/A	6.59	N/A	0.00	N/A
Apr	2.36	N/A	3.61	N/A	15.14	N/A	**32.22**	N/A	11.94	N/A	7.36	N/A	13.89	N/A	10.28	N/A	3.06	N/A	0.14	N/A
May –Oct	1.01	3.19	2.39	4.33	17.28	21.58	**35.58**	**26.72**	13.72	9.86	10.23	8.43	8.00	7.68	9.32	15.83	2.36	2.30	0.13	0.09
Nov - Apr	1.79	N/A	2.50	N/A	10.00	N/A	**35.75**	N/A	12.02	N/A	8.94	N/A	9.33	N/A	16.31	N/A	12.51	N/A	0.02	N/A
May -Apr	1.40	N/A	2.44	N/A	13.64	N/A	**35.66**	N/A	12.87	N/A	9.58	N/A	8.67	N/A	12.81	N/A	7.43	N/A	0.08	N/A

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2006 - October 2007
(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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.67	6.59	1.34	8.06	9.27	22.04	**36.96**	**30.65**	20.03	7.93	11.16	4.30	8.06	6.18	9.01	11.42	2.82	2.82	0.67	0.00
Jun	0.56	3.06	1.11	4.86	6.53	20.14	**38.06**	**31.11**	14.72	8.75	13.75	6.39	11.67	6.81	12.08	12.64	1.53	5.83	0.00	0.42
Jul	0.40	2.96	2.42	4.03	10.35	18.82	**31.85**	**30.38**	13.17	11.83	9.68	6.59	8.06	7.93	18.55	15.32	5.24	2.02	0.27	0.13
Aug	0.27	0.94	0.40	0.67	9.54	9.68	**35.89**	29.03	10.89	11.69	8.74	6.99	11.96	7.80	13.44	**29.57**	8.33	3.63	0.54	0.00
Sep	3.19	2.92	5.00	3.33	21.25	16.11	**36.25**	**28.19**	18.06	13.89	9.86	11.25	4.17	7.22	1.94	14.03	0.28	3.06	0.00	0.00
Oct	0.94	2.55	1.88	2.28	15.99	12.90	**41.26**	**23.92**	16.13	13.44	8.47	9.54	8.06	11.96	6.85	20.83	0.40	2.42	0.00	0.13
Nov	0.97	N/A	2.22	N/A	7.36	N/A	**31.67**	N/A	14.72	N/A	10.42	N/A	6.53	N/A	20.69	N/A	5.42	N/A	0.00	N/A
Dec	5.65	N/A	7.53	N/A	13.71	N/A	**38.31**	N/A	11.29	N/A	5.78	N/A	5.11	N/A	8.87	N/A	3.76	N/A	0.00	N/A
Jan	1.21	N/A	1.21	N/A	8.06	N/A	**40.46**	N/A	17.07	N/A	11.02	N/A	7.12	N/A	12.63	N/A	1.21	N/A	0.00	N/A
Feb	0.15	N/A	0.00	N/A	0.00	N/A	**28.42**	N/A	15.18	N/A	9.23	N/A	13.84	N/A	25.60	N/A	7.59	N/A	0.00	N/A
Mar	0.13	N/A	0.00	N/A	3.90	N/A	**32.80**	N/A	13.58	N/A	9.81	N/A	9.27	N/A	22.18	N/A	8.33	N/A	0.00	N/A
Apr	2.08	N/A	3.47	N/A	12.36	N/A	**32.78**	N/A	11.94	N/A	8.06	N/A	14.72	N/A	10.69	N/A	3.75	N/A	0.14	N/A
May- Oct	1.01	3.17	2.03	3.87	12.16	16.62	**36.71**	**28.88**	15.50	11.26	10.28	7.51	8.66	7.98	10.31	17.30	3.10	3.30	0.25	0.11
Nov - Apr	1.70	N/A	2.41	N/A	7.57	N/A	**34.07**	N/A	13.96	N/A	9.05	N/A	9.43	N/A	16.78	N/A	5.01	N/A	0.02	N/A
May -Apr	1.35	N/A	2.22	N/A	9.86	N/A	**35.39**	N/A	14.73	N/A	9.67	N/A	9.05	N/A	13.54	N/A	4.06	N/A	0.14	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 2006 - October 2007 (%)

	On-Peak and Off-Peak		On-Peak		Off-Peak	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	5.37	4.68	6.10	6.13	4.70	3.38
Jun	4.34	5.69	4.75	6.77	3.98	4.74
Jul	4.06	4.47	4.35	4.87	3.86	4.13
Aug	4.12	4.26	4.32	4.97	3.95	3.62
Sep	3.36	4.65	3.57	5.60	3.20	3.94
Oct	3.69	4.27	4.03	5.17	3.40	3.45
Nov	5.05	N/A	5.93	N/A	4.20	N/A
Dec	4.52	N/A	4.92	N/A	4.24	N/A
Jan	4.14	N/A	4.63	N/A	3.69	N/A
Feb	3.86	N/A	4.20	N/A	3.55	N/A
Mar	4.04	N/A	4.62	N/A	3.52	N/A
Apr	3.81	N/A	4.38	N/A	3.40	N/A
May- Oct	4.16	4.67	4.52	5.59	3.85	3.88
Nov - Apr	4.24	N/A	4.78	N/A	3.77	N/A
May -Apr	4.20	N/A	4.65	N/A	3.81	N/A

Table A-11: Total Hourly Uplift Charge by Component,
May 2006 - October 2007
($ Millions)

	Total Hourly Uplift		RT IOG*		DA IOG*		CMSC**		Operating Reserve		Losses	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	35.52	24.03	3.85	2.48	N/A	0.33	14.93	9.70	3.03	1.00	13.71	10.54
Jun	28.23	39.12	2.03	2.26	0.35	1.08	12.53	20.58	0.51	1.24	12.82	13.97
Jul	31.69	26.25	1.85	1.51	0.55	0.65	11.65	8.75	0.84	1.10	16.81	14.24
Aug	36.83	35.96	2.91	2.31	0.72	0.64	16.20	14.58	1.05	0.60	15.95	17.83
Sep	15.22	29.76	0.59	1.72	0.16	2.79	5.27	12.30	0.81	0.77	8.40	12.18
Oct	18.88	27.81	1.65	2.47	0.16	1.35	5.72	10.21	0.96	0.84	10.39	12.94
Nov	33.84	N/A	3.38	N/A	4.18	N/A	10.72	N/A	1.34	N/A	14.23	N/A
Dec	24.95	N/A	2.56	N/A	1.08	N/A	7.18	N/A	1.49	N/A	12.64	N/A
Jan	26.73	N/A	2.53	N/A	0.50	N/A	7.28	N/A	2.13	N/A	14.29	N/A
Feb	31.04	N/A	4.21	N/A	0.16	N/A	8.54	N/A	2.24	N/A	15.90	N/A
Mar	31.00	N/A	4.55	N/A	1.31	N/A	8.62	N/A	1.03	N/A	15.49	N/A
Apr	22.80	N/A	2.41	N/A	0.08	N/A	7.15	N/A	1.49	N/A	11.67	N/A
May- Oct	166.37	182.93	12.88	12.75	1.94	6.84	66.30	76.12	7.20	5.55	78.08	81.70
Nov - Apr	170.36	N/A	19.64	N/A	7.31	N/A	49.49	N/A	9.72	N/A	84.22	N/A
May -Apr	336.73	N/A	32.52	N/A	9.25	N/A	115.79	N/A	16.92	N/A	162.30	N/A

* 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 2006 - October 2007
($/MWh)

	10N		10S		30R	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	3.28	0.78	4.55	2.17	3.28	0.78
Jun	0.33	1.21	1.42	2.98	0.33	1.21
Jul	0.50	1.00	2.89	1.97	0.50	1.00
Aug	0.73	0.41	3.19	1.78	0.73	0.41
Sep	0.21	0.63	3.73	1.95	0.21	0.63
Oct	0.56	0.62	2.88	1.90	0.56	0.62
Nov	1.06	N/A	3.73	N/A	1.06	N/A
Dec	1.39	N/A	2.89	N/A	1.39	N/A
Jan	2.09	N/A	3.38	N/A	2.08	N/A
Feb	2.63	N/A	3.64	N/A	2.56	N/A
Mar	0.97	N/A	1.94	N/A	0.95	N/A
Apr	1.40	N/A	2.69	N/A	1.39	N/A
May- Oct	0.94	0.78	3.11	2.13	0.94	0.78
Nov - Apr	1.59	N/A	3.05	N/A	1.57	N/A
May -Apr	1.26	N/A	3.08	N/A	1.25	N/A

*Table A-13: Exogenous Factors Affecting HOEP, Off-Peak, May 2006 - October 2007**
(Average Hourly MW)

	Nuclear		Base-load Hydroelectric		Self-Scheduling Supply		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	8,857	9,381	1,725	1,992	688	727	13,565	13,429	33.04	24.02
Jun	9,403	9,362	1,642	1,716	803	698	14,522	14,582	33.52	27.22
Jul	10,169	9,700	1,768	1,659	751	641	15,298	14,309	35.09	27.65
Aug	10,823	9,487	1,699	1,573	750	687	14,979	15,056	36.28	35.25
Sep	9,582	8,725	1,812	1,665	799	683	13,570	13,879	25.79	29.53
Oct	8,852	8,195	1,821	1,814	887	802	13,571	13,506	30.35	32.25
Nov	8,226	N/A	1,858	N/A	890	N/A	14,520	N/A	35.49	N/A
Dec	9,455	N/A	2,114	N/A	871	N/A	15,093	N/A	28.61	N/A
Jan	9,216	N/A	1,844	N/A	958	N/A	16,165	N/A	35.45	N/A
Feb	9,721	N/A	1,925	N/A	929	N/A	17,235	N/A	48.25	N/A
Mar	8,986	N/A	1,977	N/A	920	N/A	15,589	N/A	43.92	N/A
Apr	8,860	N/A	1,944	N/A	761	N/A	14,220	N/A	32.83	N/A
May- Oct	9,614	9,142	1,745	1,737	780	706	14,251	14,127	32.35	29.32
Nov - Apr	9,077	N/A	1,944	N/A	888	N/A	15,470	N/A	37.43	N/A
May -Apr	9,346	N/A	1,844	N/A	834	N/A	14,861	N/A	34.89	N/A

* In this table, off-peak hours are defined as HE22 to HE7, inclusive, for all days of the week.

Table A-14: Exogenous Factors Affecting HOEP, On-Peak,
*May 2006 - October 2007**
(Average Hourly MW)

	Nuclear		Base-load Hydroelectric		Self-Scheduling Supply		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	8,843	9,376	2,212	2,381	822	884	16,963	16,767	55.80	48.84
Jun	9,412	9,364	2,103	2,238	936	828	18,264	18,980	55.05	56.64
Jul	10,169	9,711	2,314	2,080	875	756	20,038	18,504	61.54	55.51
Aug	10,826	9,482	2,236	2,002	900	785	19,125	19,443	64.45	66.75
Sep	9,538	8,740	2,205	1,882	932	752	16,964	17,678	42.29	55.42
Oct	8,830	8,195	2,270	2,057	993	884	16,996	16.957	47.24	60.80
Nov	8,247	N/A	2,315	N/A	1,032	N/A	17,820	N/A	59.87	N/A
Dec	9,446	N/A	2,462	N/A	1,008	N/A	18,189	N/A	46.85	N/A
Jan	9,188	N/A	2,378	N/A	1,088	N/A	19,345	N/A	50.92	N/A
Feb	9,745	N/A	2,338	N/A	1,090	N/A	20,029	N/A	66.88	N/A
Mar	8,984	N/A	2,390	N/A	1,070	N/A	18,340	N/A	62.66	N/A
Apr	8,865	N/A	2,349	N/A	921	N/A	17,109	N/A	55.50	N/A
May- Oct	9,603	9,145	2,223	2,107	910	815	18,058	15,231	54.40	57.33
Nov - Apr	9,079	N/A	2,372	N/A	1,035	N/A	18,472	N/A	57.11	N/A
May -Apr	9,341	N/A	2,298	N/A	972	N/A	18,265	N/A	55.75	N/A

* In this table, on-peak hours are defined as HE8 to HE21, inclusive, for all days of the week.

Table A-15: RT IOG Payments, Top 10 Days,
May 2007 – October 2007*

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
2007/06/02	11,385	0.4	35.36	22,302
2007/06/16	9,762	0.32	32.56	21,173
2007/07/11	13,114	0.32	24.51	23,251
2007/06/19	11,915	0.27	22.55	23,271
2007/08/03	15,484	0.27	17.39	26,517
2007/05/16	12,180	0.25	20.92	19,877
2007/10/25	18,629	0.24	12.78	19,851
2007/08/08	10,795	0.22	20.28	25,602
2007/08/29	10,176	0.22	21.59	25,476
2007/05/31	8,238	0.21	25.59	23,211
	Total Top 10 days	**2.72**		
	Total for Period	**13.39**		
	% of Total Payments	**20.31**		

* Numbers are not netted against IOG offset for the 'implied wheel'.

Table A-16: IOG Offsets due to Implied Wheeling, May 2006 - October 2007

	IOG Payments ($'000)		IOG Offset ($'000)		IOG Offset (%)	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	3,848	2,493	39	225	1.01	9.03
Jun	2,070	2,345	158	72	7.66	3.06
Jul	1,868	1,579	63	160	3.39	10.13
Aug	2,922	2,424	106	132	3.64	5.44
Sep	594	1,845	24	138	4.06	7.47
Oct	1,681	2,708	79	156	4.70	5.77
Nov	3,687	N/A	190	N/A	5.15	N/A
Dec	2,636	N/A	283	N/A	10.72	N/A
Jan	2,565	N/A	199	N/A	7.74	N/A
Feb	4,299	N/A	319	N/A	7.43	N/A
Mar	4,704	N/A	401	N/A	8.52	N/A
Apr	2,437	N/A	144	N/A	5.91	N/A
May- Oct	12,983	13,394	469	883	3.61	6.59
Nov - Apr	20,328	N/A	1,536	N/A	7.56	N/A
May -Apr	33,311	N/A	2,005	N/A	6.02	N/A

Table A-17: CMSC Payments, Energy and Operating Reserve,
May 2006 - October 2007
($ Millions)

	Constrained Off		**Constrained On**		**Total CMSC for Energy***		**Operating Reserves**		**Total CMSC Payments****	
	2006 / 2007	**2007 / 2008**	**2006 / 2007**	**2007 / 2008**	**2006 / 2007**	**2007 / 2008**	**2006 / 2007**	**2007 / 2008**	**2006 / 2007**	**2007 / 2008**
May	9.68	9.57	3.99	1.77	14.61	11.76	1.83	0.59	16.44	12.35
Jun	7.78	11.93	3.76	5.75	12.76	19.91	0.58	1.46	13.34	21.37
Jul	7.78	7.50	4.26	2.27	12.74	9.52	0.41	0.92	13.15	10.45
Aug	6.70	9.76	8.77	4.26	17.34	14.59	0.40	0.49	17.74	15.08
Sep	5.04	8.33	1.32	4.04	6.51	12.72	0.14	0.49	6.65	13.21
Oct	4.11	10.13	1.98	2.13	6.36	12.72	0.64	0.53	6.99	13.26
Nov	5.97	N/A	4.12	N/A	10.67	N/A	1.62	N/A	12.28	N/A
Dec	4.05	N/A	2.81	N/A	7.37	N/A	0.83	N/A	8.20	N/A
Jan	5.00	N/A	2.52	N/A	8.18	N/A	0.90	N/A	9.08	N/A
Feb	4.36	N/A	3.47	N/A	8.35	N/A	1.08	N/A	9.43	N/A
Mar	5.25	N/A	3.35	N/A	9.02	N/A	0.79	N/A	9.81	N/A
Apr	4.36	N/A	2.22	N/A	6.87	N/A	0.82	N/A	7.68	N/A
May- Oct	41.09	57.22	24.08	20.22	70.32	81.22	4.00	4.48	74.31	85.72
Nov - Apr	28.99	N/A	18.49	N/A	50.46	N/A	6.04	N/A	56.48	N/A
May -Apr	70.08	N/A	42.57	N/A	120.78	N/A	10.04	N/A	130.79	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 by Type of Supplier, May 2006 - October 2007 (%)

	Domestic Generators		Imports	
	2006/2007	2007/2008	2006/2007	2007/2008
May	62	60	38	40
Jun	77	67	23	33
Jul	61	74	39	26
Aug	29	68	71	32
Sep	74	67	26	33
Oct	77	71	23	29
Nov	71	N/A	29	N/A
Dec	77	N/A	23	N/A
Jan	76	N/A	24	N/A
Feb	79	N/A	21	N/A
Mar	80	N/A	20	N/A
Apr	65	N/A	35	N/A
May- Oct	63	68	37	32
Nov - Apr	75	N/A	25	N/A
May -Apr	69	N/A	31	N/A

Table A-19: Share of CMSC Payments Received by Top Facilities,
May 2006 - October 2007
(%)

	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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	50.87	58.89	48.39	41.69	34.08	45.46	33.50	27.10
Jun	56.30	57.61	52.09	46.56	45.72	34.93	39.47	30.40
Jul	54.69	59.77	53.18	53.11	39.90	47.84	37.61	38.24
Aug	45.46	67.12	67.07	51.85	31.34	54.33	53.52	34.86
Sep	61.36	67.24	53.48	53.98	43.57	53.91	36.53	38.09
Oct	52.05	75.42	50.27	50.83	38.33	68.72	34.97	34.78
Nov	54.76	N/A	59.80	N/A	40.09	N/A	43.48	N/A
Dec	57.64	N/A	51.97	N/A	41.64	N/A	38.30	N/A
Jan	58.93	N/A	55.80	N/A	40.44	N/A	39.19	N/A
Feb	55.44	N/A	65.89	N/A	44.3	N/A	50.43	N/A
Mar	65.46	N/A	51.99	N/A	51.66	N/A	37.26	N/A
Apr	51.33	N/A	58.03	N/A	39.75	N/A	38.21	N/A
May – Oct	53.46	64.34	54.08	49.67	38.82	50.87	39.27	33.91
Nov - Apr	57.26	N/A	57.25	N/A	42.98	N/A	41.15	N/A
May - Apr	55.36	N/A	55.66	N/A	40.90	N/A	40.21	N/A

*Table A-20: Domestic Supply Cushion Statistics, May 2006 – October 2007**

	Pre-Dispatch						Real-time					
	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)	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	20.0	25.4	34	0	161	34	18.4	19.9	30	4	196	159
Jun	22.4	23.1	2	2	146	126	18.5	20.0	6	15	218	192
Jul	22.8	25.7	1	0	147	68	20.9	22.3	11	0	179	134
Aug	24.3	27.6	10	4	80	56	21.5	21.8	20	8	108	126
Sep	23.9	25.6	0	8	71	47	20.5	17.6	0	28	135	256
Oct	20.4	19.9	3	0	106	147	18.4	16.6	1	3	170	270
Nov	13.8	N/A	25	N/A	310	N/A	10.5	N/A	52	N/A	416	N/A
Dec	15.5	N/A	21	N/A	261	N/A	14.9	N/A	22	N/A	270	N/A
Jan	14.9	N/A	1	N/A	294	N/A	13.6	N/A	7	N/A	336	N/A
Feb	17.8	N/A	0	N/A	102	N/A	15.2	N/A	0	N/A	184	N/A
Mar	14.7	N/A	27	N/A	284	N/A	12.7	N/A	45	N/A	341	N/A
Apr	22.0	N/A	0	N/A	68	N/A	17.6	N/A	3	N/A	160	N/A
May- Oct	22.3	24.6	50	14	711	478	19.7	19.7	68	58	1,006	1,137
Nov - Apr	16.5	N/A	74	N/A	1,319	N/A	14.1	N/A	129	N/A	1,707	N/A
May -Apr	19.4	N/A	124	N/A	2,030	N/A	16.9	N/A	197	N/A	2,713	N/A

Table A-21: Share of Real-time MCP Set by Resource, May 2006 – October 2007 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	63	61	0	0	14	13	23	26
Jun	61	61	0	0	22	18	17	21
Jul	52	58	0	0	29	20	20	22
Aug	57	44	0	0	22	38	22	17
Sep	56	52	0	0	18	25	26	23
Oct	62	46	0	0	17	30	21	24
Nov	52	N/A	0	N/A	25	N/A	23	N/A
Dec	62	N/A	0	N/A	16	N/A	22	N/A
Jan	60	N/A	0	N/A	24	N/A	16	N/A
Feb	41	N/A	0	N/A	39	N/A	20	N/A
Mar	49	N/A	0	N/A	27	N/A	24	N/A
Apr	56	N/A	0	N/A	16	N/A	28	N/A
May – Oct	59	54	0	0	20	24	22	22
Nov - Apr	53	N/A	0	N/A	25	N/A	22	N/A
May - Apr	56	N/A	0	N/A	22	N/A	22	N/A

Table A-22: Share of Real-time MCP Set by Resource, Off-Peak, May 2006 – October 2007 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	79	72	0	0	4	1	17	27
Jun	81	73	0	0	7	6	12	20
Jul	66	74	0	0	16	5	18	21
Aug	74	70	0	0	10	18	16	12
Sep	68	67	0	0	7	11	24	22
Oct	80	64	0	0	5	13	15	23
Nov	66	N/A	0	N/A	10	N/A	24	N/A
Dec	66	N/A	0	N/A	5	N/A	29	N/A
Jan	74	N/A	0	N/A	8	N/A	18	N/A
Feb	55	N/A	0	N/A	21	N/A	24	N/A
Mar	68	N/A	0	N/A	12	N/A	20	N/A
Apr	64	N/A	0	N/A	9	N/A	26	N/A
May – Oct	75	70	0	0	8	9	17	21
Nov - Apr	66	N/A	0	N/A	11	N/A	24	N/A
May - Apr	70	N/A	0	N/A	10	N/A	20	N/A

Table A-23: Share of Real-time MCP Set by Resource, On-Peak, May 2006 – October 2007 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	45	49	0	0	26	26	29	25
Jun	37	47	0	0	39	31	24	22
Jul	30	38	0	0	48	39	22	23
Aug	37	15	0	0	34	62	29	23
Sep	41	32	0	0	32	45	27	24
Oct	40	26	0	0	32	49	28	26
Nov	37	N/A	0	N/A	41	N/A	22	N/A
Dec	57	N/A	0	N/A	30	N/A	13	N/A
Jan	44	N/A	0	N/A	41	N/A	15	N/A
Feb	25	N/A	0	N/A	59	N/A	16	N/A
Mar	26	N/A	0	N/A	44	N/A	29	N/A
Apr	45	N/A	0	N/A	25	N/A	30	N/A
May – Oct	38	35	0	0	35	42	27	24
Nov - Apr	39	N/A	0	N/A	40	N/A	21	N/A
May - Apr	39	N/A	0	N/A	38	N/A	24	N/A

Table A-24: Resources Selected in Real-time Market Schedule,
May 2006 – October 2007
(%)

	Injections		Offtakes		Coal		Oil/Gas		Water		Nuclear	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	4	3	10	9	15	13	6	7	27	24	52	56
Jun	5	4	7	8	19	19	7	6	21	23	53	51
Jul	4	4	7	10	21	19	7	6	18	21	53	53
Aug	3	5	9	8	19	23	7	8	17	17	58	51
Sep	3	7	7	8	17	20	7	8	19	19	58	53
Oct	3	7	8	8	17	18	7	9	23	22	53	52
Nov	7	N/A	4	N/A	17	N/A	8	N/A	26	N/A	50	N/A
Dec	3	N/A	5	N/A	13	N/A	7	N/A	26	N/A	54	N/A
Jan	3	N/A	6	N/A	20	N/A	7	N/A	24	N/A	49	N/A
Feb	3	N/A	9	N/A	23	N/A	8	N/A	21	N/A	48	N/A
Mar	5	N/A	7	N/A	19	N/A	8	N/A	23	N/A	51	N/A
Apr	2	N/A	9	N/A	19	N/A	6	N/A	24	N/A	51	N/A
May – Oct	4	5	8	9	18	19	7	7	21	21	55	53
Nov - Apr	4	N/A	7	N/A	18	N/A	7	N/A	24	N/A	51	N/A
May - Apr	4	N/A	7	N/A	18	N/A	7	N/A	22	N/A	53	N/A

Table A-25: Resources Selected in the Real-time Market Schedule,
May 2006 – October 2007
(TWh)

	Injections		Offtakes		Coal		Oil/Gas		Water		Nuclear		Domestic Generation*	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.51	0.39	1.20	1.08	1.90	1.59	0.73	0.81	3.34	2.99	6.58	6.98	12.55	12.36
Jun	0.60	0.47	0.91	1.04	2.47	2.45	0.89	0.85	2.63	3.07	6.77	6.74	12.77	13.11
Jul	0.57	0.49	1.03	1.30	3.03	2.58	1.00	0.86	2.59	2.85	7.57	7.22	14.19	13.51
Aug	0.41	0.67	1.21	1.12	2.63	3.17	0.92	1.15	2.40	2.35	8.05	7.06	14.00	13.73
Sep	0.36	0.87	0.83	0.92	2.00	2.38	0.79	0.90	2.22	2.23	6.88	6.29	11.90	11.80
Oct	0.36	0.80	0.98	0.93	2.16	2.07	0.88	1.02	2.80	2.61	6.58	6.10	12.41	11.79
Nov	0.77	N/A	0.53	N/A	1.95	N/A	0.91	N/A	3.01	N/A	5.93	N/A	11.80	N/A
Dec	0.43	N/A	0.67	N/A	1.71	N/A	0.86	N/A	3.31	N/A	7.03	N/A	12.92	N/A
Jan	0.44	N/A	0.78	N/A	2.74	N/A	1.00	N/A	3.31	N/A	6.84	N/A	13.89	N/A
Feb	0.41	N/A	1.19	N/A	3.13	N/A	1.02	N/A	2.88	N/A	6.54	N/A	13.57	N/A
Mar	0.65	N/A	0.91	N/A	2.50	N/A	1.03	N/A	2.99	N/A	6.68	N/A	13.20	N/A
Apr	0.28	N/A	1.16	N/A	2.38	N/A	0.76	N/A	3.02	N/A	6.38	N/A	12.55	N/A
May – Oct	2.81	3.69	6.16	6.39	14.19	14.24	5.21	5.59	15.98	16.10	42.43	40.39	77.82	76.30
Nov - Apr	2.98	N/A	5.24	N/A	14.41	N/A	5.58	N/A	18.52	N/A	39.40	N/A	77.93	N/A
May - Apr	5.79	N/A	11.40	N/A	28.60	N/A	10.79	N/A	34.50	N/A	81.83	N/A	155.75	N/A

* Domestic generation is the sum of *Coal, Oil/Gas, Water, and Nuclear*.

*Table A-26: Offtakes by Intertie Zone, On-peak and Off-peak, May 2006 – October 2007**
(GWh)

		MB		MI		MN		NY		PQ	
		2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	Off-peak	0.0	3.1	32.0	170.2	1.2	11.8	625.5	334.2	52.4	57.6
	On-Peak	0.0	3.5	54.0	257.4	0.7	10.9	404.8	197.2	26.4	36.0
Jun	Off-peak	0.0	0.5	9.4	65.9	1.6	4.0	513.3	566.6	46.9	39.5
	On-Peak	0.1	0.7	45.7	109.9	0.1	6.9	274.6	228.6	22.4	20.3
Jul	Off-peak	0.6	0.0	47.2	76.4	7.9	6.3	606.5	638.4	47.8	42.2
	On-Peak	0.5	0.2	75.3	130.5	8.4	8.9	218.7	376.9	15.6	19.7
Aug	Off-peak	0.1	0.0	36.5	61.9	2.6	3.5	668.7	556.0	34.3	52.4
	On-Peak	0.1	0.1	95.4	201.6	1.5	6.0	355.1	215.6	15.5	27.2
Sep	Off-peak	2.0	0.0	14.8	21.3	1.9	0.3	441.7	491.4	48.4	65.7
	On-Peak	0.1	0.0	16.5	52.7	2.7	0.7	282.7	258.0	22.3	31.9
Oct	Off-peak	18.3	0.0	25.4	72.6	4.8	0.4	480.6	453.1	54.4	30.1
	On-Peak	7.6	0.0	38.0	68.6	4.8	0.5	320.9	284.9	25.0	22.9
Nov	Off-peak	30.8	N/A	9.5	N/A	0.8	N/A	275.4	N/A	28.4	N/A
	On-Peak	16.4	N/A	12.0	N/A	1.5	N/A	147.8	N/A	8.4	N/A
Dec	Off-peak	28.4	N/A	27.4	N/A	3.1	N/A	362.0	N/A	37.1	N/A
	On-Peak	13.2	N/A	42.9	N/A	0.9	N/A	138.0	N/A	12.5	N/A
Jan	Off-peak	25.6	N/A	21.2	N/A	2.2	N/A	346.6	N/A	54.6	N/A
	On-Peak	22.9	N/A	44.6	N/A	3.4	N/A	215.5	N/A	46.1	N/A
Feb	Off-peak	25.6	N/A	82.8	N/A	4.4	N/A	480.2	N/A	45.0	N/A
	On-Peak	8.4	N/A	102.0	N/A	2.3	N/A	403.5	N/A	40.3	N/A
Mar	Off-peak	16.8	N/A	38.8	N/A	0.7	N/A	457.9	N/A	55.0	N/A
	On-Peak	7.6	N/A	65.3	N/A	1.9	N/A	221.9	N/A	41.1	N/A
Apr	Off-peak	33.1	N/A	139.5	N/A	7.5	N/A	436.4	N/A	48.9	N/A
	On-Peak	11.6	N/A	240.7	N/A	8.7	N/A	206.9	N/A	29.6	N/A
May - Oct	Off-peak	21.0	3.6	165.3	468.3	20.0	26.3	3336.3	3039.7	284.2	287.5
	On-Peak	8.4	4.5	324.9	820.7	18.2	33.9	1856.8	1561.2	127.2	158.0
	Total	29.4	8.1	490.2	1289.0	38.2	60.2	5193.1	4600.9	411.4	445.5
Nov– Apr	Off-peak	160.3	N/A	319.2	N/A	18.8	N/A	2,358.5	N/A	269.1	N/A
	On-Peak	80.2	N/A	507.5	N/A	18.7	N/A	1,333.6	N/A	178.0	N/A
	Total	240.5	N/A	826.7	N/A	37.5	N/A	3,692.1	N/A	447.1	N/A
May - Apr	Off-peak	181.3	N/A	484.4	N/A	38.8	N/A	5,694.9	N/A	553.3	N/A
	On-Peak	88.7	N/A	832.4	N/A	36.9	N/A	3,190.3	N/A	305.2	N/A
	Total	270.0	N/A	1,316.8	N/A	75.7	N/A	8,885.2	N/A	858.5	N/A

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

*Table A-27: Injections by Intertie Zone, On-peak and Off-peak, May 2006 - October 2007**
(GWh)

		MB		MI		MN		NY		PQ	
		2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	Off-peak	58.6	36.9	177.3	33.5	1.2	7.0	5.7	71.1	1.4	4.1
	On-Peak	50.0	17.4	125.6	43.6	13.3	9.4	23.7	55.8	41.7	109.2
Jun	Off-peak	69.7	68.0	243.0	84.5	13.8	16.1	11.7	10.0	5.0	23.3
	On-Peak	62.2	49.3	117.6	86.0	16.0	13.1	25.1	50.6	32.3	73.5
Jul	Off-peak	98.9	88.5	139.8	121.4	23.4	16.6	22.0	7.1	41.5	5.7
	On-Peak	41.9	40.9	60.8	100.7	12.8	12.2	31.6	53.6	100.7	43.5
Aug	Off-peak	78.3	79.1	105.3	173.9	17.1	23.3	7.6	24.4	12.2	5.8
	On-Peak	34.9	65.3	41.5	100.3	11.8	21.4	27.2	115.1	69.9	60.3
Sep	Off-peak	63.7	79.0	115.2	340.3	10.6	29.1	14.4	10.4	0.3	6.9
	On-Peak	47.0	57.5	88.4	252.1	9.5	25.7	6.5	46.6	8.1	19.1
Oct	Off-peak	27.2	60.2	158.4	275.4	15.1	15.7	8.5	10.3	3.5	14.3
	On-Peak	5.9	45.6	92.8	309.5	7.4	14.8	10.1	37.6	28.4	16.9
Nov	Off-peak	7.5	N/A	328.7	N/A	17.6	N/A	17.2	N/A	9.0	N/A
	On-Peak	2.7	N/A	271.0	N/A	12.4	N/A	34.4	N/A	66.2	N/A
Dec	Off-peak	14.9	N/A	111.4	N/A	15.0	N/A	13.1	N/A	39.7	N/A
	On-Peak	3.9	N/A	77.7	N/A	6.5	N/A	45.0	N/A	106.6	N/A
Jan	Off-peak	24.6	N/A	146.0	N/A	18.7	N/A	17.8	N/A	18.5	N/A
	On-Peak	11.0	N/A	87.2	N/A	10.6	N/A	25.0	N/A	81.2	N/A
Feb	Off-peak	8.5	N/A	82.3	N/A	10.3	N/A	16.7	N/A	44.7	N/A
	On-Peak	5.8	N/A	99.6	N/A	11.9	N/A	33.7	N/A	96.6	N/A
Mar	Off-peak	26.8	N/A	220.8	N/A	21.9	N/A	14.8	N/A	33.9	N/A
	On-Peak	25.3	N/A	147.2	N/A	13.3	N/A	45.8	N/A	103.9	N/A
Apr	Off-peak	21.8	N/A	41.7	N/A	15.2	N/A	11.2	N/A	43.3	N/A
	On-Peak	9.8	N/A	21.4	N/A	6.5	N/A	15.5	N/A	89.0	N/A
May - Oct	Off-peak	396.4	411.7	939.0	1029.0	81.2	107.8	69.9	133.3	63.9	60.1
	On-Peak	241.9	276.0	526.7	892.2	70.8	96.6	124.2	359.3	281.1	322.5
	Total	638.3	687.7	1465.7	1921.2	152.0	204.4	194.1	492.6	345.0	382.6
Nov– Apr	Off-peak	104.0	N/A	931.0	N/A	98.7	N/A	90.8	N/A	189.1	N/A
	On-Peak	58.5	N/A	704.1	N/A	61.1	N/A	199.4	N/A	543.5	N/A
	Total	162.5	N/A	1,635.1	N/A	159.8	N/A	290.2	N/A	732.5	N/A
May - Apr	Off-peak	500.5	N/A	1,869.8	N/A	179.8	N/A	160.7	N/A	252.9	N/A
	On-Peak	300.3	N/A	1,230.7	N/A	132.0	N/A	323.7	N/A	824.5	N/A
	Total	800.7	N/A	3,100.6	N/A	311.8	N/A	484.4	N/A	1,077.5	N/A

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

Table A-28: Net Exports, May 2006 – October 2007
(MWh)

	On-peak		Off-peak		Total	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	231,286	269,688	454,918	424,277	686,204	693,966
Jun	89,601	93,969	227,996	474,515	317,597	568,484
Jul	70,645	285,182	384,413	523,963	455,058	809,145
Aug	282,463	88,026	521,687	367,333	804,150	455,359
Sep	164,847	(57,635)	304,446	112,928	469,293	55,293
Oct	251,726	(47,476)	370,919	180,297	622,645	132,820
Nov	(200,386)	N/A	(35,002)	N/A	(235,388)	N/A
Dec	(32,210)	N/A	263,848	N/A	231,638	N/A
Jan	117,584	N/A	224,741	N/A	342,325	N/A
Feb	309,106	N/A	475,559	N/A	784,665	N/A
Mar	2,242	N/A	250,960	N/A	253,201	N/A
Apr	355,182	N/A	532,213	N/A	887,395	N/A
May- Oct	1,090,568	631,754	2,264,379	2,083,313	3,354,947	2,715,067
Nov - Apr	551,518	N/A	1,712,319	N/A	2,263,836	N/A
May -Apr	1,642,086	N/A	3,976,698	N/A	5,618,783	N/A

Table A-29: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP, May 2006 - October 2007

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	6.60	7.63	419.55	72.88	(320.42)	(93.58)	30.00	16.11	20.83	30.63
Jun	4.85	6.83	48.06	99.04	(75.35)	(305.24)	12.76	22.95	14.02	25.54
Jul	7.51	3.58	114.61	62.49	(126.79)	(215.90)	15.25	16.64	17.92	15.97
Aug	9.18	7.68	168.10	79.74	(70.41)	(61.26)	27.51	14.90	16.67	19.45
Sep	2.43	3.91	41.59	60.95	(68.61)	(69.49)	8.99	12.18	17.98	17.71
Oct	3.86	6.73	62.51	82.25	(42.27)	(234.52)	10.85	15.40	13.59	25.54
Nov	8.85	N/A	62.20	N/A	(57.01)	N/A	14.87	N/A	25.36	N/A
Dec	8.16	N/A	83.82	N/A	(73.61)	N/A	14.21	N/A	15.19	N/A
Jan	6.48	N/A	46.19	N/A	(89.72)	N/A	13.18	N/A	20.38	N/A
Feb	12.93	N/A	73.34	N/A	(74.95)	N/A	17.30	N/A	29.42	N/A
Mar	11.31	N/A	88.29	N/A	(67.96)	N/A	16.83	N/A	28.05	N/A
Apr	6.76	N/A	81.19	N/A	(145.64)	N/A	18.26	N/A	24.35	N/A
May – Oct	5.74	6.06	142.40	76.23	(117.31)	(163.33)	17.56	16.36	16.84	22.47
Nov - Apr	9.08	N/A	72.51	N/A	(84.82)	N/A	15.78	N/A	23.79	N/A
May - Apr	7.41	N/A	107.45	N/A	(101.06)	N/A	16.67	N/A	20.31	N/A

Table A-30: Measures of Difference between 1-Hour Ahead Pre-dispatch Prices and HOEP, May 2006 - October 2007

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	11.94	8.23	1,739.37	71.78	(297.46)	(77.17)	67.55	14.49	29.88	35.18
Jun	5.12	6.99	44.18	94.35	(66.34)	(331.10)	11.20	21.84	15.04	25.21
Jul	6.89	5.26	60.33	62.02	(174.98)	(211.39)	13.61	15.91	18.99	22.34
Aug	9.73	8.16	262.96	74.6	(67.76)	(60.38)	25.64	13.56	19.93	20.05
Sep	3.82	5.96	34.86	83.01	(67.49)	(68.97)	8.56	12.46	24.74	22.37
Oct	6.27	8.17	52.09	66.75	(42.27)	(236.65)	10.44	14.99	21.67	30.09
Nov	8.34	N/A	59.00	N/A	(54.45)	N/A	14.52	N/A	24.82	N/A
Dec	8.77	N/A	91.68	N/A	(67.32)	N/A	13.50	N/A	22.68	N/A
Jan	7.69	N/A	40.71	N/A	(82.87)	N/A	12.08	N/A	23.88	N/A
Feb	14.00	N/A	80.63	N/A	(74.28)	N/A	16.26	N/A	32.21	N/A
Mar	11.06	N/A	87.12	N/A	(67.96)	N/A	16.30	N/A	28.46	N/A
Apr	9.57	N/A	95.48	N/A	(119.44)	N/A	17.18	N/A	31.65	N/A
May – Oct	7.30	7.13	365.63	75.42	(119.38)	(164.28)	22.83	15.54	21.71	25.87
Nov - Apr	9.91	N/A	75.77	N/A	(77.72)	N/A	14.97	N/A	27.28	N/A
May - Apr	8.60	N/A	220.70	N/A	(98.55)	N/A	18.90	N/A	24.50	N/A

Table A-31: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP, May 2006 – October 2007

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2006/2007	2007/2008	2006/2007	2007/2008
May	4.34	1.13	15.2	13.6
Jun	(0.82)	(1.59)	2.2	8.4
Jul	(0.36)	(1.87)	4.4	6.3
Aug	1.08	0.99	5.1	6.1
Sep	(0.60)	(2.35)	6.4	11.5
Oct	0.51	(3.59)	8.3	6.8
Nov	(1.26)	N/A	5.0	N/A
Dec	0.73	N/A	18.7	N/A
Jan	0.27	N/A	7.8	N/A
Feb	4.13	N/A	13.2	N/A
Mar	1.11	N/A	9.5	N/A
Apr	0.68	N/A	12.8	N/A
May – Oct	0.69	(1.21)	6.9	8.8
Nov - Apr	0.94	N/A	11.2	N/A
May - Apr	0.82	N/A	9.1	N/A

* This is an average of hourly differences relative to hourly peak MCP

Table A-32: Average Monthly HOEP Compared to Average Monthly Peak Hourly MCP, May 2006 – October 2007 ($/MWh)

	Hourly Peak MCP		HOEP		Peak minus HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	53.92	45.60	46.32	38.50	7.61	7.11
Jun	52.02	52.95	46.08	44.38	5.95	8.57
Jul	57.79	51.04	50.52	43.90	7.26	7.13
Aug	61.37	60.80	52.72	53.62	8.65	7.18
Sep	39.84	52.94	35.42	44.63	4.42	8.31
Oct	45.91	60.66	40.17	48.91	5.74	11.76
Nov	59.25	N/A	49.71	N/A	9.54	N/A
Dec	47.37	N/A	39.25	N/A	8.12	N/A
Jan	51.90	N/A	44.48	N/A	7.42	N/A
Feb	68.99	N/A	59.12	N/A	9.87	N/A
Mar	64.80	N/A	54.85	N/A	9.95	N/A
Apr	54.94	N/A	46.05	N/A	8.89	N/A
May – Oct	51.81	54.00	45.21	45.66	6.61	8.34
Nov – Apr	57.88	N/A	48.91	N/A	8.97	N/A
May - Apr	54.84	N/A	47.06	N/A	7.79	N/A

*Table A-33: Frequency Distribution of Difference Between 1-Hour Pre-dispatch and HOEP, May 2006 - October 2007**

	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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.8	0.7	1.2	2.4	1.2	1.5	6.2	11.0	49.3	48.5	**23.0**	17.7	17.5	17.5	0.8	0.7
Jun	0.1	**1.3**	1.9	1.7	3.1	2.5	**15.7**	13.6	53.6	50.4	16.1	13.6	9.4	14.6	0.0	2.4
Jul	0.3	0.8	1.2	2.2	2.7	2.6	13.6	13.0	51.6	53.1	17.9	16.5	12.4	11.3	0.4	0.5
Aug	0.5	0.1	**3.2**	1.1	3.9	1.7	13.2	13.0	44.5	51.9	16.3	16.7	15.3	14.0	**3.1**	1.5
Sep	0.3	0.4	1.1	1.3	1.8	3.7	12.6	13.9	**67.5**	51.8	12.8	19.4	3.9	8.8	0.0	0.7
Oct	0.0	0.3	0.9	0.5	2.8	2.0	12.3	14.9	54.7	45.3	19.3	20.3	9.8	16.5	0.1	0.1
Nov	0.3	N/A	3.1	N/A	**4.3**	N/A	11.1	N/A	42.8	N/A	19.0	N/A	19.0	N/A	0.4	N/A
Dec	0.4	N/A	0.9	N/A	1.3	N/A	10.4	N/A	49.1	N/A	21.5	N/A	15.2	N/A	1.2	N/A
Jan	0.3	N/A	1.2	N/A	2.4	N/A	12.9	N/A	47.3	N/A	20.0	N/A	15.9	N/A	0.0	N/A
Feb	0.2	N/A	1.0	N/A	2.8	N/A	8.9	N/A	34.1	N/A	19.8	N/A	**31.0**	N/A	2.2	N/A
Mar	0.3	N/A	2.0	N/A	2.7	N/A	12.9	N/A	35.9	N/A	20.8	N/A	24.3	N/A	1.1	N/A
Apr	0.6	N/A	2.2	N/A	2.5	N/A	10.1	N/A	45.1	N/A	15.6	N/A	22.6	N/A	1.3	N/A
May – Oct	0.3	0.6	1.6	1.5	2.6	2.3	12.3	13.2	53.5	50.2	17.6	17.4	11.4	13.8	0.7	1.0
Nov – Apr	0.3	N/A	1.7	N/A	2.7	N/A	11.1	N/A	42.4	N/A	19.5	N/A	21.3	N/A	1.0	N/A
May - Apr	0.3	N/A	1.7	N/A	2.6	N/A	11.7	N/A	48.0	N/A	18.5	N/A	16.4	N/A	0.9	N/A

* Bolded values show highest percentage within price range.

Table A-34: Difference between 1-Hour Pre-dispatch Price and HOEP within Defined Ranges, May 2006 - October 2007

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	90.1	84.3	0.5	0.1	9.4	15.6
Jun	78.6	80.7	0.6	0.3	20.8	19.0
Jul	82.1	81.2	0.1	0.3	17.7	18.6
Aug	79.0	83.9	0.1	0.1	20.8	16.0
Sep	83.5	80.7	0.7	0.0	15.8	19.3
Oct	84.0	82.3	0.0	0.0	16.0	17.7
Nov	81.0	N/A	0.3	N/A	18.8	N/A
Dec	86.7	N/A	0.3	N/A	13.0	N/A
Jan	82.8	N/A	0.4	N/A	16.8	N/A
Feb	86.6	N/A	0.5	N/A	13.0	N/A
Mar	82.0	N/A	0.1	N/A	17.9	N/A
Apr	84.0	N/A	0.6	N/A	15.4	N/A
May – Oct	82.9	82.2	0.3	0.1	16.8	17.7
Nov – Apr	83.8	N/A	0.3	N/A	15.8	N/A
May - Apr	83.4	N/A	0.3	N/A	16.3	N/A

Table A-35: Difference between 1-Hour Pre-dispatch Price and Hourly Peak MCP within Defined Ranges, May 2006 - October 2007

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	73.7	62.1	2.3	2.4	24.1	35.5
Jun	51.4	57.1	4.2	2.9	44.4	40.0
Jul	57.9	55.7	2.2	3.6	39.9	40.7
Aug	51.8	58.7	3.8	2.4	44.5	38.8
Sep	56.5	46.8	7.2	3.5	36.3	49.7
Oct	59.7	48.9	3.9	2.8	36.4	48.3
Nov	55.0	N/A	4.2	N/A	40.8	N/A
Dec	60.0	N/A	4.0	N/A	36.0	N/A
Jan	56.3	N/A	5.1	N/A	38.6	N/A
Feb	63.1	N/A	5.1	N/A	31.9	N/A
Mar	56.1	N/A	2.8	N/A	41.1	N/A
Apr	60.0	N/A	3.5	N/A	36.5	N/A
May – Oct	58.5	54.9	3.9	2.9	37.6	42.2
Nov – Apr	58.4	N/A	4.1	N/A	37.5	N/A
May - Apr	58.5	N/A	4.0	N/A	37.5	N/A

Table A-36: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2006 - October 2007

	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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	325	285	302	259	196	173	158	142	2.0	1.8	1.9	1.7	1.2	1.1	1.0	0.9
Jun	379	418	335	350	244	287	185	209	2.2	2.4	2.0	2.1	1.4	1.6	1.0	1.2
Jul	485	399	413	337	344	275	251	201	2.6	2.3	2.3	2.0	1.8	1.6	1.3	1.1
Aug	420	455	353	382	301	307	210	225	2.4	2.5	2.0	2.2	1.6	1.7	1.2	1.2
Sep	297	368	265	318	182	237	144	180	1.9	2.3	1.7	2.0	1.1	1.4	0.9	1.1
Oct	309	336	282	307	190	192	152	160	1.9	2.1	1.8	2.0	1.2	1.2	0.9	1.0
Nov	319	N/A	309	N/A	178	N/A	153	N/A	1.9	N/A	1.9	N/A	1.1	N/A	0.9	N/A
Dec	343	N/A	313	N/A	209	N/A	169	N/A	2.0	N/A	1.8	N/A	1.2	N/A	1.0	N/A
Jan	344	N/A	316	N/A	208	N/A	161	N/A	1.9	N/A	1.7	N/A	1.1	N/A	0.9	N/A
Feb	342	N/A	309	N/A	210	N/A	165	N/A	1.8	N/A	1.6	N/A	1.1	N/A	0.8	N/A
Mar	298	N/A	271	N/A	199	N/A	164	N/A	1.7	N/A	1.6	N/A	1.1	N/A	0.9	N/A
Apr	281	N/A	255	N/A	177	N/A	140	N/A	1.8	N/A	1.6	N/A	1.1	N/A	0.8	N/A
May – Oct	369	377	325	326	243	245	183	186	2.2	2.2	2.0	2.0	1.4	1.4	1.1	1.1
Nov – Apr	321	N/A	296	N/A	197	N/A	159	N/A	1.8	N/A	1.7	N/A	1.1	N/A	0.9	N/A
May - Apr	345	N/A	310	N/A	220	N/A	171	N/A	2.0	N/A	1.8	N/A	1.2	N/A	1.0	N/A

*Table A-37: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2006 – October 2007**
(%)

	> 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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	2	1	16	12	16	15	23	21	19	22	13	16	11	13	0	0	57	49	43	51
Jun	4	4	19	19	15	14	18	17	18	16	14	12	11	15	1	3	56	53	44	47
Jul	9	4	23	21	15	12	15	17	11	17	10	14	14	13	3	1	62	54	38	46
Aug	5	5	18	24	13	16	17	15	15	12	14	11	15	15	2	2	53	60	47	40
Sep	0	3	14	16	15	16	23	20	19	18	15	11	12	15	1	2	53	54	47	46
Oct	1	1	16	18	17	19	19	18	21	21	13	13	12	9	0	1	54	57	46	43
Nov	1	N/A	15	N/A	19	N/A	20	N/A	21	N/A	12	N/A	11	N/A	1	N/A	54	N/A	46	N/A
Dec	1	N/A	17	N/A	16	N/A	19	N/A	17	N/A	14	N/A	13	N/A	1	N/A	54	N/A	46	N/A
Jan	1	N/A	17	N/A	15	N/A	21	N/A	20	N/A	12	N/A	12	N/A	1	N/A	54	N/A	46	N/A
Feb	3	N/A	17	N/A	17	N/A	21	N/A	17	N/A	12	N/A	12	N/A	0	N/A	58	N/A	42	N/A
Mar	2	N/A	15	N/A	14	N/A	20	N/A	19	N/A	15	N/A	14	N/A	1	N/A	50	N/A	50	N/A
Apr	0	N/A	14	N/A	15	N/A	24	N/A	21	N/A	16	N/A	10	N/A	0	N/A	53	N/A	47	N/A
May – Oct	4	3	18	18	15	15	19	18	17	18	13	13	13	13	1	2	56	55	44	46
Nov – Apr	1	N/A	16	N/A	16	N/A	21	N/A	19	N/A	14	N/A	12	N/A	1	N/A	54	N/A	46	N/A
May - Apr	2	N/A	17	N/A	16	N/A	20	N/A	18	N/A	13	N/A	12	N/A	1	N/A	55	N/A	45	N/A

* This data includes dispatchable loads

*Table A-38: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, May 2006 – October 2007**

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	688,775	741,893	292.0	182.2	(68.5)	(194.2)	30.8	2.6	3.1	0.0
Jun	737,975	691,114	188.8	276.5	(99.3)	(144.7)	41.2	32.0	4.4	3.7
Jul	722,572	665,874	239.2	233.8	(100.7)	(147.9)	59.2	40.6	6.4	4.7
Aug	709,496	669,870	206.1	167.5	(55.1)	(167.3)	46.3	26.7	5.6	2.9
Sep	727,818	655,691	250.6	186.6	(136.4)	(162.4)	41.0	17.9	4.8	2.1
Oct	827,835	817,009	164.7	177.9	(136.8)	(247.5)	21.5	18.3	2.1	1.6
Nov	826,319	N/A	221.2	N/A	(148.7)	N/A	16.6	N/A	1.9	N/A
Dec	861,556	N/A	181.9	N/A	(168.0)	N/A	(2.5)	N/A	0.1	N/A
Jan	927,931	N/A	141.2	N/A	(216.3)	N/A	8.9	N/A	0.9	N/A
Feb	843,514	N/A	187.2	N/A	(179.8)	N/A	0.1	N/A	0.2	N/A
Mar	914,915	N/A	244.2	N/A	(191.2)	N/A	(14.0)	N/A	(1.1)	N/A
Apr	766,192	N/A	185.8	N/A	(194.9)	N/A	8.3	N/A	1.2	N/A
May – Oct	735,745	706,909	223.6	204.1	(99.5)	(177.3)	40.0	23.0	4.4	2.5
Nov – Apr	856,738	N/A	193.6	N/A	(183.2)	N/A	2.9	N/A	0.5	N/A
May - Apr	796,242	N/A	208.6	N/A	(141.3)	N/A	21.5	N/A	2.5	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 offer

Table A-39: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2006 – October 2007*

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	19,881	68,746	76.3	137.8	(61.7)	(199.9)	1.9	4.2	2.8	4.8
Jun	24,370	54,863	93.5	146.7	(124.7)	(153.0)	3.5	9.4	8.4	14.8
Jul	28,632	44,078	75.6	154.0	(97.8)	(187.8)	3.3	5.7	8.3	14.2
Aug	27,638	54,869	89.9	159.1	(91.5)	(148.8)	8.2	1.7	26.0	(11.1)
Sep	53,686	74,113	130.1	143.3	(115.1)	(205.8)	9.8	(3.3)	19.5	(2.2)
Oct	87,388	106,536	96.1	150.14	(141.1)	(227.9)	10.0	4.1	13.4	0.8
Nov	76,210	N/A	126.1	N/A	(128.6)	N/A	11.7	N/A	17.3	N/A
Dec	112,547	N/A	177.3	N/A	(144.3)	N/A	6.6	N/A	7.2	N/A
Jan	105,340	N/A	145.4	N/A	(178.4)	N/A	13.6	N/A	16.2	N/A
Feb	118,311	N/A	167.8	N/A	(166.6)	N/A	8.3	N/A	7.7	N/A
Mar	112,051	N/A	150.5	N/A	(169.0)	N/A	(11.2)	N/A	(7.7)	N/A
Apr	90,023	N/A	123.7	N/A	(164.1)	N/A	3.6	N/A	9.3	N/A
May – Oct	40,266	67,201	93.6	148.5	(105.3)	(187.2)	6.1	3.6	13.1	3.6
Nov – Apr	102,414	N/A	148.5	N/A	(158.5)	N/A	5.4	N/A	8.3	N/A
May - Apr	71,340	N/A	121.0	N/A	(131.9)	N/A	5.8	N/A	10.7	N/A

* The data has been revised to include Price Farm II generation.
** Fail rate is calculated as the average difference divided by the Pre-Dispatch offer

*Table A-40: Failed Imports into Ontario, May 2006 – October 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	121	192	818	453	135	135	3.1	6.3
Jun	187	148	848	400	153	95	4.6	2.9
Jul	207	112	1,020	700	123	123	4.3	2.8
Aug	171	207	405	546	113	118	4.5	3.5
Sep	54	155	300	525	76	146	1.1	2.5
Oct	109	173	240	607	69	116	2.1	2.4
Nov	242	N/A	595	N/A	114	N/A	3.5	N/A
Dec	137	N/A	384	N/A	102	N/A	3.1	N/A
Jan	138	N/A	553	N/A	110	N/A	3.3	N/A
Feb	230	N/A	502	N/A	92	N/A	4.9	N/A
Mar	217	N/A	550	N/A	112	N/A	3.6	N/A
Apr	105	N/A	250	N/A	89	N/A	3.3	N/A
May-Oct	142	164	605	539	112	122	3.3	3.4
Nov-Apr	178	N/A	472	N/A	103	N/A	3.6	N/A
May-Apr	160	N/A	539	N/A	107	N/A	3.4	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-41: Failed Imports into Ontario, On-Peak,
*May 2006 - October 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	66	107	818	453	123	146	3.1	6.2
Jun	78	83	490	289	132	98	3.9	2.9
Jul	115	69	587	700	107	114	4.8	3.0
Aug	72	121	405	546	91	104	3.4	3.4
Sep	20	80	300	421	99	139	1.2	2.7
Oct	60	97	240	607	74	123	3.0	2.7
Nov	148	N/A	595	N/A	112	N/A	4.1	N/A
Dec	73	N/A	300	N/A	101	N/A	3.0	N/A
Jan	67	N/A	553	N/A	99	N/A	3.0	N/A
Feb	119	N/A	502	N/A	93	N/A	4.3	N/A
Mar	131	N/A	400	N/A	108	N/A	4.1	N/A
Apr	48	N/A	235	N/A	78	N/A	2.6	N/A
May-Oct	69	93	473	503	104	121	3.2	3.5
Nov-Apr	98	N/A	431	N/A	99	N/A	3.5	N/A
May-Apr	83	N/A	452	N/A	101	N/A	3.4	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-42: Failed Imports into Ontario, Off-Peak,
*May 2006 - October 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	55	85	500	450	148	120	3.1	6.3
Jun	109	65	848	400	168	91	5.1	2.9
Jul	92	43	1,020	662	143	138	3.9	2.4
Aug	99	86	385	500	128	138	5.4	3.7
Sep	34	75	200	525	63	153	1.0	2.4
Oct	49	76	191	435	63	107	1.4	2.1
Nov	94	N/A	525	N/A	116	N/A	2.8	N/A
Dec	64	N/A	384	N/A	103	N/A	3.3	N/A
Jan	71	N/A	483	N/A	121	N/A	3.7	N/A
Feb	111	N/A	480	N/A	91	N/A	5.9	N/A
Mar	86	N/A	550	N/A	117	N/A	3.1	N/A
Apr	57	N/A	250	N/A	97	N/A	4.0	N/A
May-Oct	73	72	524	495	119	125	3.3	3.3
Nov-Apr	81	N/A	445	N/A	108	N/A	3.8	N/A
May-Apr	77	N/A	485	N/A	113	N/A	3.6	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 Exports from Ontario, May 2006 - October 2007*
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	564	522	1,136	938	318	202	13.0	8.9
Jun	324	382	817	733	176	167	5.9	5.8
Jul	354	350	850	1079	201	175	6.5	4.5
Aug	399	373	914	900	187	163	5.8	5.2
Sep	422	397	788	1071	192	208	8.9	8.2
Oct	412	390	874	898	185	194	7.3	7.5
Nov	317	N/A	765.5	N/A	157	N/A	8.6	N/A
Dec	387	N/A	865	N/A	169	N/A	8.9	N/A
Jan	415	N/A	801	N/A	153	N/A	7.5	N/A
Feb	375	N/A	1,220	N/A	130	N/A	3.9	N/A
Mar	404	N/A	671	N/A	142	N/A	5.9	N/A
Apr	455	N/A	1,028	N/A	160	N/A	5.9	N/A
May-Oct	413	402	897	937	210	185	7.9	6.7
Nov-Apr	392	N/A	892	N/A	152	N/A	6.8	N/A
May-Apr	402	N/A	894	N/A	181	N/A	7.3	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-44: Failed Exports from Ontario, On-Peak, May 2006 - October 2007*
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	239	199	1,029	938	256	224	11.2	8.1
Jun	123	150	785	733	153	179	5.2	6.8
Jul	126	164	850	1079	193	201	7.1	5.8
Aug	161	155	914	900	215	154	6.9	5.0
Sep	148	146	644	942	163	204	6.9	8.0
Oct	144	160	874	645	162	171	5.6	6.8
Nov	138	N/A	527	N/A	125	N/A	8.5	N/A
Dec	127	N/A	865	N/A	133	N/A	7.5	N/A
Jan	183	N/A	665	N/A	117	N/A	6	N/A
Feb	154	N/A	1,220	N/A	124	N/A	3.3	N/A
Mar	175	N/A	500	N/A	91	N/A	4.5	N/A
Apr	209	N/A	930	N/A	142	N/A	5.6	N/A
May-Oct	157	162	849	873	190	189	7.1	6.7
Nov-Apr	164	N/A	785	N/A	122	N/A	5.9	N/A
May-Apr	161	N/A	817	N/A	156	N/A	6.5	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-45: Failed Exports from Ontario, Off-Peak, May 2006 - October 2007* (Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	325	323	1,136	902	363	188	14.3	9.5
Jun	201	232	817	570	190	159	6.3	5.2
Jul	228	186	749	627	205	152	6.2	3.6
Aug	238	218	709	722	167	170	5.1	5.2
Sep	274	251	788	1,071	208	209	10.1	8.3
Oct	268	230	710	898	198	211	8.4	8.0
Nov	179	N/A	766	N/A	181	N/A	8.6	N/A
Dec	260	N/A	725	N/A	186	N/A	9.6	N/A
Jan	232	N/A	801	N/A	181	N/A	8.5	N/A
Feb	221	N/A	565	N/A	133	N/A	4.4	N/A
Mar	229	N/A	671	N/A	180	N/A	6.8	N/A
Apr	246	N/A	1,028	N/A	175	N/A	6.1	N/A
May-Oct	256	240	818	798	222	182	8.4	6.6
Nov-Apr	228	N/A	759	N/A	173	N/A	7.3	N/A
May-Apr	242	N/A	789	N/A	197	N/A	7.8	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: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2006 – October 2007

	% of Total Requirements													
	Average Hourly Reserve (MW)		Dispatchable Load		Hydroelectric		Fossil		CAOR		Import		Export	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	1,366	1,346	23.9	19.0	61.7	71.1	6.7	4.4	0.9	0.1	1.6	0.2	4.8	3.4
Jun	1,368	1,334	22.3	19.2	67.0	68.6	5.4	5.6	0.0	0.3	2.4	1.0	2.8	3.4
Jul	1,370	1,317	24.0	18.0	65.8	70.8	6.3	6.1	0.0	0.1	1.8	0.8	2.1	2.4
Aug	1,380	1,324	17.1	16.3	74.4	72.7	5.8	5.5	0.3	0.0	0.4	1.2	2.0	3.1
Sep	1,367	1,320	20.4	17.0	71.8	72.7	4.7	5.2	0.0	0.1	0.4	1.3	2.8	3.1
Oct	1,384	1,330	18.4	16.9	71.2	74.3	5.1	5.7	0.0	0.0	1.3	0.4	2.9	2.5
Nov	1,379	N/A	20.8	N/A	69.7	N/A	6.0	N/A	0.0	N/A	0.5	N/A	0.9	N/A
Dec	1,365	N/A	18.4	N/A	71.2	N/A	6.1	N/A	0.2	N/A	1.8	N/A	0.6	N/A
Jan	1,373	N/A	20.4	N/A	67.2	N/A	7.4	N/A	0.2	N/A	0.0	N/A	4.1	N/A
Feb	1,399	N/A	21.1	N/A	66.9	N/A	6.2	N/A	0.3	N/A	0.2	N/A	4.3	N/A
Mar	1,387	N/A	21.8	N/A	68.1	N/A	4.1	N/A	0.2	N/A	1.4	N/A	4.0	N/A
Apr	1,379	N/A	20.6	N/A	69.1	N/A	5.2	N/A	0.3	N/A	0.9	N/A	2.7	N/A
May-Oct	1,373	1,329	21.0	17.7	68.7	71.7	5.7	5.4	0.2	0.1	1.3	0.8	2.9	3.0
Nov-Apr	1,380	N/A	20.5	N/A	68.7	N/A	5.8	N/A	0.2	N/A	0.8	N/A	2.8	N/A
May-Apr	1,376	N/A	20.8	N/A	68.7	N/A	5.8	N/A	0.2	N/A	1.1	N/A	2.8	N/A

Table A-47: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2006 – October 2007

	% of Total Requirements													
	Average Hourly Reserve (MW)		Dispatchable Load		Hydroelectric		Fossil		CAOR		Import		Export	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	1,487	1,340	21.5	19.6	68.4	66.8	7.8	6.4	0.2	0.0	0.4	0.0	1.6	4.7
Jun	1,435	1,315	21.6	20.4	68.0	66.4	6.4	5.9	0.0	0.0	0.2	0.6	3.8	4.2
Jul	1,368	1,318	22.3	19.5	65.1	68.5	8.4	6.9	0.2	0.0	0.3	0.0	3.8	3.0
Aug	1,370	1,316	17.4	17.2	71.9	68.6	7.1	7.4	0.0	0.0	0.2	0.0	3.4	4.7
Sep	1,367	1,317	19.5	18.2	70.0	68.8	6.7	7.0	0.0	0.0	0.0	0.0	3.8	4.9
Oct	1,368	1,316	17.7	18.1	69.0	69.6	6.9	7.8	0.0	0.0	0.0	0.9	4.5	2.9
Nov	1,368	N/A	19.2	N/A	70.1	N/A	6.1	N/A	0.0	N/A	0.0	N/A	1.8	N/A
Dec	1,366	N/A	16.2	N/A	71.4	N/A	7.1	N/A	0.1	N/A	1.2	N/A	1.7	N/A
Jan	1,367	N/A	19.5	N/A	67.7	N/A	6.4	N/A	0.0	N/A	0.0	N/A	4.3	N/A
Feb	1,371	N/A	20.3	N/A	70.0	N/A	3.7	N/A	0.1	N/A	0.0	N/A	4.8	N/A
Mar	1,369	N/A	21.1	N/A	69.1	N/A	3.9	N/A	0.0	N/A	0.5	N/A	4.3	N/A
Apr	1,395	N/A	19.8	N/A	69.3	N/A	5.1	N/A	0.1	N/A	0.3	N/A	3.2	N/A
May-Oct	1,399	1,320	20.0	18.8	68.7	68.1	7.2	6.9	0.1	0.0	0.2	0.3	3.5	4.1
Nov-Apr	1,373	N/A	19.4	N/A	69.6	N/A	5.4	N/A	0.1	N/A	0.3	N/A	3.4	N/A
May-Apr	1,386	N/A	19.7	N/A	69.2	N/A	6.3	N/A	0.1	N/A	0.3	N/A	3.4	N/A

Table A-48: Day Ahead Forecast Error, May 2006 – October 2007
(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%	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	(98)	(26)	1.87	1.31	151	53	20	7
Jun	(100)	0	2.91	2.67	279	252	39	35
Jul	178	98	3.02	2.61	317	227	43	31
Aug	26	113	2.55	2.21	258	188	35	25
Sep	101	68	1.70	1.79	127	139	18	19
Oct	6	(70)	1.60	1.53	94	92	13	12
Nov	(76)	N/A	1.52	N/A	83	N/A	12	N/A
Dec	15	N/A	1.73	N/A	114	N/A	15	N/A
Jan	(67)	N/A	1.52	N/A	70	N/A	9	N/A
Feb	23	N/A	1.52	N/A	81	N/A	12	N/A
Mar	(77)	N/A	1.61	N/A	94	N/A	13	N/A
Apr	(38)	N/A	1.55	N/A	84	N/A	12	N/A
May-Oct	19	31	2.28	2.02	1,226	951	28	22
Nov-Apr	(37)	N/A	1.58	N/A	526	N/A	12	N/A
May-Apr	(9)	N/A	1.93	N/A	1,752	N/A	20	N/A

Table A-49: Average One Hour Ahead Forecast Error, May 2006 – October 2007

	Peak Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 2%		Percentage of Hours with Absolute Error ≥ 2%	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	38	(2)	0.96	0.89	82	63	11	8
Jun	45	19	1.03	1.19	92	129	13	18
Jul	82	39	1.32	1.14	160	126	22	17
Aug	38	61	1.15	1.22	123	125	17	17
Sep	8	22	0.89	1.06	56	94	8	13
Oct	23	39	0.93	0.99	59	92	8	12
Nov	18	N/A	0.90	N/A	58	N/A	8	N/A
Dec	20	N/A	0.98	N/A	75	N/A	10	N/A
Jan	19	N/A	0.87	N/A	53	N/A	7	N/A
Feb	42	N/A	0.84	N/A	41	N/A	6	N/A
Mar	3	N/A	0.92	N/A	67	N/A	9	N/A
Apr	8	N/A	0.84	N/A	42	N/A	6	N/A
May-Oct	39	30	1.05	1.08	572	629	13	14
Nov-Apr	18	N/A	0.89	N/A	336	N/A	8	N/A
May-Apr	29	N/A	0.97	N/A	908	N/A	10	N/A

Table A-50: Monthly Payment for Reliability Programs,
May 2006 – October 2007
($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		TDRP		ELRP		HADL	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	N/A	0.33	3.81	2.33	3.07	1.01	N/A	1.15	0.43	0.11	-0.01	0.00	N/A	0.00	0.00	0.00
Jun	0.35	1.08	1.91	2.27	0.54	1.24	0.56	2.04	0.52	0.07	0.01	0.00	0.00	0.01	0.00	0.00
Jul	0.55	0.65	1.81	1.42	0.84	1.10	1.89	2.29	0.18	0.22	0.00	0.00	0.00	0.00	0.00	0.00
Aug	0.72	0.64	2.82	2.29	1.05	0.61	2.37	1.58	0.09	0.06	0.03	0.00	0.01	0.00	0.00	0.00
Sep	0.16	2.79	0.57	1.71	0.81	0.78	1.69	1.67	0.13	0.03	0.07	0.00	0.00	0.01	0.00	0.00
Oct	0.16	1.35	1.60	2.55	0.97	0.85	1.14	1.99	0.22	0.04	0.00	0.00	0.00	0.00	0.00	0.00
Nov	4.18	N/A	3.50	N/A	1.34	N/A	2.00	N/A	0.18	N/A	0.00	N/A	0.00	N/A	0.00	N/A
Dec	1.08	N/A	2.35	N/A	1.50	N/A	2.03	N/A	0.15	N/A	0.00	N/A	0.00	N/A	0.00	N/A
Jan	0.50	N/A	2.37	N/A	2.13	N/A	2.35	N/A	0.17	N/A	0.00	N/A	0.00	N/A	0.00	N/A
Feb	0.16	N/A	3.98	N/A	2.24	N/A	2.61	N/A	0.30	N/A	0.01	N/A	0.00	N/A	0.00	N/A
Mar	1.31	N/A	4.34	N/A	1.04	N/A	1.97	N/A	0.20	N/A	0.01	N/A	0.00	N/A	0.00	N/A
Apr	0.08	N/A	2.29	N/A	1.50	N/A	1.70	N/A	0.09	N/A	0.01	N/A	0.00	N/A	0.00	N/A
May – Oct	1.94	6.84	12.52	12.57	7.28	5.59	7.65	10.72	1.57	0.53	0.10	0.00	0.01	0.02	0.00	0.00
Nov – Apr	7.31	N/A	18.83	N/A	9.75	N/A	12.66	N/A	1.09	N/A	0.02	N/A	0.00	N/A	0.00	N/A
May - Apr	9.25	N/A	31.35	N/A	17.03	N/A	20.31	N/A	2.66	N/A	0.12	N/A	0.01	N/A	0.00	N/A

* A total of about $0.83 million was eventually clawed back but not excluded from the table

*Table A-51: Low Price Hours, May 2007 - October 2007**

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/05/01	2	12,698	12,525	-1.4	277	22.07	8.22	-62.8
2007/05/01	3	12,429	12,502	0.6	902	16.60	4.80	-71.1
2007/05/01	4	12,722	12,564	-1.2	185	23.06	12.44	-46.1
2007/05/01	5	13,611	13,152	-3.4	0	25.59	19.85	-22.4
2007/05/02	24	13,748	13,237	-3.7	180	25.35	19.02	-25.0
2007/05/03	1	12,994	12,756	-1.8	170	22.76	19.13	-15.9
2007/05/03	2	12,803	12,487	-2.5	0	22.67	19.73	-13.0
2007/05/03	3	12,597	12,378	-1.7	32	22.17	19.24	-13.2
2007/05/03	24	13,458	13,288	-1.3	290	26.05	18.25	-29.9
2007/05/05	3	11,829	11,697	-1.1	25	14.05	5.62	-60.0
2007/05/05	4	11,764	11,687	-0.7	25	16.00	18.03	12.7
2007/05/05	24	12,588	12,278	-2.5	175	21.80	11.95	-45.2
2007/05/06	1	11,622	11,785	1.4	175	6.96	6.73	-3.3
2007/05/06	2	11,421	11,504	0.7	175	15.20	9.07	-40.3
2007/05/06	3	11,277	11,363	0.8	25	21.49	13.38	-37.7
2007/05/06	5	11,384	11,501	1.0	175	16.60	8.44	-49.2
2007/05/06	6	11,513	11,571	0.5	148	15.09	9.43	-37.5
2007/05/06	7	12,380	12,119	-2.1	181	21.18	6.60	-68.8
2007/05/06	8	13,437	13,072	-2.7	407	24.64	11.62	-52.8
2007/05/06	14	14,080	13,976	-0.7	205	22.41	16.98	-24.2
2007/05/06	15	14,028	13,913	-0.8	250	22.22	6.08	-72.6
2007/05/06	16	14,191	14,125	-0.5	159	24.59	17.37	-29.4
2007/05/06	19	14,488	14,229	-1.8	148	25.96	6.28	-75.8
2007/05/06	23	13,572	13,268	-2.2	325	27.93	18.29	-34.5
2007/05/06	24	12,818	12,514	-2.4	150	26.07	6.86	-73.7
2007/05/07	1	12,040	12,195	1.3	183	6.81	7.95	16.7
2007/05/07	2	11,911	12,081	1.4	325	6.81	5.35	-21.4
2007/05/07	3	11,845	12,035	1.6	175	4.80	5.63	17.3
2007/05/07	4	12,181	12,180	0.0	25	16.18	17.38	7.4
2007/05/07	5	13,313	12,711	-4.5	25	26.85	17.84	-33.6
2007/05/07	23	14,603	14,054	-3.7	331	27.42	14.14	-48.4
2007/05/07	24	13,254	12,982	-2.1	353	16.60	4.70	-71.7
2007/05/08	1	12,556	12,501	-0.4	442	5.53	4.24	-23.3
2007/05/08	2	12,410	12,203	-1.7	199	8.23	6.53	-20.7
2007/05/08	3	12,206	12,036	-1.4	300	8.23	4.56	-44.6
2007/05/08	4	12,383	12,148	-1.9	365	15.20	4.57	-69.9
2007/05/08	5	13,115	12,612	-3.8	0	24.20	11.05	-54.3
2007/05/08	6	14,753	13,711	-7.1	150	29.95	19.73	-34.1
2007/05/10	1	13,345	13,008	-2.5	250	19.58	15.63	-20.2
2007/05/10	2	12,988	12,687	-2.3	100	18.33	15.64	-14.7
2007/05/10	3	12,722	12,515	-1.6	201	17.08	14.82	-13.2
2007/05/10	4	12,771	12,465	-2.4	235	17.49	14.63	-16.4
2007/05/10	5	13,402	12,864	-4.0	347	20.00	7.55	-62.3
2007/05/10	6	14,811	14,061	-5.1	327	29.25	17.80	-39.1
2007/05/10	7	16,335	15,863	-2.9	520	27.98	19.65	-29.8
2007/05/12	3	11,893	11,753	-1.2	60	15.00	5.72	-61.9
2007/05/12	4	11,803	11,785	-0.2	38	10.00	15.55	55.5

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/05/12	5	11,945	11,805	-1.2	0	15.00	6.40	-57.3
2007/05/12	6	12,599	12,113	-3.9	170	22.13	10.28	-53.5
2007/05/12	24	12,317	12,401	0.7	-100	15.44	18.21	17.9
2007/05/13	1	12,207	11,689	-4.2	218	21.80	5.98	-72.6
2007/05/13	2	11,777	11,428	-3.0	375	17.95	4.78	-73.4
2007/05/13	3	11,427	11,314	-1.0	455	18.32	5.05	-72.4
2007/05/13	4	11,417	11,369	-0.4	466	20.00	5.88	-70.6
2007/05/13	5	11,556	11,411	-1.3	300	16.48	5.37	-67.4
2007/05/13	6	11,803	11,508	-2.5	430	15.88	4.56	-71.3
2007/05/13	7	12,499	12,183	-2.5	91	23.52	17.71	-24.7
2007/05/18	24	12,826	12,808	-0.1	175	21.95	15.69	-28.5
2007/05/19	1	12,204	12,278	0.6	200	17.00	7.92	-53.4
2007/05/19	2	12,051	11,899	-1.3	53	14.72	5.05	-65.7
2007/05/19	3	11,711	11,781	0.6	200	20.00	14.55	-27.3
2007/05/19	4	11,610	11,786	1.5	444	20.00	13.12	-34.4
2007/05/19	5	11,946	11,880	-0.6	504	23.58	16.02	-32.1
2007/05/19	6	12,399	12,129	-2.2	299	23.80	16.94	-28.8
2007/05/19	7	13,332	12,831	-3.8	124	23.83	15.43	-35.2
2007/05/19	24	12,584	12,445	-1.1	75	20.68	19.42	-6.1
2007/05/20	1	11,886	11,891	0.0	75	3.99	5.15	29.1
2007/05/20	2	11,654	11,611	-0.4	150	4.75	4.33	-8.8
2007/05/20	3	11,376	11,386	0.1	-30	2.90	2.95	1.7
2007/05/20	4	11,329	11,336	0.1	100	4.15	3.82	-8.0
2007/05/20	5	11,538	11,339	-1.7	0	4.75	4.25	-10.5
2007/05/20	6	11,618	11,407	-1.8	0	4.75	3.60	-24.2
2007/05/20	7	12,394	11,980	-3.3	-50	4.75	3.62	-23.8
2007/05/20	8	13,227	12,931	-2.2	75	21.77	7.39	-66.1
2007/05/20	14	14,167	14,012	-1.1	-175	18.95	19.27	1.7
2007/05/20	15	14,146	13,980	-1.2	175	15.72	6.37	-59.5
2007/05/20	16	14,399	14,122	-1.9	-60	15.72	14.55	-7.4
2007/05/20	20	14,426	13,999	-3.0	150	28.97	18.17	-37.3
2007/05/20	22	14,085	13,844	-1.7	0	21.86	13.32	-39.1
2007/05/20	23	13,185	13,026	-1.2	-188	21.55	18.51	-14.1
2007/05/21	1	11,908	11,860	-0.4	0	27.44	10.62	-61.3
2007/05/21	2	11,691	11,589	-0.9	0	19.23	6.47	-66.4
2007/05/21	3	11,509	11,488	-0.2	0	10.00	7.82	-21.8
2007/05/22	3	11,948	11,803	-1.2	100	17.00	12.72	-25.2
2007/05/22	4	12,282	11,904	-3.1	50	22.87	17.19	-24.8
2007/05/27	1	12,050	12,269	1.8	275	20.27	18.58	-8.3
2007/05/27	2	11,613	11,898	2.5	555	14.00	9.18	-34.4
2007/05/27	3	11,461	11,655	1.7	490	13.92	13.69	-1.7
2007/05/27	4	11,460	11,616	1.4	214	14.00	13.84	-1.1
2007/05/27	5	11,427	11,642	1.9	-49	14.99	17.90	19.4
2007/05/27	6	11,901	11,683	-1.8	184	28.52	14.18	-50.3
2007/05/27	7	12,717	12,291	-3.4	272	29.74	15.74	-47.1
2007/05/27	24	13,616	13,071	-4.0	222	29.82	18.85	-36.8
2007/05/28	1	12,700	12,564	-1.1	302	18.99	10.75	-43.4
2007/05/28	2	12,529	12,322	-1.7	643	19.20	4.02	-79.1
2007/05/28	3	12,136	12,252	1.0	668	21.97	4.04	-81.6

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/05/28	4	12,260	12,317	0.5	338	18.01	5.72	-68.2
2007/05/28	5	13,187	12,763	-3.2	15	25.47	12.10	-52.5
2007/05/28	6	14,838	13,965	-5.9	82	30.65	14.18	-53.7
2007/05/28	24	13,906	13,689	-1.6	575	28.10	19.32	-31.2
2007/05/29	1	13,302	13,057	-1.8	411	24.97	7.39	-70.4
2007/05/29	2	12,769	12,719	-0.4	179	18.29	15.17	-17.1
2007/05/29	3	12,695	12,543	-1.2	275	19.12	6.82	-64.3
2007/05/29	4	12,875	12,598	-2.1	473	24.00	11.26	-53.1
2007/05/29	5	13,569	12,972	-4.4	67	26.99	18.30	-32.2
2007/05/30	1	13,453	13,258	-1.5	150	20.54	15.46	-24.7
2007/05/30	2	13,092	12,883	-1.6	76	18.88	14.40	-23.7
2007/05/30	3	12,824	12,735	-0.7	187	16.69	8.03	-51.9
2007/05/30	4	12,812	12,742	-0.5	463	18.88	6.90	-63.5
2007/05/30	5	13,475	13,096	-2.8	228	26.80	16.58	-38.1
2007/05/31	2	14,391	14,104	-2.0	468	22.33	15.79	-29.3
2007/05/31	3	13,956	13,771	-1.3	200	19.23	16.60	-13.7
2007/05/31	4	13,855	13,691	-1.2	191	19.11	16.46	-13.9
2007/05/31	5	14,505	14,029	-3.3	134	27.93	19.46	-30.3
2007/05/31	6	16,085	15,127	-6.0	149	28.01	16.03	-42.8
May 2007**	**115**	**12,752**	**12,555**	**-1.5**	**200**	**19.15**	**11.73**	**-38.7**
2007/06/02	5	12,975	12,982	0.1	50	7.02	7.02	0.0
2007/06/02	6	13,857	13,212	-4.7	-50	22.38	8.68	-61.2
2007/06/02	7	15,304	14,287	-6.6	150	27.80	10.08	-63.7
2007/06/03	4	13,273	12,942	-2.5	450	25.00	19.63	-21.5
2007/06/03	5	13,187	12,730	-3.5	55	22.84	13.71	-40.0
2007/06/03	6	13,233	12,677	-4.2	242	23.44	7.24	-69.1
2007/06/03	7	14,242	13,412	-5.8	61	25.13	11.35	-54.8
2007/06/03	8	15,178	14,703	-3.1	161	27.00	19.72	-27.0
2007/06/04	3	13,121	13,012	-0.8	430	22.24	13.31	-40.2
2007/06/04	4	13,333	13,074	-1.9	444	22.54	9.69	-57.0
2007/06/04	5	14,108	13,588	-3.7	350	25.00	14.92	-40.3
2007/06/04	24	15,030	14,385	-4.3	434	27.29	16.64	-39.0
2007/06/05	1	14,126	13,680	-3.2	374	16.60	4.69	-71.7
2007/06/05	2	13,585	13,298	-2.1	127	10.00	4.51	-54.9
2007/06/05	3	13,080	13,100	0.2	370	15.10	11.69	-22.6
2007/06/05	4	13,038	13,121	0.6	84	9.06	14.25	57.3
2007/06/05	5	14,016	13,516	-3.6	89	18.39	10.33	-43.8
2007/06/05	6	15,550	14,648	-5.8	-16	27.24	17.72	-34.9
2007/06/05	24	13,613	13,403	-1.5	0	20.10	17.73	-11.8
2007/06/06	1	12,937	12,982	0.4	0	4.70	5.17	10.0
2007/06/06	2	12,660	12,664	0.0	0	4.50	4.86	8.0
2007/06/06	3	12,524	12,552	0.2	0	5.30	6.28	18.5
2007/06/06	4	12,555	12,589	0.3	39	6.27	6.06	-3.3
2007/06/06	5	13,187	12,980	-1.6	8	15.91	8.70	-45.3
2007/06/06	6	15,126	14,102	-6.8	8	27.71	13.32	-51.9
2007/06/06	23	15,265	14,494	-5.0	149	31.76	19.49	-38.6
2007/06/06	24	14,040	13,510	-3.8	0	23.71	18.01	-24.0
2007/06/07	1	13,176	12,911	-2.0	158	17.89	14.25	-20.3

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/06/07	2	12,875	12,590	-2.2	329	16.36	6.54	-60.0
2007/06/07	3	12,712	12,425	-2.3	200	15.00	4.33	-71.1
2007/06/07	4	12,855	12,479	-2.9	252	16.80	4.62	-72.5
2007/06/07	5	13,531	12,882	-4.8	120	27.47	15.67	-43.0
2007/06/07	6	14,859	14,097	-5.1	207	28.29	12.73	-55.0
2007/06/08	1	13,706	13,860	1.1	0	18.82	19.70	4.7
2007/06/08	2	13,490	13,451	-0.3	0	17.78	17.54	-1.3
2007/06/08	3	13,159	13,214	0.4	0	4.70	7.43	58.1
2007/06/08	4	13,303	13,259	-0.3	0	5.00	15.66	213.2
2007/06/08	5	14,099	13,634	-3.3	12	23.07	18.73	-18.8
2007/06/08	6	15,776	14,895	-5.6	0	27.58	15.03	-45.5
2007/06/09	4	12,067	11,908	-1.3	0	21.26	17.67	-16.9
2007/06/09	5	11,903	11,822	-0.7	144	21.89	19.20	-12.3
2007/06/10	2	12,246	11,769	-3.9	0	21.58	8.34	-61.4
2007/06/10	3	11,854	11,536	-2.7	19	21.34	9.72	-54.5
2007/06/10	4	11,671	11,432	-2.0	194	10.43	4.78	-54.2
2007/06/10	5	11,532	11,228	-2.6	100	10.32	4.75	-54.0
2007/06/10	6	11,956	11,318	-5.3	50	20.88	3.81	-81.8
2007/06/10	7	12,580	11,966	-4.9	0	23.53	13.51	-42.6
2007/06/13	6	16,644	15,628	-6.1	333	29.64	18.06	-39.1
2007/06/21	2	13,723	13,358	-2.7	314	22.96	19.11	-16.8
2007/06/21	3	13,157	13,147	-0.1	100	21.19	19.91	-6.0
2007/06/21	4	13,184	13,158	-0.2	100	21.31	19.99	-6.2
2007/06/21	5	13,876	13,446	-3.1	114	26.67	17.92	-32.8
2007/06/22	1	13,685	13,677	-0.1	105	18.36	18.08	-1.5
2007/06/22	2	13,315	13,233	-0.6	110	17.46	16.47	-5.7
2007/06/22	3	12,403	13,015	4.9	65	10.73	19.93	85.7
2007/06/22	4	13,164	13,038	-1.0	275	20.45	17.96	-12.2
2007/06/23	4	11,794	11,914	1.0	150	17.77	17.80	0.2
2007/06/23	5	11,893	11,837	-0.5	225	18.97	11.71	-38.3
2007/06/23	6	12,565	12,241	-2.6	0	6.15	4.83	-21.5
2007/06/23	7	13,645	13,164	-3.5	150	27.34	18.68	-31.7
2007/06/23	8	14,822	14,266	-3.8	0	26.96	18.42	-31.7
2007/06/23	23	14,000	13,880	-0.9	251	20.27	9.55	-52.9
2007/06/23	24	13,204	13,023	-1.4	0	21.39	15.89	-25.7
2007/06/24	2	12,113	12,145	0.3	0	18.34	19.27	5.1
2007/06/24	5	11,589	11,601	0.1	150	21.00	19.63	-6.5
2007/06/24	6	11,865	11,596	-2.3	0	12.63	4.51	-64.3
2007/06/24	7	13,079	12,308	-5.9	200	28.68	18.39	-35.9
June 2007**	**67**	**13,361**	**13,045**	**-2.4**	**126**	**19.29**	**13.06**	**-32.3**
2007/07/02	2	11,709	11,467	-2.1	0	21.25	19.60	-7.8
2007/07/02	3	11,411	11,344	-0.6	135	19.52	17.16	-12.1
2007/07/02	4	11,295	11,300	0.0	75	20.09	19.35	-3.7
2007/07/02	5	11,142	11,234	0.8	0	17.91	19.00	6.1
2007/07/02	6	11,537	11,373	-1.4	339	22.41	16.70	-25.5
2007/07/04	5	13,348	13,083	-2.0	327	26.64	10.54	-60.4
2007/07/04	7	16,198	15,605	-3.7	0	27.42	16.20	-40.9
2007/07/05	2	13,278	12,869	-3.1	0	24.70	19.72	-20.2

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/07/05	4	12,653	12,585	-0.5	325	24.41	11.01	-54.9
2007/07/05	5	13,329	12,963	-2.7	156	27.00	18.74	-30.6
2007/07/07	5	12,769	12,363	-3.2	0	23.56	14.45	-38.7
2007/07/07	6	12,868	12,509	-2.8	0	23.08	10.54	-54.3
2007/07/07	7	14,174	13,423	-5.3	627	30.11	16.84	-44.1
2007/07/08	5	12,386	12,503	0.9	0	17.20	13.12	-23.7
2007/07/08	6	12,990	12,483	-3.9	0	20.01	4.19	-79.1
2007/07/08	7	14,133	13,226	-6.4	0	20.00	2.41	-88.0
2007/07/08	8	15,666	14,390	-8.1	0	28.92	7.26	-74.9
2007/07/12	3	12,940	12,565	-2.9	368	23.91	4.63	-80.6
2007/07/12	4	12,766	12,659	-0.8	400	22.44	4.70	-79.1
2007/07/12	6	14,662	13,816	-5.8	200	30.12	13.96	-53.7
2007/07/12	7	16,402	15,482	-5.6	477	30.54	18.44	-39.6
2007/07/13	1	13,471	13,270	-1.5	0	10.00	8.16	-18.4
2007/07/13	2	13,124	12,845	-2.1	0	10.00	6.06	-39.4
2007/07/13	3	12,658	12,613	-0.4	0	5.83	18.37	215.1
2007/07/13	4	12,603	12,616	0.1	0	7.13	10.48	47.0
2007/07/13	5	13,153	12,951	-1.5	0	23.73	9.04	-61.9
2007/07/13	6	14,384	13,782	-4.2	0	27.91	15.09	-45.9
2007/07/14	2	12,274	12,190	-0.7	0	21.38	10.98	-48.6
2007/07/14	3	11,990	12,007	0.1	0	15.00	13.69	-8.7
2007/07/14	4	11,853	11,879	0.2	0	20.74	16.30	-21.4
2007/07/14	5	11,938	11,913	-0.2	0	15.00	6.85	-54.3
2007/07/14	6	12,347	12,060	-2.3	124	22.00	4.97	-77.4
2007/07/14	7	13,625	12,886	-5.4	108	29.32	18.01	-38.6
2007/07/15	1	12,736	12,324	-3.2	0	22.92	9.35	-59.2
2007/07/15	2	12,186	11,992	-1.6	8	22.26	18.42	-17.3
2007/07/15	3	11,801	11,738	-0.5	200	10.00	4.68	-53.2
2007/07/15	4	11,583	11,599	0.1	158	6.28	6.60	5.1
2007/07/15	5	11,429	11,525	0.8	300	6.28	4.90	-22.0
2007/07/15	6	11,813	11,483	-2.8	200	10.00	4.38	-56.2
2007/07/15	7	12,772	12,150	-4.9	0	25.69	12.07	-53.0
2007/07/17	1	14,000	13,835	-1.2	0	20.16	19.35	-4.0
2007/07/17	2	13,771	13,319	-3.3	8	21.09	18.77	-11.0
2007/07/17	3	13,231	13,039	-1.5	100	18.08	18.21	0.7
2007/07/17	4	13,074	13,046	-0.2	0	18.53	18.64	0.6
2007/07/17	5	13,721	13,354	-2.7	0	20.00	18.88	-5.6
2007/07/17	6	15,086	14,245	-5.6	0	29.87	16.82	-43.7
2007/07/18	3	13,445	13,269	-1.3	100	19.96	18.48	-7.4
2007/07/18	4	13,296	13,270	-0.2	2	19.09	19.33	1.3
2007/07/21	3	12,258	12,193	-0.5	0	18.80	6.27	-66.6
2007/07/21	4	12,078	12,042	-0.3	497	6.26	3.92	-37.4
2007/07/21	5	12,118	12,111	-0.1	448	13.19	4.80	-63.6
2007/07/21	6	12,486	12,192	-2.4	100	15.87	9.61	-39.4
2007/07/21	7	13,528	13,153	-2.8	0	23.41	19.07	-18.5
2007/07/22	5	11,652	11,670	0.2	104	20.40	19.71	-3.4
2007/07/22	6	11,995	11,627	-3.1	108	18.70	3.71	-80.2
2007/07/22	7	13,028	12,322	-5.4	129	26.39	7.59	-71.2
2007/07/22	8	14,158	13,501	-4.6	0	28.39	16.26	-42.7

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
July 2007**	**57**	**12,953**	**12,654**	**-2.3**	**107**	**20.19**	**12.57**	**-37.8**
2007/08/05	2	13,496	12,961	-4.0	83	20.43	5.37	-73.7
2007/08/05	3	13,231	12,646	-4.4	0	20.00	4.67	-76.7
2007/08/05	4	12,620	12,433	-1.5	4	10.00	4.68	-53.2
2007/08/05	5	12,618	12,410	-1.6	0	17.07	15.98	-6.4
2007/08/05	6	12,865	12,315	-4.3	0	15.00	4.63	-69.1
2007/08/05	7	13,665	12,985	-5.0	113	28.46	8.02	-71.8
2007/08/19	4	11,583	11,697	1.0	150	21.00	18.75	-10.7
2007/08/19	5	11,665	11,727	0.5	301	21.56	13.04	-39.5
2007/08/26	3	12,700	12,426	-2.2	413	26.37	12.25	-53.5
2007/08/26	4	12,341	12,286	-0.4	601	23.91	6.16	-74.2
2007/08/31	6	15,264	14,309	-6.3	96	28.25	17.95	-36.5
Aug 2007**	**11**	**12,913**	**12,563**	**-2.7**	**160**	**21.10**	**10.14**	**-52.0**
2007/09/01	2	12,922	12,686	-1.8	247	25.92	7.43	-71.3
2007/09/01	3	12,411	12,398	-0.1	100	20.00	10.64	-46.8
2007/09/01	4	12,182	12,257	0.6	470	20.00	6.86	-65.7
2007/09/01	5	12,407	12,355	-0.4	308	20.00	7.52	-62.4
2007/09/01	6	12,751	12,510	-1.9	33	23.14	10.39	-55.1
2007/09/01	24	13,382	12,987	-3.0	150	28.89	18.63	-35.5
2007/09/02	1	12,531	12,399	-1.1	234	22.72	13.13	-42.2
2007/09/02	2	12,288	12,088	-1.6	0	20.00	12.13	-39.4
2007/09/02	3	11,981	11,852	-1.1	175	17.30	9.52	-45.0
2007/09/02	4	11,651	11,723	0.6	85	10.02	9.65	-3.7
2007/09/02	5	11,890	11,765	-1.0	100	15.00	6.89	-54.1
2007/09/02	6	12,084	11,823	-2.2	200	15.23	6.52	-57.2
2007/09/02	7	12,740	12,178	-4.4	199	15.02	5.07	-66.2
2007/09/02	8	13,738	13,208	-3.9	0	27.60	15.34	-44.4
2007/09/03	1	12,893	12,532	-2.8	0	28.80	10.89	-62.2
2007/09/03	2	12,425	12,154	-2.2	0	24.57	9.39	-61.8
2007/09/03	3	11,905	11,892	-0.1	0	19.91	11.00	-44.8
2007/09/03	4	11,788	11,823	0.3	150	19.33	4.82	-75.1
2007/09/03	6	12,088	12,176	0.7	100	18.09	13.93	-23.0
2007/09/03	7	12,792	12,536	-2.0	134	24.65	12.84	-47.9
2007/09/03	8	13,919	13,497	-3.0	0	28.35	13.18	-53.5
2007/09/12	1	13,186	12,959	-1.7	521	28.35	13.85	-51.1
2007/09/12	5	13,820	13,067	-5.5	21	29.20	19.30	-33.9
2007/09/14	4	12,882	12,694	-1.5	191	21.66	16.94	-21.8
2007/09/15	2	12,586	12,248	-2.7	198	28.10	4.75	-83.1
2007/09/15	3	12,175	12,069	-0.9	150	23.05	17.20	-25.4
2007/09/15	4	11,996	11,986	-0.1	171	23.34	10.92	-53.2
2007/09/15	23	13,359	13,176	-1.4	330	28.46	15.91	-44.1
2007/09/16	2	11,990	11,684	-2.5	447	23.99	6.09	-74.6
2007/09/16	3	11,813	11,497	-2.7	1,071	22.85	0.39	-98.3
2007/09/16	4	11,555	11,450	-0.9	361	4.60	4.47	-2.8
2007/09/16	5	11,662	11,609	-0.5	75	21.00	4.88	-76.8
2007/09/16	7	12,669	12,261	-3.2	425	30.00	14.41	-52.0
2007/09/17	3	12,051	12,072	0.2	375	26.55	7.98	-69.9

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/09/17	4	12,356	12,189	-1.3	550	28.25	18.30	-35.2
2007/09/18	1	13,295	12,902	-3.0	731	25.35	-0.40	-101.6
2007/09/18	2	12,930	12,659	-2.1	100	23.40	4.74	-79.7
2007/09/18	4	12,904	12,501	-3.1	150	24.54	4.68	-80.9
2007/09/28	2	12,823	12,717	-0.8	294	22.33	14.62	-34.5
2007/09/29	2	11,893	12,048	1.3	200	20.97	11.61	-44.6
2007/09/30	2	11,521	11,658	1.2	729	23.99	13.90	-42.1
2007/09/30	3	11,196	11,449	2.3	575	20.00	4.57	-77.2
2007/09/30	4	11,210	11,377	1.5	325	21.20	4.66	-78.0
2007/09/30	5	11,301	11,472	1.5	361	20.20	5.54	-72.6
2007/09/30	6	11,639	11,741	0.9	471	22.55	12.50	-44.6
Sept 2007**	**45**	**12,391**	**12,229**	**-1.3**	**256**	**22.41**	**9.95**	**-55.6**
2007/10/03	4	13,068	12,776	-2.2	898	30.36	9.25	-69.5
2007/10/10	2	12,783	12,724	-0.5	100	26.87	10.42	-61.2
2007/10/11	2	12,743	12,488	-2.0	150	23.37	18.25	-21.9
2007/10/11	3	12,512	12,313	-1.6	220	22.57	11.46	-49.2
2007/10/12	2	12,823	12,471	-2.7	525	27.18	16.57	-39.0
2007/10/13	3	12,015	12,067	0.4	100	20.00	6.21	-69.0
2007/10/13	4	12,080	12,023	-0.5	150	25.10	4.86	-80.6
2007/10/14	2	11,846	11,782	-0.5	0	25.34	19.21	-24.2
2007/10/14	3	11,657	11,622	-0.3	100	23.10	11.97	-48.2
2007/10/17	3	12,544	12,469	-0.6	679	27.78	4.75	-82.9
2007/10/20	1	12,704	12,222	-3.8	392	30.00	16.71	-44.3
2007/10/20	2	12,222	11,920	-2.5	695	29.37	17.93	-39.0
2007/10/20	23	13,498	13,079	-3.1	200	25.00	12.82	-48.7
2007/10/20	24	12,672	12,336	-2.6	100	20.00	7.86	-60.7
2007/10/21	1	11,968	11,811	-1.3	460	27.35	4.60	-83.2
2007/10/21	2	11,788	11,429	-3.0	50	21.00	8.16	-61.1
2007/10/21	3	11,603	11,240	-3.1	50	23.75	8.00	-66.3
2007/10/21	4	11,425	11,137	-2.5	150	24.44	4.59	-81.2
2007/10/21	5	11,640	11,312	-2.8	358	19.20	4.11	-78.6
2007/10/21	6	12,054	11,759	-2.4	360	22.59	4.25	-81.2
2007/10/21	7	12,644	12,215	-3.4	290	25.14	4.34	-82.7
2007/10/21	8	13,480	12,841	-4.7	400	23.67	4.39	-81.5
2007/10/21	9	14,235	13,673	-3.9	146	28.01	8.92	-68.2
2007/10/21	24	13,206	12,578	-4.8	208	29.62	18.12	-38.8
2007/10/22	3	12,003	11,835	-1.4	255	22.54	19.38	-14.0
2007/10/22	4	12,497	11,925	-4.6	300	22.00	2.74	-87.5
2007/10/22	5	13,406	12,481	-6.9	225	25.01	10.02	-59.9
2007/10/24	4	12,753	12,383	-2.9	0	25.01	5.13	-79.5
2007/10/25	3	12,714	12,411	-2.4	50	22.00	4.95	-77.5
2007/10/25	4	13,062	12,569	-3.8	399	22.05	4.45	-79.8
2007/10/25	5	14,073	13,207	-6.2	350	31.73	13.00	-59.0
2007/10/26	2	12,891	12,728	-1.3	93	22.61	17.41	-23.0
2007/10/26	3	12,788	12,599	-1.5	211	22.73	8.25	-63.7
2007/10/28	2	12,212	11,891	-2.6	225	26.37	13.21	-49.9
2007/10/28	3	11,932	11,709	-1.9	510	24.48	4.53	-81.5
2007/10/28	4	11,854	11,662	-1.6	6	24.40	17.88	-26.7

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
Oct 2007**	**36**	**12,539**	**12,214**	**-2.6**	**261**	**24.77**	**9.96**	**-59.8**
May – Oct	**331**	**12,843**	**12,590**	**-2.0**	**182**	**20.48**	**11.66**	**-43.1**

* Low priced hours are defined as hours when the HOEP is less than $20/MWh.
*Monthly sub-totals reflect the total number of low-priced hours and unweighted averages of the Net Failed Exports, PD and RT Demand, and PD and HOEP prices, during those hours.