Market Surveillance Panel

Monitoring Report on the IMO-Administered Electricity Markets

for the period from
November 2003 to April 2004

PUBLIC

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Preface

This is the fourth monitoring report of the Market Surveillance Panel since the start of the Ontario electricity market in May 2002. It provides data and analysis of the first two years of the market but the emphasis is on the period since the last report, that is, November 1, 2003 – April 30, 2004. We intend to continue releasing our monitoring reports on a six-month cycle, covering the summer and winter seasons.

The structure of this report follows past reports. Chapter 1 and a Statistical Appendix provide a high level overview of market outcomes and basic data. Chapter 2 reviews and explains anomalous market outcomes - performance that appears to be outside expected norms and so subject to more extensive analysis. Chapter 3 summarizes the IMO initiatives related to past work of the Panel. Finally, Chapter 4 provides our overall assessment of market operations, makes preliminary comments on plans for Ontario's electricity sector and describes the work underway to more systematically monitor for the exercise of market power.

We are encouraged by the Government of Ontario's decision to continue the wholesale market. In this report as in previous monitoring reports we try to tell the 'story' of the market and identify and expose in detail the causes of anomalous events using the standard of market efficiency. The goal is to make sense of a complex system and contribute to its improvement over time. We remain of the view that a properly functioning wholesale market is central to an effective electricity sector in Ontario.

Fred Gorbet, Chair   Don McFetridge   Tom Rusnov

The Market Surveillance Panel is an independent arms-length body appointed by and accountable to the Independent Directors of the Independent Electricity Market Operator (IMO). It operates under a unique structure for electricity markets: having unimpeded access to the system operator's enormous confidential data stores and directing the work of the IMO's Market Assessment Unit, while observing a distance and neutrality from the IMO proper in carrying out its responsibilities.

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Chapter 1: Market Outcomes November 2003 to April 2004

1. *Introduction*

This chapter presents data and summary statistics on the IMO-administered markets for the period November 2003 to April 2004. The Statistical Appendix provides more detailed data covering the period May 2002 to April 2004. The focus of this chapter is a comparative assessment of market outcomes from November 2002-April 2003 and November 2003-April 2004. For ease of exposition the period November 2002-April 2003 will be referred to as winter 2003 and the period from November 2003-April 2004 will be termed winter 2004. In this chapter we also present a new section on net revenues for a hypothetical generator in Ontario.

In general, both on-peak and off-peak Ontario electricity prices were lower in winter 2004 compared to winter 2003. January 2004 was an exception, primarily due to record-high demand in that month. Indeed, the average HOEP in January was one of the highest recorded since market opening. Over the period as a whole, however, lower energy demand in combination with increased supply resulted in prices that were about $15.50 per MWh lower than in the corresponding period of the previous year. The improved balance between demand and availability within Ontario led to fewer imports and substantially reduced IOG payments. Congestion payments (particularly constrained on payments) also declined and the total hourly uplift averaged $2.43 per MWh in winter 2004 compared with $3.32 per MWh in winter 2003.

2. *Demand*

Energy consumption in Ontario declined from a monthly average of 13.22 TWh[1] in winter 2003 to 13.11 TWh in winter 2004. This lower energy demand was mainly a result of milder weather conditions and lower industrial demand for electricity in winter

[1] 1.0 TWh (terrawatt hours) equals 1,000 MWh (megawatt hours) or 1,000,000 KWh (kilowatt hours).

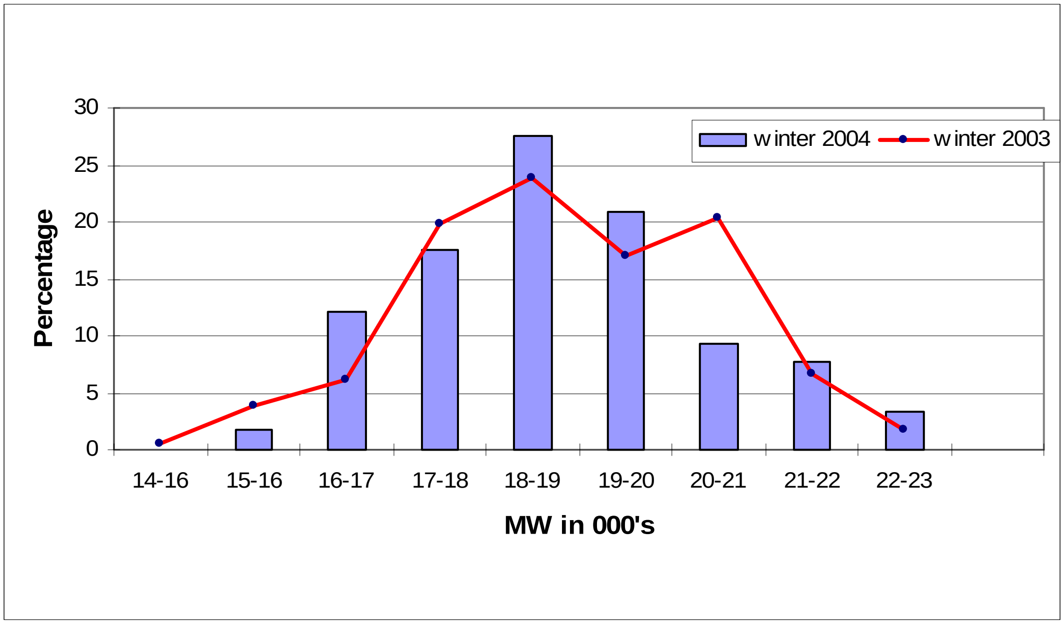
2004. Table A-1 in the Statistical Appendix indicates that monthly consumption decreased in all months except January 2004. In January energy consumption increased from 14.40 TWh to 14.77 TWh. Peak hourly demand at 24,937 MW in hour 19 on January 15, 2004 set a new winter record for Ontario. The previous record was 24,158 MW on January 22, 2003. The low temperatures that led to record high demand in January contributed to some anomalies in market outcomes that are discussed in detail in Chapter 2.

The chart below shows the distribution of demand in pre-defined ranges. The lower level of demand in the 20-21(000's) MW interval in 2004 contrasts sharply with the same interval for 2003. Table A-2 in the Statistical Appendix provides comparative temperature data and it is notable that over the period the average monthly temperature in winter 2004 was about 1.6 degrees warmer and, excluding January, almost 2.2 degrees warmer.

Although temperature was a major contributor to lower demand levels, there is some evidence that lower industrial activity in winter 2004 than winter 2003 also contributed. For example, manufacturing shipments[2] in Ontario fell 1.4% from $24,158 million in winter 2003. Furthermore a review of energy consumption by the 90 large industrial consumers that are directly connected to the IMO-controlled grid revealed that their consumption declined by almost 3.5% in winter 2004 compared with winter 2003. This decline accounted for about 2/3 of the decline in total energy demand in the province, a proportion substantially greater than their 15-16% share of total energy demand.

[2] Preliminary data obtained from Ontario Ministry of Finance, covering the period November 2002-March 2003 to November 2003-March 2004.

Figure 1-1: Demand Distributions, Winter 2003 and 2004



3. *Supply*

In winter 2004 there were more resources available in the market as a result of a number of facilities returning to service. By the beginning of winter 2004 both Pickering G4 and Bruce G4 had returned to service, providing almost 1,300 MW of additional resources. Between January and March 2004, Bruce G3 also became available bringing the total additional supply to about 2,000 MW. In the last week of winter 2004, Brighton Beach, a new gas generator rated at 580 MW,[3] began production and added more supply to the market.

Total outages for the winter 2004 were also down 18% on average compared to the previous year, with totals for 2003 at 23 TWh compared with 19 TWh for 2004. (See details in Statistical Appendix, Table A-4.) On a monthly basis however, the Figure 1-2 below shows that total outages increased in January and February 2004, offsetting most of the benefits of the increased supply in those months.

[3] See the Spring 2004 issue of the IMO's Electricity Exchange for more information about Brighton Beach. (http://www.theimo.com/imoweb/pubs/ee/ElectricityExchange-2004-1.pdf)

We saw significant downward shifts in planned outages, and a corresponding increase in forced outages, year over year. Figure 1-3, shows that planned outages for winter 2004 were consistently lower than the level for 2003. Figure 1-4 shows that forced outages were higher for all months, except December.

The explanations for lower planned outages and higher forced outages are linked. One of the main contributing factors to this increase is related to the extensive outage required by the Darlington nuclear plant in October 2003.[4] The unavailability of the entire plant severely limited the planning of other outages at the same time, postponing these until a later period. With subsequent forced outages from Darlington, Bruce and Pickering units during November and December, and the delayed return-to-service of Bruce G3 (until January 2004), only a portion of the outages planned for this period could start. Generators could only postpone these outages so long, before the units were forced out. Thus in January and February there was a cascading effect, with more forced outages and the postponing of other planned outages.[5]

[4] Nuclear plants occasionally need outages to the vacuum building, or containment ducts leading to the vacuum building. These cause the outage of all 4 units at the plant.
[5] As of June 2003, a market participant can arrange replacement energy in the form of an import to support planned outages. Participants could have influenced the approval of planned outages during winter 2004 if this option had been elected.

Figure 1-2: Total Outages, Winter 2003 and 2004

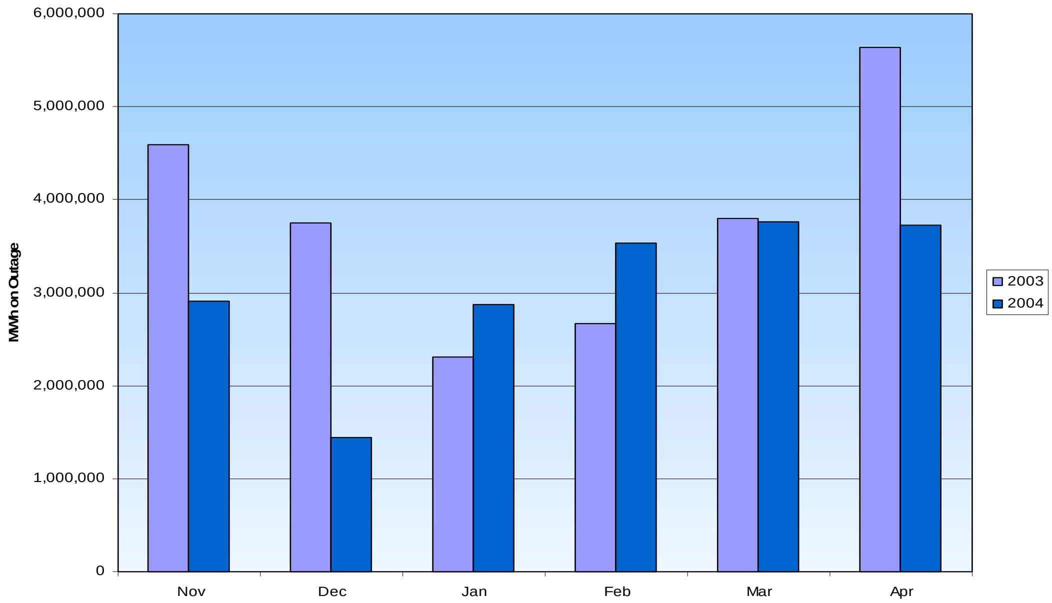


Figure 1-3: Planned Outages, Winter 2003 and 2004

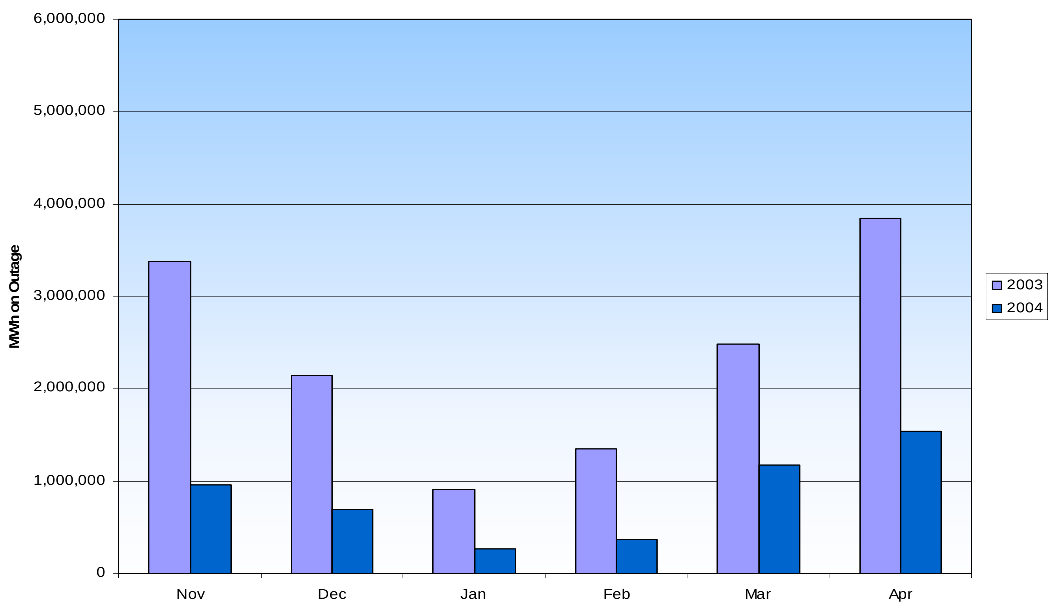
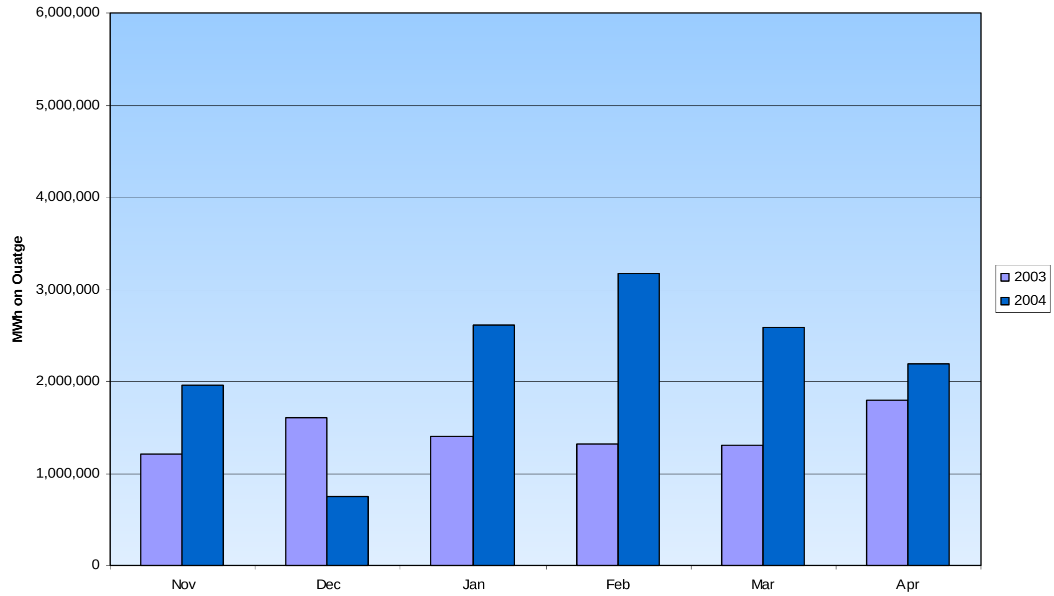


Figure 1-4: Forced Outages, Winter 2003 and 2004



4. *Supply Cushion Analysis*

For purposes of analyzing the degree of demand/supply imbalance in the Ontario electricity market, the Panel has developed a measure referred to as the 'supply cushion'.[6] It is a measure of the amount of unused energy that is available for dispatch in a particular hour, expressed as a percentage of total requirements and derived arithmetically as:

$$SC = \frac{EO - (ED + OR)}{ED + OR} x100$$

where,

EO = total amount of available energy offered

ED = total amount of energy demanded

[6] See MSP Report dated October 7, 2002, p. 53-55 for further discussion on supply cushion analysis at http://www.theimo.com/imoweb/marketSurveil/mspReports.

OR = operating reserve requirements.

A low value for the supply cushion corresponds to a relatively small amount of supply available to meet any additional demand and, as a result, the potential for even small increases in demand to increase market prices significantly. A variation of the supply cushion is the ‘domestic supply cushion’, which is calculated the same way but using only domestic offers. The domestic supply cushion could be negative, and a negative value indicates that the offer from domestic generators is insufficient to meet demand, and thus imports are necessary to balance demand and supply.

The domestic supply cushion was calculated monthly, for the winter 2004 period, for pre-dispatch and real-time. In previous reports, we have explained how conditions can change from pre-dispatch to real-time, including load levels, forced outages and production from self-dispatched generating facilities. A low or negative domestic supply cushion in pre-dispatch will likely result in more imports being attracted. A negative domestic supply cushion in real-time means that imports were necessary to meet the demand in that hour. Table 1-1 shows the number of hours in winter 2004 where the domestic supply cushion was negative in real-time and in pre-dispatch.

Table 1-1: Negative Domestic Supply Cushion Events, November 2003–April 2004

	Negative Domestic Supply Cushion (Number of Hours/% of Total Hours)			
	Real-time		Pre-dispatch	
November 2003	24	3%	17	2%
December 2003	35	5%	64	9%
January 2004	53	7%	66	9%
February 2004	27	4%	18	3%
March 2004	36	5%	34	5%
April 2004	1	0%	1	0%

The data show a moderate number[7] of hours with negative domestic supply cushion in all months, real-time and pre-dispatch, with the exception of April, where only one such event occurred. The largest occurrence of negative supply cushion was in January.

These results are entirely consistent with earlier observations of demand patterns, resource additions and total outages in these months. The pattern is also roughly consistent with the observed average HOEP for these months, except for February. February exhibited the second highest monthly HOEP in winter 2004, while the number of hours of negative supply tends to be on the low side.[8]

Comparing supply cushions between winter 2003 and 2004, demonstrates how year over year the supply/demand interaction and HOEP shifts are consistent with changes in the supply cushion. In Table 1-2 we report on the monthly average real-time domestic supply cushion, and the hours of negative events each month.

We have noted earlier that HOEP declined year over year for each month, except January, where average price increased. Average domestic supply cushion values exhibited the opposite trend. Except for January, average supply cushion improved by at least 0.7%; for January it dropped by 3%. The number of hours of negative supply cushion demonstrates the same pattern, dropping substantially in all months except January, where it increased significantly.

[7] Here the comparison is with summer 2002. See MSP report dated March 24, 2003, p.16, http://www.theimo.com/imoweb/marketSurveil/mspReports.asp.

[8] The relationship between the average domestic supply cushion and the HOEP in February is consistent with the patterns observed in other reports; the relatively high HOEP in February corresponds with the relatively low average domestic real-time supply cushion. It is surprising however that the number of hours with a negative supply cushion is low in February when compared to other months in the period; there is generally a positive correlation between the average monthly HOEP and the number of negative supply cushion events in a month.
A closer look at the data underlying the domestic real-time supply cushion indicates that the distribution of domestic supply cushions were highly concentrated about the mean value in February. A similar distribution for HOEP also existed in February with observations being highly concentrated about the mean value. This was in contrast with other months such as January where there were several days with tight domestic (negative) supply cushions and high HOEP and several other days with relatively flush supply cushions and lower HOEP with the overall mean values being higher in January than February.

Table 1-2: Real-Time Domestic Supply Cushion, Winter 2003 and 2004

	Average Supply Cushion		Negative Supply Cushion	
	% Requirement		# of Hours	
	Winter 2003	Winter 2004	Winter 2003	Winter 2004
November	8.5%	11.4%	104	24
December	11.5%	12.2%	86	35
January	14.1%	11.1%	3*	53
February	8.2%	10.7%	45*	27
March	7.2%	11.6%	145	36
April	7.7%	24.0%	130	1

*These figures differ from the December 2003 report, due to a recently identified data error.

5. *Imports and Exports*

Total imports decreased from 6.2 TWh in winter 2003 to 4.8 TWh in winter 2004 mainly as a result of lower energy demand and the increase in supply within Ontario. The resulting prices were not generally high enough to attract imports, with the exception of January 2004 where imports increased from 0.87 TWh to 1.06 TWh.

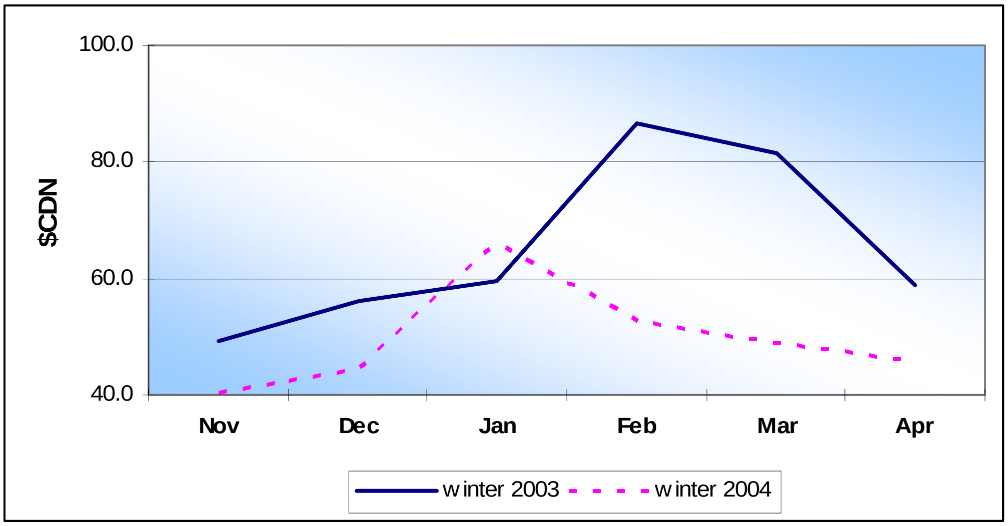
Imports and exports depend not only on supply conditions within Ontario but also on the relationship of the HOEP to prices in neighbouring markets. Section 7 below provides comparative information on Ontario wholesale prices and wholesale prices in other markets in both peak and off-peak periods. Relatively low off-peak prices in Ontario in winter of 2004 were a contributing factor to increasing exports in this period. Overall, exports increased from 2.8 TWh in winter 2003 to 3.9 TWh in winter 2004.

6. *Ontario Energy Price*

The average HOEP in $ per MWH decreased from $65.35 in winter 2003 to $49.77 in winter 2004. Prices were lower in all months except January 2004 as shown in

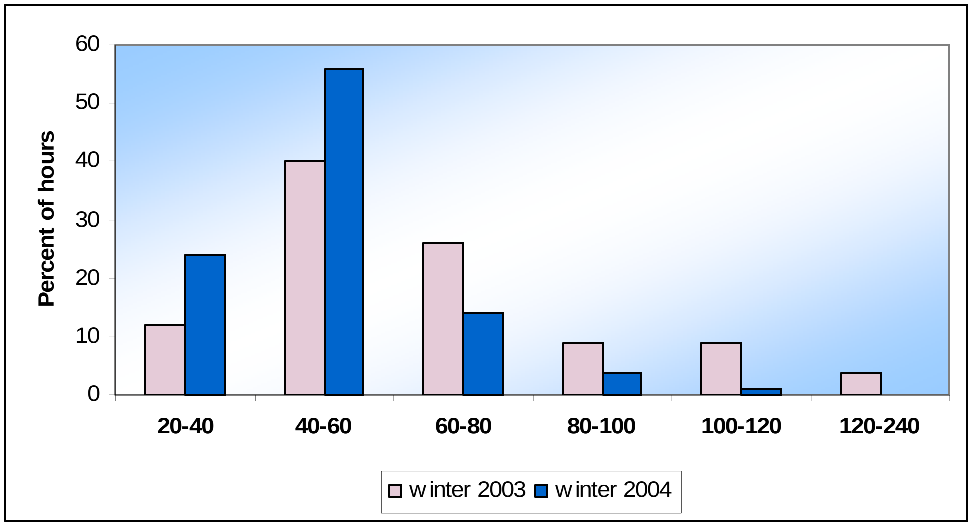
Figure 1-5. Average HOEP attained $66 in January 2004, up 11 percent from January 2003. In fact the average HOEP in January 2004 was the fourth highest since market opening (the highest average HOEP at $86 occurred in February 2003). The average monthly prices, including both on-peak and off-peak HOEP, are available in Table A-5 of the Statistical Appendix.

Figure 1-5: Monthly Average Hourly Ontario Energy Price



As discussed above, the lower level of demand and the overall increase in supply in winter 2004 were the driving forces behind the price decline. Further, there has been a leftward shift in the distribution of electricity prices in winter 2004 as shown in Figure 1-6.

Figure 1-6: Frequency Distribution of HOEP



The percentage of hours that the HOEP fell within the intervals $80-$100 and $100-$120 dropped by 5 and 8 percent respectively while prices in the intervals $20-$40 and $40-$60 increased 12 and 16 percent respectively.[9]

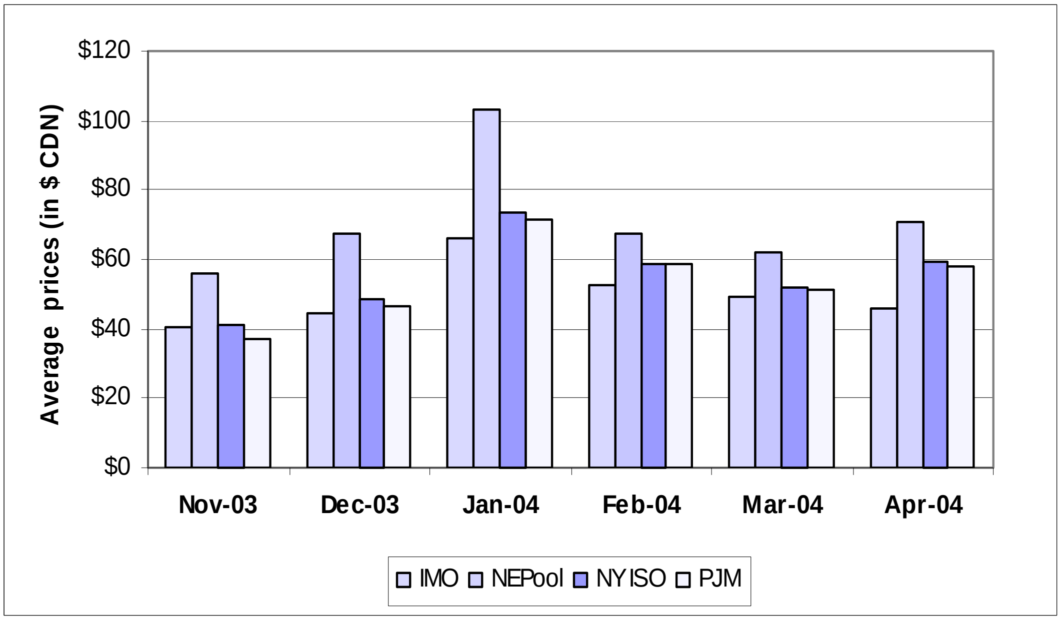
7. *Wholesale Electricity Prices in Neighbouring Markets*

Three other electricity spot markets operate in the northeast United States as 'neighbours' to Ontario. Comparing hourly spot market prices in each of these areas to the HOEP in Ontario provides a useful comparison of the respective costs of energy in these markets. Although these prices may differ because of market characteristics such as uplift, day-ahead markets, bilateral contracts, market rules and/or other specific features, the comparison is still relevant as it represents the spot market price of energy in a given hour.

Figure 1-7 shows that in general Ontario prices have been lower than New England prices and broadly similar to PJM and New York prices.

[9] Table A-7 in the Statistical Appendix provides greater detail on the frequency distribution of the HOEP since market opening.

Figure 1-7: Average HOEP Relative to Neighbouring Markets



Figures 1-8 and 1-9 show comparisons of on-peak and off-peak prices. Ontario prices were lower than neighbouring prices in all months except November 2003 where PJM prices were lower.[10] In January and February 2004 differences in average off-peak prices between Ontario and the neighbouring markets were quite large although this difference narrowed in other months.

[10] According to the PJM State of the Market Report 2003, (http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2003.pdf) PJM had large net excess capacity in November and December 2003.

Figure 1-8: Average HOEP Relative to Neighbouring Markets, On-peak

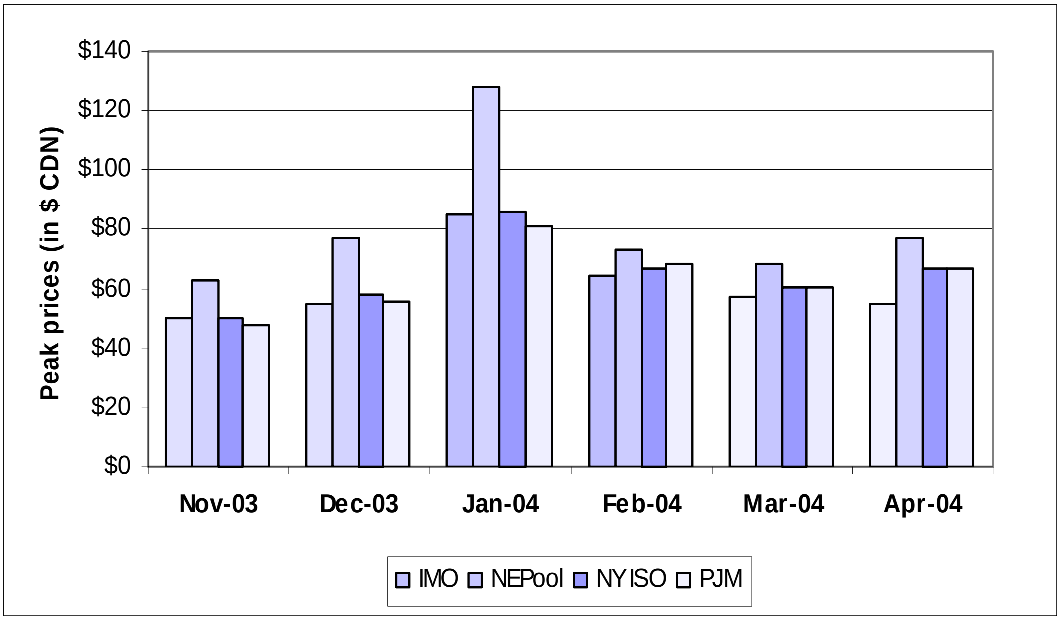
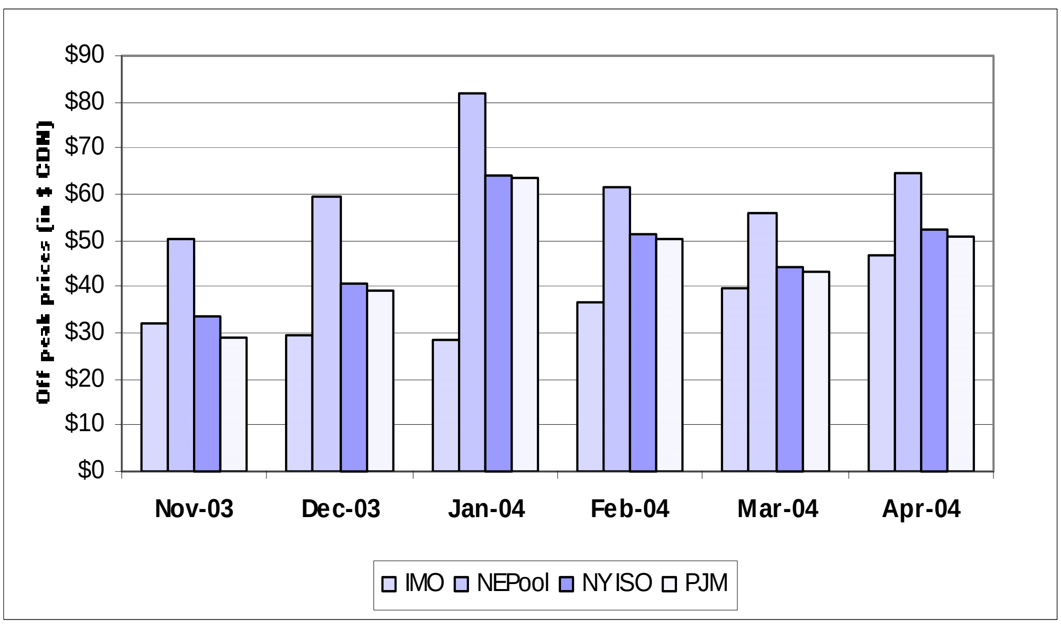


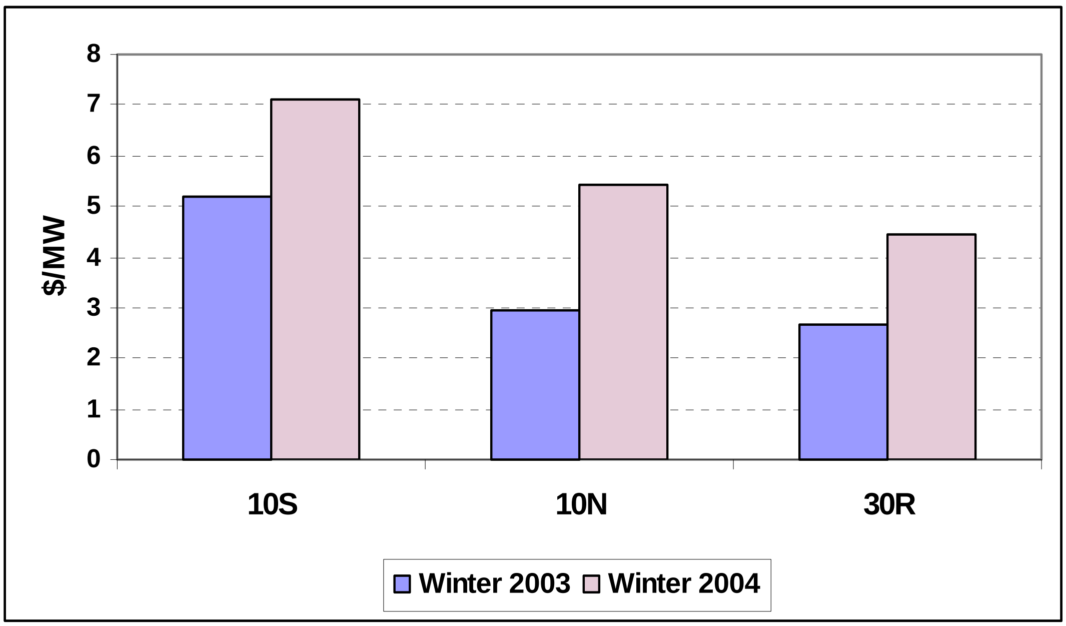
Figure 1-9: Average HOEP Relative to Neighbouring Markets, Off-peak



8. *Operating Reserve Prices*

Operating reserve (OR) prices were higher in winter 2004 for all reserve types. The price per MW for 10-minute spinning reserve (10S) increased from an average of $5.20 to $7.09 in winter 2004. Average 10-minute non-spin (10N) price rose to $5.43 from $2.95 while 30-minute OR (30R) climbed to $4.44 from $2.65 in winter 2003. Roughly speaking, the price for each product increased about $2 per MW relative to the previous winter.

Figure 1-10: Average OR Prices, Winter 2003 and 2004



The primary cause of the increased OR prices relates to the utilization of Control Action Operating Reserve (CAOR).[11] CAOR is the automatic use by the market of voltage reductions as operating reserve, whenever OR prices reach the $30 per MW level.[12]

In 2003, CAOR was not priced and therefore not available for selection by the dispatch scheduling optimization algorithm (DSO). At that time, when there was an observed OR shortfall the control room operator would manually reduce the OR requirement through

[11] See Chapter 3, section 2.1 for more detail.

the use of what we have referred to in previous reports as out-of-market control actions. These actions would eliminate the OR shortfall but had the perverse effect of lowering energy prices and OR precisely when Ontario was relatively short of supply. The IMO now prices a portion of these control actions (CAOR), consistent with previous Panel recommendations.

Statistics on the use of CAOR, presented in more detail in section 2.1 of Chapter 3, suggest that most of the increased frequency of OR prices at or above $30 is attributable to the frequency of CAOR use. On average, had out-of-market actions continued to be used in place of CAOR, OR prices in winter 2004 would have been much closer to those observed in winter 2003. Calculations by the MAU suggest that the effect of CAOR on the average price of OR was about $1.50 per MWh or roughly 3/4 of the change in the average OR price in winter of 2004.[13]

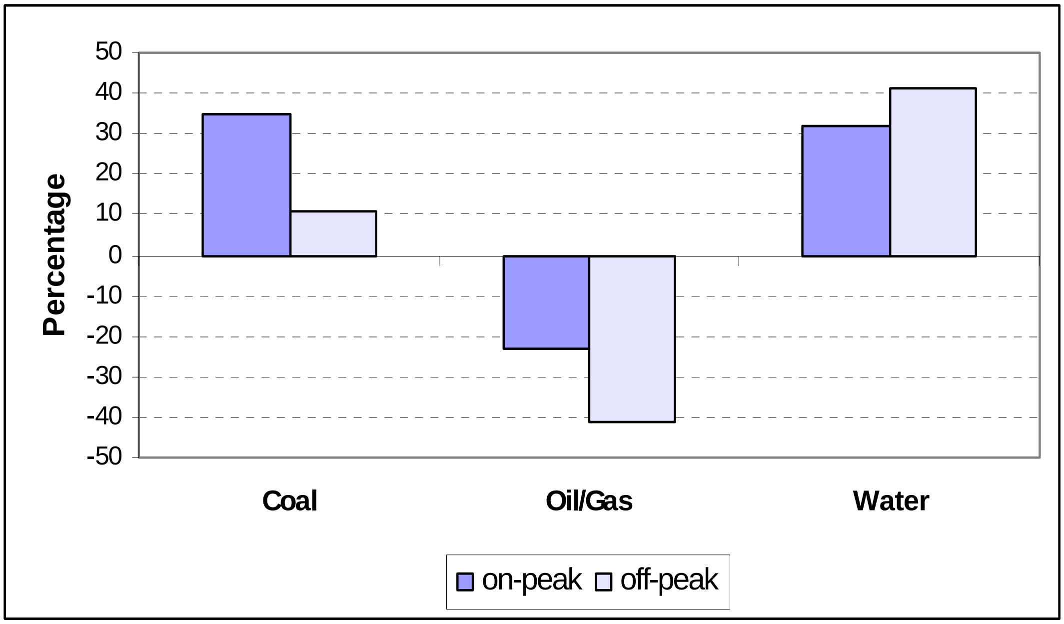
9. *Price Setters*

In the real-time market only generators and dispatchable loads set the market clearing price (MCP). In the hour ahead market, imports and exports can also set the MCP. Overall, during on-peak hours generators using oil/gas as primary fuel set the MCP most of the time in Ontario. See Tables A-16 to A-18 in the Statistical Appendix. Of note however, is the 23 percent decline during on-peak hours in the percentage of the time that price is set by these generators in winter 2004. This is because low demand levels (and therefore low prices) and increased infra-marginal supply, few of these expensive units are likely to be on-line. Coal-burning and hydroelectric generators replaced oil/gas generators as the price setters in the winter 2004 as illustrated in Figure 1-11. During off-peak hours, coal-fired generators are the dominant price setters. Overall, in winter 2004,

[12] Currently 200 MW of 30-minute OR is offered at $30/MW and another 200 MW of 10N is offered at $30.10/MW.
[13] Although CAOR had the effect of increasing OR prices on average relative to the previous year, it also contributed to reducing IOG and CMSC payments to imports. In winter 2003, out-of-market actions were used in real-time, thus when the pre-dispatch appeared short of domestic resources, imports would be scheduled in the unconstrained and constrained runs.

the share of the time that oil/gas generators set the price dropped by 25 percent. Hydro-generating units increased their share of time as a price setter by 35 percent while coal facilities increased their share by 14 percent. These shifts are consistent with the lower average electricity prices noted in winter 2004.

Figure 1-11: Change in Price Setting Percentage by Resource, Winter 2004 compared to Winter 2003



10. *Hourly Uplift and Components*

The hourly uplift consists of payments for Intertie Offer Guarantee (IOG), Congestion Management Settlements Credits (CMSC), Operating Reserve (OR) and line losses on the transmission system. Overall in winter 2004, total uplift charges dropped from $273 million to $205 million. The lower level of energy demand and increased supply account for the lower level of charges. Of the components, OR payments increased substantially in winter 2004, rising to $34 million, up from $22 million in winter 2003. This is consistent with the higher OR prices in winter 2004. CMSC payments on the other hand dropped significantly to $44 million, down from $84 million in winter 2003. This is due to the lower level of constrained on payments (mostly to imports) in winter 2004. The lower level of imports also resulted in lower IOG payments in winter 2004. Furthermore the lower level of energy prices in winter 2004 resulted in lower payments related to line losses. Table A-9 in the Statistical Appendix has more details on these payments since market opening.

10.1 Hourly Uplift – Year over Year Comparison

The declining trend in uplift observed in the winter period over period comparison has persisted over the entire period since market start-up. On an annual basis, total uplift dropped from almost $760 million in the first 12 months to just over $360 million in the next 12 months, a reduction of more than 50%.

Figure 1-12 shows monthly total uplifts in the first year of the market compared to the second. Except for the three months with lowest uplifts in the first year, uplift in the corresponding months of the second year are lower. The three months with the largest uplift in Year 1, the summer months with uplift totalling just over $400 million, exhibit the largest reductions in Year 2. By contrast in Year 2 these are the months with the lowest uplift, totalling $65 million, a drop of almost 85% compared with the corresponding months of the first year, or one-sixth of the earlier value.

Figure 1–12: Monthly Hourly Uplifts – Year over Year

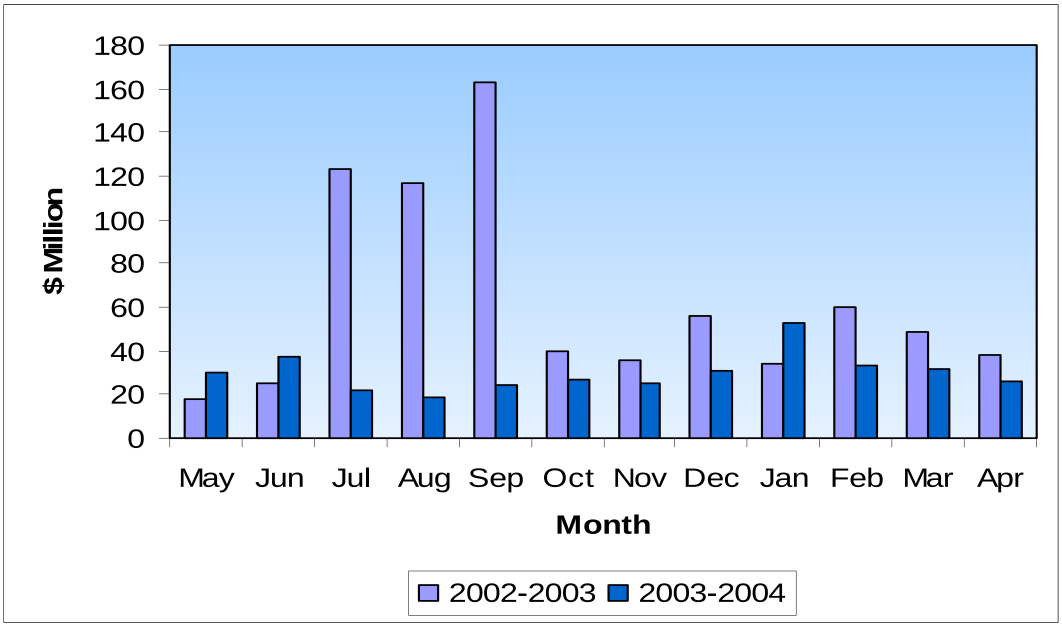
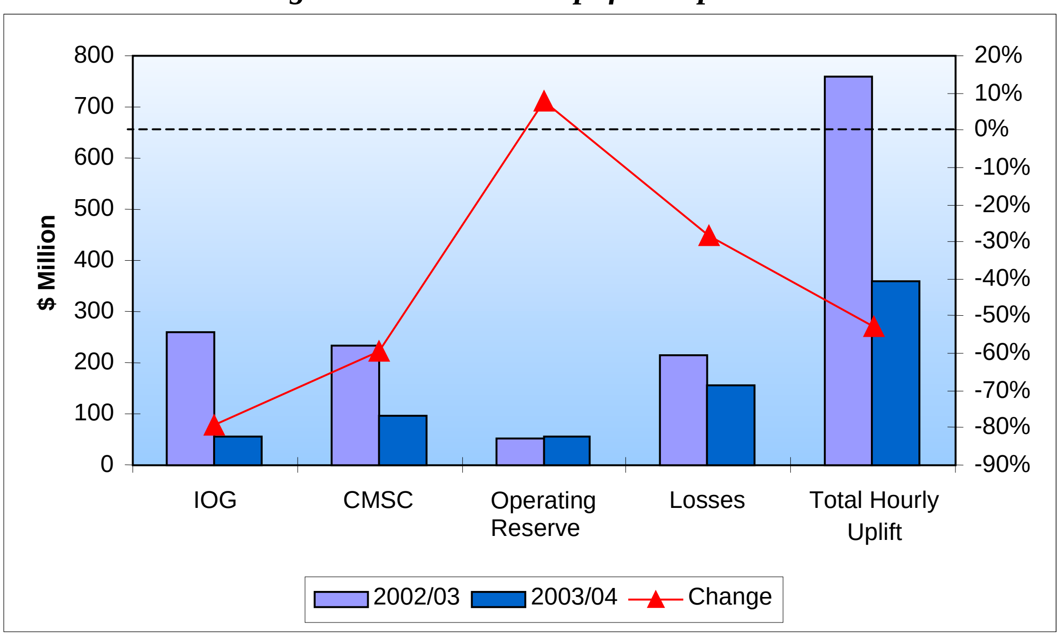


Figure 1-13 presents the annual amounts for the major components of uplift, with the year over year change. The largest reductions are in IOG (79%) and CMSC (59%), with a smaller drop in losses (27%), and an increase in OR payments.

Figure 1-13: Annual Uplift Components

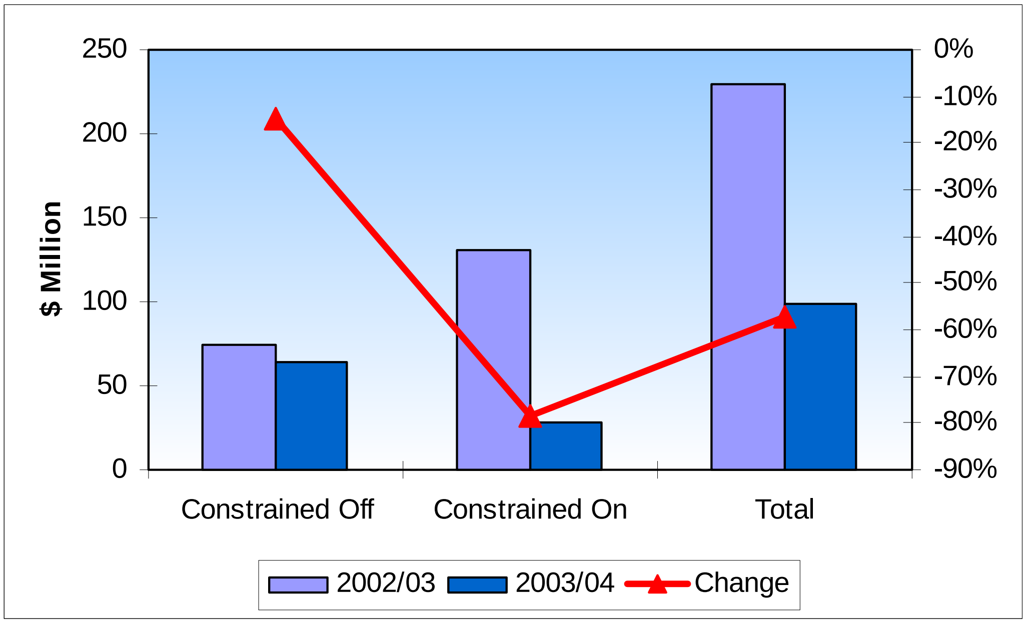


Increased OR payments are consistent with the observed increase in OR prices, while lower costs for losses are consistent with lower energy prices.

The large drop in IOG payments, from $259 million to $55 million, was driven by a combination of two factors. First, there were somewhat fewer imports in Year 2, about 5% less, thus less energy was eligible to receive IOG. Secondly, the average IOG payment, in $ per MWh, was much lower. These two factors were most obvious in July through September in Year 1, which exhibited very tight supply conditions with heavy imports and high payments per MWh. Imports in July through September of 2003 were more than 25% below the level in 2002. As noted in earlier reports, for 2002 the average payment for all IOG for the month was $238 per MWh of import which received IOG in July, and $138 per MWh in August, accounting for the very large payments in these months. In turn, these high per unit energy payments can be explained by the very large pre-dispatch to real-time price changes observed in these summer months. Average differences in these months were no lower than $40 in August but as much as $78 per MWh in July 2002. By comparison, in summer 2003 the differences were only $6 to $8 per MWh.

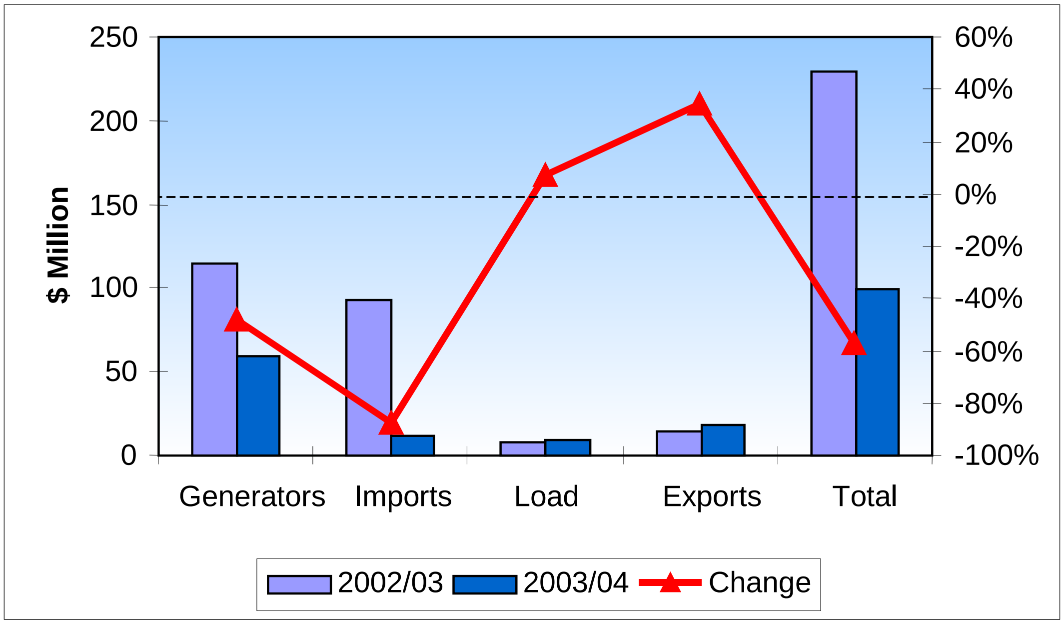
CMSC payments in Year 2 were less than half Year 1 payments, at $95 million compared with $233 million for the total of all CMSC paid. From Figure 1-14 it can be seen that this was primarily the result of lower constrained on payments, which dropped from about $130 million to $30 million.

Figure 1-14: Annual CMSC for Energy – Constrained On and Off



If we consider the data further, it can be seen in Figure 1-15, that the largest reduction in CMSC payment was to imports, whose total CMSC dropped from $93 million to $12 million. Again, this can be seen mostly in the three summer months where import CMSC dropped from $64 million in Year 1 to $2 million in Year 2. Once more, the improved resource situation in Year 2 contributed to lower imports, including constrained on imports, and lower per MWh payments to these resources.

Figure 1-15: Annual CMSC for Energy – by Participant Type



11. *One Hour Pre-dispatch Forecast and the HOEP*

The magnitude of the monthly average difference between the one-hour pre-dispatch price and the HOEP fell from an average of $16 in winter 2003 to $14 in winter 2004. The mean absolute percentage price difference[14] from HOEP dropped from 42 % in winter 2003 to 33 % in winter 2004. Furthermore, when we compare the period May 2002-April 2003 to May 2003-April 2004 (in Table A-24) we note that that the monthly average difference between the one-hour pre-dispatch and the HOEP decreased in 8 out of the last 12 months. The table also shows that since July 2003 both the maximum difference and the standard deviation of the pre-dispatch versus real-time price have reduced substantially in every month compared with the year earlier, with the exception of January. Further details are provided in Tables A-23 to A-29 in the Statistical Appendix.

[14] The mean absolute percentage price difference dropped from 48% to 36% in winter 2004. The root mean squared price difference declined to 25% in winter 2004, down from 55% in winter 2003.

There could be a number of reasons for improvements in the difference between the pre-dispatch price and the HOEP because of various changes over the last year. These include:

- an improvement in the load forecasting method of the IMO
- the consistent use of CAOR in pre-dispatch and real-time compared to its unavailability in winter 2003
- improvement in forecasting the production of self-scheduling generators compared to 2003 (See Table A-33), and
- the possibility that the 'spare generation on-line' program[15] could have smoothed the impact of demand volatility and forced outages on prices in winter 2004.

We will continue to monitor the difference between the pre-dispatch price and the HOEP for the expected improvement.

12. *Net Revenue Approximation*

Net revenue calculations are used in other ISO areas but this is the first time that we have presented a net revenue analysis for the Ontario market. We believe that the information – even though highly aggregated and subject to a number of caveats – can provide approximations of trends in returns to various types of generation over time and therefore contains useful information for market participants. We are interested in receiving feedback on the approach and usefulness of this type of information.

A net revenue analysis estimates the difference between the market revenues that a generator would expect to earn from the sale of energy, operating reserve and other ancillary services and the variable costs incurred from producing these products. This variable cost is referred to in the calculation as the 'base price'. The margin between a generator's unit market revenues and this base price (primarily fuel costs for fossil units)

[15] Recall that this program guarantees the payment of start-up costs and minimum generation costs for a minimum run-time (e.g. 4 or 5-hours) to generators that might not otherwise be on-line. A more detailed description is available in the third MSP report (December 17, 2003), pp. 96-97 at http://www.theimo.com/imoweb/marketSurveil/mspReports.asp

contributes to the recovery of its fixed costs, including non-variable operating and maintenance expenses, capital costs associated with investing in capacity, property taxes, and any costs associated with meeting regulatory requirements. In the long term, the revenues from the energy and ancillary service markets must cover all the fixed costs of a generator, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market and potentially encourage exit, eventually putting upward pressure on prices. Alternatively, revenue above this level should lead to new entrants and exert downward pressure on prices.

The analysis presented here provides estimates of the net energy revenues for generators at different levels of variable cost, based upon the actual pattern of Ontario energy prices over all hours of a year. For example, for a generator that produces electricity at a variable cost of $40, we add all of the hourly contributions to net revenue when HOEP exceeds $40. The sum represents the area on an annual price-duration curve, above $40. Similar calculations are made for other assumed variable cost levels. Note that the calculation assumes that the generator runs in every hour of the year in which it is profitable to do so.

The data can be used by market participants to assess how net revenues in the Ontario market are changing over time. They can also provide assistance in calculating the expected returns to new entry although more detailed calculations using specific generator characteristics would be required for a serious study of entry potential. In interpreting the data, several cautions are also relevant. In particular:

i) typical incremental costs for a (fossil) generator vary over the range of output, so a single variable cost is not accurate;
ii) fuel price for a generator (e.g. gas-fired) would change over a year;
iii) avoidable costs include such things as start-up and speed-no-load, which have a considerably different impact on the average running cost, depending on the number of hours and level of production;

iv) at times it may be more profitable for a generator to provide operating reserve rather than energy;

v) generators can earn additional revenue somewhat in excess of incremental costs if constrained on in the IMO dispatch (e.g. when shadow prices are higher than offer price, which may be higher than HOEP);

vi) a generator would occasionally experience forced outages or other limitations such as ramp rate and start-up times, leaving it unavailable to take advantage of all market opportunities.

The table below presents data for two years. The period May 2002 to April 2003 will be referred to as 2002 while the period May 2003 to April 2004 will be termed 2003. The values represent the revenue attracted by 1 MW.

Table 1-3: HOEP Revenues Above Base Price

Base Price	Energy Payments above Base Price ($CDN per MW)		
($ per MWh)	**2002**	**2003**	**Change**
$10	423, 649	335,533	-21%
$20	336,838	247,933	-26%
$30	258,497	172,336	-33%
$40	207,495	121,876	-41%
$50	165,821	85,800	-48%
$60	128,192	55,673	-57%
$70	98,267	32,099	-67%
$80	77,603	18,199	-77%
$90	63,509	11,311	-82%
$100	53,988	7,732	-86%
$110	46,881	5,759	-88%
$120	40,694	4,431	-89%
$130	35,239	3,622	-90%
$140	30,404	3,106	-90%
$150	26,532	2.748	-90%
$160	23,766	2,504	-89%
$170	21,656	2,331	-89%
$180	19,857	2,199	-89%

Base Price	Energy Payments above Base Price ($CDN per MW)		
($ per MWh)	2002	2003	Change
$190	18,370	2,083	-89%
$200	17,077	1,977	-88%

Consistent with the lower HOEP in winter 2004 compared with winter 2003, the above data show lower revenues in 2003 compared to 2002, at all levels of base prices. The data show, for example, that the net revenue for a generator with a base price of $70 was $32,099 per MW in 2003, less than one-third what it was in 2002. The data also show that for this same generator the net revenue fell by two-thirds between 2002 and 2003. The net revenue data is also shown graphically in Figure 1-16 below.

Figure 1-16: Revenues Above Base Price in Ontario

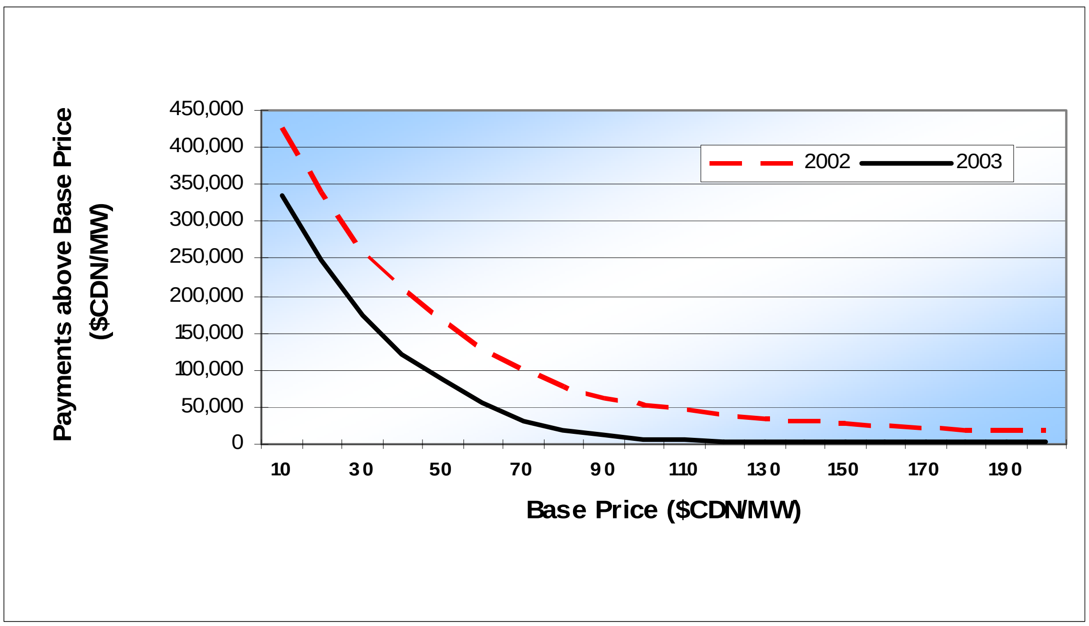
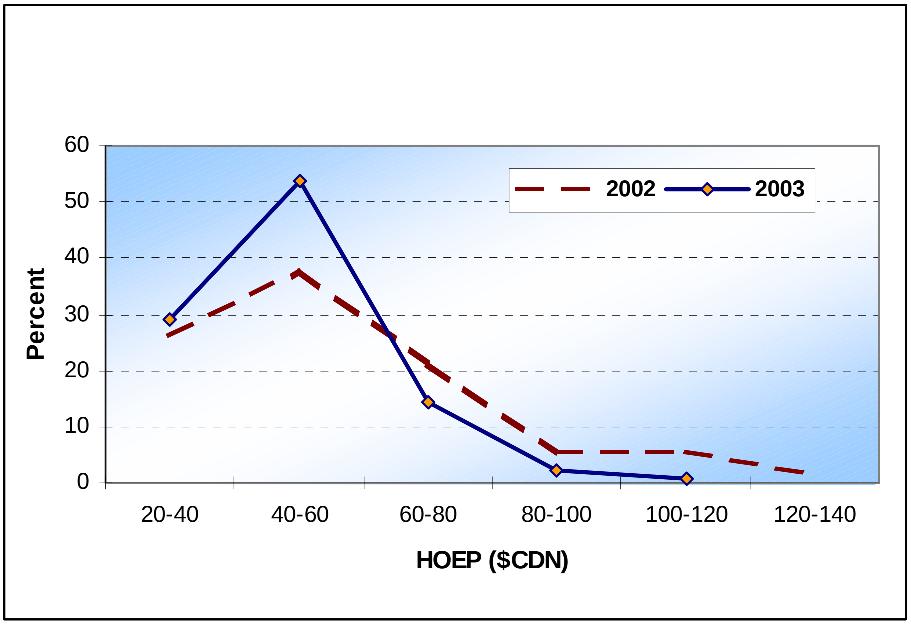


Figure 1-17: Distribution of Ontario HOEP



The decline in net revenues is largely attributed to the higher concentration of electricity prices in the $40-60 interval and the lower frequency of prices in the $60-80 interval in 2003 when compared to 2002. (See Figure 1-17 above). Further there were 4 days in 2002 when the average daily HOEP fell into the $180-200 interval compared to a maximum daily average price of $120 in 2003. In terms of hourly prices, there were 107 hours in 2002 when the HOEP exceeded or equaled $200 compared to 10 hours in 2003. In general electricity prices were higher and more volatile in 2002 than in 2003.

Overall, the data show that the net energy revenue returned to generators in the Ontario market in 2003 was substantially lower than it was in 2002, for all generation.
Again, the Panel would appreciate feedback, whether this type of analysis is of some benefit, and how it might be improved.

Chapter 2: Analysis of Anomalous Market Outcomes

1. *Introduction*

A key responsibility of the Market Assessment Unit (MAU), under the direction of the Panel, is to monitor the market for ‘anomalies’. Anomalies are actions by market participants and market outcomes that fall outside of predicted patterns or norms.

As has been the custom with our previous periodic reports, we asked the MAU to review, as a practice, all ‘high priced hours’ to identify the crucial factors leading to the high prices and report their findings to the Panel. For this purpose, ‘high priced hours’ are defined as all hours in which either the HOEP is greater than $200/MWh or hours where the uplift is greater than the HOEP. There were four hours in the period November 1, 2003 to April 30, 2004 in which the HOEP was greater than $200/MWh. These hours are discussed in section 2. The one hour during the review period in which the hourly uplift was greater than the HOEP is also discussed in the next section.

We also asked the MAU to monitor for any other events that appear to be anomalous, even though they may not meet these ‘bright-line’ price tests, and report their findings to the Panel. The MAU routinely monitors for anomalies in the market and provides the Panel with a monthly report of their monitoring activity. Section 3 provides a summary of some of the key anomalous events identified in the MAU’s monthly reports for the period November 2003 to April 2004.

Following the publication of the last MSP report, several commentators raised questions with respect to prices that appeared ‘unusually’ low. Could these ‘low priced hours’ be explained entirely by market forces or were they the result of anomalous actions by one or more market participants? As a general practice, the MAU monitors the market for anomalous participant actions, including those that would cause prices to be unusually low. As a result of the expressions of concern received following the last report however, we asked the MAU to begin to routinely review all ‘low priced hours’ and report their findings. For the purpose of this review, we defined a 'low priced hour' as any hour in which the HOEP was less than $20/MWh. A price of $20/MWh is typically below the marginal cost of any fossil-fuelled generation facility; in this respect it would be anomalous for fossil generation to be on-line providing energy in 'low priced hours'. There were seventeen hours in the period November 1 to April 30 in which the HOEP was less than $20/MWh. Section 4 of this chapter reviews the factors typically underlying the prices in these hours.

2. *Analysis of High Priced Hours*

As noted above, 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 market dynamics that led to the 'high prices' and determine whether any further analysis of either flaws in the design of the market or the conduct of market participants is warranted.[16]

Table 2-1 provides on a monthly basis, the number of high priced hours since market opening. There were only four hours in which the HOEP exceeded $200/MWh during the period November 2003 to April 2004. In contrast, the $200/MWh threshold was exceeded in 51 hours during the same period in the previous year (November 2002 to April 2003).

There was one hour during the review period in which the hourly uplift exceeded the HOEP. On February 29, 2004, delivery hour 24, the hourly uplift was $35.38 and the HOEP was $33.18. The reason for the hourly uplift exceeding the HOEP in this hour was entirely a result of IMO accounting practices; it was not a result of market factors.[17]

[16] The $200/MWh threshold is the upper 1% of all HOEP (i.e., 99% of the HOEP are less than $200/MWh).
[17] On occasion, the IMO is required to make adjustment to market participant CMSC and IOG payments. For example, the IMO recovers IOG payments on imports that were part of an implied wheel in a given delivery hour. These adjustments are made after the delivery hour has occurred; this recovery is not reflected in the hourly uplift of that hour. For accounting purposes, the amount of the adjustment is instead incorporated into the uplifts of the final hour of each month, using the same charge numbers as other CMSC and IOG in that hour. In many cases, the monthly uplift adjustment is negative, sometimes causing

The relative decline in the number of high priced hours from November 2002-April 2003 to November 2003-April 2004 is consistent with the general decline in HOEP that occurred across these two periods (see Chapter 1). Furthermore, most of the high priced hours in the previous period occurred in the months of February and March when seasonally high natural gas prices and fuel shortages at a large fossil generation facility caused electricity prices in Ontario to increase substantially.[18]

Table 2-1: High Priced Hours, Monthly, May 2002–April 2004

	HOEP>$200			Hourly Uplift Above HOEP		
	2002	**2003**	**2004**	**2002**	**2003**	**2004**
Jan		1	3		0	0
Feb		15	0		1	1
Mar		24	0		0	0
Apr		4	1		0	0
May	0	0		0	0	
Jun	1	4		0	0	
Jul	1	0		12	0	
Aug	18	0		8	0	
Sep	34	1		12	0	
Oct	0	1		1	0	
Nov	1	0		0	0	
Dec	6	0		4	0	

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

the uplift of the final hour of the month to be negative. Other times, the monthly uplift adjustment is positive and sometimes large relative to the actual uplift for the hour.
However, such monthly charges are debited to load (including exports) on the basis of total consumption in the month. Thus actual consumption in the last hour does not (significantly) increase or decrease the amount of the monthly uplift debited to an individual participant. The appearance on February 29, delivery hour 24 of the large uplift, $34.57 per MWh of load consumed in the hour, was in effect just $0.81 per MWh for charges from that hour and debited to load in that hour, with the rest being monthly charges debited to monthly consumption. The total of the monthly adjustment plus the actual hourly uplift appeared as $35.38, which exceeded the HOEP.

[18] These events were discussed at pp. 58-59 of our December 2003 report.

- Real-time demand is much higher than the pre-dispatch forecasts of demand
- One or more imports fail real-time delivery
- Real-time provision of energy by self-scheduling and intermittent generators is less than scheduled in pre-dispatch
- 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 tightens the real-time supply cushion relative to the pre-dispatch supply cushion.[19] Spikes of the HOEP above $200 are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10%. When the real-time supply cushion falls below the 10% level, generally all of the offers from Ontario's traditional price setting generating units have been accepted to provide energy to meet the Ontario demand. At this point the market must turn to the more expensive Ontario offers: the offers of combustion turbine units (CTUs), peaking hydroelectric units that did not expect to run, or dispatchable loads, all of which tend to be offered at prices above $200.[20]

For the period November 2003–April 2004, this scenario applied in only one of the four 'high priced hours'. On January 10, delivery hour 12, extreme cold weather created fuel handling problems at one of the province's large generation facilities, leading to a derating of 915 MW of supply (the fourth condition listed above). The sudden derate of the facility contributed to a tightening of the real-time supply cushion relative to pre-dispatch; the supply cushion was 23.3% in pre-dispatch but only 1.1% in real-time. This hour is discussed as Case 1 below.

The high HOEP of April 6, 2004 delivery hour 8, was the result of a new issue to the market, one that had not been observed by the MAU to this point. The issue related to the decision of a 'quick start' facility not to synchronise its generation unit in order to be available to provide 10-minute spinning reserve. The details of this event are described

[19] Section 4 of Chapter 1 reports supply cushion calculations for the period November 2003-April 2004.

in Case 2 below.

The MAU's review of the remaining two high priced hours for the period indicates that the high HOEP could be attributable to seasonally high levels of demand.

a. January 14, Delivery Hour 18

On January 14, 2004, delivery hour 18, Ontario primary demand reached an all-time winter peak of 24,572 MW.[21] The pre-dispatch supply cushion was only 9%, which is extremely low by pre-dispatch standards given that in pre-dispatch all import offers are available. The pre-dispatch price of $448 signalled the expected tight supply and demand conditions. In real-time, the average load was roughly 268 MW lighter than forecast in pre-dispatch. However, in three of the 12 intervals, the real-time demand achieved and slightly exceeded (by 9 MW) the pre-dispatch demand forecast. There were also 267 MW of failed imports in the hour, which further tightened the supply demand in several intervals. There were no unusual outages or offers.

As the hour began, demand was roughly 700 MW lighter than the peak of the hour demand that had been forecast. Even with the failed imports the supply demand balance was better than had been forecast in pre-dispatch and the real-time price in interval 1 was $80.38/MWh. The demand continued to increase over the hour leading to gradually increasing prices. By interval 6, demand was within 100 MW of the pre-dispatch forecast however, given the 267 MW of failed imports, the market faced a severe supply strain and cleared on the steep portion of the offer stack. The MCP spiked to $1,850. The IMO had already begun to identify the shortage of supply in the constrained sequence and had started to lower the reserve requirement to reflect available out-of-market control actions. The requirement was lowered by 459 MW in interval 6 and then lowered by an additional 200 MW in interval 8. Demand declined by roughly 200 MW for the next two intervals

[20] Higher priced imports are not included in this list. Imports are scheduled in the one-hour ahead pre-dispatch market (no new imports are available in real-time) and cannot set the price in the real-time market.
[21] This new peak was surpassed the following day, when Ontario primary demand reached 24,937 in delivery hour 19.

and prices reached the $130 and $140 level. By interval 10, demand had increased again to levels just above the pre-dispatch forecast. However, with the reserve requirement now lowered by 659 MW, prices spiked but only to the $400 and $450 level; the reduction in the reserve requirement prevented the price from spiking to $1,850 as it did in interval 6.

b. January 26, Delivery Hour 18

The high HOEP in delivery hour 18 on January 26 was also attributable to a seasonally high demand. The highest hourly market demand of the winter was reached in this hour, with market demand at 25,446 MW.[22] Once again, the pre-dispatch price of $212 signalled the relatively tight supply and demand conditions. The supply and demand conditions carried over into real-time and the real-time HOEP was $207.56. Once again, there were no unusual outages or offers in this hour.

<u>Case 1: January 10, 2004, Delivery Hour 12</u>

The derating of several units of a generation facility due to extremely cold weather was the key cause of the spike in the HOEP in this hour. Just after the final pre-dispatch was run, the total facility was derated by 915 MW. These units were infra-marginal in the supply stack and hence the loss of these units caused an upward pressure on prices. This hour also provides an illustration of how the dispatch scheduling optimization algorithm (DSO) establishes the market clearing prices when there are insufficient energy and operating reserve offers available to satisfy the energy demand and operating reserve requirements.

[22] Market demand and Ontario demand provide two different measures of electricity consumption. Market demand includes the demand from all Ontario consumers (residential, commercial, industrial and dispatchable load customers) plus external consumers in the form of exports from Ontario. Ontario demand, as its name suggests, does not include export customers.

Key Factors Affecting Market Outcomes

The key factor creating the relative supply shortage conditions in the hour was the derate of the generation plant. The derate was for 915 MW of the facility's capacity. The cause of the derate was fuel handling problems caused by the extremely cold weather. The problems were not identified in time to be captured in the final pre-dispatch schedule. As a result, the pre-dispatch was unable to schedule other resources in place of the generation facility, particularly imports. The supply available in real-time was therefore less than had been anticipated in pre-dispatch.

A reduction in supply in real-time, not anticipated in pre-dispatch, places upward pressure on the real-time market-clearing price. Furthermore, a loss of 915 MW of infra-marginal supply in real-time can create severe reliability concerns. However, there were several factors offsetting the 915 MW reduction in available supply in this hour. First, the real-time demand for electricity was less than what had been expected in pre-dispatch. The pre-dispatch forecast for the hourly peak demand was 21,229 MW. The real-time peak demand in the hour was only 20,983 MW in interval 3, which was 246 MW less than what was forecast. The real-time demand declined as the hour progressed with the real-time demand being 632 MW lower than the forecast peak demand by interval 12. The over-forecast of demand in pre-dispatch (relative to the real-time peak demand) would have resulted in several imports being scheduled for real-time that would not have been selected had the forecast been accurate. These additional imports offset some of the loss of the 915 MW at the generation facility.

Second, due to the unexpected loss of supply at the generation facility, the IMO reduced a portion of its 30-minute reserve requirement.[23] This is consistent with NPCC standards where after a contingency a control area can reduce its 30-minute reserve requirement if it expects to replace it within a four-hour period. On this day, a nuclear generator was returning from a prolonged outage and was expected to be generating at full capacity

[23] The reserve requirement varied across the hour from 1,200 MW in interval 1 to 1,120 MW in interval 12.

within the four-hour time period. It was also expected that in the coming delivery hour, additional imports would be scheduled in pre-dispatch that would offset the loss of production at the generation facility.

As the delivery hour began, the demand was running lighter than had been projected in pre-dispatch. The IMO had lowered its 30-minute reserve requirement by 280 MW to partially offset some of the lost supply from the generation facility. In interval 1, demand was 419 MW less than forecast in pre-dispatch. However, the combination of the lighter than expected demand and the reduction of the total reserve requirement (total of 699 MW) was not sufficient to mitigate the loss of the 915 MW of supply. As a result, the market cleared on the steep part of the supply curve and the price in interval 1 spiked to $600 (the price was established by a dispatchable load bid).

Note that when the market cleared in interval 1, there were still sufficient energy offers and operating reserve offers available to meet the energy demand and operating reserve requirements. This was not the case in the next four intervals. In each of the next four intervals, there were insufficient offers to meet the energy and reserve requirements (i.e., the market was in a shortage condition). Based on these offers the DSO was unable to find a solution.

Rules for Determining Prices at Times of Shortage

The possibility that there could be insufficient offers available to meet the energy and reserve requirements was anticipated prior to market opening. Initially, the solution to the problem was to use “penalty factors” and “shortage variables”. Such functions and variables would ensure that the software was able to determine an economic dispatch even under shortage conditions. The outcome of the “penalty factor” approach for solving for the shortage however was to cause the price for operating reserve and for energy to immediately rise to the Maximum Market Clearing Price (MMCP) in the event of any shortage in operating reserve.

Just prior to market opening, the IMO reconsidered the appropriateness of this approach to solving shortages and shortage pricing. It was viewed that having the market clearing price rise to the Maximum Market Clearing Price in the event of any shortage in operating reserve would be inappropriate given that under the existing reliability standards, a temporary deficiency in operating reserve is in fact tolerated for a period of time and given that there are usually out-of-market control actions available as operating reserve such that a shortage may not actually exist. A more practical basis for determining the market clearing price under such situations would be to set price at the (greatest) price of a bid or offer for operating reserve (or energy) actually scheduled in the market. As a result, the rules were changed. Section 8.2.2.2, Chapter 7 of the Market Rules now provides that in the event of a shortage in operating reserve (but not a shortage in energy), the price of operating reserve will correspond to the price of a bid or offer (for either energy or reserve) actually scheduled (accepted) in the market.

To implement this shortage-pricing regime, the DSO algorithm was modified in the following manner. First, if the DSO cannot find a solution due to insufficient energy and operating reserve offers, the DSO will identify the magnitude of the shortage in the operating reserve requirement and automatically adjust the reserve requirement by the amount of the shortage plus 2 MW.[24] The DSO is then re-run to find a dispatch solution based on the lower reserve requirement.

The expected outcome of this algorithm would be to have the energy price established at the offer price (cost) of the last available MW. The operating reserve price would then be set (automatically) at the larger of the highest accepted energy price or the highest accepted operating reserve offer.

The new shortage-pricing algorithm also has implications for dispatchable loads that bid at least a portion of their load as non-dispatchable. Dispatchable loads that do not want to be dispatched below a certain consumption level bid this consumption level into the market at $2,000. For example, a dispatchable load may make a bid with two

[24] The additional 2 MW was subtracted to ensure a solution could be found.

consumption points. The first bid is for 20 MW at a price of $600. That is, as long as the market price is less than $600, the load would consume 20 MW. The second part of the load's bid is for 10 MW at $2,000. That is, the load is signalling that regardless of the price, it does not want to be dispatched below 10 MW.

Under the new shortage-pricing algorithm, when the DSO initially solves short, it fixes the dispatchable load's consumption level so that it is not dispatched below its 'non-dispatchable' offer. In the example above, the load's schedule would be fixed at 10 MW. Then, when the DSO adjusts the reserve requirement for the shortage amount and performs its second run, it keeps the dispatchable load's consumption level fixed at 10 MW. Fixing the dispatchable load's schedule has implications for the market price that is ultimately produced in the second run of the DSO. Holding the dispatchable load's schedule fixed means that the load cannot be a marginal unit. That is, the DSO cannot get another MW from the load so it cannot set the market price. In particular, even though the dispatchable load has a bid at $600 this bid price cannot set the price. The market price must instead be set by another offer/bid in the market.

This was the situation in intervals 2 through 5 of delivery hour 12. In each of these intervals demand was higher than it was in interval 1. The higher demand meant that the DSO did not have sufficient offers available to meet the higher demand and the operating reserve requirement. As a result, the shortage-pricing algorithm was invoked. In interval 2, the DSO was short 27 MW of the 30-minute reserve requirement. The DSO automatically adjusted for the shortage (plus 2 MW) and re-solved. The second run produced an energy and operating reserve price (all three classes) of $323.63. This price was lower than the $600 price set in interval 1, even though demand in interval 2 was higher. The reason for the lower price was due to the fixing of the dispatchable load schedules. In interval 2, the shortage conditions meant that the schedule of the dispatchable load that set the price in interval 1 was fixed at the consumption level reflecting its non-dispatchable consumption point. As a result, this dispatchable load was no longer available as a marginal unit and hence could no longer set the clearing price with its $600 bid price. Instead, the price was set by a resource other than the dispatchable load; a resource whose offer represented the last available MW of energy, which was the lower price of $323.63.[25]

In intervals 3, 4 and 5, a similar outcome occurred. In these intervals, the DSO was short 88 MW, 179 MW, and 80 MW respectively. The DSO therefore ran a second time in each interval, automatically adjusting the reserve requirement by the amount of the shortage in order to find a solution. In each interval, the dispatchable load's schedule was fixed at its non-dispatchable consumption level and its $600 bid price was prevented from setting the price. The market price cleared at the lower price of $323.63 in each interval.

In the remaining 7 intervals of the hour, demand declined so that by the end of the hour, the real-time demand was roughly 700 MW lighter than had been forecast in pre-dispatch. At the same time, the IMO had lowered the total reserve requirement by an additional 100 MW, now fully reducing its 30-minute reserve. The combination of these two factors fully offset the loss of the 915 MW of supply and also meant that the market sequence was no longer short supply to meet both energy and reserve. The market clearing prices across the next 7 intervals fell from $165.07 to $148.89 by the end of the hour.

By the start of delivery hour 13, additional imports were added to the supply. At the same time, demand declined and the nuclear facility that was returning to service from a prolonged outage was continuing to increase its generation level. The supply shortage caused by the generation facilities had been corrected and the HOEP in the hour fell to $99.26.

Case 2: April 6, 2004, Delivery Hour 8

The MAU's monitoring of the market in April identified one hour in which the HOEP exceeded $200. The HOEP for delivery hour 8 on April 6 was $258.93. The peak

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[25] Note that the $323.63 price reflected the incremental cost of getting 1 more MW of energy which as a result of joint optimization, in this case incorporated not only the energy offer of a unit but the opportunity

5-minute MCP reached $2,000 in interval 9 of this hour. The price spike was aggravated by the decision of a market participant not to synchronise its 'quick start' facility in order to make it available to provide 10-minute spinning reserve. Following its identification and review of the event, the MAU contacted the participant to remind them of the need to synchronise their units when they are expected to provide spinning reserve. The MAU also forwarded its review to the IMO Compliance division for their independent review of the event. The following provides a brief summary of the relevant rules governing quick start facilities and a more detailed explanation of the event.

<u>Background: Definition of a Quick Start Facility and its Implication in Market Operation</u>

The Market Rules define a quick start facility as a "generation facility whose electrical energy output can be provided to the IMO-controlled grid within 5 minutes of the IMO's request and is provided by equipment not synchronised to the IMO-controlled grid when the request to start providing energy is made." Units that generally qualify as quick start facilities are hydroelectric facilities and CTU's. Nuclear units and fossil units are not quick start facilities.

Unlike all other facilities, quick start facilities need not be synchronised to the grid in order to receive a dispatch schedule (either constrained or unconstrained) for energy, 10-minute reserve or 30-minute reserve. A facility is synchronised when it closes its breaker and begins to inject or withdraw energy onto or out of the grid. Many hydroelectric generators (quick start facilities) can achieve synchronisation by condensing their units - they close their breakers to consume energy in order to keep their motors turning. Note that there is a cost to quick start facilities for operating in condensed mode. The units must consume energy from the grid (roughly 1 or 2 MW). The cost to the facility for doing this is generally equal to the MCP times the amount of energy consumed (e.g., MCPx2MWh or on an hourly basis HOEPx2MW).

cost of having to back down the unit from reserve.

Under the Market Rules, all generation units that offer 10-minute spinning reserve, including quick start facilities, must synchronise their units (close their breakers) in order to be scheduled for 10-minute spinning reserve. The reason for this relates to the IMO's interpretation of a NERC standard. The IMO interprets NERC standards as requiring a unit to be available for the entire 5-minute interval if it is scheduled for 10-minute spinning reserve. To ensure that a unit will be synchronised for the entire interval, the Market Rules require it to be synchronised prior to the start of the interval.

The need to be synchronised in order to receive a schedule poses a sort of "chicken and egg" problem for the operator of the quick start facility. That is, the operator of a quick start facility may wait to get a dispatch message before synchronising its unit - it waits to get the dispatch message in order to avoid the cost of condensing. However, if the unit does not synchronise, the market algorithm (DSO) will not schedule it in real-time for spinning reserve and hence the unit will not be sent a dispatch message. In this case, the operator will remain idle (not get scheduled for spinning reserve) even though the eventual market clearing price for the reserve was above the facility's offer price, and presumably above its cost for providing reserve. That is, the operator misses out on an opportunity to earn revenue in excess of its operating cost and hence make a contribution towards its overall profitability.

Events of April 6, 2004, Delivery Hour 8

The decision of a market participant to offer its quick start facility (referred hereto as "Unit A") for 10-minute spinning reserve but not to synchronise the facility, coupled with the sudden outage of a nuclear generation unit, contributed to a price spike to $2,000 in interval 9 and an eventual HOEP of $258.93 in delivery hour 8.

Unit A was offered for energy and 10-minute spinning reserve in the hour. The unit's energy offer was for 77.5 MW at a price of $2,000. The unit's spinning reserve offer was for 77.5 MW at a price of $0.19.

One hour prior to the delivery hour, the pre-dispatch projected an energy market clearing price of $67 and a 10-minute spinning reserve price of $30. Based on these prices, and the offers of Unit A, Unit A was projected to be scheduled for 77.5 MW of spinning reserve.

Table 2-2 provides a summary of the key data outlining how the actual real-time delivery hour evolved. At the commencement of the delivery hour, demand was lighter than had been forecast in pre-dispatch. As a result, the energy clearing price was lower than had been projected at $60.16 and the 10-minute spinning reserve price was $27.13, roughly $3 lower than had been projected. This data is reported in columns 2 and 3, row 1 of Table 2-2 below. Note that with the spinning reserve price clearing at $27.13, based on its offer price, Unit A should be scheduled for 77.5 MW of spinning reserve. However, Unit A had not synchronised. As a result, the DSO did not see the unit as being available for spinning reserve and hence did not schedule it (see column 4).

Table 2-2: Key Data for April 6, 2004, Delivery Hour 8

Interval (1)	Energy MCP ($/MWh) (2)	10S MCP ($/MWh) (3)	Unit A's 10S Schedule (MWh) (4)	Unit A's Energy Schedule (MWh) (5)	Supply of Nuclear Unit (MWh) (6)	Ontario Demand (MWh) (7)
1	60.16	27.13	0	0	795	18,683
2	63.22	30.00	0	0	795	18,685
3	63.60	30.00	0	0	795	18,763
4	63.32	30.00	0	0	795	18,708
5	64.51	30.00	0	0	795	18,815
6	71.02	30.10	0	0	795	18,893
7	35.32	3.93	0	0	795	18,237
8	83.19	33.55	0	0	0	18,419
9	2,000.00	1,955.22	0	15.4	0	18,453
10	453.50	408.72	0	0	0	18,393
11	89.54	30.10	74.9	0.1	0	18,567
12	59.80	3.93	74.9	0.1	0	18,489

The delivery hour progressed in roughly the same manner over the next six intervals. However, just prior to the completion of interval 7, a large nuclear unit was forced out of service. The unit started to run back its production, but since its breaker was still closed it appeared that the unit was available for dispatch. At the same time, the IMO activated 650 MW of 10-minute operating reserve and requested an additional 400 MW of shared reserve activation from neighbouring markets. The supply demand balance appeared to be relatively flush and the energy price fell to $35.32.[26]

By interval 8, the nuclear unit was identified as being unavailable and was not scheduled, thereby tightening the relative supply and demand balance. The reserve energy was still activated and somewhat offsetting the loss of the nuclear output. The price increased to $83.19. Note that since Unit A had still not synchronised it was not being scheduled for reserve or activated for energy.

In interval 9, the 10-minute reserve was de-activated; the DSO now needed to satisfy both the energy demand and the full operating reserve requirement of 1,480 MW. The loss of the nuclear generation now showed up as a severe tightening of the supply relative to the energy and reserve requirements in the market. Due to the severe tightness of supply, the DSO scheduled essentially all the reserve that was available and had to turn to the highest energy offered in the market to meet its energy demand requirement. This included the energy offered by Unit A at a price of $2,000; recall that a quick start facility does not need to synchronise in order to be scheduled for energy. The unit was sent a schedule for 15.4 MW of energy (see column 5 in Table 2-2); it was the marginal unit and it set the energy price at $2,000.

As soon as the operator of Unit A received its energy dispatch instruction, it synchronised its unit to provide the energy; once synchronised it was then available to provide 10-minute spinning reserve. With an offer price of $0.19 for spinning reserve, once the DSO

[26] Note also the large decline in the market demand (656 MW). This would contribute to a decline in the energy price. The appearance of a large decline in demand in the interval is deceiving, as it is likely the result of the lost telemetry caused by the sudden run back of the nuclear unit.

identified Unit A as being synchronised, it quickly converted it from energy to 10-minute spinning reserve. Unit A remained synchronised for the remainder of the day.

In short, it was the shortage of energy in delivery interval 9 caused by the loss of a nuclear unit that finally induced the operator of Unit A to synchronise.

Impact on Market Clearing Prices

The MAU simulated the impact that the Unit A operator's actions had on the market clearing prices in this hour. These price impacts are presented in Table 2-3. The simulation assumed that the unit had synchronised for the start of hour 8. Under the simulated outcome, had Unit A been synchronised at this time, it would have been scheduled for 75 MW of 10-minute spinning reserve in all intervals of delivery hour 8.

Table 2-3: Actual Market Clearing Prices vs Simulated Market Clearing Prices for Delivery Hour 8, April 6, 2004

	Energy Price ($/MW)			10-Minute Spin Price ($/MW)		
Interval	**Actual**	**Simulated**	**Difference**	**Actual**	**Simulated**	**Difference**
1	60.16	59.80	0.36	27.13	26.39	0.74
2	63.22	59.80	3.42	30.00	26.48	3.52
3	63.60	63.60	0.00	30.00	30.00	0.00
4	63.32	63.02	0.30	30.00	29.70	0.30
5	64.51	64.51	0.00	30.00	30.00	0.00
6	71.02	71.02	0.00	30.10	30.00	0.10
7	35.32	35.32	0.00	3.93	2.73	1.20
8	83.19	83.19	0.00	33.55	30.00	3.55
9	2,000.00	400.00	1,600.00	1,955.22	352.43	1,602.79
10	453.50	74.88	378.62	408.72	30.00	378.72
11	89.54	89.54	0.00	30.10	30.10	0.00
12	59.80	59.80	0.00	3.93	3.93	0.00
Average	258.93	93.71	165.23	217.72	51.81	165.91

As Table 2-3 indicates, the impact on the energy market clearing price and 10-minute spin price was considerable in several intervals in hour 8. In particular had Unit A been synchronised, the energy HOEP for hour 8 would have been $93.71 instead of $258.93.

IMO Response to the Event

Following the identification of this event, the MAU contacted the operator of Unit A to inquire why they did not synchronise their unit. The MAU also informed them of the impact that their actions had on the energy clearing price. The operator indicated that it was an oversight on their part not to synchronise and that they would ensure that such an event would not happen again. Since April 6, the participant has synchronised its unit whenever it was selected in pre-dispatch. The IMO is also planning a public education for market participants to remind them of the need to synchronise their quick start facilities when they expect to receive a spinning reserve dispatch schedule.

3. *Summary of MAU Monthly Reports on Anomalous Events*

Each month, the MAU provides the Panel with a report that describes its analysis of any other events that in its view appear to be anomalous, even though the event may not meet the Panel's 'bright-line' price tests. The following is a summary of three such anomalies that were reported to the Panel in the MAU's monthly reports.

3.1 Events of January 15, 2004

Thursday, January 15, 2004 was an anomalous day for several reasons. First, it was one of the coldest days of the winter, both in Ontario and the rest of the eastern region of North America. As a result of the extreme cold weather, Ontario demand reached an all-time winter peak of 24,937 MW in delivery hour 19. Furthermore, a new all-time daily energy demand was reached at 528,061 MWh. This surpassed the previous all-time peak daily energy demand of 525,253 MWh set on August 13, 2002 and the previous winter peak of 517,809 MWh. Although this day was extreme in terms of demand, there were no hours on this day in which the HOEP exceeded the Panel's $200 high priced hour threshold. Additionally, there were two days during the period for which the daily average price was higher than January 15. The daily average price on January 15 was $99.73 while the daily average price was $109.65 on January 26 and $101.52 on January 27.

Second, supply was particularly uncertain because a generating station experienced substantial (thousands of MW's) unavailability due to fuel handling problems brought on by the cold weather. The operator could not predict in advance with any degree of certainty as to the size and timing of the unavailability.

Third, the IMO employed several out-of-market control actions on this day in order to manage the severe conditions on the grid. These out-of-market actions all had impacts on the market outcomes. While the objective behind the use of out-of-market control actions is to ensure system reliability, these actions can affect market signals and market efficiency. We have commented on these unintended consequences in previous reports and have recommended that the IMO price out-of-market actions in order to improve market signalling and efficiency. In fact, the IMO in consultation with market participants has made some progress in this direction as reported in Chapter 3. From a market design standpoint, it is important to ensure that out-of-market control actions are implemented in a manner necessary to achieve the objective of reliability but also in a manner that minimizes the potential distortion of market signals and market efficiency. The events of January 15, 2004 are worth reviewing in some detail because they provide a good example of the way in which out-of-market actions can distort price signals.

Fourth, there were 36 intervals on this day that required administered pricing. The reason for the administered pricing was due to an input coding error. At times, the differences between the initial prices produced in the market and the eventual prices administered by the IMO were considerable; in all cases the administered prices were lower, with the average price difference between the initial prices and the administered prices being $967.56. Several market participants raised questions regarding the appropriateness of the administered prices on this day given the relative scarcity of supply under such extreme demand conditions.

For these reasons, the MAU reviewed the day's events to better understand the forces behind the eventual market outcomes. The following is a summary of the MAU's findings for the key delivery hours 17 to 22. The summary begins with a brief description of the supply and demand conditions affecting the day's events. It then provides a review of the different out-of-market control actions generally available to the IMO to manage system reliability. Following this, a description of the key factors affecting the market outcomes in each of delivery hour 17 through 22 is provided. Particular attention is given to the discussion of the events that triggered the IMO's use of different control actions and the impacts that these various control actions had on market outcomes. There is also a discussion of the reasons for the administrative pricing in hours 19 through 22. The discussion of January 15 concludes with the Panel's overall assessment of the day's events.

Summary of Key Factors Affecting Market Outcomes on January 15, 2004

Demand Factors: As mentioned above, Ontario demand reached an all-time winter peak on this day of 24,937 MW in hour 19 as well as a new all-time peak daily energy demand of 528,061 MWh. Other neighbouring markets also set all-time winter peaks on this day; New York reached 25,262 MW in hour 19, beating the old record by 600 MW, while New England topped 22,450 MW in hour 18, beating their old record of 21,597 MW. Quebec had also issued public appeals to reduce consumption.

Supply Factors: All available Ontario generation was on-line during the peak hours of the day to supply the high demand levels. About 25,000 MW of Ontario generation was offered during the peak hours (17 to 22). There were no unusual offers identified (offer prices were consistent with the offer prices of the previous 30 days). There were roughly 3,850 MW of supply in planned and forced outage: 3 nuclear units at 2,100 MW, and 4 coal-fired generation facilities at 1,750 MW. At approximately 1:00 p.m. (delivery hour 13), a large generation facility began experiencing difficulties with its fuel handling systems because of the extremely cold weather. The fuel problems aggravated over the next few hours causing a loss of total available supply of roughly 2,300 MW per hour across each of the peak hours. There were further fuel handling problems at another facility but to a lesser degree with reductions in available supply of about 250 MW. The fuel problems at these facilities meant that the available supply from Ontario generation was reduced to 22,500 MW during the key hours of the day (hours 17 to 22). As a result of the high levels of demand and the fuel problems at the two generation facilities, Ontario relied on imports to meet demand during the peak hours. As much as 4,500 MW of imports were offered in each of the peak hours (17 to 22).

Market Procedure and Design Factors: Due to the problems at the above mentioned generation facility's fuel handling systems, both the operator of the facility and the IMO were uncertain of the amount of output that would be available from the facility at any point in time. As a result, they managed the derate of the facility on an ongoing basis. The uncertainty of the facility's availability affected the scheduling of imports in pre-dispatch. In particular, in some hours (17, 21, and 22), the derates on the units caused the pre-dispatch to overstate the actual output available for real-time (the maximum hourly differences were 927 MW in hour 17, 553 MW in hour 21 and 302 MW in hour 22). In this case, the pre-dispatch scheduled fewer imports than would have been required for economically efficient dispatch had the outage of the units been correctly identified. On tight supply days, this can have reliability consequences – the failure to schedule sufficient imports in pre-dispatch can lead to resource shortfalls in real-time. When resource shortfalls occur, the use of out-of-market control actions are often necessary (see below). Under-predicting the lost energy from a derate in pre-dispatch, all else held constant, causes real-time prices to rise above pre-dispatch prices.

Another factor that caused reliability issues on this day was the amount of failed imports. Failed imports have the same impact on the market as does the failure to correctly account for a derate of units in pre-dispatch – the potential for resource shortfalls in real-time and higher real-time prices than the projected pre-dispatch prices. There was a significant amount of failed imports on January 15 in hours 18 (933 MW), 19 (1,112 MW), 20 (1,712 MW), 21 (1,284 MW) and 22 (965 MW). The amount of import failures was unusually high on this day, presumably in large part due to the unusually cold weather that was affecting all markets in the region. Several generators in the New York and New England markets were reported as being unable to access natural gas supply causing relative shortages of generation in these markets. As well, there were several transmission limitations and other security limitations in these regions that prevented inflows to Ontario.

Review of Out-of-Market Control Actions Employed and their Market Impact

During hours 17 through 22, the IMO employed several out-of-market control actions to manage system reliability. In general, there are four types of out-of-market control actions that the IMO can take and all four of these were utilized in this period. The four types of action are:

a) carrying non-market sources of operating reserve,
b) cancelling exports that were initially scheduled in pre-dispatch,
c) purchasing additional imports from available offers after the final pre-dispatch, and
d) purchasing emergency energy from neighbouring markets.

The following provides a review of these actions and a general explanation of the impact that they can have on market outcomes.

a) Carrying non-market sources as operating reserve

Under the Market Rules, if the IMO identifies a shortage or potential shortage of reserve in the real-time constrained sequence (i.e., it is unable to meet both the energy demand and its reserve requirement with offers from market participants), it can use out-of market sources of reserve to meet NERC and NPCC standards. At the same time, when it uses these out-of-market sources, it can then lower the reserve requirement input into the market algorithms, (i.e., the amount of reserve to be purchased from market sources). These out-of market sources of reserve include:

- the potential to reduce voltage (3% and 5% voltage reduction);
- reducing the 30-minute reserve requirement following a contingency, such as generator outages, failed imports or heavier than expected demand, if the IMO believes it can replenish this reserve within 4 hours;
- making an export recallable and holding the potential to cancel the export.

Manually reducing the reserve requirement and carrying non-market sources of reserve to meet NERC and NPCC requirements has two potential impacts on market outcomes. First, when the IMO identifies a (potential) shortage of market resources in the constrained sequence to meet the NERC and NPCC requirements, it relies on out-of-market reserves and reduces the requirement used in the DSO accordingly. This reduction affects both the constrained and unconstrained (price setting) sequences and generally leads to a lowering of price (all else held constant).[27] Second, given that the control action is never a precise measure of the actual shortages in the market, when the actions are used, there are often resources in the province that are offered into the market but are not utilized (i.e., not scheduled for reserves or for energy). These unused resources may have a lower social cost (reserve offer) than the potential social cost of using one of the above control actions. If this were the case, it would represent a loss of efficiency to society. While we are aware that there is some debate as to a variety of methodologies to determine real resource cost (and thus the social cost) of out-of-market control actions, we do not believe that this cost is zero. And by assuming it is, the efficiency of dispatch is reduced and price signals become distorted.

In several previous reports, we have argued that out-of-market control actions should not be regarded as 'free'. They have resource implications and, ideally, should be priced and

[27] It is generally true that the amount of the manual reduction of the reserve requirement used in the DSO is different and often larger than the IMO's foreseen shortage in the constrained sequence. Furthermore, the shortage foreseen in the constrained sequence is almost always different (typically larger) than any potential shortage that may or may not exist in the unconstrained sequence. Reducing the reserve requirement in the unconstrained sequence (whether there is a shortage or not) will always cause a lowering of the energy and reserve prices, all else held constant.

'purchased' at the social opportunity cost. The IMO, in consultation with market participants, has responded to these arguments by pricing a tranche of out-of-market operating reserves and this is a welcome step toward greater efficiency.

b) Cancelling exports that were initially scheduled in the final pre-dispatch

Following the final pre-dispatch run, if the IMO determines that there was a material change to the availability of resources or an increase in demand such that, in its opinion, the real-time schedules will not have sufficient resources available to maintain the reliable operation of the Ontario grid, it can recall (cancel) exports that had been scheduled in the final dispatch. When this occurs, the IMO essentially removes the export from both the real-time constrained and unconstrained sequences. The export receives/makes no payment.

The removal of the export from the unconstrained schedule, all else held constant, has the effect of lowering the HOEP. Note however that if the amount of cancelled exports is equal to the amount of the sudden loss of supply (i.e., failed imports), the impact on HOEP should be neutral. Traditionally, the IMO only cancels exports if it is felt that there is no available commercial option within the market to solve the shortage.

c) Purchasing additional imports from available offers after the final pre-dispatch

Following the final pre-dispatch run, if the IMO determines that there was a material change to the availability of resources or an increase in demand such that, in its opinion, the real-time schedules will not have sufficient resources available to maintain the reliable operation of the Ontario grid, it can purchase any import that was offered into the Ontario market but was not initially selected in the final pre-dispatch. This is subject to the import being available. The import is added to both the real-time constrained and unconstrained sequence. The import is eligible for an IOG payment.

The addition of the import to the market schedule (all else held constant) has the effect of lowering the HOEP.[28] Note however that if the amount of additional imports purchased is equal to the amount of the sudden loss of supply (i.e., failed imports), the impact on HOEP should be neutral. The IOG payments in this case however will likely increase since it would be the higher price imports that were rescheduled.

d) Purchasing emergency energy from a neighbouring market

As a last resort, when the control room is concerned that there are insufficient resources available to maintain reliability, it can purchase emergency energy from a neighbouring market. The energy is generally purchased on an hourly basis. The price of the emergency energy is generally 1.5 times the clearing price in the market from which the emergency energy is purchased.

When emergency energy is purchased, it impacts the market outcomes through market demand. The amount of the emergency energy purchased is subtracted from the market demand. The impact on the market outcomes is sudden and can be significant. The effect, all else held constant, is to lower the market clearing price.[29] It should be noted that the IMO buys emergency energy to ensure that it can meet its obligations for energy and operating reserve in the constrained schedule. However, the emergency purchase is linked to both the unconstrained and constrained schedules. With an unconstrained schedule that is 'better off' than a constrained schedule (i.e., has more available resources to meet the requirements) this emergency purchase can lead to a sharp reduction in the

[28] This is because the import is placed at the bottom of the offer curve, at a zero price, since imports cannot set the market clearing price in real time. The import is compensated through an IOG payment.
[29] The following example illustrates how emergency energy can impact the market. The market demand in one interval may be 24,000 MW and the market price may be $300.00. In the next interval, the actual market demand may increase by 100 MW to 24,100 MW. Without emergency energy, the market would not have sufficient resources to meet both the market demand and to satisfy the operating reserve requirements. The market price would increase to as much as $2,000. Suppose instead however, that the 500 MW of emergency energy was purchased in the interval. The amount of the emergency energy purchase would be subtracted from the market demand. The market would run assuming a market demand of 23,600 MW (24,100 minus 500). The market price would now clear below the $300 of the previous interval.

price. This price can be below the incremental cost of either the generation needed to supply the actual load or the actual price of the emergency energy purchased.

Specific Factors Affecting Market Outcomes in Delivery Hours 17 through 22

Table 2-15 in Appendix B provides a summary of key variables for each of hours 17 through 22 on January 15. Table 2-15 is organized into three parts, (i) Material Change in Supply, (ii) Out-of-Market Control Actions, and (iii) Prices. The quantity amounts reported in this table represent the amounts reflected in the unconstrained sequence. The unconstrained sequence is reported to emphasis the impact on the market clearing prices of the various control actions.

First, columns 2 through 5 present hourly data for the two factors that the IMO viewed as causing a material change in supply on this day; the derate of the generation facility and the failed imports. Columns 2 and 3 present the difference between the pre-dispatch schedule of the generation facility and the actual (real-time) schedule of the facility (column 2 is the three-hour ahead pre-dispatch while column 3 is the one-hour ahead pre-dispatch). The three-hour ahead pre-dispatch is important because it is the final signal provided to all resources before the closing of the offer/bid window. If the three-hour ahead pre-dispatch overstates the amount of available supply (i.e., because a derate is not identified) then the eventual price signal sent to participants (particularly imports/exports) will not provide an accurate signal of the need for supply in real-time. Column 4 presents the amount of failed imports that occurred following the final pre-dispatch. Column 5 presents the total amount of supply lost -- the total amount of the material change in supply.

Second, columns 6 through 10 provide the hourly amounts of control actions taken in response to the material change in supply, with column 10 presenting the total amount (in MW) of the control actions used in a given hour.

Third, columns 11 through 14 provide the hourly average prices that were set for each hour. Column 11 provides the three-hour ahead pre-dispatch price while column 12 details the one-hour ahead pre-dispatch price. Column 13 lists the HOEP as it was initially computed on the day. Column 14 provides the administrated price for each applicable hour.

a. Delivery hour 17

In delivery hour 17, the key factor influencing the need for out-of-market control actions was the problems with the generation facility. As mentioned above, the facility operator and hence the IMO, were having difficulty gauging the likely availability of the facility for the coming hour. This difficulty was impacting the scheduling of resources in pre-dispatch, particularly imports and exports. As column 2 illustrates, the three-hour ahead pre-dispatch scheduled 2,051 MW from the generation facility that ultimately was unavailable in real-time (column 2). With the facility's supply being fully scheduled, the three-hour ahead pre-dispatch price failed to signal the eventual supply shortage; it was projecting a price of $175 for delivery hour 17 (column 11). On this day, given the relative supply shortages in all the surrounding markets, this price would not have been as attractive to importers (more attractive to exporters) as the prices in other markets; the one-hour ahead New York-Ontario zone price for example was $257.56 CDN.

When the final pre-dispatch was run, the pre-dispatch was still scheduling supply from the facility that would not be available in real-time (773 MW). The magnitude of the loss of supply became clear to the IMO just prior to the start of the delivery hour. The IMO viewed the significant derate of the facility as a material change in supply requiring control action. In particular, at this time, the control action taken was to cancel 566 MW of exports that had been scheduled in pre-dispatch.

As the hour began, the demand came in roughly 300 MW lighter than had been forecasted. However, supply disruptions at another generation facility and performance problems at a third facility were adding strain on supply. The IMO was projecting shortfalls in its ability to meet its 10-minute reserve requirements in the hour. It responded by purchasing 125 MW of emergency energy to free up energy for reserve. The IMO also responded by manually reducing its total reserve and 10-minute reserve requirements at various points in the hour and, as a substitute, carrying out-of-market sources of reserve. The hourly average amount of the out-of-market sources of reserve carried was 603 MW (column 9).

The total of the control actions taken in the hour exceeded both the initial material change in supply as well as the supply problems experienced at other generation facilities. The energy clearing prices in the hour ranged from a low of $115.82 to a high of $153.84 with the HOEP being $122.80. The HOEP was lower than the cost of the emergency energy purchased as well as many of the imports purchased on the hour. In this regard, the HOEP was likely an understatement of the true incremental cost of meeting the energy and reserve requirements in the hour.

b. Delivery Hour 18

Just prior to the start of delivery hour 18, the IMO determined that a significant number of imports had failed to make checkout in one of the surrounding markets. The total amount of these failed imports was 933 MW. Given the uncertainty around the supply at the facility and the large number of failed imports, the IMO decided that there was a material reduction in supply following the final pre-dispatch that necessitated control actions to ensure global adequacy. As was the case in hour 17, the IMO cancelled exports (133 MW) that had been scheduled in pre-dispatch. It also purchased 400 MW of imports that were still available after the final pre-dispatch was run. These imports were initially uneconomic in the final pre-dispatch and hence were not initially scheduled. Since the final pre-dispatch price cleared at $500, these imports were offered at (and ultimately paid) a price higher than $500. Other control actions taken in hour 18 were the purchase of 600 MW of emergency energy from other markets.[30]

[30] The imports purchased after the final pre-dispatch were input into the constrained sequence but not in the unconstrained sequence. As will be discussed further below, this input error was deemed not to have had a

As in the previous hour, in real-time, due to production difficulties at several generation facilities, the IMO could not meet its 10-minute reserve requirement through market based sources (offer and bid) alone. It relied on out-of-market sources to meet its NERC and NPCC requirements. Delivery hour 18 offers a good illustration of how the IMO can use out-of-market sources of reserve to meet its NERC and NPCC requirements. Tables 2-4 and 2-5 show the interval-by-interval details of how the IMO satisfied its reserve requirements for this hour. Table 2-4 presents the reserve carried in the constrained schedule. This is the schedule that the control room uses to manage reliability. Table 2-5 provides the reserve carried in the unconstrained schedule. This is the schedule that determines the market prices.

Table 2-4: Summary of Reserve Market for Hour 18 (Constrained Schedule)

	NPCC Standard		DSO Requirement		Reserve Sourced from the Market					Out-of-Market Reserve		NPCC Deficit	
Interval (1)	10 Min (2)	Total (3)	10 N (4)	Total (5)	Gen/DL 10 Min (6)	Gen/DL 30R (7)	CAOR 10 Min (8)	CAOR 30R (9)	CAOR Energy (10)	5% 10N (11)	30 Min (12)	10 N (13)	Total (14)
1	920	1,380	920	1,380	776.1	60.9	143.8	254.2	0	0	145	0	0
2	920	1,380	920	921	667.1	1.0	252.8	0	0	0	459	0	0
3	920	1,380	920	921	673.2	1.0	246.8	0	0	0	459	0	0
4	920	1,380	920	921	422.9	100.1	398.0	0	0	99	360	0	0
5	920	1,380	700	701	317.5	1.0	382.5	0	14	154	459	67	67
6	920	1,380	700	701	284.5	52.5	364.1	0	34	152	408	120	120
7	920	1,380	620	621	389.3	0.9	230.7	0	0	300	459	0	0
8	920	1,380	620	621	588.2	0.9	31.7	0	0	300	459	0	0
9	920	1,380	620	621	575.7	0.9	44.2	0	0	300	459	0	0
10	920	1,380	620	621	619.8	0.9	0.0	0	0	300	459	0	0
11	920	1,380	920	921	783.7	0.9	136.3	0	0	0	459	0	0
12	920	1,380	920	921	215.9	193.7	380.0	0	20	150	266	174	174

Tables 2-4 and 2-5 present five categories of data. The first category (columns 2 and 3) lists the amount of reserve required to be scheduled to meet NPCC standards. The

greater impact on the market price than would the administered prices and hence prices were not second category of data (columns 4 and 5) lists the reserve requirements that were input into the DSO to schedule reserve from the market. The IMO must use non-market sources of reserve to make up the difference between the NPCC standard and the requirements used in the DSO. The third category of data (columns 6 to 9) represents the amount of reserve purchased from the different market sources of reserve via the DSO. Included in this reserve are the 3% and 5% voltage reductions that have been priced and placed into the market (CAOR).[31] Note that column 10 represents the amount of CAOR that was scheduled as energy. When CAOR is scheduled as energy, the DSO is indicating that voltage reductions are required to meet all requirements. Voltage reductions were not actually implemented on this day however. The fourth category of data (column 11 and 12) represents the non-market sources of reserve that had to be carried by the IMO to meet its NPCC standard. Finally, the last two columns represent the amount by which the IMO fell short of meeting its NPCC standard through the sum of market sources, 5% voltage reductions or by disregarding its 30-minute reserve.

administered.

[31] CAOR stands for Control Action Operating Reserve that has been assigned a price and has been incorporated into the market as a reserve offer. This reserve is generally made up of the potential for 3% and 5% voltage reductions. The CAOR was implemented in August, 2003. The implementation of CAOR was a result of recommendation made by the Panel in its first report to make the use of out-of-market control action by the IMO more transparent to market participants. Putting a price on this reserve and placing it into the market is one approach to achieving this transparency. The impacts of CAOR are discussed more fully in Chapter 3 of this report.

Table 2-5: Summary of Reserve Market for Hour 18 (Unconstrained Schedule)

	NPCC Standard		DSO Requirement		Reserve Sourced from the Market					Out-of-Market Reserve		NPCC Deficit	
Interval (1)	10 Min (2)	Total (3)	10 N (4)	Total (5)	Gen/DL 10 Min (6)	Gen/DL 30R (7)	CAOR 10 Min (8)	CAOR 30R (9)	CAOR Energy (10)	5% 10N (11)	30 Min (12)	10 N (13)	Total (14)
1	920	1,380	920	921	920.0	1	0	0	0	0	459	0	0
2	920	1,380	920	921	920.0	1	0	0	0	0	459	0	0
3	920	1,380	920	921	700.2	1	0	0	0	220	459	0	0
4	920	1,380	920	701	700.1	1	0	0	0	220	459	0	0
5	920	1,380	700	701	700.1	1	0	0	0	300	459	0	0
6	920	1,380	700	621	620.1	1	0	0	0	300	459	0	0
7	920	1,380	620	621	620.1	1	0	0	0	300	459	0	0
8	920	1,380	620	621	620.1	1	0	0	0	300	459	0	0
9	920	1,380	620	621	920.0	1	0	0	0	0	459	0	0
10	920	1,380	620	921	920.1	1	0	0	0	0	459	0	0
11	920	1,380	920	921	920.0	1	0	0	0	0	459	0	0
12	920	1,380	920	921	712.5	1	207.5	0	0	0	459	0	0

There are several points to be gleaned from these tables. First, note that the simple reduction of the DSO requirement does not reduce the strain on the grid caused by the high energy demand and tight supply conditions. In this sense, lowering the requirement has no impact on reliability. Put another way, lowering the reserve requirement does not increase the amount of reserve available to the IMO. It rather makes transparent the reduced availability of market sources to be used in the event of an adverse contingency. Indeed, in intervals where reserve requirements are not fully met, the IMO is at greater risk that, in the event of a contingency, it will actually have to shed load.

Second, when the reserve requirements in the DSO are reduced below the NERC and NPCC standards, implicitly the IMO must carry the difference through a non-market source. The IMO strives to lower the requirement by the amount of the expected shortfall. The reduction in the requirement is generally blunt however and often means that some market sources are left idle (i.e., not used for either energy or reserve). If carrying these out-of-market sources of reserve has a higher social cost than the reserve offered in the market, then when the reserve requirement is lowered, the control room is essentially undermining the efficient dispatch as higher cost resources are used ahead of lower cost resources. For example, in interval 10, the out-of-market 5% voltage reductions were carried instead of the CAOR, which is backed largely by 3% voltage reductions. Other sources of reserve with offers in the market were also not selected in this interval.

In the Panel's view the purpose of the OR market is to choose the lowest cost sources of operating reserve in the short-term and to provide a price signal that attracts efficient investment in OR in the longer term. If 5% voltage reductions were the lowest cost source of operating reserve, they would always be carried first in the merit order, the price of operating reserve would be lower and so would the uplift. Given that the IMO chooses to carry a 5% voltage reduction as operating reserve only under extreme circumstances, it is reasonable to infer that it is a relatively high-cost source of operating reserve. It is therefore inefficient and socially costly to carry it in preference either to resources that have been voluntarily bid into the market or to CAOR.

Third, as our first report noted, when the DSO reserve requirement is lowered, it is lowered in both the constrained and unconstrained sequences (generally with a 10-minute lag). However, the two sequences do not generally have the same degree of shortage, since the shortages are typically larger in the constrained sequence. As a result, in many intervals, the unconstrained sequence, and hence the market price, do not signal the true shortage of resources that is present in the constrained sequence.[32] One consequence of this is that actions that might be taken in response to higher price signals – to reduce consumption or bring additional peaking capacity to market – are not taken and the reliability situation is not improved.

[32] Since the unconstrained sequence is fictitious in that it does not recognize real transmission constraints on the grid and it includes the assumption that units can ramp at 12-times their actual capabilities, the unconstrained sequence tends to understate the true cost of dispatch relative to the constrained sequence. However, when the reserve requirement in the DSO is reduced it causes the unconstrained sequence to further understate the incremental cost of dispatch as reflected in the constrained schedule.

Intervals 5, 6 and 12 provide a good illustration of this. The IMO was short of reserve in intervals 5, 6 and 12. However, as Table 2-5 indicates, the market schedule did not see the same degree of shortage. In fact, the DSO reserve requirement was lowered to a level so low that even the CAOR was not scheduled in interval 5 and 6 and was only scheduled for about half of its allocated capacity in interval 12. The market clearing price in these intervals was not likely signalling the true social cost of energy or operating reserves. The energy prices were $140, $141 and $156 for intervals 5, 6 and 12, while the 10-minute reserve price was only $10, $12 and $30.

The MAU conducted several simulations to estimate the price impacts of the different control actions. The results of this simulation are presented in Table 2-6. The second column of Table 2-6 reports the actual MCP produced in the hour. The third column provides the prices simulated assuming that there were no failed imports in the market in the hour and the IMO did not require the use of control actions.[33]

Table 2-6: Simulation of Effects of Control Actions Taken on the Market Clearing Price Delivery Hour 18, Prices per MWh

Interval	Actual MCP	MCP no Failed Imports and no Control Actions Taken	MCP with Failed Imports and Proper Coding of Imports/ Exports	MCP with Failed Imports but no Control Actions Taken
1	141.89	136.29	129.13	163.89
2	142.09	141.89	136.27	525.00
3	142.09	141.89	138.90	164.11
4	141.89	135.53	137.29	450.00
5	140.22	130.85	137.51	163.90
6	141.89	135.53	137.51	400.00
7	141.89	141.89	138.85	164.11
8	141.89	135.41	137.51	163.90

[33] In particular, in this simulation the IMO did not purchase additional imports/cancel exports following the final pre-dispatch, did not manually reduce the operating reserve requirement and did not purchase emergency energy.

Interval	Actual MCP	MCP no Failed Imports and no Control Actions Taken	MCP with Failed Imports and Proper Coding of Imports/ Exports	MCP with Failed Imports but no Control Actions Taken
9	142.09	141.89	129.19	550.00
10	142.09	141.89	129.19	600.00
11	142.29	141.89	130.83	164.11
12	156.62	159.55	142.29	2,000.00

The fourth column presents the simulated prices assuming that the IMO had properly coded the additional imports and cancelled exports in the unconstrained sequence. This error was the cause of the administered prices in hours 19 through 22. As the fourth column indicates, had the IMO properly coded the imports/exports, there would have been only a small impact on the market price. This small impact was deemed to be less of an error than would administering the prices and hence, the prices were not administered in hour 18.[34] Finally, the last column presents the simulated prices assuming that following the failed imports, no control actions were taken.

The events of the day make it clear that the failed imports, along with the uncertainty as to the available output from the large generation facility, represented the material loss of supply that triggered the need for control actions. The simulations suggest that the impact of the control actions essentially offset the price impact of the failed imports, and without the control actions the price would have been substantially higher in many of the intervals within the hour.

c. Delivery Hours 19 through 22

In delivery hours 19 through 22, the IMO continued to cancel exports and purchase imports following the final pre-dispatch as a response to the material loss of supply caused by failed imports and the derating of the generation facility. However, in doing so

[34] The price impacts in hours 19-22 were larger and hence administered pricing applied.

the export transactions were removed from the constrained schedule but were left inadvertently in the unconstrained schedules. Similarly, the additional import transactions were added to the constrained schedule but were inadvertently left out of the unconstrained schedules. Collectively, these inadvertent errors in inputs caused the real-time unconstrained sequence to be shorter supply than the real-time constrained sequence by the sum of the export and import transactions (730 MW in hour 19, 1,360 MW in hour 20, 1,451 MW in hour 22 and 1,224 MW in hour 22).

As the hours progressed, many of the supply problems that had been experienced at the generation facilities subsided. With the additional purchase of imports and the cancellation of exports, the constrained sequence no longer indicated shortages of supply. As a result, the IMO gradually reduced its use of other out-of-market control actions such as emergency purchases or the carrying of out-of-market sources of reserve. However, the unconstrained sequence, not recognizing the additional imports and the cancelled exports, was (at least on appearance) in short supply. The DSO ran under these apparent shortage conditions and the clearing prices reflected this shortage: the energy clearing price reached $2,000 (the maximum market clearing price) in 13 intervals.

Reasons for Administered Prices

Due to the data input error described above, the IMO administered the prices for the period beginning with interval 11 of hour 19 and ending with interval 10 of hour 22 (a period of 36 intervals).

Under the Market Rules, the IMO can administer prices when:

(i) it determines that a published energy market price or operating reserve market price is incorrect due to incorrect inputs which affected the outcome of the dispatch algorithm, and

(ii) the impact satisfied the criteria approved by the IMO Board relating to price error materiality and acceptable causal events. (Market Rules, Chapter 7, Section 8.4.2 and 8.4.3).

The IMO determined that the input error was an acceptable causal event in the 36 intervals listed above and hence administered the prices.

The Market Rules specify how the administered price is to be selected (Market Rules, Chapter 7, Section 8.4.4). If it is determined that a dispatch interval was incorrect as discussed above, the market price and corresponding market schedule shall be the market price and corresponding market schedules for the last correct dispatch interval.

Furthermore, if the error persists for more than 24 consecutive dispatch intervals, the IMO will choose a dispatch hour (interval) with dispatch conditions similar to those of the dispatch interval to which the administered price applies. The administered price shall be the market price that prevailed in the corresponding hour on the similar day.

On January 15, the IMO followed these procedures for determining the administered price for the 36 intervals. For the first 24 intervals (hour 19 interval 11 to hour 21 interval 10, the administered price was $142.55 which was the price in interval 10 of hour 19). For the remaining 12 intervals, the price was set using the HOEP for the comparable hours of January 13, 2004. The administered prices were $92.65 for the last two intervals in hour 21 and $87.22 for hour 22.

Note, as discussed above there were input errors in hour 18 and for intervals 1 through 10 of hour 19. However, the IMO did not administer these prices since it concluded that the input errors in these intervals did not cause a change in market prices that was greater than would have been caused by administering the prices.

The Panel's Overall Assessment

The events of January 15 highlight several concerns regarding the impact that control actions can have on market outcomes, market signals and market efficiency.

In particular, it is unclear to us why the IMO needs to reduce the reserve requirement in the DSO when a shortage of reserve occurs in the constrained sequence in real-time. As far as we can tell, reducing the requirement in the DSO does not improve system adequacy since it does not increase the resources available to the system. We have argued consistently that out-of-market actions blunt the price signals that are necessary to provide consumers and potential suppliers with valuable information about the scarcity value of the resource. The IMO practice of pricing some of the out-of-market actions is a welcome response but the events of January 15 quite clearly show that energy prices on that day failed to reflect the very serious supply/demand pressure that the energy market was facing.

Since the manual reduction in reserve requirements is not necessary for system reliability and results only in the lowering of the market prices, we are concerned that this action is distorting market signals and market efficiency and ultimately in a way that could undermine reliability.[35] We are not sure what the 'true' scarcity price is at these moments in time,[36] perhaps society is not willing to pay too high a price to maintain operating reserve. However, if the market price is 'too' low – or if peaks are cut off -- because of the manual reduction in the reserve requirement then the price is not sending appropriate short-term signals to generation of the need for operating reserve (i.e., to imports that may themselves provide reserve or provide energy in upcoming hours that will allow Ontario resources to be freed up for reserve, or to Ontario generators that are off-line). Reserve prices that are too low will also understate the market value to future entrants and undermine efficient investment. In particular, loads that may view it profitable to be dispatchable if they could earn higher reserve prices may not become dispatchable even though the market currently has a general shortage of reserve.

[35] Manually reducing the reserve requirement in the constrained schedule also affects shadow prices. This can sometimes undermine reliability when there are fossil units running at minimum levels that are ramping up to reach optimal levels to provide reserve. The shortage in the constrained sequence may result precisely because of the ramping limitations on these units. If the IMO then lowers the reserve requirement, the effect will be to depress the shadow prices, potentially to the point where units stop ramping. This further aggravates or perpetuates the reserve shortage as no additional reserve is created from these units.

[36] One might suggest that the best approximation of a 'true' scarcity price is the Maximum Market Clearing Price, which has been determined by the IMO Board to be $2,000/MWh.

It seems to us that a good part of the difficulty arises because of the joint optimization of the operating reserve and energy markets and the constraints in the DSO that require any manual reduction in operating reserve requirements in the constrained schedule to also be made to the unconstrained schedule. The essence of the difficulty is that out-of-market sources of reserves are acceptable ways of meeting industry-mandated reserve requirements, but when they are implemented manually they have a zero-cost and affect both the constrained schedule (where there is a shortage) and the unconstrained schedule (where there may not be a shortage and they have perverse price effects). Imputing a price to out-of-market control actions appears to us to offer a way to resolve this dilemma because it will allow the DSO to automatically select 'least costly' sources of operating reserve (including appropriately priced out-of-market actions) as required in the constrained schedule without necessarily making the same selection in the unconstrained schedule. The IMO has made significant progress in implementing a pricing regime for out-of-market reserves over the past year and we report on this in Chapter 3. We believe that more can and should be done.

An additional source of concern to the Panel is the way in which emergency imports are introduced into the DSO. It seems logical to us that if the supply/demand balance is sufficiently tight to require emergency imports the energy price ought to reflect that circumstance. One would think that an appropriate outcome would be for the price of the emergency imports to set the MCP in the interval, so that consumers and potential providers of peaking energy understand what the true scarcity cost of the resource is. Not only do emergency imports not set the price, but the way in which they are introduced into the DSO actually results in a lower price than would be obtained had there been no need for emergency imports. This seems to us to be counter-intuitive and counter-productive and we believe that the IMO should take action to incorporate emergency imports into the pricing algorithm in a more appropriate manner.

3.2 Procedure for Managing Outages of Commissioning Units

The MAU's monitoring of the market in February identified three hours on February 4, 2004 in which confusion from both a market participant and the IMO regarding the implementation of a new procedure for managing outages of commissioning units affected market outcomes. The event eventually caused the MCP in one interval to increase to $600.

New Procedure for Managing Outages of Commissioning Units

Just prior to February 4, 2004, the IMO revised its procedures for dealing with outages and derates of commissioning units. These are units that are returning from a prolonged outage and choose to re-enter the market by first operating as a self-scheduling unit in order to test the unit's capabilities.

Prior to the procedure change, outages and derates of commissioning units were managed in the same way that outages of dispatchable units were managed. First, the owner of the unit would submit an outage slip to the IMO for approval. The IMO would then approve or not approve the outage. If the outage was approved, the IMO would transfer the outage information (i.e., derate the capacity of the unit) to the DSO. The DSO would then recognize the unit's new capability in determining the future schedules of the unit. The owner of the unit may or may not then remove or update the offers of the unit to reflect the outage condition. The owner's decision to remove or update its offer was not crucial however, since the IMO's transfer of the outage information to the DSO alone would be sufficient to assure proper scheduling of the unit.

In applying this procedure to commissioning units, the IMO experienced several problems. In particular, commissioning units are frequently derated or forced out while testing. It is common for the status of a commissioning unit to change several times over a period of a few hours. The IMO found that because of the frequency of these changes, the outage approval process outlined above was difficult to manage and at times increased the risk that input errors could occur. It also found that the details involved in the submission process could compromise the timeliness of the changes.

As a result of these concerns, the IMO revised the outage submission process for these units. The new procedure places the onus on the market participant to manage the outage/derate status of their units through their offers. This new approach should reduce the workload for the IMO and improve the timeliness of incorporating the status changes into the DSO.

Events of Wednesday, February 4, 2004

During the early part of February, a nuclear unit ("Unit B") was commissioning, operating as a self-scheduling generator. On Tuesday, February 3, the operator of Unit B submitted standing offers for the unit for supply in all hours of Wednesday February 4. In each hour of February 4, the operator of Unit B offered 680 MW of energy at a price of -$40.

At roughly 8:45 on the morning of February 4, the operator of Unit B reported that the unit had a heat transport leak. The operator informed the IMO that it would force the unit out of service at 14:00 (the start of delivery hour 15) and that the unit would be out of service for 5 to 6 days. The operator submitted an outage slip for IMO approval as per the old procedure. The operator did not remove its standing offers for delivery hour 15 and beyond. Shortly after the call, IMO staff approved the outage as per the old procedure. The outage was transferred to the DSO.

For the next several hours (delivery hour 10 to 13), Unit B was scheduled in each of the respective final pre-dispatch runs for 680 MW. The unit also ran steadily in real-time at roughly the same level of output.

At approximately 13:20 (40 minutes prior to its planned/forced outage), Unit B began experiencing boiler troubles. As a result, the unit ran at roughly 100 MW below its offered quantity for the next few intervals. Then, in the final 2 intervals of the hour, the unit ramped down as per its planned/forced outage.

In the meantime, at roughly 13:09, the final pre-dispatch for hour 15 was run. The outage that was approved at 9:00 was still reflected in the DSO. As a result, Unit B was not scheduled in pre-dispatch for hour 15. By 14:00 (start of delivery hour 15), the breaker of Unit B was open and the unit was officially off-line and unavailable for real-time energy production for the next 5 to 6 days. Unit B did not produce energy in delivery hour 15 as projected in the final pre-dispatch.

Sometime between 13:09 and 14:09, staff in the IMO's Market Forecasts and Integration department identified the Unit B outage in the outage data base tools as it was initially approved at 9:00 that morning. Staff was aware of the new procedure change that required the market participant to manage the outage through the unit's offer. In accordance with the new procedure, the staff effectively reversed the initial decision to approve the outage. The outage information was automatically removed from the DSO. The staff member did not however inform the control room of its decision to remove the outage from the outage database tools. At the same time, the operator of Unit B had not updated or removed its offers to reflect the outage. As a result, the unit appeared to be available in the DSO for scheduling. Had the staff informed the control room, the control room could have either contacted the operator of Unit B to request that they update their offers as per the new procedure or manually rejected Unit B's offers. Either of these actions would have prevented the eventual problem.

At 14:09, the final pre-dispatch for delivery hour 16 was run. At this time, because the IMO staff had removed the outage information from the DSO and the operator of Unit B had failed to remove its offer, the unit was scheduled for the delivery of 680 MW of energy in the upcoming hour. Similarly, at 15:09 and 16:09, the final pre-dispatch for delivery hours 17 and 18 respectively was run and Unit B was scheduled for 680 MW in each of these pre-dispatches.

Sometime around 16:55, the IMO recognized that Unit B was being scheduled in pre-dispatch. Staff manually rejected the Unit B offers for subsequent hours. The final pre-dispatch for delivery hour 19 was run. As a result of the IMO's manual rejection of the Unit B offer, the unit was not scheduled in this or subsequent pre-dispatches.

Impact of the Events on the Market Outcomes

All else held constant, incorrectly identifying a unit as available for supply in pre-dispatch when it is not available for supply in real-time, places upward pressure on the real-time price (real-time price should be higher than the pre-dispatch price). In times of tight supply, this error can also cause reliability concerns if as a result, too few imports are selected to meet the real-time demand.

On February 4, the impact of the pre-dispatch scheduling error of Unit B in delivery hours 16 to 18 on both the real-time price and reliability was generally mitigated by other factors. For example, the load projected in pre-dispatch was significantly higher than the actual load realized in real-time in each of these hours. This discrepancy meant that some imports that were scheduled in order to meet the higher pre-dispatch load that did not materialize, could instead be available in real-time to offset the 680 MW of Unit B that was expected in pre-dispatch but unavailable in real-time. A second factor that offset the Unit B scheduling error was an unexpected removal of a derate on four generation facilities that were owned by another operator. This increased the amount of supply available in real-time by 220 MW. However, this increase in supply was not recognized in the hour 16 and 17 pre-dispatch. As a result, the increase in 220 MW of supply in real-time in these hours offset some of the 680 MW of Unit B that was unavailable in real-time. Additional factors affecting the market outcome were failed net imports, although these played only a limited role.

Table 2-7: Key Data for Delivery Hours 16 –18 on February 4, 2004

Delivery Hour	Supply Unavailable in Real-time due to Unit B Outage (MWh)	Pre-dispatch Load Forecast (MWh)	Average Real-time Load (MWh)	Peak Real-time Load (MWh)	Average Forecast Difference (MWh)	Pre-dispatch Price ($/MWh)	HOEP ($/MWh)	Failed Net Imports (MWh)	Output from Units Returning From Derates (MWh)
16	680	21,367	20,697	20,832	670	81.2	55.75	15	220
17	680	22,161	21,026	21,361	1,135	93.3	41.79	0	220
18	680	22,952	22,115	22,721	837	100.0	138.20	27	N/A

Table 2-7 provides a summary of how these factors mitigated the impacts of the pre-dispatch scheduling error of Unit B. In delivery hour 16, the difference between the projected peak load in pre-dispatch and the real-time average load was 670 MW. In the first 6 intervals, the difference between projected and real-time load was greater than the 680 MW of Unit B. In these intervals, the MCP was lower than the pre-dispatch price and well within typical levels for this period. By interval 7, the difference between projected and real-time load had fallen below the 680 MW level. This typically should cause the real-time price to increase above the pre-dispatch price. However, by interval 7, 220 MW of derates had been removed on four units and this increased supply plus the load forecast error was still sufficient to offset the 680 MW unavailable from Unit B. The MCP for the remaining intervals began to approach the pre-dispatch price of $81.20 but still remained roughly $10 lower. As Table 2-7 indicates the HOEP was lower than the pre-dispatch price for this hour.

In delivery hour 17, the difference between the projected and the real-time load was significant, averaging 1,135 MW. This difference always exceeded 680 MW. At the same time, the real-time supply from the four generation facilities was higher than the pre-dispatch supply by 220 MW. Both of these factors more than offset the loss of 680 MW of expected supply from Unit B, causing the real-time prices to be considerably lower than the pre-dispatch price of $93.30.

By hour 18, the 220 MW of derated supply of the four units had now been recognized as available and was scheduled in pre-dispatch. The difference between projected and real-time load was still significant in this hour – it exceeded the 680 MW level in intervals 1 through 7. In these intervals, the MCP was lower than the pre-dispatch price of $100. However, by interval 8, the load forecast difference was 580 MW. This meant that the over-projection of load was no longer sufficient to mitigate the 680 MW Unit B error. This coupled with 27 MW of failed imports meant that the real-time supply/demand balance was tighter than projected in pre-dispatch. The MCP in this interval increased to $119. This was $19 above the pre-dispatch price. Real-time demand continued to increase in the next few intervals, as did the MCP; it was $124 in interval 10. By interval 11, the real-time demand reached its peak value for the hour. The real-time demand was still 189 MW higher than what was projected in the final pre-dispatch. However, given the 680 MW discrepancy in supply from Unit B, the real-time supply/demand balance became extremely tight causing the price to spike to $600. By this time, the IMO lowered the operating reserve requirement to 1,200 MW of total reserve. In interval 12, real-time demand declined by roughly 90 MW. This coupled with the lower OR requirement caused the MCP to decline from $600 to $125.

Lessons Learned

Both the relevant IMO staff and the market participant are aware of the implementation requirement of the new procedure. If the new procedure is applied properly in the next instance, the outage status of commissioning units should be properly accounted for in pre-dispatch. Going forward the IMO and market participants may wish to consider discussing in the appropriate consultative forum ways to ensure that new provisions and procedures are effectively communicated to all involved.

3.3 A Large Accumulation of IOG Payments in Delivery Hours 22 through 24

In its March 2004 report to the Panel, the MAU indicated that there were persistent Import Offer Guarantee (IOG) payments being made to importers in delivery hours 22 through 24. The IOG provides importers with a guarantee that if selected in the final pre-dispatch, the price that they will receive for their import is no less than their offer price.

The IMO implemented the IOG just prior to market opening. The intent behind implementing the IOG was to reduce importers' trading risk to encourage imports to Ontario during periods of tight supply or supply shortages in Ontario.

The MAU had been monitoring the persistent IOG payments in these three hours for some time. They linked the regular payment of IOG's in these hours to the persistent difference between the demand projection used in the final pre-dispatch and the actual average (and peak) demand that occurred in real-time. In particular, the pre-dispatch demand is persistently and substantially higher than the real-time average and the real-time peak demand in these hours. This persistent and substantial difference causes the pre-dispatch to schedule more imports than would otherwise be required in real-time. It also causes the real-time price to be lower than the pre-dispatch price and the offer price of a very large proportion of the imports that were selected in pre-dispatch. As a result, IOG payments are made to the importers.

The MAU report to the Panel raised three concerns.

First, it questioned why the pre-dispatch demand was persistently higher than the actual demand in these hours. The tendency of pre-dispatch forecasts of demand and price to over-estimate real-time outcomes has been a characteristic of the Ontario market since its inception and we have commented on it in all of our reports to date. What is significant is the extent to which the over-estimates in hours 22-24 stand out.

Second, the MAU report to the Panel noted that persistent (and predictable) differences between pre-dispatch and real-time could be resulting in offsetting flows of imports and exports; imports sold into Ontario just to be exported out of Ontario. These transactions would be driven by the difference between the pre-dispatch price and the real-time price but supported by the IOG payment. Importers are attracted to the Ontario market by the relatively high pre-dispatch price and the guarantee provided by the IOG. At the same time, exporters (who pay the real-time Ontario price) are attracted by the relatively low real-time price. In this sense, the persistent and substantial differences between pre-dispatch and real-time create an artificial arbitrage opportunity for offsetting imports and exports. These transactions do not improve market efficiency but they do result in payments from Ontario consumers to traders.

Third, the MAU questioned whether the IOG was performing its intended role in these three hours. Specifically, the IOG was implemented to ensure imports would be available at times when Ontario supply was tight. However, hours 22 through 24 are not traditionally hours where Ontario is tight supply.

In response to this report, we asked the MAU to begin discussions with the IMO to seek to ensure that our understanding of the situation was appropriate and to explore ways to remedy it. The following sections provide greater elaboration of these points and report on the ongoing efforts to address the underlying problem.

Significant Accumulation of IOG Payments

Table 2-8 presents the IOG payments made to importers by year and by hour since market opening.[37] Overall, one can see the large decrease in IOG payments in the 12 months of 2003 compared with the 8 months during which the market functioned in 2002. This reflects the more favourable supply/demand conditions in 2003. IOG payments in 2004 appear to be rising again, with the total for the first four months amounting to almost half the total for all of 2003.

Table 2-8 also presents comparative data on IOG payments, and the percentage of imports receiving such payments, in a given hour. If we consider hour 24, for example, for the period May 1, 2002 to December 2002, a total of $1,016,495.01 was paid to importers as an IOG. For the period, January 1, 2004 to April 30, 2004, a total of $1,530,866.92 was paid to importers as an IOG. The IOG payments for the 2004 period are a half a million dollars higher than for the 2002 period even though the 2004 period covers four fewer months than 2002.[38] Also, in 2002, only 17% of the imports scheduled in delivery hour 24 received an IOG payment. By 2004, the percentage of imports that received an IOG payment in hour 24 increased to 56.5%.

[37] These are IOG payments net of payments made to imports that were part of an implied wheel. Imports that are part of an implied wheel where the importing market participant also has a corresponding export out of Ontario are not eligible for an IOG payment.
[38] Furthermore, for the 2004 period, the supply demand balance was much improved compared to the 2002.

Table 2-8: Measures of Difference between Pre-dispatch and Real-time Demand

	IOG Payments Net of Implied Wheeling			Percentage of Imports Receiving IOG (%)		
Hour	**2002 (May-Dec)**	**2003* (12 months)**	**2004 (Jan-Apr)**	**2002**	**2003**	**2004**
1	$270,502.94	$1,168,005.81	$631,928.66	7	8.5	33.2
2	$186,142.06	$686,459.79	$486,100.69	6	7.5	30.3
3	$49,865.66	$424,799.43	$348,857.44	3	5.2	24.9
4	$57,924.06	$246,652.58	$228,014.20	3	4.6	18.7
5	$110,411.17	$389,794.71	$268,861.40	5	6.1	22.3
6	$231,882.04	$902,528.82	$452,398.16	8	8.8	27.9
7	$257,000.02	$1,010,094.54	$526,852.44	7	10.7	32.1
8	$383,262.33	$725,328.06	$283,238.44	9	11.6	22.7
9	$699,742.16	$1,247,642.48	$267,100.18	13	14.5	20.0
10	$2,732,546.97	$1,544,711.51	$522,986.84	16	14.3	26.4
11	$5,650,218.53	$1,849,997.19	$623,090.66	19	17.1	33.8
12	$8,557,257.41	$2,624,331.46	$728,566.17	19	17.3	33.5
13	$12,416,773.63	$2,415,286.06	$769,600.43	23	16.8	38.9
14	$17,888,076.53	$2,170,809.40	$636,537.68	25	16.5	35.2
15	$22,833,291.71	$2,463,467.09	$943,393.34	27	18.5	41.5
16	$26,535,052.66	$4,466,453.80	$1,167,728.75	30	22.1	47.6
17	$34,841,265.02	$4,068,359.06	$2,366,335.49	31	24.5	56.9
18	$30,202,837.28	$4,202,206.83	$2,392,429.50	29	22.8	48.3
19	$27,499,493.26	$3,914,742.50	$2,231,494.24	27	21.5	40.3
20	$17,775,324.45	$2,228,819.27	$1,812,086.33	22	18.0	37.8
21	$6,808,222.02	$2,180,205.25	$1,801,214.86	23	19.4	43.0
22	$5,386,901.50	$2,937,161.52	$2,121,560.84	26	27.9	49.0
23	$3,995,602.40	$4,164,373.28	$1,951,409.83	27	26.5	60.1
24	$1,016,495.01	$3,425,692.75	$1,530,866.92	17	19.7	56.5
Total	**$226,386,090.82**	**$51,457,923.19**	**$25,092,653.49**	**100%**	**100%**	**100%**

* Excludes data for August 2003 due to blackout.

While the cumulative IOG payments made in hours 22 through 24 are not large relative to other hours such as hours 17, 18 and 19 - their size is still surprising given that hours 22 through 24 are not typically hours where a large number of imports are required to deal with tight supply conditions. It is also surprising that such a large percentage of imports scheduled in these hours are paid an IOG. For the year 2004, these three hours are among the highest four hours in this respect with hour 23 being the first highest, hour 24 the third highest and hour 22 the fourth highest.

Source of the IOG Payments

As we described in our first report, for IOG payments to occur, it is necessary that there be a positive difference between the pre-dispatch price and the real-time HOEP. To understand why there were a relatively large amount of IOG payments being made in hours 22 through 24, the MAU sought to determine the source of the positive difference between the pre-dispatch and real-time prices in these hours. Table 2-9 provides some indication of the differences and the source of the differences.

Table 2-9: Measures of Difference between Pre-dispatch and Real-time Demand and Price by Delivery Hour
Since Market Opening*

	Mean Forecast Difference: Pre-dispatch minus Average Demand divided by the Average Demand (%)			**Mean Forecast Difference: Pre-dispatch minus Peak Demand divided by the Peak Demand (%)**			**Mean Forecast Difference: Pre-dispatch Price minus HOEP divided by the HOEP (%)**		
Hour	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
1	2.64	2.42	2.82	0.76	0.65	0.97	21.66	25.44	30.58
2	2.37	2.16	2.76	1.06	0.93	1.57	13.73	24.09	35.14
3	1.53	1.27	1.93	0.57	0.39	1.13	7.59	13.38	22.77
4	1.30	1.20	1.62	0.48	0.37	1.00	7.77	9.88	17.85
5	2.63	2.48	2.27	0.86	0.85	1.16	13.39	21.56	23.69
6	4.16	4.01	3.64	0.77	0.93	1.14	26.44	39.01	38.00
7	3.61	3.68	3.95	0.06	0.24	0.65	20.38	41.81	42.78
8	2.66	2.35	2.37	0.35	0.26	0.19	12.79	30.90	23.07
9	2.24	1.74	1.58	0.58	0.38	0.58	18.34	32.35	19.15
10	1.58	1.40	1.47	0.45	0.51	0.72	23.18	33.03	30.91
11	1.42	1.15	1.11	0.67	0.50	0.56	40.13	30.63	28.50
12	1.38	0.86	0.91	0.67	0.24	0.30	37.65	34.09	22.62
13	1.17	0.73	1.04	0.55	0.08	0.39	43.93	25.97	24.79
14	1.25	0.78	1.11	0.63	0.12	0.41	55.78	25.16	20.24

	Mean Forecast Difference: Pre-dispatch minus Average Demand divided by the Average Demand (%)			**Mean Forecast Difference: Pre-dispatch minus Peak Demand divided by the Peak Demand (%)**			**Mean Forecast Difference: Pre-dispatch Price minus HOEP divided by the HOEP (%)**		
Hour	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
15	1.52	1.01	1.19	0.89	0.35	0.57	58.15	32.04	25.80
16	1.86	1.47	1.83	0.98	0.56	0.87	68.67	46.73	35.38
17	2.31	1.99	2.41	0.90	0.45	0.75	91.20	45.46	48.21
18	2.06	1.84	2.09	0.92	0.50	0.44	89.60	47.58	45.22
19	1.87	1.71	1.85	0.84	0.57	0.64	81.01	43.18	36.89
20	1.64	1.41	1.67	0.54	0.37	0.78	61.02	28.65	30.55
21	1.76	1.59	2.20	0.32	0.19	0.70	32.74	31.46	38.49
22	3.27	2.96	5.72	0.40	0.31	0.71	40.05	54.70	55.44
23	4.86	4.27	3.96	1.54	1.02	1.04	59.42	71.79	71.62
24	4.83	4.47	4.60	2.06	1.75	1.80	43.64	57.06	66.88

* Data for 2002 cover the period May-December; data for 2003 exclude data for August 2003 due to the blackout; and data for 2004 cover the period January-April.

Table 2-9 reports the measures of difference between pre-dispatch forecasts and real-time outcomes for price and demand by delivery hour since market opening.[39] This is an hourly version of the data presented in Table A-24 and A-31 of the Statistical Appendix. As indicated, the percentage difference in terms of the real-time average is largest in hours 22 through 24 and generally by a considerable margin. At the same time, the percentage difference in terms of peak demand also tends to be higher in these hours, although it is also relatively high in the morning hours as well. Not surprisingly, the pre-dispatch to real-time price difference as a percentage of the real-time HOEP is also largest in hours 22 through 24.

Table 2-10 provides further indication of the persistent difference between the pre-dispatch forecasts and real-time outcomes in the hours of 22 through 24. Table 2-10 charts the frequency with which the pre-dispatch prices and demand exceed the real-time price and demand by delivery hour since market opening. As indicated, in over 97% of the hours, the pre-dispatch demand value exceeds the real-time average demand in hours

[39] All demand values reported are the non-dispatchable load plus losses component of demand, calculated as the sum of the unconstrained schedules of all generation plus net imports minus dispatchable load.

23 and 24. The frequency for the pre-dispatch to 'over-forecast' real-time peak demand is also considerably high in these hours - 79% and 87% of the hours for delivery hour 23 and 24 respectively). This is considerably higher than it is during hours 7 and 8 when the frequency of an 'over-forecast' of the hourly peak is only 53% to 55%.

Table 2-10: Frequency of Over-Forecast, Hourly Price and Demand Since Market Opening*

Delivery Hour	Percentage Time Over-forecast of Price	Percentage Time Over-forecast Peak Demand	Percentage Time Over-forecast Average Demand
1	86.0	66.8	92.2
2	84.7	73.5	91.2
3	77.8	63.1	83.0
4	77.3	64.6	82.4
5	86.9	72.5	91.7
6	93.7	72.0	97.2
7	91.5	55.5	96.6
8	83.8	53.3	93.0
9	79.0	62.2	88.7
10	75.9	65.2	85.4
11	74.5	66.3	81.8
12	69.3	62.7	79.2
13	68.9	57.1	76.6
14	69.4	60.3	76.4
15	74.0	64.7	80.7
16	80.0	69.0	86.7
17	80.9	65.6	86.8
18	85.6	67.6	88.9
19	82.2	69.3	88.3
20	79.3	63.4	86.1
21	80.7	57.8	86.4
22	93.5	62.5	97.8
23	97.2	79.2	99.4
24	97.3	87.3	99.4

* Excludes data for August 2003 due to blackout.

The key source of the persistent difference between the pre-dispatch price and real-time HOEP in hours 22 through 24, and hence the key factor contributing to the accumulation of IOG payments in these hours, is the persistent and positive difference between the pre-dispatch demand value and the real-time demand values. There appear to be two reasons for this persistent difference.

First, the demand value used in pre-dispatch is the expected peak demand value for the delivery hour. The IMO uses the expected peak demand value for the hour in order to ensure that sufficient resources are scheduled or on-line to meet the hourly peak demand. However, the use of the peak demand value in pre-dispatch will cause a general positive bias between the pre-dispatch price and the HOEP. Even if the pre-dispatch demand value actually equals the real-time value in some interval in the hour, it will exceed the demand value in all other intervals. This suggests that there will always be a forecast bias when the pre-dispatch demand is compared to the real-time average demand. It also suggests that since the real-time HOEP is more reflective of the average real-time demand, there will generally be a positive bias between the pre-dispatch price and the HOEP. In some hours, where demand changes are relatively small across the hour, this bias will be small. However, in other hours where there is a large difference between the peak demand value and the minimum demand value, the bias will be quite large. This is the case for delivery hours 22 through 24. The hourly change in demand is presented in Table 2-11.

Table 2-11: Difference Between Hourly Peak and Hourly Minimum Demand Since Market Opening

	Difference Between Hourly Peak and Minimum Demand (MW)			Percentage Difference Between Hourly Peak and Minimum Demand (%)		
Hour	**2002**	**2003***	**2004**	**2002**	**2003***	**2004**
1	538	566	549	3.6	3.8	3.4
2	373	360	347	2.6	2.5	2.2
3	269	257	243	1.9	1.8	1.6
4	228	232	213	1.6	1.7	1.4
5	454	422	378	3.1	2.9	2.5
6	948	857	775	6.0	5.5	4.7
7	1,253	1,179	1,142	7.3	7.0	6.4
8	869	834	892	4.9	4.7	4.8
9	609	554	375	3.3	3.1	2.1
10	442	359	292	2.3	2.0	1.6
11	303	283	225	1.6	1.5	1.2
12	270	295	257	1.4	1.6	1.4
13	241	300	255	1.3	1.6	1.4
14	246	252	268	1.3	1.4	1.4
15	245	296	246	1.3	1.6	1.3
16	327	431	317	1.7	2.2	1.7
17	530	539	559	2.7	2.8	2.8
18	481	598	663	2.4	3.1	3.2
19	399	425	474	2.0	2.2	2.4
20	414	399	414	2.2	2.1	2.1
21	599	584	772	3.2	3.1	3.8
22	1,083	1,058	1,066	5.9	5.9	5.5
23	1,132	1,139	1,091	6.6	6.7	6.0
24	840	898	890	5.2	5.6	5.2

* Excludes data for August 2003 due to blackout.

As Table 2-11 indicates, delivery hour 22 through 24 are the hours with the second to fourth highest difference between peak and minimum hourly demand. The hour with the largest difference between peak and minimum demand is delivery hour 7. This is the morning hour were demand increases rapidly. Hours 22 through 24 are the hours were demand declines most rapidly. The large difference between the hourly peak and minimum demand in these hours contributes to the general positive bias between pre-dispatch prices and real-time prices.

A second source of the persistent difference between pre-dispatch and real-time in hours 22 through 24 is the persistent and positive difference between the demand value used in pre-dispatch and the actual peak demand value realised in real-time. For example as Table 2-10 above indicates, roughly 80% of the time the pre-dispatch demand value is higher than the real-time peak demand value in hours 23 and 24, the highest percentage of all hours. The difference is positive 62.5% of time in delivery hour 22.

The MAU and IMO have examined this persistent discrepancy and believe that it may relate to the manner in which the IMO projects the peak demand value for the hour. In particular, the IMO forecasts the average demand value in each hour. However, because the pre-dispatch requires the input of the hourly peak demand, the IMO must make an adjustment to their demand forecast to account for the peak demand. The adjustment does not attempt to forecast the actual peak demand. Instead, it uses a simple linear combination of the average forecast demand to project the hourly peaks. For example, suppose that the IMO forecasts that the average hourly demand for hour 21 is 21,000 MW while the hourly average demand for hour 22 is 20,000 MW. To compute the peak hourly demand for hour 22 it would simply add the forecasted demands for hour 21 and hour 22 and divide by 2 (i.e., 20,500 MW would be the hourly peak demand used in pre-dispatch for hour 22). Note however, that if the rate of change in demand in the hour is not linear there is a strong possibility that the algorithm used to calculate the peak demand will be biased. In particular, if the demand declines across these hours at an increasing rate (i.e., is convex) then this method for selecting the peak will overstate the peak demand value.

The MAU does not have data on the actual demand forecasts made by the IMO (i.e., the forecasts of the hourly average demands). The MAU has only the values input into the DSO (the values that ultimately influence the prices). The IMO have indicated to the MAU that its records do not indicate the same degree of persistent over-forecast in demand in hours 22 through 24 as do the MAU's data. The MAU and IMO are working together to understand the extent to which the IMO's algorithm to project the peak hourly demand values in hours 22 through 24 is contributing to the pre-dispatch to real-time bias.

Offsetting Flows of Imports and Exports

As noted above, the MAU report also raised concerns that persistent (and predictable) differences between pre-dispatch and real-time could be resulting in offsetting flows of imports and exports. These transactions would be driven by the difference between the pre-dispatch price and the real-time price but supported by the IOG payment. Importers are attracted to the Ontario market by the relatively high pre-dispatch price and the guarantee provided by the IOG. At the same time, exporters (who pay the real-time Ontario price) are attracted by the relatively low real-time price. In this sense, the persistent and positive difference between pre-dispatch and real-time creates an artificial arbitrage opportunity for offsetting imports and exports. These transactions do not improve market efficiency but they do result in payments from Ontario consumers to traders in the form of IOG's.[40]

Table 2-12 provides some indication of the tendency for offsetting imports and exports in hours 22 through 24. Table 2-12 reports the average hourly amount of offsetting imports at (i) the Michigan intertie, (ii) the New York intertie, and (iii) across the aggregate of the Michigan and New York interties.

Table 2-12 indicates the following. First, offsetting imports and exports occur most often on the New York intertie in delivery hour 24 with an average hourly amount 243 MW in 2004 (i.e., on average each hour has at least 243 MW of imports that are offset by 243 MW of exports). Delivery hour 22 and 23 are also among the highest four hours with offsetting imports in New York. The same story is not true for Michigan however, where offsetting imports/exports are most likely to occur during hours 13 and 14. In general, there are more offsetting imports/exports on the New York tie than on the Michigan tie and the number of offsetting imports/exports appears to be increasing overtime in all hours. Finally, when Michigan and New York are grouped together, the largest number of offsetting imports/exports occurs in the off-peak hours of hour 1 through hour 6 and in hour 24.

Table 2-12: Offsetting Imports, Hourly Averages (MW)
Since Market Opening

Intertie	Michigan			New York			Michigan + New York		
Hour	**2002**	**2003***	**2004**	**2002**	**2003***	**2004**	**2002**	**2003***	**2004**
1	0	107	49	50	122	126	373	625	746
2	0	109	55	46	106	99	414	642	776
3	0	99	44	41	86	82	419	628	757
4	0	101	43	39	74	57	443	628	790
5	0	119	54	43	78	68	474	654	799
6	0	116	76	40	100	81	448	671	774
7	64	113	91	30	84	83	292	538	648
8	73	119	95	26	65	75	199	403	479
9	82	127	84	38	79	107	176	388	482
10	61	137	92	41	110	137	158	380	491
11	54	141	115	44	115	98	160	388	498
12	53	144	127	51	129	107	174	398	519
13	49	147	166	53	115	122	169	394	544
14	57	142	153	47	108	126	171	397	540
15	56	130	147	50	103	107	161	382	514
16	57	137	140	52	102	120	168	378	503
17	47	137	139	55	101	144	170	377	496
18	61	133	100	55	93	132	154	364	457
19	57	133	89	49	96	161	153	359	456
20	35	138	117	53	97	163	147	357	444
21	42	133	104	55	114	186	147	366	457

[40] Where electricity is 'wheeled' through Ontario by a single entity, no IOG payments apply. The issue here is independent decisions by different traders in response to perceived arbitrage opportunities that have the overall effect of increasing IOG payments.

Intertie	Michigan			New York			Michigan + New York		
Hour	2002	2003*	2004	2002	2003*	2004	2002	2003*	2004
22	36	137	88	55	122	174	162	375	480
23	0	127	122	70	136	186	231	503	568
24	250	143	79	93	231	243	348	605	704

* Excludes data for August 2003 due to blackout.

From the data available, it is difficult to determine if persistent differences between pre-dispatch and real-time, particularly those in delivery hour 22 to 24 are resulting in a large number of offsetting imports and exports. In any event, improvements in the IMO's approach to adjusting the pre-dispatch demand to project the hourly peak demand should reduce the potential for these types of offsetting transactions.

Purpose of the IOG in Delivery Hour 22 through 24

The MAU report to the Panel also posed the question as to whether the IOG was necessary in the hours of 22 through 24. As discussed above, the intent behind implementing the IOG was to reduce importers' trading risk to encourage imports to Ontario during periods of tight supply or supply shortages in Ontario. In this regard, the IOG represents a form of insurance - it is a payment made to importers to assure that sufficient supply is available to avoid shortages. However, one would not expect that supply shortages would be an issue for delivery hour 22 through 24.

There is a broader issue here that deserves further investigation by the IMO, and that is whether the systematic over-prediction of real-time outcomes in pre-dispatch is contributing to IOG payments that may not be required for reliability concerns in hours other than 22-24. In other words, are we paying more for this 'insurance policy' than we should be.

4. *Analysis of Low Priced Hours*

Commencing with this report, we have asked the MAU to begin to routinely review all 'low priced hours' and report their findings. For the purpose of this review, we defined a 'low priced hour' as any hour in which the HOEP was less than $20/MWh. Table 2-13 provides the number of hours in which the HOEP was less then $20 by month and by year since market opening.

Table 2-13: Hours with HOEP <$20, Monthly Since Market Opening

	Hours with HOEP<$20		
Month/Year	**2002**	**2003**	**2004**
Jan	N/A	3	1
Feb	N/A	0	0
Mar	N/A	0	1
Apr	N/A	0	2
May	119	8	N/A
Jun	43	40	N/A
Jul	0	20	N/A
Aug	0	1	N/A
Sep	0	10	N/A
Oct	0	0	N/A
Nov	0	0	N/A
Dec	0	13	N/A

There have been a total of 261 hours since market opening for which the HOEP was less than $20. Most of the hours (46%) occurred in the first month of market opening when demand was relatively low and there were few planned outages or forced outages. In comparison to the same months in 2002, there was a large number of hours in July, September and December, 2003 in which the HOEP was less than $20. The relatively large number of low priced hours during July, September and December of 2003 is attributable to the lower demand levels that occurred in 2003. There was also a relative abundance of available (lower cost) supply during these months compared to the same months in 2002. Several large nuclear generation facilities had returned to service by this time in 2003, higher water levels due to increased amounts of rainfall around July and September of 2003 increased the amount of hydroelectric energy available, and a new entrant in 2003 added additional supply in 2003.

Since market opening, the lowest HOEP was $7.84 in delivery hour 25 on May 16, 2002. The lowest HOEP for the period reviewed under this report was $13.36, which occurred on December 23, 2003 in delivery hour 4.

The MAU reviewed the 'low priced' hours and determined that a HOEP below $20 typically occurs in hours when at least one of the following occurs:

- *Demand is low.* Ontario demand is less than 15,000 MW. This typically occurs in the overnight hours, on holidays or during the spring/fall.
- *A large amount of base-load supply is available.* There is a significant portion of the demand that is satisfied by base-load generation. In periods of freshet such as the spring time months of April, May and June, this base-load supply is augmented by the supply from a number of hydroelectric facilities that become "run-of-river" facilities due to the abundance of water from the spring run-off.

While these are the primary factors that contribute to a HOEP less than $20, there are other factors that can exaggerate the supply demand balance in a manner that places additional downward pressure on the HOEP. These factors include:

- *A large pre-dispatch to real-time forecast difference.* A large pre-dispatch to real-time forecast difference can result in an over-purchase of imports or an under-purchase of exports. Then in real-time, when demand is lower than forecasted, the extra imports are placed at the bottom of the offer stack and other relatively lower cost Ontario generation is backed down to meet the lower real-time demand. This causes the real-time HOEP to be lower than it would otherwise have been. In periods when there is a relative abundance of base-load supply to meet the relatively low demand, it is the relatively costlier fossil generation that is backed down due to the effects of the over-forecast of demand and prices are then set by the base-load generation.

- *A relatively large amount of failed exports.* When exports are scheduled in pre-dispatch, at times, either additional fossil generation facilities may be committed to remain on-line (through low offer prices at their minimum loading points) or additional imports may be scheduled in pre-dispatch to service the exports. If a large amount (MW) of these exports then fail however, then the committed fossil units and imports are still scheduled and cannot be dispatched off. Some other units are dispatched off. Once again, in periods when there is a relative abundance of base-load supply to meet the relatively low demand, it is the relatively costlier fossil generation that is backed down due to the effects of the failed transactions and prices are then set by the base-load generation.

Furthermore, a price of $20/MWh is typically below the marginal cost of the fossil-fuelled generation facilities that are located in the eastern part of the province. In this respect, one would not expect a fossil generation unit to be on-line providing energy in 'low priced hours'; it would be a potential anomaly. The MAU therefore paid particular focus to the fossil units that were on-line in these hours to see if there were any potential anomalous offers. In particular, were there any generators that appeared to be operating below their incremental cost?

The MAU did identify several hours with HOEP less than $20 when eastern fossil-fired generation units were on-line and providing energy. In reviewing each case, the MAU determined that these units were on-line for one or more of the following reasons:

- The unit was operating at its minimum loading point in order to stay on-line and be available for the peak hours of the day. Units often stay on-line in off-peak hours to avoid having to incur cost for restarting their units or to avoid the risk of potential damage and future forced outages that may be caused by frequently shutting down the unit. Furthermore for some units, once they are shutdown, they cannot be restarted for several hours. This would mean that the unit would not be available later in the day when prices are higher. In each of these cases, the incremental heat rate measure of incremental cost does not reflect the true (opportunity) cost, with the true cost being less than the heat rate measure of cost.

- The unit was on-line in order to provide 10-minute spinning reserve. In off-peak hours, an additional fossil unit may be required to stay on-line in order that sufficient 10-minute spinning reserve is available to meet NERC and NPCC standards. In this instance, the unit may be scheduled at minimum levels to ensure it stays on-line to provide reserve. The unit may also be 'force-loaded' to provide reserve. In particular, the amount of reserve that a unit can provide depends on how much energy it is providing. For each unit, there is an optimal production point at which the unit can provide the most amount of reserve. Sometimes, a unit is scheduled for energy to this point to increase the amount of reserve available. It will thus be scheduled for energy even though its energy offer is higher than the market clearing price. In this instance, the unit will be fully compensated for both its energy and operating reserve through the operating reserve price; it will be profitable for the unit to produce energy even though the energy clearing price is less than its energy offer (incremental cost).

As Table 2-13 above indicates, there were seventeen hours in the period November 1, 2003 to April 30, 2004 in which the HOEP was less than $20/MWh. Fourteen of these occurred during the Christmas holiday period (between December 23, 2003 and January 1, 2004). In all of these hours, the Ontario demand was below 14,000 MW. Table 2-16 in Appendix C provides key data describing the factors affecting the low HOEP in these hours.

One of these days was December 23, 2003. There were two consecutive hours on this day with HOEP below $20, delivery hour 4 and delivery hour 5. We discuss the factors influencing the low HOEP in these hours in Case 1 below.

The other three hours occurred in late March (March 30) and early to mid April (April 9 and April 19). On March 30, delivery hour 4, demand was 13,500 MW, while for the two hours in April, demand was never higher than 13,000 MW. At the same time, there was a considerable abundance of hydroelectric generation available due to the large freshet experienced in the spring. Given the relatively low level of demand and the abundance of base-load generation in these hours, the price never exceeded $20.

Case 1: December 23, 2003, Delivery Hours 4 and 5

On December 23, there were two consecutive hours (hours 4 and 5) for which the HOEP was less than $20. There were several factors influencing the HOEP in these hours. First, the demand was relatively low with the average demand being 13,797 MW in hour 4 and 13,956 MW in hour 5. Mild winter temperatures contributed to the relatively low demand on this day, as did the upcoming Christmas holiday period. When demand is at these low levels, it can generally be satisfied by base-load generation; less fossil generation is required.

A second factor influencing the HOEP in these hours was the large over-forecast of demand in pre-dispatch. As Table 2-16 in Appendix C indicates, the final pre-dispatch demand was 540 MW and 667 MW higher than the actual hourly average demand in hours 4 and 5 respectively. When pre-dispatch demand is 500 or 600 MW higher, additional imports are selected in pre-dispatch and fewer exports are selected than would have been selected had the forecast been more accurate. The over-forecast is also reflected in the pre-dispatch price. The pre-dispatch price in these hours was $22.24 and $23.29 respectively; the HOEP was well below these levels.

The over-forecast of demand (price) in pre-dispatch has two effects on real-time outcomes. First, the additional imports selected cannot be dispatched off in real-time, even though they may be more expensive than some of the Ontario generators. When these imports are placed at the bottom of the offer curve, and demand comes in lighter than expected, the most expensive Ontario generators are dispatched off, causing the base-load generators with offer prices below $20 to establish the price. Second, if the pre-dispatch is signalling a higher demand and higher price for the hours, fossil units may decide to commit their units by offering their minimum running levels at prices that will assure that the units stay on-line. When the actual demand is lighter than forecast, these units stay on-line and other base-load units are dispatched down to meet the lower than expected demand. These units set the price with an offer price below $20.

In delivery hours 4 and 5 on this day, both of these factors influenced the low HOEP. First, the pre-dispatch price of $22.24 and $23.29 attracted 233 MW and 84 MW of imports that would not have been selected if the forecast had been more accurate. These are imports that were offered above the HOEP in the hour.

Second, 174 MW of exports were not selected as a result of the higher pre-dispatch price. The failure to select the exports also means that the HOEP will be lower than it would have been had the forecast accurately identified the load.

Third, there were a considerable number of fossil units on-line in this hour. The MAU has no way of detecting whether the pre-dispatch price signal was the cause of the units staying on-line at their minimum loading point or if the units were on-line for one of the other reasons discussed above. There were a total of 10 fossil units (at three facilities) on-line. Each unit had been on-line the entire prior day and for the earlier hours of December 23. In each of these hours, the market clearing prices were higher than the units' incremental (heat rate measured) cost; it would have been economic for the units to run.

All but two of the units were running at minimum levels. The two units that were running above their minimum were running at 80 MW below full capacity. During this period these units were having operating problems. The units were running at full capacity for several hours on the day and on the previous days. The units were offered at low prices to ensure they ran at full or near full capacity in order to avoid sporadic dispatch that could affect the stability of the units' operations and potential outages.

Appendix A: Summary Data on High Priced Hours

Table 2-14: Summary Data on Hours Greater than $200 MWh

Delivery Date	10-Jan-04	14-Jan-04	26-Jan-04	06-Apr-04
Delivery Hour	12	18	18	8
HOEP ($/MWh)	249.55	340.45	207.56	258.93
Hourly Uplifts ($/MWh)	9.94	22.74	8.28	13.70
Ontario Pre-Dispatch Price ($/MWh)	150.00	448.00	212.00	67.00
Pre-dispatch Demand (MW)	21,229	24,478	24,604	18,822
Average Actual Demand (MW)	20,788	24,210	24,361	18,592
Actual Peak Demand (MW)	20,983	24,488	24,764	18,892
Failed Imports (MW)	0	275	25	0
Failed Exports (MW)	0	0	0	0
Self Scheduled Under-generating (MW)	200	29.2	-20	-94
Pre-dispatch Supply Cushion (%)	23.3	9.0	10.2	10.3
Real-time Supply Cushion (%)	1.1	0.0	3.3	0.6

Appendix B: Events of January 15, 2004

Table 2-15: Summary of Out of Market Control Actions Employed, January 15, 2004

	Material Change in Supply				Out of Market Control Actions					Prices			
Hour (1)	Derate 3Hr PD - RT (MW) (2)	Maximium Hourly Derate 1Hr PD - RT (MW) (3)	Failed Imports (MW) (4)	Total Material Change in Supply (MW) (5)	Imports Purchased After Pre-dispatch (MW) (6)	Exports Cancelled After Pre-dispatch (MW) (7)	Emergency Purchases (MW) (8)	Out-of-Market Sources of Reserve (MW) (9)	Total of Out-of-Market Control Actions (MW) (10)	3 Hr Pre-dispatch Price ($/MWh) (11)	1 Hr Pre-dispatch Price ($/MWh) (12)	HOEP ($/MWh) (13)	Admin. Price ($/MWh) (14)
17	2,051	937	0	773	0	566	125	603	1,294	175.00	400.00	122.08	N/A
18	1,847	255	933	827	400	133	600	586	1,719	450.00	500.00	143.08	N/A
19	(454)	(458)	1,112	378	553	177	680	136	1,546	1,000.00	925.00	145.9	144.61
20	(1,162)	228	1,712	1,783	1,204	156	500	0	1,860	801.99	500.00	873.02	142.55
21	(563)	553	1,284	1,786	1,331	120	0	63	1,514	501.00	444.00	1,871.13	134.23
22	353	302	965	1,085	790	434	0	0	1,224	400.00	453.50	529.59	95.57

Appendix C: Summary Data on Low Priced Hours

Table 2-16: Summary Data on Hours Less than $20/MWh

Date	**23-Dec-03**	**23-Dec-03**	**24-Dec-03**	**26-Dec-03**	**26-Dec-03**	**29-Dec-03**	**29-Dec-03**	**29-Dec-03**	**31-Dec-03**	**31-Dec-03**	**31-Dec-03**	**31-Dec-03**	**31-Dec-03**	**01-Jan-04**	**30-Mar-04**	**09-Apr-04**	**19-Apr-04**
Delivery Hour	**4**	**5**	**4**	**4**	**5**	**4**	**5**	**6**	**2**	**3**	**4**	**5**	**6**	**9**	**4**	**3**	**2**
Demand (MW)	13,797	13,956	13,140	12,354	12,411	12,471	12,481	12,864	13,813	13,383	13,299	13,290	13,711	13,543	13,563	12,950	12,529
Percentage Base-load Supply (%)	76.4	76.9	80.8	85.8	85.8	84.4	84.0	82.8	81.2	81.4	81.3	81.4	81.7	85.0	81.3	87.8	88.9
Fossil Generation (MW)	1,908	1,914	1,290	750	750	928	928	1,191	1,360	1,260	1,260	1,260	1,260	1,063	1,328	600	548
Percentage of Fossil Generation (%)	13.9	13.7	9.6	6.0	6.0	7.3	7.2	8.8	9.6	9.2	9.2	9.2	9.0	7.5	8.9	4.6	4.0
Difference Between Pre-dispatch and Avg Real-time Demand (MW)	540	667	254	78	106	105	264	609	403	250	87	146	218	768	195	335	500
Imports (MW)	1,223	1,126	1,269	1,186	1,226	873	872	919	1,096	1,095	1,100	1,098	1,098	898	232	1,127	911
Exports (MW)	765	836	1,203	980	969	738	790	1,163	1,177	1,177	1,177	1,177	1,102	1,261	1,077	936	1,549
Net Failed Exports (MW)	85	0	0	0	0	390	338	250	0	201	0	201	201	0	75	467	0
Pre-dispatch Price ($/MWh)	22.24	23.29	21.55	18.00	19.00	22.64	22.41	24.00	21.39	21.39	20.36	21.05	23.00	25.00	20.67	35.05	34.12
HOEP ($/MWh)	13.36	18.33	19.32	17.43	17.72	18.30	14.66	19.44	19.54	18.62	19.48	18.56	19.93	19.87	19.84	19.65	17.83

Chapter 3: Summary of Changes to the Market Since the Last Report

1. *Introduction*

A market is operating efficiently when energy is produced by the cheapest supplier, is consumed by those most willing to pay for it and the price of energy covers the production cost of the marginal supplier. The reliability of the system is dependent on market participants' response to clear and transparent market signals in all time frames.

In the last MSP report, we reported upon changes made during the first 18 months of the market as participants and the IMO learned how the market worked in practice.

This chapter describes some of the continuing changes in Market Rules and procedures made over the course of the past six months.

2. *IMO Initiatives*

2.1 The Introduction of Control Action Sources of Operating Reserve in the Market

As discussed in earlier chapters and previous reports, when there is insufficient operating reserve (OR) the IMO is permitted to use out-of-market control action sources of operating reserve in real-time.[41] These sources are: 3 percent voltage cuts, 5 percent voltage cuts, recallable exports and the reduction of 30-minute operating reserve for up to 4 hours if it is felt that it can be restored. In the past when the IMO saw an energy shortage it introduced these resources manually in real-time. This had the effect of lowering the real-time price relative to pre-dispatch price and our analysis suggested that this contributed substantially to the discrepancy between the pre-dispatch and real-time prices. In July 2003, a rule amendment was passed to allow standing offers for these

[41] See our December 2003 report at pp. 94-96 (http://www.theimo.com/imoweb/marketSurveil/mspReports.asp).

sources to be introduced in the market at prices to be determined by the IMO Board.[42] These standing offers would then be available for selection by the dispatch scheduling algorithm on the basis of need and the relative prices of all offers of operating reserve. This program of including control action sources of operating reserve in the market is known as "CAOR".

Following consultation with participants, the IMO Board decided to introduce a portion of these resources into the unconstrained and constrained schedules in two 200 MW tranches so that price effects as well as unpredicted effects could be determined. The first 200 MW was introduced on August 6, 2003 with prices imputed to these resources at $30.10 for 10-minute non-spin and $30 for 30-minute OR. The second 200 MW was introduced on October 15, 2003 with the same price structure.

In December 2003, the IMO also decided to discontinue its purchases of supplemental OR. On January 14, 2004, the 200 MW requirement for supplemental OR during on-peak hours was removed. This reduced OR requirements from 1,580 MW to 1,380 MW. The 200 MW supplemental OR requirement had been introduced in June 2002 amid concerns about system reliability.

Since the introduction of the CAOR and the elimination of the supplemental OR requirement, the MAU has observed a reduction in the incidence of out-of-market control actions measured as the percentage of intervals with manual OR reductions. Six percent of intervals experienced out-of-market OR reductions prior to August 6, 2003 compared to 2% after August 6, 2003 through to April 30, 2004.[43]

We understand that the IMO is considering a further transfer of out-of-market sources of OR into the CAOR program, this time using the 30-minute OR that can be reduced for up to 4 hours. The expectation is that inclusion of this resource will eliminate the need for manual out-of-market reductions.

[42] To be consistent with the emergency control actions list, in practice, the IMO uses recallable exports before voltage cuts.

CAOR can be selected in differing amounts in the constrained and unconstrained schedules in both pre-dispatch and real-time, and this provides important additional flexibility with regard to preserving the integrity of price signals in the energy market. As is evident from Table 3-1, CAOR has been used much more frequently in the constrained schedule than the unconstrained schedule. This is consistent with the fact that fewer alternatives are available under the constrained schedule than under the unconstrained schedule. Causes of the difference between the schedules include:

- the constrained schedule recognizes that some generation is bottled by transmission limitations;
- the real-time constrained schedule is based on actual ramp rates while the real-time unconstrained schedule assumes ramp rates that are 12-times higher;
- the real-time constrained schedule is based upon forecast demand while the real-time unconstrained schedule is based on actual demand. When the constrained forecast demand is higher, resources are tighter.

Over the past nine months, the frequency with which CAOR has been used has increased in both schedules and in both pre-dispatch and real-time. A possible explanation is that CAOR is relatively inexpensive in comparison to an increasing quantity of other sources of OR available in the market. We will continue to monitor developments in the OR market with a view to determining the effect of current pricing of CAOR on the incentive for new sources of OR to enter the market.

We understand from the IMO that over 200 MW of new dispatchable load is in the process of entering the market. This is consistent with the current, higher prices of OR being attractive to some new sources. Of course, current pricing of CAOR might be crowding out other potential sources and the Panel will continue to be alert to this possibility.

[43] See Table A-30 in the Statistical Appendix for additional data.

Table 3-1: Use of CAOR in Real-time and Pre-dispatch

	Real-Time use of CAOR	
	Constrained	**Unconstrained**
August 6, 2003 - October 14, 2003	8.20%	1.80%
October 15, 2003 - January 14, 2004	13.40%	5.90%
January 15, 2004 - April 30, 2004	14.40%	5.00%
	Pre-Dispatch use of CAOR	
	Constrained	**Unconstrained**
August 6, 2003 - October 14, 2003	7.90%	2.90%
October 15, 2003 - January 14, 2004	11.30%	7.70%
January 15, 2004 - April 30, 2004	16.00%	10.60%

2.2 Clarifying Transmitter's Role to Co-ordinate Outages with Affected Market Participants

Effective at the end of November 2003, the IMO modified the Market Rules relating to co-ordinating transmission outages. Except where reliability is an issue, the process has been streamlined so as to give the transmitter the responsibility of notifying and discussing planned transmission outages with affected market participants. Since transmission outages can lead to additional costs or inconvenience to market participants, direct co-ordination among them is expected to improve market efficiency. This is also consistent with the Transmission System Code, which requires transmitters to report changes to equipment that could materially impact a customer.

In previous reports the MSP has stressed the importance of the co-ordination of transmission outages with generation and load.

2.3 Observations following Changes to Confidentiality Classifications

In January 2003, the IMO Board requested the MSP to advise it regarding the potential impacts, if any, of proposed changes to certain confidentiality classifications, and the release of information pertaining to generator output and intertie transactions.

Market participants consulted by the MSP in the preparation of its report cited the following benefits from greater disclosure:

1) Improved timing of start-up fossil generation;
2) More efficient short-term decisions about fuel deployment in particular whether contracted natural gas should be used for generation or resold;
3) Improved timing of planned outages;
4) Greater liquidity in the forward markets;
5) A more favourable investment climate for new generation in Ontario;
6) Easier detection of inappropriate behaviour.

At the same time, OPG argued that the release of such information was inappropriate, as such information is not required in any of the control areas adjacent to Ontario. OPG was also of the view that the release of such information could affect the efficiency of the market by allowing other participants to "price up" or withhold offers.

In its report to the Board, the Panel provided its assessment of the effect of the proposed disclosure on competition in the wholesale market.[44] The Panel concluded that the proposed disclosure would have no material impact on competition. The Panel also recommended that, in the event that the Board decided to proceed with the proposed release of information to the market, the consequences of this action should be monitored and provisions for disclosure should be revisited periodically.

[44] Our report to the Board, dated March 17, 2003, is available at http://www.theimo.com/imoweb/marketSurveil/mspReports.asp.

In March 2003, the IMO Board approved the release of information pertaining to generator output and intertie transactions with a one hour time delay. On December 15, 2003, the IMO began publishing generator-specific information one hour after the fact.

The MSP has asked the MAU to determine whether the publication of generator-specific information with a one hour delay is having any impact, either positive or negative, on the market. One hypothesis is that improved information increases market efficiency. In the simplest terms, the availability of more accurate and more timely knowledge of buying and selling opportunities in the market should result in both a market equilibrium that is more efficient (in the sense of involving the lowest cost sellers and the buyers most willing to pay) and faster convergence to this equilibrium state. An alternate hypothesis is that improved information about suppliers that are absent from the market may make it easier to engage in a strategy of withholding supply and raising the market price. The resulting market equilibrium would then be characterized by higher cost sellers and a higher price. It is not clear how withholding would change the path to equilibrium.

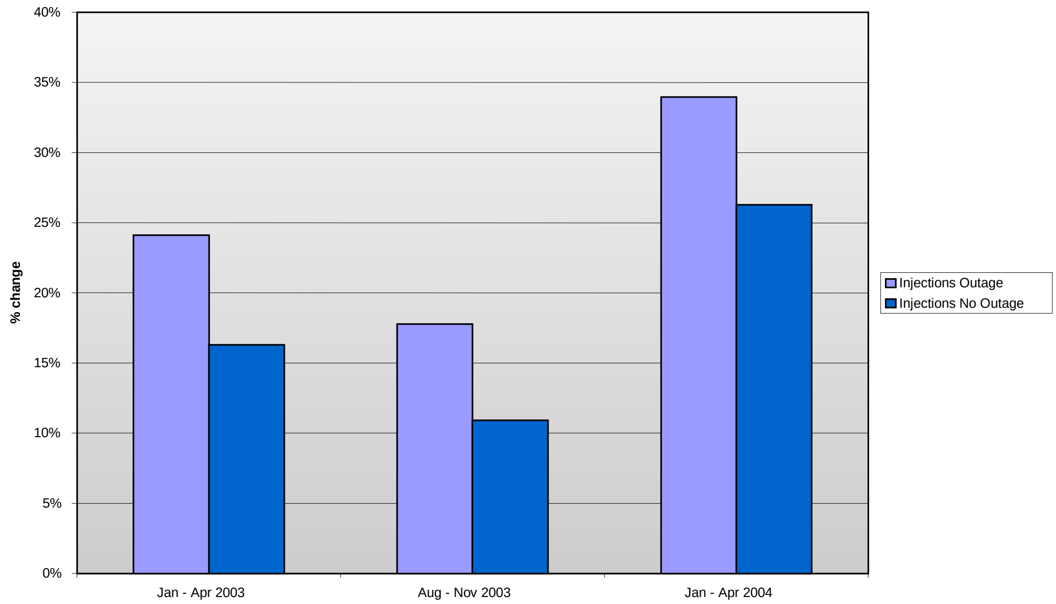
In the course of its normal surveillance functions, the MAU has not been able to discern any change in behaviour that could be attributed to the increase in information available to the market. In particular, the MAU has found no evidence of economic or physical withholding.

The MAU also attempted a more formal analysis of whether behaviour in the market changed after publication of generator-specific information with a one hour delay began in December 2003 and if so, whether this change was pro-competitive or anti-competitive.

The MAU conducted a variety of tests and the results of two of them are reported here. The general test methodology is to compare behaviour in the market after the implementation of the disclosure policy (January–April, 2004) with behaviour during comparable periods of time before its implementation. The “before” periods chosen for purposes of this comparison are January–April 2003 and August–November 2003.

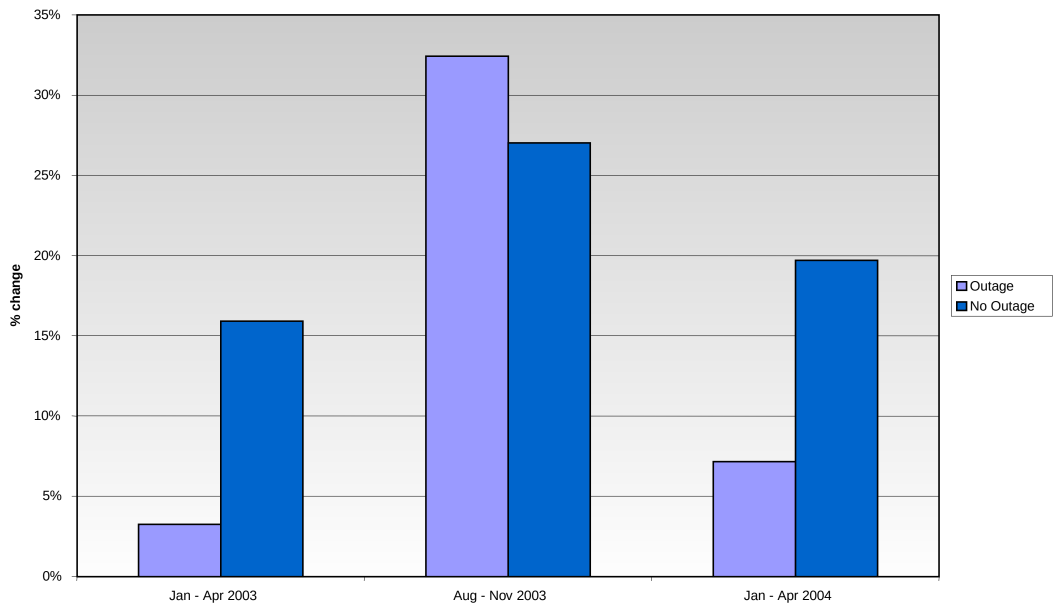
The first test compares the responsiveness of import offers to news of an outage before and after the implementation of the disclosure policy. The responsiveness of the market to news of an outage at time *t*, is defined as the percentage difference between import offers seven hours ahead as at time *t*-2 and import offers two hours ahead as at time *t*+3. In essence, this is a comparison of imports offered for a given hour two hours before an outage occurs with imports offered for the same hour three hours after the outage occurs. This comparison is made for all occasions in each of the three periods in which there was an outage. The average percentage increase in import offers after an outage for each of the three periods is shown by the lighter bars in Figure 3-1. Since import offers may increase between seven hours ahead and two hours ahead even if there is no outage, the average percentage change in import offers between seven hours ahead and two hours ahead is calculated for all the hours in each of the three periods for which there was no intervening outage. This is shown by the darker bars in Figure 3-1. Figure 3-1 shows that during all three periods, import offers increased more when there was an outage than when there was not. There does not appear to be much difference, however, between the period after the implementation of the disclosure policy and the two periods before as far as the differential response of import offers is concerned. While a variety of other influences could have been at play, this test implies that the provision of additional information to the market made import offers neither more nor less responsive to the occurrence of an outage.

Figure 3-1: Change in Import Offers 7 Hours Ahead to 2 Hours Ahead



The second test conducted by the MAU and reported here is essentially the same as described above except that it is applied to export bids (offtakes). The results of this test are presented in Figure 3-2. The percentage increase in export bids after an outage is shown by the lighter bars in Figure 3-2. The average percentage difference between seven hours ahead and two hours ahead when there are no outages is shown by the darker bars. The darker bars show that when there are no outages, export bids are higher two hours ahead than they are seven hours ahead. The interpretation of Figure 3-2 is easiest for the two winter (January to April) periods. The darker bars show that export bids are 16 to 20 percent higher two hours ahead than seven hours ahead when there are no outages in winter 2003 and winter 2004 respectively. The lighter bars for the two winter periods show that export bids are only 3 to 7 percent higher two hours ahead than they were seven hours ahead when there was an outage five hours ahead. Thus, the two winter periods show plausible and similar behaviour – export bids increase by a smaller amount when there has been an outage than when there hasn't. An implication of this behaviour of export bids in the two winter periods is that even without disclosure, exporters were able to identify periods where price risk after an outage had increased. The middle two bars in Figure 3-2 say that in the fall (August to November) of 2003 export bids were much higher (around 30 percent) two hours ahead than seven hours ahead regardless of whether there was an outage or not. The factors that may have been at work to produce this result are not obvious.

Figure 3-2: Changes in Export Bids 7 Hours Ahead to 2 Hours Ahead



It is, in general, quite difficult to test whether additional information has made a market more responsive, holding all else equal in order to discern the marginal effect of a policy change. The Panel is persuaded by the MAU's conclusion that the disclosure of generator-specific information has not resulted in any anti-competitive behaviour. Nor is it apparent from the tests that have been conducted to date that there has been any material change in behaviour that is traceable to the provision of this additional information to the market.

3. *MSP Initiatives*

3.1 Update on Implementation of MSP CMSC Recommendations

In previous reports, we have discussed our examination of the role played by constrained off congestion management settlement credits (CMSC payments). This examination resulted in a report submitted to the IMO Board on July 3, 2003, with recommendations that dealt with:[45]

1) the reduction or elimination of some constrained off CMSC payments;
2) the mechanics of CMSC review for hydroelectric facilities;
3) CMSC payments related to the Niagara 25 Hz sub-system and;
4) impediments to effective transmission planning as well as suggestions for reform.

Presently the IMO Board has put on hold proposed changes to the Niagara 25 Hz sub-system until the financial status of the major customer of this system becomes clearer.

Since then there have been ongoing activities in each of these areas, as mentioned in our Monitoring Report on the First Eighteen Months. It is worth noting at this time the subsequent progress in one particular area – self-induced CMSC payments.

3.1.1 Facility (Self) Induced CMSC Payments

On December 12, 2003, the IMO Board approved a market rule amendment (section 3.5.1A of Chapter 9) which effectively states that a dispatchable load facility is not entitled to CMSC resulting from the facility's own equipment or operational limitations. Thus the IMO would not pay or could recover CMSC if it were induced by the load not following dispatch instructions, and/or the result of a low ramp rate quoted in the bid.

[45] For more details on the consultation and recommendations please refer to the IMO web site, http://www.theimo.com/imoweb/consult/consult_cmsc.asp and specifically http://www.theimo.com/imoweb/pubs/marketSurv/ms_CMSC-Consultation_20030703.pdf

We had identified the situation where a dispatch deviation in one interval could lead to restricting the dispatch in the subsequent intervals, thus inducing a constrained off CMSC payment.

This is of concern for both dispatchable load and generating facilities, but a rule was introduced at the time only for dispatchable loads. The rule amendment was so limited because of the larger CMSC payments being made to dispatchable load (for each event and possibly even in total), and because of significant complexity associated with the assessment for generation facilities.

The MAU has been reviewing these dispatchable load payments and has offset approximately $1.8 million in CMSC to date. This is associated with trade days in March and April only,[46] and is higher than the $6 million per year or about $0.5 million per month anticipated when the rule was put into effect.

Due to the significant complexity in discerning self-induced payments to generators this continues to be under review by the IMO as to whether such a rule should be proposed.

[46] In earlier months this was being dealt with by the Compliance Unit as a continuation of earlier procedures where this may have been a matter of non-compliance as well, or the participant was voluntarily allowing recovery of some of this CMSC.

Chapter 4: State of Competition within, and the Efficiency of, the IMO-Administered Markets

1. *General Assessment*

This report is typical of our earlier reports insofar as the market anomalies identified are explained by the interaction of demand and supply or learning experiences for the IMO and market participants on the implications of the Market Rules and facilitating procedures. In this six-month period two of the four high priced events were caused by demand pressures, a third by a forced derate of a large unit and the last by procedures governing selection of offers by the Dispatch Scheduling Optimizer (DSO). One of the contributing factors to more stable prices in the recent period was significantly improved supply towards the end of 2003 with the return of three nuclear generation units and expanded capacity at other Ontario-based facilities adding about 2,500 MW. As observed in our very first report, a better supply-demand balance goes a long way to alleviating stresses and strains in the market. In terms of market participant conduct, we have found no evidence of gaming, nor any evidence of the abuse of market power.

Our review of anomalous events in Chapter 2 has pointed once again to the way in which the use of out-of-market control actions can distort price signals and to the continuing tendency of pre-dispatch price forecasts to overstate real-time outcomes. The IMO has, in consultation with market participants, undertaken actions to address these issues and progress is being made. Chapter 2 contains one observation that we have not previously made. In discussing the events of January 15, we noted that the way in which emergency imports are introduced into the DSO has the effect of lowering the market clearing price, which appears inconsistent with sending appropriate signals regarding the supply/demand balance. We suggest that the IMO reconsider this approach.

2. *Moving Forward*

Since our last report dated December 10, 2003, the Government of Ontario has provided further guidance on its plans for the electricity sector.[47] We welcome the comprehensive nature of the government's plans and the conscious effort to provide a more certain regulatory and public policy environment. Most important to the Panel is that the government has chosen to continue the wholesale market. The Panel's view, as stated in its last report, is that market-based dispatch is working very well in Ontario and has the near-term potential to work even better.

The government has also proposed a number of initiatives intended to supplement the market. While we recognize that the new framework will take time to implement and will evolve over that time, we also believe that there are some crucial implementation issues. Here we offer some initial comments on some of the main challenges:

- A key element of the government framework is that "ratepayers must pay the true cost of the electricity they consume." The wholesale market is the best vehicle for ascertaining the real cost of electricity - as long as market prices accurately reflect the supply-demand balance. The wholesale market price will not reflect the true cost of electrical energy if there is gaming or the abuse of market power. In light of the likelihood of the continuing concentration of the ownership of generation resources in relatively few hands, the restraint of the exercise of market power will be a key policy issue. We discuss our work in this area in section 3 below.
- IMO procedures or Market Rules may also have the unintended consequence of distorting market prices. The Panel will continue its work in identifying, documenting and publishing its findings regarding any such distortions. Operational issues of this nature are frequently a result of a concern with system reliability. While we recognize that reliability is paramount, reliability should be achieved in a way that minimizes the distortion of market signals. Since market opening, a number of

[47] At the time of writing, the government's legislation had not been tabled.

changes in Market Rules and procedures have been made to make market signals better reflect the supply-demand balance. One example is the introduction of control action sources of operating reserve in the market (CAOR) discussed in Chapter 3. The Panel is of the opinion that this experiment could be pursued further still.

- The wholesale marketplace has the capability of providing much more information about the true cost of energy than it is currently doing. In this regard, the Panel continues to support an evolution of the market to locational marginal pricing. In the Panel's opinion, nodal prices provide the best signal for both investment and consumption decisions.
- The government has announced its intention to issue Requests for Proposals (RFP) to provide new generation capacity in Ontario. As we understand it, there will be a competitive process for potential investors to bid to build new capacity. We understand the perceived need to compensate investors in new generation capacity although we are also of the opinion that a reduction in regulatory uncertainty and an increase in the transparency of the objectives and obligations of OPG will improve the investment climate considerably. We are also of the view that the RFP process will be more successful the less uncertain and the more transparent is the regime in which the potential bidders can expect to operate.
- Experience with the wholesale market over the last two years has provided compelling evidence of the efficiency of market-based dispatch. For this reason, it is crucial that all current sources of generation in Ontario continue to bid into the wholesale market and that all future sources of generation do so as well. The Panel strongly urges the government to incorporate this design feature in the terms of the RFP's for new generation it intends to issue.
- With the creation of a new entity, the Ontario Power Authority, it will be important to have clarity as to the relationships between it and the existing institutions, the IMO and the OEB. An ongoing dialogue among the three should be promoted with clear communications to participants.

We welcome the importance given to conservation and encouraging load responsiveness to price in the government's proposals. The challenge will be to provide education and incentives that encourage consumers to act rationally in their use of energy. Smart meters are important and the steps the government is proposing are welcome. But it will also be critical that the price signals from an effectively competitive wholesale market – reflecting the true cost of energy – be permitted to pass through to all consumers. The design of the standard rate plan for small businesses and residential consumers will be quite important. In our last report we set out three principles that we think should guide the elaboration of such a standard rate plan.[48] These are:

- "first, to promote efficiency in use through ensuring that the price paid for consumption at the margin reflects the incremental cost of producing electricity;
- second, to provide market driven opportunities for consumers to protect themselves against volatility; and
- third, to encourage and facilitate the ability of consumers to invest in interval meters to conserve energy where it is efficient for them to do so."

It seems to us that these principles should continue to apply. There will obviously be a need in rate design to reflect the lower cost of the 'heritage' electricity through some blended rate that recognizes regulated heritage rates and spot rates as determined in the wholesale market. There will also be a need for some stability through a periodic 'true-up' of the standard rate to market realities. We believe that both of these aspects of rate-setting can be managed in a way that is consistent with the principles set out above.

3. *Monitoring for the Exercise of Market Power*

The Market Rules charge us under section 3.1.1.1 of Chapter 3 to "…identify inappropriate or anomalous market conduct including, but not limited to, unilateral or interdependent behaviour resulting in abuses and possible abuses of market power and gaming". As discussed in earlier reports, market power is the ability to profitably set the market clearing price above competitive levels. When this occurs it is said that there is

[48] See page 109 of the December 2003 report.

an exercise of market power. We have drawn the distinction between the exercise of market power and the abuse of market power. The abuse of market power in our view is behaviour by market participants that interferes with the operation of the market so that competitive forces are not able to check the exercise of market power.

The original market design recognized the potential for the exercise of market power because of the dominance of Ontario Power Generation. The Market Power Mitigation Agreement (MPMA) addressed this market power issue by providing a schedule for the divestiture of key OPG generating assets and requiring the payment of a partial rebate to consumers if the average annual market price exceeded $38/MWh. One of the IMO licence conditions directed the Market Surveillance Panel to these arrangements and specified that if the annual price exceeded this threshold, the rebate was to be the 'sole remedy'. The calculations underlying the MPMA rebate come to an end at the close of 2004 and the government will likely be addressing its approach to market power issues as part of its final legislative package.

Although we clearly have a special responsibility with respect to addressing the potential abuse of market power we have found that understanding and identifying the exercise of market power is fundamental to carrying out our work. When the market price spikes upward we need to understand the causes. If the cause is the withholding of supply, the key characteristic of the exercise of market power, we believe it is part of our role to identify and, at a minimum, discuss our analysis of these events with the market participant in question. To do so requires a rigorous analytical framework that is understood and accepted by market participants. During the last several months we have begun to define in operational terms how we would identify the exercise of market power. We believe it would now be constructive to consult with market participants and other stakeholders on this framework.

STATISTICAL APPENDIX

TO

MARKET SURVEILLANCE PANEL
MONITORING REPORT ON
THE IMO-ADMINISTERED ELECTRICITY MARKETS

(MAY 2002 – APRIL 2004)

N.B. All figures and tables presented in this Appendix (and throughout this Report) exclude date from August 14, 2003 00:00:00 EST to August 22, 2003 23:59:59 EST. This is due to the suspension of the IMO-administered markets caused by the August 14, 2003 system failure in the Northeast.

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.

Table A-1: Monthly Energy Demand (TWh)

	Energy Consumption		Total Market Demand		Export	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	11.87	11.63	11.99	12.35	0.11	0.72
Jun	12.19	11.89	12.42	12.54	0.23	0.66
Jul	14.03	12.90	14.11	13.89	0.08	0.99
Aug	13.75	12.51	13.79	13.07	0.04	0.56
Sep	12.59	11.79	12.70	12.19	0.11	0.40
Oct	12.40	12.16	12.71	12.31	0.31	0.15
Nov	12.66	12.39	13.03	12.71	0.38	0.32
Dec	13.48	13.33	14.02	13.95	0.54	0.62
Jan	14.49	14.77	15.17	15.57	0.68	0.80
Feb	13.12	13.09	13.59	13.59	0.46	0.50
Mar	13.41	13.22	13.84	13.79	0.43	0.56
Apr	12.10	11.79	12.38	12.64	0.29	0.85

Table A-2: Average Monthly Temperature (°Celsius)

	2002	2003	2004
Jan	-0.3	-7.7	-9.0
Feb	-1.3	-6.9	-3.3
Mar	0.4	-0.5	2.3
Apr	7.3	5.6	6.9
May	11.3	12.3	N/A
Jun	19.2	18.6	N/A
Jul	24.2	21.4	N/A
Aug	22.7	21.9	N/A
Sep	20.2	17.2	N/A
Oct	9.2	9.1	N/A
Nov	3.3	5.0	N/A
Dec	-1.8	0.0	N/A

Table A-3: Number of Days Temperature Exceeded 30°C

	2002	2003	2004
Jan	0	0	0
Feb	0	0	0
Mar	0	0	0
Apr	0	0	0
May	0	0	N/A
Jun	5	4	N/A
Jul	15	1	N/A
Aug	7	3	N/A
Sep	4	0	N/A
Oct	0	0	N/A
Nov	0	0	N/A
Dec	0	0	N/A

Table A-4: Outages, May 2002-April 2004 (TWh)

	Total Outage		Planned Outage		Forced Outage	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	4.97	5.29	3.60	3.46	1.37	1.83
Jun	3.54	3.77	2.62	1.51	0.92	2.27
Jul	2.80	2.22	1.39	0.95	1.41	1.27
Aug	3.06	2.82	1.10	0.73	1.96	2.08
Sep	3.95	3.94	2.97	2.28	0.98	1.65
Oct	5.29	5.52	4.34	3.48	0.95	2.05
Nov	4.59	2.91	3.38	0.96	1.21	1.96
Dec	3.75	1.45	2.15	0.69	1.61	0.75
Jan	2.31	2.88	0.91	0.27	1.40	2.61
Feb	2.68	3.53	1.35	0.36	1.32	3.17
Mar	3.80	3.76	2.48	1.17	1.31	2.59
Apr	5.64	3.73	3.84	1.54	1.79	2.19

Table A-5: Average HOEP, On and Off-Peak, May 2002-April 2004

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	29.19	43.17	34.59	56.53	24.35	32.16
Jun	35.13	41.64	43.75	55.54	28.24	29.47
Jul	58.10	40.08	73.00	53.14	44.71	28.35
Aug	64.18	46.85	83.42	65.77	48.34	36.28
Sep	75.19	48.56	110.48	58.63	46.96	39.74
Oct	48.66	57.09	61.61	68.42	37.02	46.92
Nov	49.38	40.45	60.92	50.29	39.27	32.59
Dec	56.27	44.42	69.49	54.55	46.30	36.08
Jan	59.62	66.22	74.31	84.76	46.42	50.94
Feb	86.46	52.74	96.83	64.46	77.03	42.77
Mar	81.49	48.90	94.61	57.33	70.69	40.65
Apr	58.88	45.92	74.41	55.04	46.46	37.95
May-02-Apr-03	58.36	N/A	72.71	N/A	46.12	N/A
May-03-Apr-04	N/A	48.20	N/A	60.35	N/A	37.81

Table A-6: Average Richview Slack Bus Price, On and Off-Peak
May 2002-April 2004

	Average On-Peak Richview Slack Bus Price		Average Off-Peak Richview Slack Bus Price		Average Richview Slack Bus Price	
	2002 / 2003	2003 / 2004	2002 / 2003	2003 / 2004	2002 / 2003	2003 / 2004
May	226.74	107.50	42.91	45.55	129.88	73.53
Jun	151.98	107.87	43.41	41.01	91.67	72.21
Jul	272.39	72.09	65.55	32.09	163.41	51.02
Aug	206.03	77.08	64.04	40.81	128.16	55.10
Sep	540.12	65.74	66.48	45.65	276.98	55.03
Oct	94.68	83.98	61.17	59.82	77.02	71.25
Nov	80.26	69.73	51.06	39.46	64.69	52.91
Dec	195.59	87.78	67.07	56.86	122.35	70.83
Jan	92.14	136.59	59.67	63.03	75.03	96.25
Feb	129.04	80.61	106.51	55.33	117.24	66.95
Mar	147.53	84.33	103.84	53.67	123.57	68.84
Apr	135.54	77.63	78.53	48.26	105.13	61.97

*Table A-7: Frequency Distribution of HOEP, May 2002-April 2004 (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**	
	2002/2003	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**
May	0.67	0.00	15.32	1.08	31.45	**48.66**	**46.24**	11.83	2.82	7.53	1.34	5.38	1.08	7.39	0.93	16.67	0.13	1.48	0.00	0.00
Jun	0.56	0.00	5.42	5.56	30.14	**52.78**	**49.44**	8.47	3.33	6.39	2.92	5.00	4.58	6.67	2.78	11.81	0.69	2.78	0.14	0.56
Jul	0.00	0.00	0.00	2.69	9.01	**52.28**	**29.30**	5.91	12.10	4.57	9.27	6.05	12.23	15.86	21.10	12.37	6.71	0.27	0.26	0.00
Aug	0.00	0.00	0.00	0.19	6.85	24.43	**25.40**	**29.36**	18.28	9.09	8.60	7.01	10.48	13.64	21.38	15.34	6.58	0.95	2.38	0.00
Sep	0.00	0.00	0.00	1.39	1.67	10.56	**34.03**	**40.56**	13.89	11.11	8.33	8.19	9.72	8.47	20.69	19.31	6.94	0.28	4.72	0.14
Oct	0.00	0.00	0.00	0.00	**32.53**	11.96	14.11	20.70	7.53	7.80	8.47	8.60	20.30	12.90	15.73	**37.10**	1.34	0.81	0.00	0.13
Nov	0.00	0.00	0.00	0.00	**30.14**	**36.67**	10.69	29.03	8.19	9.31	11.25	8.61	28.47	6.81	10.56	9.31	0.56	0.28	0.14	0.00
Dec	0.00	0.00	0.00	1.75	**38.17**	**36.69**	6.45	26.21	5.38	6.72	6.18	4.57	7.39	3.36	30.11	19.35	5.51	1.34	0.81	0.00
Jan	0.00	0.00	0.40	0.13	**34.41**	11.56	8.60	**21.37**	5.24	9.54	4.84	8.06	4.84	11.69	32.66	18.82	8.87	18.41	0.13	0.40
Feb	0.00	0.00	0.00	0.00	18.90	2.73	6.70	**33.05**	6.55	22.70	5.21	10.78	6.40	9.20	24.40	19.11	**29.61**	2.44	2.23	0.00
Mar	0.00	0.00	0.00	0.13	13.58	10.89	12.77	21.64	7.39	**28.49**	6.18	14.92	7.93	11.83	**25.27**	11.83	23.66	0.27	3.23	0.00
Apr	0.00	0.00	0.00	0.28	20.00	15.28	12.64	**26.39**	7.08	25.42	17.78	14.44	**25.00**	10.28	9.72	7.50	7.22	0.28	0.56	0.14
May-02 Apr-03	0.10	N/A	1.78	N/A	**22.31**	N/A	21.40	N/A	8.16	N/A	7.52	N/A	11.52	N/A	17.97	N/A	8.04	N/A	1.20	N/A
May-03 Apr-04	N/A	0.00	N/A	1.10	N/A	**26.21**	N/A	22.59	N/A	12.39	N/A	8.47	N/A	9.84	N/A	16.54	N/A	2.47	N/A	0.11

*Bolded values show highest percentage within month.

Table A-8: Frequency Distribution of HOEP plus Hourly Uplift, May 2002-April 2004
*(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**	
	2002/2003	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**
May	0.67	0.13	13.84	0.81	26.34	**39.78**	**51.34**	18.41	3.36	7.80	1.75	5.65	1.21	5.78	1.21	19.49	0.27	2.02	0.00	0.13
Jun	0.56	0.00	3.89	3.75	27.50	**51.25**	**51.94**	9.86	3.33	6.53	3.33	5.42	3.61	5.69	4.86	12.78	0.83	4.03	0.14	0.69
Jul	0.00	0.13	0.00	2.02	6.05	**50.94**	**28.23**	6.85	14.38	4.97	7.39	4.57	9.14	12.37	21.51	17.88	11.29	0.27	2.02	0.00
Aug	0.00	0.00	0.00	0.19	4.97	22.54	19.09	**22.94**	**22.72**	15.72	9.81	15.11	10.35	14.20	20.83	18.18	7.93	1.14	4.30	0.00
Sep	0.00	0.00	0.00	1.25	1.25	9.31	**28.19**	**35.28**	18.19	15.00	7.22	8.75	9.72	7.36	21.94	22.50	6.53	0.42	6.94	0.14
Oct	0.00	0.13	0.00	0.00	**26.34**	4.97	17.47	26.34	8.47	8.06	7.53	7.39	13.71	10.89	24.19	**40.99**	2.28	1.08	0.00	0.13
Nov	0.00	0.14	0.00	0.00	**26.81**	24.17	11.81	**39.72**	8.47	7.50	9.03	9.58	22.64	6.94	20.00	11.67	0.97	0.28	0.28	0.00
Dec	0.00	0.13	0.00	1.34	**34.95**	23.92	8.74	**36.42**	5.24	7.12	6.18	5.65	6.32	3.23	30.78	18.82	6.45	3.36	1.34	0.00
Jan	0.00	0.13	0.40	0.00	29.84	7.26	12.23	**21.51**	4.84	10.89	4.97	8.74	4.84	10.08	**30.11**	20.30	12.50	20.43	0.27	0.67
Feb	0.00	0.00	0.00	0.00	12.50	2.30	10.12	25.14	6.85	**27.44**	5.36	12.21	6.99	8.48	21.73	20.55	**33.63**	3.88	2.83	0.00
Mar	0.00	0.13	0.00	0.00	7.39	10.35	16.80	19.09	7.53	**25.40**	5.51	17.47	8.87	12.90	25.00	13.84	**25.27**	0.81	3.63	0.00
Apr	0.00	0.14	0.00	0.14	13.61	13.06	16.53	22.50	7.22	**26.39**	12.64	15.83	**26.94**	10.83	14.72	10.56	7.78	0.42	0.56	0.14
May-02 Apr-03	0.10	N/A	1.53	N/A	18.18	N/A	**22.76**	N/A	9.24	N/A	6.72	N/A	10.33	N/A	19.77	N/A	9.51	N/A	1.85	N/A
May-03 Apr-04	N/A	0.09	N/A	0.79	N/A	21.65	N/A	**23.67**	N/A	13.57	N/A	9.70	N/A	9.06	N/A	18.96	N/A	3.18	N/A	0.16

*Bolded values show highest percentage within month.

Table A-9: Total Hourly Uplift Charge, May 2002-April 2004

	Total Hourly Uplift $ Millions		IOG* $ Millions		CMSC $ Millions		Operating Reserve $ Millions		Losses $ Millions	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	18	30	0	3	4	8	5	8	9	11
Jun	25	37	1	6	6	14	7	5	10	11
Jul	123	22	67	2	29	8	5	2	22	10
Aug	117	19	47	2	46	5	2	3	22	9
Sep	163	24	84	1	48	7	7	4	25	12
Oct	40	27	6	2	15	9	4	2	15	15
Nov	36	25	2	1	15	7	3	6	16	10
Dec	56	31	23	8	13	4	3	5	18	13
Jan	34	53	4	15	9	14	3	5	18	20
Feb	60	33	14	8	17	6	3	3	25	16
Mar	49	32	8	4	16	7	3	6	22	16
Apr	38	31	3	3	14	6	7	9	13	14

*Numbers are not net of IOG offsets which was implemented in July 2002 and totalled $7.9 million in recoveries by the end of April 2004. See Table A-11 and accompanying description.
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*Table A-10: IOG Payments, Top 10 Days, November 2003 to April 2004**

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
15-Jan-04	20,204	4.71	233.10	25,367
16-Jan-04	25,185	1.52	60.50	24,831
10-Jan-04	18,465	1.02	55.05	23,470
18-Mar-04	32,234	0.83	25.63	21,022
14-Jan-04	10,459	0.78	74.28	25,789
28-Jan-04	16,900	0.77	45.30	24,097
05-Feb-04	25,431	0.73	28.87	22,864
08-Feb-04	24,217	0.72	29.77	21,298
19-Dec-03	22,594	0.68	30.32	22,348
17-Jan-04	24,301	0.65	26.64	22,859
	Total Top 10 days	12.41		
	Total for period	38.80		
	% of Total Payments	32%		

*Numbers are not netted against IOG offset for the 'implied wheel'.

Table A-11: IOG Offsets due to Implied Wheeling

	IOG Offset ($'000)		IOG Offset %	
	2002/2003	2003/2004	2002/2003	2003/2004
May	N/A	286	N/A	11.3
June	N/A	430	N/A	6.6
Jul	465	166	0.7	10.6
Aug	745	92	1.6	6.1
Sep	1,223	33	1.5	2.3
Oct	27	23	0.5	1.2
Nov	49	47	2.4	3.8
Dec	582	289	2.6	3.6
Jan	170	1,368	4.6	9.0
Feb	417	692	3.0	8.7
Mar	376	329	4.5	7.8
Apr	26	67	0.9	2.7

*Table A-12: CMSC Payments, Energy and Operating Reserve, May 2002-April 2004**

	Constrained Off $ Millions		Constrained On $ Millions		Total CMSC for Energy* $ Millions		Operating Reserves $ Millions		Total CMSC Payments** $ Millions	
	2002/2003	2003/2004	2002/003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	2.8	5.0	0.9	3.1	3.6	8.3	0.5	1.0	4.1	9.3
Jun	4.1	7.3	1.2	7.0	5.4	14.5	0.3	0.7	5.6	15.2
Jul	7.5	8.2	19.3	1.6	29.0	10.0	0.5	0.7	29.5	10.7
Aug	8.2	4.3	23.3	0.7	46.0	5.3	0.1	0.4	46.1	5.7
Sep	5.3	4.9	37.6	1.4	48.1	6.6	0.2	0.3	48.3	6.9
Oct	7.4	6.2*	7.4	2.1	14.8	8.9	0.5	0.2	15.3	9.1
Nov	6.4	5.5	7.1	0.9	15.2	6.8	0.1	0.4	15.3	7.2
Dec	2.8	3.4	10.3	1.6	12.9	5.9	0.0	0.4	13.0	6.3
Jan	6.2	7.8	2.9	4.0	9.1	14.7	0.1	0.3	9.2	15.0
Feb	7.8	3.1	8.8	1.9	16.6	5.2	0.3	0.3	16.8	5.5
Mar	6.6	3.8	8.5	2.4	15.2	6.5	0.2	0.6	15.4	7.1
Apr	9.7	4.6	3.8	1.3	13.6	6.2	0.7	0.8	14.3	7.0
May-02-Apr-03	74.6	N/A	131.1	N/A	229.5	N/A	3.5	N/A	232.9	N/A
May-03-Apr-04	N/A	64.0	N/A	28.1	N/A	98.9	N/A	6.1	N/A	105.0

*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-9: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months.

Table A-13: Share of Constrained On Payments by Import and Domestic Suppliers

	Domestic (%)		Imports (%)	
	2002/2003	2003/2004	2002/2003	2003/2004
May	93	83	7	17
Jun	51	33	49	67
Jul	32	85	68	15
Aug	17	81	83	19
Sep	22	82	78	18
Oct	33	86	67	14
Nov	34	74	66	26
Dec	29	69	71	31
Jan	78	38	22	62
Feb	80	56	20	44
Mar	86	56	14	44
Apr	93	60	7	40

Table A-14: Share of CMSC Payments Received by Top Facilities
November 2003-April 2004

	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 (%)
Nov 03	70.5	47.5	59.8	29.6
Dec 03	61.6	47.4	42.1	32.8
Jan 04	55.9	53.0	34.7	40.0
Feb 04	61.3	41.3	44.9	27.3
Mar 04	51.3	43.7	37.0	32.1
Apr 04	57.2	45.4	44.4	30.3
May 2002 - Apr 2003	39.0	50.0	26.7	41.0
May 2003 - Apr 2004	41.1	36.2	24.5	22.2

Table A-15: Local Market Power Investigation Statistics

	May 2002 to April 2003	May 2003 to April 2004	Total
Number of LMP Investigations			
Terminated (no CMSC Adjustment)	50	25	75
Completed (CMSC Adjustment)	265	189	454
Pending	0	10	10
Total Initiated	315	224	539
Inquiry Cases Terminated	5	0	5
Inquiry Cases Completed	46	0	46
CMSC Adjustment ($ million)			
Completed Cases	6.2	2.9	9.1
Pending – Potential Adjustment	-	0.6	0.6

Table A-16: Share of Real-time MCP Set by Resource (%), May 2002-April 2004

	Coal		Nuclear		Oil/Gas		Water	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	75	66	0	0	1	23	24	11
Jun	80	69	0	0	5	13	15	19
Jul	70	66	0	0	19	25	11	9
Aug	68	65	0	0	16	27	16	8
Sep	58	41	0	0	18	34	23	25
Oct	52	37	0	0	29	53	19	11
Nov	47	66	0	0	42	25	11	9
Dec	53	54	0	0	29	21	18	24
Jan	51	28	0	0	36	51	13	21
Feb	42	47	0	0	42	42	16	11
Mar	34	45	0	0	54	35	12	20
Apr	32	54	0	0	54	19	13	27

Table A-17: Share of Real-time MCP Set by Resource (%), Off-Peak, May 2002-April 2004

	Coal		Nuclear		Oil/Gas		Water	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	67	83	0	0	0	9	33	8
Jun	81	82	0	0	0	4	19	15
Jul	81	85	0	0	10	7	9	8
Aug	79	79	0	0	11	12	10	9
Sep	76	48	0	0	10	18	14	34
Oct	75	48	0	0	8	41	17	12
Nov	67	78	0	0	18	10	15	12
Dec	64	62	0	0	19	10	16	28
Jan	69	40	0	0	21	38	10	23
Feb	49	70	0	0	30	20	21	10
Mar	44	60	0	0	41	16	15	24
Apr	46	66	0	0	43	7	11	27

Table A-18: Share of Real-time MCP Set by Resource (%), On-Peak, May 2002-April 2004

	Coal		Nuclear		Oil/Gas		Water	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	86	44	0	0	3	40	11	15
Jun	77	53	0	0	12	23	11	25
Jul	61	47	0	0	27	42	12	10
Aug	56	44	0	0	21	49	23	7
Sep	35	33	0	0	30	52	36	16
Oct	23	25	0	0	57	65	21	10
Nov	21	53	0	0	73	42	6	4
Dec	37	46	0	0	43	33	20	20
Jan	30	15	0	0	55	65	16	20
Feb	34	27	0	0	56	61	10	12
Mar	22	33	0	0	71	50	7	16
Apr	16	42	0	0	68	31	16	27

Table A-19: Resources Selected in Real-time Market Schedule (%), May 2002-April 2004

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	2	7	1	6	16	24	5	7	33	27	45	41
Jun	2	8	2	6	20	26	5	6	30	23	44	42
Jul	5	5	1	8	26	30	8	6	22	21	40	46
Aug	8	6	0	6	26	27	7	6	19	22	41	45
Sep	8	8	1	4	25	18	6	7	19	22	43	49
Oct	7	9	3	1	27	28	8	9	22	26	39	30
Nov	9	6	3	3	27	23	8	7	21	28	39	39
Dec	9	7	4	5	28	18	8	7	20	26	40	46
Jan	6	7	5	6	30	25	7	7	19	23	43	43
Feb	8	6	3	4	26	23	7	7	18	23	38	45
Mar	8	5	3	5	22	19	9	7	19	24	39	50
Apr	6	5	2	8	25	15	8	7	21	29	37	52

Table A-20: Resources Selected in the Real-time Market Schedule (TWh)
May 2002-April 2004

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear		Total	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	0.19	0.87	0.12	0.74	1.88	2.80	0.63	0.79	3.93	3.11	5.36	4.79	11.88	11.62
Jun	0.29	0.95	0.23	0.69	2.45	3.09	0.63	0.75	3.64	2.79	5.38	4.99	12.16	11.88
Jul	0.65	0.60	0.09	1.09	3.62	3.86	1.09	0.83	3.08	2.72	5.63	5.97	13.99	12.89
Aug	1.04	0.49	0.04	0.59	3.53	2.48	0.98	0.58	2.65	2.06	5.57	4.11	13.72	9.13
Sep	1.06	0.94	0.13	0.45	3.10	2.17	0.78	0.79	2.38	2.59	5.40	5.77	12.59	11.81
Oct	0.87	1.06	0.35	0.17	3.33	3.40	0.94	1.10	2.74	3.13	4.87	3.60	12.41	12.12
Nov	1.12	0.72	0.40	0.36	3.42	2.87	1.00	0.87	2.61	3.41	4.91	4.86	12.66	12.37
Dec	1.16	0.98	0.55	0.64	3.75	2.41	1.11	0.94	2.64	3.44	5.38	6.18	13.49	13.31
Jan	0.87	1.06	0.69	0.85	4.28	3.74	1.07	1.09	2.75	3.35	6.22	6.34	14.50	14.73
Feb	1.07	0.84	0.48	0.53	3.65	2.97	1.02	0.93	2.50	3.03	5.34	5.85	13.10	13.09
Mar	1.16	0.68	0.43	0.60	3.17	2.49	1.32	0.95	2.64	3.14	5.52	6.55	13.38	13.21
Apr	0.82	0.55	0.29	0.93	3.15	1.81	1.05	0.81	2.70	3.35	4.66	6.16	12.09	11.75

*Table A-21: Offtakes by Intertie Zone, On-peak and Off-peak (MWh), May 2002-April 2004**

		MB		MI		MN		NY		PQ	
		2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	Off-peak	0	0	12,227	8,278	0	139	57,106	460,429	9,005	20,955
	On-Peak	0	1,045	20,264	33,007	400	2,919	20,503	205,235	550	4,777
Jun	Off-peak	0	3,312	11,334	9,710	1,800	943	79,837	350,691	4,495	44,240
	On-Peak	0	2,133	47,370	28,716	1,215	10,564	87,937	220,195	0	23,789
Jul	Off-peak	0	14,675	9,216	69,856	1,400	18,854	46,353	521,199	624	43,708
	On-Peak	0	31,929	53	98,096	540	31,828	30,418	235,600	0	21,673
Aug	Off-peak	0	46,801	0	7,126	0	13,817	26,694	353,700	350	18,348
	On-Peak	0	29,619	0	33,644	1,000	28,389	15,447	52,269	0	2,376
Sep	Off-peak	0	31,961	0	159	3,965	2,775	89,543	247,693	13,617	26,908
	On-Peak	0	24,188	450	1,072	4,745	11,683	13,625	86,484	722	13,198
Oct	Off-peak	0	40,830	200	446	1,140	139	258,720	58,563	26,536	13,949
	On-Peak	0	16,079	3,000	4,387	2,385	2,781	50,683	23,839	5,155	6,757
Nov	Off-peak	130	55,006	250	688	0	973	267,209	111,894	41,236	22,004
	On-Peak	114	27,790	0	1,863	0	19,738	68,306	111,769	22,512	6,860
Dec	Off-peak	0	43,116	0	2,675	0	2,085	374,664	347,624	41,915	30,522
	On-Peak	0	26,495	176	2,746	695	15,393	119,697	150,844	16,522	15,612
Jan	Off-peak	13	53,207	1,415	3,797	1,260	8,340	363,451	412,602	37,257	50,457
	On-Peak	0	26,656	8,306	3,463	0	15,797	253,297	240,286	22,707	35,896
Feb	Off-peak	0	21,875	0	555	0	0	294,170	313,363	34,585	54,437
	On-Peak	0	7,520	510	2,820	890	3,000	124,145	100,634	21,346	28,899
Mar	Off-peak	0	10,477	2,416	3,871	139	1,964	316,178	253,878	19,293	58,351
	On-Peak	0	110	6,998	24,471	1,251	49,892	75,680	159,004	12,644	39,482
Apr	Off-peak	0	4,094	306	10,501	100	5,485	212,969	481,821	17,487	57,719
	On-Peak	0	39	8,988	25,077	0	40,690	49,824	260,816	2,790	39,770

*MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ - Quebec

*Table A-22: Injections by Intertie Zone, On-peak and Off-peak (MWh), May 2002-April 2004**

		MB		MI		MN		NY		PQ	
		2002 / 2003	**2003 / 2004**	**2002 / 2003**	**2003 / 2004**	**2002 / 2003**	**2003 / 2004**	**2002 / 2003**	**2003 / 2004**	**2002 / 2003**	**2003 / 2004**
May	**Off-peak**	60,456	85,264	187	318,783	9,182	29,752	348	5,374	6,422	3,765
	On-Peak	72,027	68,058	176	281,276	2,985	21,817	1,416	48,009	37,627	7,012
Jun	**Off-peak**	73,090	73,990	4,671	351,737	16,279	29,390	4,044	9,045	28,739	201
	On-Peak	63,040	66,820	5,726	308,741	9,495	19,225	8,923	86,715	72,703	5,839
Jul	**Off-peak**	82,875	65,164	35,522	247,645	5,255	17,864	32,733	27,195	59,426	4,229
	On-Peak	79,410	67,930	96,261	97,847	2,501	4,592	88,086	66,803	171,284	2,016
Aug	**Off-peak**	106,514	43,836	208,749	226,597	11,930	13,026	20,312	1,570	94,465	6,585
	On-Peak	87,863	40,800	244,916	65,393	15,200	84	95,944	35,758	154,851	55,109
Sep	**Off-peak**	100,261	47,388	257,363	380,029	19,789	24,651	68,481	21,330	12,407	3,799
	On-Peak	78,701	61,925	243,642	296,925	13,597	11,843	205,410	75,660	56,357	12,615
Oct	**Off-peak**	73,250	65,634	260,874	294,639	32,009	26,447	18,954	119,571	1,209	18,648
	On-Peak	62,454	54,109	274,506	263,018	26,843	17,548	101,980	163,378	22,430	32,427
Nov	**Off-peak**	86,173	19,669	406,874	315,854	31,818	20,249	17,638	47,658	105	9,551
	On-Peak	74,594	200	372,829	234,892	28,208	5,547	98,114	59,115	2,813	10,725
Dec	**Off-peak**	101,180	47,872	450,013	371,020	32,742	23,362	41,925	67,631	304	13,216
	On-Peak	76,467	3,313	358,898	309,766	23,959	6,573	74,569	112,489	2,408	28,733
Jan	**Off-peak**	99,284	5,790	298,259	481,990	33,262	17,708	14,896	49,852	640	5,659
	On-Peak	90,591	7,003	273,961	363,567	30,663	6,516	25,709	102,299	3,660	17,035
Feb	**Off-peak**	77,022	21,933	388,210	344,345	26,984	12,848	62,893	77,751	40	0
	On-Peak	71,136	17,366	312,942	257,303	25,107	7,572	103,877	99,389	190	720
Mar	**Off-peak**	62,879	42,797	454,822	258,140	32,607	4,638	106,813	35,812	0	0
	On-Peak	50,621	61,078	300,637	196,008	25,291	9,928	122,076	70,978	0	2,561
Apr	**Off-peak**	77,094	26,878	307,144	303,658	22,992	0	51,806	5,581	7,050	0
	On-Peak	70,749	39,065	162,462	161,750	16,413	0	88,109	8,864	14,865	384

*MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ - Quebec

Table A-23: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP

	3-hour ahead pre-dispatch price minus HOEP ($/MWh)									
	Average difference		Maximum difference		Minimum difference		Standard deviation		Average difference as a % of the HOEP	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	1.65	13.11	195.83	1,976.90	(64.61)	(150.79)	10.46	75.66	11.14	46.07
Jun	8.31	12.41	418.15	405.10	(656.69)	(103.26)	42.27	33.43	25.41	38.59
Jul	87.94	7.98	1,918.16	91.16	(51.75)	(38.59)	289.59	13.97	104.49	29.25
Aug	36.35	8.24	1,907.36	56.15	(512.2)	(53.16)	150.18	14.75	47.27	24.91
Sep	42.26	6.94	1,907.67	63.98	(928.42)	(282.68)	268.32	17.09	36.25	20.39
Oct	8.32	7.28	320.42	45.48	(108.40)	(249.97)	21.78	17.22	23.16	19.87
Nov	11.97	7.82	1,578.57	52.69	(132.85)	(53.37)	61.44	12.06	31.53	22.71
Dec	18.57	18.18	1,813.14	73.35	(101.57)	(49.56)	131.17	20.58	36.47	51.31
Jan	16.68	27.09	630.95	855.39	(81.76)	(77.54)	38.22	59.01	41.26	48.22
Feb	25.13	18.44	447.50	77.18	(221.94)	(33.54)	61.71	17.75	75.89	42.22
Mar	20.00	11.93	338.30	63.43	(173.92)	(93.06)	44.22	14.11	51.58	28.32
Apr	7.75	12.89	178.31	63.98	(333.11)	(199.13)	30.66	15.53	22.73	34.51

Table A-24: Measures of Differences between 1-Hour Ahead Pre-dispatch Prices and HOEP

	1-hour ahead pre-dispatch price minus HOEP ($/MWh)									
	Average difference		Maximum difference		Minimum difference		Standard deviation		Average difference as a % of the HOEP	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	1.61	11.04	47.89	78.53	(62.89)	(128.79)	8.03	19.54	10.88	35.10
Jun	7.24	11.63	365.46	490.1	(661.69)	(225.41)	36.44	32.79	23.17	38.76
Jul	77.94	7.65	1,929.71	55.27	(48.78)	(38.59)	266.52	13.19	91.94	26.93
Aug	40.04	8.23	1,506.00	52.98	(572.20)	(47.28)	166.81	13.96	50.06	23.92
Sep	47.93	7.01	1,907.67	63.14	(640.13)	(287.68)	270.92	16.41	38.28	19.59
Oct	17.63	7.25	1,949.32	47.62	(104.99)	(223.15)	103.13	15.46	38.72	19.53
Nov	10.51	6.86	195.05	74.23	(139.85)	(56.49)	19.51	11.47	28.63	19.65
Dec	19.83	15.92	1,723.14	70.15	(121.62)	(83.54)	125.44	19.33	38.88	44.92
Jan	17.59	23.07	525.95	780.39	(80.56)	(99.55)	37.84	51.72	42.17	42.34
Feb	24.03	15.86	348.64	62.16	(219.15)	(38.2)	58.33	16.17	72.30	36.15
Mar	18.40	10.45	238.30	57.54	(126.59)	(92.83)	40.98	12.93	48.40	24.79
Apr	7.80	12.02	219.30	57.45	(329.11)	(191.93)	29.78	14.74	22.50	31.29

Table A-25: Measures of Difference between Pre-dispatch Prices and Peak Hourly MCP

	1-Hour Ahead Pre-dispatch Price minus Peak Hourly MCP			
	Average Difference ($/MWh)		Average Difference as % of Peak Hourly MCP	
	2002 / 2003	2003 / 2004	2002 / 2003	2003 / 2004
May	(2.08)	0.81	0.2	16.8
Jun	(0.49)	0.73	14.6	21.0
Jul	68.44	3.15	73.9	14.9
Aug	28.37	2.87	37.7	12.2
Sep	17.73	0.78	22.5	7.1
Oct	9.43	0.58	22.4	6.8
Nov	2.14	1.65	11.4	8.4
Dec	6.55	7.15	18.2	24.2
Jan	5.75	8.19	20.5	19.4
Feb	(1.58)	6.53	37.1	18.3
Mar	(1.46)	2.47	20.9	9.7
Apr	(9.79)	2.20	5.9	15.3

Table A-26: Average Monthly HOEP Compared to Peak Hourly MCP

	HOEP		Peak Hourly MCP		Peak minus HOEP	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	29.19	43.17	32.88	53.41	3.68	10.25
Jun	35.13	41.64	42.87	52.54	7.73	10.91
Jul	58.10	40.08	67.41	44.52	9.31	4.44
Aug	64.18	48.97	75.88	53.62	11.69	4.65
Sep	75.19	48.56	105.37	54.81	30.17	6.26
Oct	48.66	57.09	56.86	63.77	8.21	6.68
Nov	49.38	40.45	57.75	45.70	8.37	5.25
Dec	56.27	44.42	69.49	53.16	13.22	8.74
Jan	59.62	66.22	71.46	81.29	11.84	15.08
Feb	86.46	52.74	112.05	62.12	25.6	9.37
Mar	81.49	48.90	101.90	56.89	20.41	7.99
Apr	58.88	45.92	76.67	55.72	17.79	9.80

*Table A-27: Frequency Distribution of Difference between 1-Hour Pre-dispatch and HOEP, May 2002-April 2004**

	1-hour ahead pre-dispatch price minus HOEP (% of time within range)															
	Greater than -$50.01		**-$50 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**		**Greater than $50.00**	
	2002/2003	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**	**2002/2003**	**2003/2004**
May	0.40	0.67	1.48	1.08	2.42	2.29	**20.43**	8.36	**67.34**	50.27	6.99	9.30	0.94	26.28	0.00	1.75
Jun	0.28	**0.84**	1.11	**3.63**	1.53	2.51	8.89	13.11	67.22	45.05	11.11	8.51	8.19	21.90	1.67	4.46
Jul	0.00	0.00	1.08	0.81	1.61	0.54	9.95	**14.80**	49.19	**58.68**	9.54	6.86	13.17	18.17	15.46	0.13
Aug	0.67	0.00	2.15	0.95	1.75	1.52	12.65	14.02	49.39	55.68	11.57	7.58	11.84	20.08	9.96	0.19
Sep	4.31	0.14	3.62	1.11	1.81	2.50	18.36	14.72	48.40	50.69	9.46	15.42	8.62	15.14	5.42	0.28
Oct	0.67	0.54	0.54	0.81	1.75	1.88	14.38	14.13	48.92	52.22	13.17	14.27	17.74	16.15	2.82	0.00
Nov	0.42	0.14	0.56	0.70	0.97	1.67	15.74	10.57	46.52	57.58	11.28	16.55	22.70	12.52	1.81	0.28
Dec	1.21	0.13	**7.41**	1.21	3.10	1.48	16.31	6.45	37.20	43.28	7.01	11.96	23.99	29.30	3.77	6.18
Jan	0.40	0.40	2.02	2.02	1.88	**3.36**	11.29	10.77	41.13	30.96	8.87	11.57	**24.87**	29.21	9.54	**11.71**
Feb	**5.96**	0.00	4.02	0.72	3.87	1.58	13.86	5.32	22.80	38.22	6.71	18.10	20.42	**33.48**	**22.35**	2.59
Mar	3.90	0.13	2.83	1.34	3.23	1.88	13.06	9.95	31.09	42.07	10.63	23.79	19.25	20.43	16.02	0.40
Apr	2.36	0.28	3.62	0.42	**3.89**	1.53	16.97	7.92	36.16	37.50	**14.05**	**29.03**	18.64	22.64	4.31	0.69

*Bolded values show highest percentage within price range.

Table A-28: Difference between 1-Hour Pre-dispatch and HOEP within Defined Ranges

	Hourly Difference - % of Time within Range 1-hour ahead pre-dispatch price minus HOEP					
	Greater than $0		Equal to $0		Less than $0	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	74.03	87.60	0.69	0.00	25.28	12.40
Jun	88.19	79.78	0.00	0.14	11.81	20.08
Jul	85.22	83.58	2.15	0.27	12.63	16.15
Aug	81.97	83.33	0.81	0.19	17.23	16.48
Sep	71.00	80.97	0.80	0.56	28.20	18.47
Oct	82.70	82.50	0.00	0.13	17.30	17.36
Nov	81.90	86.93	0.00	0.00	18.10	13.07
Dec	71.60	90.73	0.00	0.00	28.40	9.27
Jan	84.30	83.31	0.00	0.13	15.70	16.55
Feb	72.28	92.39	0.00	0.00	27.72	7.61
Mar	76.85	86.56	0.13	0.13	23.01	13.31
Apr	72.88	89.86	0.28	0.00	26.84	10.14

Table A-29: Difference between One Hour Pre-dispatch and Peak Hourly MCP within Defined Ranges

	Hourly Difference - % of Time within Range 1-hour ahead pre-dispatch price minus peak hourly MCP					
	Greater than $0		Equal to $0		Less than $0	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	44.58	65.90	5.83	2.83	49.58	31.27
Jun	72.22	57.04	1.81	2.65	25.97	40.31
Jul	65.99	61.78	6.45	2.83	27.55	35.40
Aug	63.80	63.64	4.17	2.46	32.03	33.90
Sep	47.43	56.39	2.64	4.17	49.93	39.44
Oct	57.80	55.05	1.34	4.58	40.86	40.38
Nov	54.87	65.09	2.37	2.92	42.76	31.99
Dec	49.87	71.10	2.02	2.02	48.11	26.88
Jan	57.93	60.97	2.82	3.63	39.25	35.40
Feb	44.71	70.26	1.19	2.30	54.10	27.44
Mar	46.30	68.15	2.96	2.82	50.74	29.03
Apr	50.90	71.67	3.62	1.11	45.48	27.22

*Table A-30: Percentage Intervals with Operating Reserve Reductions (Market Schedule), May 2002-April 2004**

	No Reductions		>1 MW and <200 MW		>200 MW and <400 MW		>400 MW and <800 MW		>800 MW	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	97.98	96.98	0.83	0.43	0.53	1.78	0.48	0.80	0.18	0.02
Jun	86.97	96.82	0.97	0.15	8.16	1.45	3.21	1.35	0.69	0.23
Jul	77.83	98.53	0.6	0.15	18.26	0.65	2.12	0.56	1.19	0.11
Aug	94.8	96.54	0.46	0.19	1.09	2.73	1.94	0.47	1.71	0.07
Sep	93.78	99.61	0.58	0.05	2.19	0.19	1.83	0.14	1.62	0.02
Oct	92.84	97.77	0.84	0.77	3.07	0.96	2.76	0.30	0.49	0.19
Nov	97.97	99.11	0.19	0.42	0.67	0.35	0.66	0.13	0.13	0.00
Dec	96.1	97.95	0.22	0.45	1.86	0.93	1.46	0.55	0.36	0.12
Jan	97.68	96.81	0.16	0.74	1.64	1.66	0.49	0.56	0.03	0.21
Feb	97.97	98.68	0.43	0.49	1.18	0.63	0.36	0.19	0.06	0.00
Mar	95.92	98.75	0.16	0.72	2.21	0.25	1.60	0.29	0.11	0.00
Apr	96.2	97.99	0.44	1.16	1.98	0.69	0.97	0.08	0.41	0.08

*In previous reports, the Market Assessment Unit utilized a static OR requirement (=1,580 MW). Since then, the MAU has refined its capability to calculate and now utilizes the approximate OR requirement for each hour.

Table A-31: Forecast Bias in Demand

	Mean forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean 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	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	300	338	303	333	63	111	66	105	1.99	2.31	2.00	2.26	0.46	0.78	0.46	0.73
Jun	484	339	460	325	218	84	194	70	3.02	2.16	2.86	2.06	1.34	0.53	1.18	0.43
Jul	595	417	542	380	304	141	251	104	3.30	2.54	3.00	2.31	1.65	0.86	1.35	0.63
Aug	386	356	384	345	103	85	100	74	2.18	2.21	2.16	2.11	0.57	0.56	0.54	0.47
Sep	404	328	394	320	130	75	121	67	2.43	2.09	2.35	2.03	0.79	0.47	0.71	0.41
Oct	319	324	331	325	70	81	82	83	1.98	2.13	2.05	2.11	0.43	0.56	0.50	0.55
Nov	380	366	374	357	119	101	113	93	2.25	2.26	2.20	2.19	0.71	0.65	0.67	0.58
Dec	404	418	397	404	136	134	129	120	2.27	2.48	2.23	2.36	0.75	0.83	0.71	0.72
Jan	375	435	378	438	114	137	117	140	1.97	2.58	1.98	2.57	0.60	0.75	0.61	0.74
Feb	341	422	330	401	91	167	80	146	1.79	2.34	1.72	2.21	0.47	0.93	0.41	0.80
Mar	299	367	299	366	63	120	63	119	1.71	2.21	1.70	2.18	0.37	0.75	0.35	0.73
Apr	291	349	292	348	65	124	67	123	1.84	2.26	1.83	2.23	0.44	0.82	0.43	0.78

Table A-32: Percentage of Time that Mean Forecast Error (forecast to hourly peak) within Defined MW Ranges (%)

	>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	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	5	3	26	28	17	17	12	22	14	14	11	10	13	6	3	0	59	71	41	29
Jun	17	6	31	23	12	13	11	17	10	16	7	11	8	13	3	1	72	58	28	42
Jul	26	10	24	25	10	12	11	13	9	11	7	13	10	16	3	1	72	59	28	41
Aug	10	10	25	23	11	12	16	15	14	11	8	9	13	16	3	4	62	60	38	40
Sep	10	5	28	22	14	16	14	17	12	16	9	9	10	13	4	1	65	60	35	40
Oct	4	3	22	28	16	15	22	18	15	14	13	10	7	10	1	1	64	64	36	36
Nov	4	5	29	28	19	17	17	16	12	13	9	10	9	10	0	1	70	66	30	34
Dec	10	8	29	28	15	17	12	15	12	14	9	8	11	9	2	1	66	68	34	32
Jan	5	8	33	33	17	15	15	13	12	10	8	9	10	11	1	1	70	70	30	30
Feb	6	5	26	35	15	19	15	17	14	12	10	7	12	5	2	1	62	76	38	24
Mar	4	6	26	33	14	16	17	16	14	11	9	8	14	9	2	2	61	71	39	29
Apr	6	7	23	30	13	17	18	15	13	14	13	8	13	9	1	1	60	68	40	32

Table A-33: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities

	Total MW Pre-dispatch		Maximum Difference (MW)		Minimum Difference (MW)		Average Difference (MW)		Fail Rate (Difference/MW Pre-dispatch) (%)	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	817,406	778,341	261.43	290.51	(124.26)	(69.88)	65.21	62.34	6.55	6.26
Jun	802,612	886,176	350.04	668.18	(333.99)	(243.79)	65.55	93.82	4.71	8.65
Jul	878,350	1,249,147	299.48	509.86	(74.80)	(146.78)	46.15	94.12	3.84	5.68
Aug	843,516	703,045	241.39	364.83	(82.37)	(193.14)	62.06	86.83	5.61	6.92
Sep	695,346	764,657	305.81	543.98	(32.07)	(111.61)	103.61	37.07	11.01	3.80
Oct	900,153	821,786	196.15	154.27	(86.90)	(94.26)	59.03	(0.42)	4.87	0.07
Nov	850,818	964,681	242.40	277.22	(131.30)	(139.22)	55.80	(5.73)	4.95	(0.68)
Dec	1,123,099	863,853	667.80	404.54	(317.20)	(140.32)	96.70	(0.74)	6.39	0.11
Jan	1,188,390	1,080,865	575.70	1,317.40	(317.90)	(834.48)	69.10	17.39	4.29	1.11
Feb	891,147	834,172	370.68	643.54	(313.42)	(249.99)	90.62	(3.99)	7.12	(0.92)
Mar	943,991	1,174,221	421.15	724.42	(427.07)	(130.98)	51.08	11.08	4.24	0.55
Apr	689,538	760,221	231.88	262.47	(139.09)	(112.58)	59.77	(11.35)	6.83	(1.00)

*Self-scheduled generators also include those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.

Table A-34: Incidents and Average Magnitude of Failed Imports into Ontario

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	66	239	220	654	61.3	63.4	1.9	1.7
Jun	154	151	300	687	60.5	105.3	3	1.6
Jul	256	111	1,000	891	167.8	110.4	6.1	2.0
Aug	232	87	1,121	389	156.7	90.1	3.4	1.6
Sep	317	167	1,460	525	202.6	97.4	5.7	1.7
Oct	284	279	700	792	176.0	133.1	5.4	3.4
Nov	194	164	711	682	126.8	100.3	2.2	2.2
Dec	253	191	871	861	150.3	118.7	3.2	2.3
Jan	202	287	774	1,233	80.4	127.1	1.8	3.3
Feb	399	160	795	654	79.8	90.8	2.9	1.7
Mar	406	148	604	700	66.9	90.8	2.3	1.9
Apr	312	130	498	463	56.6	67.9	2.1	1.6

Table A-35: Incidents and Average Magnitude of Failed Exports from Ontario

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004	2002/2003	2003/2004
May	120	427	400	1,020	120.2	214.9	10.7	11.1
Jun	275	386	600	1,107	144.4	337.3	14.5	15.9
Jul	339	464	800	1,300	247.7	343.5	49.0	12.8
Aug	280	306	900	1,036	264.9	322.5	63.1	14.4
Sep	188	291	500	977	201.6	236.5	23.0	13.4
Oct	332	148	986	815	192.0	171.7	15.5	13.2
Nov	179	262	800	737	156.3	158.7	6.6	10.4
Dec	219	270	740	903	222.5	192.5	8.1	7.5
Jan	255	285	650	1214	175.5	167.9	6.1	5.4
Feb	206	240	800	740	151.8	152.2	6.2	6.4
Mar	187	281	550	675	136.4	137.4	5.6	6.0
Apr	254	301	500	977	142.3	188.4	11.0	5.8