MARKET SURVEILLANCE PANEL

MONITORING REPORT ON

THE IMO-ADMINISTERED ELECTRICITY MARKETS

THE FIRST EIGHTEEN MONTHS

(MAY 2002 - OCTOBER 2003)

DECEMBER 17, 2003

Preface

The Panel is an independent arms-length body appointed by and accountable to the Independent Directors of the Independent Electricity Market Operator (IMO). We operate 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 our responsibilities. A backgrounder released in April 2002 and available on the surveillance page of the IMO website explains our role in more detail.* Briefly, our specific responsibilities include:

- Monitoring behaviour in the marketplace,
- Investigating and recommending on:
  - the behaviour of specific market participants,
  - the design of rules and operating procedures of the marketplace,
  - the structure of the marketplace, and
- Reporting on the results of our monitoring and investigations.

Our approach to monitoring and investigations is guided by our main objective which is to improve the way the energy market works by identifying impediments to effective competition and recommending actions to mitigate them.

As part of our mandate we prepare periodic reports on the state of the marketplace. This is the third such report and it covers the first 18 months of the Ontario electricity marketplace, May 1, 2002 – October 31, 2003 with special emphasis on the period since our last report, the nine months following January 2003.

Our overall assessment of the evolution of the market is found in Chapter 4. Here we have tried to focus on what has worked well and what hasn't, what steps are underway to improve the market and the other changes that we think will be helpful.

Leading to this assessment, Chapter 1 of our report and its Statistical Appendix provide a high level overview of market outcomes and basic data for intertemporal comparisons. The next chapter reviews and explains anomalous market outcomes, in other words performance that appears to be outside expected norms or on the face of it unusual and worthy of a more extensive analysis. Finally, Chapter 3 gives a status report on the IMO initiatives that have been put in place since market opening to improve market performance.

* The URL for the Backgrounder is http://www.theimo.com/imoweb/pubs/marketSurv/ms_MSP_Backgrounder.pdf

We feel that Ontario's electricity market is evolving along the right path to promote the mutually reinforcing goals of market efficiency and system reliability. Under the former, energy is produced by the lowest cost supplier and consumed by those willing to pay the incremental cost of production. Under the latter, the reliability of Ontario's electricity system is ensured by market participants' responses to clear and transparent signals. We are pleased to participate in this important evolution.

Fred Gorbet, Chair	Don McFetridge	Tom Rusnov

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Chapter 1: Market Outcomes February 1, 2003 to October 31, 2003 and Year-to-Year Review

1. *Introduction*

This Chapter and its Statistical Appendix provide data for the period since the release of our last monitoring report. While the focus is the new information available for the 9-month period, February 1, 2003 to October 31, 2003, in every case the tables and figures include data since the opening of the IMO-administered markets in May 2002. This allows comment and comparison over 18 months of market experience. Subsequent chapters draw on the data made available here to analyze in more detail issues we felt important enough to warrant comment.

In general, Ontario electricity prices were lower in 2003 compared to 2002. This was a result of lower demand and additions to supply in the province. In the summer of 2003, imports of energy were lower and as a result, payments for the Intertie Offer Guarantee and Congestion Settlement Management Credits were much less than the previous year. At the same time, it should be noted that average energy prices in February and March 2003, notably average off-peak prices, were among the highest since market opening.

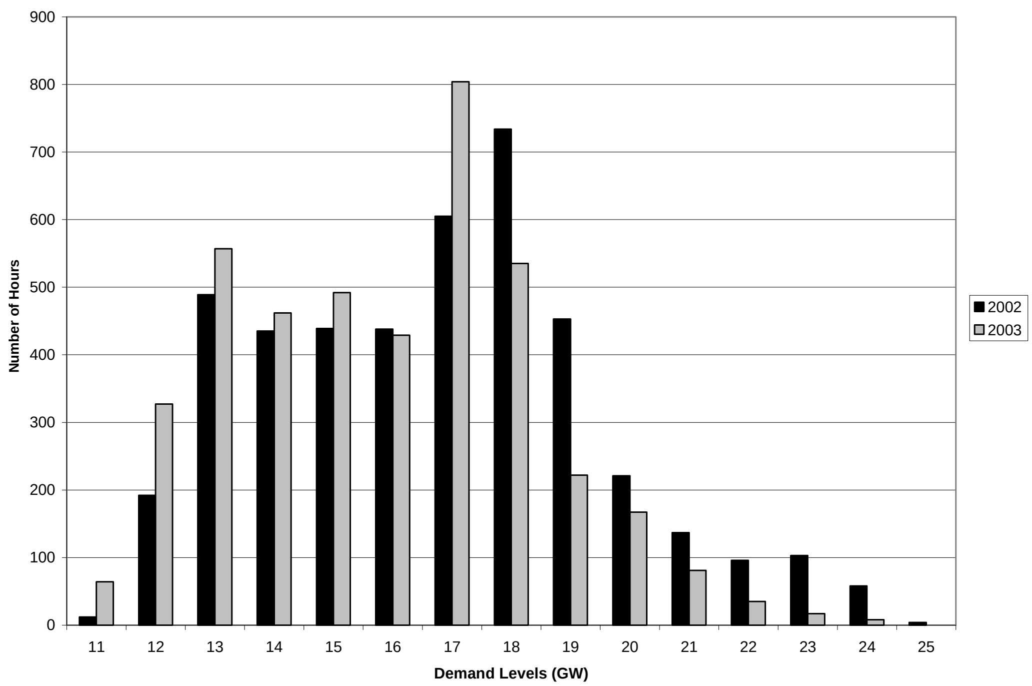
Special care is required when considering data for the month of August 2003. Because the market was suspended for more than 8 days due to a system failure in parts of the Northeast, the data for August cover only that portion of the month when the market was functioning.

2. *Demand*

Energy consumption in Ontario was lower in 2003 compared to 2002 for the period May 1 to October 31. Table 1-1 in the Statistical Appendix to the Chapter shows that monthly consumption ranged between 0.26 TWh – 1.10 TWh lower for each of these months (August excluded).[1] Taking into consideration exports, total market demand was lower in three of the months, July, September and October 2003 compared to the previous year.

Figure 1-1 below plots a comparison of demand values over the period May–October for 2002 and 2003. The measure used is the number of hours where the Ontario non-dispatchable market demand falls into predefined ranges.[2]

Figure 1-1: Ontario Non-dispatchable Demand Comparison (May-Oct, 2002 and 2003)*



*Demand figures exclude exports.

The figure shows that for the comparable months the frequency of demand was higher in 2003 for the lower demand ranges, 11,000 MW to just below 18,000 MW; whereas 2002 had the higher frequency for demand ranges of 18,000 MW and above.[3] One of the factors explaining this split was higher temperatures during the summer months of 2002 compared

[1] A terrawatt hour, abbreviated as TWh, is one million megawatt hours (1,000,000 MWh).
[2] Each value on the X-axis of Figure 1-1 represents a demand range just short of 1,000 MW to the next value on the X-axis. For example, 11 GW (gigawatts) represents a demand range of 11,000 MW – 11,999 MW.

to 2003. Tables 1-2 and 1-3 in the Appendix provide temperature information, showing for example that 31 days exceeded 30 degrees Celsius in 2002 compared to 8 days in 2003.

While it is true that demand was generally lower in 2003 than in 2002 for the overlap months of market operation (May–October), Table 1-1 in the Appendix also shows that demand was strong in the winter of 2002-2003.

3. *Supply*

In general, there was more Ontario-based generation available in 2003 than was the case in 2002. This was because of the addition of new and restored generation in the province and fewer significant outages in some months.

Between September and December 2002, TransAlta's Sarnia facility came on stream and began offering an additional 515 MW into the Ontario market. During the months of August and September 2003, OPG's nuclear unit, Pickering G4, returned 515 MW to the market. And between October and November 2003, the Bruce Energy G4 nuclear unit also returned to the market, making available an additional 790 MW of generation. Table 2-34 of Chapter 2 provides a more detailed breakdown of the additions to supply and other factors for five months.

Generators require outages for maintenance and due to sudden equipment failure that requires them to be forced from service. Figure 1-2 shows combined planned and forced outages over the period 2000–2003.

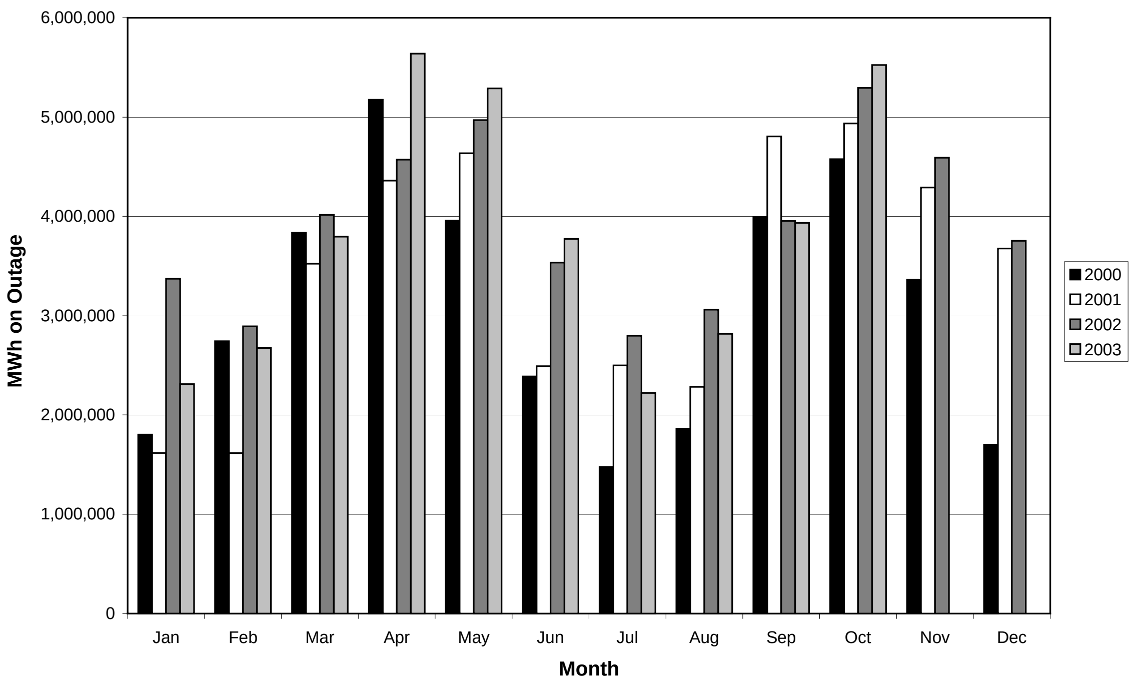
Generation outages – either planned or forced – can have a significant impact upon price. We can discern no distinct change in the total outage pattern pre to post market. As can be seen in Figure 1-2, outages continue to be taken in the 'shoulder months' - spring and fall - when both market demand and prices tend to be lowest. The 2003 values tracked 2002

[3] Note the exception to this general statement for the demand range represented by 16 GW where for

except for two months, May and September. Figures 1-12 and 1-13 in the Appendix break out planned and forced outages separately.

In our second surveillance report we note that changing reporting requirements appear to have increased the forced outage rate on hydroelectric plants and in some circumstances fossil plants.[4] We will continue to monitor the outages.

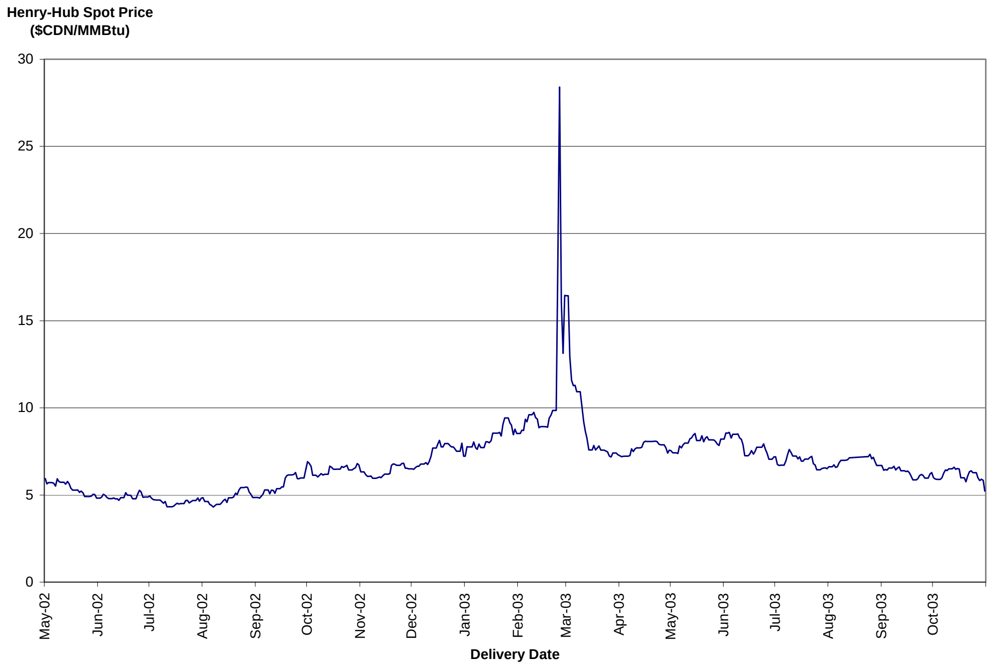
Figure 1-2: Total Outages, 2000-2003



The final major influence on supply over the period was the changing nature of natural gas prices. Figure 1-3 below plots the Henry Hub spot price for the relevant period.

comparable months in 2002, the frequency of demand was slightly higher than in 2003.
[4] See MSP, "Monitoring Report for the Period from September 2002-January 2003", March 24, 2003, p. 109.

Figure 1-3: Daily Natural Gas Prices



As discussed in our March report, natural gas is a fuel for some Ontario-based generation and influences import offers into Ontario and export bids out of the province.[5] Therefore, the extraordinary rise in natural gas prices in February and March 2003 depicted in Figure 1-3 impacted Ontario electricity prices. This is examined more fully in Chapter 2.

[5] See MSP March report, pp. 16-20.

4. *Wholesale Energy Prices*

Figure 1-4: Average HOEP for May 2002–October 2003

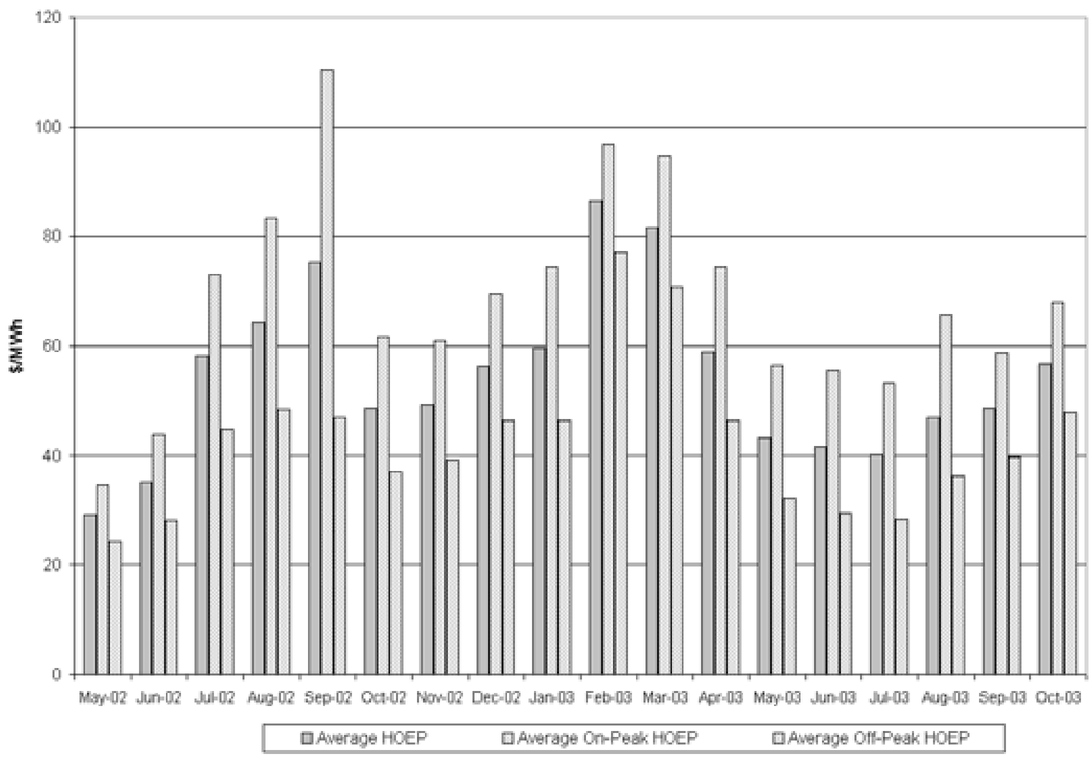


Figure 1-4 above shows the average Hourly Ontario Energy Price (HOEP) and the average values for on-peak and off-peak periods from market opening in May 2002 to October 2003. In general, the average energy prices for the second year of the market are lower than the average prices for the first year of the market. The information in the previous sections on demand and supply provides a general explanation for this difference but we analyze the contributing factors more systematically in section 5 of Chapter 2.

For the period, February to October 2003, the various measures of average price decline until August when they start to rise again, although not reaching the highs of February and March. The average HOEP over this period as a whole is $56.06. The months of February and March had the highest average energy prices since market opening. The average monthly prices, including both on-peak and off-peak HOEP, are available in Table 1-4 of the Statistical Appendix.

September 2002 remains the month with the highest on-peak prices since market opening. As can be seen from Figure 1-4, the average on-peak and the average off-peak HOEP clusters around the average HOEP in February and March 2003, whereas in September 2002 off-peak prices were more than 50 percent less than the on-peak average. As noted in our first report,[6] high average prices in the first few months of the market were accounted for by relatively few numbers of hours where prices were really high, thus increasing the average. For the period of February to October 2003, individual prices were not as high but the frequency of relatively high prices increased. Further data on this is found in Table 1-5 of the Statistical Appendix that shows the percentage of hours where HOEP fell in defined price ranges.

A final observation on Figure 1-4 is the simple comparison of the overlap period May–October for both years of market operation. For the months of May and June, the monthly HOEP was lower in 2002 compared to 2003; however, for July to September inclusive, energy prices were lower in 2003. This is true for all the average prices, both on-peak and off-peak in addition to the average HOEP.[7] October 2003 reversed the trend by posting higher average prices than in October 2002.

As noted in our previous reports, in addition to the HOEP, the wholesale customers directly connected to the IMO-controlled grid pay an hourly uplift.[8] Uplift payments have been much less significant in 2003 compared to 2002 and we provide information on this in section 6 of this Chapter. On average, hourly uplift charges added less than $6.00 to the HOEP for the period of February to October 2003. Table 1-6 in the Statistical Appendix shows the addition of hourly uplift to HOEP across defined price ranges.

Of course the final cost of electricity for wholesale customers depends on the impact any contracts entered into outside of the spot market and the Market Power Mitigation

[6] See MSP, "Monitoring Report for the First Four Months, May-August 2002", October 7, 2002.
[7] This pattern may be easier to observe in the Tables 1-4 and 1-5 of the Appendix.
[8] This uplift is fixed for consumers using 250,000 KWh or less per year who are guaranteed a commodity price of 4.3 cents per KWh and a fixed wholesale market service charge of 0.62 cents per KWh. On November 25, 2003, the Government of Ontario introduced in the Legislature the *Ontario Energy Board*

Agreement rebate.[9] We do not have information on bilateral contracts; however estimates of the MPMA rebate indicate a significant impact. The rebate rate was $12.41/MWh for the first year of the market. Most participants with a large residential component, the local distribution companies, clustered around the average price of $62.34/MWh and therefore were charged an effective price of about $50.00. However, the large customers' weighted average prices ranged between $54.00 to $77.00, reflecting different abilities to shift consumption from high priced periods. After taking into consideration the MPMA rebate, the net effective cost to these customers ranged from about $42.00 to $65.00 per MWh.

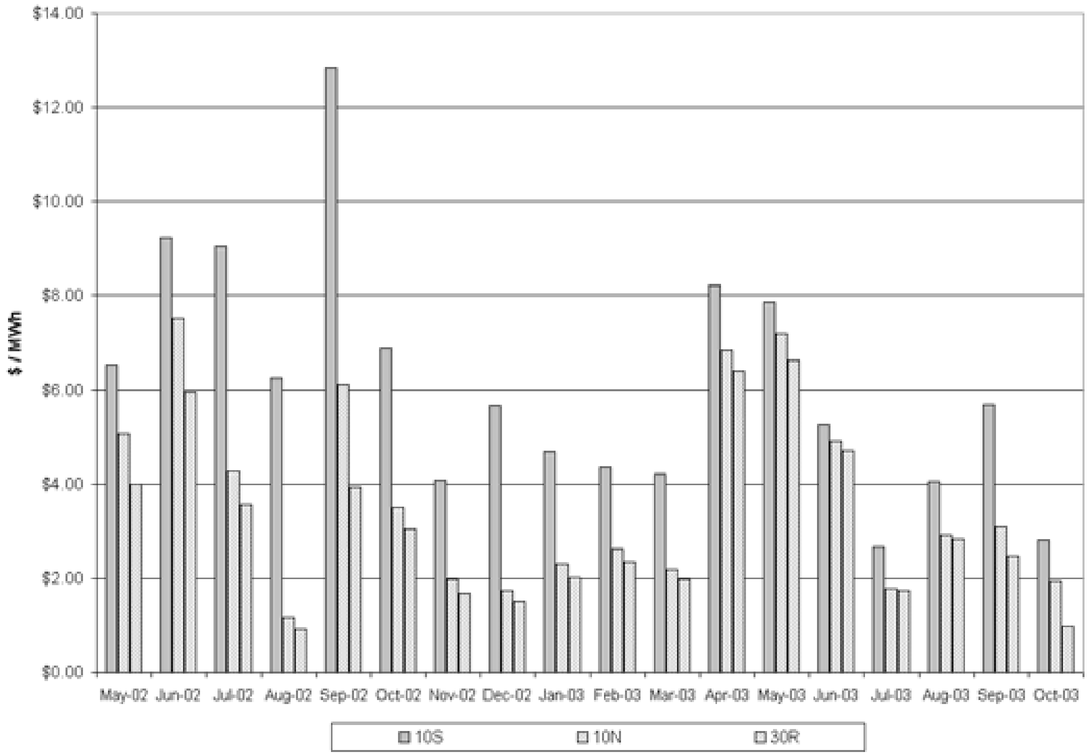
5. *Operating Reserve Prices*

Figure 1-5 provides a summary of real-time operating reserve (OR) prices during the period May 2002 to October 2003. Over the past nine months, prices for all three types of OR were the lowest in February, March and July 2003. Also, the real-time OR prices in July 2003 are lower than for the same month in 2002, by an average of $3.56/MWh. This is because demand and real-time energy prices were significantly lower in July 2003 compared to July 2002.

Amendment Act that would replace the 4.3 cent/KWh cap with an interim pricing plan to be implemented April 1, 2004.

[9] Under the MPMA Ontario Power Generation is obligated to rebate consumers for revenues earned on a portion of its capacity when the average annual wholesale price exceeds 3.8 cents per KWh. We briefly described the rebate mechanism at pp. 30-31 of our October 2002 report.

Figure 1-5: Average Hourly Operating Reserve Prices (Real-time)
May 2002–October 2003



In the months of April and May 2003, prices for all three types of OR were the highest since September 2002, when extraordinary events caused a major increase in average OR prices. These unusually high OR prices are commented on in Chapter 2.

6. *Hourly Uplift and its Components*

This section reports on the main components of the hourly uplift charge for the period under review. The hourly uplift consists of payments for the Intertie Offer Guarantee (IOG), Congestion Management Settlement Credits (CMSC), Operating Reserve (OR), and line losses on the transmission system.

Figure 1-6 below shows that average hourly uplift charges were much lower in 2003 compared to 2002. The most striking change is the decrease in IOG and CMSC payments. February recorded the highest total charges, with the cost of line losses on the transmission system accounting for 40 percent of the total. These losses are not controllable and are a function of the characteristics of the transmission system and the energy demand. While August shows as the lowest value for the entire 18-month period, this is due to the extended market suspension that left only 22 days of market operation.

Figure 1-6: Average Hourly Uplift, by Month, by Component

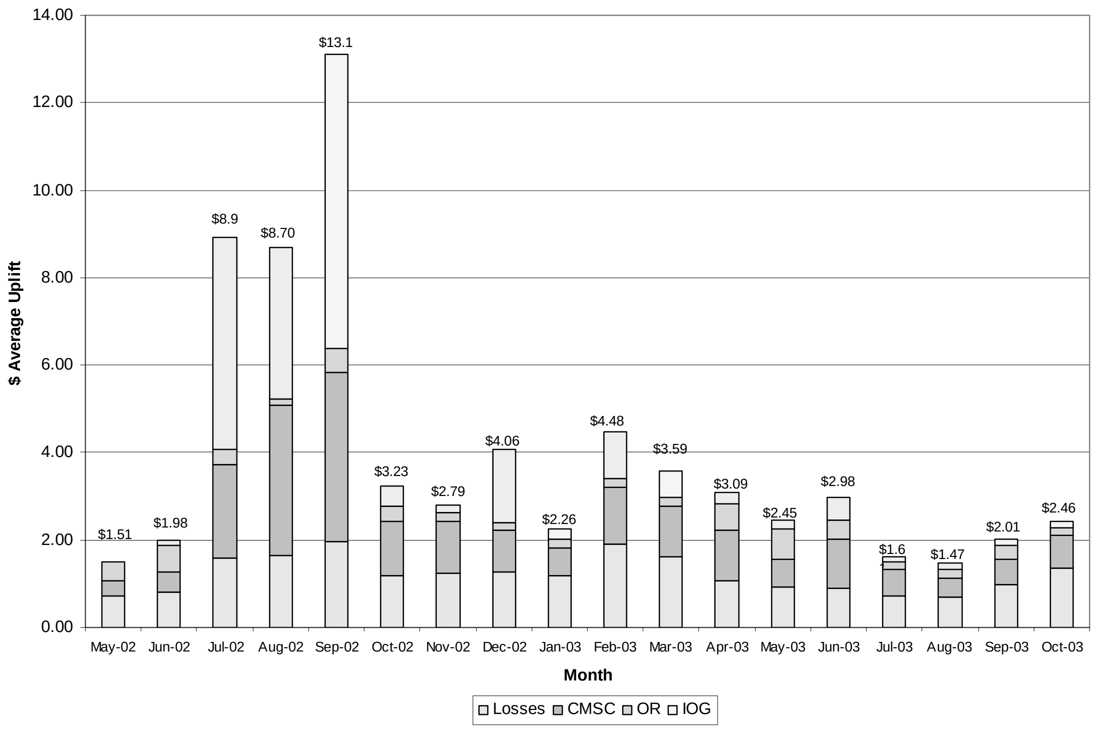
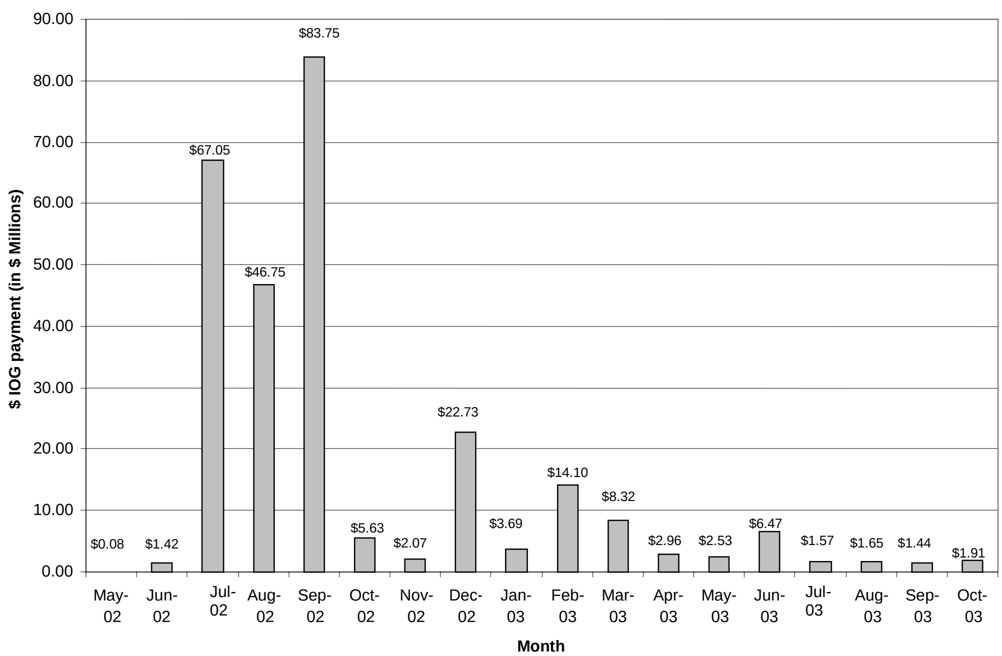


Table 1-7 in the Appendix shows the actual values for each component of the hourly uplift over the 18-month period. The next subsections provide highlights on two components, IOG and CMSC, that we have commented on in our earlier reports.

6.1 Intertie Offer Guarantee

Figure 1-7 below illustrates the distribution of total IOG payments by month since market opening. Note that these IOG payments include the more than $5 million recovered from market participants as implied wheel transactions.[10] For the period of February to October 2003, IOG payments totalled more than $41 million with the highest payment in the month of February at $14.10 million, followed by March at $8.32 million. The sum of these nine months is less than half the total IOG payment made in the month of September 2002 when the payment was $83.75 million, the highest since market opening. The payments for the second year of the market from May to October 2003 have dropped from the previous year by a total of $189 million.

Figure 1-7: IOG Payments by Month, May 2002-October 2003



For purposes of comparison with data provided in our earlier reports, Table 1-8 in the Appendix lists the values associated with the 10 highest payment days in the period February to October 2003.

The IMO recovers the IOG for imports where the same market participant had exports scheduled for the same hour. The total IOG recovered from these ‘implied wheeling

[10] We comment further on the ‘implied wheel’ at the end of this subsection. Further information is contained in our October 2002 report at p. 77.

transactions' since market opening has been more than $5 million. Recoveries have been made in every month since the rule came into effect in July 2002. Additional information is contained in Table 1-9 of the Appendix.

6.2 Congestion Management Settlement Credits

CMSC payments are made to market participants when the (unconstrained) market schedule and (constrained) dispatch schedule for a registered facility subject to dispatch, differ. The payment is based on the difference between the energy market price and the offer or bid prices for the registered facility. If a registered facility has local market power, because of the local nature of the energy or related product required, it may be able to modify its offer or bid prices to force up its congestion settlement credits to unreasonable levels. The Market Rules provide for review and possible mitigation in such circumstances.

Since market opening, there has been about $290 million allocated to CMSC payments for energy and operating reserves. The CMSC payments for the period February to October account for almost 34 percent of the total payment made and almost 34 percent of the total uplift. These CMSC amounts do not take into account the amounts that are recovered as a result of the local market power mitigation (LMP) process and the urgent rule amendments for negative priced offers.[11]

Tables 1-10 to 1-12 in the Appendix provide additional data on the nature of CMSC payments. For example, it shows the pattern of a small number of facilities accounting for the majority of payments.

6.2.1 Review of Local Market Power Mitigation

The local market power mitigation (LMP) framework is a multi-step approach to reviewing the conditions that led to high CMSC payments with the potential for adjusting settlements

[11] This urgent rule is described in section 2 of Chapter 3.

and possibly applying penalties when these are determined appropriate. Initial steps in the review determine: (i) whether the CMSC has been induced by transmission or security constraints, (ii) whether there is insufficient local competition, and (iii) whether the observed prices are outside a calculated allowed price range (or safe harbour). An adjustment to CMSC is pursued after consultation with the participant, and only if it is determined that the prices were not consistent with cost or opportunity cost.

Over the period May 2002 to October 2003, there has been a total recovery of approximately $8.1 million through the LMP review process. About 25 percent are associated with the 8 months of 2002, and the remaining 75 percent with the 10 months in 2003. As with CMSC payments themselves, recoveries are highly concentrated. Of the more than $8 million recovered, 57 percent was associated with 5 facilities, while 79 percent related to 10 facilities.[12]

There were no penalties assessed as part of the LMP review. These are reserved for situations where a participant has repeatedly and actively changed its prices with a clear intention to take advantage of the local constraints, without any overall market justification for pricing in this manner. There is no evidence that this has occurred.

7. *Wholesale Electricity Prices in Neighbouring Jurisdictions*

This section provides a comparison between prices in the Ontario market and prices in the three neighbouring jurisdictions that operate in the Northeast United States. These prices have been converted to Canadian currency to better reflect the comparison.[13] This information represents the hourly market price for energy. Since the neighbouring jurisdictions operate under locational marginal pricing schemes as opposed to Ontario's single uniform pricing mechanism, as in past reports, we have selected zone or hub prices most likely comparable to Ontario. Even though these prices ignore the different treatment

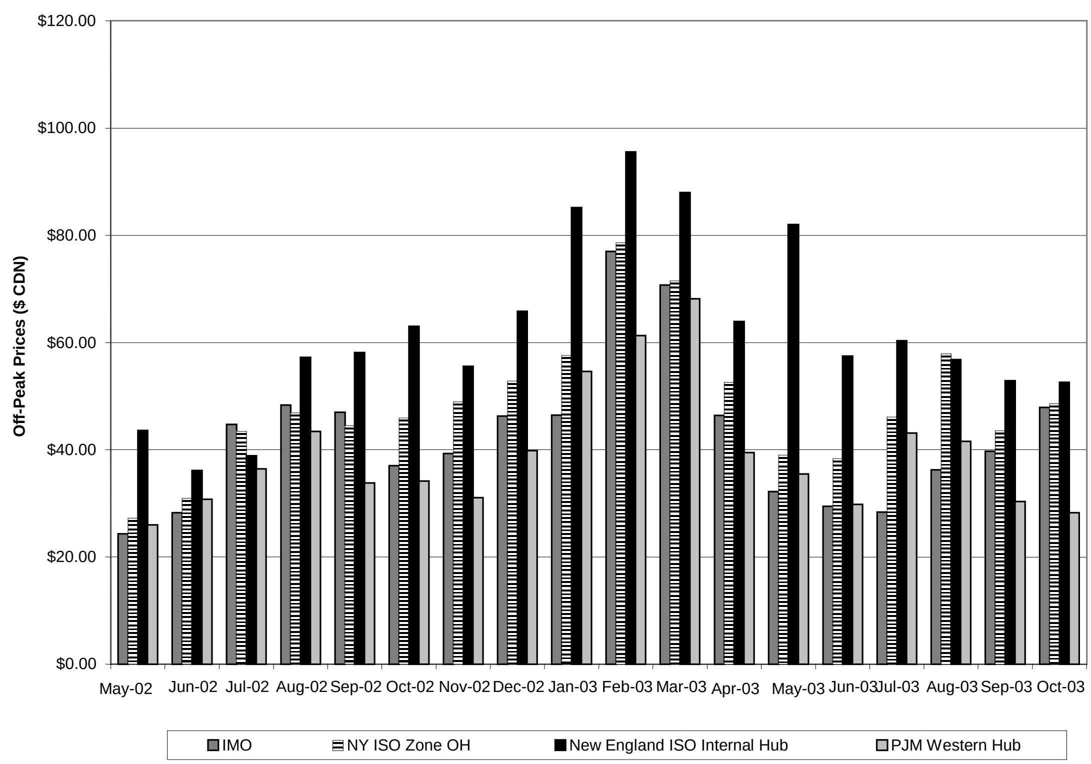
[12] Further information on the number of cases is available in Table 1-13 of the Appendix.
[13] Average monthly exchange rates from the Bank of Canada were used.

of market characteristics such as uplift, day-ahead markets, bilateral contracts, etc., we believe the comparison still gives a rough benchmark of market prices.

Figure 1-8 below shows the comparison for off-peak periods. As in the previous reports, New England still has the highest average prices, followed by New York. Ontario has the second lowest average.

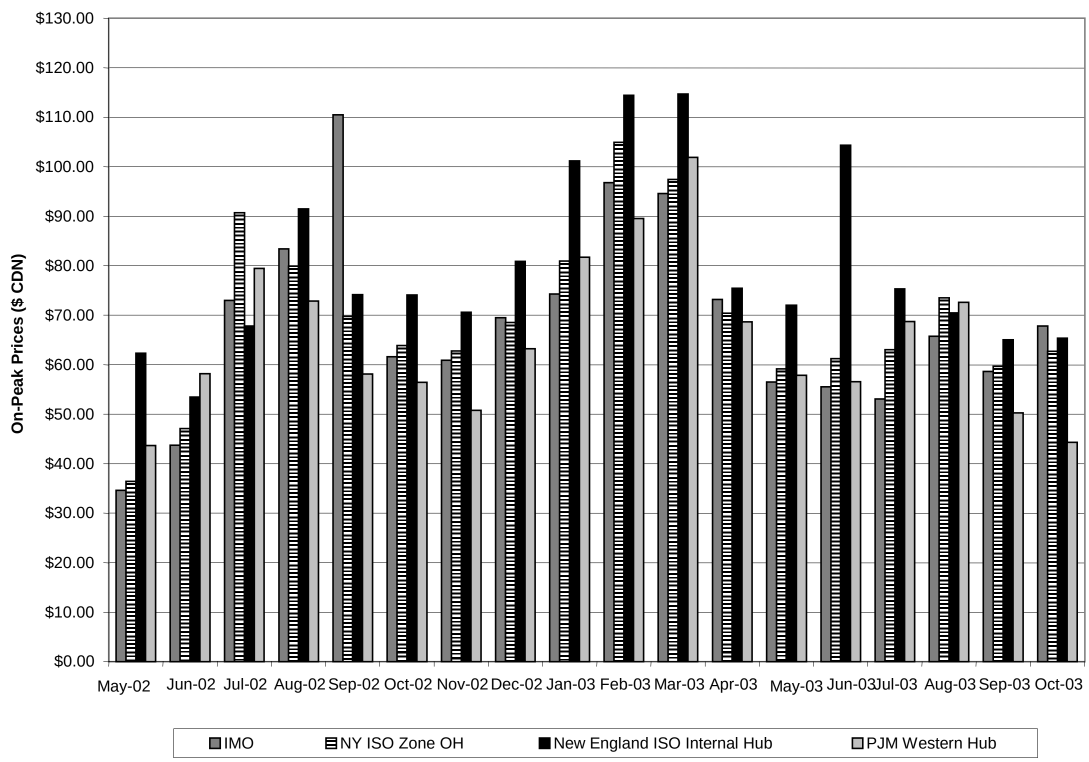
A trend that can be seen is that overall, average prices for the off-peak period show an upward trend up to February 2003. With the exception of the spike in the ISO New England internal hub price for May 2003, off-peak prices continue to drop until they stabilized during the summer months at levels comparable to those of the summer of 2002.

Figure 1-8: Average HOEP Relative to Neighbouring Control Areas, Off-Peak May 2002-October 2003



The distribution of on-peak periods as shown by the Figure 1-9 below is slightly different. While off-peak prices portray almost a normal distribution around the period highs in the first quarter of 2003, on-peak prices in the summer of 2002 and 2003 did not fall away as much. For the first time since September 2002, the October 2003 average monthly on-peak energy price in Ontario was more expensive than in any other neighbouring jurisdiction.

Figure 1-9: Average HOEP Relative to Neighbouring Control Areas, On-Peak May 2002-October 2003



8. *Price Setters*

As in past reports, we have reviewed the influence of facilities of each fuel type on the real-time market clearing price (MCP). Tables 1-14 to 1-16 summarize the data for the 18 months of market operation. Coal facilities continue to be the dominant price setter but their dominance has declined in 2003 compared to 2002. Oil/gas units and hydroelectric facilities alternated with coal in particular months and depending whether on-peak and off-peak times. We draw no particular conclusions on these shifts observed over time, but the impact of changing fuel prices on Ontario electricity prices is considered in Chapter 2.

Tables 1-17 and 1-18 in the Appendix highlight the contribution of various resources to the total supply of energy. Over the last nine months, the proportion of output from the various types of resources has remained relatively constant and consistent with that in the first nine months of market operation.

Between February and June 2003, Ontario continued to be a net importer of energy at an average of 0.45 TWh per month. However, the months of July and August 2003 saw Ontario export energy at a net average of 0.3 TWh each month. This is in contrast to the summer of 2002, when net imports to Ontario were very significant during July and August. Ontario returned to its position as a net importer in September and October 2003. Another measure of these shifts is provided by the incidence of negative supply cushion events as summarized in Table 1-19 of the Appendix. Except in March and April, the number of hours in 2003 with a negative supply cushion is substantially lower than in 2002, implying the Ontario market required imports less often to meet domestic demand.

Tables 1-20 to 1-21 in the Appendix provide data on monthly trade flows by intertie zone and for on-peak and off-peak times. Through February to October 2003, New York continued to be the largest destination for Ontario exports in both off-peak and on-peak hours. Exports to New York were the largest since market opening in July 2003, with 521,199 MWh and 235,600 MWh traded during off and on-peak hours, respectively. Both off-peak and on-peak exports to Michigan were also significantly higher during July 2003. June 2003 marked the beginning of significant exports of energy across the Manitoba intertie.

Over the past nine months, Michigan continued to be the largest source of imports into Ontario at a monthly average of 328,986 MWh during off-peak hours and 219,594 MWh during on-peak hours. The notable increase in imports from Michigan seen between July and December 2002 has stabilized through to April 2003. Imports from Quebec fell to a minimum in March 2003, but increased again through the remainder of the spring and summer. For the period from May to September 2003, the magnitude of imports from Quebec is much smaller than for the same period in the previous year.

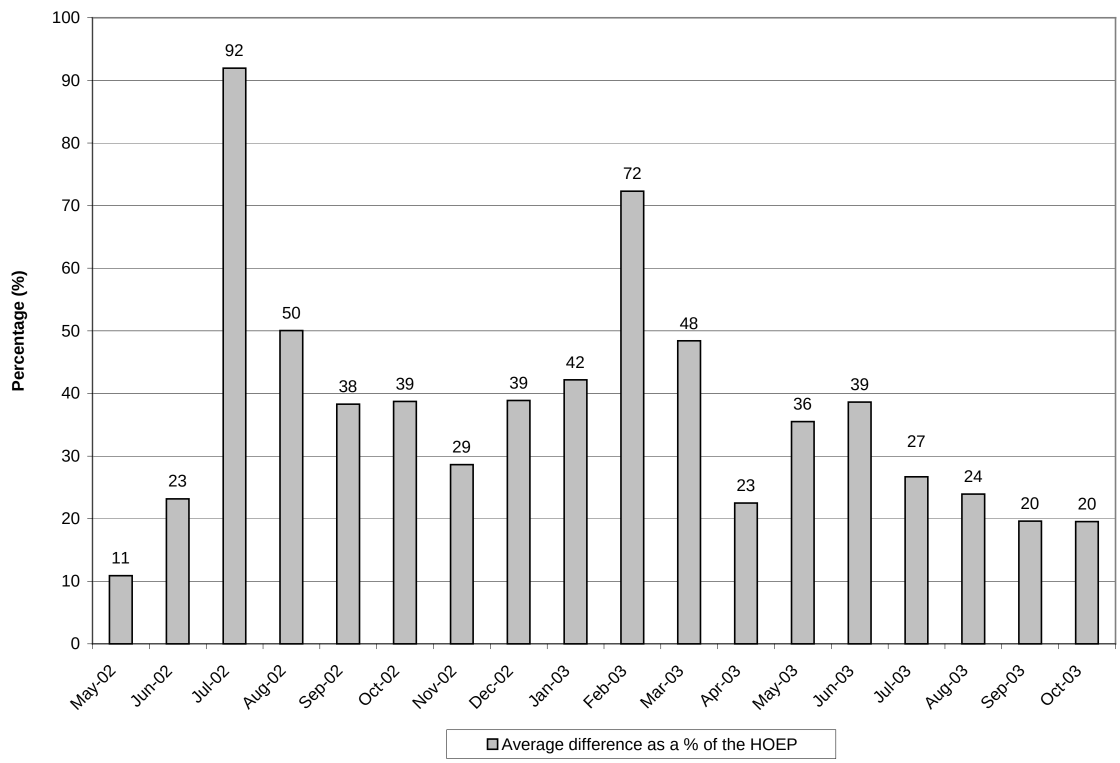
9. *Pre-dispatch to Real-time Discrepancies*

As discussed in past reports, we continue to believe the discrepancy between the pre-dispatch and a real-time price is important.[14] First, various types of facilities require a reliable pre-dispatch price signal to schedule production for the coming hours. Secondly, the convergence of the two is a sign of a credible and mature marketplace, and could contribute to increased awareness and understanding on the part of market participants. Because of the number of variables involved, we don't expect the pre-dispatch and real-time prices to perfectly match but we would expect that the difference should be more randomly distributed and less systematic than we observed over the past 18 months.

The data for across the first 18 months show persistent disparities in the pre-dispatch and real-time prices, although the results have varied over the period as shown in Figure 1-10. The difference was less in the last four months of 2003 compared to the same months of 2002, but the earlier months showed little improvement on 2002 results except for April 2003.[15] Tables 1-22 to 1-26 provide more detail on the differences between pre-dispatch and real-time prices.

[14] See October 2002 report at pp. 87-103 and March 2003 report at pp. 63-96
[15] The difference between the pre-dispatch and real-time operating reserve prices diminished in 2003 compared to 2002. Over the period May 2002 to January 2003, the average difference was $20.84 MWh. This compares to a difference of only $1.60/MWh over the period February to October 2003. See Table 1-27 in the Statistical Appendix.

Figure 1-10: Average Difference between One-Hour Ahead Pre-dispatch and Real-time as a Percentage of HOEP



In our past reports we identified four key factors that affect the difference between the pre-dispatch and HOEP or Peak Hourly MCP. These are:

- demand forecast error
- performance of self-scheduling and intermittent generation
- the role of import offers and export bids in both pre-dispatch and real-time
- out-of-market control actions.

Our most significant finding in reviewing the last nine months is that out-of-market control actions appear to be a much less significant contributing factor. Table 1-27 in the Appendix shows that out-of-market control actions are still taken, but the frequency and magnitude have decreased to levels that no longer have a significant impact.

The results for the other factors are contained in Tables 1-28 to 1-31 in the Appendix. The demand forecast error remains persistent although it is within the IMO operational standard of 3 percent in terms of a monthly average. Self-scheduler errors continue. As an example the data in Table 1-30 show that there were a number of occasions where self-schedulers failed to deliver significant quantities of megawatts (for example, more than 500 MW over the course of an hour) in real-time. An important contributing factor to the large deviation is the temporary classification of some large units as self-schedulers as they return from maintenance. Finally, the data on failed transactions summarized in Table 1-31 shows a lower rate of failures.

STATISTICAL APPENDIX

TO

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

THE FIRST EIGHTEEN MONTHS
(MAY 2002 - OCTOBER 2003)

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.

Table 1-1: Monthly Energy Demand (TWh)

Month	Energy Consumption		Total Market Demand		Export	
	2002	2003	2002	2003	2002	2003
May	11.88	11.62	12.00	12.36	0.12	0.74
Jun	12.16	11.88	12.39	12.57	0.23	0.69
Jul	13.99	12.89	14.08	13.98	0.09	1.09
Aug	13.72	9.13	13.76	9.72	0.04	0.59
Sep	12.59	11.81	12.72	12.26	0.13	0.45
Oct	12.41	12.12	12.76	12.29	0.35	0.17
Nov	12.66		13.06		0.40	
Dec	13.49		14.04		0.55	
Jan		14.50		15.19		0.69
Feb		13.10		13.58		0.48
Mar		13.38		13.81		0.43
Apr		12.09		12.38		0.29

Table 1-2: Average Monthly Temperate (°Celsius)

Month	2002	2003
May	11.3	12.3
Jun	19.2	18.6
Jul	24.2	21.4
Aug	22.7	21.9
Sep	20.2	17.2
Oct	9.2	8.9
Nov	3.3	N/A
Dec	-1.8	N/A
Jan	-0.3	-7.7
Feb	-1.3	-6.9
Mar	0.4	-0.5
Apr	7.3	5.6

Table 1-3: Number of Days Temperature Exceeded 30°C

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

Figure 1-11: Planned Outages in MWh by Month

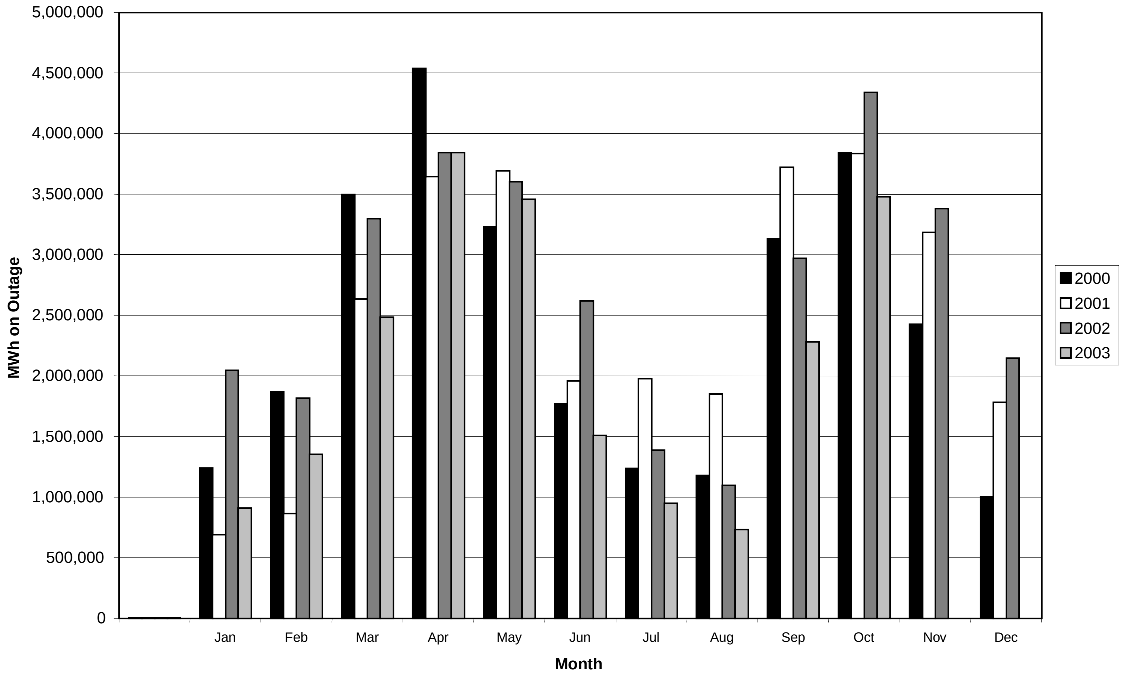


Figure 1-12: Forced Outages in MWh by Month

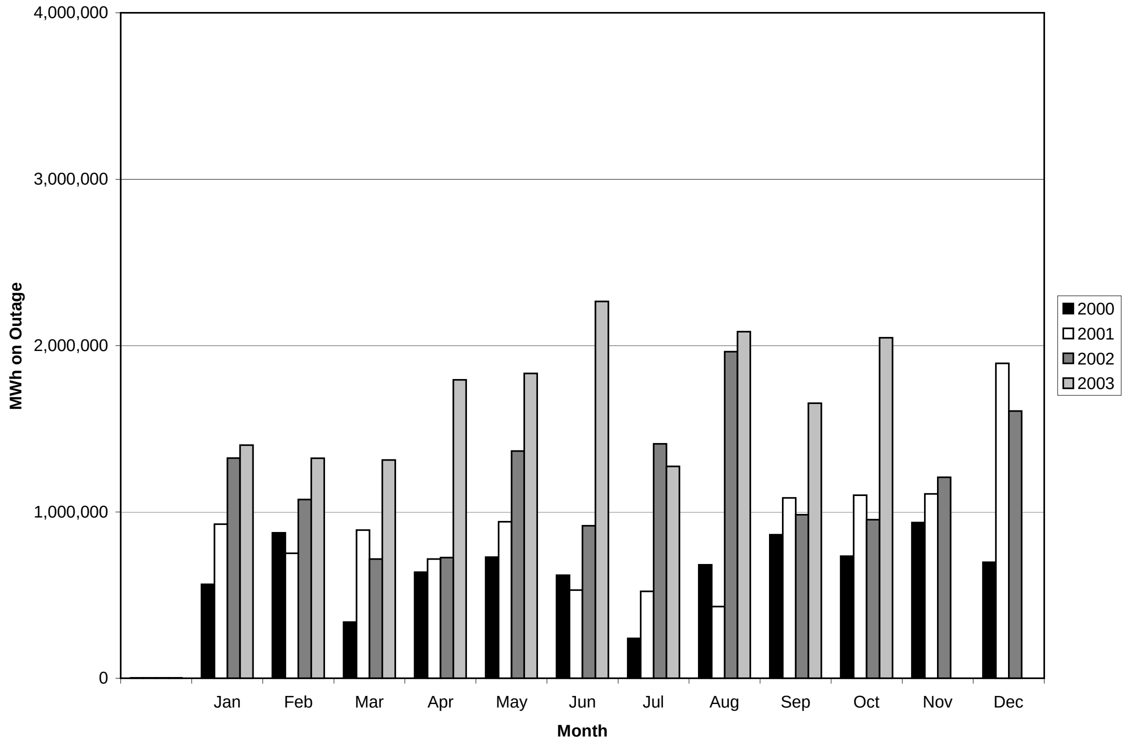


Table 1-4: Average HOEP, On and Off-Peak
May 2002-October 2003

Delivery Month	Average HOEP	Average On-Peak HOEP	Average Off-Peak HOEP
May-02	29.19	34.59	24.35
Jun-02	35.13	43.75	28.24
Jul-02	58.10	73.00	44.71
Aug-02	64.18	83.42	48.34
Sep-02	75.19	110.48	46.96
Oct-02	48.66	61.61	37.02
Nov-02	49.38	60.92	39.27
Dec-02	56.27	69.49	46.3
Jan-03	59.62	74.31	46.42
Feb-03	86.46	96.83	77.03
Mar-03	81.49	94.61	70.69
Apr-03	58.88	74.41	46.46
May-03	43.17	56.53	32.16
Jun-03	41.64	55.54	29.47
Jul-03	40.08	53.14	28.35
Aug-03	46.85	65.77	36.28
Sep-03	48.56	58.63	39.74
Oct-03	56.75	67.86	47.86
Feb-03-Oct-03	56.06	69.00	45.17
May-02-Oct-03	54.42	68.34	42.67

Table 1-5: Frequency Distribution of HOEP through May 2002–October 2003 (Percentage of Hours within Defined Range)*

Period	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
May-02	0.67	15.32	31.45	**46.24**	2.82	1.34	1.08	0.93	0.13	0.00
Jun-02	0.01	15.00	31.00	**46.00**	3.00	1.00	1.00	2.78	0.70	0.14
Jul-02	0.00	0.00	9.01	**29.30**	12.1	9.27	12.23	21.10	6.71	0.26
Aug-02	0.00	0.00	6.85	**25.40**	18.28	8.6	10.48	21.38	6.58	2.38
Sep-02	0.00	0.00	1.67	**34.03**	13.89	8.33	9.72	20.69	6.94	4.72
Oct-02	0.00	0.00	**32.53**	14.11	7.53	8.47	20.30	15.73	1.34	0.00
Nov-02	0.00	0.00	**30.14**	10.69	8.19	11.25	28.47	10.56	0.56	0.14
Dec-02	0.00	0.00	**38.17**	6.45	5.38	6.18	7.39	30.11	5.51	0.81
Jan-03	0.00	0.40	**34.41**	8.60	5.24	4.84	4.84	32.66	8.87	0.13
Feb-03	0.00	0.00	18.9	6.70	6.55	5.21	6.40	24.40	**29.61**	2.23
Mar-03	0.00	0.00	13.58	12.77	7.39	6.18	7.93	**25.27**	23.66	3.23
Apr-03	0.00	0.00	20.00	12.64	7.08	17.78	**25.00**	9.72	7.22	0.56
May-02-Apr-03	0.10	1.78	**22.31**	21.40	8.16	7.52	11.52	17.97	8.04	1.20
May-03	0.00	1.11	**48.89**	12.08	7.08	5.42	7.22	16.67	1.53	0.00
Jun-03	0.00	5.42	**52.92**	8.47	6.39	5.00	6.67	11.81	2.78	0.56
Jul-03	0.00	2.69	**52.28**	5.91	4.57	6.05	15.73	12.5	0.27	0.00
Aug-03	0.00	0.19	24.43	**29.36**	9.09	7.01	13.64	15.34	0.95	0.00
Sep-03	0.00	1.39	10.56	**40.56**	11.11	8.19	8.47	19.31	0.28	0.14
Oct-03	0.00	0.00	11.96	20.70	7.80	8.60	12.90	**37.10**	0.81	0.13

*Bolded values show highest percentage within month.

Table 1-6: Frequency Distribution of HOEP plus Hourly Uplift, May 2002–October 2003 (Percentage of Hours within Defined Range)*

Period	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
May-02	0.67	13.84	26.34	**51.34**	3.36	1.75	1.21	1.21	0.27	0.00
Jun-02	0.56	3.89	27.5	**51.94**	3.33	3.33	3.61	4.86	0.83	0.14
Jul-02	0.00	0.00	6.05	**28.23**	14.38	7.39	9.14	21.51	11.29	2.02
Aug-02	0.00	0.00	4.97	19.09	**22.72**	9.81	10.35	20.83	7.93	4.30
Sep-02	0.00	0.00	1.25	**28.19**	18.19	7.22	9.72	21.94	6.53	6.94
Oct-02	0.00	0.00	**26.34**	17.47	8.47	7.53	13.71	24.19	2.28	0.00
Nov-02	0.00	0.00	**26.81**	11.81	8.47	9.03	22.64	20.00	0.97	0.28
Dec-02	0.00	0.00	**34.95**	8.74	5.24	6.18	6.32	30.78	6.45	1.34
Jan-03	0.00	0.40	29.84	12.23	4.84	4.97	4.84	**30.11**	12.50	0.27
Feb-03	0.00	0.00	12.50	10.12	6.85	5.36	6.99	21.73	**33.63**	2.83
Mar-03	0.00	0.00	7.39	16.80	7.53	5.51	8.87	25.00	**25.27**	3.63
Apr-03	0.00	0.00	13.61	16.53	7.22	12.64	**26.94**	14.72	7.78	0.56
May-02-Apr-03	0.10	1.53	18.18	**22.76**	9.24	6.72	10.33	19.77	9.51	1.85
May-03	0.13	0.81	**39.78**	18.41	7.80	5.65	5.78	19.49	2.02	0.13
Jun-03	0.00	3.75	**51.25**	9.86	6.53	5.42	5.69	12.78	4.03	0.69
Jul-03	0.13	2.02	**50.94**	6.85	4.97	4.57	12.37	17.88	0.27	0.00
Aug-03	0.00	0.18	**22.10**	22.64	15.76	5.07	13.95	18.12	1.99	0.18
Sep-03	0.00	1.27	8.70	**31.52**	14.86	9.78	6.88	26.63	0.36	0.00
Oct-03**	0.00	0.00	5.51	26.19	7.74	7.44	10.86	**41.07**	1.04	0.15

*Bolded values show highest percentage within month.
** October 2003 distribution is based on preliminary hourly uplift values.

Table 1-7: Total Hourly Uplift Charge, May 2002-October 2003

	Total Hourly Uplift $ Millions	IOG* $ Millions	CMSC $ Millions	Operating Reserve $ Millions	Losses $ Millions
May-02**	18	0	4	5	9
Jun-02	25	1	6	7	10
Jul-02	123	67	29	5	22
Aug-02	117	47	46	2	22
Sep-02	163	84	48	7	25
Oct-02	40	6	15	4	15
Nov-02	36	2	15	3	16
Dec-02	56	23	13	3	18
Jan-03	34	4	9	3	18
Feb-03	60	14	17	3	25
Mar-03	49	8	16	3	22
Apr-03	38	3	14	7	13
May-03	30	3	8	8	11
Jun-03	37	6	14	5	11
Jul-03	22	2	8	2	10
Aug-03	19	2	5	3	9
Sep-03	24	1	7	4	12
Oct-03	29	2	9	2	16

*Numbers are not net of IOG offset which was implemented in July 2002 and totalled $5.1 million in recoveries by the end of October 2003. See Table 1-9 and accompanying description.
**The data for May to August 2002 differ from those values in the report on the first four months (October 7, 2002) because of changed definitions and the manner of assigning labels.

*Table 1-8: IOG Payments, Top 10 Days, February-October 2003**

Time Period	Guaranteed Imports for Day (MWh)	IOG Payment ($ Millions)	Average IOG Payment ($/MW)	Peak Demand in 5-minute Interval (MW)
02/26/2003	34,651	4.68	135.12	22,583
06/26/2003	25,443	2.03	79.66	25,042
06/25/2003	19,703	1.67	84.69	24,903
02/27/2003	21,217	1.59	75.00	22,115
02/25/2003	14,720	1.47	99.86	22,909
03/05/2003	23,107	1.42	61.25	22,392
03/01/2003	13,252	1.05	79.45	20,151
02/20/2003	16,525	0.82	49.66	22,094
02/24/2003	12,942	0.81	62.39	23,134
03/02/2003	11,882	0.80	67.50	21,375
	Total Top 10 Days	16.34		
	Total for Period	40.95		
	% of Total Payments	40%		

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

Table 1-9: IOG Offsets due to Implied Wheeling

Month	IOG Offset ($'000)	IOG Offset %
May-02	N/A	N/A
Jun-02	N/A	N/A
Jul-02	465	0.7
Aug-02	745	1.6
Sep-02	1,223	1.5
Oct-02	27	0.5
Nov-02	49	2.4
Dec-02	582	2.6
Jan-03	170	4.6
Feb-03	417	3.0
Mar-03	376	4.5
Apr-03	26	0.9
May-03	286	11.3
Jun-03	430	6.6
Jul-03	166	10.6
Aug-03	92	6.1
Sep-03	33	2.3
Oct-03	22	1.0
Total	5,109	

Table 1-10: CMSC Payments, Energy and Operating Reserve
*May 2002-October 2003**

	Energy CMSC Payments $ Millions		Total CMSC for Energy	Operating Reserves	Total CMSC Payments
Month	**Constrained Off**	**Constrained On**	**$ Millions**	**$ Millions**	**$ Millions**
May-02**	3	1	4	1	4
Jun-02	4	1	5	0	6
Jul-02	7	19	29	0	29
Aug-02	8	23	46	0	46
Sep-02	5	38	48	0	48
Oct-02	7	7	15	0	15
Nov-02	6	7	15	0	15
Dec-02	3	10	13	0	13
Jan-03	6	3	9	0	9
Feb-03	8	9	17	0	17
Mar-03	7	9	15	0	15
Apr-03	10	4	14	1	14
May-03	5	3	8	1	9
Jun-03	7	7	15	1	15
Jul-03	8	2	10	1	11
Aug-03	4	1	6	0	6
Sep-03	5	1	7	0	7
Oct-03	7	2	9	0	9
May-02-Apr-03	75	131	229	3	233
Feb-03- Oct-03	60	38	100	4	104

*The sum for energy being constrained on and constrained 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 data for May to August 2002 differ from those values in the report on the first four months (October 7, 2002) because of changed definitions and the manner of assigning labels.

Table 1-11: Share of Constrained On Payments by Import and Domestic Suppliers

Month	Import (%)	Domestic (%)
May-02	7	93
Jun-02	49	51
Jul-02	68	32
Aug-02	83	17
Sep-02	78	22
Oct-02	67	33
Nov-02	66	34
Dec-02	71	29
Jan-03	22	78
Feb-03	20	80
Mar-03	14	86
Apr-03	7	93
May-03	17	83
Jun-03	67	33
Jul-03	15	85
Aug-03	19	81
Sep-03	18	82
Oct-03	13	87

Table 1-12: Share of Total Payments Received by Top Facilities

	Share of Total Payments Received by Top 10 Facilities		Share of Total Payments Received by Top 5 Facilities	
Month	**Constrained Off (%)**	**Constrained On (%)**	**Constrained Off (%)**	**Constrained On (%)**
May-02	66.0	65.1	53.5	53.2
Jun-02	67.5	65.7	47.6	47.3
Jul-02	69.1	52.0	59.1	42.1
Aug-02	71.2	78.0	54.6	68.0
Sep-02	47.1	71.3	34.9	61.6
Oct-02	47.9	73.1	34.0	63.1
Nov-02	43.1	77.5	25.3	63.0
Dec-02	48.4	61.3	30.2	50.1
Jan-03	67.1	43.1	58.7	26.9
Feb-03	44.3	58.4	31.1	38.2
Mar-03	43.8	42.8	28.3	27.4
Apr-03	74.9	40.5	63.7	27.9
May-03	61.2	49.8	42.0	36.0
Jun-03	55.7	71.1	43.0	61.3
Jul-03	55.4	43.9	43.7	30.3
Aug-03	59.1	58.8	43.3	46.1
Sep-03	57.4	58.0	43.4	49.4
Oct-03	51.7	51.2	34.3	40.1
Feb-03-Oct-03	42.7	35.7	27.3	20.0
May-02-Oct-03	36.1	45.5	22.7	36.5

Table 1-13: Local Market Power Investigation Statistics

	2002 May - Dec	2003 Jan – Sep	Total
Number of LMP Investigations			
Terminated (no CMSC Adjustment)	28	36	64
Completed (CMSC Adjustment)	105	211	316
Pending	0	20	20
Total Initiated	133	267	400
Inquiry Cases Terminated	5	0	5
Inquiry Cases Completed	46	0	46
CMSC Adjustment ($ million)			
Completed Cases	2.1	6.0	8.1
Pending – Potential Adjustment	-	0.2	0.2

Table 1-14: Share of Real-time MCP Set by Resource (%)
May 2002-October 2003

	Coal		Nuclear		Oil/Gas		Water	
	2002	2003	2002	2003	2002	2003	2002	2003
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	42	53	11	11
Nov	47		0		42		11	
Dec	53		0		29		18	
Jan		51		0		36		13
Feb		42		0		42		16
Mar		34		0		54		12
Apr		32		0		54		13

Table 1-15: Share of Real-time MCP Set by Resource, Off-Peak (%)
May 2002-October 2003

	Coal		Nuclear		Oil/Gas		Water	
	2002	2003	2002	2003	2002	2003	2002	2003
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		0		18		15	
Dec	64		0		19		16	
Jan		69		0		21		10
Feb		49		0		30		21
Mar		44		0		41		15
Apr		46		0		43		11

Table 1-16: Share of Real-time MCP Set by Resource, On-Peak (%)
May 2002-October 2003

	Coal		Nuclear		Oil/Gas		Water	
	2002	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**
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	15
Oct	23	25	0	0	57	65	21	10
Nov	21		0		73		6	
Dec	37		0		43		20	
Jan		30		0		55		16
Feb		34		0		56		10
Mar		22		0		71		7
Apr		16		0		68		16

Table 1-17: Resources Selected in the Real-time Market Schedule (%)
May 2002-October 2003

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear	
	2002	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002	2003
May	2	7	1	6	16	21	5	6	33	24	45	37
Jun	2	7	2	5	20	23	5	6	30	21	44	38
Jul	5	4	1	7	26	26	8	5	22	18	40	40
Aug	8	5	0	6	26	24	7	6	19	20	41	40
Sep	8	7	1	4	25	17	6	6	19	20	43	45
Oct	7	9	3	1	27	27	8	9	22	25	39	29
Nov	9		3		27		8		21		39	
Dec	9		4		28		8		20		40	
Jan		6		5		30		7		19		43
Feb		8		3		26		7		18		38
Mar		8		3		22		9		19		39
Apr		6		2		25		8		21		37

Table 1-18: Resources Selected in the Real-time Market Schedule (TWh)
May 2002-October 2003

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear		Total	
	2002	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002	2003
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		0.40		3.42		1.00		2.61		4.91		12.66	
Dec	1.16		0.55		3.75		1.11		2.64		5.38		13.49	
Jan		0.87		0.69		4.28		1.07		2.75		6.22		14.50
Feb		1.07		0.48		3.65		1.02		2.50		5.34		13.10
Mar		1.16		0.43		3.17		1.32		2.64		5.52		13.38
Apr		0.82		0.29		3.15		1.05		2.70		4.66		12.09

Table 1-19: Negative Supply Cushion Events, May 2002–October 2003

		Real-time		Pre-dispatch	
		No. of Hours	% of Total Hours	No. of Hours	% of Total Hours
2002	May	0	0	7	1
	June	19	3	114	16
	July	125	17	168	23
	August	133	18	174	23
	September	236	33	234	33
	October	177	24	206	28
	November	104	14	140	19
	December	86	12	138	19
2003	January	46	6	46	6
	February	0	0	59	9
	March	145	19	108	15
	April	130	18	98	14
	May	59	8	71	10
	June	50	7	53	7
	July	23	3	13	2
	August	17	2	12	2
	September	1	0	18	3
	October	12	2	90	13

Table 1-20: Offtakes by Intertie Zone, On-peak and Off-peak (MWh)
May 2002-October 2003*

		MB		MI		MN		NY		PQ	
		2002	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**
May	**Off-peak**	0	0	12,227	8,278	0	139	57,106	406,429	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		250		0		267,209		41,236	
	On-peak	114		0		0		68,306		22,512	
Dec	**Off-peak**	0		0		0		374,664		41,915	
	On-peak	0		176		695		119,697		16,522	
Jan	**Off-peak**		13		1,415		1,260		363,451		37,257
	On-peak		0		8,306		0		253,297		22,707
Feb	**Off-peak**		0						294,170		34,585
	On-peak		0		510		890		124,145		21,346
Mar	**Off-peak**				2,416		139		316,178		19,293
	On-peak				6,998		1,251		75,680		12,644
Apr	**Off-peak**				306		100		212,969		17,487
	On-peak				8,988				49,824		2,790

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

*Table 1-21: Injections by Intertie Zone, On-peak and Off-peak (MWh) May 2002-October 2003**

		MB		MI		MN		NY		PQ	
		2002	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**
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		406,874		31,818		17,638		105	
	On-peak	74,594		372,829		28,208		98,114		2,813	
Dec	**Off-peak**	101,180		450,013		32,742		41,925		304	
	On-peak	76,467		358,898		23,959		74,569		2,408	
Jan	**Off-peak**		99,284		298,261		33,262		14,896		640
	On-peak		90,591		273,923		30,663		25,709		3,660
Feb	**Off-peak**		77,022		388,210		26,984		62,893		40
	On-peak		71,136		312,942		25,107		103,877		190
Mar	**Off-peak**		62,879		454,822		32,607		106,813		0
	On-peak		50,621		300,637		25,291		122,076		0
Apr	**Off-peak**		77,094		307,144		22,992		51,806		7,050
	On-peak		70,749		162,462		16,413		88,109		14,865

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

Table 1-22: Measures of Difference between Pre-dispatch Prices and HOEP

	5-hour ahead pre-dispatch price minus HOEP ($/MWh)					1-hour ahead pre-dispatch price minus HOEP ($/MWh)				
	Average difference	Maximum difference	Minimum difference	Standard deviation	Average difference as a % of the HOEP	Average difference	Maximum difference	Minimum difference	Standard deviation	Average difference as a % of the HOEP
May-02	1.03	33.61	(64.08)	8.18	10.12	1.61	47.89	(62.89)	8.03	10.88
Jun-02	8.14	420.15	(661.69)	43.10	25.15	7.24	365.46	(661.69)	36.44	23.17
Jul-02	108.65	1929.05	(51.75)	323.27	128.90	77.94	1929.71	(48.78)	266.52	91.94
Aug-02	38.02	1932.36	(501.20)	132.38	48.23	40.04	1506.00	(572.20)	166.81	50.06
Sep-02	34.44	1,907.67	(962.94)	241.73	32.70	47.93	1,907.67	(640.13)	270.92	38.28
Oct-02	9.27	1,802.42	(114.78)	70.01	23.10	17.63	1,949.32	(104.99)	103.13	38.72
Nov-02	10.22	417.57	(111.85)	23.27	28.60	10.51	195.05	(139.85)	19.51	28.63
Dec-02	20.42	1,923.14	(142.43)	142.55	37.60	19.83	1,723.14	(121.62)	125.44	38.88
Jan-03	18.33	1,896.42	(83.15)	81.46	41.40	17.59	525.95	(80.56)	37.84	42.17
Feb-03	36.08	1,920.46	(216.94)	131.04	91.30	24.03	348.64	(219.15)	58.33	72.30
Mar-03	23.92	363.30	(178.57)	48.00	57.80	18.40	238.30	(126.59)	40.98	48.40
Apr-03	8.70	387.56	(343.82)	37.50	24.80	7.80	219.30	(329.11)	29.78	22.50
May-03	12.56	1,976.32	(164.82)	78.11	45.50	11.18	78.53	(128.79)	19.63	35.50
Jun-03	15.17	1,455.10	(172.84)	69.30	38.30	11.56	490.10	(225.41)	32.76	38.60
Jul-03	7.33	96.14	(64.50)	15.24	27.00	7.59	55.27	(38.59)	13.14	26.70
Aug-03	6.98	56.15	(72.67)	15.33	21.90	8.23	52.98	(47.28)	13.96	23.90
Sep-03	6.11	49.69	(272.29)	17.75	18.90	7.01	63.14	(287.68)	16.41	19.60
Oct-03	7.82	77.55	(259.97)	18.73	21.40	7.24	47.62	(223.15)	15.45	19.50

Table 1-23: Measures of Difference between Pre-dispatch Prices and Peak Hourly MCP

	1-hour ahead pre-dispatch price minus peak hourly MCP ($/MWh)	
	Average Difference	Average Difference as % of peak hourly MCP
May-02	(2.08)	0.20
Jun-02	(0.49)	14.60
Jul-02	68.44	73.90
Aug-02	28.37	37.70
Sep-02	17.73	22.50
Oct-02	9.43	22.42
Nov-02	2.14	11.35
Dec-02	6.55	18.16
Jan-03	5.75	20.47
Feb-03	(1.58)	37.10
Mar-03	(1.46)	20.90
Apr-03	(9.79)	5.90
May-03	0.85	17.20
Jun-03	0.84	21.30
Jul-03	3.14	14.90
Aug-03	2.87	12.20
Sep-03	0.78	7.10
Oct-03	0.58	6.80

Table 1-24: Average Monthly HOEP Compared to Peak Hourly MCP

	HOEP	Peak Hourly MCP	Peak minus HOEP
May-02	29.19	32.88	3.68
Jun-02	35.13	42.87	7.73
Jul-02	58.10	67.41	9.31
Aug-02	64.18	75.88	11.69
Sep-02	75.19	105.37	30.17
Oct-02	48.66	56.86	8.21
Nov-02	49.38	57.75	8.37
Dec-02	56.27	69.49	13.22
Jan-03	59.62	71.46	11.84
Feb-03	86.46	112.05	25.60
Mar-03	81.49	101.90	20.41
Apr-03	58.88	76.67	17.79
May-03	43.17	53.41	10.25
Jun-03	41.64	52.54	10.91
Jul-03	40.08	44.52	4.44
Aug-03	48.97	53.62	4.65
Sep-03	48.56	54.81	6.26
Oct-03	57.09	63.95	6.86

Table 1-25: Frequency Distribution of Difference between One-Hour Pre-dispatch and HOEP*

	1-hour ahead pre-dispatch price minus HOEP (% of Time within Range)							
	Less than $49.99	**-$50.00 to -$19.99**	**-$20.00 to -$9.99**	**-$10.00 to -$0.01**	**$0.00 to $9.99**	**$10.00 to $19.99**	**$20.00 to $49.99**	**Greater than $50.00**
May-02	0.42	1.53	2.50	**20.83**	**67.36**	6.39	0.97	0.00
Jun-02	0.28	1.11	1.53	8.89	67.22	11.11	8.19	1.67
Jul-02	0.00	1.08	1.61	9.95	49.19	9.54	13.17	15.46
Aug-02	0.80	2.15	1.75	12.65	49.39	11.57	11.71	9.96
Sep-02	4.60	3.60	1.80	18.20	48.30	9.50	8.60	5.40
Oct-02	0.80	0.50	1.70	14.30	49.10	13.00	17.80	2.80
Nov-02	0.70	0.70	1.00	15.70	46.30	11.20	22.70	1.70
Dec-02	1.60	**7.40**	3.10	16.30	37.10	6.90	24.00	3.60
Jan-03	0.40	2.20	1.80	11.30	41.00	9.00	24.90	9.40
Feb-03	**5.96**	4.02	3.87	13.86	22.80	6.71	20.42	**22.35**
Mar-03	3.90	2.83	3.23	13.06	31.09	10.63	19.25	16.02
Apr-03	2.36	3.62	**3.89**	16.97	36.16	14.05	18.64	4.31
May-03	0.70	1.11	2.09	7.94	50.56	9.47	**26.32**	1.81
Jun-03	0.84	3.63	2.51	13.11	45.05	8.51	21.90	4.46
Jul-03	0.00	0.81	0.54	14.80	58.68	6.86	18.17	0.13
Aug-03	0.00	0.95	1.52	14.02	55.68	7.58	20.08	0.19
Sep-03	0.14	1.11	2.50	14.72	50.69	**15.42**	15.14	0.28
Oct-03	0.54	0.81	1.88	14.13	52.22	14.27	16.15	0.00

*Bolded values show highest percentage within price range.

Table 1-26: Difference between One-Hour Pre-dispatch and HOEP and Peak Hourly MCP Within Defined Ranges

	Hourly Difference - % of Time within Range					
	1-hour ahead pre-dispatch price minus HOEP			1-hour ahead pre-dispatch price minus peak hourly MCP		
	Greater than $0	Equal to $0	Less than $0	Greater than $0	Equal to $0	Less than $0
May-02	74.03	0.69	25.28	44.58	5.83	49.58
Jun-02	88.19	0.00	11.81	72.22	1.81	25.97
Jul-02	85.22	2.15	12.63	65.99	6.45	27.55
Aug-02	81.97	0.81	17.23	63.80	4.17	32.03
Sep-02	71.00	0.80	28.20	47.43	2.64	49.93
Oct-02	82.70	0.00	17.30	57.80	1.34	40.86
Nov-02	81.90	0.00	18.10	54.87	2.37	42.76
Dec-02	71.60	0.00	28.40	49.87	2.02	48.11
Jan-03	84.30	0.00	15.70	57.93	2.82	39.25
Feb-03	72.28	0.00	27.72	44.71	1.19	54.10
Mar-03	76.85	0.13	23.01	46.30	2.96	50.74
Apr-03	72.88	0.28	26.84	50.90	3.62	45.48
May-03	88.16	0.00	11.84	66.99	2.51	30.50
Jun-03	79.78	0.14	20.08	57.04	2.65	40.31
Jul-03	83.58	0.27	16.15	61.78	2.83	35.40
Aug-03	83.33	0.19	16.48	63.64	2.46	33.90
Sep-03	80.97	0.56	18.47	56.39	4.17	39.44
Oct-03	82.50	0.13	17.36	55.05	4.58	40.38

Table 1-27: Percentage Intervals with Operating Reserve Reductions (Market Schedule), May 2002-October 2003

	No Reduction	> 1 MW	> 200 MW	> 400 MW	> 800 MW
May-02	41.44	21.94	35.22	0.86	0.54
Jun-02	48.08	15.60	29.52	4.64	2.16
Jul-02	88.80	1.62	3.99	3.42	2.17
Aug-02	93.40	0.63	1.42	2.48	2.06
Sep-02	89.50	1.27	3.83	2.30	3.10
Oct-02	87.72	2.31	4.80	3.99	1.19
Nov-02	97.08	0.39	1.39	1.00	0.13
Dec-02	94.10	0.99	1.90	2.37	0.64
Jan-03	96.21	1.07	2.01	0.56	0.15
Feb-03	96.58	0.85	1.90	0.37	0.30
Mar-03	93.70	0.87	3.25	2.02	0.17
Apr-03	93.85	1.58	2.46	1.65	0.45
May-03	95.00	1.92	1.79	1.29	0.00
Jun-03	94.71	1.09	2.07	1.84	0.30
Jul-03	97.86	0.69	0.88	0.40	0.18
Aug-03	96.96	0.86	1.39	0.64	0.14
Sep-03	97.88	1.43	0.38	0.27	0.04
Oct-03	98.89	0.08	0.56	0.35	0.12

Table 1-28: 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 (%)	
	5-hour ahead	1-hour ahead	5-hour ahead	1-hour ahead	5-hour ahead	1-hour ahead	5-hour ahead	1-hour ahead
May-02	272	300	36	63	1.85	1.98	0.31	0.44
Jun-02	497	454	231	188	3.15	2.82	1.47	1.14
Jul-02	616	535	325	244	3.48	2.96	1.82	1.31
Aug-02	362	381	79	98	2.08	2.15	0.47	0.54
Sep-02	384	391	112	118	2.36	2.33	0.73	0.70
Oct-02	279	329	30	80	1.75	2.04	0.20	0.48
Nov-02	369	372	107	112	2.20	2.19	0.66	0.66
Dec-02	377	390	110	123	2.13	2.19	0.62	0.68
Jan-03	383	376	122	115	2.01	1.97	0.64	0.59
Feb-03	351	327	100	77	1.85	1.71	0.54	0.39
Mar-03	277	296	45	60	1.62	1.68	0.30	0.34
Apr-03	278	292	54	66	1.80	1.82	0.41	0.43
May-03	339	331	113	104	2.35	2.24	0.83	0.72
Jun-03	353	320	100	66	2.30	2.03	0.68	0.41
Jul-03	474	376	199	101	2.88	2.29	1.20	0.61
Aug-03	365	342	94	71	2.34	2.10	0.70	0.46
Sep-03	319	317	67	64	2.09	2.01	0.47	0.40
Oct-03	257	323	16	81	1.75	2.10	0.21	0.54

Table 1-29: Percentage of Time that Mean Forecast Error (forecast to hourly peak) is within Defined MW Ranges

	> 500	500 to 200	200 to 100	100 to 0	0 to -100	-100 to -200	-200 to -500	< -500	> 0	< 0
May-02	5	26	17	12	14	11	13	3	59	41
Jun-02	17	31	12	11	10	7	8	3	72	28
Jul-02	26	24	10	11	9	7	10	3	72	28
Aug-02	10	25	11	16	14	8	13	3	62	38
Sep-02	10	28	14	14	12	9	10	4	65	35
Oct-02	4	22	16	22	15	13	7	1	64	36
Nov-02	4	29	19	17	12	9	9	0	70	30
Dec-02	10	29	15	12	12	9	11	2	66	34
Jan-03	5	33	17	15	12	8	10	1	70	30
Feb-03	6	26	15	15	14	10	12	2	62	38
Mar-03	4	26	14	17	14	9	14	2	61	39
Apr-03	6	23	13	18	13	13	13	1	60	40
May-03	3	28	17	22	14	10	6	0	71	29
Jun-03	6	23	13	17	16	11	13	1	58	42
Jul-03	10	25	12	13	11	13	16	1	59	41
Aug-03	10	23	12	15	11	9	16	4	60	40
Sep-03	5	22	16	17	16	9	13	1	60	40
Oct-03	3	28	15	18	14	10	10	1	64	36

Table 1-30: Discrepancy between SS Generators' Offered and Delivered Quantities*

	Total MW Pre-dispatch	Maximum Difference	Minimum Difference	Average Difference	Fail Rate (Difference/MW Pre-dispatch)
May-02	817,406	261.43	(124.26)	65.21	6.55
Jun-02	802,612	350.04	(333.99)	65.55	4.71
Jul-02	878,350	299.48	(74.80)	46.15	3.84
Aug-02	843,516	241.39	(82.37)	62.06	5.61
Sep-02	695,346	305.81	(32.07)	103.61	11.01
Oct-02	900,153	196.15	(86.90)	59.03	4.87
Nov-02	850,818	242.40	(131.30)	55.80	4.95
Dec-02	1,123,099	667.80	(317.20)	96.70	6.39
Jan-03	1,188,390	575.70	(317.90)	69.10	4.29
Feb-03	891,147	370.68	(313.42)	90.62	7.12
Mar-03	943,991	421.15	(427.07)	51.08	4.24
Apr-03	689,538	231.88	(139.09)	59.77	6.83
May-03	778,341	290.51	(69.88)	62.34	6.26
Jun-03	886,176	668.18	(243.79)	93.82	8.65
Jul-03	1,249,147	509.86	(146.78)	94.12	5.68
Aug-03	703,045	364.83	(193.14)	86.83	6.92
Sep-03	764,657	543.98	(111.61)	37.07	3.80
Oct-03	821,786	154.27	(94.26)	(0.42)	0.07

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

Table 1-31: Incidents and Average Magnitude of Failed Intertie Transactions

	Failed Imports into Ontario				Failed Exports from Ontario			
	Number of Incidents	Maximum Hourly Failure (MW)	Average Hourly Failure (MW)	Failure Rate (%)	Number of Incidents	Maximum Hourly Failure (MW)	Average Hourly Failure (MW)	Failure Rate (%)
May-02	66	220	61.3	1.9	120	400	120.2	10.7
Jun-02	154	300	60.5	3.0	275	600	144.4	14.5
Jul-02	256	1,000	167.8	6.1	339	800	247.7	49.0
Aug-02	232	1,121	156.7	3.4	280	900	264.9	63.1
Sep-02	317	1,460	202.6	5.7	188	500	201.6	23.0
Oct-02	284	700	176.0	5.4	332	986	192.0	15.5
Nov-02	194	711	126.8	2.2	179	800	156.3	6.6
Dec-02	253	871	150.3	3.2	219	740	222.5	8.1
Jan-03	202	774	80.4	1.8	255	650	175.5	6.1
Feb-03	399	795	79.8	2.9	206	800	151.8	6.2
Mar-03	406	604	66.9	2.3	187	550	136.4	5.6
Apr-03	312	498	56.6	2.1	254	500	142.3	11.0
May-03	239	654	63.4	1.7	427	214.9	49.7	11.1
Jun-03	151	687	105.3	1.6	386	1107	337.3	15.9
Jul-03	111	891	110.4	2.0	464	1300	343.5	12.8
Aug-03	87	389	90.1	1.6	306	1036	322.5	14.4
Sep-03	168	525	97.4	1.7	291	977	236.7	13.4
Oct-03	138	693	123.9	3.1	52	815	149.9	12.6

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 indicated in our first two reports, the MAU routinely analyzes all hours in which the HOEP is greater than $200/MWh (see section 2.1) and all hours where the uplift is greater than the HOEP (see section 2.2).

The Panel has 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 its findings to the Panel. The MAU analyzed several such events during the February-October period and reported its findings to the Panel. Sections 3 and 4 summarize the MAU's findings regarding two of these events.

None of these anomalous events has led us to conclude that there was any inappropriate behaviour on the part of any market participant.

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 its review is to understand the market dynamics that led to the 'high prices' and determine whether any further analysis of the conduct of market participants is warranted.[16]

Table 2-32 provides on a monthly basis, the number of high priced hours since market opening. There are two things worth noting from this table. First, for the period January to October 2003, most of the high priced hours (78%) occurred in the months of February and March. The underlying causes of these high priced hours are discussed in general terms in section 3 and specific hours are examined in section 2.1.

Second, comparing the months May to October (the overlapping months of 2002 and 2003 in which the market was in operation), there were considerably fewer high price hours in 2003 than in 2002. This is consistent with the fact, reported in Chapter 1, that the HOEP was generally lower in 2003 than in 2002. When comparing the overlapping months of May to October, the number of hours in which the HOEP was greater than $200/MWh decreased from 54 in 2002 to 6 in 2003. Furthermore, there were no hours in May–October 2003 in which the hourly uplift exceeded the HOEP. In contrast, there were 37 hours in 2002 in which the hourly uplift exceeded the HOEP. The reasons for the reduced number of high priced hours in 2003 are explained in section 4 of this Chapter.

Table 2-32: High Priced Hours, Monthly, May 2002–October 2003

	HOEP>$200		Hourly Uplift Above HOEP	
Month	**2002**	**2003**	**2002**	**2003**
Jan		1		0
Feb		15		1
Mar		24		0
Apr		4		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	
Dec	6		4	

[16] The $200/MWh threshold is the upper 1% of all HOEP (i.e., 99% of the HOEP are less than $200/MWh).

2.1 Hours with HOEP above $200

In our first two reports, we noted that a HOEP greater than $200 occurs in hours when the pre-dispatch supply cushion is relatively tight and the real-time supply cushion is made considerably tighter by at least one of the following factors:[17]

- Real-time demand was much higher than the pre-dispatch forecasts of demand
- One or more imports failed real-time delivery
- Real-time provision of energy by self-scheduling and intermittent generators was less than scheduled in pre-dispatch
- One or more generating units that appeared to be available in pre-dispatch became unavailable in real-time as a result of a forced outage or derating.

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%.[18] 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.[19]

In the February to October 2003 period, there were 47 hours in which the HOEP exceeded $200/MWh. The data describing the characteristics of these 47 hours are summarized in Table 2-36 in Appendix A. For most of these hours, the high HOEP is associated with a real-time supply cushion below 10%, which can be explained in turn by the factors articulated in our first two reports and listed above.

[17] The supply cushion is explained at pp. 11-16 of our March 2003 report.
[18] As reported in our first two reports, in all but one case in which the HOEP was greater than $200/MWh, the real-time supply cushion was less than 10% and generally considerably less than 10%. The one exception occurred on September 3, 2002, when the real-time supply cushion was 10.5%.
[19] 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.

There were 17 high price hours during the months of February and March in which the real-time supply cushion was in excess of the critical 10% threshold; in some cases it was roughly 20%. The causes of the high HOEP in these cases were a shortage of fuel at one Ontario generating station and the high price and occasionally limited availability of natural gas. An illustrative instance, delivery hour 5 on February 25, 2003 is described in detail as Case 1 below.

Another high price hour with a unique explanation is delivery hour 14 on June 25, 2003. This hour had the highest HOEP ($549/MWh) for the period February to October 2003. The high HOEP in this hour was primarily a result of the timing of a derating of a generating unit that was operating temporarily under the status of a self-scheduling facility following a long planned outage. The details of this hour are discussed as Case 2 below.

Case 1: February 25, 2003, Delivery Hour 5

The HOEP for this delivery hour was $279.15. This HOEP was seen as anomalous for three reasons. First, it was the first off-peak hour in which the price exceeded the $200/MWh threshold; all other high HOEP hours had occurred in the peak hours of the day. The HOEP in off-peak hours typically ranges between $25-$50 and averages $36-$43. Second, both the pre-dispatch and real-time supply cushions were sizeable at 33% and 20% respectively. Traditionally, when the supply cushion is this large, the market clears on the flat portion of the offer curve. When the market operates on the flat portion of the offer curve, unexpected changes to the market that tighten the real-time supply cushion (i.e., unexpected load growth) normally have very little impact on the market price. Third, there was considerable volatility in the real-time prices in this hour. Prices in this hour ranged from a low of $38.31 in intervals 3 and 4 to a high of $356.90 in interval 12; the percentage change in price from interval 4 to 5 was 638%.

The anomalous HOEP in this hour can be traced to the unusual shape of the real-time offer curve. The real-time offer curve was extremely inelastic at the forecast level of demand (17,600 MW); at this point on the offer curve, an increase in load of 70 MW would have increased the market clearing price from $30 to $350. The real-time offer curve was extremely inelastic in this range for three reasons. First, two Ontario generation facilities that would normally be offering supply at prices below $100 had increased the offer prices of much of their capacity to $350 in off-peak periods. These facilities increased their offer prices because of a physical shortage of fuel in one case and a substantial increase in the price of fuel in the other. The facility that was short of fuel had implemented an offer strategy that sought to preserve its available fuel for peak demand periods.

Second, there were very few offers from generation facilities located in Ontario that were made at prices between $100 and $350. As a result, no Ontario-based generation offers were available as alternatives to the energy–limited generation facilities; there was no alternative supply to mitigate potential price increases caused by increases in demand. This is not uncommon in off-peak periods. The remaining Ontario-based offers were from energy-limited hydroelectric facilities, which were offered at higher prices so they would be available in the peak demand periods when prices were expected to be much higher.

A third factor that contributed to the extreme inelasticity of the real-time offer curve was the scheduling process for imports. As we discussed in Chapter 2, Appendix 2 of our October 2002 report, imports and exports are selected one hour in advance of the dispatch hour, their schedules are fixed in real-time, and they cannot set the real-time price. This scheduling process causes the real-time offer curve to become more inelastic in the range around the pre-dispatch demand forecast. This problem was exacerbated by the fact that self-scheduling generators fell short of their scheduled supply by as much as 267 MW.

Figure 2-13: Comparison of Pre-dispatch Offer Curve and Real-time Offer Curve, February 25, 2003, Delivery Hour 5

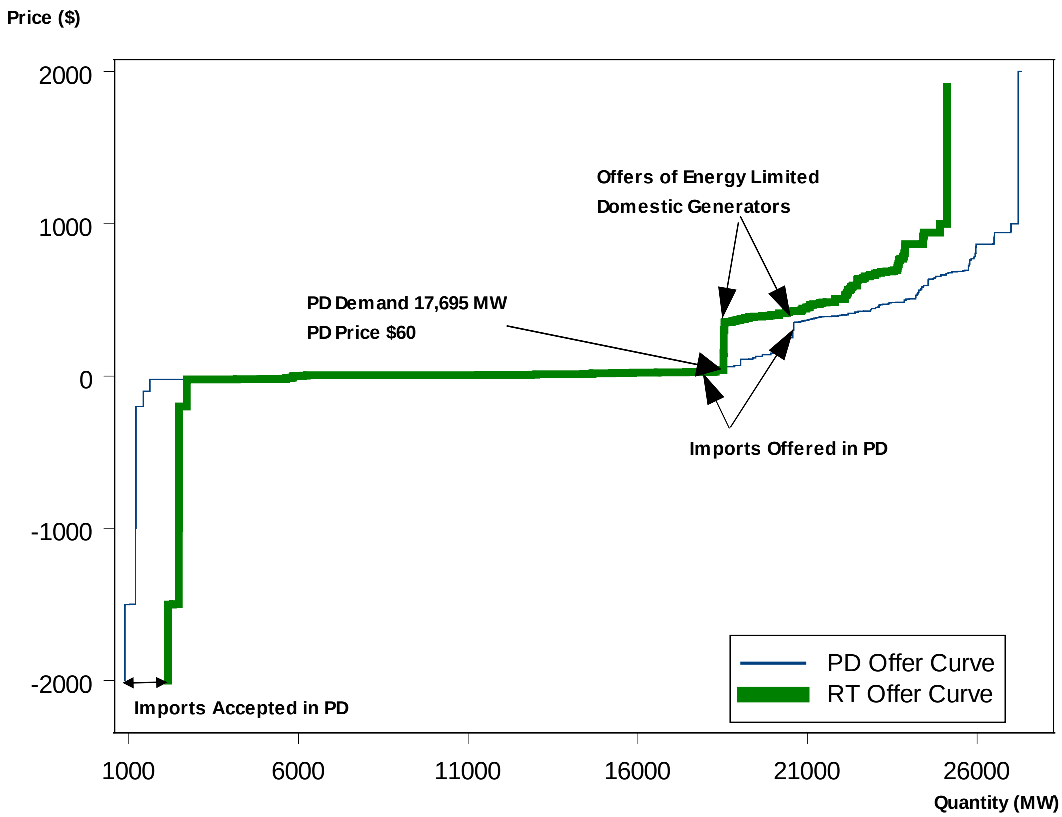


Figure 2-13 replicates both the pre-dispatch and real-time offer curves for this hour to illustrate how the factors listed above contributed to the anomalous price. The pre-dispatch offer curve for this hour included roughly 3,500 MW of imports. A large percentage of the imports offered (3,390 MW) was offered at prices between $40 and $350. These imports provided some elasticity in the pre-dispatch offer curve. The pre-dispatch demand forecast was 17,695 MW. At this level of demand, 1,418 MW of imports were selected and the market clearing price in pre-dispatch was $60. At this price none of the capacity of the energy-limited Ontario generation units was selected although it was still available for dispatch in real-time if needed. For this reason, the real-time supply cushion was 20%.

The difference between the real-time and pre-dispatch offer curves does not matter if real-time load is the same as the pre-dispatch forecast and generation corresponds to what was scheduled. In this case, there were no failed imports or exports but self-scheduling generators fell short of their scheduled supply by as much as 267 MW. To replace this, the market turned to the best alternative available in real-time, which was the energy-limited Ontario generators, which had offered their capacity at prices of $350 and above. As a consequence, the market cleared at prices in this range for most of the hour although it collapsed to $38.40 during one five-minute interval when load decreased slightly.

Case 2: June 25, 2003, Delivery Hour 14

The HOEP in this delivery hour was the highest for the period February to October 2003. There were several factors that were contributing to the high HOEP in this hour. Demand was near the annual peak level at 24,064 MW and there were several generating units that were unavailable due to outages. The pre-dispatch supply cushion was 17% but this was largely a result of the volume of imports being offered to Ontario in the hour. The domestic supply cushion was –8.9%, indicating that we were relying on imports to meet the Ontario demand. All of these factors combined to cause the Ontario market to clear on the steep portion of the pre-dispatch offer curve. The pre-dispatch offer price cleared at $323, the offer price of an import.

In real-time, there were 33 MW of failed imports but demand was lighter than forecast. These two factors combined would normally cause the real-time price to be less than the pre-dispatch price of $323.

Offsetting this was a reduction of the real-time supply of a self-scheduling unit of roughly 200 MW from what was scheduled in pre-dispatch. This caused the real-time supply cushion to tighten to 1.4% and the market to clear on the steep portion of the offer curve. It was this under-generation that caused the HOEP to spike to $549; over $200 higher than what had been forecast in pre-dispatch.

To measure the price impact of the under-generation by the self-scheduling unit, the MAU simulated the market under the assumption that the self-scheduling unit actually generated as scheduled in pre-dispatch. Had the unit conformed to its pre-dispatch schedule, the HOEP for the hour would have been $234.30 rather than $549.

The deviation of the self-scheduling generating unit from its pre-dispatch schedule was investigated by the IMO's compliance department. This unit was temporarily operating as self-scheduling following a planned outage. This is sometimes done following a prolonged outage to allow for robustness tests. It is the responsibility of the owner of a generating unit operating as a temporary self-scheduler to inform the IMO on a timely basis of any changes in the operating capacity of the unit through the submission of outage slips. In this case, the owner of the unit identified an unanticipated problem shortly after the close of the final pre-dispatch. The owner informed the IMO that it had to derate its unit. However, since it was after the final pre-dispatch, the IMO could not turn to alternative sources of supply such as imports to replace the lost capacity.

2.2 Hours where the hourly uplift charge is higher than HOEP

There was only one hour in which the hourly uplift was greater than the HOEP during the period February to October 2003. This occurred on February 26 in delivery hour 12. In this hour, the HOEP was $24.83/MWh. The hourly uplift was $24.95/MWh. The largest component of the hourly uplift was the IOG, which was $22.96/MWh.

The factors that caused the hourly uplift to exceed the HOEP in this hour were the extreme inelasticity of the real-time supply curve (exaggerated by the scheduling process for imports) and an over-forecast of demand in pre-dispatch. The pre-dispatch forecast for demand in the hour was 21,493 MW. At this forecast level, the market accepted roughly 3,000 MW of imports all at prices ranging from $40 to $300. The market ended up clearing on the portion of the pre-dispatch offer curve where the energy limited fossil units were offering capacity at $350 and above (See Figure 2-13 above as an illustration).

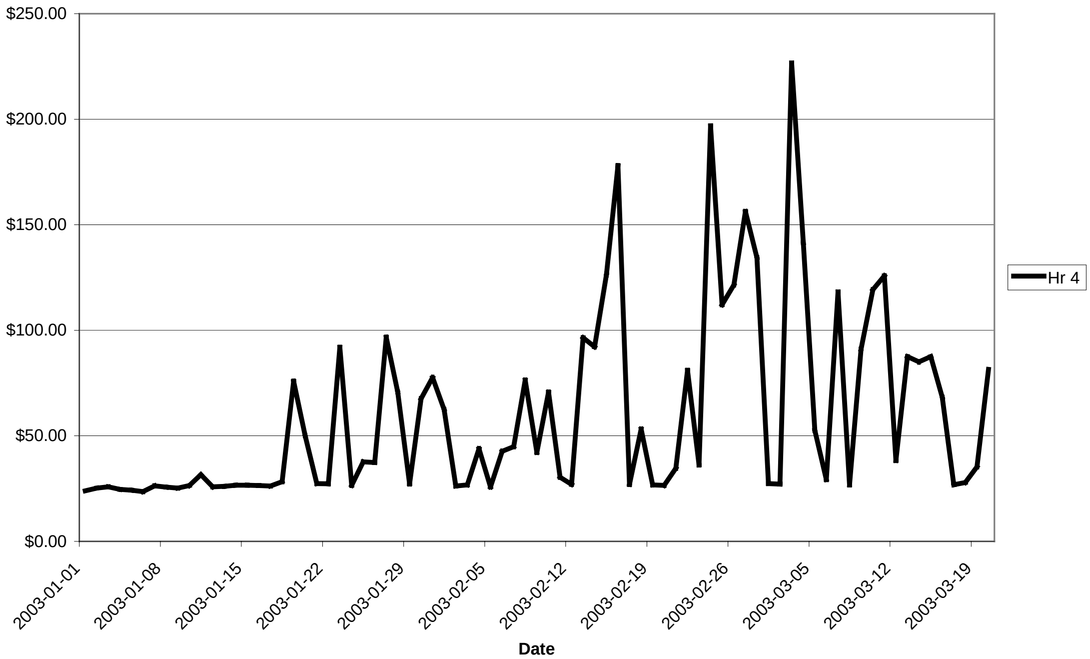
The pre-dispatch clearing price was $356.32, which was the offer price of one of the energy-limited fossil units.

In real-time, the demand was 500 MW to 800 MW lighter than forecast. This caused the market to clear to the left of the extremely inelastic portion of the offer curve. This caused the real-time price to fall to the $25 level. However, imports are guaranteed their offer prices. In this case, the importers (3,000 MW of imports) were paid prices ranging from $40 to $300. These payments are embedded in the hourly uplift. Given the magnitude of imports accepted and the large difference between the real-time price and the offer prices of these imports, the hourly uplift was higher than the HOEP.

3. *Unusually High Off-Peak Prices in Period February and March*

As shown in Chapter 1, the average HOEP was relatively high in the first quarter of 2003. This period differed from other high price periods in that off-peak prices were the highest since the market opened. The average off-peak price was $77.03/MWh in February and $70.69 in March 2003. No other monthly average off-peak price has been higher than $48.34/MWh (August 2003) and monthly off-peak prices have averaged in the $36-$43 range. Figure 2-14 illustrates the price movements in the first quarter of 2003 for a typical off-peak hour.

Figure 2-14: HOEP from January 1 to March 20, 2003 for Hour 4 (MWh)



The MAU conducted an analysis to determine the cause of the high off-peak prices observed during the first quarter of 2003. The MAU found that the rise in off-peak prices in January and February was the result of many factors. One factor was the pricing and supply of natural gas. As was noted in the Panel's last report, natural gas prices began to rise in the second half of 2002 and continued to rise early in 2003. At the same time, supplies of natural gas became less certain. Natural gas is an important feedstock for some generating plants, particularly in surrounding markets like New England and New York. As an extensively interconnected market, Ontario is heavily influenced by prices in the neighbouring markets.

A second factor was the reduced availability to the Ontario market of natural gas-fuelled generation. As a result of high natural gas prices, some generators found it more profitable to sell their natural gas rather than use it to produce electricity.

In addition, the winter of 2002-2003 was colder than previous years and there was a sustained high demand for electricity. As a result a facility became energy-limited due to limitations on fuel availability. Accordingly, the operator of the facility increased its off-peak offers from this facility consistent with its energy-limited status. This strategy was communicated to IMO operations staff as part of the notice that is required when a change in the status of a generation facility could have a material impact on the operation of the market.[20] The MSP considers the response of the market participant to be not unreasonable in the circumstances.

4. *Unusually High Operating Reserve Prices*

For a period of 6 hours on September 7, 2003, the MAU observed operating reserve (OR) prices for each class of reserve that appeared unusually high by comparison with similar periods and with energy prices. Indeed, operating reserve prices were as high as the energy prices.

The cause of the higher OR prices was an increase in the operating reserve requirement from a total requirement of 1,580 MW (peak periods) to 2,350 MW. This increase was a result of a situation in which two Bruce nuclear units, which are normally connected to the grid by separate transmission lines, were connected to the grid by a single transmission line due to a planned outage of one of the lines. The operating reserve requirement was increased in recognition of a change in the largest possible single contingency. In this case, the contingency in question was the potential loss of the single transmission line connecting both nuclear units to the grid. The loss of this transmission line would have led to the loss of two Bruce units – a total of nearly 1,600 MW.

Northeast Power Coordinating Council standards oblige the IMO to carry operating reserves sufficient to cover the largest first contingency as 10-minute reserve and half the next largest contingency as 30-minute reserve. To respect this obligation, the IMO increased the reserve requirement to 2,350 MW.

[20] See Chapter 5, section 3.6.1.3 of the Market Rules.

The increase in the operating reserve requirement caused a sizeable increase in the operating reserve price. However, since the energy supply cushion was large at the time, the increase in the operating reserve requirement did not increase the energy price significantly.

5. *Explanation of Year-to-Year Differences in the HOEP*

As we reported in Chapter 1, the average monthly HOEP in 2003 differed considerably from the average monthly HOEP in 2002. This is shown in Table 2-33. The average HOEP in May was $13.98 higher per MWh in 2003 than in 2002. The average HOEP was also higher in June and October in 2003 than it was during the corresponding months of 2002. The difference between 2002 and 2003 is especially noticeable during the summer months. In July 2003, when the demand is usually at its yearly peak, the HOEP was $40.08, which was $18.02 lower than in July 2002. In September 2003, the average HOEP was $26.63 lower than it was during September 2002. Overall, the HOEP was $5.50/MWh lower in 2003 than it was in 2002.

Table 2-33: Comparison Average Monthly HOEP per MWh
May-October, 2002 & 2003

Month	2002	2003	Difference
May	29.19	43.17	(13.98)
Jun	35.13	41.64	(6.51)
Jul	58.10	40.08	18.02
Aug	64.18	46.85	17.33
Sep	75.19	48.56	26.63
Oct	48.66	57.09	(8.43)
Average	51.71	46.21	5.50

We asked the MAU to identify the factors that contributed to the differences in the monthly prices between 2002 and 2003 and, where possible, to quantify the contribution of each factor on the overall price difference. In general, the factors that might explain the observed year-to-year differences in the monthly HOEP include:

- *Shifts in Ontario demand;*
- *Changes in the amount of available capacity from base-load nuclear generators;*
- *Increased supply from new entrants;*
- *Changes in the amount of available capacity from self-schedulers;*
- *Changes in the amount of water available to hydro facilities;*
- *Changes in operating reserve purchased from the market;*
- *Changes in the amount of imports offered and scheduled;*
- *Changes in the amount of exports bid and scheduled;*
- *Changes in the amount of available capacity from fossil generators;*
- *Changes in fuel prices;*
- *Changes in participant offer strategies.*

Chapter 1 described the general changes in demand and supply between the two years. For ease of reference, Table 2-34 below provides a summary of the year-to-year changes in the monthly values of most of the factors listed above.[21] As Table 2-34 indicates, there is considerable month-to-month variability in the year-to-year comparisons. Furthermore, the directional impact on the year-to-year price change differs from factor to factor. For example, the Ontario demand was lower in May 2003 than it was in May 2002. This would generally imply that prices would be lower in May 2003 than May 2002. However, there was less supply from base-load nuclear generators in May 2003 than there was in May 2002, which would generally imply higher prices in 2003 than 2002.

[21] We do not report the month of August since the August 2003 data were limited by the suspension of the market following the August 14 blackout.

Table 2-34: Year-to-Year Comparison of Factors Contributing to Difference in HOEP

	May		June		July		September		October	
Factor	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**
Ontario Demand (TWh)	11.88	11.62	12.16	11.88	13.99	12.89	12.59	11.81	12.41	12.12
Operating Reserve (MW)	1,019,639	1,104,224	974,903	1,064,558	1,078,246	1,108,358	1,035,834	1,106,712	1,078,883	1,034,382
Nuclear (MW)	5,364,858	4,792,593	5,383,515	4,988,462	5,629,942	5,968,010	5,402,550	5,773,009	4,870,382	3,597,137
Self-Scheduling (MW)	777,037	782,395	761,155	695,942	853,436	710,049	681,448	748,586	903,533	810,369
Hydroelectric (MW)	3,862,405	3,059,120	3,565,174	2,742,979	3,012,983	2,686,146	2,351,300	2,558,309	2,720,273	3,105,598
New Entry (MW)	0	48,705	0	52,456	0	9,520	0	157,136	4,959	182,155
Imports (MW)	190,824	869,109	286,710	951,704	653,353	601,285	1,056,006	937,375	874,508	1,055,417
Exports (MW)	120,055	736,784	233,889	694,292	88,604	1,087,417	126,667	446,927	347,819	167,771
Net Imports (MW)	70,769	132,325	52,821	257,412	564,749	(486,132)	929,339	490,448	526,689	887,646
Available Supply From Fossil (MW)	4,516,874	4,337,858	5,436,072	5,060,483	5,436,072	5,060,483	4,720,872	4,086,258	4,560,137	5,320,992
Natural Gas Price \$CDN/MMBtu*	5.40	8.01	4.90	7.81	4.60	6.92	5.58	6.28	6.45	6.14
Coal Price \$CDN/MMBtu**	1.67	1.80	1.67	1.79	1.84	1.84	1.84	2.06	1.75	1.98

*Henry Hub spot price.
**NYMEX market prices.

Shift-share analysis

The MAU employed a technique of shift-share analysis to isolate the respective impacts of changes in some of the factors listed above on year-to-year differences in the monthly average HOEP. Appendix B provides a detailed description of how the technique was applied. The analysis focuses on the factors that are strictly causal. These factors are shifts in Ontario demand and the factors that shift the Ontario offer curve. An economist would call these exogenous factors. Their common feature is that they affect the HOEP but are not affected by it. The remaining factors are either difficult to measure or are both causes and consequences of changes in the HOEP. These factors are grouped together in a residual category.

The causal or exogenous factors (that are also measurable) are: shifts in Ontario demand, changes in the available capacity of base-load nuclear generation, changes in supply due to entry and exit, changes in supply from self-scheduling generators and changes in supply of water available to hydroelectric generating facilities.[22] These factors change the HOEP but are largely insensitive to it. For example, Ontario load is largely insensitive to price and therefore, year-to-year changes in demand are due, in all likelihood, to changes in the weather or changes in industrial activity. Similarly, self-scheduling generators (SSG) operate under long-term fixed-price contracts. The capacity they offer into the market does not depend on the HOEP although it does depend on the price of natural gas (another exogenous factor). The same is true of year-to-year changes in available nuclear capacity and water flow which depend on technical factors and the weather among other things, but not on the HOEP.

The residual category includes demand for operating reserve, imports, exports, the price of fuel and offer strategies. Most of these factors not only cause but are also caused by price changes. For example, an increase in imports reduces the HOEP but a reduction of the HOEP also decreases imports. For this reason, the effect of a change in imports on the HOEP cannot be estimated using shift-share analysis. The price of fuel is an exogenous factor. However, the shift-share analysis is performed using exogenous variables measurable as a quantity (i.e., MW). Fuel prices cannot be directly measurable as a quantity. As a result, the effect of a change in fuel prices on the HOEP cannot be estimated using shift-share analysis.

Shift-share analysis isolates the effect of the change in Ontario load on the HOEP by asking what the 2002 monthly average HOEP would be if demand were the same in 2002 as it was in the same month in 2003. To do this, the hourly Ontario load is divided into 500-megawatt classes, for example 20,001–20,500 MW, 20,501–21,000 MW, etc. The average HOEP is typically higher in the higher load classes. For this reason, if load is more concentrated in the higher load classes, the monthly average HOEP will be higher. The 2002 monthly average HOEP can be calculated on the assumption that the 2003

[22] New entry was not in response to 2003 HOEP. In this regard, any new supply in 2003 due to entry was exogenous. However, the way the new supply was allocated in 2003 was affected by HOEP. The allocation of the new supply due to entry was endogenous. Similarly, a change in hydroelectric supply due

distribution of load across load classes prevailed in 2002. The difference between this and the actual monthly HOEP in 2002 is the effect of the load change on the HOEP. The effects of changes in the various causal supply-side factors can be isolated in a similar way.

Table 2-35 provides a summary of the respective impacts of changes in Ontario demand, nuclear plant availability, SSG supply, hydroelectric supply and entry of new capacity on the difference between the 2002 and 2003 HOEP. The values in Table 2-35 represent estimates of how much different (in $/MWh) the 2002 average monthly HOEP would have been if each of these five factors had been the same in 2002 as it was in 2003.

Taking the month of July as an example, Table 2-35 can be explained as follows. The July monthly HOEP was $18.02 lower in 2003 than in 2002. The reasons for this are, first that Ontario demand was lower in July 2003 compared to July 2002. As a consequence, the average monthly HOEP in July 2002 would have been $10.84 lower had Ontario demand been the same as in July 2003. Second, new entry of a 510 MW unit at the end of 2002 contributed to lower prices in 2003. In particular, had this generator been available in July 2002 and produced the same quantities as it did in 2003, the average HOEP in July 2002 would have been $0.91 lower. Third, there was more nuclear supply available in July 2003 than in July 2002. Had this additional nuclear supply been available in 2002, the average HOEP in July 2002 would have been $3.55 lower. Fourth, less supply from self-scheduling generators was available in July 2003 than in July 2002. If this supply had been the same in 2002 as it was in 2003, the July HOEP would have been $0.79 higher. Fifth, there was a greater abundance of water available for hydroelectric production in July 2002 than in July 2003. If the supply of water had been the same in 2002 as it was in 2003, the July HOEP would have been $0.26 higher. Finally, other factors such as changes in fuel prices or the availability of fossil generation also contributed to the difference in what the July 2002 HOEP would have been with

to changes in water levels is exogenous. However, the allocation of the water is affected by HOEP and is endogenous.

these factors at July 2003 levels. The cumulative effect would have been to reduce the July 2002 HOEP by $3.77.

Table 2-35: Estimated Impacts on 2002 Average Monthly HOEP with Factors at 2003 Levels, ($/MWh)

Factor	Month				
	May	**June**	**July**	**Sept**	**Oct**
Ontario Demand	(2.23)	(3.33)	(10.84)	(23.09)	(4.60)
New Entry	(0.44)	(0.12)	(0.91)	(2.18)	0.00
Nuclear Supply	4.03	1.29	(3.55)	(5.34)	9.66
Self-Scheduling Supply	(0.34)	(0.27)	0.79	(4.66)	2.69
Hydroelectric Supply	7.28	4.18	0.26	(6.48)	(2.47)
Residual Effect	5.67	4.75	(3.77)	15.11	3.16
Observed Difference in HOEP	**13.97**	**6.50**	**(18.02)**	**(26.64)**	**8.44**

Turning to the factors that caused the change in the HOEP, Table 2-35 shows that, other things being equal, lower Ontario demand in 2003, would have resulted in a lower average HOEP in the five months of 2002 included in the analysis. The magnitude of the price decline ranged from $2.23 in May to $23.09 in September.

The effect of the available supply of nuclear units varied across the months. In May and June of 2003, there was considerably less nuclear generation available compared to the same months in 2002. The reduced availability of nuclear supply in these months was a result of having fewer nuclear units on-line in 2003 due to planned outages. As the refurbished Bruce A and Pickering A units began to return to service, new supply was added to the market in the later months. The number of nuclear outages was also lower during the months of July and September of 2003 as compared to 2002. The impact of the increased nuclear supply (all else held constant) would have been to reduce the HOEP by $3.55/MWh in July 2002 and $5.34 in September 2002. Finally, in October 2003, there were outages at the Darlington and Bruce facilities that would have caused the HOEP to increase by nearly $10.00/MWh had they occurred in 2002.

In October of 2002, a new entrant began offering 510 MW of new capacity to the Ontario market. The impact of this new supply was to reduce the monthly average HOEP. The magnitude of the price impact varied from month-to-month depending on the amount of energy produced from the new facility.

The effect of changes in the water available to hydroelectric generating facilities on the HOEP varied from month-to-month. It would have increased the price in May 2002 by $7.28/MWh and reduced it by $6.48 in September 2002.

Analysis of the effects of other factors

The residual effect captures the impact of changes in all the remaining factors. In some months this residual effect aggregates the effect of several offsetting factors. For example, increases in net imports in May 2003 compared to May 2002 would contribute to a lower price in 2003. However, offsetting this are higher natural gas prices and less available fossil generation due to outages. For this reason, it is difficult to make any definitive statement of the effects of individual factors based only on the size of the residual effect.

Among the factors included in the residual category is the change in fuel prices, specifically natural gas and coal. Fuel prices are an exogenous factor and in principle, their impact on the HOEP could be estimated through econometric methods.

Higher gas prices should result in higher HOEP for three reasons: lower production by self-schedulers who sell their gas contracts back to the spot market, higher offer prices from Ontario gas-fired generators and increased prices of imports from jurisdictions relying on gas-fired generation. Higher coal prices should result in higher HOEP as a result of higher offer prices from Ontario coal-fired generators.

The MAU has conducted econometric analyses to assess the impacts of changes in fuel prices on the HOEP. It has also conducted econometric analyses to estimate the impact of changes in fuel prices on offer prices. The MAU reports that based on the available reported prices of coal, they have not been able to find a meaningful statistical relationship between coal prices and either the HOEP or the offer prices of coal-fired generation units.

The MAU has conducted econometric analyses of the impact of changes in natural gas spot prices on the HOEP and on offer prices of gas-fired generators. We described the analysis of the relationship between gas prices and offer prices in our previous report.[23] The MAU has found a statistical relationship between the price of natural gas and the HOEP over relatively brief intervals but this is not sufficient to draw any inferences about the marginal effect of the price of natural gas on the HOEP.[24]

Conclusions

In summary, several factors have influenced the difference in the average monthly HOEP between 2002 and 2003. Our analysis has identified three important influences: changes in Ontario demand, nuclear supply availability and hydroelectric supply availability. Demand was consistently lower in 2003, contributing to lower HOEP in 2003 compared to 2002 in all months. The effect of changes in available nuclear and hydroelectric supply varies by month. Increases in available nuclear supply contribute to lower HOEP in July and September 2003, compared to 2002. Decreases in available nuclear supply contribute to higher HOEP in May, June and October of 2003 compared to 2002. Changes in hydroelectric supply contribute to lower HOEP in September and October 2003, but higher HOEP in May through July of 2003.

The shift-share analysis cannot explain all the differences in the HOEP between 2002 and 2003. The MAU was unable to attribute an impact on the HOEP from changes in fuel

[23] See our March 2003 report at pp. 16-20.
[24] For the months of January to March 2003 when the gas units were likely to be the marginal units, the MAU found a simple correlation between natural gas prices and the HOEP. However this does not allow us to draw any inferences about the marginal effects of changes in natural gas prices upon changes in the HOEP.

prices. The MAU will continue to develop its analytic capability to provide more explanations of annual price differences.

Appendix A: Summary Data on High Priced Hours

Table 2-36: Summary Data on Hours Greater than $200 MWh

Delivery Date	24-Feb-03	24-Feb-03	25-Feb-03	25-Feb-03	25-Feb-03	25-Feb-03	25-Feb-03	25-Feb-03	25-Feb-03	25-Feb-03	26-Feb-03	26-Feb-03	26-Feb-03
Delivery Hour	19	20	1	5	8	9	15	20	21	22	2	8	9.
HOEP	266.22	219.71	292.20	279.15	357.33	366.94	355.18	278.27	348.63	229.06	231.33	337.49	367.47
Hourly Uplifts	8.69	7.71	8.95	8.21	9.13	8.18	7.11	12.61	7.73	7.30	6.27	11.34	8.96
Ontario Pre-Dispatch Price ($/MWh)	277.84	254.2	110.00	60.00	286.08	354.36	190.00	316.55	200.00	200.00	108.00	360.29	369.04
Pre-dispatch Demand (MW)	23,211	22,688	17,874	17,695	21,426	21,591	20,395	22,741	22,129	21,361	18,072	21,559	21,865
Average Actual Demand (MW)	22,566	22,378	18,005	17,587	21,029	21,313	20,403	22,413	21,985	21,291	17,765	21,345	21,633
Actual Peak Demand (MW)	22,742	22,601	18,390	17,825	21,517	21,462	20,477	22,512	22,159	21,663	17,958	21,644	21,710
Failed Imports (MW)	0	0	0	0	769	450	200	0	399	0	100	293	20
Failed Exports (MW)	0	40	0	0	0	0	0	0	0	0	0	0	0
Self Scheduled Under-generating (MW)	75	96	91	127	164	132	25	45	58	68	114	101	135
Pre-dispatch Supply Cushion (%)	7.0%	9.2%	32.0%	33.0%	17.9%	17.8%	23.2%	13.4%	16.6%	20.1%	29.8%	14.2%	13.2%
Real-time Supply Cushion (%)	3.2%	5.4%	19.2%	20.1%	10.3%	10.2%	12.4%	6.3%	7.5%	12.1%	13.1%	10.6%	11.4%
Average Supply Made Unavailable after Pre-dispatch (MW)	555	681	145	90	24	194	100	403	444	200	749	59	103

Delivery Date	26-Feb-03	26-Feb-03	02-Mar-03	02-Mar-03	02-Mar-03	02-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03
Delivery Hour	10	11	20	21	22	23	4	5	6	7	8	9	10
HOEP	375.19	344.58	251.47	326.16	321.62	229.31	226.59	208.08	215.03	282.53	368.24	392.86	221.15
Hourly Uplifts	9.12	9.57	10.20	12.62	11.64	9.68	7.61	6.23	6.80	16.46	22.56	5.28	13.34
Ontario Pre-Dispatch Price ($/MWh)	367.16	353.74	212.45	223.15	231.31	226.41	100.00	140.00	193.67	222.83	286.89	300.00	457.83
Pre-dispatch Demand (MW)	21,913	21,717	20,638	20,243	19,859	19,432	17,514	17,906	18,887	20,408	21,584	21,941	22,500
Average Actual Demand (MW)	21,442	21,193	20,793	20,574	20,059	19,189	17,656	17,916	18,657	20,187	21,567	21,547	21,508
Actual Peak Demand (MW)	21,587	21,314	20,953	20,679	20,305	19,607	17,760	18,200	19,297	20,769	21,825	21,739	21,620
Failed Imports (MW)	520	269	150	0	0	0	100	0	400	0	-100	230	75
Failed Exports (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Self Scheduled Under-generating (MW)	130	194	111	103	94	85	240	244	288	354	248	185	164
Pre-dispatch Supply Cushion (%)	15.0%	19.8%	8.9%	11.2%	12.5%	15.8%	26.1%	23.6%	23.6%	14.9%	10.0%	8.7%	9.8%
Real-time Supply Cushion (%)	11.9%	13.3%	3.3%	4.5%	7.2%	12.2%	11.9%	15.2%	16.6%	10.3%	7.2%	4.5%	5.9%
Average Supply Made Unavailable after Pre-dispatch (MW)	54	87	373	282	138	197	113	0	111	383	238	279	423

Delivery Date	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	03-Mar-03	22-Mar-03	22-Mar-03	22-Mar-03	22-Mar-03
Delivery Hour	11	12	13	15	17	19	20	21	22	10	11	12	14
HOEP	343.90	381.28	206.62	208.09	201.19	210.00	214.95	205.67	200.79	207.31	202.36	204.01	200.24
Hourly Uplifts	14.12	9.48	6.70	5.47	5.31	10.00	6.16	7.49	5.51	6.14	6.65	6.71	8.33
Ontario Pre-Dispatch Price ($/MWh)	386.41	289.00	245.00	194.00	199.00	285.00	222.83	215.20	215.20	133.00	177.43	151.43	175.00
Pre-dispatch Demand (MW)	22,579	22,150	21,823	21,270	22,010	23,294	23,276	22,767	22,084	17,271	17,764	17,661	17,174
Average Actual Demand (MW)	21,971	21,837	21,500	21,046	21,463	22,805	22,955	22,557	21,708	17,345	17,681	17,655	17,228
Actual Peak Demand (MW)	22,124	21,930	21,741	21,115	21,658	23,105	23,077	22,817	22,147	17,664	17,779	17,735	17,362
Failed Imports (MW)	50	137	0	0	548	45	-18	0	50	0	0	0	0
Failed Exports (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Self Scheduled Under-generating (MW)	167	137	68	45	48	19	13	1	3	142	130	135	168
Pre-dispatch Supply Cushion (%)	6.7%	13.2%	10.9%	16.3%	14.3%	8.2%	9.6%	13.4%	16.2%	16.0%	12.8%	13.7%	18.9%
Real-time Supply Cushion (%)	4.4%	4.5%	4.3%	8.7%	9.7%	5.3%	4.2%	6.3%	12.3%	3.9%	3.9%	4.3%	6.4%
Average Supply Made Unavailable after Pre-dispatch (MW)	556	822	225	292	406	0	134	134	153	100	130	450	100

Delivery Date	04-Apr-03	17-Apr-03	17-Apr-03	21-Apr-03	2-Jun-03	25-Jun-03	25-Jun-03	26-Jun-03
Delivery Hour	20	19	21	11	17	14	15	15
HOEP	219.00	270.32	413.11	351.13	231.00	549.00	498.77	201.72
Hourly Uplifts	9.22	29.02	53.24	31.98	22.00	67.00	74.70	14.11
Ontario Pre-Dispatch Price ($/MWh)	325.00	62.14	84.00	78.11	99.00	323.00	434.00	249.00
Pre-dispatch Demand (MW)	20,827	18,350	18,294	17,377	17,895	24,078	24,352	24,500
Average Actual Demand (MW)	20,445	18,127	18,074	17,763	17,733	23,942	24,106	24,386
Actual Peak Demand (MW)	20,617	18,397	18,427	17,892	17,948	24,064	24,246	24,595
Failed Imports (MW)	385	0	0	0	232	33	50	516
Failed Exports (MW)	0	0	0	50	0	0	0	0
Self Scheduled Under-generating (MW)	24	78	76	43	28	279	148	63
Pre-dispatch Supply Cushion (%)	6.8%	12.9%	14.8%	9.7%	12.6%	17.6%	17.9%	20.8%
Real-time Supply Cushion (%)	5.7%	2.7%	1.6%	1.2%	0.9%	1.4%	1.3%	1.2%
Average Supply Made Unavailable after Pre-dispatch (MW)	250	191	265	80	0	0	50	74

Appendix B: Description of the Shift-Share Analysis

This Appendix provides an overview of the methodology of shift-share analysis. The results of this analysis are reported in section 5 of Chapter 2.

The analysis aims to decompose the difference between average monthly prices in 2002 and 2003 into a demand-induced effect and a residual effect. Put simply, the total change in price is assumed to be a linear combination of a demand-induced effect and a residual effect.

Total change in price = change in price due to a change in demand
(demand effect)
\+
change in price due to change in other factors
(residual effect)

This Appendix consists of two sections. The first section provides a step-by-step description of the shift-share analysis. It uses data in the months of May 2002 and May 2003 to illustrate each step. The data is presented in Table 2-37. The second section provides the mathematics underlying the description of the total price change into a demand and residual effect.

1. Step-by-Step Description of Shift-Share Analysis

Step 1:
We first group demand into 500 MW intervals (column 1 of Table 2-37).

Step 2:
We then derive a demand distribution by allocating hours for the month of May into the demand intervals (columns 2 and 4 of Table 2-37).

Example:

Consider row two and column one in Table 2-37. This says that there were 4 hours in May 2002 during which demand was in the interval 11,501 MW to 12,000 MW.

Step 3:

We calculate the average energy price for each demand interval (columns 3 and 5).

Step 4:

The total price effect is computed as follows:

(1) Change in price due to change in demand **(demand effect)** $= \dfrac{\text{(column 4 – column 2)*column 3}}{\text{Total hours in May}}$

(2) Change in price due to change in other factors (**residual effect)** $= \dfrac{\text{(column 5 - column3)*column 4}}{\text{Total hours in May}}$

Total change in price = (1) + (2).

Example:

For demand interval 11,501 to 12,000 (row 2):

Change in price due to change in demand = [(15-4)*25.08]/744 = 0.370806

Change in price due to change in other factors = [15*(22.01-25.08)]/744 = -0.061895

Total price effect = 0.370806 + (-0.061895) = 0.3089

Step 5:

We sum the price effects over the demand intervals to obtain the price effects for the month of May.

Analysis by sources of supply

The above analysis can be further refined to see how different sources of energy supply influence the average energy price. For instance we can quantify how the average energy price is influenced by the use of nuclear supply. To do this we simply subtract the nuclear generation from the total supply needed to meet Ontario demand. We then apply Steps 1 through 5 to the new data series (demand-nuclear supply) to get the following:

Demand effect = change in price due to change in demand (*excluding nuclear supply to meet this demand)*

Residual effect = change in price due to change in other factors (*excluding the effect of nuclear supply)*

It follows that:

Nuclear supply effect on price = residual effect (from total supply) – residual effect (excluding nuclear supply)

The analysis can be extended to other sources of supply namely:

1) New entrants
2) Self-scheduling generators
3) Hydroelectric energy.

Results are reported in Chapter 2.

2. Mathematical Derivation

This section demonstrates mathematically how the total price change from 2002 to 2003 can be decomposed into a demand induced effect and a residual effect.

Let I be the set of Ontario load intervals and $i \in I$ be a specific load interval.

Define H_t^i to be the number of hours in which the load fell within a particular interval i in year t.

H_t^i = hours in interval i in year t

Then the average HOEP in year t for a given load interval i can be expressed as:

$$HOEP_t^i = \frac{\sum_h^{H^i} HOEP_t^h}{H_t^i} \qquad (1)$$

where h runs from 1 up to the $\mathbf{H_t^i}$.

Now note that using equation (1), we can write the average monthly HOEP in year t as:

$$HOEP_t = \frac{\sum_I H_t^i * HOEP_t^i}{H} \qquad (2)$$

where H is the total number of hours in the month.

Using equation (2), we can write the difference in the monthly average HOEP between year t and year t-1 as:

$$HOEP_t - HOEP_{t-1} = \frac{\sum_I H_t^i * HOEP_t^i - \sum_I H_{t-1}^i * HOEP_{t-1}^i}{H} \qquad (3)$$

Equation (3) can be re-written by first subtracting and then add $\sum_I H_t^i * HOEP_{t-1}^i$ so that

$$HOEP_t - HOEP_{t-1} = \frac{\sum_I H_t^i * HOEP_t^i - \sum_I H_t^i * HOEP_{t-1}^i + \sum_I H_t^i * HOEP_{t-1}^i - \sum_I H_{t-1}^i * HOEP_{t-1}^i}{H}$$

The last two terms in the numerator of the above equation measures the effect on the HOEP due to changes in demand (the demand effect). In other words, it measures what the 2002 monthly average HOEP would have been if the Ontario load were distributed in 2002 as it was in the same month in 2003. The first two terms in the equation measure the effect on HOEP from changes in all other factors (the residual effects).

That is $HOEP_t - HOEP_{t-1} =$ R_{-D} + Demand Effect (4)

where the subscript –D on the residual effect indicates the effect of all factors other than demand.

<u>*Analysis by sources of supply*</u>

To calculate the effect of changes in available nuclear capacity, the MAU subtracted the hourly amount of nuclear generation from the hourly Ontario demand to create a new series of hourly demand values net of nuclear supply. Call this series the net nuclear demand.

Define

${}^{N}H_t^i$ = the number of hours in which the net nuclear demand fell within a particular interval i in year t.

Then the average HOEP in year t for a given segment i can be expressed as:

$$HOEP_t^i = \frac{\sum_h^{{}^N H^i} HOEP_t^h}{{}^N H_t^i} \qquad (5)$$

Performing the same algebraic manipulations as above we can write the year-to-year difference in monthly prices as:

$$HOEP_t - HOEP_{t-1} = R_{-N} + \text{Net Nuclear Demand Effect} \qquad (6)$$

Note that the difference between the two residual effects represents the effect on the HOEP from the changes in nuclear supply from 2002 to 2003. That is

$$\text{Nuclear effect} = R_{-D} - R_{-N} \qquad (7)$$

Using equations 4 and 7 we have:

$$HOEP_t - HOEP_{t-1} = \text{Nuclear Effect} + \text{Demand Effect} + R_{-N}$$

That is, we have decomposed the average monthly price difference between 2002 and 2003 into three effects, the effects of changes in Ontario demand, the effect of changes in available nuclear supply, and the effects of all remaining factors.

To measure the effects of the changes in supply from new entry the MAU simply subtracted the hourly supply from new entrants from the hourly net nuclear demand and conducted the same calculations for this new series as was done via equations 5 through 7. Similar calculations were performed for the other factors: changes in the supply from self-scheduling generation, and available hydroelectric energy.

Table 2-37: Demand and Average Price Distribution for May 2002 and May 2003

Column 1	Column 2	Column 3	Column 4	Column 5
Interval (i)	May 2002		May 2003	
	No of Hours (H_{t-1}^{i})	AVG HOEP ($HOEP_{t-1}^{i}$)	No of Hours (H_{t}^{i})	AVG HOEP ($HOEP_{t}^{i}$)
11,001-11,500	N/A	N/A	5	24.02
11,501-12,000	4	25.08	15	22.01
12,001-12,500	19	19.53	36	23.82
12,501-13,000	44	18.42	55	25.05
13,001-13,500	67	18.91	64	25.30
13,501-14,000	54	21.66	42	27.31
14,001-14,500	32	23.19	32	28.50
14,501-15,000	58	25.89	74	33.87
15,001-15,500	63	29.30	59	37.32
15,001-16,000	41	31.86	28	56.49
16,001-16,500	34	28.49	34	43.10
16,501-17,000	38	29.10	38	53.08
17,001-17,500	63	30.56	103	51.04
17,501-18,000	107	32.16	131	64.35
18,001-18,500	73	39.67	25	78.46
18,501-19,000	28	46.81	3	109.75
19,001-19,500	14	44.94	N/A	N/A
19,501-20,000	5	65.27	N/A	N/A
Total	**744**	**29.19**	**744**	**43.16**

Chapter 3: Improving Market Operation: The Past 18 Months

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 right amount of energy is produced. The reliability of the system is dependent on market participant response to clear and transparent market signals in all time frames.

During the first 18 months of market operation, a great deal was learned by market participants, the IMO and the MSP with regard to how a market for electricity in Ontario would operate in fact, rather than in theory. On balance the IMO-administered markets performed reasonably well from an operational perspective, but experience showed that there were areas where both the rules and the structure of the market could be improved. Some improvements have been introduced and others are being considered for implementation. This Chapter describes some of the more significant changes made over the past 18 months. Chapter 4 sets out our view about what needs to be done going forward.

In brief, the key changes made since market opening have fallen into three broad groups. First, there have been changes to the rules to eliminate opportunities for market participants to game the market (that is, to increase their own revenues at the expense of other market participants without adding to efficiency or reliability). In all cases these situations resulted from unintended consequences of Market Rules or design and there was no evidence that participants intended to take advantage of the situation. Second, a number of changes to the design of the market have been introduced by the IMO, in consultation with market participants, to reduce volatility and increase the credibility of price signals. Finally, in response to the urging of many market participants, the IMO Board has authorized the regular and timely dissemination of information regarding generation and outages by unit. Each of these types of changes is reviewed in sections 2 to 4 below.

Section 5 provides our broad conclusion on the changes that have been made to Market Rules and design, and section 6 reports on two further sets of initiatives that are underway.

2. *Changes to the Rules to Prevent Gaming*

As part of the ongoing monitoring of the IMO-administered markets, the MSP reviews both market clearing prices and payments under the CMSC regime. When it becomes apparent that payments are being made that are simple transfers without contributing to efficiency, or may be subject to manipulation by market participants, provisions within the Market Rules allow for urgent rule amendments to address such situations in a timely way.

MSP and IMO urgent amendments relating to unintended consequences of the market design that were implemented over the last 18 months include:

- so-called 'implied wheels'
- constrained off payments for negative offers, and
- constrained off payments to exports at uncontested interties.

Our October 2002 report describes the action taken to address the implied wheel.[25] This section describes how the IMO responded quickly to the other issues and initiated urgent rule amendments. To some extent this arose as a result of our review of constrained off payments and the management of CMSC.[26]

2.1 Constrained Off Payments for Negative Price Offers

Our review of CMSC payments, and in particular those payments made to generators and imports[27] that were constrained off, led to a recommendation to the IMO Board in July to modify payments of CMSC for offer prices below zero dollars. The Market Rules provided for constrained off payments equal to the difference between the MCP and the offer price

[25] See October 2002 report, p. 77. See also section 6.1 of Chapter 1 of this report and Table 1-9 of the Statistical Appendix.
[26] See http://www.theimo.com/imoweb/consult/consult_cmsc.asp
[27] See Chapter 1, section 6.2 and Tables 1-10 to 1-12 of the Appendix.

of the constrained off energy. Where energy is offered at negative prices this resulted in a CMSC payment that exceeded the MCP and could, in some circumstances, be very large. We concluded that there is no efficiency rationale for such payments on the grounds that if the MCP is sufficient compensation for producing energy, it ought to be sufficient compensation for not producing energy. We recommended that – as a general rule – where offers at negative prices became constrained off the CMSC payment be limited to the MCP.

As this recommendation was being developed for the IMO Board, constrained off payments to a particular generator began occurring on a regular basis, at negative offer prices. Over a two-month period, large CMSC payments were incurred for one plant as the result of these negative offer prices. This offer strategy was implemented for operational reasons and there was no suggestion that the market participant tried to take advantage of the rule. An urgent Market Rule (MR-0239-R00) implemented on June 26, 2003, was enacted to limit such CMSC payments to generators in the manner described above. To date some $1.8 million in CMSC payments have been recovered due to this Rule. The IMO undertook to review the operation of this Rule within six months to assess whether any unforeseen issues or concerns have arisen.

2.2 Constrained Off Exports at an Uncontested Export Intertie

Exports account for a relatively small portion of all CMSC payments. Over the period from May 2002 to April 2003, CMSC payments to exports amounted to about $14 million, or about 6 percent of the total $229 million in CMSC energy payments. Partly for this reason, and partly because constraining off an export increased supply in Ontario,[28] we excluded constrained off CMSC payments from our review in early 2003.

In July 2003, the MAU began to observe CMSC payments on the order of $100,000 per day at one of the interties other than New York. This was unusual, and of some concern, since these payments were not explained by system-wide adequacy problems, or even local

[28] About 90 percent of constrained off payments occur for exports to New York, with about 5 percent each to Manitoba and Minnesota. Exports are typically constrained off during tight reserve periods in Ontario. Thus

transmission outages. The payments appeared to be an anomalous and persisting event, possibly related to there being one dominant player exporting at the interface in question.

Investigation by the MAU revealed that the exports were being constrained off due to a local adequacy problem and resulting heavy loading on circuits into the area. The market participant wanted the exports and began to increase its bid price in an effort to ensure that the exports would be approved. As the bid price increased the exports were scheduled for dispatch in the unconstrained schedule, but notwithstanding the higher bid prices, continued to be constrained off in the dispatch schedule in order to maintain local supply in the area. The consequence was increasing constrained off payments as the market participant's bid price increased. Discussions with the market participant confirmed that the bid prices were above any costs they were incurring and above the value of the purchase.

Where interties are contested, competition for exports can congest the interface and in such a situation the exporter will pay his actual bid price, rather than the MCP. Where an intertie is not congested, however, the market participant can control whether or not congestion results and is always assured – regardless of his bid – of paying no more than the MCP where his bid is successful. The unintended consequence is that constrained off exports in such circumstances can result in very high CMSC payments.

A further consideration is that the Local Market Power rules made it difficult for the IMO to recover CMSC payments in these circumstances because the structure of the recovery framework is such that, over time, accepted bid prices become effective safe harbours for market participants.[29]

The MAU, after reviewing the situation, concluded that there was no intent to game the Market Rules in this instance, and a substantial amount of the CMSC payments was recovered in this case through the operation of the Local Market Power rules.

$8.5 million of CMSC payments for constrained off exports were made in the three months of July and September 2002 and February 2003.

However, the recognition of this situation led to the amendment of the Market Rules, through the Urgent Rule Amendment process, on August 8, 2003 (MR-00243-R00). A new section defined an 'uncontested export intertie' and provided that where constrained off payments were made over such an intertie, the historical bids would not be allowed to create a safe harbour for the purposes of Local Market Power review. As of August 11, four interties have been designated as 'uncontested'. These are the interties with Manitoba, Minnesota, and two interties with Quebec, at Kipiwa and Maclaren respectively. The MAU has not found any instances of gaming on any of these interties, but the amendment to the rule will remove the potential ability of market participants to manipulate CMSC payments for constrained off exports.

3. *IMO Initiatives to Improve the Market Design*

In our previous report we described how the IMO established an internal team to address concerns about energy pricing and uplift and to consult with market participants about possible improvements through the Market Operations Standing Committee and the Technical Panel.[30] In particular, the issues of insufficient price transparency, the different treatment of imports in setting pre-dispatch versus real-time market prices and the inability to hedge uplift costs were identified as significant concerns. The IMO distilled those concerns into three key pricing issues to be addressed:

[29] This framework is described in Appendix 7.6 of the Market Rules.
[30] See pp. 89-96 of our March 2003 report.

Disconnect between pre-dispatch price and real-time price

As documented in previous MSP reports, the pre-dispatch prices (in particular, for one-hour and five-hours ahead of dispatch) consistently and substantially overestimated the real-time price (HOEP). This persisting bias resulted in the pre-dispatch price being a less effective signal to market participants of what to expect in real-time than would be desirable for the market to function efficiently.

Counter intuitive prices in times of shortage

A particular manifestation of the above situation has occurred under some circumstances where the market has seen pre-dispatch prices that are very high, due to a very tight supply situation, followed by a real-time price that is significantly lower. The result is counter intuitive and confusing to market participants with respect to what behaviour they should adopt in response to the high pre-dispatch prices.

Size and variability of hourly uplift charges

Generally the uplift costs are a relatively small portion of the total cost of electricity. However, in some hours the uplift charges can be close to or higher than the energy price causing the overall cost of energy and associated uplift to be much higher in those hours than expected.[31]

In their review, the IMO team recognized that each of these issues detracted from the efficient operation of the IMO-administered markets and, at times, jeopardized the reliability of the IMO-controlled grid. The reliability of the system is enhanced when the IMO can rely on market participant response to clear and transparent market signals in all time frames. Price signals that are confusing and not credible compromise efficiency and

[31]This issue was discussed in the March 2003 MSP report under the anomalous event section of Chapter 2, pp 41-42.

reliability in the short-term. Over the longer term, they can also erode confidence in the operation of the market and thus discourage new investment.

Over the past 12 months, these issues have been addressed by implementing the following design changes to the operation of the markets:

- Market participants are now allowed more opportunities to revise their offers prior to dispatch.
- An Hour-Ahead Dispatchable Load (HADL) program has been introduced.
- The IMO has changed its practice of using 'out-of-market' operating reserve actions in a way that includes such actions in the market, with an imputed price attached.
- A program has been introduced to encourage greater supply by compensating producers for start-up costs that they might otherwise not recover from the market.

The balance of this section describes these initiatives in more detail.

3.1 Adjustment of Four Hour Restriction for Submission of Dispatch Data to Two Hours

In mid-November 2002, the IMO lowered the restriction on offer and bid submissions from 4 hours to 2 hours on a trial basis. The trial ended in February 2003 and the change was incorporated into the Market Rules. This change allows market participants to make unrestricted revisions to dispatch data up to two hours prior to the applicable dispatch hour. Prior to this the Market Rules allowed unrestricted revisions to dispatch data only up to four hours prior to the applicable dispatch hour, and imposed restrictions to revisions of dispatch data made in the period between four and two hours before the applicable dispatch hour.

The trial was established to determine if the market, being allowed additional time to revise dispatch data with no restrictions, could and would respond to changes in market conditions that occur after four hours before the dispatch hour.

The results and experience have been positive, from both the perspectives of market participants and the IMO. This may have been one of the factors contributing to a convergence between pre-dispatch and real-time prices. This is discussed in section 5 below.

3.2 Hour-Ahead Dispatchable Load (HADL) Program

The initial market design recognised the importance of demand response in creating effective competition and of attracting demand response to the market. We continue to believe that demand response is critical to a continuing efficient market.

Dispatchable loads are price responsive. They bid into the market and are dispatched (potentially every five minutes) on the basis of these bids. These loads are price responsive. Currently, approximately 250 MW of load are regularly bidding as dispatchable load.

There are many other loads in the province that are price responsive but for a variety of reasons they have not elected to bid directly into the market.[32] From discussions that the IMO conducted with loads, it became apparent that many large consumers simply did not have the capability to respond to dispatch instructions on a five-minute timeline, and others who did felt that the disruption this could create for their production processes was likely to be too great to compensate for the savings in energy costs they would realize. For these reasons many large users have declined to participate as dispatchable load.

Even though large loads do not bid as dispatchable, they have nevertheless responded to very high prices by cutting back their consumption.[33] Their response is often not fully forecast by the IMO. When this happens, other things equal, real-time demand will be lower than pre-dispatch demand. As a result, imports may be scheduled in the hour-ahead pre-dispatch schedule that, in real-time, turn out to be unnecessary and more expensive than domestic options. At the same time, the real-time price falls relative to the pre-dispatch price because demand is lower. This, in turn, exacerbates the signalling problem that occurs when the pre-dispatch price consistently overestimates the real-time price.

[32] See pp. 90-92 of our March report.

The Hour-Ahead Dispatchable Load (HADL) program was introduced in an effort to address these issues by increasing the price responsiveness of large loads and making such price responsiveness more transparent to the market. It was launched in July of 2003.

Participants now have the opportunity to submit offers to reduce consumption by indicating the amount of reduction at a specified price. Offers are evaluated for each dispatch hour on the basis of the pre-dispatch schedule and clearing price three hours prior to the dispatch hour. If the offer to be dispatched is accepted, the IMO reduces the pre-dispatch market demand for the applicable hour by the amount of MW accepted in the HADL program.

Loads in this program are protected against the possibility that their offer to be dispatched turns out to be based upon a higher price than actually obtains in real-time. If the HOEP for the dispatch hour turns out to be less than the offer price of a scheduled hour-ahead dispatchable load, the IMO pays the participant the difference between the offer price and HOEP for the load scheduled. This Hour-Ahead Dispatchable Load Offer Guarantee compensates the load for reducing demand when real-time prices turn out to be such that it would have wanted to consume. In a sense this is similar to the treatment of imports via the IOG payment.

Since the program was launched in July 2003, four facilities have registered for a total of 240 MW. There were a total of 25 hours in July where hour-ahead dispatchable load reductions were scheduled. The maximum single hour reduction was 30 MW.
There was one hour of reductions scheduled in August. In total up to October 31, 2003 less than $10,000 has been paid out to HADL participants in the form of the HADL guarantee.

While the initial take up of the program was encouraging as loads recognized it helped them achieve some of their goals, actual results in terms of dispatch of HADL resources have been low. We believe that one reason for the low take-up to date has been the relative absence of large price spikes since the program was introduced. Since then the pre-

[33] See pp. 96-105 of our March 2003 report.

dispatch price has been above $85 in less than 2% of hours and has not exceeded $160. At prices in this range, it may well be inefficient for a load to agree to be dispatched off and not consume. The structure of the program, however, provides protection for loads to refrain from consuming where they believe that the energy costs they will incur represent too high a proportion of their total costs. And by encouraging these decisions in a manner that is transparent, the program also contributes to the efficiency of the market.

3.3 Operating Reserve Control Action Introduced into the Market

As previously reported, the IMO is permitted when there is insufficient operating reserve (OR) to use out-of-market sources of operating reserve in real-time.[34] When using these sources the IMO in turn reduces the OR requirement in the market schedules by the amount of 'out-of-market' sources employed. Out-of-market sources of OR available to the IMO include:

- 3% voltage cuts (approximately 400 MW at peak);
- 5% voltage cuts (approximately 280 additional MW at peak); and
- reduction of 30-minute operating reserve for up to 4 hours if it is felt that it can be restored (approximately 480 MW).

Our previous reports have pointed out that the use of 'out-of-market' resources in real-time but not in pre-dispatch, contributed substantially to the persistent discrepancies between the pre-dispatch and real-time price.

In our last report, we indicated some options that the IMO was considering to ameliorate these effects. We concluded that:

> …the efficiency implications of moving to incorporate 'out-of-market' actions are important and (we) support assigning prices to 'out-of-market'

[34] See our October 2002 report at pp. 97-101 and March 2003 report at pp. 93-96.

> resources in both pre-dispatch and real-time as soon as this can reasonably be done.[35]

Following extensive consultation with market participants it was agreed that the use of 'out-of-market' resources would be integrated into the market in a way that is both predictable and transparent. The consensus was to apply a price to each of the 'out-of-market' resources and directly insert these resources into the market as operating reserve offers in both pre-dispatch and real-time. This would allow different quantities of these resources to be used in the constrained and unconstrained schedules in both pre-dispatch and real-time. To ensure transparency, the use of these resources would be established at a pre-determined price and actual use would be published in real-time.

The IMO Board decided to introduce the first of these resources into the schedules in 200 MW tranches so that price effects, as well as unpredicted effects, could be monitored to determine if there were unforeseen adverse effects. The implementation of the first 200 MW tranche was on August 6, 2003 with prices attributed to these resources at $30.10 for 10-minute non-spin and $30 for 30-minute OR. The second tranche of 200 MW was implemented October 15, 2003 with the same price structure.[36] The next initiative consists of the removal of the 200 MW of supplemental operating reserve requirement that was introduced in June 2002.[37] The IMO, subject to Board approval, will implement this in mid-January 2004.

As reported in Chapter 1, there has been a reduction in the use of out-of-market control actions over time (see Statistical Appendix, Table 1-27). In particular, the frequency of use

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[35] See our March 2003 report at p. 95.

[36] The prices being used are prices arrived at by consensus with load and generation through the process of consultation. They may not be the most efficient prices but they do represent a major improvement from assuming that the price is zero.

[37] In June 2002, the IMO increased the operating reserve requirement by 200 MW for the daily peak period (i.e. between 0700 and 2100 hours) to address grid reliability concerns. This change was introduced to attract more market sources of operating reserve to the market so that the market could better supply the operating reserve required under the applicable reliability standards. Prior to the introduction of the 200 MW of supplemental operating reserve requirement, there were frequent market shortfalls of operating reserve and the IMO had to take significant control actions in order to maintain reliability e.g. purchase emergency energy.

of out-of-market control actions by the IMO has declined from 5 percent of all hours prior to implementation to 2 percent in the period from August 6 through October 31. Actions are now more transparent. We will continue to monitor the impact of this approach.

3.4 Spare Generation On-Line

The IMO-administered markets select and schedule just enough resources to meet energy and operating reserve demands. If there is any disturbance to the market or the system in real-time, the impact on the price and on the supplying resources can be dramatic. Market prices can fluctuate out of proportion to the size of the disturbance, and re-dispatch of resources on-line can cause large output swings, stressing these facilities.

In the 14 months prior to the introduction of the Spare Generation On-Line (SGOL) program, there were some situations where real-time disturbances occurred and there were additional resources available to the market, but these resources were not on-line and therefore not in a position to be dispatched with short notice.[38] Due to the physical nature of these facilities, if they are not already synchronized to the grid they are of little help when a disturbance occurs in real-time, since it takes from 2 to 16 hours for them to start and synchronize to the grid. There is no way of knowing with certainty why such facilities choose to be off-line but one can presume that they have calculated that starting up and synchronizing to the grid, at the prices they expect, will put them in a loss position that they are unwilling to accept. These types of facilities (typically fossil plants) incur significant start-up costs and speed-no-load costs to connect to the grid.

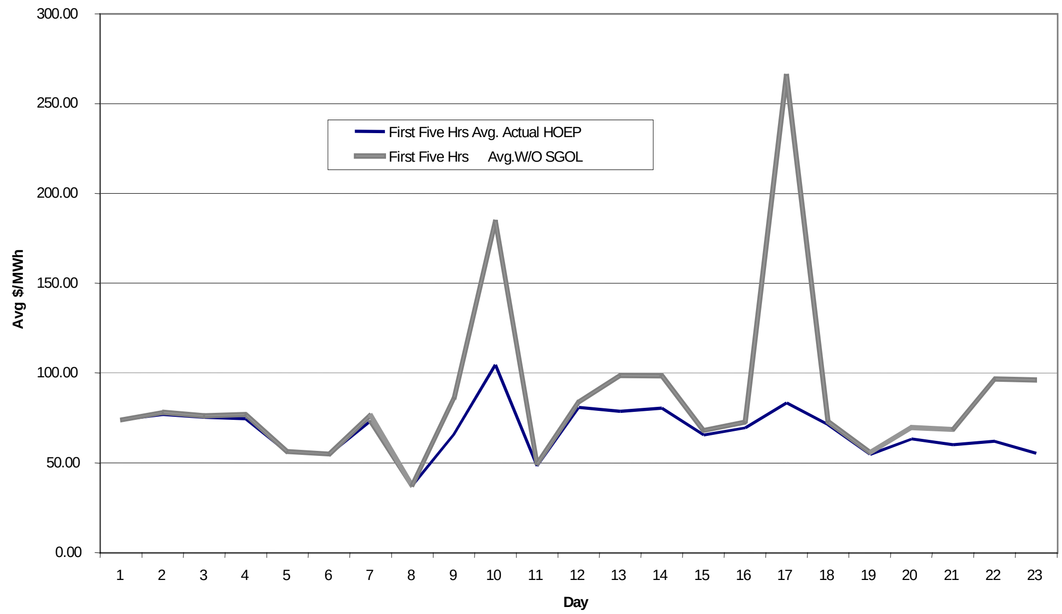
The SGOL program was launched by the IMO in August 2003 to provide incentives to large units that have significant timing issues and costs to commit (fossil-fired) to come on-line where the profit opportunity is marginal at best. The program guarantees the payment of start-up costs and minimum generation costs for a minimum 5-hour runtime. This is a voluntary program and if the generator believes that there is little possibility to profit from coming to market it may decide not to participate. The provision of SGOL uplift payments in the real-time market accelerates the introduction of a provision that would be implemented under the Day Ahead Market (DAM), which is now under consideration by the IMO.

Programs such as the SGOL exist in other markets. New York has a similar program, called the Bid Production Cost Guarantee (BCPG), which ensures that if a generator comes to market it can recover its costs either from profits from the market or through an uplift payment provided by the ISO. Having a similar guarantee of costs in Ontario will facilitate competition between Ontario and neighbouring resources, as both would have similar costs guaranteed by their native market. At the same time having spare generation on-line in Ontario is consistent with the reliability practice of neighbouring control area operators.

Since the program began on August 7, about 4,500 MW of generation have registered for SGOL. There were no SGOL scheduled start-ups in the month of August, but generators have begun to take advantage of the program since early September.

[38] See MSP report (October 7, 2002), Appendix 1, p. 109, which describes one such incident on June 11, 2002.

Figure 3-15: SGOL – Average Price Effect Difference over First 5 Hours
23 Days of Activity – September 11-November 3, 2003



Since implementation of the SGOL in the market there have been 23 days in which SGOL units have requested payment via the program. Using a market simulation tool created by the MAU, it is possible to examine the impact of the SGOL program on the HOEP, under that assumption that the SGOL units would not have been in the market had the SGOL not been available. The simulation shows that, on average, over the 23 days where the program paid out, the average HOEP was reduced by almost $19/MWh. This is illustrated in Figure 3-15 above. The program paid generators about $400,000 in SGOL payments over the same period.

4. *Greater Transparency of Generation and Outage Information*

In January 2003, the Market Surveillance Panel was requested by the IMO Board of Directors to submit comments regarding possible changes to the IMO Confidentiality Catalogue, permitting greater disclosure of generator specific information. The proposal for generator disclosure had been initiated by some market participants in response to concerns they had about the asymmetry of information in the Ontario marketplace that resulted from the dominant position of Ontario Power Generation. Based on a review of relevant background material, consultation with market participants and discussions with market monitoring personnel from other jurisdictions, we concluded that should the IMO Board choose to release such information, there were not likely to be any adverse implications for the operation of the market.[39]

On September 12, the IMO announced the publication of daily reports pertaining to the operation and maintenance of generating facilities. These reports include unit specific data on generator output and capability. Release of two of the daily reports, the Daily Generator Energy Output Report and the Daily Energy Capability Report began September 12 and publication of the Daily Generator Outages Report began on October 2. All daily reports are published every business day at 4:00 PM for the previous day's activities and remain available on the IMO website for one month. The Daily Generator Energy Output Report provides information on the net energy injected into the system by each generating facility with a maximum output capability of 20 MW or greater. The values posted are the product of operational metering, which is less accurate than revenue metering, but is available in a timelier manner. The Capability Report publishes each unit's capability, which is the measure of the maximum output of power that could be produced by that unit, and not necessarily what is actually being produced. Generators that are out of service will appear in this report as having zero capability in those respective hours.

The Panel undertook to monitor the operation of the market for any adverse effects that might appear as a result of the release of this information. To date, the information has not been in the market for very long but we see no appreciable impact of the publication of this data on the behaviour of market participants.

[39] Our Report may be found on the IMO website (www.theimo.com) under Market Integrity/Surveillance/Panel Reports/Other MSP Reports.

5. *Conclusions with Respect to Market Operation*

We believe that the actions that have been taken to date have, overall, improved the operation of the IMO-administered markets.

The urgent rule changes aimed at preventing gaming have protected market integrity and credibility.

The design changes introduced by the IMO, and described above, have addressed some of the serious concerns that we have previously identified in the market – particularly the divergence between the pre-dispatch and real-time prices and the resulting impairment of price as a signalling instrument to promote market efficiency. As we noted in Chapter 1, section 9, the disparity between the pre-dispatch and real-time prices have persisted over the first 18 months. The difference (both in absolute terms and in percentage terms) was less in the last four months of 2003 compared to the same months of 2002. These are the months through which the design changes were implemented. While it is difficult to discern how any one of the design changes may have affected the difference, we are encouraged by the most recent trend.

6. *Ongoing Initiatives*

Two initiatives that were initiated over the past 18 months, and are continuing, are the Market Evolution Program that is being pursued by the IMO, and the review of CMSC payments – and particularly constrained off payments – that the MSP initiated. These are briefly described below.

6.1 Market Evolution Program

As identified in our first two reports, there is a need for further evolution of the Ontario electricity markets. The IMO's Market Evolution Program (MEP), in consultation with stakeholders, initiates and analyzes changes to improve the operation of the Ontario electricity market design. The Program is driven by, among other things, the desire to encourage generation investment and to achieve resource adequacy. Current initiatives include:

- *Resource Adequacy*
  This addresses the need for additional capacity in the Province.
- *Day-Ahead Market, in addition to the real-time market*
  This would allow participants to transact quantities and make critical operating decisions in advance of real-time, thereby providing greater stability for the day at hand.
- *Wholesale/Retail Integration*
  This will address the issue of potential realignment of prudential support obligations faced by local distribution companies, review demand response products to be made available to retail customers and ensure wholesale and retail market entities keep pace with emerging technologies, such as retail-level metering and distributed generation.
- *Locational Marginal Pricing*
  Benefits include the management of congestion to ensure that the transmission system is utilized in most efficient manner; socialization of congestion costs are avoided and prices better reflect the cost of transmission from one location to the other.
- *Multi-interval Optimization*
  This will provide better optimization of bid and offer schedules over the day and hour to provide market participants with more certain and predictable dispatch and operating instructions.

Further information on the Market Evolution Program is available at http://www.theimo.com/imoweb/consult/marketDev.asp. Some of these initiatives are discussed further in Chapter 4.

6.2 MSP CMSC Review and Recommendations

As part of our ongoing analysis of the efficiency of the design and operation of the market, we undertook an examination of the role played by constrained off congestion management settlement credits (CMSC payments). In February 2003, we prepared a discussion paper on the issues and requested comments. Following public consultation and further review, we submitted our report to the IMO Board on July 3, with the intention of making practical and timely recommendations to both the IMO Board and other decision-makers.

The report recommendations dealt with:
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.

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

The Market Rule amendment process to give effect to the recommendations in the first two groups above is now in progress, with one element of the recommendations already having been implemented through an urgent rule change (see section 1.1 of Chapter 3). Two working groups have been established to take action with respect to the latter two recommendations. The IMO is leading the 25 Hz working group, while the OEB is taking the lead for the transmission planning discussions.

Our report concluded that efficiency considerations suggested strongly that all constrained off payments to generators and imports should be terminated. We did not recommend proceeding with this measure at this time, because we recognize that the market design viewed CMSC payments as transitional to a local marginal pricing regime and that consideration is now being given to such a regime. We did indicate in our report that, should local marginal pricing not go ahead or be substantially delayed beyond the end of 2004, then constrained off payments should be eliminated and other aspects of the CMSC framework reviewed. We have undertaken to monitor progress toward the introduction of local marginal pricing and will revisit the issue of CMSC payments towards the end of 2004, in light of conditions at that time.

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

1. *Introduction*

Over the past 18 months, we have reviewed and studied the operation of the IMO-administered markets. In our review, we have paid particular attention to identifying inappropriate participant conduct, or deficiencies or flaws in the rules and design or structure of the market that impede or are inconsistent with the efficient and fair operation of a competitive market.

Our mandate requires us, on an annual basis, to provide our "general assessment as to the state of competition within, and the efficiency of, the IMO-administered markets".[40] This chapter provides this assessment, organized according to three dimensions of efficiency: efficiency in consumption; efficiency in dispatch; and efficiency in investment. Within each section we describe the benchmark that we apply for measuring efficiency. We then discuss how the market has operated against this benchmark over the past 18 months - what has worked well and what has not worked so well. Finally, we provide suggestions to improve the market design and structure to achieve more effective competition.

We also, in section 5 of this chapter, provide comments on some of the implications of the August blackout that we feel are relevant to our mandate.

In our October 2002 report we commented at some length on effective competition and electricity markets.[41] Our conclusions at that time about the benefits of competition, and the special nature of electricity markets, continue to inform our assessment after 18 months of operation and are worth recalling. In brief:

[40] See 3.3.10 of the Market Rules.
[41] See our October 2002 report at pp. 3-11.

- Competitive markets make the best use of resources available. Supply is drawn from the most efficient source and output is allocated to the highest value use. Competitive markets also allow for an efficient distribution of risk. Risk is typically borne in competitive markets by shareholders who choose to bear it rather than by customers or taxpayers who typically bear the risk of government-owned monopolies.
- Perfect competition is an ideal construct. The practical question is whether competition is effective: that is, does it result in more efficient consumption, dispatch and investment decisions than government-owned monopolies with regulated prices.
- Markets do not function in a vacuum. All markets operate within a framework of laws, regulations and rules of general application, and some markets are also subject to specific laws and regulations where public policy deems it important to constrain behaviour to achieve certain objectives (health, safety, and environmental standards are examples).
- Electricity markets are relatively recent and are characterized everywhere by special rules and procedures that recognize the unique characteristics of electricity as a product and the overriding need to assure reliability.

After monitoring 18 months of operation, we continue to believe that competitive markets provide a superior solution to government-owned monopoly provision of electricity. The continuing challenge is to develop the rules and frameworks necessary to ensure that the markets evolve in a way that is seen by consumers as predictable and fair, while maximizing the efficiency gains to consumption, dispatch and investment so that reliability over time is ensured at the lowest real resource cost to the people of Ontario.

2. *Efficiency in Consumption*

Consumption decisions are efficient when the amount consumers are willing to pay for the last unit consumed in a given time period is equal to the incremental cost of producing it. This occurs where the market price of the product is equal to the incremental cost of producing it at any point in time. It is important to recognize that this concept applies at the margin. That is, it does not imply that all consumers need pay the spot market determined price at all times on all their electricity in order for efficiency in consumption to obtain. Indeed, efficient markets typically provide options for consumers to hedge risk through contracting or other means.

The original design of the Ontario market offered consumers the option of securing all their energy at spot market prices or entering into contracts with producers (for large loads) or retailers (for residential loads) at fixed prices. The Market Power Mitigation Agreement (MPMA) also provided for rebates to consumers in the event that the average spot market price exceeded $38.00 per MWh.

After seven months of market operation, marked by extraordinary weather conditions resulting in a period of high and volatile spot prices, the previous government introduced a retail price cap of 4.3 cents per KWh that ultimately covered the vast majority of consumers and about half of total consumption.[42] The introduction of this price cap, which was significantly below the incremental cost of producing electricity, removed any incentive that consumers subject to the cap had to conserve energy and clearly resulted in inefficient consumption decisions.[43] It also had the effect of eliminating retailers from the market place. It effectively replaced market driven hedging opportunities with a government provided hedge with Ontario taxpayers taking all the risk. The current government has introduced legislation to replace the price freeze with an interim, two-tier pricing regime, effective April 2004, to be followed by a new pricing framework to be established by the Ontario Energy Board (OEB). We comment further on this initiative below.

[42] The 4.3 cents/KWh was the regulated pre-market price. The actual average price over the period of operation of the market from May 2002 until the introduction of the cap was 5.15 cents/KWh. The increase in the commodity price of energy through this period did not reflect the total increase in electricity bills faced by consumers because of additional charges introduced at the time of market opening and because volumes of electricity used were substantially higher due to the extremely hot summer in 2002.

[43] The price freeze results in two forms of consumption inefficiency. In the short-term, most consumers have no incentive to shift their consumption to lower cost off-peak or shoulder periods. In the long-term, most consumers do not have the proper incentive to purchase electrical appliances that economize on the use of electricity or to invest in retrofitting in order to economize on the use of electricity.

Some large industrial and commercial customers do respond to price signals, and others could do so. There are currently five Ontario customers who have chosen to be dispatchable loads. These customers indicate their willingness to pay directly through bids in the market and are dispatched on or off every five minutes according to their bids. Large industrial loads are interval-metered and they are not covered by the price protection afforded to smaller customers under the price freeze. They therefore have an incentive to economize on their use of electricity during high price periods. Our March 2003 report noted evidence of price responsiveness among some of the largest industrial loads during the very high price periods of July and August 2002.[44] As we discussed in Chapter 3, the introduction of the Hour Ahead Dispatchable Load Program provides additional opportunity, and guarantees, for large industrial and commercial loads to respond to price signals.

We have repeatedly emphasized the need for electricity consumption decisions to be informed by generation costs. In this regard, we continue to be of the view that the best way to encourage large loads to respond to price signals is to improve the accuracy of the pre-dispatch price as a forecast of the real-time price. We are pleased that progress has been made on this front and we urge the IMO to continue to work in that direction.

Exports and imports are price responsive. Electricity is exported from Ontario when prices in other jurisdictions exceed those in Ontario and is imported when the reverse is true. These gains through trade economize on real resource costs in both Ontario and the markets with which it is linked, although the efficiency gains to consumption through trade may not be maximized due to limited intertie capacity and the operational need to select exports and imports an hour in advance of dispatch.

With regard to the new pricing regime that will replace the price freeze, the government has announced that, effective April 2004, the energy cost for the first 750 KWh of consumption will be capped at 4.7 cents, and the energy cost for any consumption in excess of that amount will be capped at 5.5 cents. This new regime is an interim regime,

[44] See March report, pp. 96-105.

pending the establishment of a regulatory framework to govern prices for low volume consumers by the OEB. The OEB is required to have such a framework in place by May 2005 at the latest.

We welcome the removal of the price freeze as a positive step in achieving greater efficiency in consumption. In the regulation to be issued by the government directing the OEB on the establishment of a price setting mechanism we believe it is important that the new pricing regime be consistent with three key objectives:

- 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.

In practical terms, if the pricing regime respects these objectives, the market may evolve in a way that sees the spot market become more of a balancing market, with the bulk of consumption being purchased in a Day Ahead Market or through contracts. Our hope is that the OEB price design will support, and not preclude, such evolutionary developments.

With regard to the third objective, we suggest two areas that the government should direct the OEB to consider. First, any pricing regime should recognize that the real resource costs of producing electricity vary through the day and should provide a pricing structure that recognizes this, in order to encourage efficient consumption. Second, in this context, it may well be desirable to consider whether there are rate recovery regimes for distributors or other market intermediaries that might assist them and their customers in introducing interval meters where appropriate to do so.[45]

[45] This is a recommendation that we made earlier, in our October 2002 report (See pp. 139-140)

3. *Efficiency in Dispatch*

Efficient dispatch requires that the market price be equal to the incremental cost of the marginal supplier and that all suppliers with an incremental cost less than this be selected for dispatch.

Efficient dispatch involves both domestic generation and imports. The two must be examined separately because imports are fixed an hour ahead of the real-time dispatch while domestic generation can change in real-time. Efficient dispatch of domestic generation requires that available generating units be dispatched in order of their incremental cost (merit order). If this occurs, it implies that there has been no withholding of inframarginal capacity by generators. The efficiency of the decision to import requires that domestic generating units and imports be accepted in pre-dispatch in order of their respective incremental costs.

Insofar as dispatch is concerned, we are satisfied that domestic dispatch has been efficient. That is, having regard for transmission and other constraints, Ontario's available generating capacity is being dispatched in merit order. This implies that there has been no physical or economic withholding of capacity by Ontario generators.

We are also satisfied that, to the extent that it can be determined, the imports selected in pre-dispatch have been the lowest cost imports available and that the choice between imports and domestic generation has been efficient in pre-dispatch. Because circumstances turn out to be different in real-time, however, there are numerous instances in which the quantity of imports scheduled differs from what turns out to be efficient in real-time.

The achievement of efficient dispatch may have been a result in part of administrative intervention. The key policy question is whether this intervention is conducive to the development of a truly competitive market in the longer-run.

As the Panel has emphasized in previous reports, the current structure of the market is not consistent with effective competition. One reason for this is that generation remains concentrated, with Ontario Power Generation (OPG) being the major electricity provider in the province. OPG's share of the provincial electricity market is roughly between 70 and 75 percent. While OPG has the ability to exercise market power and this would have resulted in inefficient dispatch, this has not been an issue during the past 18 months.

Efficient dispatch may also be a consequence, in part, of IMO control room intervention for reliability. The control room may constrain on slow ramping generating units well in advance of anticipated periods of rapid increases in demand so as to ensure that load and reserve requirements can be met during high ramp periods and later in the day. Similarly, the control room may begin to constrain off slow ramping units in advance of anticipated decreases in demand. By anticipating the future demand for slow ramping generating units, this procedure can minimize the cost of generation over time although this is not the motivation for this procedure. It is important to understand, however, that it involves a trade-off between running slow ramping units when they are not needed and relying on fast ramping, energy-limited generating units during periods of rapidly increasing demand. For this reason, the IMO is developing a "multi-interval optimization algorithm" which will make this trade-off calculation automatically, obviating the need for control room intervention.

This begs the question of why control room intervention has been needed in the first place. There is no conceptual reason why the system operator must perform this intertemporal optimization function. The prospect of higher prices during high demand periods should be a profit opportunity for generators. In a competitive market, a price-taking generator should have an incentive to respond to anticipated higher prices in the periods of increasing demand by making sure that it offers at prices that ensure that it will be ramped up in time to take full advantage of peak period prices. Similarly, in periods when demand is expected to decline, a price-taking generator should be offering at prices that ensure that it will be ramped down so that it is not producing at low, off-peak prices.

The outcome of a competitive market would be that both the fast-start, quick ramping units and slow-start, slower ramping units would respond to these profit incentives and allocate themselves via their offers to achieve the most efficient, intertemporal dispatch.

The embodiment of the 12-times ramp rate assumption in the determination of the MCP has muted if not eliminated the price signals needed to induce the types of competitive responses outlined above. The 12-times ramp rate assumption essentially pretends that capacity can enter or leave the market faster than it can. This prevents spikes in the MCP. But it has also reduced the incentive for the type of market responses that could also have prevented spikes in the MCP. In our opinion, it is at least arguable that removing the 12-times ramp rate assumption would induce market participants themselves to respond to anticipated changes in demand and reduce the need for IMO intervention, automated or otherwise.

Our assessment is that the major reason for introducing the 12-times ramp rate assumption was to mitigate the very large swings in the spot market price that were observed in the testing period prior to market opening. In a market environment where all consumers, or at least all smaller consumers, were buying all their energy at spot market prices and where the MPMA rebate was paid annually and not able to compensate cash outlays in a timely manner, it is understandable why actions to smooth such volatility may have been desirable, even though they may have caused interventions to ensure reliability.

Our earlier comments on efficiency in consumption, and pricing frameworks that might promote this, stressed the adherence to three key objectives with the possible consequence of the spot market becoming more of a balancing market. As well, the MPMA is now being delivered quarterly rather than annually. Both of these developments would result in spot market volatility becoming a less serious financial issue for individual consumers and, in this environment, we believe it would be appropriate to ease or eliminate the 12-times ramp rate assumption to assess the extent to which the market reaction will contribute to greater efficiency in dispatch.

Regulatory intervention in the form of the Intertie Offer Guarantee (IOG) may also have had an impact on the efficiency of import dispatch. The intent of the IOG is to increase reliability by providing importers with a price guarantee so that they are assured the higher of the real-time MCP or their offer price. This guarantee is likely at times to influence the amount of imports selected for dispatch. In effect, the IOG shifts the risk that the real-time price will be lower than the pre-dispatch price from importers to Ontario load. Although Ontario load benefits from this in the form of lower prices, this allocation of the burden of risk bearing may not be efficient and the likely result is an over-reliance on imports both in the short-run and in the long-run. As the IMO continues to pursue measures that bring pre-dispatch and real-time prices into closer convergence, the IOG will continue to diminish in importance and the perceived need for price guarantees for imports may be reduced.

It is our preference that dispatch efficiency be the result of the operation of the market itself rather administrative intervention. Competitive market outcomes are best achieved by competition. As the market continues to develop, opportunities may arise to revisit and to remove some of the administrative arrangements that have been introduced to mitigate volatility and to compensate for persistent divergences between pre-dispatch and real-time prices. We believe that such opportunities should be acted upon as they arise.

4. *Efficiency in Investment*

Efficiency in investment has three aspects: efficient technology choice; timeliness; and capacity sufficiency. In competitive markets, current and expected future prices guide the investment decisions of existing and potential suppliers as well as the consumption decisions of customers. Markets work best when price signals are accurate and when both suppliers and users can see them and are able to respond to them. While important, price is not the only signal of importance to potential investors. Investors must also have confidence that they can reasonably predict future regulatory and public policy.

We have stated in previous reports that there is a shortage of generating capacity in Ontario and that new investment is required. There has, however, been an apparent lack of willingness to invest in new generation capacity in the province. In our view, the most serious impediments to new investment are, first, the uncertainty in the regulatory and public policy environment and second, a market price that does not accurately reflect the shortage of supply in Ontario.

i. Uncertain regulatory and public policy environment

There are several questions, which a potential investor in generation or transmission in Ontario might reasonably ask. These include:

- Will there be further government-backed investment in nuclear generation?
- Will the province's coal-fired generation facilities actually be shut down by 2007 as has been announced and if so, how will the shutdowns be timed?
- Will OPG divest facilities as initially announced or will it continue to control a large share of the province's generation assets and if so, what will its operational mandate be?
- What will the new pricing regime to be developed by the OEB look like?
- Will conservation measures be imposed and, if so, in what form?
- How will the current market design evolve? Will it involve locational marginal pricing or will the uniform pricing regime continue for the foreseeable future?
- What is the overall commitment of the government to a market approach to production and sale of electricity at the wholesale level? Will there be even a semblance of a market at the retail level?

Potential investors need to be clear about the rules so that they can adequately assess the risks and returns they face. The new government is taking welcome steps to clarify these uncertainties. As policy continues to evolve, it will be important for the government to be clear about the operational implications of its policy decisions. For example, the government has indicated its intent to not proceed with the divestiture of OPG's generating assets. So long as OPG remains a dominant supplier in the market its ability to influence price will be a source of uncertainty to potential competitors. In such an environment it may be helpful for the government, as shareholder, to be more transparent to the market about when and how OPG's output will be offered. Such a measure could assist in increasing the efficiency of investment.

Similarly, the government has reaffirmed its commitment to phase out coal-fired generation in Ontario. The sooner it can indicate how and when it will act on this commitment, the greater will be the policy certainty needed to encourage enhanced efficiency of investment.

ii. The MCP does not reflect the shortage of supply in Ontario

The MCP does not provide an accurate signal to potential investors in electricity generation in Ontario for the reason that it understates the scarcity of supply in the province. This is primarily a consequence of the regime of uniform pricing which includes as supply all generation available anywhere in the province even though it may be unavailable due to transmission transfer limitations.

The MCP is a province-wide price that equates aggregate supply and demand in the province. Due to transmission limitations, however, some of this supply cannot be delivered and the price that would balance actually deliverable supply with demand is often considerably higher. Put another way, the price that would clear the market in some parts of the province would be much higher than the present MCP and would be lower than the present MCP in other parts of the province. If generators were paid these prices, there would be an incentive to invest in generation in the under-served areas of the province or transmission to relieve congestion.

However, as it now stands the MCP, by itself, has been too low over much of the last 18 months to provide an adequate return to attract new generation investment in the province. The MAU has conducted a preliminary analysis of revenue opportunities for new gas-fired generators. This analysis suggests that the current Ontario uniform price would not provide these generators with sufficient revenue to cover both their variable operating costs and fixed operating costs.

It could be argued that the MCP plus congestion management payments (CMSC) would support new investment, but CMSC payments are not transparent to the market and as a consequence the Ontario market lacks a clear signal of revenue opportunities for prospective investors.

We believe that the most effective way to attract efficient investment in generation and transmission is to eliminate sources of distortion in the market price and eliminate the present approach to congestion management. In this regard, we continue to favour the introduction of locational marginal pricing as was contemplated in the original market design.

If the 12-times ramp rate assumption was removed and locational marginal pricing introduced we would be much more confident in achieving efficient investment in the province.

It is important again to stress that efficiency in investment, as in consumption and dispatch, is achieved by appropriate price signals at the margin. It need not preclude a regime under which the average price paid by consumers is less than the higher marginal price that we believe is required to attract new investment. Effective markets will develop mechanisms for producers and consumers to contract with one another at mutually agreeable prices that do not attenuate the efficiency benefits that come from market prices that reflect scarcity more accurately. It is critically important that this be recognized and that the market design move forward in a way that facilitates and supports the development of such contracting arrangements.

5. *August 14, 2003 Blackout*

The causes of the August 14 blackout have been well documented in the Interim Report of the Canada-US Power System Outage Task Force.[46] The Interim Report made it very clear that the cause of the blackout was not due to any action or lack of action in the Ontario electricity markets, and that the response of Ontario market participants, including the IMO and Ontario nuclear power operators, was appropriate. The Final Report of the Task Force, expected in January, will contain policy recommendations directed at minimizing the risk that such blackouts will occur.

There are two aspects of the reaction to the blackout itself that we feel merit comment in light of our mandate to report on how well the IMO-administered markets are working. The first of these is the view that has been expressed by some that the opening of electricity markets to competition in many jurisdictions has, itself, increased the likelihood (and some would say inevitability) of major supply interruptions. The second view is that Ontario would be better served if it were not linked to, and thereby exposed to, other markets. In our view neither of these perceptions is factually correct or appropriate.

With regard to the first perception, the Interim Report found no correlation between the blackout and the restructuring of the electric utility industry. The primary causes of the blackout were clearly identified as factors related to the operation and maintenance in a utility in Ohio – "deficiencies in specific practices, equipment failures and human decisions that coincided that afternoon".[47]

Chapter 6 of the Interim Report discusses some of the factors that may contribute to reducing reliability in the future unless effective countermeasures are taken. Primary among these is the absence of major transmission projects undertaken in North America over the last ten or fifteen years in the face of increasing demand for electricity (load

[46] The full text of the report may be viewed at the Natural Resources Canada or the US Department of Energy websites - www.NRCan.gc.ca or www.DOE.gov.
[47] Interim Report of the Canada–U.S. Power System Outage Task Force, p. 23.

growth). As well, demands on transmission systems have increased to accommodate commercial transactions among more distant parties than typically took place prior to restructuring. It is this last factor that has given rise to the notion that electricity market restructuring has caused a decline in reliability.

The Interim Report itself makes clear that this is not a major factor, when it affirms that "It is a basic principle of reliability management that 'operators must operate the system they have in front of them' – unconditionally".[48] That is operators must operate the system in their control area within its design limits and to respect well known rules for maintaining reliability. The most important of these responsibilities are included in Chapter 2 of the Interim Report and are paraphrased as follows. Operators shall operate their system so that instability, uncontrolled separation or cascading outages will not occur as a result of the most severe single contingency and shall have plans in place to restore their system to a safe mode within 30 minutes. Each system and control area shall have emergency plans and responses in place to relieve any abnormal conditions that jeopardize reliability. They shall coordinate their response to emergencies with neighbouring control areas or systems including actions to relieve transmission line overloading in order to be prepared for the next most severe contingency.

Therefore, regardless of the demands placed on transmission systems by commercial interests (contingencies, traders, marketers etc.), the operators are required to forecast (longer term seasonally and shorter term down to day-ahead and day-at-hand) and to continuously monitor conditions on their transmission systems. These activities are intended to alert the operator that power flows may exceed design limits and that they must take action to prevent them. These preventive actions include rescheduling generation, restricting imports or exports and in extremes, even shedding native loads in order to prevent the loss of electricity to larger populations or widespread cascading blackouts such as occurred on August 14. A number of these requirements were violated in Ohio on August 14.

[48] Interim Report, p. 15.

Detailed modelling studies by the Task Force's investigators found that up to approximately one hour before the blackout began, "the system was being operated near (but still within) prescribed limits and in compliance with NERC's operating policies".[49] This is extremely significant because it means that none of the electrical conditions on the system before 3:05 pm EDT on August 14 were a direct cause of the blackout either individually or collectively. These include high power flows to Canada, a condition sometimes attributed to industry restructuring. The level of imports into Ontario from the U.S. was high (1,443 MW) on August 14, but not unusual and well within Ontario's interconnection capability.

The second perception that has arisen as a result of the blackout is that it may make sense for Ontario to isolate itself from neighbouring jurisdictions and rely on a policy of self-supply to isolate itself from the risk of supply interruption through events it cannot control. In our view this would be exactly the wrong way to go. As we reported in our October 2002 report, without the ability to rely on imports we would not have been successful in keeping the lights on in Ontario in the summer of 2002. And as we stressed at that time, this has nothing to do with the operation of the market and everything to do with the shortage of capacity in the province. Similarly, assessments of the California electricity crisis of 2000 make clear that the situation in that state was exacerbated by the lack of interconnections with neighbouring jurisdictions.

We are fortunate to be part of a strong regional trading network and we benefit from the ability to trade with our partners. The people of Ontario will be best served by continuing efforts to make such trading arrangements more seamless and more secure. This will require the IMO, the OEB and the government to work diligently with regulators in the United States and Canada, in response to the recommendations that will be made in the Final Report of the Task Force, so that we can enhance and enforce the reliability standards that are essential to allow us to secure the benefits of trade without exposing ourselves, and our partners, to undue reliability risks.

[49] See Interim Report of the Canada–U.S. Power System Outage Task Force at p. 15.