Market Surveillance Panel

Monitoring Report on the IMO-Administered Electricity Markets

for the period from
May 2004 to October 2004

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Preface

This is the 5th semi-annual monitoring report of the Market Surveillance Panel since the IMO-administered markets opened. It provides highlights of market outcomes over the period May 1 to October 31, 2004.

As in past reports we have examined in detail the functioning of the market from the perspective of efficiency and competitiveness. We have tried to do so in a way that is accessible to those interested in a deeper understanding of the market and ways that it can continue to improve. Chapter 1 and the Statistical Appendix provide the basic data on market outcomes over the period. This time we found it useful to compare the similar period in 2003 in order to shed light on explanations for 2004 price increases.

Chapters 2 and 3 highlight market results we believe noteworthy, including the status of some changes introduced into the market since our last report. The final chapter has a broader policy orientation and offers our perspective on some future directions.

This will be our last report as a Panel of the Independent Electricity Market Operator; Bill 100, the *Electricity Restructuring Act, 2004* transfers the Panel to the Ontario Energy Board with the same mandate. We would like to express our appreciation to all levels of the IMO from the Board of Directors, through Dave Goulding, its President and CEO, to the many talented staff who have assisted us in establishing the surveillance function and provided concrete help that improved our understanding of the issues. We look forward to continuing our work under the auspices of the OEB.

Fred Gorbet (Chair), Don McFetridge, Tom Rusnov

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Chapter 1: Market Outcomes May 2004 to October 2004

1. *Introduction*

This chapter presents data and summary statistics on the IMO-administered markets for the period May 2004 to October 2004. The Statistical Appendix provides more detailed data covering the period May 2003 to October 2004. The focus of this chapter is a comparative assessment of May 2003-October 2003 and May 2004-October 2004.

In general, the supply-demand balance improved in 2004 relative to 2003. The return of three nuclear generators from a seven-year extended outage, the increased availability of hydroelectric supply due to an abundant spring freshet and the entry of two gas-fired generation units exceeded the year-to-year increase in demand. Despite the improved supply-demand balance, average monthly prices (HOEP) were frequently higher in 2004 than they were during the same period in 2003.

An analysis of the factors that could have led to higher prices is presented in sections 5 and 6 of this chapter. This analysis suggests that the higher prices observed in 2004 were largely attributable to the increase in coal prices that occurred between 2003 and 2004.

2. *Ontario Energy Price*

As Table 1-1 indicates, the average monthly HOEP was higher in 2004 than in 2003 for the months of May, June, July and September. This increase was more pronounced for off-peak prices than it was for on-peak prices. For example, the average monthly off-peak HOEP for July increased by 31.8% between 2003 and 2004, while the average monthly on-peak HOEP for July increased by only 4.5%. Similarly, while the average monthly HOEP was lower in 2004 than in 2003 for the months of August and October, the percentage decline was larger on-peak than off-peak. Taking the May to October period as a whole, the average HOEP was $0.87 higher in 2004 than in 2003, on-peak prices were $1.14 lower in 2004, and off-peak prices were $2.71 higher in 2004.

Table 1-1: Average HOEP, On and Off-Peak, May-October 2003 & 2004

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2003	2004	2003	2004	2003	2004
May	43.17	48.06	56.53	61.93	32.16	37.60
Jun	41.64	46.69	55.54	60.15	29.47	33.81
Jul	40.08	45.58	53.14	55.55	28.35	37.38
Aug	46.85	43.51	62.99	52.81	36.37	35.84
Sep	48.56	49.57	58.63	59.17	39.74	41.16
Oct	57.09	49.11	68.42	57.48	46.92	42.80
Avg.*	**46.21**	**47.08**	**58.98**	**57.84**	**35.46**	**38.17**

*These averages are calculated as the average of all hourly HOEP during the period May 2003 to October 2003 and are not the average of the six monthly averages.

3. *Demand*

Table 1-2: Monthly Energy Demand (TWh), May-October, 2003 & 2004

	Ontario Demand			Exports			Total Market Demand		
	2003	2004	% Difference	2003	2004	% Difference	2003	2004	% Difference
May	11.63	11.84	1.81	0.72	1.11	54.17	12.35	12.95	4.86
Jun	11.89	12.05	1.35	0.66	1.04	57.58	12.54	13.09	4.39
Jul	12.90	12.77	(1.01)	0.99	1.05	6.06	13.89	13.82	(0.50)
Aug	12.51*	12.75	1.92	0.56	1.21	116.07	13.07	13.96	6.81
Sep	11.79	12.37	4.92	0.40	0.44	10.00	12.19	12.81	5.09
Oct	12.16	12.22	0.49	0.15	0.50	233.33	12.31	12.72	3.33

*Data for August 2003 includes the reduced demand during the blackout period (August 14-August 22, 2003).

As Table 1-2 indicates, both total market demand and Ontario demand increased from 2003 to 2004 in all months except July.[1] Ontario demand was up by roughly 1.5% (May to October) in 2004 when compared to 2003. This increase in Ontario demand occurred despite lower overall temperatures and fewer extreme degree-days as is illustrated in Tables 1-3 and 1-4.

As Table 1-5 indicates, the increase in Ontario demand was largely attributable to increased consumption by wholesale loads. Wholesale energy consumption increased by 5.0% (May to October inclusive) from 2003 to 2004 while consumption by residential and small commercial customers (supplied by LDC's) increased by only 0.3 % from 2003 to 2004. During the May to August period, residential and commercial energy consumption was actually lower in 2004 than in 2003. This is a consequence, in part, of the lower average temperature prevailing in 2004.

Both exports and total market demand also increased between 2003 and 2004. As is shown in Table 1-2, exports increased from 2003 to 2004 in all months during the May to August period, increasing by as much as 233% in October. The factors affecting export demand are discussed in section 8 below.

Table 1-3: Average Monthly Temperature (°Celsius)

	2003	2004
May	12.3	13.4
Jun	18.6	17.8
Jul	21.4	20.7
Aug	21.9	19.6
Sep	17.2	19.8
Oct	9.1	10.9

[1] Ontario demand excludes export consumption. Total market demand includes consumption from all Ontario consumers, including dispatchable generators and exports.

Table 1-4: Number of Days Temperature Exceeded 30°C

	2003	2004
May	0	0
Jun	4	3
Jul	1	0
Aug	3	0
Sep	0	0
Oct	0	0

Table 1-5: Ontario Demand (GWh) by Market Segmentation, May-October, 2003 & 2004

	LDC's		Wholesale Loads		Generation		Metered Energy Consumption		Transmission Losses*		Total Energy Consumption	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	9,166	9,334	2,081	2,011	144	155	11,390	11,501	238	334	11,627	11,835
Jun	9,583	9,538	1,889	2,024	168	164	11,639	11,727	246	319	11,885	12,046
Jul	10,665	10,299	1,801	1,935	158	177	12,624	12,411	274	359	12,898	12,770
Aug	10,341	10,233	1,752	2,016	170	178	12,263	12,427	251	319	12,514	12,746
Sep	9,431	9,960	1,944	1,988	168	157	11,543	12,104	251	266	11,794	12,370
Oct	9,686	9,692	2,034	2,102	198	167	11,918	11,961	241	254	12,160	12,215

* This is commented on further in section 12.

4. *Supply*

The amount of generating capacity available in Ontario during the May to October period was greater in 2004 than it was during the same period in 2003. Four factors contributed to this increase:

- First, there were fewer outages at nuclear generation facilities during 2004 compared to 2003 for the months May, June and October. As a result, more capacity was available from nuclear generation in these months. The opposite was true of the months of July and September.

- Second, three nuclear generation units returned to service after roughly seven years of refurbishment: the Bruce G3 unit (750 MW) on March 29, 2004, Bruce G4 (750 MW) on November 19, 2003, and Pickering G4 (500 MW) on August 23, 2003. The return of these facilities accounted for an increase of roughly 2,000 MW in base-load nuclear capacity as compared with the May-October, 2003 period.
- Third, the Brighton Beach facilities began production in July 2004, with two gas-fired units totalling 560 MW of capacity.
- Fourth, due to the higher levels of rainfall during the freshet period and early summer, there was an increase in the amount of energy capacity available from hydroelectric generation stations in all months in the period May-October 2004 compared to 2003, with October being the only exception.

Table 1-6 provides a monthly summary of the year-to-year changes in available capacity.

Table 1-6: Available Amounts of Supply (Average MWh), May-October, 2003 & 2004*

	Nuclear Supply		New Nuclear Supply		New Entry (Non Nuclear)		Hydroelectric Supply	
	2003	2004	2003	2004	2003	2004	2003	2004
May	6,442	7,454	0	1,317	0	2	4,150	4,954
Jun	6,928	8,261	0	1,212	0	5	3,838	4,319
Jul	8,022	7,898	0	1,657	0	137	3,634	4,436
Sep	7,924	6,169	94	1,927	0	106	3,572	3,953
Oct	4,446	5,051	454	1,980	0	76	4,177	3,794
Period Average	6,744	6,963	110	1,619	0	65	3,876	4,293

*August data is not included due to blackout in August 2003.

5. *Reasons for the Increase in the HOEP: Shift Share Analysis*

One way of isolating the respective impacts of changes in various possible causal (exogenous) factors on year-to-year differences in the monthly average HOEP is to employ shift share analysis. This technique is explained in the Panel's December 2003 report.[2] The measurable exogenous factors that could explain changes in the HOEP include shifts in Ontario demand, changes in the available capacity of base-load nuclear generation, changes in supply due to generator entry and exit, changes in supply from self-scheduling generators and changes in supply of water available to hydroelectric generating facilities. These factors can change the HOEP but are largely insensitive to it. That is why they are called exogenous factors. The remaining explanatory 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.

Shift share analysis isolates the effect of the change in Ontario load on the HOEP by asking what the 2003 monthly average HOEP would have been if demand were the same in 2003 as it was in the same month in 2004. 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 2003 monthly average HOEP can be calculated on the assumption that the 2004 distribution of load across load classes prevailed in 2003. The difference between this and the actual monthly HOEP in 2003 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. Data on the changes in hourly average values for each of the exogenous demand and supply factors identified above are provided in Tables 1-7 and 1-8.

The shift share analysis in this report differs from the analysis in the Panel's December 2003 report in that it divides the monthly data into off-peak and on-peak hours and conducts the shift share analyses separately for the two periods. The peak period is defined as the hours from delivery hour 8 through 21 inclusive and off-peak as the hours from delivery hour 22 through 7 inclusive. The on-peak and off-peak distinction is applied to all the days in a month including weekends and holidays. As a result, the price differences in this section may differ from those reported in section 2 above.

Table 1-7: Exogenous Factors (Average Hourly MW), Off-Peak May to October, 2003 & 2004*

	Nuclear Supply		New Nuclear Supply		Self-Scheduling Supply		New Entry (Non Nuclear)		Hydroelectric Supply		Ontario Demand	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	6,445	7,446	0	1,326	805	804	0	0	3,570	4,289	13,702	13,735
Jun	6,919	8,260	0	1,213	787	882	0	2	3,111	3,425	14,184	14,335
Jul	8,014	7,910	0	1,659	766	872	0	81	2,767	3,517	14,758	14,599
Sep	7,917	6,195	99	1,931	745	809	0	13	2,840	3,248	14,074	14,414
Oct	4,454	5,040	452	1,981	928	884	0	7	3,354	3,225	14,178	14,041
Period Average	**6,741**	**6,967**	**111**	**1,623**	**807**	**850**	**0**	**21**	**3,130**	**3,543**	**14,180**	**14,223**

*August data is not included due to blackout in August 2003.

Table 1-8: Exogenous Factors (Average Hourly MW), On-Peak May to October, 2003& 2004*

	Nuclear Supply		New Nuclear Supply		Self-Scheduling Supply		New Entry (Non Nuclear)		Hydroelectric Supply		Ontario Demand	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	6,439	7,459	0	1,311	954	933	0	3	4,565	5,430	16,702	16,884
Jun	6,935	8,261	0	1,212	939	1,015	0	7	4,358	4,957	17,842	17,949
Jul	8,027	7,890	0	1,655	915	1,026	0	177	4,253	5,092	18,929	18,556
Sep	7,929	6,150	91	1,924	888	942	0	172	4,096	4,456	17,669	18,355
Oct	4,439	5,059	456	1,979	1,059	1,006	0	124	4,764	4,201	17,382	17,261
Period Average	**6,745**	**6,961**	**110**	**1,617**	**951**	**984**	**0**	**97**	**4,410**	**4,829**	**17,704**	**17,796**

*August data is not included due to blackout in August 2003.

[2] Market Surveillance Panel Monitoring Report on The IMO-Administered Electricity Markets, The First Eighteen Months, May 2002 - October 2003, pp. 68-74.

Tables 1-9 and 1-10 present the monthly results of the shift share analysis for off-peak and on-peak periods.

Table 1-9: Estimated Impacts on 2003 Average Monthly Off-Peak HOEP with Factors at 2004 Levels, ($/MWh)

Factor	Month				
	May	Jun	Jul	Sep	Oct
Ontario Demand	0.22	0.45	(0.52)	1.52	(0.23)
Nuclear Supply	(2.28)	(3.75)	0.75	7.77	(3.57)
New Nuclear Supply	(1.70)	(1.87)	(3.17)	(7.42)	(9.64)
Self-Scheduling Supply	(0.35)	(0.04)	(0.27)	0.51	0.52
New Entry (Non Nuclear)	(0.01)	0.00	(0.07)	(0.16)	(0.04)
Hydroelectric Supply	(5.96)	(1.40)	(2.00)	(1.29)	(0.05)
Predicted Effect of Changes in Exogenous Factors	(10.08)	(6.61)	(5.28)	0.93	(13.01)
Observed Difference in HOEP	2.13	5.90	8.20	2.97	(1.88)
Residual Effect	12.20	12.50	13.47	2.05	11.12

Table 1-10: Estimated Impacts on 2003 Average Monthly On-Peak HOEP with Factors at 2004 Levels, ($/MWh)

Factor	Month				
	May	Jun	Jul	Sep	Oct
Ontario Demand	6.01	(2.98)	(4.02)	6.59	(0.31)
Nuclear Supply	(9.28)	(8.83)	0.83	15.29	(4.94)
New Nuclear Supply	(8.71)	(5.56)	(11.94)	(13.98)	(17.63)
Self-Scheduling Supply	(7.11)	(3.33)	(1.11)	(0.74)	(0.57)
New Entry (Non Nuclear)	(0.06)	(0.04)	(1.00)	(1.36)	(2.05)
Hydroelectric Supply	(7.20)	(2.39)	(5.40)	(4.11)	(1.42)
Predicted Effect of Changes in Exogenous Factors on the HOEP	(26.35)	(23.13)	(22.64)	(1.69)	(26.92)
Observed Difference in HOEP	6.87	4.45	3.58	(0.39)	(12.34)
Residual Effect	33.22	27.58	26.22	(2.08)	14.60

The shift share analysis imparts the following insights:

- The average hourly Ontario demand was marginally higher in 2004 compared to 2003 in the months of May, June and September and lower in July and October. The shift share analysis indicates that if Ontario demand in 2003 had been at 2004 levels, the higher levels of demand in May, June and September would have contributed to higher off-peak prices (an increase above the monthly average of $0.22 in May, $0.45 in June and $1.52 in September) and higher on-peak prices in May ($6.01) and September ($6.59). The lower demand levels in July and October would have contributed to a decrease in the average monthly off-peak price of $0.52 and $0.23 respectively and in the average monthly on-peak price of $4.02 and $0.31 respectively.

- While average demand was higher in on-peak periods during June 2004 than in June 2003, the shift share analysis indicates that 2003 on-peak prices would have been $2.98 lower in June 2003 had Ontario demand been distributed as it was in June of 2004. A closer inspection of the Ontario demand data indicates that the hourly Ontario demand levels were more widely distributed in June 2003 compared to June 2004. Average demand was higher in June 2004, but most hourly demand levels were fairly tightly distributed around the mean value. In June 2003, the distribution of hourly Ontario demand was skewed, with several extreme demand days. The shift share analysis suggests that the extreme demand days in June 2003 contributed to several hours of more extreme prices and that had demand been more evenly distributed in 2003 as it was in 2004, the average on-peak prices would have been $2.98 lower.

- The increase in available supply from the return of the nuclear generation facilities at Pickering and Bruce in 2004 would have resulted in a significant reduction in average monthly prices in 2003 had these facilities been available that year. Of all the exogenous factors considered in the shift share analysis, the increased supply from the return to operation of the nuclear generation facilities had the largest impact on overall price levels. Note, however, that the nuclear outage levels in September more than offset the price-reducing effects of the increased capacity, both off-peak and on-peak.

- The relatively more abundant supply of water in 2004 reduced the average HOEP (in both on-peak and off-peak periods) in all months in 2004 compared to 2003. The largest impact was in the month of May where the average monthly HOEP in 2003 would have been $5.96 lower in off-peak hours and $7.20 lower in on-peak hours, had the 2004 supply of water been available in 2003. The impact of new entry by non-nuclear generating facilities was small in all off-peak hours, when the running cost of these facilities is such that it is not typically economic to have them operating. The impact of this new entry in on-peak hours in the months of September and October was more significant. The available supply from this new entry would appear to have offset some of the higher levels of demand in 2004 and the higher levels of nuclear outages in September.

Overall, the impacts of the exogenous supply factors outweighed the impacts of higher Ontario demand implying that the average HOEP in both on-peak and off-peak periods should be lower during the period May-October, 2004 than during the same period in 2003. This was, in fact, the case in the on-peak hours during the month of September and in both the on-peak and off-peak hours in the month of October (see the bracketed values in the "Observed Differences in HOEP" row of Tables 1-9 and 1-10). In all the other months, however, the average HOEP was higher in 2004 than in 2003.

The substantial residual effects implied by the shift share analysis for the months of May through July and October mean that in these months factors not included in the shift share analysis were largely responsible for the increase in the average monthly HOEP between 2003 and 2004. These factors could include increases in fuel prices, changes in the offer strategies of Ontario generators and changes in export and import activity in response to price changes in surrounding markets. The role of fuel (particularly coal) price changes is examined in section 6. The impacts of changes in imports and exports are examined in section 8.

6. *Changes in Fuel Prices*

As Table 1-11 indicates, coal prices and natural gas prices increased from 2003 to 2004 in all months, May to October. Table 1-11 lists average monthly coal prices (NYMEX Over-the-Counter Price for the Central Appalachian Region) and average monthly natural gas prices (Henry Hub Spot Price). These fuel prices are spot prices and do not include fuel delivery charges. The average monthly coal price increases from 2003 to 2004 ranged between 61.9% to 79.3%, depending on the month. Natural gas price increases ranged from 2.3% to 28.8%.

Table 1-11: Average Monthly Fuel Prices, May to October, 2003 & 2004

	Coal Price (NYMEX ($CDN/MMBtu))			Natural Gas Price (Henry-Hub Spot Price ($CDN/MMBtu))		
	2003	**2004**	**% Change**	**2003**	**2004**	**% Change**
May	1.78	3.01	69.1	8.03	8.74	8.8
Jun	1.79	2.97	66.0	7.86	8.51	8.3
Jul	1.84	3.30	79.3	6.94	7.84	13.0
Aug	1.93	3.34	72.8	6.94	7.1	2.3
Sep	2.06	3.35	62.4	6.32	6.55	3.6
Oct	1.98	3.20	61.9	6.14	7.91	28.8

Coal and natural gas are the fuel sources for Ontario's largest fossil generation facilities. These facilities are a key component in the Ontario supply mix. While much of the electricity used by Ontario consumers is nuclear and hydroelectric, coal-fired generation and natural gas-fired generation are important because these facilities set the market-clearing price in most hours. Coal-fired generation facilities were particularly important in this regard during 2003 and 2004; a coal-fired unit was the marginal price setter in more than half the hours in each of the months May to October 2003 and 2004.[3]

Since real-time prices were set by a coal-fired unit in more than half the hours in 2003 and 2004, it is reasonable to think that the coal price increase that occurred over this same

[3] The exception was October 2003 when coal set the real-time price only 40 percent of the time. See the discussion and data later in this chapter at section 10, Price Setters.

period would be a key contributing factor towards generally higher HOEP in 2004 compared to 2003. The increases in coal prices should also provide at least a partial explanation for the generally positive residual effects estimated by the shift share analysis for both off-peak and on-peak periods during the months of May through July and October 2004.

The unit specific heat rate was used to estimate the effect that a change in the price of coal would have on the marginal cost of generation of each of the province's largest coal-fired facilities. The estimated dollar impact varies by unit due to the differences in each unit's operating efficiency.[4] Table 1-12 provides an upper and lower bound estimate of these impacts by month: one derived from the province's least efficient facility and one derived from the province's most efficient facility. Table 1-12 also reproduces the monthly residual effects of the shift share analysis for both the on-peak and off-peak periods for comparison purposes. As Table 1-12 indicates, the 69% increase in spot coal prices between May 2003 and May 2004 (see Table 1-11 above) would translate into an increase of roughly $10.70/MWh in the marginal cost of the province's most efficient coal unit and an increase of roughly $12.60/MWh in the marginal cost of the least efficient coal unit.

Table 1-12: Estimated Impact of 2003 to 2004 Coal Price Increases on the Marginal Cost of Select Ontario Coal-fired Units, May to October

	Least Efficient ($/MWh)	Most Efficient ($/MWh)	Residual Effect Off-Peak	Residual Effect On-Peak
May	12.60	10.70	12.20	33.20
Jun	12.10	10.30	12.50	27.60
Jul	15.00	12.70	13.50	26.20
Sep	13.20	11.20	2.10	(2.10)
Oct	12.60	10.70	11.10	14.60

[4] We estimated the impact of coal prices on marginal cost assuming that all coal-fired units purchased coal at the NYMEX spot prices reported in Table 1-11. In practice, different units use different coal types and the prices of different coal types will vary. This may affect the estimated marginal cost impact but the impact should not be material.

For all months but September, the estimated residual effect in the off-peak period falls between the upper and lower bound estimated increases in marginal cost.[5] This implies that coal price increases could explain most of the off-peak residual effects for these months. The estimated residual effect in on-peak periods for these same months is generally larger than the estimated increases in marginal cost. The estimated increase in marginal cost amounts to as much as 86% of the on-peak residual effect in October and as little as 38% of the residual effect in May. This suggests that factors in addition to higher coal prices contributed to the higher on-peak HOEP during the months of May through July 2004.

The month of September appears anomalous when compared to the other months in that the estimated residual effect is small in the off-peak period and negative in the on-peak periods. This is the case even though the estimated increase in marginal cost caused by the increase in coal prices between 2003 and 2004 was larger than in any other month except July. It appears that other factors offset the effect of year-to-year coal price increases on the HOEP in September.

As noted above, the estimated increase in marginal cost attributable to increases in coal prices is based on unit-specific heat rates. There are factors other than spot coal prices and heat rates that affect the cost of the coal-fired generation units. These other factors include the following:

i. Changes in fuel delivery costs will impact the marginal cost of producing electricity and hence would affect offer prices. As mentioned above, published coal prices do not include coal delivery costs. It is reasonable to assume that increases in delivered coal prices were greater, perhaps considerably greater, than the increases in the published (FOB) coal prices used in this analysis. In this case, the predicted year-to-year increase in marginal generation cost would be larger and the ‘unexplained’ residual smaller.

[5] The residual effect in June is slightly higher than the estimated marginal cost increase for the least efficient unit.

ii. Environmental emission standards may impact the offer prices of some coal facilities at different times of the year. In particular, coal generation may at times have to be priced in a manner so as to avoid producing more than their allowable nitric oxide (NO) and acid gas emissions (AGE) limits.

iii. The offer price of a coal unit may be affected by expectations regarding the hourly energy production of that unit. For example, if it is expected that the market clearing price in an hour is likely to be well above the average avoidable cost of a generating unit, that unit may be offered at marginal cost so that it is assured to run at full capacity. If it is anticipated that the MCP will be such that the unit does not run at full capacity, the unit may be offered at a price that covers average avoidable cost (which for most fossil units is higher than marginal cost for most of the unit's capacity). This ensures that if the unit does run at lower levels of capacity and it is marginal, it operates at a price that covers all of its costs. The implication is that the offer price of a fossil generation unit could increase year-to-year if, for example, increases in nuclear generation capacity changed its status from infra-marginal to marginal.

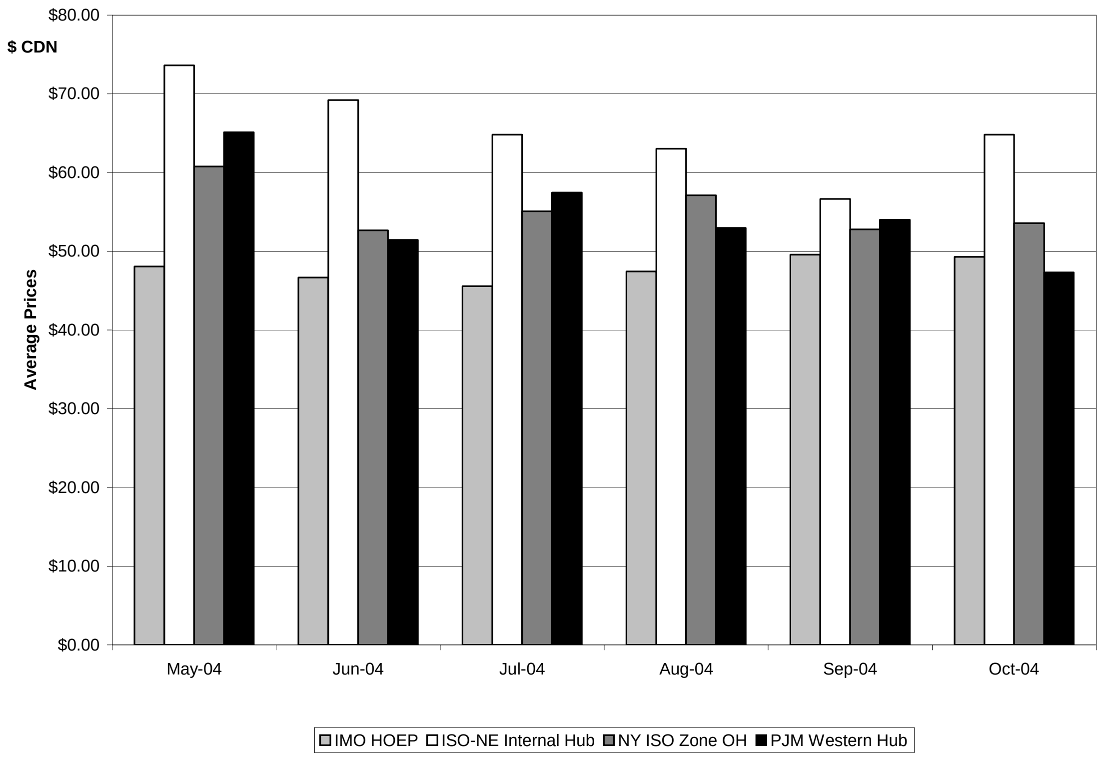
Changes in any or all of these factors would affect the marginal cost of coal-fired generation and, along with increases in coal prices, could explain the residual effect implied by the shift share analysis. Changes in imports and exports may also have attenuated the effect of the improved Ontario supply-demand balance on the HOEP (thereby reducing the residual implied by the shift share analysis). This is discussed briefly in section 8. There may also be some other factors such as changes in offer strategies or business policies that could affect the offer prices of coal-fired generation facilities and thus impact on the residual from the shift share analysis.

7. *Wholesale Electricity Prices in Neighbouring Markets*

Three other electricity markets operate in the northeast United States as 'neighbours' to Ontario. Comparing hourly spot market prices in each of these areas to the HOEP in

Ontario provides a useful indication of the respective costs of energy in these markets. Although these prices may differ because of market characteristics such as uplift, day ahead markets, bilateral contracts, market rules and/or other specific features, the comparison is still relevant as it represents the spot market price of energy in a given hour.

Figure 1-1: Average HOEP Relative to Neighbouring Markets*

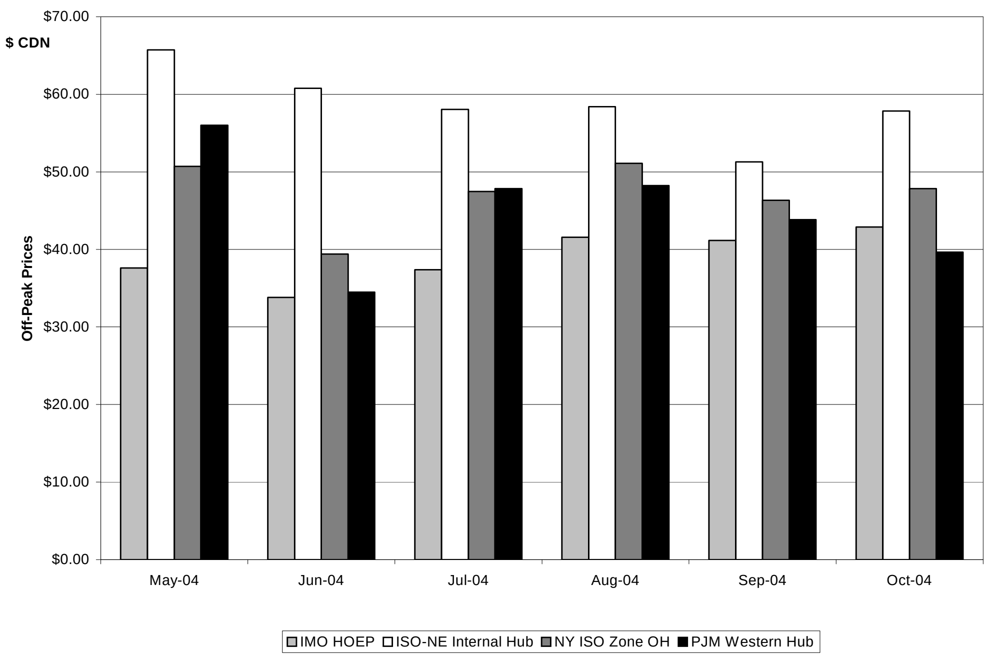


*Average daily exchange rates from the Bank of Canada were used for conversion purposes.

Figure 1-1 shows that in May to October 2004 Ontario prices have generally been lower than the prices in surrounding markets. The Ontario HOEP is generally considerably lower than prices in New England and PJM (except in October) and broadly similar to New York prices.

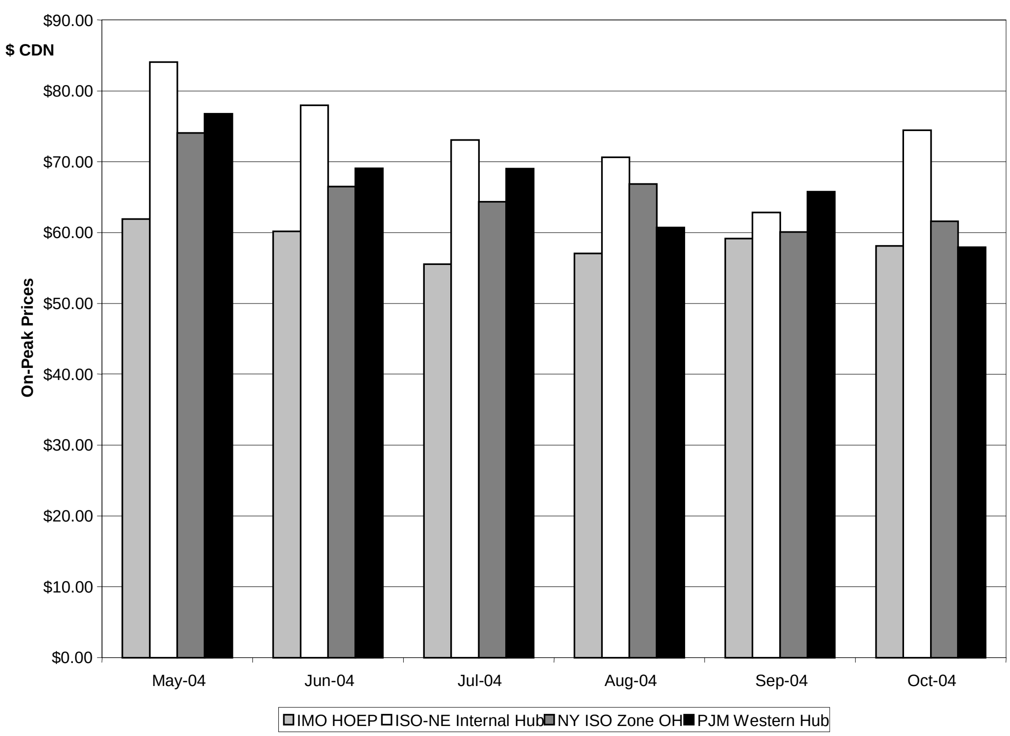
Figures 1-2 and 1-3 show comparisons of off-peak and on-peak prices. Once again, Ontario prices are lower than the prices in surrounding markets in all months and in both off-peak and on-peak with the exception of PJM prices in October.

Figure 1-2: Average HOEP Relative to Neighbouring Markets, Off-peak



*Average daily exchange rates from the Bank of Canada were used for conversion purposes.

Figure 1-3: Average HOEP Relative to Neighbouring Markets, On-peak



*Average daily exchange rates from the Bank of Canada were used for conversion purposes.

It is apparent from the figures above and from previous reports of the Panel that there are persistent differentials between the Ontario HOEP and the real-time prices in surrounding markets. The reason for this is that the ability of traders to arbitrage real-time price differences between markets is limited. These limits affect real-time trade flows and thus the impact of imports and exports on the HOEP. They include:

- First, transmission constraints within Ontario and between Ontario and surrounding jurisdictions can limit the flow of energy among these markets. Therefore, even when real-time inter-market price differences are expected to exist, there may be a limited ability for imports/exports to arbitrage these price differences due to the physical limitations on the grid.

- A second barrier relates to the pre-dispatch scheduling protocols. Imports and exports are selected in the one-hour ahead market in Ontario. Surrounding markets also schedule imports and exports at least 30 minutes in advance of the real-time market. This scheduling protocol affects the role of imports/exports as arbitrageurs of real-time price differences in several ways. First, traders must make import/export decisions roughly two hours before real-time and are unable to respond to supply and demand shocks that happen closer to or in real-time. Second, in Ontario and in markets such as New York, imports are paid according to the one-hour ahead pre-dispatch price via the Intertie Offer Guarantee (the IOG makes the pre-dispatch market a pay-as-you-bid market for imports), while exports pay the real-time prices. Therefore, import/export activity will respond to different price signals.

- Third, forecasts made in the pre-dispatch will affect both the relative amounts of imports and exports scheduled in real-time and the relative inter-market price differences. Inaccurate forecasts lead to non-optimal quantities of imports/exports being scheduled resulting in misleading inter-market price differences that impact trading activities. For example, the over-forecast of demand in pre-dispatch may cause too many imports to be selected in pre-dispatch. In real-time, these imports are placed at the bottom of the real-time offer curve. When the real-time demand is less than the forecast, these imports are still scheduled but other less costly resources must be 'backed-down' instead of the imports, causing the real-time HOEP to be lower than would have been the case had the imports and exports been scheduled in real-time.

These last two bullets suggest that there is likely to be more arbitrage between the Ontario pre-dispatch prices and those surrounding markets than between the HOEP and surrounding real-time prices. Figures 1-4 and 1-5 support this view. These figures plot the distribution of the differences between the Ontario and New York one-hour ahead prices and the Ontario and New York real-time prices for May to October, 2003 and 2004. The New York market was selected for this comparison, as it is the jurisdiction that typically has the smallest price differential (New York minus Ontario) with Ontario; the differential for the other jurisdictions such as PJM and ISONE is typically larger. Furthermore, the New York zone OH is used as a comparison as it represents the New York zone that is closest to Ontario.

In both figures, the distribution of the differences in pre-dispatch prices (solid line) is more closely centred on the mean than the distribution of the differences in real-time prices. Furthermore, the mean differences of the pre-dispatch prices are smaller than the mean differences in the real-time prices. In particular, the mean differences in pre-dispatch prices were $1.49 in 2003 and -$1.83 in 2004 with New York prices being higher in 2004. The mean differences in real-time prices were -$5.89 in 2003 and -$7.98 in 2004 with New York prices being higher in both years. These data suggest that import/export activity is more effective at arbitraging price differences in pre-dispatch than it is at arbitraging price differences in real-time with the lack of real-time arbitrage being prevented due to the factors discussed above.

Figure 1-4: Distribution of Ontario-New York Price Differences, May-October 2003

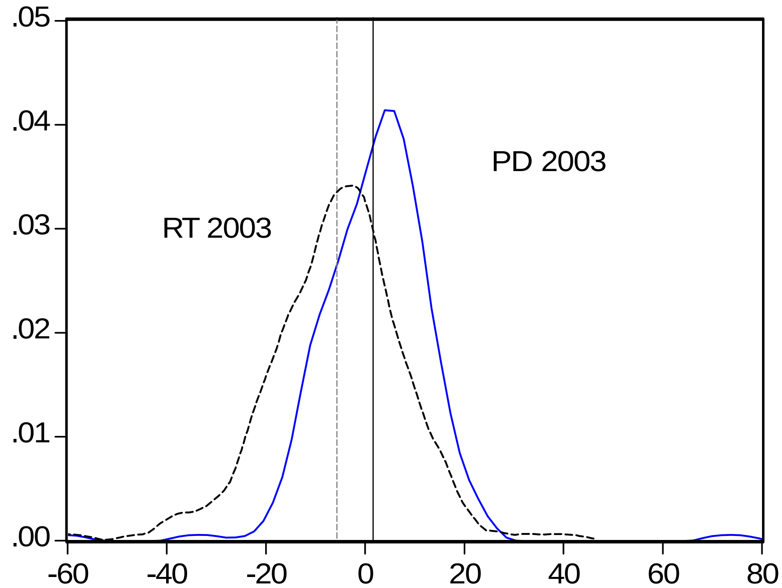
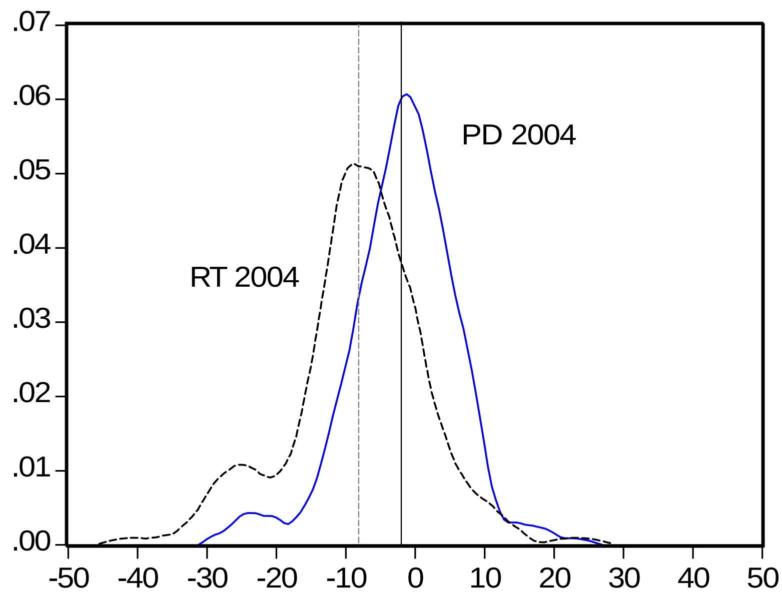


Figure 1-5: Distribution of Ontario-New York Price Differences, May-October 2004



8. *Imports and Exports*

As Table 1-13 indicates, Ontario was a net exporter[6] in both off-peak and on-peak periods in the months of May to August of 2004 and a net importer in September and October. This is in contrast to 2003 when Ontario was a net importer in on-peak periods in May, June and August and in off-peak periods in June. Furthermore, in all months in which Ontario was a net exporter in 2004 (except off-peak periods in July) there was a greater amount of net exports in 2004 than in 2003. The fact that Ontario was a larger net exporter in the months of May to August 2004 than in the same months for 2003 is consistent with the improvement in the supply-demand balance in 2004. It is also true that Ontario was a smaller net importer in 2004 in the months of September and October than it was in 2003 (except for off-peak periods in September). This is also consistent with the improved supply-demand balance that existed in Ontario in these months due to the higher nuclear and hydroelectric supply (the improved supply-demand balance meant that fewer imports were required in 2004).

Table 1-13: Net Exports (Unconstrained Schedule) from Ontario, On-Peak and Off-Peak (MWh), May-October, 2003 & 2004

	Off-Peak		On-Peak	
	2003	**2004**	**2003**	**2004**
May	46,772	454,735	(179,076)	350,336
Jun	(55,667)	236,599	(202,022)	232,714
Jul	305,453	266,695	179,647	276,239
Aug	146,942	256,691	(65,709)	332,929
Sep	(169,022)	(253,894)	(322,205)	(295,300)
Oct	(410,546)	(221,592)	(476,348)	(175,481)

[6] Trade flows measured in terms of the imports/exports scheduled in the constrained schedule present a more accurate measure of the actual flow of electricity than the unconstrained schedule since the constrained schedule recognizes all internal transmission limitations while the unconstrained schedules do not. However, imports and exports measured in the unconstrained schedule present a more accurate measure of the trade flows affecting the HOEP. For this latter reason, we present trade flows based on the unconstrained schedules. Tables A-23 and A-24 in the Statistical Appendix provide data from the constrained schedule on monthly trade flows by intertie zone for on-peak and off-peak times.

Net exports disaggregated by intertie zone are reported in Table 1-14. Positive values in Table 1-14 indicate that Ontario exported more electricity to the identified intertie zone than was imported, while negative numbers (shown by bracketed figures) indicate that Ontario imported more from the zone than it exported. As Table 1-14 indicates, the Michigan zone typically exports more electricity to Ontario than it imports from Ontario. Conversely, the New York Zone typically imports more electricity from Ontario than it exports to Ontario. In general, these trends illustrate the typical flows of electricity that have characterized the surrounding markets over the past couple of years, with relatively cheap electricity from the Michigan area flowing through the Ontario market on its way to higher priced markets to the southeast of Ontario such as New York and New England. The Quebec zone also imported more from Ontario than it exported to Ontario over the past two years. However, in some months such as May and August of 2003 and July and August of 2004, Quebec exported more in off-peak periods and imported more in on-peak periods. The Minnesota zone was also primarily an importer of electricity to Ontario in 2004. In 2004, due to transmission limitations in Manitoba, no imports from Ontario were selected so that Manitoba was a net importer to Ontario in all months of 2004.

In all jurisdictions, there was a general trend for more exports out of Ontario and fewer imports into Ontario in 2004 compared to 2003. This provides further support for the view that the relative improvement in the Ontario supply-demand balance in 2004 (and the price lowering effect that this improvement had) made exporting out of Ontario more attractive in 2004.

Table 1-14: Net Exports (Unconstrained Schedule) by Intertie Zone, On-Peak and Off-Peak (MWh), May-October, 2003 & 2004*

		MB		MI		MN		NY		PQ	
		2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	Off-peak	(85,264)	(12,169)	(310,486)	(227,279)	(29,613)	1,091	454,944	661,981	17,190	31,112
	On-Peak	(67,013)	(31,624)	(248,107)	(1,281)	(18,898)	21,232	157,177	348,068	(2,235)	13,940
Jun	Off-peak	(70,678)	(43,718)	(342,034)	(297,355)	(28,447)	(19,399)	341,461	561,132	44,031	35,940
	On-Peak	(64,687)	(61,812)	(279,906)	(110,171)	(8,661)	(8,033)	133,281	391,588	17,950	21,141
Jul	Off-peak	(50,478)	(63,958)	(177,843)	(273,817)	997	(23,694)	493,349	592,119	39,429	36,045
	On-Peak	(36,172)	(14,288)	260	(10,380)	27,236	13,661	168,649	312,903	19,674	(25,656)
Aug	Off-peak	3,868	(73,518)	(227,430)	(337,952)	426	(26,735)	358,573	667,315	11,505	27,580
	On-Peak	(12,584)	(31,238)	(39,468)	(56,926)	29,403	(11,645)	15,540	440,998	(58,600)	(8,259)
Sep	Off-peak	(15,412)	(73,961)	(379,839)	(406,195)	(21,876)	(19,196)	224,996	253,072	23,109	(7,615)
	On-Peak	(37,670)	(38,403)	(295,838)	(274,401)	(160)	(7,879)	10,881	122,129	583	(96,746)
Oct	Off-peak	(24,791)	(78,755)	(293,795)	(356,089)	(26,308)	(23,600)	(60,966)	279,541	(4,686)	(42,689)
	On-Peak	(38,030)	(34,964)	(258,583)	(223,065)	(14,767)	(2,701)	(139,335)	236,248	(25,633)	(150,999)

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

The question remains as to the effect of the increase in net exports in 2004 on the HOEP. Given the endogenous nature of exports and imports, it is difficult to assess the extent to which either contributed to an overall higher HOEP in May to October 2004 compared to May to October 2003. As indicated in section 4, increases in nuclear and hydroelectric supply caused a relative improvement in the supply-demand balance in Ontario in 2004. Holding all else constant, including the supply-demand conditions in surrounding markets, this shift should increase the incentive to export out of Ontario and reduce the incentive to import into Ontario. The price responsiveness of export and import demands serves to mitigate but not eliminate the HOEP-reducing effects of an improvement in the Ontario supply-demand balance. The limits on export and import activity discussed in section 7 ensure that, all else equal, an improvement in the Ontario supply-demand balance has a HOEP-reducing effect.

9. *Operating Reserve Prices*

Table 1-15 provides a comparison of average operating reserve prices for each of the three classes of reserve for May to October in 2003 and 2004.

Table 1-15: Operating Reserve Prices ($/MWh), May-October, 2003 & 2004

	10N		10S		30R	
	2003	2004	2003	2004	2003	2004
May	7.20	8.66	7.85	10.90	6.64	8.20
Jun	4.92	3.97	5.27	5.93	4.70	3.77
Jul	1.79	3.60	2.67	5.62	1.74	3.47
Aug	2.91	0.88	4.06	3.27	2.84	0.87
Sep	3.10	1.06	5.69	3.54	2.48	1.02
Oct	1.93	0.54	2.82	2.93	0.99	0.54

The factors that influenced the year-to-year changes in operating reserve prices include:

- The IMO purchased an additional 200 MW of ten-minute non-spinning reserve during the peak delivery hours 7 through 21 in 2003. This was the supplemental reserve that was introduced in June 2002 to deal with the frequent reserve shortages that were occurring at the time. In January 2004, this supplemental reserve requirement was removed from the market. The lower reserve requirement should exert a downward effect on OR prices in 2004.

- Greater availability of water for hydroelectric generation in 2004 implies that in any given hour, hydroelectric facilities are more likely to be offered at prices that ensure they are called as energy instead of reserve. This is to avoid the wasteful spilling of water. When this occurs, fossil generation replaces hydroelectric generation as the supplier of operating reserve. This is particularly true with respect to the ten-minute spinning reserve as only fossil generation and quick-start hydro can provide this reserve. Since fossil generating units ramp more slowly than hydroelectric generating units, the amount of reserve available is reduced. In addition, the offer prices of fossil generators are typically higher than the offer prices of hydroelectric generators. The combined effects of less reserve available and higher offer prices is referred to as the 'freshet effect' and it contributes to higher reserve prices.

- Control Action Operating Reserve (CAOR) was introduced in August 2003. CAOR represents the use of voltage reductions as a source of reserve. Beginning in August 2003 as much as 400 MW of voltage reductions was offered as operating reserve at a price of $30 (for thirty-minute reserve) and $30.10 (for ten-minute non-spinning reserve). CAOR will be selected in the market as reserve whenever the conditions imply that it is the most economic (based on the offer prices) to use it. Recall that prior to the implementation of CAOR, the voltage reductions were used as a source of reserve whenever the IMO identified an actual or potential shortage of reserve in the constrained schedule. The voltage reductions were introduced manually in conjunction with reducing the overall reserve requirement by the amount of the voltage reduction carried (estimated to be the amount of the reserve shortage). When the voltage reductions were introduced in this manner, they were introduced essentially at a zero price, and often the price of reserve would fall when this occurred. Therefore, the impact of the implementation of CAOR on the price of reserve depends on the frequency with which the IMO manually reduced the reserve requirement in 2003 relative to what it would have reduced it in 2004. If the CAOR was carried in 2004 periods when the IMO would have otherwise manually reduced the reserve requirement, operating reserve prices would increase since the manual reduction uses voltage reductions at an offer price of $0 instead of the $30 for the CAOR. In contrast, if the CAOR was scheduled in 2004 in periods when the IMO would not have manually lowered the reserve requirement, operating reserve prices would tend to be lower.

- More dispatchable loads entered the reserve market in 2004, thereby increasing the supply of operating reserve and putting downward pressure on the price.

- There was generally a greater supply of reserves from imports in 2003 than there was in 2004.

Changes in each of these factors listed above would impact the year-to-year changes in operating reserve prices. However, the degree to which each factor affects the price differences differs across each month in the comparison period. To study the likely causes of year-to-year price changes in each month Table 1-15 is divided into off-peak (Table 1-16) and on-peak (Table 1-17) periods. Also useful in this exercise are Table 1-18 and Table 1-19, which show the percentage of reserve requirements met by each type of generation.

Table 1-16: Operating Reserve Prices ($/MWh), Off-Peak Periods, May-October, 2003 & 2004

	10N		10S		30R	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**
May	2.95	4.43	3.69	8.17	2.93	4.28
Jun	1.35	0.93	1.70	4.15	1.33	0.93
Jul	0.83	1.41	1.98	4.64	0.82	1.37
Aug	1.21	0.35	2.68	3.66	1.18	0.35
Sep	1.26	0.21	4.24	3.66	1.18	0.21
Oct	0.82	0.23	2.00	3.36	0.57	0.23

Table 1-17: Operating Reserve Prices ($/MWh), On-Peak Periods, May-October, 2003 & 2004

	10N		10S		30R	
	2003	2004	2003	2004	2003	2004
May	12.36	14.27	12.91	14.52	11.13	13.39
Jun	9.01	7.16	9.35	7.80	8.54	6.75
Jul	2.85	6.27	3.44	6.81	2.75	6.03
Aug	5.53	1.52	6.19	2.78	5.39	1.51
Sep	5.20	2.04	7.35	3.40	3.97	1.94
Oct	3.17	0.94	3.73	2.35	1.47	0.94

The prices of all three operating reserve classes were higher in May and July of 2004 than in May and July of 2003 in both the off-peak and on-peak periods. The key factors contributing to the higher prices in May 2004 were the 'freshet effect' and the reduced amount of supply from imports. These factors offset the effect of increased supply of ten-minute spinning reserve from dispatchable loads and the lower reserve requirements. The freshet effect was most notable in on-peak periods when the share of reserve accounted for by fossil generators increased dramatically from 8.9% in 2003 to 34% in 2004. The key factors contributing to higher prices in July 2004 were the reduced supply of reserve from imports and the continuation of the freshet effect.

Table 1-18: Shares by Fuel Type of Total Operating Reserve Requirements, Off-peak Periods, May-October, 2003 & 2004

	Dispatchable Load (% of Total Requirement)		Hydroelectric (% of Total Requirement)		CAOR (% of Total Requirement)		Fossil (% of Total Requirement)		Import (% of Total Requirement)		Total (Average Hourly Value MW)	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	4.1	14.1	85.5	69.0	0.0	0.2	2.6	16.3	7.8	0.4	1,456	1,409
Jun	4.4	13.0	87.4	80.1	0.0	0.0	1.6	6.7	6.5	0.1	1,452	1,418
Jul	4.2	10.3	84.6	82.1	0.0	0.1	4.4	6.9	6.8	0.6	1,455	1,403
Sep	8.1	18.9	67.9	72.4	0.0	0.0	6.1	8.5	17.8	0.2	1,486	1,373
Oct	10.3	19.3	65.3	71.0	0.0	0.0	3.6	8.1	20.8	1.6	1,353	1,417

Table 1-19: Shares by Fuel Type of Total Operating Reserve Requirements, On-peak Periods, May-October, 2003 & 2004

	Dispatchable Load (% of Total Requirement)		Hydroelectric (% of Total Requirement)		CAOR (% of Total Requirement)		Fossil (% of Total Requirement)		Import (% of Total Requirement)		Total (Average Hourly Value MW)	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**
May	3.9	12.9	72.9	49.3	0.0	2.1	8.9	34.0	14.4	1.8	1,518	1,391
Jun	4.1	10.5	82.7	68.8	0.0	0.4	4.0	19.3	9.3	1.1	1,510	1,400
Jul	3.6	8.4	78.8	70.1	0.0	0.3	5.7	17.6	11.9	3.5	1,529	1,403
Sep	5.7	17.1	66.6	75.0	0.4	0.0	6.1	7.3	21.2	0.7	1,599	1,376
Oct	7.4	18.6	65.2	76.2	0.0	0.0	4.4	4.9	23.0	0.2	1,432	1,417

The month of June was different from May and July with all reserve prices being higher in 2003 with the exception of the ten-minute spinning reserve prices in off-peak periods. The freshet effect was the key factor contributing to the higher ten-minute spinning reserve price in off-peak periods in June 2004. In all other periods, the increase in supply from dispatchable loads and the lower reserve requirements resulted in lower overall reserve prices in 2004 compared to 2003.

In September and October, prices were lower in 2004 than in 2003 in all reserve classes and in both off-peak and on-peak periods with the exception of the ten-minute spinning price in off-peak periods in October 2004. The increased supply of reserve from dispatchable loads coupled with the lower reserve requirements in 2004 were the key contributing factors to lower prices in 2004.

10. *Price Setters*

The percentage of the time in May–October 2003 and 2004 that a given fuel type set the market clearing price in the real-time market (in both off-peak and on-peak hours) is shown in Tables 1-20 to 1-23.

Table 1-20: Share of Real-time MCP Set by Resource (%), May-October, 2003 & 2004

	Coal		Nuclear		Oil/Gas		Water	
	2003	2004	2003	2004	2003	2004	2003	2004
May	66	54	0	0	23	11	11	35
Jun	68	63	0	0	13	7	19	30
Jul	66	60	0	0	25	6	9	32
Aug	66	70	0	0	25	6	9	24
Sep	51	70	0	0	26	13	23	17
Oct	40	76	0	0	48	5	13	18

Table 1-21: Share of Real-time MCP Set by Resource (%), Off-Peak, May-October, 2003 & 2004

	Coal		Nuclear		Oil/Gas		Water	
	2003	2004	2003	2004	2003	2004	2003	2004
May	85	51	0	0	7	5	8	45
Jun	82	59	0	0	4	1	14	40
Jul	85	53	0	0	8	2	7	44
Aug	83	62	0	0	8	2	9	36
Sep	61	73	0	0	12	3	28	24
Oct	55	86	0	0	31	2	14	12

As Tables 1-20 to 1-23 indicate, for the months of May through August, the percentage of time in which hydroelectric and coal-fired resources established the real-time price was higher in 2004, while the percentage of time in which the natural gas and oil-fired resources established the real-time price was lower. This phenomenon was most prominent in off-peak periods.

Table 1-22: Share of Real-time MCP Set by Resource (%), On-Peak, May-October, 2003 & 2004

	Coal		Nuclear		Oil/Gas		Water	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**
May	43	58	0	0	42	19	15	23
Jun	52	67	0	0	24	14	24	19
Jul	44	69	0	0	44	11	11	18
Aug	39	80	0	0	52	10	9	10
Sep	41	67	0	0	41	24	17	9
Oct	23	62	0	0	66	10	11	27

Table 1-23 provides another indication of the effects of the increased supply of nuclear and hydroelectric generation in 2004 compared to 2003. It provides a measure of energy production by fuel type for the months of May to October 2003 and 2004. As Table 1-23 shows, the level of production of coal-fired generation facilities was down considerably in May, June and July of 2004 compared to the same months in 2003 and down in the months of August and October as well.

Table 1-23: Resources Selected in the Real-time Market Schedule (TWh) May-October, 2003 & 2004

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear		Total	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**
May	0.87	0.41	0.74	1.21	2.80	1.60	0.79	0.78	3.11	3.72	4.79	6.53	11.62	11.83
Jun	0.95	0.65	0.69	1.12	3.09	1.75	0.75	0.79	2.79	3.15	4.99	6.82	11.88	12.04
Jul	0.60	0.57	1.09	1.11	3.86	1.99	0.83	0.83	2.72	3.34	5.97	7.11	12.89	12.73
Aug	0.49	0.69	0.59	1.28	2.48	2.23	0.58	0.73	2.06	2.91	4.11	7.43	9.13	12.71
Sep	0.94	1.03	0.45	0.49	2.17	2.21	0.79	0.86	2.59	2.87	5.77	5.83	11.81	12.31
Oct	1.06	0.95	0.17	0.56	3.40	2.81	1.10	0.91	3.13	2.84	3.60	5.23	12.12	12.18

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

In past reports the Panel has noted that there is a persistent discrepancy between pre-dispatch and real-time prices.[7] It is unrealistic to expect pre-dispatch and real-time prices to match perfectly. There are aspects of market design that make the hour-ahead pre-dispatch price conceptually distinct from the HOEP.[8] Notwithstanding these considerations, however, the pre-dispatch price is the signal to which domestic and generators and load will react. Generators and loads require a reliable pre-dispatch price signal to plan their production schedules. The convergence of the pre-dispatch and real-time price is a sign that demand-supply conditions in the market are being accurately projected. Market participants will react more meaningfully, and market outcomes will be more efficient, the closer the pre-dispatch price comes to reflecting real-time supply-demand conditions.

The Panel has consistently emphasized that accurate price signals are critical for the decisions of market participants, and has focussed its recommendations on aspects of market operation that cause divergence between the pre-dispatch price and the HOEP. These include forecasting methodology, the use of out-of-market control actions, and the assumption of a 12-times ramp rate.

As Table 1-24 indicates the difference between the one-hour ahead pre-dispatch price and the HOEP was persistent although it declined from 2003 to 2004, both in terms of the average difference and the percentage difference. The difference also declined relative to the first six months of 2004.

[7] See October 2002 report at pp. 87-103 and March 2003 report at pp. 63-96

[8] These include the fact that the pre-dispatch price is an hourly price (with one estimate of demand for the hour) whereas the HOEP is an average of 5-minute prices, each with a distinct level of demand), as well as the different ways that imports and exports are treated in pre-dispatch and real time, with imports and exports being allowed to set the price in pre-dispatch but not in real time.

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

	1-hour ahead pre-dispatch price minus HOEP ($/MWh)									
	Average difference		Maximum difference		Minimum difference		Standard deviation		Average difference as a % of the HOEP	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	11.04	10.05	78.53	72.62	(128.79)	(62.19)	19.54	14.11	35.10	27.58
Jun	11.63	6.73	490.1	53.2	(225.41)	(108.31)	32.79	12.84	38.76	24.09
Jul	7.65	5.21	55.27	41.29	(38.59)	(71.62)	13.19	10.06	26.93	18.32
Aug	8.23	4.99	52.98	33.05	(47.28)	(36.79)	13.96	7.58	23.92	17.61
Sep	7.01	4.01	63.14	31.99	(287.68)	(93.98)	16.41	7.97	19.59	11.57
Oct	7.25	5.72	47.62	51.21	(223.15)	(45.55)	15.46	10.12	19.53	12.69

In the Panel's past reports four factors that affect the difference between the pre-dispatch and HOEP or peak hourly MCP have been identified. 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.

The role played by each of these contributing factors is discussed below. Section 3.3 in Chapter 2 extends the analysis and comments on the implications of the continued price disparity, focussing in particular on the 12-times ramp rate assumption.

<u>Demand Forecast Error</u>

A review of the last six months reveals that there has been a reduction in the demand forecast error, in comparison with 2003. As Table 1-25 indicates, the mean absolute percentage forecast difference between pre-dispatch and the average hourly demand has declined from a range of 2.25% to 2.51% in 2003 to a range of 1.94% to 2.31% in 2004. When comparing the pre-dispatch to the real-time hourly peak demand, the improvement is more pronounced.

The reduction in forecast error has reduced the gap between the one-hour ahead pre-dispatch price and the HOEP. Despite the overall reduction in the demand forecast error, there is still a persistent over-forecast of demand, even when comparing the forecast peak to the actual peak.[9]

Table 1-25: Forecast Bias in Demand

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-hour ahead		1-hour ahead		3-hour ahead		1-hour ahead		3-hour ahead		1-hour ahead		3-hour ahead		1-hour ahead	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	356	356	345	322	203	233	179	192	2.41	2.38	2.33	2.14	1.33	1.52	1.17	1.23
Jun	386	373	360	341	250	284	208	233	2.45	2.30	2.28	2.11	1.55	1.70	1.29	1.40
Jul	479	433	417	384	336	322	259	261	2.87	2.61	2.51	2.31	1.94	1.89	1.50	1.53
Aug	451	403	403	359	327	297	261	238	2.70	2.44	2.42	2.17	1.87	1.73	1.50	1.39
Sep	375	368	354	342	244	247	203	201	2.38	2.30	2.25	2.12	1.51	1.47	1.25	1.20
Oct	370	314	358	300	226	200	196	169	2.40	2.04	2.31	1.94	1.42	1.26	1.23	1.06

Performance of Self-Scheduling and Intermittent Generation

Improvements in the performance of self-scheduling and intermittent generation have also contributed to reduced demand forecast error. As Table 1-26 indicates, the average hourly discrepancy between the offers of self-scheduling units and the actual delivered quantities declined significantly in every month of 2004 compared to 2003, except September and October. The magnitude of this difference is now so small that it has a trivial impact on the difference between the hour ahead pre-dispatch price and the HOEP.

[9] Because the IMO uses an estimate of peak demand, rather than average demand for the hour, one would expect the forecast to be consistently higher than the actual average demand.

Table 1-26: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities

	Total MW Pre-dispatch		Maximum Difference (MW)		Minimum Difference (MW)		Average Difference (MW)		Fail Rate (Difference/MW Pre-dispatch) (%)	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**
May	778,341	712,553	290.51	145.81	(69.88)	(118.3)	62.34	(5.70)	6.26	(0.42)
Jun	886,176	754,026	668.18	283.55	(243.79)	(91.13)	93.82	10.00	8.65	0.82
Jul	1,249,147	842,044	509.86	582.64	(146.78)	(282.74)	94.12	51.68	5.68	4.32
Aug	703,045	737,531	364.83	227.87	(193.14)	(53.35)	86.83	33.11	6.92	3.61
Sep	764,657	719,483	543.98	308.92	(111.61)	(103.57)	37.07	42.28	3.80	4.54
Oct	821,786	770,163	154.27	276.43	(94.26)	(97.43)	(0.42)	24.44	0.07	2.50

The Role of Import Offers and Export Bids in both Pre-dispatch and Real-time

Failed exports reduce the HOEP relative to the pre-dispatch price. This is because when exports fail, the IMO has to dispatch down generation to reflect the reduced level of demand in the market. The magnitude of failed exports declined in every month except October in 2004. The decline on an average hourly basis ranged from a low 32 MW to a high of 153 MW. The average hourly failure increased by 60 MW in October 2004, compared to October 2003. Table 1-27 also shows the significant reduction in the rate of failure of exports from Ontario (the failure rate for October 2004 was only marginally higher than in 2003). Lower amounts and lower frequency of failed exports narrowed the price gap and contributed to the convergence between the generally higher pre-dispatch price and the HOEP in 2004.

Table 1-27: Incidents and Average Magnitude of Failed Exports from Ontario

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**
May	427	437	1,020	958	214.9	183.4	11.1	6.2
Jun	386	471	1,107	1,104	337.3	203.3	15.9	7.9
Jul	464	467	1,300	950	343.5	189.7	12.8	7.4
Aug	306	454	1,036	1,052	322.5	229.3	14.4	7.5
Sep	291	264	977	900	236.5	197.0	13.4	16.0
Oct	148	388	815	964	171.7	231.6	13.2	14.0

Failed imports increase the HOEP relative to the pre-dispatch price. When imports fail, the IMO has to replace them with more expensive Ontario generation. The magnitude of import failures was generally lower in 2004 compared to 2003. This is evident from Table 1-28. Although the failure rate rose for all months in 2004 compared to 2003, it remained significantly lower than the failure rate for exports. On balance, the lower magnitudes of failed imports and the relatively low rates of failure offset the narrowing of the difference between the HOEP and the pre-dispatch price in 2004.

Table 1-28: Incidents and Average Magnitude of Failed Imports into Ontario

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2003	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**
May	239	141	654	388	63.4	59.3	1.7	2.0
Jun	151	292	687	864	105.3	109.8	1.6	4.7
Jul	111	289	891	545	110.4	108.3	2.0	5.2
Aug	87	341	389	667	90.1	85.1	1.6	4.0
Sep	167	270	525	509	97.4	76.8	1.7	2.5
Oct	279	311	792	482	133.1	123.0	3.4	3.9

Out-of-Market Control Actions

The use of out-of-market control actions and their subsequent impact on market prices has been extensively discussed in previous MSP reports.[10] In general the use of control actions to meet reserve requirements results in depressed real-time prices. Table 1-29 indicates that the percentage of intervals in which the IMO reduced the reserve requirements in the range of 200 MW to 400 MW dropped sharply in the months of June to October in 2004 as compared to the same months in 2003. The effect of using control actions less frequently is to reduce the number of occasions on which the HOEP is depressed relative to the pre-dispatch price. This has reduced the average difference between the HOEP and the pre-dispatch price.

Table 1-29: Percentage Intervals with Operating Reserve Reductions (Market Schedule), May 2003-October 2004

	No Reductions		>1 MW and <200 MW		>200 MW and <400 MW		>400 MW and <800 MW		>800 MW	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
May	96.98	94.02	0.43	3.14	1.78	1.87	0.80	0.96	0.02	0.01
Jun	96.82	97.28	0.15	1.05	1.45	1.19	1.35	0.47	0.23	0.00
Jul	98.53	98.41	0.15	0.73	0.65	0.53	0.56	0.32	0.11	0.01
Aug	96.54	99.12	0.19	0.38	2.73	0.40	0.47	0.10	0.07	0.00
Sep	99.61	99.20	0.05	0.34	0.19	0.03	0.14	0.43	0.02	0.00
Oct	97.77	99.63	0.77	0.15	0.96	0.10	0.30	0.12	0.19	0.00

12. *Hourly Uplift and Components*

The hourly uplift consists of payments for Intertie Offer Guarantee (IOG), Congestion Management Settlements Credits (CMSC), Operating Reserve (OR) and line losses on the transmission system. Overall, for the months of May through October 2004, total uplift charges remained fairly constant at $155 million, compared to $159 million for the same six months in 2003. Table A-10 in the Statistical Appendix provides more details of the components of these payments for the past eighteen months.

Table 1-30: Period to Period Comparisons of Total Hourly Uplift

	Total Hourly Uplift $ Millions	IOG $ Millions	CMSC $ Millions	Operating Reserve $ Millions	Losses $ Millions
May 2003 - Oct 2003	159	16	51	24	68
May 2004 - Oct 2004	155	6	46	19	85
Nov 2002 - Oct 2003	432	70	142	46	180
Nov 2003 - Oct 2004	360	45	90	52	174

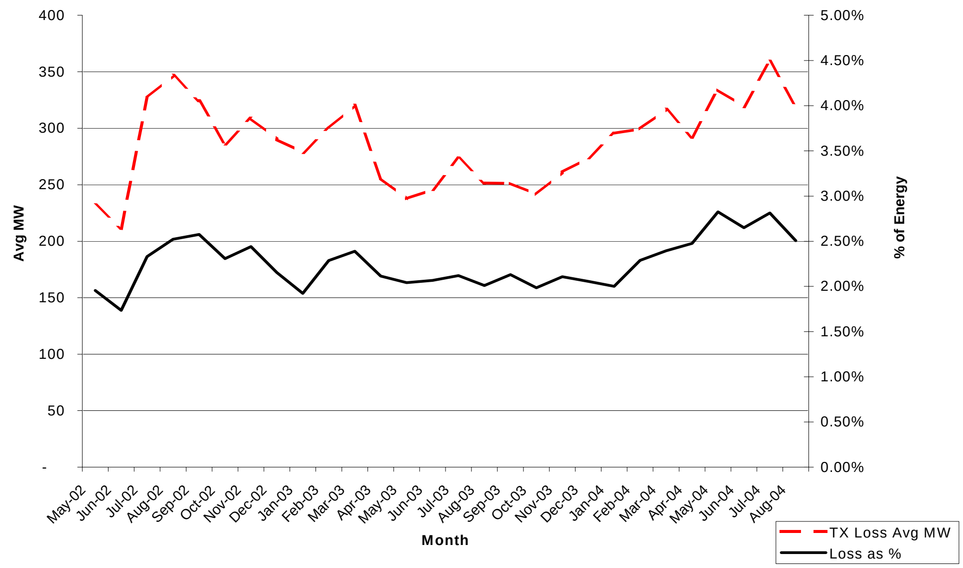
All components of uplift dropped slightly in comparison to the similar period in 2003 with the exception of line losses, which rose $17 million. The reduction in all other categories of uplift is consistent with other trends in the marketplace. The narrowing of the gap between the pre-dispatch and the real-time price has reduced IOG payments. This can be attributed, in part, to the increased accuracy of demand forecasts (see the earlier discussion in section 11).

In January 2004, the IMO made a decision to stop purchasing 200 MW of supplemental OR. While average OR prices have been fairly stable on a year-to-year basis (see Table 1-15), the reduction in the volume purchased has reduced payments for OR by $5 million.

Total transmission loss payments increased by approximately $17 million over the six month period in 2004 compared to 2003. Some of this can be attributed to the increase in the HOEP but the energy loss also appears to be have increased by roughly 30 to 40% over 2003. This is shown in Table 1-5 and graphically in Figure 1-6. The increase in losses in 2004 appears anomalous, as losses are generally a function of total consumption and the distribution of supply sources relative to load centres. The IMO is reviewing this matter.[11]

[10] See October 2002 MSP Report, Chapter 2, pp 97-101 and March 2003 MSP Report, Chapter 3 pp 87-89.

Figure 1-6: Transmission Loss in Average MW and as a Percentage of Monthly Energy, May 2002-August 2004



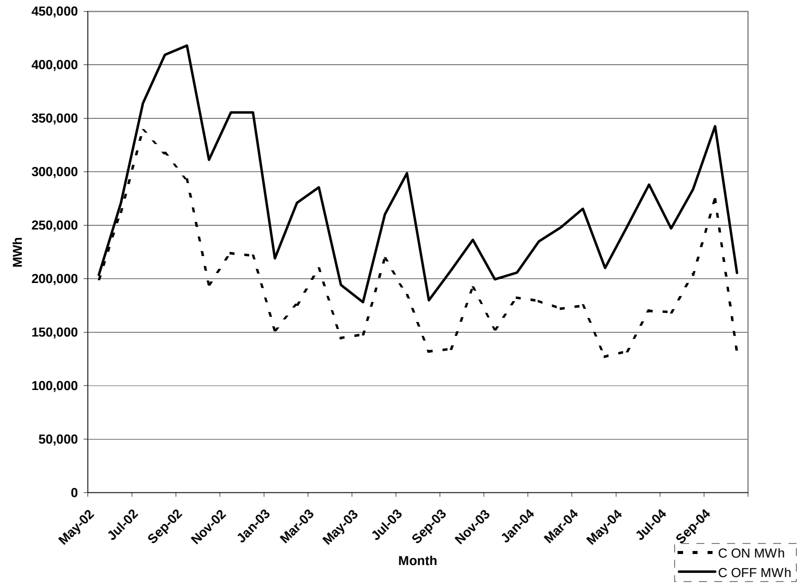
12.1 Hourly Uplift – Year-over-Year Comparison

Table 1-30 also provides a comparison of hourly uplift payments for two twelve month periods, November 2003-October 2004 and November 2002-October 2003. Total uplift dropped from almost $432 million during the November 2002 to October 2003 period to just over $360 million in the last 12 months, a reduction of more than 16%. The large reduction in year-over-year uplift payments is most apparent in CMSC payments, which have fallen by $52 million or roughly 36%. In the past six months, the decline in CMSC payments has not been as dramatic, declining by only 10%.

With respect to the volumes of constrained on and off MWh, there was a significant reduction in the overall volume of constrained MWh during the first six months of the market, but further volume reductions are not evident. This is illustrated in Figure 1-7. The excess of constrained off over constrained on MWh may be attributable to the difference between the forecast and the actual load.

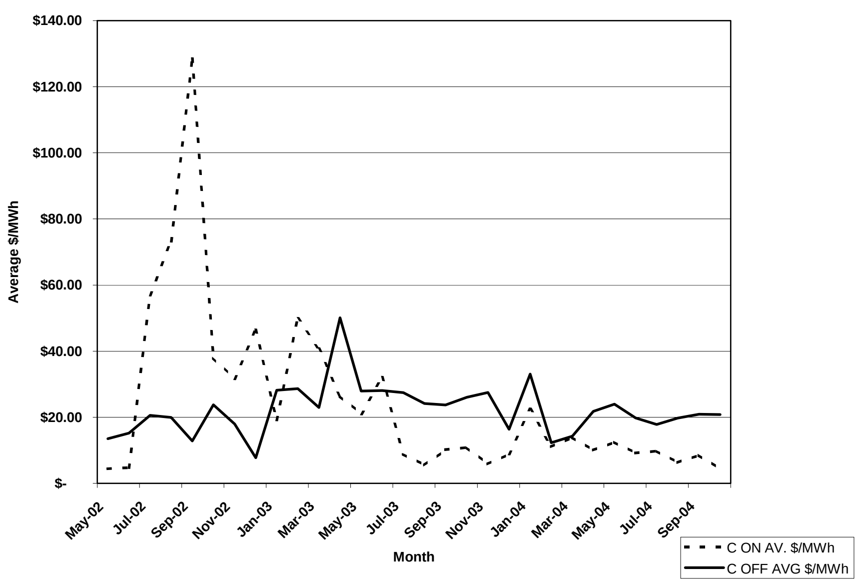
[11] The correction of a significant meter error in February 2004 accounts for some but by no means all of the increased transmission losses. A description of the metering issue is found at http://www.theimo.com/imoweb/pubs/macd/macd_Public_Statement_MR_Breaches.pdf.

Figure 1-7: Monthly MWh Constrained On and Off, May 2002-October 2004



There has been a noticeable reduction in the average $/MWh paid for constrained on and off energy. The average payment has dropped significantly. This is illustrated in Figure 1-8 below.

Figure 1-8: Monthly Average $/MWh for Constrained On and Off, May 2002-October 2004



The relatively small decline in the average constrained off payment per MWh is attributable to the fact that the cost of generation has not changed too markedly over the first two and a half years of the market. Constrained on payments which are traditionally more reflective of opportunity cost have dropped dramatically from payments as high as $128/MWh in September 2002 to as low as $4.34/MWh in October 2004.

Chapter 2: Analysis of Market Outcomes

1. *Introduction*

The Market Assessment Unit (MAU), under the direction of the Market Surveillance Panel, monitors the market for 'anomalies'. Anomalies are actions by market participants and market outcomes that fall outside of predicted patterns or norms.

The MAU reviews all 'high priced hours' to identify the critical factors leading to the high prices and reports its findings to the Panel. For the purpose of this report, 'high priced hours' are defined as all hours in which the HOEP was greater than $200/MWh or the hourly uplift exceeded the HOEP. The MAU also reviews all 'low priced hours' and reports its findings to the Panel. For the purpose of this review, a 'low priced hour' is defined as any hour in which the HOEP was less than $20/MWh.[12]

In addition, the MAU monitors for any other events that appear to be anomalous, even though they may not meet the 'bright-line' price tests, and reports its findings to the Panel. Section 3 of this chapter provides a summary of some of the key events identified in the MAU's monthly reports for the period May 2004 to October 2004.

With respect to high priced hours, there were no hours during the period May 1, 2004 to October 31, 2004 in which the HOEP was greater than $200/MWh. There was one hour during the review period in which the hourly uplift exceeded the HOEP. On July 31, 2004, delivery hour 24, the hourly uplift was $1,072.04 and the HOEP was $45.72. The reason for the hourly uplift exceeding the HOEP in this hour was entirely a result of IMO settlement procedures;[13] it was not a result of market factors and had no effect on the market.

[12] The $200/MWh price limit is chosen based on the fact that the highest cost of a fossil generation unit is typically no higher than $200. The lower $20 MWh limit is chosen based on the fact that this reflects a lower bound for the cost of a fossil unit.
[13] The IMO is sometimes required to make adjustments to a participant's settlement after their final settlement statement has been issued for the period for which the adjustment is required. These adjustments

With respect to low priced hours, there were 314 hours in the period May to October 2004 in which the HOEP was less than $20/MWh. Section 2 of this chapter reviews the factors typically driving the prices in these hours. Data on the state of the market during these low priced hours are provided in Table 2-9 in Appendix A.

In its review and analyses of high priced and low priced hours and other anomalous events, the MAU did not find any event which suggests that there was any exercise or abuse of market power by any market participant.

2. *Analysis of Low Priced Hours*

A 'low priced hour' is any hour in which the HOEP was less than $20/MWh. The number of low priced hours during the months of May to October since market opening is reported in Table 2-1 below.

Table 2-1: Hours with HOEP <$20, May-October, 2002-2004

	Hours with HOEP<$20		
Month/Year	**2002**	**2003**	**2004**
May	119	8	70
Jun	43	40	84
Jul	0	20	70
Aug	0	1	75
Sep	0	10	15
Oct	0	0	0

There have been a total of 314 hours in the period May to October 2004 for which the HOEP was less than $20. During the same months in 2003, there were 79 low priced

are uplifted to all market participants and are applied as an uplift to the final hour for that month. On July 31 in hour 24, only $1.58 per MWh is for uplift charges from that hour. The remaining amounts represent monthly charges debited to load for the total adjustment on the basis of total monthly consumption. The reason for this very high addition to uplift was the one-time correction for a significant metering error that hours. The increase in the number of low priced hours is largely attributable to the increase in base-load generating capacity in Ontario in 2004. More details on the supply-demand balance during the period May-October 2004 can be found in Chapter 1.

The MAU has found that, in general, a HOEP below $20 occurs in hours when at least one of the following occurs:

- Ontario demand is less than 15,000 MW. This typically occurs in the overnight hours, on holidays or during the spring/fall season.

- Base-load supply is augmented by the supply from a number of hydroelectric facilities that become 'run-of-river' facilities due to the abundance of water from the spring run-off. This occurs most frequently during the spring time months of April, May and June but it can occur at other times.

While these are the primary factors that contribute to a HOEP less than $20, demand forecast errors and failed export transactions can place additional downward pressure on the HOEP. This can occur as follows:

- An over-forecast of demand can result in higher imports into Ontario and lower exports out of Ontario than are warranted by the true (real-time) Ontario supply and demand situation. Once scheduled, these imports and exports cannot be dispatched off in real-time even though they may be more expensive than some Ontario generators. As a consequence, if real-time demand is less than forecast, the market clearing price falls as the most expensive Ontario generators are dispatched off to re-establish supply-demand balance. This causes the real-time HOEP to be lower than it would have been had the load forecast been correct. When real-time demand is low enough that it can be met by imports and base-load generation, the HOEP is set by base-load generators with offer prices below $20.

had lasted 21 months. More information of the settlement statement adjustment is found at http://www.theimo.com/imoweb/news/newsItem.asp?newsItemID=1194.

- An over-forecast of demand and thus of the real-time price for the hour incorrectly induces operators of fossil generating units to commit them by offering their minimum running levels at prices that will ensure that these units stay on-line. When the actual demand is lighter than forecast, these units stay on-line and base-load units are dispatched down to meet the lower than expected demand. These units set the price with an offer price below $20.

- When exports are scheduled in pre-dispatch, additional fossil generation facilities may be committed to remain on-line (through low offer prices at their minimum loading points) or additional imports may be scheduled in pre-dispatch to meet the export commitment. If large export transactions fail, there is suddenly an excess supply in the Ontario market. Imports scheduled in pre-dispatch cannot be dispatched off. Again, the market clearing price falls as Ontario generation is backed down to re-establish supply-demand balance. Given the failure of significant export transactions, Ontario base-load generation and pre-scheduled imports may be sufficient to satisfy demand. In this case the HOEP is set by base-load generation which is typically bid into the market at a relatively low price.

The case of the lowest HOEP for the May–October 2004 period is illustrative. It occurred on July 6, 2004 in delivery hour 6 and, at $5.25, was also the lowest HOEP since market opening. There were several factors influencing the HOEP in this hour. First, Ontario demand was relatively low, averaging 13,926 MW over the hour. When demand is this low, base-load generation may be sufficient to meet it.

Second, there were more than 400 MWh of failed exports between pre-dispatch and real-time.

A third factor influencing the HOEP in this hour was the large over-forecast of demand in pre-dispatch. As Table 2-2 below indicates, the forecast pre-dispatch demand in hour 6 was substantially higher than the actual Ontario demand. When there is an over-forecast of demand, the quantity of imports selected and scheduled in pre-dispatch is larger and the quantity of exports selected and scheduled is smaller than would have been the case had the forecast been more accurate. In addition, fossil generating units may be committed prematurely to the market.

The over-forecast of demand for hour 6 on July 6 resulted in a pre-dispatch price of $19, some $5 higher than the pre-dispatch price that would have prevailed if demand had been forecast correctly. The higher pre-dispatch price led, in turn, to the scheduling of approximately 500 MW more in imports than would have been scheduled had demand been forecast accurately. These excess imports cannot be dispatched off in real-time, even though they may be more expensive than some of the Ontario generators. Imports are placed at the bottom of the offer curve in real-time and if demand comes in lighter than forecast, as it did in this case, Ontario generators are dispatched off according to merit order with the offer of the marginal Ontario generator setting the MCP. In some cases, the price could end up being set by low offers from either Ontario base-load generation or Ontario fossil units priced to remain on-line.

Table 2-2: Summary of Demand-Supply Conditions on July 6, 2004, Hour 6

		Real-time	Pre-dispatch
Market Demand	**(MW)**	15,345	16,858
Ontario Demand	**(MW)**	13,926	15,133
Total Nuclear and Hydro*	**(MW)**	12,202	13,593
Fossil generation**	**(MW)**	2,225	2,445
Import	**(MW)**	1,008	1,008
Export	**(MW)**	1,419	1,825
Net Export	**(MW)**	411	817
Pre-dispatch Price	**($/MWh)**	N/A	19.00
HOEP	**($/MWh)**	5.25	N/A

*includes hydroelectric self-scheduler units.
**includes fossil self-scheduler units.

3. *Summary of MAU Monthly Reports on the Market*

The MAU provides the Panel with a monthly report that describes the salient features of market outcomes in that particular month. The monthly report includes explanations of anomalous events as well as other occurrences, the analysis of which is conducive to a better understanding of the operation of the market.

The following issues were analyzed by the MAU in reports to the Panel over the period May to October 2004:

- The change in the Quebec-Ontario intertie limit and its subsequent impact on the transmission rights market.
- The responsiveness of large industrial loads to a price spike.
- Convergence of real-time and pre-dispatch prices; convergence of constrained and unconstrained prices; the role of 12-times ramp rate in explaining the difference between constrained and unconstrained real-time prices.

3.1 The Change in the Quebec-Ontario Intertie Limit and its Subsequent Impact on the Transmission Rights Market

<u>Background</u>

In April 2004, the MAU noticed several hours in which the transmission path between Quebec and Ontario at the intertie designated ON-QH4Z was export congested. Prior to this period, export congestion on the tie was a rare occurrence – there were only 15 hours for the period May 2002 to December 2003 in which the tie was congested. In the month of April 2004, there were 150 hours in which the intertie was congested. The months in which there was congestion on this intertie are presented in Table 2-3.

Investigation by the MAU revealed that the increase in the number of hours with congestion was the result of a change in the manner in which the IMO calculated transmission limits on the interties. The previous procedure had been to set the transmission limit equal to the flow capacity of the interface. The flow capacity of the

ON-QH4Z intertie was 110 MW. Under the new procedure, the intertie limit was based on the lower of the flow capacity of the interface or an external limit that limited the flow on the interface, in this case, transmission limits within the province of Quebec.[14] Since it was external limits in Quebec that were binding, the new intertie limit was set in the range of 25 MW to 35 MW rather than the 110 MW flow capacity of the interface which was the previous limit.

Table 2-3: Hours with Export Congestion on ON-QH4Z Intertie

Month*	Hours with Congestion	Average ICP $
Nov 2002	14	1.99
Sep 2003	1	0.03
Jan 2004	1	0.02
Feb 2004	10	0.14
Mar 2004	14	0.23
Apr 2004	150	4.05
May 2004	136	7.97
Jun 2004	62	8.12
Jul 2004	37	0.31
Aug 2004	2	0.66

*There was no congestion on this tie in the months that are not reported here.

The IMO's reason for changing its method of calculating intertie limits was to reduce the number of export transaction failures. To see how this was intended to work, consider the following example. Suppose the IMO uses an export limit of 110 MW (the flow capacity of the intertie) for the interface ON-QH4Z. There is then the potential that up to 110 MW of exports could be scheduled in pre-dispatch from Ontario to Quebec on the interface. However, the actual external limit (which is generally known by the IMO at the time of scheduling) may be only 35 MW. In real-time, exports scheduled in pre-

[14] The procedure establishes that "restrictions caused by transmission systems external to Ontario may also be included in the scheduling limits if these are expected to limit the IMO market's imports or exports that would otherwise clear the market." The external limit set by Hydro-Quebec Transmission is a function of how much incremental load, that is not being satisfied by local HQ generation in the Temiskaming area, can be switched over to Ontario.

dispatch in excess of 35 MW would fail as they would be unable to navigate the Quebec grid.

The change in procedure to reflect the lower external limit when it is binding was intended to improve system reliability and reduce control room workload. The change in procedure would likely have improved reliability when the Ontario market was in tight supply and import failures increased the risk of potential real-time supply shortages. It would have prevented imports destined to fail for external security reasons from being scheduled in pre-dispatch. The DSO would then be able to select imports on other interties (or reduce exports) to avoid the real-time supply shortages. This would also have reduced the workload of the control room, particularly at times when supply was strained, since it would not have to look for additional sources of supply to replace the failed imports.

While it could potentially have increased reliability and reduced control room workload, the reduction in the intertie limit on interface ON-QH4Z also created a potential problem for the transmission rights (TR) market.[15] This problem arose because the new, lower intertie limits were consistently and significantly lower than the number of transmission rights sold. For example, in the month of April, 110 MW of transmission rights were sold to participants with one participant holding as much as 57 MW in transmission rights. The typical limit on the interface in this month was 35 MW.

The large difference between the intertie limit and the number of transmission rights sold created the potential for the IMO to run a deficit in its funding of the transmission rights market. When export congestion occurs, the price paid by exporters and the price paid by Ontario consumers diverges. The amount by which the two prices diverge is equal to the difference between the bid price of the last export bid accepted on the intertie and the Ontario hour ahead pre-dispatch price. For example, if the highest bid price of the last MW of export scheduled on the congested interface is $500 while the Ontario hour ahead

[15] A transmission right in the IMO market is a financial product that can help mitigate the price risk associated with congestion on the intertie. TRs are sold in one MW amounts for a particular intertie in a specific hour.

pre-dispatch price is $100, the IMO computes an intertie congestion price (ICP) equal to $400.[16] Exporters on this interface pay the real-time Ontario price plus the ICP for their exports while Ontario generators supplying these exports are only paid the real-time Ontario price. The difference between the amount the IMO receives from exports and the amount paid to generators (on behalf of loads) represents export congestion rent.

At the same time, when congestion occurs, holders of transmission rights on the interface receive a payment equal to the ICP times the number of TRs that they own. In principle, the IMO funds the payments to the TR holders with the money that it receives in the form of the congestion rent. The IMO also receives a payment for the initial sale of the TRs, which are auctioned for each interface periodically through the year. This money is also available to fund the transmission rights payments.

When the quantity of transmission rights sold exceeds the quantity of exports scheduled, the money raised as congestion rent is less than the IMO's payment obligation to the TR holders. When this is persistently the case, there is an increased possibility that the IMO's TR payments will exceed the amount it receives from congestion rent and the TR auction. Ontario loads ultimately make up the difference through the uplift.[17]

Continuing with the example, if 110 MW in TRs were sold but the external limit were such that only 35 MW of exports could be scheduled, the IMO would pay out $400 x 110 MW=$44,000 to transmission rights holders. At the same time, it would only receive $400 x 35 MW=$14,000 of congestion rents from exporters. In this hour, congestion would result in a deficit of $30,000 to the IMO's transmission rights account.

Table 2-4 provides an update on the different payment streams for the ON-QH4Z intertie. The second column presents the amount of TR payments made in each month since market opening during which there was congestion. Column 3 of Table 2-4 shows the

[16] The difference between the Ontario MCP and the intertie zone MCP is known as the Intertie Congestion Price (ICP).
[17] Although Table 2-4 shows a deficit on this particular intertie, there is no overall deficit across the interties involved in this market. To date there has been no effect on uplift.

amount of congestion rents received by the IMO in each month since market opening. Column 4 shows the revenues from the auction of TRs for the ON-QH4Z tie. At the bottom of the table, the monthly payments are totalled. As Table 2-4 indicates, the difference between the rents accruing to the IMO and the payments made to TR holders is negative with the deficiency growing considerably between January 2004 and June 2004.

Table 2-4: Adjustment to Transmission Rights Account for* ON-QH4Z, *since Market Opening

Month	Estimated TR Payout	Estimated Congestion Rent	Auction Revenues	Total TRs Held	Average TR Payment (per 1 TR)
Nov 2002	$802,149	$114,902	$2,424	110	$7,292
Sep 2003	$1,900	$0	$1,340	95	$20
Jan 2004	$1,650	$525	$2,618	110	$15
Feb 2004	$10,481	$6,690	$2,653	110	$95
Mar 2004	$18,835	$14,113	$2,198	110	$171
Apr 2004	$320,536	$215,823	$2,511	110	$2,914
May 2004	$563,447	$204,125	$2,061	95	$5,931
Jun 2004	$555,413	$98,830	$2,061	95	$5,846
Jul 2004	$21,832	$13,318	$10,602	95	$223
Aug 2004	$4,650	$3,067	$10,602	95	$49
Total	$2,300,893	$671,393	$39,070		

The reduction in the intertie limit also increased the incentive for market participants to congest the intertie so as to enhance their TR payouts. In particular, at least one market participant (based on IMO auction sales) owned more TRs than the limit on the ON-QH4Z tie. If the intertie is congested and the number of TRs sold exceeds the intertie limit, the IMO pays out more to TR holders than it receives in congestion rents.

The possibility that a market participant might be able to congest the tie and receive more for TRs than it pays in congestion rents should be reflected in the price market participants are willing to pay for TRs. This has clearly been the case. On May 11th and May 14th, the IMO sold in two auctions additional (one year) TRs on ON-QH4Z. The sale price for these TRs were $650 per MW and $5,702 per MW respectively. Prior to the first auction held on May 11th, the average price paid for TRs on this path was only $153.

Panel's Recommendations

The MAU advised the Panel of this matter in the middle of June 2004. The Panel's general view was that the purpose of the TR market can best be served if the quantity of TRs offered for sale is equal to the intertie limit. The Panel observed that this could most readily be achieved by returning to the practice of setting the intertie limit at its flow capacity and it recommended that the IMO do so. The Panel further noted that the large TR payments were really 'unintended consequences' due to the change in the intertie limit. The Panel was satisfied that there was no infringement of the Market Rules by the market participant's activities in the TR market. The Panel has asked the MAU to continue to monitor congestion rents and TR auction revenue received by the IMO and payments by the IMO to TR holders.

Response of the IMO

In July 2004, the IMO returned to its former practice of setting intertie limits according to the flow capacity of the tie.

3.2 Potential Demand Responsiveness of Industrial Loads and the Importance of Price Signals

Background

On June 7, 2004, from 11:00 to 12:00, an outage to the IOMS (Integrated Outage Management System) was taken to implement RFC-2410.

An RFC is a 'request for change'. In this instance the request for change was related to a NERC requirement which stipulated that outages and derates have to be updated in the System Data Exchange (SDX) database every hour. To implement this change, the IMO's information technology group had to devise a fix that allowed the IOMS outages and derates to be transferred automatically to the SDX database. Because of the large amount of data that IOMS transfers to the SDX, the IT group also decided to improve the efficiency of the data transfer process by the IOMS. To do so, the IT group implemented a more efficient transfer process between the IOMS and the OS (Outage Scheduler) program. This program is used by the DSO in the optimization algorithm.

Shortly after the implementation of the RFC, a defect related to data content was detected with the new transfer process. Under normal operations, data on derates and outages from the Outage Scheduler program are used by the DSO in the optimization procedure. For example, if a derate of 10 MW is entered for a 100 MW unit, the DSO interprets this as a constraint on the unit, meaning the unit can only produce 90 MW. The defect in the RFC implementation made the OS program return a null value for units that were derated. The DSO interprets the 'null' to mean that the unit is not available. For example, a 100 MW unit with a 10 MW derate is interpreted as a unit on outage with zero output. The DSO solves assuming that the unit's output is zero. In reality the unit's output is 90 MW. On June 7, many units that were previously derated ended up as units on outages in the Outage Scheduler. Consequently the DSO solved indicating severe supply shortages. Hence prices hit $2,000.

The IMO can administer prices when:

- it determines that a published energy market price or operating reserve market price is incorrect due to incorrect inputs which affected the outcome of the dispatch algorithm, and
- the impact satisfies the criteria approved by the IMO Board relating to price error materiality and acceptable causal events (Market Rules, Chapter 7, Section 8.4.2 and 8.4.3).

Due to the market tool problem described above, the IMO administered prices for a period of 9 intervals starting in hour 12 interval 12 to hour 13 interval 8 (inclusive). Table 2-5 below shows the actual MCP and the administered MCP for the relevant intervals.[18]

[18] Note that the IMO also administered prices in hour 14 interval 2 to hour 15 interval 9 (inclusive). Prices in these intervals were administered because the real-time unconstrained sequence failed; this DSO sequence failure does not appear to be related to the IOMS incident.

Table 2-5: IMO Administered Prices, June 7, 2004, Hours 12 & 13

Hour	Interval	MCP Price	Administered Price
12	**12**	$178	$82.60
13	**1**	$2,000	$82.60
13	**2**	$2,000	$82.60
13	**3**	$2,000	$82.60
13	**4**	$2,000	$82.60
13	**5**	$280	$82.60
13	**6**	$138	$82.60
13	**7**	$132	$82.60
13	**8**	$85	$82.60

The price shocks in intervals 1, 2, 3, and 4 occurred in real time. These shocks thus provide an opportunity to gauge the responsiveness of Ontario industrial loads to a severe price spike. In an earlier analysis of price sensitivity, the MAU found that large industrial loads cut their consumption by as much as 200-300 MW in some high priced hours during the summer of 2002.[19]

Demand Response - Industrial Loads in Ontario

Potentially price responsive load that the IMO can monitor comprises about 95 market participants - large industrial loads that are directly connected to the IMO-controlled grid. They represent 15 percent of the total load in Ontario.

Table 2-6 below reports the consumption of electricity by the top 90 of the monitored loads during the intervals when prices were administered. Here the reported prices are actual, non-administered prices. For four intervals (1 to 4), prices shot up to $2,000/MWh. Over these four intervals the top 90 monitored loads reduced their consumption by 242 MW with the largest cut in consumption (158 MW) occurring between intervals 3 and 4. The reduction in consumption by the top 90 loads in hour 13 was 295 MW.

[19] March 24, 2003 MSP Report, Chapter 3, section 3, page 96.

Table 2-6: Consumption by IMO-Monitored Loads in Hour 13, June 7, 2004

Hour	Interval	MW	Price
12	12	2,734	$178.00
13	1	2,749	$2,000.00
13	2	2,716	$2,000.00
13	3	2,665	$2,000.00
13	4	2,507	$2,000.00
13	5	2,496	$279.00
13	6	2,510	$138.00
13	7	2,517	$132.00
13	8	2,475	$85.00
13	9	2,493	$62.00
13	10	2,562	$62.40
13	11	2,597	$61.40
13	12	2,605	$60.33

Between interval 3 and 4, there were three loads that showed most sensitivity to the price shock. Together their cut in consumption (147 MW) accounted for 94 per cent of the total drop in electricity consumption (158 MW) in interval 4.

It is apparent that the consumption of the top 90 monitored loads fell during the period of the price spike and after. Whether this decline in consumption was in response to the price spike or whether the behaviour of the large loads during hour 13 implies price responsiveness is another matter. Some part of this reduction in consumption might have been coincidental.

A simple way of determining whether the observed reduction in demand by the loads would have occurred in any event is to conduct some form of 'but-for' analysis. For example, the behaviour of the loads might be compared with the behaviour of smaller non-dispatchable loads that pay a fixed price. Unfortunately non-dispatchable load cannot be used as a benchmark in this hour because the tool outage prevented the system from capturing the demand data.

An alternative form of but-for analysis is to compare the percentage change in consumption of the top 90 monitored loads over the first four intervals of hour 13 on (Monday) June 7 with the behaviour of these same loads over the same intervals on the previous twenty Mondays. This comparison reveals that consumption fell by 8.3 percent over intervals 1 to 4 in hour 13 on Monday June 7 versus an average of 0.6 percent over intervals 1 to 4 on the preceding twenty Mondays. The clear implication of this comparison is that the 8.3 percent reduction in consumption by these loads between intervals 1 and 4 in hour 13 on June 7 was not a matter of chance.

It is reasonable to conclude that the monitored loads cut consumption by roughly 8 percent during the four intervals in which the MCP spiked from $178 to $2,000. The implied elasticity of demand is obviously not very high but this is not unexpected in the case of a price spike. Moreover, small demand responses can have significant price effects when supply is tight. The important point to note is the effect this reduction in consumption might have had on the market price.

Panel's Response

The Panel reiterates its view of the fundamental importance of price incentives in the efficient operation of the market. The Panel continues to emphasize the critical importance of reducing distortions in the economic signals that prices transmit to market participants. To this end, the Panel has asked the MAU to continue its analysis of the extent and nature of the price responsiveness of large loads.

The Panel believes that price signals will play an even more important role in the market in light of two important initiatives that have been planned for the Ontario electricity market, namely:

1) the Government of Ontario's effort to promote demand-side management initiatives;
2) the creation of a Day Ahead Market with the expectation that it will provide advance price signals which will permit better energy demand management.

3.3 Price Convergence and Price Gaps

The Panel has consistently stressed the importance of the pre-dispatch price as a market signal of supply-demand conditions in real time. Market participants react to this signal and their reactions increase the effectiveness of competition and the efficiency of the market. When the price in real time consistently diverges from the pre-dispatch price, the signalling role of the pre-dispatch price is weakened. In previous reports the Panel has focussed on the gap between pre-dispatch prices and the HOEP and, in particular, on aspects related to the operation of the market that appear to contribute to this gap. Section 11 of Chapter 1 reported that the gap has been diminishing and examined the recent behaviour of some of the factors accounting for this. This section examines the gap between constrained and unconstrained prices. It also provides an estimate of the relative importance of the 12-times ramp rate assumption in the continuing gap between the one-hour pre-dispatch unconstrained price and the HOEP.

Although it has had less attention, the gap between constrained and unconstrained prices is important. As will be explained below, the constrained price reflects the true supply conditions in the Ontario market while the unconstrained price is influenced downward by a number of fictitious additions to supply (including bottled energy and overstated ramping rates). As a consequence, the unconstrained price tends to be below the constrained price. A price that is consistently lower than the price that would reflect the true supply conditions in the Ontario market can lead to under-investments in transmission, generation and conservation.

One reason why there has been limited analysis of the difference between the unconstrained and a constrained price is that there is no single constrained price. There are many constrained prices corresponding to shadow prices at different locations or nodes in Ontario. An innovation in the analysis reported below is to treat the nodal price at the Richview Transformer Station in the Greater Toronto Area as the representative constrained price, the single price that most accurately reflects the true supply conditions in Ontario at any point in time.

3.3.1 The Richview Reference Price

The DSO is capable of providing two sets of prices – a uniform Ontario market price from the unconstrained run (the HOEP, which is the hourly average of the MCP's) and a set of nodal prices from the constrained run. Nodal prices represent the cost of serving an extra MWh of load at a particular node or location on the IMO-controlled grid. The nodal price includes the cost of energy at a reference bus, the cost of losses incurred in moving the energy from the reference bus to the node in question and the cost of additional congestion incurred on transmission between the reference bus and the node in question.

Since nodal prices are generated from the constrained model, they reflect the cost of supply taking into consideration both the physical limitations of the IMO-controlled grid and the intertie constraints. The unconstrained model generates uniform market prices assuming there are no constraints on the IMO-controlled grid. The unconstrained model overstates the supply stack for example by assuming that generators can ramp up twelve times faster than they actually can. It also assumes that energy and operating reserve capacity in the northwest is available in its entirety when in fact, some of it is bottled in due to transmission limitations. The result is that constrained nodal prices for most of Ontario exceed the uniform market price.

Richview is the reference bus, located on the 230 kV system near Toronto. Richview was chosen as the reference bus because it is located near the major load centre in Ontario and it is well connected to most parts of the province. The loss factors and flow factors in the DSO are based on Richview as the reference bus.[20] The nodal price at the Richview bus is representative of prices over a large area and a load-weighted average of nodal prices around the province would not differ markedly from the nodal price at Richview (under most conditions).

[20] It is not essential that Richview be the reference bus. However, the reference bus must be consistent between the DSO and IMO's other transmission and security assessment tools that employ a similar

In essence, the nodal price at the Richview bus is a more accurate indicator of supply and demand conditions in the Ontario market than the unconstrained, uniform market price. Supply and demand decisions are, however, based on the unconstrained price. To the extent that the unconstrained price differs from the constrained nodal prices, these decisions are inefficient.

The purpose of comparing the constrained and unconstrained prices is to determine how much they have differed since market opening, whether that difference has narrowed and what aspects of market design are causing any remaining difference. The chart in Appendix C provides a time line showing the major changes in Market Rules or design that have occurred since market opening.

The analysis that follows assumes that the nodal price at the Richview bus reflects the information contained in the 'constrained' price and compares this constrained price with the uniform unconstrained market clearing price. The analysis then quantifies the contribution of the artificially high ramp rate used in the unconstrained model to the magnitude of the persistent price gap between the constrained and the unconstrained prices.

3.3.2 Comparing Pre-dispatch and Real-time Prices

The price comparison makes use of the following four price series: (1) the real-time uniform price (the HOEP); (2) the pre-dispatch uniform price; (3) the real-time constrained (Richview nodal) price and; (4) the pre-dispatch constrained (Richview nodal) price.

The first price comparisons are: (1) between the pre-dispatch and real-time uniform (unconstrained) prices and; (2) between the pre-dispatch and real-time constrained (Richview) prices. These two comparisons are illustrated in Figure 2-1. The dotted line

concept. However, the choice of a different reference bus would require different loss factors and flow in Figure 2-1 is the ratio of the one-hour Ontario pre-dispatch price to the real-time uniform Ontario price (the HOEP). This essentially tracks the difference in unconstrained prices. The thick black line is the ratio of the hour ahead pre-dispatch constrained price to the real-time constrained price at the Richview node. This traces the difference in constrained prices over time. Average percentage differences between pre-dispatch and real-time unconstrained prices and between pre-dispatch and real-time constrained prices on a quarterly basis are reported in Table 2-7.

Among the conclusions that examination of Figure 2-1 and Table 2-7 yields are first, that the difference between pre-dispatch and real-time unconstrained prices exceeds the difference between pre-dispatch and real-time constrained prices. Second, the difference between pre-dispatch and real-time prices, whether constrained or unconstrained, has narrowed over time.[21] Third, while the difference between unconstrained pre-dispatch and real-time prices has narrowed, a significant difference remains.

One implication of this price comparison is that the pre-dispatch constrained price is a better forecast of the real-time constrained price than the pre-dispatch unconstrained price is of the HOEP. A second implication is that both the pre-dispatch prices are better forecasts of their real-time counterparts than they used to be.

factors, and should still lead to the same nodal prices.

[21] Statistical (unit root) tests showed convergence between real-time and pre-dispatch constrained prices and between real-time and pre-dispatch unconstrained prices (see Appendix B).

Figure 2-1: Trends in Price Differences:
Ratio of Pre-dispatch Prices to Real-time Prices

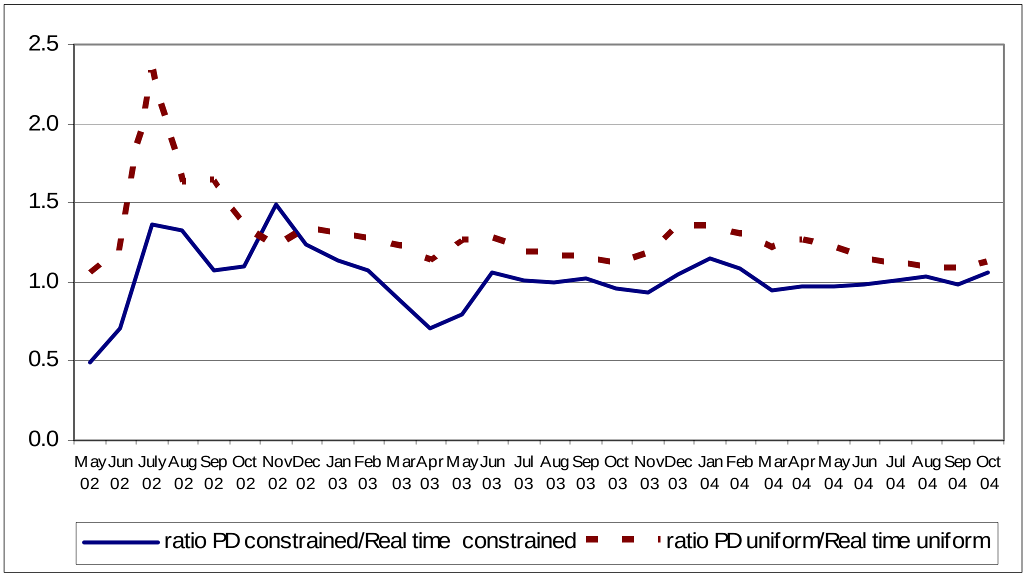


Table 2-7: Percentage Price Differences: Pre-dispatch to Real-time (%)

		Constrained*	**Unconstrained****
2002	**Q2†**	(67.4)	12.0
	Q3	19.3	45.6
	Q4	20.8	23.7
2003	**Q1**	1.1	20.9
	Q2	(21.3)	17.4
	Q3	0.8	14.4
	Q4	(1.9)	17.5
2004	**Q1**	6.8	22.8
	Q2	(2.6)	17.1
	Q3	0.7	9.3

*Constrained refers to pre-dispatch constrained price minus the real-time constrained price expressed as a percent of the pre-dispatch constrained price.
**Unconstrained refers to pre-dispatch unconstrained price minus the real-time unconstrained price expressed as a percent of the pre-dispatch unconstrained price.
† May and June 2002 only.

3.3.3 Comparing Constrained and Unconstrained Prices

The second price comparisons are: (1) between constrained and unconstrained prices in pre-dispatch and; (2) between constrained and unconstrained prices in real-time. These comparisons are illustrated in Figure 2-2. The figure shows that the difference between the constrained price and the unconstrained price is larger in real-time than in pre-dispatch and that the difference between the constrained and the unconstrained price has narrowed over time in both real-time and pre-dispatch. Table 2-8 indicates the magnitudes of the differences in the constrained and unconstrained prices and how they have changed over time. The conclusion that the difference between constrained and unconstrained prices has narrowed over time in both pre-dispatch and real-time is confirmed by a statistical (unit root) test for convergence (see Appendix B).

As stated above, the constrained price is a truer signal of the supply reality in the Ontario market at a given time than is the unconstrained price. The narrowing of the gap between constrained and unconstrained prices implies that the unconstrained price on which market participants rely in their long-term decision-making is becoming a less misleading indicator of the true supply-demand balance than it has been in the past. Since it is pre-dispatch prices upon which generators and dispatchable and other large loads must base their short-term decisions, the finding that the gap between the constrained and unconstrained prices is small in pre-dispatch implies that the signal on which they are relying is a reasonable reflection of true supply and demand conditions as they are known at the time.

Figure 2-2: Trends in Price Differences:
Ratio of Constrained Prices to Uniform Prices

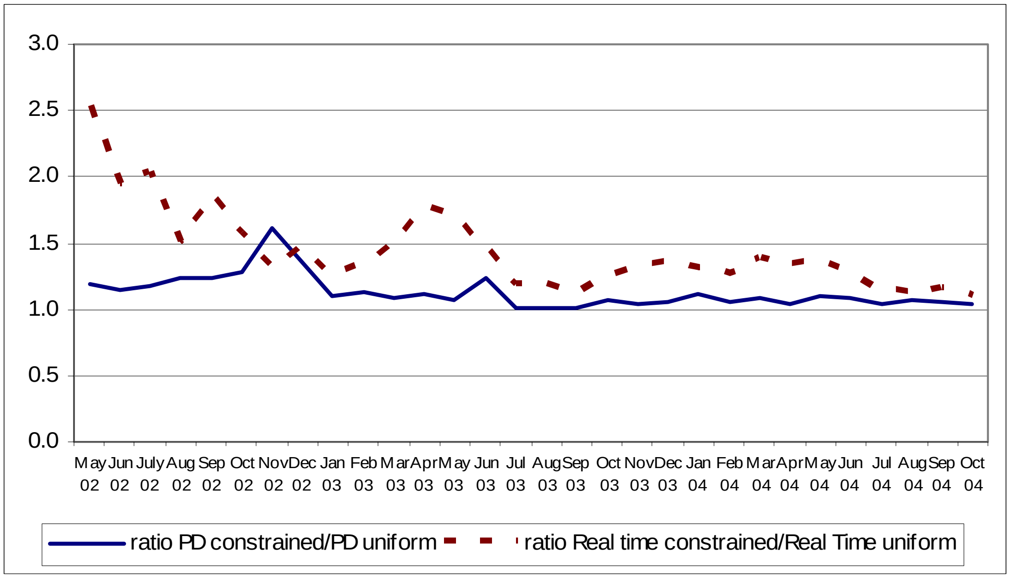


Table 2-8: Percentage Price Differences:
Richview Price to Uniform Price

		Pre-dispatch*	Real-time**
2002	Q2†	14.1	54.9
	Q3	17.7	44.6
	Q4	28.8	31.4
2003	Q1	9.5	27.7
	Q2	12.1	40.1
	Q3	1.1	14.6
	Q4	5.4	23.2
2004	Q1	8.4	24.2
	Q2	6.8	24.7
	Q3	4.9	13

*Pre-dispatch refers to the pre-dispatch constrained price minus the pre-dispatch uniform price expressed as a percent of the pre-dispatch constrained price.
**Real-time refers to the real time constrained price minus the real time unconstrained price expressed as a percent of the real time constrained price.
† May and June 2002 only.

These findings raise a number of questions for further analysis. A question addressed in the next section is how the assumption of 12-times ramp rate in the real-time unconstrained schedule contributes to the persistent price gap between the real-time constrained price and the real-time unconstrained price.

3.3.4 Use of 12-times Ramp Rate in the Real-Time Unconstrained Model

The real-time constrained schedule is based on actual ramp rates of market participants while the real-time unconstrained schedule assumes generators can ramp up their production 12-times faster than their true capability. Thus, the unconstrained schedule effectively assumes that supply is available when it is not. This, in turn, reduces the real-time unconstrained price (the HOEP) relative to the constrained (Richview nodal) price during periods in which load is increasing. For fifteen days in May and June 2004, the IMO conducted dispatch tests for Multi-Interval Optimization in a 'sand-box' environment.[22] During the tests, prices in the real-time unconstrained schedule were calculated using the actual ramp rates of generators as well as the usual assumption that ramp rates are 12-times their true value. This means that the test generated a market clearing price that reflected the actual ramp rates of Ontario generating facilities. During the fifteen days on which the test was run, the average sandbox HOEP was $50.49 under the assumption that the ramp rate was 12-times the true ramp rate while the average sandbox HOEP was $58.47 on the assumption that the ramp rate was equal to its true value. Thus the average sandbox HOEP was about $8 higher when ramp rates are set at their true values.

Since the price difference is higher during the peak hours, the difference between the weighted average HOEP for those fifteen days should be greater. The weighted average sandbox HOEP was $53.38 assuming 12-times ramp rate while the weighted average sandbox HOEP was $61.93 when ramp rates are set at their actual values, a difference of $8.55.

The results of these tests clearly indicate that the assumption that ramp rates are 12-times their true value has the effect of reducing the HOEP (the real-time, unconstrained price)

[22] The 'sand-box' is a generic term that describes a real-time experimental set up that captures the behaviour of all the key variables as they evolve in real-time.

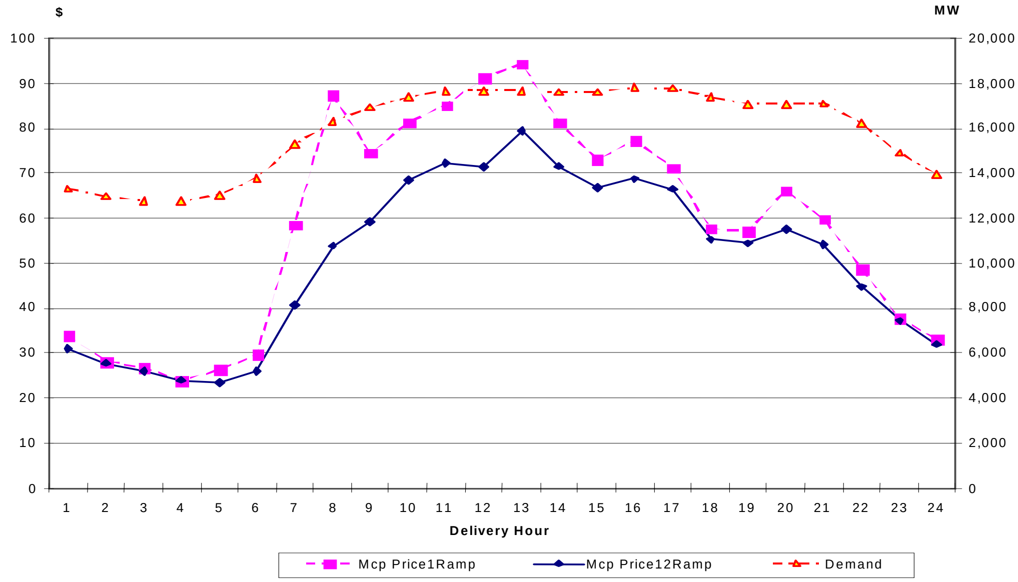
significantly, relative to what it would be if actual ramp rates were used. Since the constrained real-time (Richview nodal) price is based on actual ramp rates, a significant portion of observed differences between the two must be due to differing assumptions regarding ramp rates.

Figure 2-3 illustrates the daily pattern of the HOEP assuming actual ramp rates and 12-times actual ramp rates respectively. The daily load profile is also shown in Figure 2-3.

The figure shows that assuming a ramp rate that is 12-times faster than the actual ramp rate results in a HOEP that understates the true price when load is picking up sharply. It also shows that assuming a ramp rate that is 12-times faster than the actual ramp rate slows the decline in the true price when load drops sharply. That is, assuming generators can ramp down faster than they actually can is equivalent to assuming that supply can be withdrawn faster than it really can and this slows the decline in the HOEP during periods of decreasing load.

Assuming a ramp rate is 12-times faster than the actual ramp rate also results in a less volatile HOEP. This is an obvious consequence of understating the true price during periods of increasing load and overstating it during periods of declining load. Some see virtue in the HOEP-stabilizing effect of the 12-times ramp rate assumption. As the discussion below indicates, the Panel takes a different point of view.

Figure 2-3: 12-times Ramp Rate vs. 1-times Ramp Rate



Panel's Response

The overriding concern of the Panel is with the efficient operation of the IMO-administered markets. A market cannot operate efficiently if price signals to market participants are distorted. In the present context, efficient operation of the market requires that pre-dispatch prices be as accurate a signal as possible of real-time supply and demand conditions.

The Panel has discussed the issue of the price gap between pre-dispatch and real-time prices extensively in its earlier reports. The Panel has advocated and will continue to advocate reforms in Market Rules and procedures that close this gap. The Panel is encouraged that some portion of CAOR (Control Action Operating Reserve) is now priced into the market. The Panel continues to advocate the pricing of additional CAOR into the market on the basis that more accurate price signals allow more efficient use of resources by generators and more effective responses by loads. The Panel also continues to advocate the replacement of the uniform Ontario price with locational marginal pricing (LMP) on the grounds that LMP reflects true supply and demand conditions that vary, due to transmission constraints, throughout Ontario.

The real-time unconstrained price (the HOEP) is the only price that is determined under the assumption that ramp rates are 12-times their actual value. The real-time constrained price and both the constrained and unconstrained pre-dispatch prices are based on actual ramp rates[23]. The analysis above demonstrates that a significant portion of the difference between the constrained and unconstrained real-time prices is due to the 12-times ramp rate assumption. It follows that a significant portion of the remaining difference between the HOEP and the (unconstrained) pre-dispatch price must also be due to the 12-times ramp rate assumption.

The Panel is of the view that the continued understatement of the HOEP leads to inefficient decisions by both loads and generators in both the short-term and the long-term. This takes the form of an inefficient load profile and of under-investment in both conservation and generation.

With respect to the argument that the assumption that ramp rates are 12-times their true value results in a more stable HOEP, the Panel recognizes that price stability can be beneficial to market participants. The Panel observes, however, that it is open to market participants to insulate themselves contractually from price variation. Moreover, price volatility presents a profit opportunity for more price responsive generation and loads. To the extent that it is efficient to do so, volatility can be reduced by the actions of market participants. This is much better, in the Panel's view, than suppressing price variation by artificial means, especially when this has the side effect of understating the average price. The Panel strongly recommends that actual ramp rates be used to determine the HOEP. The Panel understands that this is being considered by the IMO Pricing Working Group but that little progress has been made. The Panel observes in this connection that while stakeholder consultation is important, no stakeholder should have an effective veto over changes in Market Rules that make the market more efficient.

[23] The pre-dispatch schedule assumes that 12-times the 5-minute ramp rate is achievable over the course of the hour. This is true when generators ramp evenly over the entire hour.

Appendix A: Summary Data on Low Priced Hours

*Table 2-9: Summary Data on Hours Less than $20/MWh**

	May 04	Jun 04	Jul 04	Aug 04	Sep 04	Oct 04
Total Hours	**70**	**84**	**70**	**75**	**15**	**0**
Average Demand (MW)	12,678	12,976	13,501	13,228	13,028	N/A
Total Nuclear and Hydro (MW)	12,879	12,515	12,949	12,784	11,986	N/A
Fossil Generation (MW)**	1,340	1,378	1,483	1,565	979	N/A
Self-scheduler over-production (MW)	(4)	0	40	34	34	N/A
Difference Between Pre-dispatch and Avg Real-time Demand (MW)	262	289	320	217	259	N/A
Imports (MW)	470	894	949	1,044	1,345	N/A
Exports (MW)	1,762	1,584	1,703	1,915	963	N/A
Net Failed Exports (MW)	168	181	136	121	232	N/A
Pre-dispatch Price ($/MWh)	23.19	26.76	25.49	26.23	29.29	N/A
HOEP ($/MWh)	14.61	14.61	14.63	14.73	14.74	N/A

*Reading the table: The table shows the total number of hours where HOEP was less than $20 in a given month. The values expressed represent averages for the hours in which the HOEP was less than $20/MWh. For example in May 2004, there were 70 such hours. Average demand in those hours was 12,678 MW. Average pre-dispatch price was $23.19 and average failed exports were 168 MW.

**All fossil units including self-schedulers.

Appendix B: Details on the Convergence Method

Definition of Price Convergence

Let

P_t^R *be the real – time electricity price at time t*

P_t^D *be the hour – ahead electricity price at time t*

Convergence in prices occur if the long-term forecasts of prices for hour-ahead and real-time prices are equal at a fixed time t,[24]

[1]

$$\lim_{k \Rightarrow \infty} E(P_{t+k}^R - P_{t+k}^D \,|\, I_t) = 0$$

I_t is the information set at time t

For our purpose we examine the time series properties of the hour-ahead prices and real-time prices to derive a convergence test.

In particular we examine the price difference between hour-ahead and real-time prices i.e.

[2]

$$P_t^R - P_t^D = \delta + \varepsilon_t$$

If [2] contains either a non-zero mean or a unit root, then definition [1] of convergence is violated. This would imply that the price differences do not converge to zero in expected value as the forecast horizon is extended.

[24] This applies to any two set of prices.

Implementation of the Test for Convergence

We conduct Augmented Dickey-Fuller (ADF) unit root tests on the price difference series for each hour of the day.

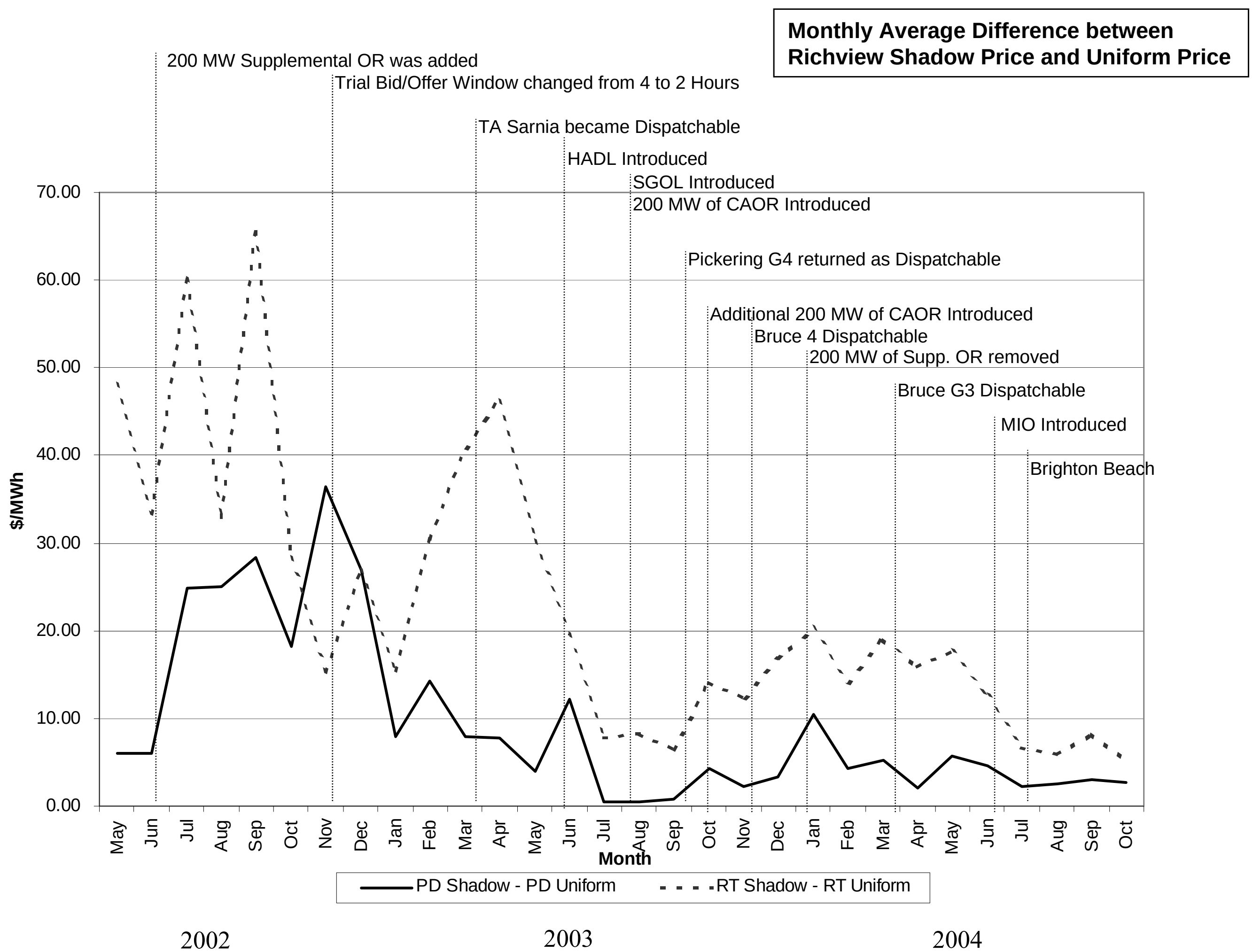
For a particular series Y the test runs the following regression,

$$\Delta Y_t = \delta_0 + \delta_1 Y_{t-1} + \theta t + \sum_{i=2}^{q} \delta_i \Delta Y_{t-(i-1)} + U_t$$

U is an error term with mean zero and constant variance

The null hypothesis of no convergence is $\delta_1 = 0$ against the alternative of $\delta_1 < 0$. The lag q is selected via the Schwarz Information Criterion. ADF test statistics as well as Mackinnon p-values are used to evaluate the null hypothesis. Detailed test results are available upon request from the MAU.

Appendix C: Timeline of Major Changes to Market Rules or Design
May 2002-October 2004



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

1. *Introduction*

This chapter reports on changes to the operation of the market since our last report. It is divided into two separate sections. Section 2 reports what has been done in response to outstanding Panel recommendations for change, while section 3 highlights and assesses changes to the market that have not resulted from Panel observations or recommendations but that we feel are important.

In previous reports the Panel has consistently emphasized the importance of accurate and transparent price signals for the efficient and reliable functioning of the market and we have pointed out the way in which the implementation of out-of-market control actions can distort price signals. While the IMO has made some progress in introducing out-of-market control actions into the market, we urged that they go further in our last report. No action on this recommendation has been taken to date. Section 2.1 below presents an analysis of what market prices would have been had the IMO avoided the manual implementation of control actions over the period from January-October 2004. The Panel has also highlighted the persistent tendency of the pre-dispatch price to overstate real-time outcomes, and in our last report we recommended that the IMO reconsider the way in which it forecasts peak demand in hours 22-24. The IMO has worked with the MAU to implement a more effective forecasting process and this is reported in section 2.2.

On June 23, 2004, the IMO moved away from myopic dispatch and introduced inter-temporal optimization. Section 3 presents a preliminary evaluation of the performance of Multi-Interval Optimization against its intended objectives.

2. *Status of Matters Identified in Previous Reports*

2.1 The Impacts of Out-of-Market Control Actions

In our June report, we discussed the impact on market signals and market efficiency from the use of certain out-of-market control actions.[25] There were two types of control actions that raised our specific concern: (i) the carrying of out-of-market sources as operating reserve, and (ii) the purchase of emergency energy from neighbouring control areas. Our general observations and conclusions regarding the implementation of these control actions were as follows.

(i) They are only implemented when there is a shortage (actual or potential) in the constrained schedule. A shortage occurs when there are insufficient available market-based offers to satisfy both the energy demand and operating reserve requirements.

(ii) When these control actions are implemented, they generally lead to a reduction in the market clearing price; even though the shortage conditions persist or at times worsen. In this regard, the control actions frustrate the ability of the market price to signal the relative shortage. The distorted price signal can preclude potentially efficient responses to the shortage such as load curtailment or (in subsequent hours if the shortage were to persist) and the starting of generation. In addition, if the behaviour is recurrent, it changes importer/exporter expectations.

(iii) In the case of the manual implementation of out-of-market sources as operating reserve, no improvement in the reliability of the grid is achieved. In fact, we noted examples of how manual implementation of out-of-market reserve could actually perpetuate or exaggerate reliability problems.

Since the publication of our last report, the IMO has not made any changes to the way it implements these control actions, although the frequency with which these control

[25] This was discussed within the reporting of the events of January 15, 2004 in the June 14, 2004 MSP Report, Chapter 2, section 3.1, at page 43.

actions have been implemented has declined in response to both the introduction of multi-interval optimization and a healthier supply-demand balance.

The IMO has referred the question of pricing all out-of-market control actions into the market to the Market Evolution Program's (MEP) Market Pricing Working Group (MPWG) for their review.[26] We continue to believe that this would enhance market efficiency and in this section we present some estimates of the impact that such a decision might have on energy prices.

Our analysis estimates what the prices would have been over the period from January-October 2004 had the IMO not manually implemented out-of-market sources of reserve.[27] Our estimates are based on the most extreme case. That is, we simulate the market prices assuming that the IMO never manually implemented out-of-market sources (i.e. reduced the reserve requirement to be scheduled from market offers by the amount of the expected reserve shortage).[28] Instead, the reserve shortage is addressed via the DSO, which identifies a reserve shortage (actual) and solves the market outcome by automatically reducing the reserve requirement by the amount of the shortage less 2 MW. This is an alternative that is currently available to the IMO; the DSO is already configured to produce this outcome at times of reserve shortage and this would be the natural outcome in the market absent the IMO's manual intervention.

[26] The MPWG provides a forum where stakeholders can raise and discuss concerns and issues relating to price determination in the IMO-administered markets and possible options for their resolution. While any changes to the market design or market operations must be co-ordinated within the overall Market Evolution Program and with the activities of other working groups, the IMO will use the Market Pricing Working Group as a primary vehicle for soliciting detailed stakeholder advice on specific changes or enhancements that are planned or contemplated to address known pricing issues and concerns.

[27] We did not conduct a similar analysis for emergency purchases. There were only two emergency purchases made during this period.

[28] We assume that the 400 MW that is currently included in the market as CAOR remains in the market. The CAOR is implemented in the market via an offer price and does not represent a manual action by the IMO.

Table 3-1: Estimated Price Change from Allowing the DSO to Automatically Solve for a Reserve Shortage, January-October 2004

	Actual (Manual Use of Out-of-Market Reserve)				Allowing the DSO to Automatically Solve for the Reserve Shortage				Average Difference in Energy Price
	10N	10S	30R	ENGY	10N	10S	30R	ENGY	
January Averages	4.45	6.70	3.48	66.22	6.70	8.82	5.85	67.95	1.73
February Averages	2.35	4.54	2.25	52.74	2.40	4.59	2.37	52.78	0.04
March Averages	5.12	6.64	5.10	48.90	5.29	6.81	5.28	49.04	0.14
April Averages	9.41	10.93	8.80	45.92	9.73	11.24	9.14	46.18	0.26
May Averages	8.66	10.90	8.20	48.06	9.71	11.89	9.44	48.80	0.74
June Averages	3.96	5.92	3.78	46.69	4.39	6.34	4.28	46.90	0.33
July Averages	3.59	5.61	3.46	45.57	5.35	7.35	5.29	47.16	1.59
August Averages	0.88	3.27	0.87	43.51	0.89	3.27	0.89	43.51	0.00
September Averages	1.06	3.54	1.02	49.57	1.16	3.66	1.13	49.53	(0.04)*
October Averages**	0.54	2.29	0.54	49.11	0.54	2.99	0.54	49.11	0.00

* The negative price impact in September was attributable to the rules for determining prices at times of shortages (see June 2004 MSP Report at page 34). In this case, the manual reduction of the reserve requirement avoided a shortage condition. When we increased the reserve requirement in our simulation, the higher requirement induced a shortage and hence shortage prices were in fact lower then the actual prices.
**There were no manual OR reductions in this month.

Table 3-1 provides a summary of the average monthly impact on prices from allowing the DSO to automatically solve for reserve shortages. As Table 3-1 indicates, in periods such as January and July, when there are generally more occurrences of reserve shortages, the impact on the average monthly price is larger. The higher prices occurred over a few hours in January, May and July. However, the magnitude of the price increase in these hours was significant enough to add to the monthly average price. Overall, allowing the DSO to automatically solve for reserve shortages over the period January to October would have added $0.48 to the overall energy price level.

Table 3-2 provides a measure of the potential increase in price from allowing the DSO to automatically solve for reserve shortages. We compared the actual prices in those hours in which the IMO used out-of market control actions to our simulated prices (assuming instead that the DSO automatically solved for the reserve shortages). We identified those hours in which the difference between the actual prices and the simulated prices was greater then $25, $50, $75 and $100. In the months from January through October, our simulation estimates that there would have been a total of 25 hours in which the price would have been at least $25 higher had the DSO been allowed to automatically solve for the reserve shortage. For the same period, we estimate that there would have been 6 hours for which the price would have been at least $100 higher.

Table 3-2: Number of Hours with Price Increased by Specific Amount, January-October 2004

	Number of Hours			
	>$25/MWh	>$50/MWh	>$75/MWh	>$100/MWh
January	9	6	4	3
February	0	0	0	0
March	1	0	0	0
April	3	1	0	0
May	6	2	0	0
June	2	2	1	0
July	4	4	3	3
August	0	0	0	0
September	0	0	0	0
October	0	0	0	0
Total	25	15	8	6

2.2 Systematic Over-Forecast of Peak Demand

In our last report, we noted that the algorithm used by the IMO to select the peak demand values in pre-dispatch contributed to the over-forecast of the real-time peak demand in certain hours. In particular, we observed that the algorithm tends to over-forecast peak demand in hours 23 and 24.[29] The IMO has now modified its approach to forecasting demand in these hours. The following section provides a brief summary of the issue

[29] See page 79 of June 14, 2004, MSP Report.

originally identified, outlines the details of this modification and compares the forecasting performance of the modified approach with the IMO's previous approach.

Summary of the Issue

Prior to running the pre-dispatch sequences, the IMO forecasts average Ontario primary demand for a given hour (the IMO does not forecast the hourly peak demand). The IMO then adjusts this hourly average demand to approximate what the peak demand will be within the delivery hour. The IMO uses this peak demand value in the DSO to determine the pre-dispatch schedules and prices.

The approach to approximating the peak demand within an hour is relatively simple. In essence the estimated peak demand is constructed as a linear combination of the IMO's forecast of average demand in two adjacent delivery hours. During periods of increasing demand (e.g. morning pick-up), the estimated peak demand for a given delivery hour is the linear combination of average of demand in the hour and average demand in the next hour. During periods of load drop-off (such as in the evening after 10 p.m.), the estimated peak demand for a given delivery hour is the linear combination of average demand in that hour and average demand in the previous hour.

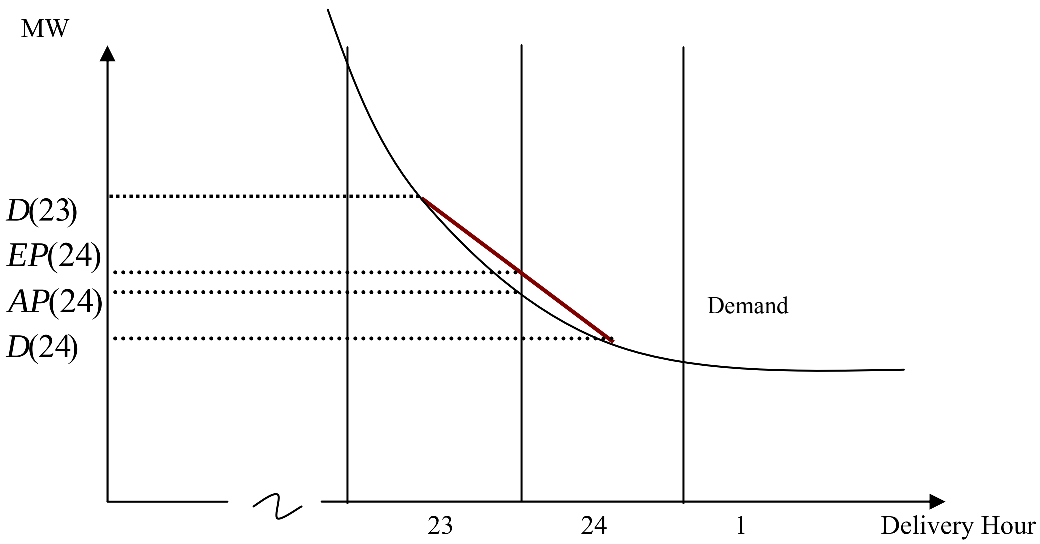
The assumption behind this approach is that the change in demand between two adjacent hours is linear, i.e. demand decreases/increases in these hours at the same rate. This linearity assumption overstates the true peak demand when the demand path is convex and it understates the true peak demand when the demand path is concave. Thus even if the IMO's forecasts of average hourly Ontario primary demand for each delivery hour are accurate, the peak demand within the hour estimated by this approach will be inaccurate.

Figure 3-1 illustrates how the method used by the IMO results in over-forecasting of demand when the demand path is convex. Assume the average demands for delivery hours 23 and 24 are respectively $D(23)$ and $D(24)$, and the actual peak demand for hour 24 is $AP(24)$. With the IMO's approach the estimated peak demand for hour 24 would be $EP(24)$ and it is calculated as follows:

$$EP(24) = 0.5 * D(23) + 0.5 * D(24) > AP(24)$$

We note that equal weights of 0.5 are applied to the average demand values. From the graph we see that this calculated peak demand will be greater than the actual peak demand $AP(24)$. Clearly the IMO's approach overstates the peak demand for delivery hour 24 even when the forecasts of the average demands for hours 23 and 24 are correct.

Figure 3-1: Rate of Change of Demand



Approach Proposed by the Market Assessment Unit

The IMO and MAU worked together to find a simple improvement to the forecast bias; a modification to the existing approach that would account for the convexity properties of the demand path in hours 23 and 24. In particular, the approach used by the IMO prior to our report essentially applied equal weights (i.e., a weight of 0.5) to the IMO's forecast in adjacent hours; the equal weights assumed a linear demand path. For example, using notation from Figure 3-1, the expected peak demand for hour 24 under the IMO's previous approach would be calculated as:

$$EP(24) = 0.5 * D(23) + 0.5 * D(24) > AP(23)$$

To correct for the known bias of projecting the peak demand under this approach, the IMO and MAU used actual hourly data of average demands in adjacent hours and actual hourly peak demands to compute differing weights that would better reflect the convexity in the demand path. In particular, the new approach would compute a weight α that would solve the following relationship:

$$AP(24) = \alpha * D(23) + (1 - \alpha) * D(24)$$

or

$$\alpha = \frac{AP(24) - D(24)}{D(23) - D(24)}$$

Under this approach, if most of the decline in demand across the two hours occurred during hour 23, then the difference between the actual peak demand and the average demand in hour 24 would be less than half the difference between the average demand in hour 23 and the average demand in hour 24. That is, the weight α would be less than 0.5; when picking the peak demand for hour 24, more weight should be given to the forecast average hourly demand for hour 24 than the forecast for hour 23. Conversely, if most of the load decline occurred during hour 24, more weight would be given to the hour 23 forecast.

The IMO and MAU used actual hourly data for the period May 2002 to May 2004 to compute hourly values for α and from this set of data estimated a mean value for α for each of hours 23 and 24.[30] The mean values estimated were α=0.42 for hour 23 and α=0.38 for hour 24.

Results of the New Approach

Beginning in August, the IMO implemented the new weights into their algorithm for choosing the hourly peak demand values to be used in pre-dispatch for hours 23 and 24. Table 3-3 below reports comparison statistics for the two approaches.

[30] The data were analysed on a monthly basis to determine that the mean value of α did not vary considerably by month.

Table 3-3: Comparison of Forecast Errors

	Hour 23		Hour 24	
	Previous Approach	New Approach	Previous Approach	New Approach
Average	175	84	250	121
Maximum	1,809	1,691	1,683	1,508
Minimum	(1,218)	(1,315)	(1,068)	(1,190)
Standard Deviation	298	294	300	297
Outside the bound of 2% of peak demand	28.08%	20.26%	39.52%	28.78%

As expected, we note that the new approach yields a smaller mean forecast error and a narrower dispersion of this error around its mean value compared to the previous approach. On average the new approach reduces the over-forecast by 91 MW for hour 23 and by 129 MW for hour 24.[31] The last row in the table shows the percentage of total hours in which the forecasts were either 2 percent higher or lower than the actual peak demand values.

To evaluate the forecasting performance of the new approach vis-à-vis the previous approach, the MAU computed the mean absolute percentage errors for both approaches. Table 3-4 below shows that the new approach yields better forecasts than the previous approach.

Table 3-4: Forecast Evaluation of the Two Approaches

	Mean Absolute Percentage Forecast Error (%)	
Hour	**New Approach**	**Previous Approach**
23	1.31	1.52
24	1.52	1.93

[31] Note that there is still a persistent over-forecast of demand in these hours. This is likely reflective of the IMO's persistent over-forecast of the average Ontario primary demand in hour 23 and 24. Recall that the new approach does not modify the manner in which the IMO forecasts average Ontario primary demand for a given hour, it only modifies the manner in which the peak hourly demands are estimated. If the IMO's forecasts for average Ontario primary demand in hour 23 and 24 are off, then this will affect the estimation of peak demand regardless of the approach chosen.

This issue for hours 23 and 24 may be indicative of a general issue across all hours and we have asked the MAU to undertake a review of all hours.

3. *Impact of Recent Changes to the Market*

3.1 Implementation of MIO

On June 23, 2004 the IMO implemented software changes to the DSO that allows multi-interval optimization (MIO) in the real-time constrained sequence.[32,33] With MIO, the DSO now optimizes gains from trade over a rolling 11 intervals (55-minute 'study period'), instead of considering just the single, upcoming five-minute dispatch interval. The IMO introduced MIO in the expectation that it would lower the overall cost to dispatch the market, enhance unit scheduling and reduce dispatch volatility, as described below.

Improved Unit Scheduling

With MIO, the DSO solves reliability issues automatically, based on future interval requirements. By recognizing ramp rate restrictions for future intervals the DSO schedules resources in advance of actual requirements to allow ramp rate capability to be utilized to solve for reliability concerns. For example, if additional generation from a slow-ramping unit will be required in thirty minutes, the DSO is now able to have the unit begin ramping up early enough to meet that requirement. In the past, the myopic scheduling of the constrained sequence of the DSO did not recognize energy or reserve shortages in future periods that could be ameliorated if slow moving fossil units were ramped early. In response to such shortages, the Control Room would either manually constrain units on early or lower the operating reserve requirement. One of the outcomes

[32] MIO dispatch affects the constrained dispatch schedule only and does not impact the unconstrained schedule.
[33] For a fuller description of the MIO initiative, see the IMO Quick Take: Multi-Interval Optimization http://www.theimo.com/imoweb/pubs/training/QT14_MIO.pdf

of such actions that we have previously reported is the counter-intuitive effect of suppressing price during a period of operating reserve shortage.

Improved Operational Stability

Reduced unit cycling: With MIO, resources are scheduled recognizing requirements over future intervals. This should reduce the number of start/stop sequences that units are exposed to and thereby result in less wear-and-tear and an increase in overall unit availability.

Improved compliance with dispatch instructions: With MIO, dispatch advisories indicating potential dispatch targets are issued to market participants for each interval of the study period. These advisories allow the market participants to proactively manage the transition to potential new dispatch instructions.

Improved Market Transparency

Because the DSO can solve some of the reliability issues for future intervals, the need for manual intervention in the dispatch solution will be reduced. In the past the Control Operators at times would manually constrain generators up to solve a perceived shortage in future intervals. With the implementation of MIO this manual intervention would no longer be required.

Improved Market Efficiencies

With MIO, the DSO considers future intervals as well as the current interval. This should result in more efficient constraining on or off of units.

At the same time that MIO was introduced, several additional (related) software changes were implemented to address real-time dispatch issues identified by market participants. These issues relate to generating facilities being dispatched in a manner that increases equipment wear-and-tear, or that is not sustainable in the long run:

Minimum Loading Point: Many generating facilities have a requirement to operate at or above a minimum loading point unless they are synchronizing to the grid or shutting down. The change to the DSO recognized the minimum loading point of units.

Period of Steady Operation: The change to the DSO ensured that non quick-start units were not dispatched to reverse their direction (up or down) without a minimum period of steady operation.

Forbidden Region: Hydroelectric units have operating ranges where the units are unable to maintain steady operation without causing equipment damage. The change to the DSO recognized these ranges, called 'forbidden regions'.

<u>Preliminary Outcomes of MIO</u>

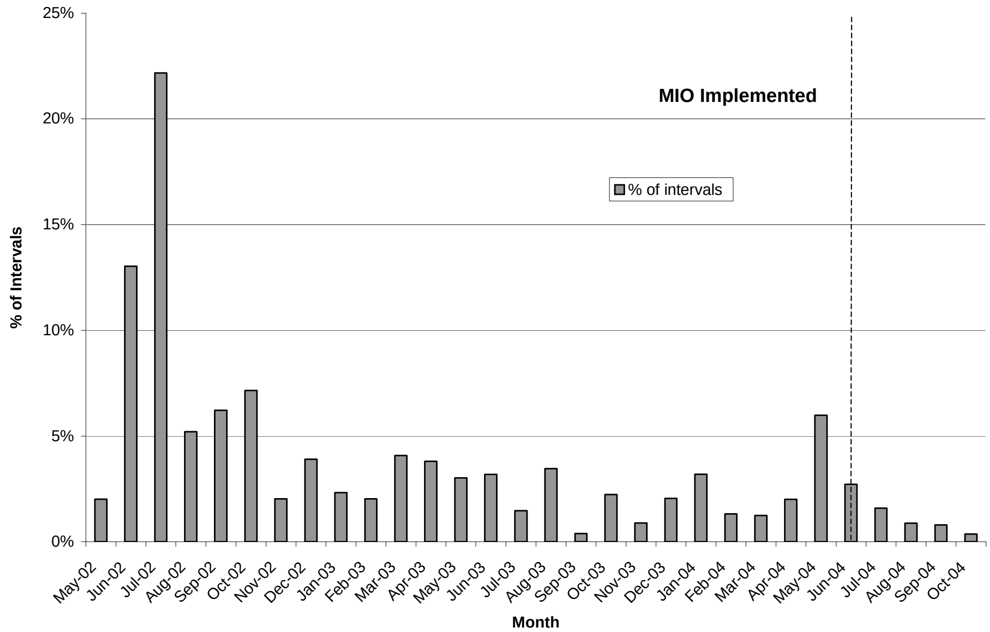
There have now been approximately four months of operations in which to assess the performance of MIO and the related changes in terms of achieving the stated objectives. The following are the MAU's preliminary observations. Further study will be undertaken by the MAU to verify that the results are not caused by other factors, such as lower demands and increased supply of both energy and operating reserve.

<u>Reduction in the Use of Out-of-Market Operating Reserves</u>

One of the expected outcomes of MIO was improved unit scheduling, leading to a reduction in the necessity to use out-of-market operating reserve to meet shortages.

The MAU, as part of its normal monitoring, reviews the usage of out-of-market operating reserves in Table A-32 of the Statistical Appendix. Figure 3-2 is extracted from this data and preliminary results appear to show a continued and persistent reduction in the usage of out-of-market OR since MIO implementation.

Figure 3-2: Percentage of Intervals with Operating Reserve Reductions May 2002-October 2004

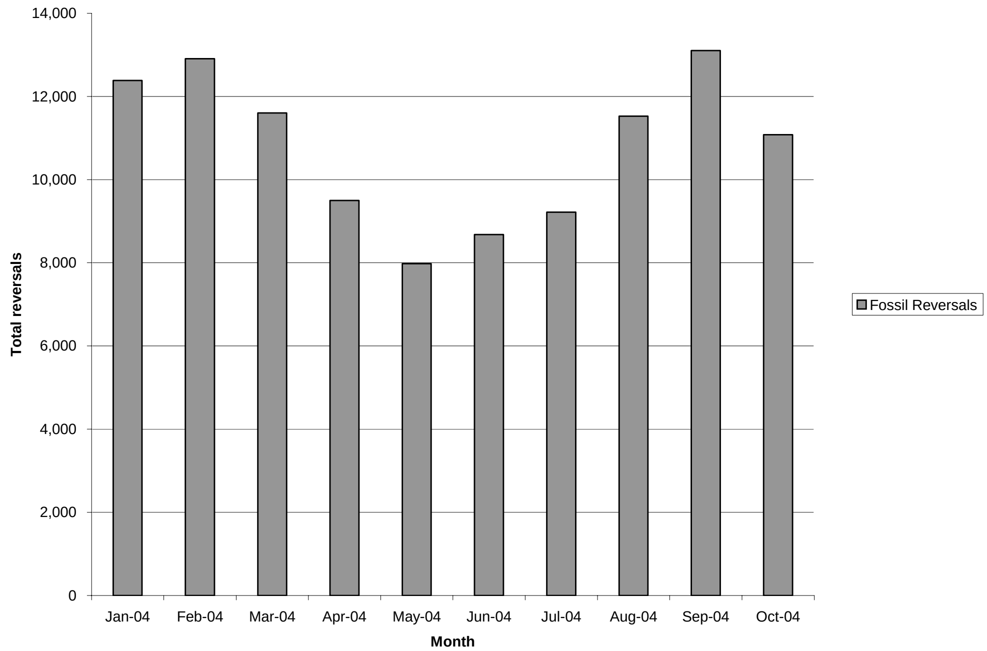


<u>Improved Unit Scheduling</u>

Another of the expected outcomes was a better dispatch of fossil-fired generators that were suffering dispatch reversals as a result of the myopic scheduling of the DSO. Typically in the Ontario market, fossil generators' offers are marginal and as a result, the marginal generator moves as demand moves. Generators have indicated that the outcome of such generator reversals is an increased in forced outage rates as a result of increased wear-and-tear on the generators.

Figure 3-3 below shows the total number of fossil MW changes from interval to interval. The data seem to show that there has been little change in the actual dispatch reversals.

Figure 3-3: Monthly Total Fossil Reversals, January-October 2004



<u>Initial State</u>

The IMO has expended further effort into determining the reasons why there has not been a smoothing of dispatch reversals. Data analysis suggests that 20 percent of the dispatch reversals can be attributed to load predictor changes from positive to negative and then back to positive within two intervals. Load predictor changes, in turn, can be traced back to fluctuations in the measurement of actual demand between intervals. This value, known as the 'initial state', is used to extrapolate the demand for the succeeding intervals. As demand fluctuates from interval to interval this change in magnitude is reflected in all future load forecasts. Thus a change in initial state is reflected in the next 12 intervals. MIO in turn uses the next 12 load forecasts in order to determine the correct dispatch of generators. In the next interval when demand fluctuates in the opposite direction, the MIO would begin to reverse the dispatches it had previously sent.

The IMO is now looking at de-sensitizing the load predictor tool by averaging the actual state across 2 or 3 intervals to smooth the future demand. This will lead to more of the minute-to-minute variations being picked up by AGC rather than being reflected in generator dispatch.

We have asked the MAU to report back on the results of such tests and its impact on generator reversals.

Appendix D: MAU's Modified Approach to the Forecast of Peak Demand

The MAU used actual hourly data of average demands and actual hourly peak demands to compute the weights that generated the actual peak demands. In particular, the new approach computes a weight α_i that satisfies the following relationship:

$$AP_i(h) = \alpha_i * D_i(h-1) + (1-\alpha)_i * D_i(h)$$

or

$$\alpha_i = \frac{AP_i(h) - D_i(h-1)}{D_i(h-1) - D_i(h)}$$

where $AP_i(h)$ is actual peak demand for day i in hour h

$D_i(h-1)$ is the average forecasted demand for day i in hour h-1

The MAU computed the α_i in hours 23 and 24 for the period May 2002 to May 2004. A mean value for α for each of hours 23 and 24 was then calculated.[34] Table 3-5 reports the results. The MAU then simulated the peak demands by applying the implied weights respectively to hour 23 and 24 for the period of June 1, 2002 to August 20, 2004.

Table 3-5: Statistics for Alpha

	Hours	
	23	**24**
Mean Value	0.42	0.38
Standard Deviation	0.077	0.078

[34] Seasonal fluctuations did not significantly affect the mean value of α.

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

1. *General Assessment*

Our review of the summer of 2004 suggests that the wholesale market continues, in general, to function well. With regard to operational issues that affect the integrity of market signals, some progress has been made but additional steps could be taken to improve the competitive efficiency of the wholesale market. In particular, we continue to urge the IMO to rely on market approaches rather than 'out-of-market' actions to cope with periods of shortage in operating reserve, and to use actual ramping rates in the real-time unconstrained schedule. With regard to the behaviour of market participants, we found no instances that suggested the rules were being gamed or market power was being abused.

There are a number of critical issues that will affect the evolution of the market, and the role of the Panel as Ontario moves forward with the implementation of the new regime in Bill 100. We discuss some of these in the next section.

2. *Moving Forward*

2.1 The Operation of the Real-time Market

There are two issues that we focused on in our last report with regard to the operation of the real-time market in an environment that reflects the changes the government is proposing in Bill 100. The first is the desirability that all production be offered in the market, including 'heritage' energy and new sources of supply that may have supporting financial guarantees through the RFP process being pursued by the Ontario Power Authority. This will continue to provide a framework that allows efficient dispatch. Also ensuring that all generation is offered through the marketplace provides a continued framework for reliability. A co-ordinated mechanism ensures that all dispatch decisions implicitly take reliability into account. Our understanding is that all current and new supply will continue to be offered into the market.

Second, the MPMA effectively expires at the end of this year. Although the MPMA has been characterized by some as a subsidy to consumers, its rationale was in fact to provide a transitional framework that would remove the incentive for OPG to exercise its market power. Notwithstanding the regulated price for 'heritage generation', OPG continues to have considerable market power with regard to how it offers its non-regulated fossil and hydro generation into the market. As well, the government has indicated that OPG will no longer pursue the path of privatizing generation that was previously foreseen. As discussed further below, we will be paying increasing attention as we go forward to the exercise, as well as the abuse, of market power in the operation of the Ontario real-time market.

2.2 Preparation for DAM

With Multi-Interval Optimization (MIO) now part of the market design, the next major evolution is expected to be the Day Ahead Market (DAM). The current in-service date for DAM is the third quarter of 2006. Detailed design documents for this market were published for comment in August and provide a fairly complete statement of the intended design.

Until December 2003 it appeared that DAM might be based on locational marginal pricing (LMP or nodal pricing). However, following a review of the history of nodal prices in Ontario, the decision was taken not to pursue LMP in DAM.[35] From the Panel's perspective, this was a missed opportunity. We continue to view nodal pricing as a more efficient market design than the current uniform pricing, and are disappointed that the Ontario market is not moving in this direction. We note that the design of the day ahead market can accommodate a move to locational pricing in future and encourage the IMO to adopt nodal pricing soon.

The MAU has monitored the development of the day ahead market and has reported on its progress to the MSP on a number of occasions. From these reports, and discussions with IMO's DAM design team, it is evident that the design is quite complicated. This is a concern to the Panel since we anticipate that such complexity may be conducive to gaming and challenging for the detection of gaming. In particular, the design of the DAM CMSC regime is a highly complicated structure. This will inevitably require significant participant training to understand, and consequently may limit transparency (and understanding) of the net payment streams and causes of CMSC. With CMSC payments taking place in both the day ahead and real-time markets, the Panel does have some concerns about potential gaming. DAM will require considerable monitoring by the MSP and MAU.

As in the real-time market, transmission or security constraints in DAM can allow a participant to exercise local market power over limited areas of the IMO-controlled grid, which may result in large CMSC payments. In the real-time market this is controlled through the local market power process, Appendix 7.6 of the Market Rules. The MAU and MSP discussed the need for and desirability of extending such rules to DAM. The Panel concluded that the existing local market power mitigation process should not be extended to DAM at this time for the following reasons:

- DAM allows for load to respond more readily over time by participating as price responsive load, even if it is not dispatchable load in real-time. This has the potential to create more local competition in DAM than in real-time.
- Transmission constraints in DAM are likely to continue to be constraints in real-time.[36] To the extent that DAM CMSC has a corresponding real-time CMSC, mitigating real-time CMSC can be viewed as limiting some portion of DAM payments as well.

[35] Historical Nodal Pricing Analysis, Market Evolution Program January 2004 (http://www.theimo.com/imowebpub/200405/mo_pres_NodalAnalysis_2004jan14.pdf)
[36] There likely will be additional transmission constraints in real-time.

- Because of the significant complexities of DAM CMSC and its 2nd settlement interaction with real-time CMSC, modification to the existing mitigation process has the potential to dramatically complicate the existing tools and process, and could require a fundamental re-definition of some of the principles in the current Market Rules.

It should be noted that for loads to respond to DAM CMSC, as suggested above, they would need more information to recognize that market opportunities exist. Publishing nodal prices and CMSC payments in different areas of the province will be essential to promote the desired market response. The Panel's conclusion that the mitigation process of Appendix 7.6 need not be implemented at the outset is conditional on the timely release of these data. If they cannot be provided to market participants then we may be forced to a more onerous regulatory regime. In any event, DAM CMSC must be monitored. If it is concluded later that some aspects of DAM CMSC need mitigation, specific solutions could be developed at the time.

2.3 Constrained Off Payments

In 2003 the MSP initiated a consultation on CMSC, in particular constrained off CMSC, which led to a variety of recommendations to the IMO Board in July 2003.[37] The primary conclusion in the report was the need to modify the treatment of constrained off CMSC for generation and imports. More specifically, if locational marginal pricing were not to go ahead or be substantially delayed beyond the end of 2004, the Panel concluded that constrained off CMSC payments should be eliminated and other aspects of the CMSC framework reviewed. The issue of CMSC payments was to be revisited towards the end of 2004, in light of conditions at the time.

Market participants have raised two concerns with regard to the potential position that the Panel might take in respect of constrained off payments. The first has to do with the

[37] See http://www.theimo.com/imoweb/pubs/marketSurv/ms_CMSC-Consultation_20030703.pdf

operation of the DAM, and the second concerns the real-time market. This section sets out our current thinking on both of these concerns.

With regard to the DAM, the Panel has discussed the specific issue of constrained off CMSC payments with the IMO DAM design team. The design team emphasized the importance to members of the Market Operations Standing Committee (MOSC) and DAM Working Group (a stakeholder body) of having a stable DAM design and that CMSC, including constrained off CMSC, was a critical component of that design. The Panel advised the IMO design team that even if it undertook a further review of real-time CMSC, it would not seek elimination of DAM constrained off payments during the design phase. However, the Panel must still reserve the right to consider all options in future, given the outstanding concerns around the complexity of the DAM design related to CMSC and the potential for gaming.

This position regarding DAM CMSC was not intended in any way to constrain a decision by the Panel to review the appropriateness of constrained off payments in the real-time market. The design of DAM already allows for some differences in real-time and day ahead treatment. In light of several factors, however, we have concluded that we will not call for the elimination of real-time constrained off payments and a review of other aspects of the framework for CMSC at this time. In particular:

- CMSC payments have been dropping since market opening. In the first 12 months total CMSC was about $230 million, compared with $95 million in the second year. Constrained on payments accounted for most of the decline but constrained off payments also dropped, and have stayed lower in the last six months.
- Some of the more disconcerting aspects of constrained off payments have been addressed through other changes to Market Rules which followed after these were highlighted in the July 2003 CMSC report to the IMO Board.
  - In particular, the calculation of constrained off CMSC has been modified, such that it no longer compensates generation and imports for offer prices

below zero. In many cases even large payments would not trigger a local market power review because consistent offers at these negative prices led to comparable historical reference prices and 'safe harbour'.

- The IMO has been recovering constrained off payments to dispatchable loads where these were induced by the facility's or participant's own behaviour.

- As was a factor in our July 2003 assessment, there have been further major changes to the electricity sector in Ontario over the past year and the issue of uncertainty about the future structure of the market is still a concern.

2.4 Monitoring for the Exercise of Market Power

In our last report we commented on the need we feel to monitor the marketplace for the exercise of market power, as well as for its abuse. At that time we commented:

> The original market design recognized the potential for the exercise of market power because of the dominance of Ontario Power Generation. The Market Power Mitigation Agreement (MPMA) addressed this market power issue by providing a schedule for the divestiture of key OPG generating assets and requiring the payment of a partial rebate to consumers if the average annual market price exceeded $38/MWh. One of the IMO licence conditions directed the Market Surveillance Panel to these arrangements and specified that if the annual price exceeded this threshold, the rebate was to be the 'sole remedy'. The calculations underlying the MPMA rebate come to an end at the close of 2004 and the government will likely be addressing its approach to market power issues as part of its final legislative package.
>
> Although we clearly have a special responsibility with respect to addressing the potential abuse of market power we have found that understanding and identifying the exercise of market power is fundamental to carrying out our work. When the market price spikes upward we need to understand the causes. If the cause is the withholding of supply, the key characteristic of the exercise of market power, we believe it is part of our role to identify and, at a minimum, discuss our analysis of these events with the market participant in question. To do so requires a rigorous analytical framework that is understood and accepted by market participants. During the last several months we have begun to define in operational terms how we would identify the exercise of market power.

> We believe it would now be constructive to consult with market participants and other stakeholders on this framework.[38]

Over the past six months other commitments and priorities have slowed our work on developing this framework. But we continue to believe it is important and we hope to be able to issue a discussion paper on the exercise of market power in the early part of 2005.

2.5 The Future Role of the Panel

Bill 100, the *Electricity Restructuring Act, 2004*, continues the Market Surveillance Panel as a panel of the Ontario Energy Board to carry out market surveillance functions under the *Electricity Act, 1998* with respect to the IESO-administered markets. The Panel has worked with representatives of the OEB and the IMO to ensure a smooth transition. Although the accountability of the Panel will in future be to the OEB, rather than to the Board of Directors of the IMO, we intend to continue to rely on the IMO's Market Assessment Unit to carry out the day-to-day monitoring and analysis of the market under our direction. Our experience suggests strongly that monitoring market outcomes, as well as explaining anomalous events and, where necessary, reacting quickly to them require expert staff support with access to the market operator. The MAU has served us well in this regard and we believe it will continue to do so. The Panel will retain the right to seek expertise and advice from sources outside the IMO, as appropriate, and the relations between the MAU and the Panel will be governed by a protocol between the IMO and the OEB.

The OEB has consulted with us on the drafting of an OEB by-law that describes the mandate and procedures of the Panel once Bill 100 comes into force. This by-law is patterned after section 3 of Chapter 3 of the Market Rules but contains some new features. While the Panel has never hesitated to examine IMO operations, and to make recommendations for changes where we believed it appropriate, the OEB by-law will explicitly include conduct by the system operator in our mandate to monitor and investigate the IESO-administered markets. Another change is to improve transparency

[38] See our June 2004 surveillance report, pp. 108-109.

by building on the statutorily allowed disclosure of confidential information. Subsection 37.3(3) of the *Electricity Act, 1998* allows us to make an order permitting the disclosure of confidential information obtained by compulsory procedures if we believe that it is in the public interest, after giving the interested parties an opportunity to comment. During the period since market opening, we have on occasion faced situations where we believe the ability to discuss confidential information would have enriched the explanation of market outcomes. While it is understandable that as a matter of course information on market operations is classified as confidential, from time to time we believe it would be helpful to shed more light on certain market activities. As a result, the new by-law will include a provision that allows us to disclose confidential information “essential for a full understanding of the market activities that are the subject of a report”. This will happen only where the affected market participant has been given an opportunity to be heard and will apply only to information that has not been obtained by compulsory means.

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IMO-Administered Electricity Markets

Data for the period from
May 2003 to October 2004

PUBLIC

December 13, 2004

List of Tables

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

In some instances, the data reported in this Report has been updated or recalculated and therefore may differ from values previously quoted in our earlier reports**.**

Table A-1: Monthly Energy Demand (TWh)

	Ontario Demand		Total Market Demand		Exports	
	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005
May	11.63	11.84	12.35	12.95	0.72	1.11
Jun	11.89	12.05	12.54	13.09	0.66	1.04
Jul	12.90	12.77	13.89	13.82	0.99	1.05
Aug	12.51*	12.75	13.07	13.96	0.56	1.21
Sep	11.79	12.37	12.19	12.81	0.40	0.44
Oct	12.16	12.22	12.31	12.72	0.15	0.5
Nov	12.39	N/A	12.71	N/A	0.32	N/A
Dec	13.33	N/A	13.95	N/A	0.62	N/A
Jan	14.77	N/A	15.57	N/A	0.80	N/A
Feb	13.09	N/A	13.59	N/A	0.50	N/A
Mar	13.22	N/A	13.79	N/A	0.56	N/A
Apr	11.79	N/A	12.64	N/A	0.85	N/A

*Data for August 2003 includes blackout period (August 14-August 22, 2003).

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

	2002	2003	2004
Jan	-0.3	-7.7	-9.0
Feb	-1.3	-6.9	-3.3
Mar	0.4	-0.5	2.3
Apr	7.3	5.6	6.9
May	11.3	12.3	13.4
Jun	19.2	18.6	17.8
Jul	24.2	21.4	20.7
Aug	22.7	21.9	19.6
Sep	20.2	17.2	19.8
Oct	9.2	9.1	10.9
Nov	3.3	5.0	N/A
Dec	-1.8	0.0	N/A

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

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

Table A-4: Outages (TWh), May 2003-October 2004

	Total Outage		Planned Outage		Forced Outage	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	5.29	3.13	3.46	2.17	1.83	0.97
Jun	3.77	2.11	1.51	0.80	2.27	1.31
Jul	2.22	3.55	0.95	1.19	1.27	2.36
Aug	2.82	3.11	0.73	0.93	2.08	2.18
Sep	3.94	3.98	2.28	1.67	1.65	2.32
Oct	5.52	6.19	3.48	3.23	2.05	2.95
Nov	2.91	N/A	0.96	N/A	1.96	N/A
Dec	1.45	N/A	0.69	N/A	0.75	N/A
Jan	2.30	N/A	0.27	N/A	2.04	N/A
Feb	2.84	N/A	0.36	N/A	2.48	N/A
Mar	2.98	N/A	1.17	N/A	1.81	N/A
Apr	3.48	N/A	1.54	N/A	1.94	N/A

Table A-5: Average HOEP, On and Off-Peak, May 2003-October 2004

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	43.17	48.06	56.53	61.93	32.16	37.60
Jun	41.64	46.69	55.54	60.15	29.47	33.81
Jul	40.08	45.58	53.14	55.55	28.35	37.38
Aug	46.85	43.51	62.99	52.81	36.37	35.84
Sep	48.56	49.57	58.63	59.17	39.74	41.16
Oct	57.09	49.11	68.42	57.48	46.92	42.80
Nov	40.45	N/A	50.29	N/A	32.59	N/A
Dec	44.42	N/A	54.55	N/A	36.08	N/A
Jan	66.22	N/A	84.76	N/A	50.94	N/A
Feb	52.74	N/A	64.46	N/A	42.77	N/A
Mar	48.90	N/A	57.33	N/A	40.65	N/A
Apr	45.92	N/A	55.04	N/A	37.95	N/A

*Table A-6: Average Richview Slack Bus Price, On and Off-Peak May 2003-October 2004**

	Average On-Peak Richview Slack Bus Price		Average Off-Peak Richview Slack Bus Price		Average Richview Slack Bus Price	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	107.50	88.85	45.51	48.13	73.53	65.64
Jun	84.45	81.39	41.01	37.95	61.28	59.19
Jul	65.46	62.91	32.09	43.64	47.90	52.34
Aug	77.08	62.74	40.81	38.42	55.78	49.38
Sep	65.74	69.63	45.65	47.31	55.03	57.73
Oct	83.98	63.47	59.82	47.32	71.23	54.26
Nov	69.73	N/A	39.46	N/A	52.91	N/A
Dec	73.38	N/A	50.94	N/A	61.08	N/A
Jan	115.00	N/A	63.03	N/A	86.50	N/A
Feb	80.58	N/A	55.33	N/A	66.95	N/A
Mar	82.56	N/A	53.61	N/A	67.93	N/A
Apr	77.32	N/A	48.26	N/A	61.82	N/A

* The methodology for calculating the average Richview Slack Bus Price has been revised subsequent to previous reports so that instances of shadow prices greater than $2,000 have been reduced to the Maximum Market Clearing Price (MMCP) of $2,000 and instances of shadow prices less than -$2,000 have been increased to the Minimum Market Clearing Price of -$2,000.

Table A-7: Ontario Demand (GWh) by Market Segmentation, May 2003-October 2004

	LDC's		Wholesale Loads		Generation		Metered Energy Consumption		Transmission Losses		Total Energy Consumption	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	9,166	9,334	2,081	2,011	144	155	11,390	11,501	238	334	11,627	11,835
Jun	9,583	9,538	1,889	2,024	168	164	11,639	11,727	246	319	11,885	12,046
Jul	10,665	10,229	1,801	1,935	158	177	12,624	12,411	274	359	12,898	12,770
Aug	10,341	10,233	1,752	2,016	170	178	12,263	12,427	251	319	12,514*	12,746
Sep	9,431	9,960	1,944	1,988	168	157	11,543	12,104	251	266	11,794	12,370
Oct	9,686	9,692	2,034	2,102	198	167	11,918	11,961	241	254	12,160	12,215
Nov	10,017	N/A	1,978	N/A	176	N/A	12,171	N/A	219	N/A	12,390	N/A
Dec	11,025	N/A	1,906	N/A	184	N/A	13,114	N/A	213	N/A	13,327	N/A
Jan	12,289	N/A	2,027	N/A	199	N/A	14,515	N/A	253	N/A	14,768	N/A
Feb	10,685	N/A	1,904	N/A	180	N/A	12,769	N/A	319	N/A	13,088	N/A
Mar	10,667	N/A	2,047	N/A	171	N/A	12,885	N/A	340	N/A	13,225	N/A
Apr	9,524	N/A	1,889	N/A	135	N/A	11,549	N/A	242	N/A	11,791	N/A

*Total energy consumption for the month of August 2003 includes blackout period.

Table A-8: Frequency Distribution of HOEP, May 2003-October 2004 (Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	<$10.00		**$10.01-$20.00**		**$20.01-$30.00**		**$30.01-$40.00**		**$40.01-$50.00**		**$50.01-$60.00**		**$60.01-$70.00**		**$70.01-$100.00**		**$100.01-$200.00**		**>$200.01**	
	2003/2004	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**
May	0.00	0.54	1.08	8.87	**48.66**	15.59	11.83	15.59	7.53	**19.35**	5.38	15.46	7.39	9.95	16.67	9.68	1.48	4.97	0.00	0.00
Jun	0.00	0.83	5.56	10.83	**52.78**	8.19	8.47	14.31	6.39	**31.53**	5.00	17.36	6.67	4.86	11.81	8.61	2.78	3.47	0.56	0.00
Jul	0.00	0.81	2.69	8.60	**52.28**	10.62	5.91	15.46	4.57	**32.80**	6.05	12.10	15.86	9.81	12.37	9.54	0.27	0.27	0.00	0.00
Aug	0.00	0.00	0.19	10.08	24.43	7.26	**29.36**	20.97	9.09	**33.47**	7.01	14.38	13.64	8.20	15.34	5.51	0.95	0.13	0.00	0.00
Sep	0.00	0.20	1.39	2.78	10.56	7.94	**40.56**	21.23	11.11	**31.55**	8.19	20.24	8.47	12.70	19.31	2.98	0.28	0.40	0.14	0.00
Oct	0.00	0.00	0.00	0.00	11.96	2.28	20.70	**32.80**	7.80	18.82	8.60	29.17	12.90	9.54	**37.10**	6.99	0.81	0.40	0.13	0.00
Nov	0.00	N/A	0.00	N/A	**36.67**	N/A	29.03	N/A	9.31	N/A	8.61	N/A	6.81	N/A	9.31	N/A	0.28	N/A	0.00	N/A
Dec	0.00	N/A	1.75	N/A	**36.69**	N/A	26.21	N/A	6.72	N/A	4.57	N/A	3.36	N/A	19.35	N/A	1.34	N/A	0.00	N/A
Jan	0.00	N/A	0.13	N/A	11.56	N/A	**21.37**	N/A	9.54	N/A	8.06	N/A	11.69	N/A	18.82	N/A	18.41	N/A	0.40	N/A
Feb	0.00	N/A	0.00	N/A	2.73	N/A	**33.05**	N/A	22.70	N/A	10.78	N/A	9.20	N/A	19.11	N/A	2.44	N/A	0.00	N/A
Mar	0.00	N/A	0.13	N/A	10.89	N/A	21.64	N/A	**28.49**	N/A	14.92	N/A	11.83	N/A	11.83	N/A	0.27	N/A	0.00	N/A
Apr	0.00	N/A	0.28	N/A	15.28	N/A	**26.39**	N/A	25.42	N/A	14.44	N/A	10.28	N/A	7.50	N/A	0.28	N/A	0.14	N/A
May-03 Apr-04	0.00	N/A	1.10	N/A	**26.21**	N/A	22.59	N/A	12.39	N/A	8.47	N/A	9.84	N/A	16.54	N/A	2.47	N/A	0.11	N/A
May-04 Oct-04	N/A	0.40	N/A	6.86	N/A	8.82	N/A	19.86	N/A	**27.64**	N/A	18.81	N/A	8.98	N/A	7.12	N/A	1.58	N/A	0.00

*Bolded values show highest percentage within month.

*Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2003-October 2004 (Percentage of Hours within Defined Range)**

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<$10.00		$10.01-$20.00		$20.01-$30.00		$30.01-$40.00		$40.01-$50.00		$50.01-$60.00		$60.01-$70.00		$70.01-$100.00		$100.01-$200.00		>$200.01	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	0.13	0.13	0.81	8.47	**39.78**	12.77	18.41	16.40	7.80	15.59	5.65	**17.20**	5.78	11.69	19.49	11.29	2.02	6.45	0.13	0.00
Jun	0.00	0.69	3.75	10.00	**51.25**	8.19	9.86	12.92	6.53	**29.31**	5.42	17.22	5.69	7.78	12.78	9.03	4.03	4.72	0.69	0.14
Jul	0.13	0.67	2.02	7.80	**50.94**	9.81	6.85	13.71	4.97	**30.65**	4.57	12.50	12.37	12.50	17.88	11.29	0.27	0.94	0.00	0.13
Aug	0.00	0.00	0.19	9.54	22.54	7.26	**22.94**	17.47	15.72	**33.06**	15.11	14.92	14.20	11.69	18.18	5.91	1.14	0.13	0.00	0.00
Sep	0.00	0.00	1.25	2.78	9.31	5.75	**35.28**	20.44	15.00	**29.76**	8.75	16.47	7.36	20.04	22.50	4.37	0.42	0.40	0.14	0.00
Oct	0.13	0.00	0.00	0.00	4.97	2.56	26.34	27.56	8.06	19.07	7.39	**30.77**	10.89	12.66	**40.99**	6.89	1.08	0.48	0.13	0.00
Nov	0.14	N/A	0.00	N/A	24.17	N/A	**39.72**	N/A	7.50	N/A	9.58	N/A	6.94	N/A	11.67	N/A	0.28	N/A	0.00	N/A
Dec	0.13	N/A	1.34	N/A	23.92	N/A	**36.42**	N/A	7.12	N/A	5.65	N/A	3.23	N/A	18.82	N/A	3.36	N/A	0.00	N/A
Jan	0.13	N/A	0.00	N/A	7.26	N/A	**21.51**	N/A	10.89	N/A	8.74	N/A	10.08	N/A	20.30	N/A	20.43	N/A	0.67	N/A
Feb	0.00	N/A	0.00	N/A	2.30	N/A	25.14	N/A	**27.44**	N/A	12.21	N/A	8.48	N/A	20.55	N/A	3.88	N/A	0.00	N/A
Mar	0.13	N/A	0.00	N/A	10.35	N/A	19.09	N/A	**25.40**	N/A	17.47	N/A	12.90	N/A	13.84	N/A	0.81	N/A	0.00	N/A
Apr	0.14	N/A	0.14	N/A	13.06	N/A	22.50	N/A	**26.39**	N/A	15.83	N/A	10.83	N/A	10.56	N/A	0.42	N/A	0.14	N/A
May-03 Apr-04	0.09	N/A	0.79	N/A	21.65	N/A	**23.67**	N/A	13.57	N/A	9.70	N/A	9.06	N/A	18.96	N/A	3.18	N/A	0.16	N/A
May-04 Oct-04	N/A	0.25	N/A	6.43	N/A	7.81	N/A	17.95	N/A	**26.21**	N/A	18.43	N/A	12.44	N/A	8.26	N/A	2.18	N/A	0.45

*Bolded values show highest percentage within month.

Table A-10: Total Hourly Uplift Charge, May 2003-October 2004

	Total Hourly Uplift $ Millions		IOG* $ Millions		CMSC ** $ Millions		Operating Reserve $ Millions		Losses $ Millions	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	30	36	3	2	8	10	8	8	11	17
Jun	37	29	6	1	14	9	5	4	11	15
Jul	22	30	2	1	8	8	2	4	10	17
Aug	19	26	2	1	5	8	3	1	9	16
Sep	24	20	1	1	7	7	4	1	12	11
Oct	27	14	2	0	9	4	2	1	15	9
Nov	25	N/A	1	N/A	7	N/A	6	N/A	10	N/A
Dec	31	N/A	8	N/A	4	N/A	5	N/A	13	N/A
Jan	53	N/A	15	N/A	14	N/A	5	N/A	20	N/A
Feb	33	N/A	8	N/A	6	N/A	3	N/A	16	N/A
Mar	32	N/A	4	N/A	7	N/A	6	N/A	16	N/A
Apr	31	N/A	3	N/A	6	N/A	9	N/A	14	N/A

* Prior to September 2004, the numbers are not net of IOG offsets which was implemented in July 2002. IOG offsets totalled $8.8 million in recoveries by the end of October 2004. See Table A-13.
** Numbers are not net of Negative Price CMSC Revision and Self-Induced CMSC Revisions for Dispatchable Loads. Negative Price CMSC Revision was implemented in July 2003 and totalled $8.1 million in recoveries by the end of August 2004. Self-Induced CMSC Revisions for Dispatchable Loads was implemented in March 2004 and totalled $3 million in recoveries by the end of August 2004.

Table A-11: Operating Reserve MCP ($/MWh), May 2003-October 2004

	10N		10S		30R	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	7.20	8.66	7.85	10.90	6.64	8.20
Jun	4.92	3.97	5.27	5.93	4.70	3.77
Jul	1.79	3.60	2.67	5.62	1.74	3.47
Aug	2.91	0.88	4.06	3.27	2.84	0.87
Sep	3.10	1.06	5.69	3.54	2.48	1.02
Oct	1.93	0.54	2.82	2.92	0.99	0.54
Nov	6.17	N/A	7.05	N/A	4.18	N/A
Dec	5.10	N/A	6.70	N/A	2.85	N/A
Jan	4.45	N/A	6.70	N/A	3.48	N/A
Feb	2.35	N/A	4.54	N/A	2.25	N/A
Mar	5.12	N/A	6.64	N/A	5.10	N/A
Apr	9.41	N/A	10.93	N/A	8.80	N/A

*Table A-12: IOG Payments, Top 10 Days, May 2004-October 2004**

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
10/28/2004	13,945	0.30	21.72	20,264
06/14/2004	10,278	0.18	17.48	21,031
05/14/2004	10,957	0.17	15.79	20,509
10/25/2004	10,686	0.17	15.9	20,256
07/02/2004	10,555	0.14	13.36	22,352
05/18/2004	6,266	0.14	22.03	19,405
08/15/2004	10,854	0.13	11.78	18,831
05/13/2004	5,985	0.12	19.29	20,940
09/22/2004	16,993	0.11	6.23	20,986
05/12/2004	4,611	0.11	22.93	21,044
	Total Top 10 days	1.57		
	Total for period	8.02		
	% of Total Payments	20%		

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

Table A-13: IOG Offsets due to Implied Wheeling*

	IOG Offset ($'000)		IOG Offset %	
	2003/2004	2004/2005	2003/2004	2004/2005
May	286	81	11.3	5.6
June	430	98	6.6	7.3
Jul	166	135	10.6	11.6
Aug	92	155	6.1	16.6
Sep	33	69	2.3	5.3
Oct	23	409	1.2	21.1
Nov	47	N/A	3.8	N/A
Dec	289	N/A	3.6	N/A
Jan	1,368	N/A	9.0	N/A
Feb	692	N/A	8.7	N/A
Mar	329	N/A	7.8	N/A
Apr	67	N/A	2.7	N/A

Table A-14: CMSC Payments, Energy and Operating Reserve, May 2003-October 2004

	Constrained Off $ Millions		Constrained On $ Millions		Total CMSC for Energy* $ Millions		Operating Reserves $ Millions		Total CMSC Payments** $ Millions	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	5.0	6	3.1	1.6	8.3	8.2	1.0	1.4	9.3	9.6
Jun	7.3	5.7	7.0	1.6	14.5	7.7	0.7	1.2	15.2	8.9
Jul	8.2	4.4	1.6	1.7	10.0	6.5	0.7	1	10.7	7.5
Aug	4.3	5.6	0.7	1.3	5.3	7.1	0.4	0.5	5.7	7.7
Sep	4.9	6.9	1.4	2.3	6.6	9.5	0.3	0.5	6.9	10
Oct	6.2*	4.7	2.1	0.7	8.9	5.8	0.2	0.1	9.1	5.9
Nov	5.5	N/A	0.9	N/A	6.8	N/A	0.4	N/A	7.2	N/A
Dec	3.4	N/A	1.6	N/A	5.9	N/A	0.4	N/A	6.3	N/A
Jan	7.8	N/A	4.0	N/A	14.7	N/A	0.3	N/A	15.0	N/A
Feb	3.1	N/A	1.9	N/A	5.2	N/A	0.3	N/A	5.5	N/A
Mar	3.8	N/A	2.4	N/A	6.5	N/A	0.6	N/A	7.1	N/A
Apr	4.6	N/A	1.3	N/A	6.2	N/A	0.8	N/A	7.0	N/A
May-03-Apr-04	64.0	N/A	28.1	N/A	98.9	N/A	6.1	N/A	105.0	N/A
May-04-Oct-04	N/A	33.3	N/A	9.20	N/A	44.8	N/A	4.70	N/A	49.60

*The sum for energy being constrained on and off does not equal the total CMSC for energy in some months. This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC amounts.
**The totals for CMSC payments do not equal the totals for CMSC payments in Table A-10: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months.

Table A-15: Share of Constrained On Payments by Import and Domestic Suppliers

	Domestic (%)		Imports (%)	
	2003/2004	2004/2005	2003/2004	2004/2005
May	83	63	17	37
Jun	33	69	67	31
Jul	85	83	15	17
Aug	81	78	19	22
Sep	82	49	18	51
Oct	86	85	14	15
Nov	74	N/A	26	N/A
Dec	69	N/A	31	N/A
Jan	38	N/A	62	N/A
Feb	56	N/A	44	N/A
Mar	56	N/A	44	N/A
Apr	60	N/A	40	N/A

Table A-16: Share of CMSC Payments Received by Top Facilities, May 2004-October 2004

	Share of Total Payments Received by Top 10 Facilities		Share of Total Payments Received by Top 5 Facilities	
	Constrained Off (%)	**Constrained On (%)**	**Constrained Off (%)**	**Constrained On (%)**
May 04	46.6	44.9	34.3	30.5
Jun 04	51.7	29.4	35.7	16.4
Jul 04	40.6	46.9	28.0	32.8
Aug 04	58.9	48.8	41.4	36.6
Sep 04	66.4	64.5	51.2	51.2
Oct 04	55.6	72.0	36.3	56.8
May 2003 - Apr 2004	41.1	36.2	24.5	22.2
May 2004 – Oct 2004	53.3	51.1	37.8	37.4

Table A-17: Local Market Power Investigation Statistics

	May 2002 to April 2003	May 2003 to April 2004	May 2004 to October 2004*	Total
Number of LMP Investigations				
Terminated (no CMSC Adjustment)	50	25	0	75
Completed (CMSC Adjustment)	265	200	4	469
Pending	0	3	11	14
Total Initiated	315	228	15	558
Inquiry Cases Terminated	5	0	0	5
Inquiry Cases Completed	46	0	0	46
CMSC Adjustment ($ million)				
Completed Cases	6.2	3.3	0.0	9.5
Pending – Potential Adjustment	-	0.1	0.6	0.7

* The data for this period represents approximately 4 months of data, compared to 12 months in the other two periods due to the time lag between the trade date and date on which cases are opened for investigation. A number of cases with trade dates prior to May 2004 have been completed during the current period and are reflected in the May 2003 to April 2004 statistics.

Table A-18: Share of Real-time MCP Set by Resource (%), May 2003-October 2004

	Coal		Nuclear		Oil/Gas		Water	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	66	54	0	0	23	11	11	35
Jun	68	63	0	0	13	7	19	30
Jul	66	60	0	0	25	6	9	32
Aug	66	70	0	0	25	6	9	24
Sep	51	70	0	0	26	13	23	17
Oct	40	76	0	0	48	5	13	18
Nov	71	N/A	0	N/A	20	N/A	9	N/A
Dec	61	N/A	0	N/A	18	N/A	21	N/A
Jan	39	N/A	0	N/A	37	N/A	24	N/A
Feb	61	N/A	0	N/A	27	N/A	12	N/A
Mar	60	N/A	0	N/A	18	N/A	21	N/A
Apr	63	N/A	0	N/A	9	N/A	28	N/A

Table A-19: Share of Real-time MCP Set by Resource (%), Off-Peak, May 2003-October 2004

	Coal		Nuclear		Oil/Gas		Water	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	85	51	0	0	7	5	8	45
Jun	82	59	0	0	4	1	14	40
Jul	85	53	0	0	8	2	7	44
Aug	83	62	0	0	8	2	9	36
Sep	61	73	0	0	12	3	28	24
Oct	55	86	0	0	31	2	14	12
Nov	83	N/A	0	N/A	6	N/A	11	N/A
Dec	65	N/A	0	N/A	8	N/A	27	N/A
Jan	54	N/A	0	N/A	23	N/A	23	N/A
Feb	80	N/A	0	N/A	10	N/A	10	N/A
Mar	70	N/A	0	N/A	7	N/A	23	N/A
Apr	71	N/A	0	N/A	3	N/A	25	N/A

Table A-20: Share of Real-time MCP Set by Resource (%), On-Peak, May 2003-October 2004

	Coal		Nuclear		Oil/Gas		Water	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	43	58	0	0	42	19	15	23
Jun	52	67	0	0	24	14	24	19
Jul	44	69	0	0	44	11	11	18
Aug	39	80	0	0	52	10	9	10
Sep	41	67	0	0	41	24	17	9
Oct	23	62	0	0	66	10	11	27
Nov	57	N/A	0	N/A	36	N/A	6	N/A
Dec	55	N/A	0	N/A	31	N/A	15	N/A
Jan	21	N/A	0	N/A	54	N/A	25	N/A
Feb	40	N/A	0	N/A	46	N/A	14	N/A
Mar	50	N/A	0	N/A	30	N/A	20	N/A
Apr	53	N/A	0	N/A	16	N/A	31	N/A

Table A-21: Resources Selected in Real-time Market Schedule (%), May 2003-October 2004

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	7	3	6	10	24	14	7	7	27	31	41	55
Jun	8	5	6	9	26	15	6	7	23	26	42	57
Jul	5	4	8	9	30	16	6	7	21	26	46	56
Aug	6	5	6	10	27	18	6	6	22	23	45	58
Sep	8	8	4	4	18	18	7	7	22	23	49	47
Oct	9	8	1	5	28	23	9	7	26	23	30	43
Nov	6	N/A	3	N/A	23	N/A	7	N/A	28	N/A	39	N/A
Dec	7	N/A	5	N/A	18	N/A	7	N/A	26	N/A	46	N/A
Jan	7	N/A	6	N/A	25	N/A	7	N/A	23	N/A	43	N/A
Feb	6	N/A	4	N/A	23	N/A	7	N/A	23	N/A	45	N/A
Mar	5	N/A	5	N/A	19	N/A	7	N/A	24	N/A	50	N/A
Apr	5	N/A	8	N/A	15	N/A	7	N/A	29	N/A	52	N/A

Table A-22: Resources Selected in the Real-time Market Schedule (TWh)
May 2003-October 2004

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear		Total	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	0.87	0.41	0.74	1.21	2.80	1.60	0.79	0.78	3.11	3.72	4.79	6.53	11.62	11.83
Jun	0.95	0.65	0.69	1.12	3.09	1.75	0.75	0.79	2.79	3.15	4.99	6.82	11.88	12.04
Jul	0.60	0.57	1.09	1.11	3.86	1.99	0.83	0.83	2.72	3.34	5.97	7.11	12.89	12.73
Aug	0.49	0.69	0.59	1.28	2.48	2.23	0.58	0.73	2.06	2.91	4.11	7.43	9.13	12.71
Sep	0.94	1.03	0.45	0.49	2.17	2.21	0.79	0.86	2.59	2.87	5.77	5.83	11.81	12.31
Oct	1.06	0.95	0.17	0.56	3.40	2.81	1.10	0.91	3.13	2.84	3.60	5.23	12.12	12.18
Nov	0.72	N/A	0.36	N/A	2.87	N/A	0.87	N/A	3.41	N/A	4.86	N/A	12.37	N/A
Dec	0.98	N/A	0.64	N/A	2.41	N/A	0.94	N/A	3.44	N/A	6.18	N/A	13.31	N/A
Jan	1.06	N/A	0.85	N/A	3.74	N/A	1.09	N/A	3.35	N/A	6.34	N/A	14.73	N/A
Feb	0.84	N/A	0.53	N/A	2.97	N/A	0.93	N/A	3.03	N/A	5.85	N/A	13.09	N/A
Mar	0.68	N/A	0.60	N/A	2.49	N/A	0.95	N/A	3.14	N/A	6.55	N/A	13.21	N/A
Apr	0.55	N/A	0.93	N/A	1.81	N/A	0.81	N/A	3.35	N/A	6.16	N/A	11.75	N/A

*Table A-23: Offtakes by Intertie Zone, On-peak and Off-peak (MWh), May 2003-October 2004**

		MB		MI		MN		NY		PQ	
		2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	**Off-peak**	0	0	8,278	21,592	139	9,138	460,429	668,221	20,955	31,115
	On-Peak	1,045	0	33,007	73,147	2,919	30,633	205,235	363,678	4,777	14,485
Jun	**Off-peak**	3,312	0	9,710	16,175	943	794	350,691	565,888	44,240	36,048
	On-Peak	2,133	0	28,716	44,143	10,564	7,465	220,195	417,033	23,789	27,585
Jul	**Off-peak**	14,675	0	69,856	21,568	18,854	2,085	521,199	608,976	43,708	41,731
	On-Peak	31,929	0	98,096	67,785	31,828	19,549	235,600	331,014	21,673	21,238
Aug	**Off-peak**	46,801	0	7,126	14,568	13,817	1,000	353,700	692,843	18,348	34,207
	On-Peak	29,619	0	33,644	74,885	28,389	400	52,269	447,670	2,376	16,535
Sep	**Off-peak**	31,961	0	159	8.458	2,775	0	247,693	285,404	26,908	12,600
	On-Peak	24,188	0	1,072	12.051	11,683	377	86,484	162,580	13,198	4,251
Oct	**Off-peak**	40,830	0	446	5,098	139	39	58,563	284,241	13,949	4,296
	On-Peak	16,079	0	4,387	13,662	2,781	1,888	23,839	243,433	6,757	2,583
Nov	**Off-peak**	55,006	N/A	688	N/A	973	N/A	111,894	N/A	22,004	N/A
	On-Peak	27,790	N/A	1,863	N/A	19,738	N/A	111,769	N/A	6,860	N/A
Dec	**Off-peak**	43,116	N/A	2,675	N/A	2,085	N/A	347,624	N/A	30,522	N/A
	On-Peak	26,495	N/A	2,746	N/A	15,393	N/A	150,844	N/A	15,612	N/A
Jan	**Off-peak**	53,207	N/A	3,797	N/A	8,340	N/A	412,602	N/A	50,457	N/A
	On-Peak	26,656	N/A	3,463	N/A	15,797	N/A	240,286	N/A	35,896	N/A
Feb	**Off-peak**	21,875	N/A	555	N/A	0	N/A	313,363	N/A	54,437	N/A
	On-Peak	7,520	N/A	2,820	N/A	3,000	N/A	100,634	N/A	28,899	N/A
Mar	**Off-peak**	10,477	N/A	3,871	N/A	1,964	N/A	253,878	N/A	58,351	N/A
	On-Peak	110	N/A	24,471	N/A	49,892	N/A	159,004	N/A	39,482	N/A
Apr	**Off-peak**	4,094	N/A	10,501	N/A	5,485	N/A	481,821	N/A	57,719	N/A
	On-Peak	39	N/A	25,077	N/A	40,690	N/A	260,816	N/A	39,770	N/A

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

*Table A-24: Injections by Intertie Zone, On-peak and Off-peak (MWh), May 2003-October 2004**

		MB		MI		MN		NY		PQ	
		2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	**Off-peak**	85,264	12,169	318,783	248,883	29,752	8,047	5,374	5,650	3,765	0
	On-Peak	68,058	31,634	281,276	74,405	21,817	9,401	48,009	15,338	7,012	545
Jun	**Off-peak**	73,990	43,718	351,737	313,700	29,390	20,193	9,045	4,634	201	96
	On-Peak	66,820	61,812	308,741	154,277	19,225	15,512	86,715	25,145	5,839	6,445
Jul	**Off-peak**	65,164	63,958	247,645	295,430	17,864	25,797	27,195	16,530	4,229	5,683
	On-Peak	67,930	14,288	97,847	78,344	4,592	5,895	66,803	17,577	2,016	46,895
Aug	**Off-peak**	43,836	73,522	226,597	352,551	13,026	27,778	1,570	25,378	6,585	6,659
	On-Peak	40,800	31,238	65,393	131,802	84	12,045	35,758	6,418	55,109	24,802
Sep	**Off-peak**	47,388	73,961	380,029	414,710	24,651	19,196	21,330	31,519	3,799	20,215
	On-Peak	61,925	38,403	296,925	286,465	11,843	8,256	75,660	40,357	12,615	100,997
Oct	**Off-peak**	65,634	78,755	294,639	361,365	26,447	23,639	119,571	4,489	18,648	46,985
	On-Peak	54,109	34,964	263,018	236,722	17,548	4,589	163,378	7,051	32,427	153,582
Nov	**Off-peak**	19,669	N/A	315,854	N/A	20,249	N/A	47,658	N/A	9,551	N/A
	On-Peak	200	N/A	234,892	N/A	5,547	N/A	59,115	N/A	10,725	N/A
Dec	**Off-peak**	47,872	N/A	371,020	N/A	23,362	N/A	67,631	N/A	13,216	N/A
	On-Peak	3,313	N/A	309,766	N/A	6,573	N/A	112,489	N/A	28,733	N/A
Jan	**Off-peak**	5,790	N/A	481,990	N/A	17,708	N/A	49,852	N/A	5,659	N/A
	On-Peak	7,003	N/A	363,567	N/A	6,516	N/A	102,299	N/A	17,035	N/A
Feb	**Off-peak**	21,933	N/A	344,345	N/A	12,848	N/A	77,751	N/A	0	N/A
	On-Peak	17,366	N/A	257,303	N/A	7,572	N/A	99,389	N/A	720	N/A
Mar	**Off-peak**	42,797	N/A	258,140	N/A	4,638	N/A	35,812	N/A	0	N/A
	On-Peak	61,078	N/A	196,008	N/A	9,928	N/A	70,978	N/A	2,561	N/A
Apr	**Off-peak**	26,878	N/A	303,658	N/A	0	N/A	5,581	N/A	0	N/A
	On-Peak	39,065	N/A	161,750	N/A	0	N/A	8,864	N/A	384	N/A

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

Table A-25: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP

	3-hour ahead pre-dispatch price minus HOEP ($/MWh)									
	Average difference		Maximum difference		Minimum difference		Standard deviation		Average difference as a % of the HOEP	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	13.11	9.56	1,976.90	89.29	(150.79)	(67.17)	75.66	15.72	46.07	28.42
Jun	12.41	6.32	405.10	56.29	(103.26)	(114.16)	33.43	14.04	38.59	24.00
Jul	7.98	5.12	91.16	45.73	(38.59)	(72.63)	13.97	11.49	29.25	18.63
Aug	8.24	4.80	56.15	37.7	(53.16)	(40.78)	14.75	8.10	24.91	17.56
Sep	6.94	4.77	63.98	40.83	(282.68)	(93.73)	17.09	9.07	20.39	13.19
Oct	7.28	4.97	45.48	51.93	(249.97)	(63.19)	17.22	10.82	19.87	11.47
Nov	7.82	N/A	52.69	N/A	(53.37)	N/A	12.06	N/A	22.71	N/A
Dec	18.18	N/A	73.35	N/A	(49.56)	N/A	20.58	N/A	51.31	N/A
Jan	27.09	N/A	855.39	N/A	(77.54)	N/A	59.01	N/A	48.22	N/A
Feb	18.44	N/A	77.18	N/A	(33.54)	N/A	17.75	N/A	42.22	N/A
Mar	11.93	N/A	63.43	N/A	(93.06)	N/A	14.11	N/A	28.32	N/A
Apr	12.89	N/A	63.98	N/A	(199.13)	N/A	15.53	N/A	34.51	N/A

Table A-26: Measures of Differences between 1-Hour Ahead Pre-dispatch Prices and HOEP

	1-hour ahead pre-dispatch price minus HOEP ($/MWh)									
	Average difference		Maximum difference		Minimum difference		Standard deviation		Average difference as a % of the HOEP	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	11.04	10.05	78.53	72.62	(128.79)	(62.19)	19.54	14.11	35.10	27.58
Jun	11.63	6.73	490.10	53.20	(225.41)	(108.31)	32.79	12.84	38.76	24.09
Jul	7.65	5.21	55.27	41.29	(38.59)	(71.62)	13.19	10.06	26.93	18.32
Aug	8.23	4.99	52.98	33.05	(47.28)	(36.79)	13.96	7.58	23.92	17.61
Sep	7.01	4.01	63.14	31.99	(287.68)	(93.98)	16.41	7.97	19.59	11.57
Oct	7.25	5.72	47.62	51.21	(223.15)	(45.55)	15.46	10.12	19.53	12.69
Nov	6.86	N/A	74.23	N/A	(56.49)	N/A	11.47	N/A	19.65	N/A
Dec	15.92	N/A	70.15	N/A	(83.54)	N/A	19.33	N/A	44.92	N/A
Jan	23.07	N/A	780.39	N/A	(99.55)	N/A	51.72	N/A	42.34	N/A
Feb	15.86	N/A	62.16	N/A	(38.2)	N/A	16.17	N/A	36.15	N/A
Mar	10.45	N/A	57.54	N/A	(92.83)	N/A	12.93	N/A	24.79	N/A
Apr	12.02	N/A	57.45	N/A	(191.93)	N/A	14.74	N/A	31.29	N/A

Table A-27: Measures of Difference between Pre-dispatch Prices and Peak Hourly MCP

	1-Hour Ahead Pre-dispatch Price minus Peak Hourly MCP			
	Average Difference ($/MWh)		Average Difference as % of Peak Hourly MCP	
	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005
May	0.81	1.69	16.8	10.7
Jun	0.73	0.39	21.0	8.0
Jul	3.15	(0.03)	14.9	4.7
Aug	2.87	0.91	12.2	5.4
Sep	0.78	(0.19)	7.1	2.8
Oct	0.58	1.45	6.8	4.6
Nov	1.65	N/A	8.4	N/A
Dec	7.15	N/A	24.2	N/A
Jan	8.19	N/A	19.4	N/A
Feb	6.53	N/A	18.3	N/A
Mar	2.47	N/A	9.7	N/A
Apr	2.20	N/A	15.3	N/A

Table A-28: Average Monthly HOEP Compared to Peak Hourly MCP

	HOEP		Peak Hourly MCP		Peak minus HOEP	
	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005
May	43.17	48.06	53.41	56.47	10.25	8.41
Jun	41.64	46.69	52.54	53.15	10.91	6.46
Jul	40.08	45.58	44.52	50.83	4.44	5.25
Aug	46.85	43.51	52.22	47.59	5.37	4.08
Sep	48.56	49.57	54.81	53.76	6.26	4.19
Oct	57.09	49.11	63.77	53.47	6.68	4.36
Nov	40.45	N/A	45.70	N/A	5.25	N/A
Dec	44.42	N/A	53.16	N/A	8.74	N/A
Jan	66.22	N/A	81.29	N/A	15.08	N/A
Feb	52.74	N/A	62.12	N/A	9.37	N/A
Mar	48.90	N/A	56.89	N/A	7.99	N/A
Apr	45.92	N/A	55.72	N/A	9.80	N/A

*Table A-29: Frequency Distribution of Difference between 1-Hour Pre-dispatch and HOEP, May 2003-October 2004**

	1-hour ahead pre-dispatch price minus HOEP (% of time within range)															
	Greater than -$50.01		**-$50 to-$20.01**		**-$20.00 to -$10.01**		**-$10.00 to -$0.01**		**$0.00 to $9.99**		**$10.00 to $19.99**		**$20.00 to $49.99**		**Greater than $50.00**	
	2003/2004	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**	**2003/2004**	**2004/2005**
May	0.67	0.27	1.08	2.02	2.29	1.75	8.36	11.29	50.27	40.32	9.30	**24.60**	26.28	**18.68**	1.75	**1.08**
Jun	**0.84**	**0.70**	**3.63**	0.97	2.51	**2.92**	13.11	16.02	45.05	45.54	8.51	22.28	21.90	11.28	4.46	0.28
Jul	0.00	0.13	0.81	**1.48**	0.54	2.15	**14.80**	**20.43**	**58.68**	48.79	6.86	19.49	18.17	7.53	0.13	0.00
Aug	0.00	0.00	0.95	0.40	1.52	2.02	14.02	14.54	55.68	62.05	7.58	16.69	20.08	4.31	0.19	0.00
Sep	0.14	0.28	1.11	0.14	2.50	1.39	14.72	18.89	50.69	**63.89**	15.42	12.50	15.14	2.92	0.28	0.00
Oct	0.54	0.00	0.81	0.40	1.88	2.02	14.13	19.95	52.22	53.10	14.27	15.23	16.15	9.16	0.00	0.13
Nov	0.14	N/A	0.70	N/A	1.67	N/A	10.57	N/A	57.58	N/A	16.55	N/A	12.52	N/A	0.28	N/A
Dec	0.13	N/A	1.21	N/A	1.48	N/A	6.45	N/A	43.28	N/A	11.96	N/A	29.30	N/A	6.18	N/A
Jan	0.40	N/A	2.02	N/A	**3.36**	N/A	10.77	N/A	30.96	N/A	11.57	N/A	29.21	N/A	**11.71**	N/A
Feb	0.00	N/A	0.72	N/A	1.58	N/A	5.32	N/A	38.22	N/A	18.10	N/A	**33.48**	N/A	2.59	N/A
Mar	0.13	N/A	1.34	N/A	1.88	N/A	9.95	N/A	42.07	N/A	23.79	N/A	20.43	N/A	0.40	N/A
Apr	0.28	N/A	0.42	N/A	1.53	N/A	7.92	N/A	37.50	N/A	**29.03**	N/A	22.64	N/A	0.69	N/A

*Bolded values show highest percentage within price range.

Table A-30: Difference between 1-Hour Pre-dispatch and HOEP within Defined Ranges

	Hourly Difference - % of Time within Range 1-hour ahead pre-dispatch price minus HOEP					
	Greater than $0		Equal to $0		Less than $0	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	87.60	84.14	0.00	0.54	12.40	15.32
Jun	79.78	78.97	0.14	0.42	20.08	20.61
Jul	83.58	75.40	0.27	0.40	16.15	24.19
Aug	83.33	81.83	0.19	1.21	16.48	16.96
Sep	80.97	79.17	0.56	0.14	18.47	20.69
Oct	82.50	77.63	0.13	0.00	17.36	22.37
Nov	86.93	N/A	0.00	N/A	13.07	N/A
Dec	90.73	N/A	0.00	N/A	9.27	N/A
Jan	83.31	N/A	0.13	N/A	16.55	N/A
Feb	92.39	N/A	0.00	N/A	7.61	N/A
Mar	86.56	N/A	0.13	N/A	13.31	N/A
Apr	89.86	N/A	0.00	N/A	10.14	N/A

Table A-31: Difference between One Hour Pre-dispatch and Peak Hourly MCP within Defined Ranges

	Hourly Difference - % of Time within Range 1-hour ahead pre-dispatch price minus peak hourly MCP					
	Greater than $0		Equal to $0		Less than $0	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	65.90	59.68	2.83	4.57	31.27	35.75
Jun	57.04	59.89	2.65	1.39	40.31	38.72
Jul	61.78	52.69	2.83	3.36	35.40	43.95
Aug	63.64	58.41	2.46	2.96	33.90	38.63
Sep	56.39	56.67	4.17	1.94	39.44	41.39
Oct	55.05	56.6	4.58	2.83	40.38	40.57
Nov	65.09	N/A	2.92	N/A	31.99	N/A
Dec	71.10	N/A	2.02	N/A	26.88	N/A
Jan	60.97	N/A	3.63	N/A	35.40	N/A
Feb	70.26	N/A	2.30	N/A	27.44	N/A
Mar	68.15	N/A	2.82	N/A	29.03	N/A
Apr	71.67	N/A	1.11	N/A	27.22	N/A

*Table A-32: Percentage Intervals with Operating Reserve Reductions (Market Schedule), May 2003-October 2004**

	No Reductions		>1 MW and <200 MW		>200 MW and <400 MW		>400 MW and <800 MW		>800 MW	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	96.98	94.02	0.43	3.14	1.78	1.87	0.80	0.96	0.02	0.01
Jun	96.82	97.28	0.15	1.05	1.45	1.19	1.35	0.47	0.23	0.00
Jul	98.53	98.41	0.15	0.73	0.65	0.53	0.56	0.32	0.11	0.01
Aug	96.54	99.12	0.19	0.38	2.73	0.40	0.47	0.10	0.07	0.00
Sep	99.61	99.20	0.05	0.34	0.19	0.03	0.14	0.43	0.02	0.00
Oct	97.77	99.63	0.77	0.15	0.96	0.10	0.30	0.12	0.19	0.00
Nov	99.11	N/A	0.42	N/A	0.35	N/A	0.13	N/A	0.00	N/A
Dec	97.95	N/A	0.45	N/A	0.93	N/A	0.55	N/A	0.12	N/A
Jan	96.81	N/A	0.74	N/A	1.66	N/A	0.56	N/A	0.21	N/A
Feb	98.68	N/A	0.49	N/A	0.63	N/A	0.19	N/A	0.00	N/A
Mar	98.75	N/A	0.72	N/A	0.25	N/A	0.29	N/A	0.00	N/A
Apr	97.99	N/A	1.16	N/A	0.69	N/A	0.08	N/A	0.08	N/A

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

Table A-33: Forecast Bias in Demand

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-hour ahead		1-hour ahead		3-hour ahead		1-hour ahead		3-hour ahead		1-hour ahead		3-hour ahead		1-hour ahead	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
Jan	422	484	406	466	253	297	219	253	2.22	2.82	2.13	2.72	1.31	1.55	1.13	1.31
Feb	398	441	372	408	260	254	220	208	2.08	2.43	1.94	2.24	1.34	1.37	1.13	1.12
Mar	359	434	341	404	238	271	209	226	2.05	2.57	1.94	2.38	1.34	1.57	1.17	1.30
Apr	367	399	341	376	251	259	213	222	2.27	2.57	2.11	2.40	1.51	1.62	1.28	1.38
May	356	356	345	322	203	233	179	192	2.41	2.38	2.33	2.14	1.33	1.52	1.17	1.23
Jun	386	373	360	341	250	284	208	233	2.45	2.30	2.28	2.11	1.55	1.70	1.29	1.40
Jul	479	433	417	384	336	322	259	261	2.87	2.61	2.51	2.31	1.94	1.89	1.50	1.53
Aug	451	403	403	359	327	297	261	238	2.70	2.44	2.42	2.17	1.87	1.73	1.50	1.39
Sep	375	368	354	342	244	247	203	201	2.38	2.30	2.25	2.12	1.51	1.47	1.25	1.20
Oct	370	314	358	300	226	200	196	169	2.40	2.04	2.31	1.94	1.42	1.26	1.23	1.06
Nov	408	N/A	383	N/A	241	N/A	207	N/A	2.49	N/A	2.33	N/A	1.44	N/A	1.23	N/A
Dec	478	N/A	441	N/A	282	N/A	229	N/A	2.82	N/A	2.57	N/A	1.65	N/A	1.32	N/A

Table A-34: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges (%)

	>500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	3	3	28	21	17	16	22	17	14	15	10	12	6	14	0	1	71	57	29	43
Jun	6	6	23	20	13	14	17	14	16	14	11	11	13	18	1	3	58	53	42	47
Jul	10	9	25	21	12	12	13	14	11	12	13	10	16	18	1	4	59	56	41	44
Aug	10	7	23	21	12	13	15	17	11	13	9	10	16	16	4	4	60	57	40	43
Sep	5	4	22	19	16	11	17	19	16	18	9	10	13	16	1	3	60	53	40	47
Oct	3	1	28	17	15	18	18	20	14	18	10	11	10	1	1	1	64	56	36	44
Nov	5	N/A	28	N/A	17	N/A	16	N/A	13	N/A	10	N/A	10	N/A	1	N/A	66	N/A	34	N/A
Dec	8	N/A	28	N/A	17	N/A	15	N/A	14	N/A	8	N/A	9	N/A	1	N/A	68	N/A	32	N/A
Jan	8	N/A	33	N/A	15	N/A	13	N/A	10	N/A	9	N/A	11	N/A	1	N/A	70	N/A	30	N/A
Feb	5	N/A	35	N/A	19	N/A	17	N/A	12	N/A	7	N/A	5	N/A	1	N/A	76	N/A	24	N/A
Mar	6	N/A	33	N/A	16	N/A	16	N/A	11	N/A	8	N/A	9	N/A	2	N/A	71	N/A	29	N/A
Apr	7	N/A	30	N/A	17	N/A	15	N/A	14	N/A	8	N/A	9	N/A	1	N/A	68	N/A	32	N/A

Table A-35: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities

	Total MW Pre-dispatch		Maximum Difference (MW)		Minimum Difference (MW)		Average Difference (MW)		Fail Rate (Difference/MW Pre-dispatch) (%)	
	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005	2003 / 2004	2004 / 2005
May	778,341	712,553	290.51	145.81	(69.88)	(118.30)	62.34	(5.70)	6.26	(0.42)
Jun	886,176	754,026	668.18	283.55	(243.79)	(91.13)	93.82	10.00	8.65	0.82
Jul	1,249,147	842,044	509.86	582.64	(146.78)	(282.74)	94.12	51.68	5.68	4.32
Aug	703,045	737,531	364.83	227.87	(193.14)	(53.35)	86.83	33.11	6.92	3.61
Sep	764,657	719,483	543.98	308.92	(111.61)	(103.57)	37.07	42.28	3.80	4.54
Oct	821,786	770,163	154.27	276.43	(94.26)	(97.43)	(0.42)	24.44	0.07	2.50
Nov	964,681	N/A	277.22	N/A	(139.22)	N/A	(5.73)	N/A	(0.68)	N/A
Dec	863,853	N/A	404.54	N/A	(140.32)	N/A	(0.74)	N/A	0.11	N/A
Jan	1,080,865	N/A	1,317.40	N/A	(834.48)	N/A	17.39	N/A	1.11	N/A
Feb	834,172	N/A	643.54	N/A	(249.99)	N/A	(3.99)	N/A	(0.92)	N/A
Mar	1,174,221	N/A	724.42	N/A	(130.98)	N/A	11.08	N/A	0.55	N/A
Apr	760,221	N/A	262.47	N/A	(112.58)	N/A	(11.35)	N/A	(1.00)	N/A

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

Table A-36: Incidents and Average Magnitude of Failed Imports into Ontario

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	239	141	654	388	63.4	59.3	1.7	2.0
Jun	151	292	687	864	105.3	109.8	1.6	4.7
Jul	111	289	891	545	110.4	108.3	2.0	5.2
Aug	87	341	389	667	90.1	85.1	1.6	4.0
Sep	167	270	525	509	97.4	76.8	1.7	2.5
Oct	279	311	792	482	133.1	123	3.4	3.9
Nov	164	N/A	682	N/A	100.3	N/A	2.2	N/A
Dec	191	N/A	861	N/A	118.7	N/A	2.3	N/A
Jan	287	N/A	1,233	N/A	127.1	N/A	3.3	N/A
Feb	160	N/A	654	N/A	90.8	N/A	1.7	N/A
Mar	148	N/A	700	N/A	90.8	N/A	1.9	N/A
Apr	130	N/A	463	N/A	67.9	N/A	1.6	N/A

Table A-37: Incidents and Average Magnitude of Failed Exports from Ontario

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
May	427	437	1,020	958	214.9	183.4	11.1	6.2
Jun	386	471	1,107	1,104	337.3	203.3	15.9	7.9
Jul	464	467	1,300	950	343.5	189.7	12.8	7.4
Aug	306	454	1,036	1,052	322.5	229.3	14.4	7.5
Sep	291	264	977	900	236.5	197.0	13.4	16.0
Oct	148	388	815	964	171.7	231.6	13.2	14
Nov	262	N/A	737	N/A	158.7	N/A	10.4	N/A
Dec	270	N/A	903	N/A	192.5	N/A	7.5	N/A
Jan	285	N/A	1,214	N/A	167.9	N/A	5.4	N/A
Feb	240	N/A	740	N/A	152.2	N/A	6.4	N/A
Mar	281	N/A	675	N/A	137.4	N/A	6.0	N/A
Apr	301	N/A	977	N/A	188.4	N/A	5.8	N/A