Ontario Energy Board

Commission de l'énergie de l'Ontario



Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from May 2013 – October 2013

September 2014

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Executive Summary

This semi-annual monitoring report covers the period May to October of 2013 (the "Summer 2013 Period"). As is the Panel's practice for reports covering a May to October period (the "Summer Period"), this report focuses on the results of the Panel's review of high-price and low-price hours and of other market outcomes that are potentially anomalous (Chapter 2). It also discusses notable changes and developments that affect the efficient operation of the IESO-administered markets (Chapter 3) and the status of implementation of recommendations made in the Panel's last monitoring report (Chapter 4).

Consistent with the Panel's practice, the Panel's assessment of the state of the IESOadministered markets will be included in its next winter period monitoring report (covering the period November 2013 to April 2014).

With the exception of Chapter 4 and references elsewhere to the Panel's June 2014 Monitoring Report, and of references to the release of a Panel investigation report in July 2014, the information set out in this report does not go beyond December 31, 2013.

1. Demand and Supply Conditions

Ontario demand totalled 70.55 TWh in the Summer 2013 Period, down by 2.05 TWh (2.8%) from the preceding Summer Period. In the Summer 2013 Period, demand was lower in all months compared to the same months in 2012. Relative to 2012, the largest percentage decrease in demand occurred in June at 5.7%.

No additional generation capacity was added to the IESO-controlled grid during the Summer 2013 Period. Ontario saw another reduction in its coal-fired generating capacity in furtherance of the provincial government's policy of eliminating coal-fired generation by the end of 2014. The Lambton coal-fired generation facility was taken offline by Ontario Power Generation Inc. in September 2013, removing 1,016 MW of capacity from service.

This loss of capacity resulted in a total installed capacity of 35,000 MW as at October 31, 2013. This total includes 166 MW of renewable (wind) capacity from the Comber Wind Farm that was added to the province's supply resources in April 2013, just prior to the Summer 2013 Period.

2. Market Prices and Effective Prices

The average load-weighted Hourly Ontario Energy Price (HOEP) was \$24.69/MWh during the Summer 2013 Period, a decrease of \$0.84/MWh from the prior Summer Period.

The Panel reports what it calls the "effective price" for Ontario consumers, which is comprised of the HOEP, the Global Adjustment (GA) and uplift. For the Summer 2013 Period, the effective price was \$52.89/MWh for Class A consumers that are directly connected to the IESO-controlled grid, and \$89.73/MWh for all other consumers (Class B consumers and Class A consumers that are connected at the distribution level).¹ The principal reason for the difference in the effective price is the amount of GA that was charged to each Class. In the Summer 2013 Period, the average GA charge was \$28.18/MWh for Class A consumers that are directly connected to the IESO-controlled grid and was \$61.62/MWh for all other consumers.

Operating Reserve (OR) prices were much higher compared to the previous Summer Period, with 10-minute spinning and 10-minute non-spinning OR prices reaching their highest levels in the history of the Ontario market. As noted below, this report includes an analysis of the reasons for the record high OR prices.

Long-term transmission right (TR) auction prices for imports into the Northwest (Manitoba and Minnesota) decreased by 77% compared to the previous Summer Period. Short-term TR auction prices for imports at the Manitoba interface were also significantly lower in the Summer 2013 Period than in the previous Summer Period. The Panel largely attributes these decreases to Market Rule amendments that eliminated

¹ The "Class A" and "Class B" distinction stems from the classification of consumers into different classes for purposes of the allocation of the GA, Class A consumers being those whose average peak demand exceeds 5 MW and Class B consumers being all other consumers. This is discussed further in section 1 of Chapter 1, as is the reason why Class A consumers that are connected at the distribution level are grouped with Class B consumers for purposes of this report.

constrained-off Congestion Management Settlement Credit (CMSC) payments for import transactions into the Northwest effective October 2012. With the opportunity to earn constrained-off CMSC payments effectively eliminated, one could reasonably expect fewer import offers and fewer low-priced offers targeting such payments in the Northwest zone. Market participants would then expect less frequent congestion and lower absolute intertie congestion prices. This change in expectations would in turn reduce the expected value of ownership of TRs for imports into the Northwest zone.

3. Market Outcomes

There were eight hours in the Summer 2013 Period in which the HOEP exceeded \$200/MWh, which is significantly more than in the preceding Summer Period but consistent with earlier Summer Periods. The majority of the high-price events in the Summer 2013 Period were caused by higher than forecast temperatures, although in several cases the absence of offers from some generators in pre-dispatch also contributed to the higher prices.

Relative to the previous four Summer Periods, the Summer 2013 Period saw a significant increase in the number of hours in which the HOEP was below \$0/MWh (224 hours). This is largely attributable to a large increase in negative-priced offers from nuclear generation facilities resulting from the return to service of two units at the Bruce nuclear generating station.

There were ten instances in which the Panel's anomalous uplift screening thresholds were met in relation to CMSC payments in the Summer 2013 Period. On eight days, CMSC payments exceeded \$1,000,000, and on three of those days the vast majority of the CMSC payments were made to a dispatchable load. There were also 2 hours in the Summer 2013 Period in which CMSC payments exceeded \$500,000.

The Panel's anomalous uplift screening thresholds were not met in relation to Intertie Offer Guarantee payments in the Summer 2013 Period. There were six hours in which the Panel's screening threshold of \$100,000 in a given hour was met in relation to OR payments.²

4. *Matters to Report in the Ontario Electricity Marketplace*

Investigations

The Panel currently has investigations under way in relation to three market participants (one generator and two dispatchable loads), all of which relate to potential gaming. In July, 2014, the Panel issued its report on an investigation into possible gaming behaviour by Greenfield Energy Centre LP in respect of CMSC payments.

Record High Prices in Operating Reserve Market

In May 2013, OR prices in the 10-minute spinning and 10-minute non-spinning categories reached record high levels. This was predominantly caused by a confluence of three factors; specifically, a reduction in the number of resources offering into the OR market relative to the previous two Summer Periods, a reduction in the total number of MWs offered into the OR market relative to the previous two Summer Periods, and actions by the IESO to more accurately reflect the amount of OR that was available through voltage reductions (referred to as Control Action Operating Reserve). These factors together contributed to the overall increase in prices for 10-minute spinning and 10-minute non-spinning OR, although there was no comparable increase in the price paid for 30-minute OR.

Ontario Consumer Costs and Export Subsidization

Over the past year, the role of electricity exports in the Ontario market has been the subject of considerable commentary. Questions have arisen about the value that export transactions provide to Ontario consumers, and more specifically around the question of whether and the extent to which Ontario ratepayers are subsidizing export transactions (in other words, paying costs that are incurred as a result of export transactions). Two

 $^{^{2}}$ OR is standby power that can be called upon to re-establish the balance between supply and demand in the event of a contingency such as a sudden or unexpected increase in demand or a decrease in generation or transmission service.

recent press reports have claimed that Ontarians paid over \$1 billion to subsidize export transactions to neighbouring jurisdictions in 2013. The Panel considered the methodology that was used in arriving at this estimate, and examined in greater detail the costs that are triggered by exports to determine the extent to which those costs are not fully covered by the market price or by other charges paid by exporters. The Panel's analysis found that, without taking into account any benefit that exports provide, Ontario consumers paid an average of \$43 million for exporter-induced costs in each of 2012 and 2013. This is far lower than the \$1 billion claimed by some commentators. The cost subsidization from Ontario consumers to exporters would go towards offsetting any benefit that exports provide to Ontario, for example, in the form of transmission service charges (an average of \$34 million per year in 2012 and 2013) that would otherwise have been borne by Ontario consumers or the creation of surpluses for Ontario generators (which offset the Global Adjustment). Quantification of the benefits provided by exports is difficult, and was outside the scope of the Panel's analysis. The Panel therefore did not compare the costs paid by exporters with any such benefits to arrive at any net benefit of exports to Ontario.

In terms of the source of the cross-subsidization, the Panel's analysis of costs triggered by exports reveals that there is no cross-subsidization associated with exporters not paying the Global Adjustment, which makes up over half of the all-in cost paid by Ontario consumers, nor is there cross-subsidization associated with the Hourly Ontario Energy Price. However, the Panel has found that exporters do not bear the full cost of starting generators under the IESO's generation cost guarantee programs to meet export demand. An alternative approach to the allocation of uplift charges associated with payments under those generation cost guarantee programs could more closely align cost recovery with cost causality and better reflect the extent to which Ontario consumers, on the one hand, and exporters, on the other, cause those payments to be incurred.

5. *Recommendations*

In this report, the Panel makes one recommendation related to the use of Control Action Operating Reserve in the OR market and one recommendation related to the way in which uplift charges associated with generation cost guarantee program payments are allocated as between domestic consumers and exporters. These recommendations flow from the analyses referred to above regarding record high prices in the OR market and the cross-subsidization of exports.

Recommendation 3-1

The Panel recommends that the IESO make more information available to market participants about its practices of de-rating Control Action Operating Reserve, including the criteria used to determine the amount and duration of such de-ratings.

Recommendation 3-2

The Panel recommends that the IESO revise the way it allocates uplift charges associated with top-up payments under the real-time generation cost guarantee and day-ahead production cost guarantee programs so that the charges to Ontario consumers and to exporters better reflect the extent to which each group causes those payments to be incurred.

Chapter 1: Market Outcomes

This chapter provides a brief summary of the results for the IESO-administered markets over the period May 1, 2013 to October 31, 2013 (the "Summer 2013 Period"), with comparisons to the same period one year earlier (the "Summer 2012 Period"), as well as other periods where relevant. A reference to a "Summer Period" is to the period May 1 to October 31, inclusive.

1 Pricing

This section sets out a summary of pricing in the IESO-administered markets, covering: the Hourly Ontario Energy Price (HOEP); effective prices (HOEP plus the Global Adjustment (GA) and uplift)³, operating reserve prices; and transmission rights auction prices. For the first two categories of prices, the information is presented by consumer class according to the classification that applies to the allocation of the GA. For GA allocation purposes, consumers are divided into two groups: Class A, being consumers whose average peak demand exceeds 5 MW (these consumers - typically factories or other large industrial consumers – can be directly connected to the IESO-controlled grid or connected at the distribution level); and Class B, being all other consumers (including all residential consumers).⁴ Because information regarding hourly consumption by Class A consumers that are connected at the distribution level is not readily available, HOEP and effective price information pertaining to Class A consumers below relates only to Class A consumers that are directly connected to the IESO-controlled grid (referred to as "Direct Class A"). During the Summer 2013 Period, there were 67 Direct Class A consumers. Information pertaining to Class A consumers that are connected at the distribution level (referred to as "Embedded Class A") is aggregated with information pertaining to Class B customers.

³ In this chapter, uplift refers to (i) hourly uplift, which includes hourly payments for operating reserve, Congestion Management Settlement Credit payments, Intertie Offer Guarantee payments and line losses; and (ii) monthly uplift, which are costs that the IESO incurs in obtaining services required to ensure the reliability of the IESO-controlled grid. These include charges related to the IESO's generation cost guarantee programs, black start service, and the provision of regulation. The monthly uplift category referred to in this chapter differs from the "non-hourly uplift" category referred to in Chapter 3 of this report.

⁴ See Ontario Regulation 398/10 (Adjustments under section 25.33 of the Act) made under the *Electricity Act, 1998,* available at http://www.e-laws.gov.on.ca/html/source/regs/english/2010/elaws_src_regs_r10398_e.htm).

1.1 HOEP and Effective Prices

While the average HOEP (both simple monthly average and load-weighted average) in the Summer 2013 Period decreased relative to the Summer 2012 Period, the average GA and the average effective price (comprised of the HOEP, the GA and uplift) were both higher.

Figure 1-1 plots the monthly (simple) average HOEP between May 2012 and October 2013. The average HOEP was \$23.23/MWh during the Summer 2013 Period; the average HOEP for the Summer 2012 Period was \$24.13/MWh. The HOEP fluctuated somewhat during the Summer 2013 Period, although these fluctuations appear to be broadly consistent with the pattern seen in the preceding two 6-month reporting periods.





As shown in Table 1-1, the average effective price for electricity in the Summer 2013 Period was \$52.89/MWh for Direct Class A consumers and \$89.07/MWh for Class B and Embedded Class A consumers. Both classes saw a reduction in the average loadweighted HOEP⁵ and an increase in average GA and average uplift charges in the Summer 2013 Period relative to the Summer 2012 Period. Direct Class A consumers, who consumed approximately 12% of the province's total electricity, paid 6% of the total average GA charges in the Summer 2013 Period, which is roughly half of what they would have paid under the volumetric GA allocation methodology regime that existed prior to January 1, 2011.⁶ Class B and Embedded Class A consumers, who consumed approximately 88% of the electricity output in the province, paid 94% of the total average GA charges. The effective price for all consumers increased by \$13.74/MWh, from \$71.06/MWh in the Summer 2012 Period to \$84.8/MWh in the Sumer 2013 Period.⁷

Consumer Class (Summer Period)	Weighted HOEP	Average Global Adjustment	Average Uplift	Average Effective Price
Direct Class A - 2013	22.65	28.18	2.06	52.89
Direct Class A - 2012	23.49	22.37	1.84	47.70
Class B and Embedded Class A - 2013	24.96	61.62	2.50	89.07
Class B and Embedded Class A - 2012	25.77	46.28	1.94	73.99
All Consumers 2013	24.69	57.66	2.45	84.80
All Consumers 2012	25.53	43.60	1.93	71.06

Table 1-1: Average Effective Electricity Price by Consumer Class May – October, 2012 & 2013 (\$/MWh)

As shown in Figure 1-2, Direct Class A consumers have experienced a decline in their effective price and Class B and Embedded Class A consumers have seen their effective price increase following implementation of the change in the GA allocation methodology in January 2011.

⁵ The average effective price is calculated using the average load-weighted HOEP rather than the simple average HOEP presented in Figure 1-1. This takes into account the fact that a greater percentage of large consumers' consumption occurs during off-peak hours when the actual HOEP is lower than the average HOEP, and that a greater percentage of small consumers' consumption occurs during on-peak hours when the actual HOEP is higher than the average HOEP. ⁶ The Panel calculated what the effective price would have been under the prior GA allocation regime for Direct Class

A consumers based on their pro-rata share of total energy consumption for all consumers.

⁷ In prior monitoring reports, the Panel included uplift payments paid by exporters in the "All Consumer" group for the purposes of calculating the average effective price for that group. As a result, the average uplift and average effective prices for All Consumers presented in this report are not exactly comparable to those presented in earlier reports.



Figure 1-2: Monthly Average Effective Electricity Price May 2008– October 2013

Figures 1-3 and 1-4 show, by consumer class, the relative amounts that the HOEP, the GA and uplift have each contributed to the effective electricity price in the period May 2012 to October 2013.

Figure 1-3: Average Effective Electricity Price for Direct Class A Consumers by Component May 2012– October 2013 (\$/MWh) Figure 1-4: Average Effective Electricity Price for Class B & Embedded Class A Consumers by Component May 2012– October 2013 (\$/MWh)



Figure 1-5 plots the monthly GA by source from May 2012 to October 2013. The sources are divided into six groups: nuclear facilities (Bruce Power and Ontario Power Generation nuclear assets); gas-fired generation facilities under Clean Energy Supply and "early-mover" contracts with the Ontario Power Authority (OPA) (these facilities are collectively referred to as "CES" for the purposes of Figure 1-5); non-utility generation facilities (NUGs) under contract with the Ontario Electricity Financial Corporation (currently being re-negotiated with the OPA); baseload hydroelectric facilities owned by Ontario Power Generation whose rates (payment amounts for output) are set by the Ontario Energy Board ("Prescribed Hydro"); renewable power generation facilities under contract with the OPA under the feed-in tariff program (FIT and microFIT); and all other sources (including the OPA's demand response programs, conservation programs, the former renewable energy supply program, the combined heat and power programs, hydroelectric contract initiatives, and the contract with OPG's Lennox generating station).

Total GA charges for the Summer 2013 Period were significantly higher than they were for the Summer 2012 Period. One reason for this increase was increased payments under the FIT and microFIT programs. However, the largest single source of this significant year-over-year increase in total GA charges was a sustained increase in payments made to nuclear units.



Figure 1-5: Monthly Global Adjustment by Source May 2012 – October2013 (\$ millions)

1.2 Operating Reserve Prices

Figure 1-6 plots average monthly operating reserve (OR) prices from May 2012 to October 2013. In the Summer 2013 Period, the average amounts paid for 10-minute spinning, 10-minute non-spinning and 30-minute OR were \$9.27/MW per hour, \$7.73/MW per hour and \$1.47/MW per hour, respectively. In the Summer 2013 Period, OR payments were approximately \$35 million.

On average, there has been a significant increase in price for all categories of OR compared to the Summer 2012 Period, with average monthly prices for 10-minute spinning and 10-minute non-spinning OR being higher in May 2013 than in any other month in the history of the Ontario markets.⁸





⁸ See Chapter 3 of this report for a detailed analysis of the reasons for the high OR prices during the Summer 2013 Period.

1.3 Transmission Right Auction Prices

The IESO offers two types of transmission rights ("TRs") for sale: long-term TRs, which are valid for 12 months and which are auctioned quarterly; and short-term TRs, which are valid for a period of one month and which are auctioned monthly.

TRs guarantee the TR holder a payout for each hour in which there is congestion for one direction (import or export) on a specific path (e.g., Ontario to Manitoba) during the period when the TR is valid. Auction prices for transmission rights therefore reflect TR holders' expectations of congestion at a given interface over the relevant period, and are influenced by factors such as planned outages for the interface in question, expected price differences between Ontario and the relevant external market, and speculation as to the actions of intertie traders. TR prices will vary depending on the time period covered, the interface, and/or the direction (import or export) in question, and can in some cases be very volatile.

In October 2012, market rule amendments came into force that eliminated constrainedoff Congestion Management Settlement Credit (CMSC) payments for import transactions in the Northwest (the "October 2012 Rule Change").⁹ With the opportunity to earn constrained-off CMSC payments for imports in the Northwest effectively eliminated, one could reasonably expect fewer import offers and fewer low-priced offers targeting constrained-off CMSC payments in that zone. Market participants would then expect less frequent congestion and lower absolute intertie congestion prices; this change in expectations would in turn reduce the expected value of ownership of TRs for imports into the Northwest zone. As discussed below, the October 2012 Rule Change appears to have had the anticipated impact.¹⁰

⁹ Under amendments to Chapters 9 and 11 of the Market Rules that came into effect on October 1, 2012, an import transaction in a "designated chronically congested area" that is constrained off in the last pre-dispatch run prior to the dispatch hour is not eligible for constrained-off CMSC payments. A "designated chronically congested area" is an area within Ontario, including connected intertie zones, that has been designated as such by the IESO by reason of oversupply due to transmission constraints. Currently, only one area – the Northwest (which includes the Manitoba and Minnesota interties) – has been so designated. For details, see Market Rule Amendment Proposal MR-00395-R00, available at: http://www.ieso.ca/Documents/Amend/mr2012/MR-00395-R00 Amendment Proposal v5 Board Approved.pdf.

¹⁰ For an analysis of the impact of the October 2012 Rule Change on market participant behaviour and market outcomes in the Northwest, see the Panel's January 2014 Monitoring Report, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf.

Table 1-2 presents average long-term TR auction prices by interface and direction for the Summer 2012 Period and the Summer 2013 Period. The numbers presented in the table are weighted average prices for two rounds at each auction. Since many small, import-only interfaces exist between Ontario and Québec, of the interfaces between Ontario and Québec only the prices at the Outaouais interface are reported in this table and in Table 1-3.¹¹

As shown below, long-term import TR prices for the Northwest (Manitoba and Minnesota) interfaces decreased by 77% in the Summer 2013 Period when compared to the Summer 2012 Period, which the Panel believes is largely attributable to the October 2012 Rule Change.

Table 1-2: Average Long-term (12-month) Transmission Right Auction Pricesby Interface and DirectionMay – October, 2012 & 2013

(\$/ MW)*								
Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Outaouais	
	May-12	July 2012 – June 2013	31,731	-	-	-	136	
	Aug-12	October 2012 – September 2013	18,291	-	34,591	-	269	
Import May	May-13	July 2013 – June 2014	-	841	-	798	253	
	Aug-13	October 2013 – September 2014	6,769	1,016	5,239	905	431	
	May-12	July 2012 – June 2013	-	-	6,956	-	1,301	
Export	Aug-12	October 2012 – September 2013	1,164	-	6,938	-	499	
	May-13	July 2013 – June 2014	2,053	15,595	-	16,066	2,569	
	Aug-13	October 2013 – September 2014	-	21,081	-	18,729	2,509	

* A dash (-) indicates that no long-term TRs were auctioned for the corresponding 12 month period and interface.

Short-term TRs are valid for the month after which they are auctioned. Table 1-3 displays monthly auction prices for short-term TRs by interface and by direction. During the

¹¹ These small interfaces are rarely congested and, as such, their TR auction prices have historically been very low.

Summer 2013 Period, import TR prices at the Manitoba interface were significantly lower than in the Summer 2012 Period. Again, the Panel largely attributes these lower prices to the October 2012 Rule Change.

Table 1-3: Short-Term (One Month) Transmission Right Auction Prices by Interface and Direction May – October, 2012 & 2013

(\$/**M**W)*

Direction	Month TRs	Man	itoba	Mich	nigan	Minnesota		New York		Outaouais	
	are Valid	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
	May	2,292	328	4	30	-	-	12	22	18	45
	June	2,794	333	6	34	-	-	7	29	22	39
	July	2,284	302	7	47	-	-	15	49	45	45
Import	August	2,748	454	14	52	-	475	8	30	58	82
	September	4,834	415	22	12	-	-	-	53	60	75
	October	652	498	30	22	2,189	455	-	18	60	221
Export	May	50	-	930	908	-	-	975	1,000	107	125
	August	250	-	1,504	1,498	0	-	1,188	1,205	52	152
	July	250	-	1,719	2,738	759	-	1,272	1,510	55	186
	August	90	28	1,691	2,887	789	670	1,488	1,510	60	201
	September	75	-	1,034	2,002	-	-	-	1,836	60	157
	October	-	-	243	2,265	-	_	-	1,682	149	210

* A dash (-) indicates that no short-Term TRs were auctioned for the corresponding month and interface.

2 Demand

Ontario energy demand on the IESO-controlled grid (Ontario system demand net of embedded generation and net exports) totalled 70.55 TWh in the Summer 2013 Period, down by 2.05 TWh (2.8%) from the Summer 2012 Period.¹² Ontario demand was lower in all months of the Summer 2013 Period relative to the Summer 2012 Period, with the largest year-over-year-percentage difference in monthly demand occurring in June 2013 (a decrease of 5.7% as compared to June 2012).

¹² The Panel has modified the methodology used to calculate Ontario demand to include load served locally by embedded generation, to the extent this load is visible to the Panel. In the Panel's report covering the Summer 2012 Period it was reported that Ontario demand was 71.1 TWh. However, the Ontario demand for the Summer 2012 Period used in this report for comparison with Ontario demand in the Summer 2013 Period is a newly calculated total based on the new methodology.

3 Supply

No additional generation capacity was added to the IESO-controlled grid during the Summer 2013 Period.

Ontario saw another reduction in its coal-fired generating capacity in furtherance of the provincial government's policy of eliminating coal-fired generation by the end of 2014. The Lambton coal-fired generation facility was taken offline by Ontario Power Generation Inc. in September 2013, removing 1,016 MW of capacity from service.

This loss of capacity resulted in a total installed capacity of 35,000 MW as at October 31, 2013. This total includes 166 MW of renewable (wind) capacity from the Comber Wind Farm that was added to the province's supply resources in April 2013, just prior to the Summer 2013 Period.

4 Imports and Exports

This section reports on intertie activity.

Figure 1-7 plots the total monthly imports, exports and net exports during the period from May 2012 to October 2013, using data that is based on the unconstrained schedules as these directly affect market prices. Net exports totalled 6.98 TWh in the Summer 2013 Period, an increase of 3.1 TWh (80%) relative to the Summer 2012 Period.





^{*} Linked wheeling-through transactions are excluded.

Figure 1-8 and Figure 1-9 show total imports, exports and net exports for the Summer 2013 Period on each of the interties for the unconstrained and constrained schedules, respectively. As noted above, the Panel reports on imports and exports using data that is based on the unconstrained schedule as these directly affect market prices. The Panel also reports on imports and exports using data that is based on the constrained schedule because these indicate actual energy flows across Ontario's interties. It can be seen that Ontario primarily imports energy from other Canadian jurisdictions (Québec and Manitoba) and exports energy to the United States (New York, Minnesota and Michigan).

Figure 1-8: Total Imports, Exports & Net Exports,^{*} by Interface (Unconstrained Schedule) May 2013 – October 2013 (GWh)**



* Imports are positive indicating energy flowing into Ontario and exports are negative indicating energy flowing out of Ontario. Net exports (found under the interface name) can be positive or negative indicating the net flow of imports or exports.

** Linked wheeling-through transactions are excluded.

Figure 1-9: Total Imports, Exports & Net Exports,^{*} by Interface (Constrained Schedule) May 2013 – October 2013 (GWh)**



* Imports are positive indicating energy flowing into Ontario and exports are negative indicating energy flowing out of Ontario. Net exports (found under the interface name) can be positive or negative indicating the net flow of imports or exports.

** Linked wheeling-through transactions are excluded.

Chapter 2: Analysis of Market Outcomes

1 Introduction

The Market Surveillance Panel is responsible for monitoring activities related to the IESO-administered markets. Market monitoring occurs over several timeframes, ranging from the day-to-day monitoring activities of the Market Assessment Unit, to the longer term analysis of the Panel. Central to this monitoring function is the identification and study of market outcomes that fall outside of the predicted patterns or norms. Analysis of these anomalous events contributes to greater transparency, enhances the understanding of the market for market participants and other interested stakeholders, and often leads to recommendations aimed at improving market efficiency and effective competition.

Of particular interest to the Panel are anomalous price events; these events typically involve prices that are higher or lower than normally observed. The Panel defines a high-price hour as an hour in which the Hourly Ontario Energy Price (HOEP) exceeds \$200/MWh, while prices below \$0/MWh are considered low-price hours and are referred to as negative-price hours.

The Panel also reports on high uplift events associated with the various IESOadministered markets and programs. The Panel has set payment thresholds to identify uplift events in which anomalous market outcomes, or market participant behaviour, generated uplift payments that exceed normally observed levels. Uplift payments include payments such as Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments and operating reserve (OR) payments.

Table 2-1 sets out a summary of the anomalous price and uplift events that occurred during the May 2013 to October 2013 period (the "Summer 2013 Period"). The remainder of this chapter contains the Panel's analysis of a selected subset of those events, with comparative data from preceding Summer Periods (May 1 to October 31, inclusive) as relevant.

Table 2-1: Anomalous Price and Uplift Events
May 2013 – October 2013
(Number of Hours & Days)

Anomalous Event	Panel Threshold	Number of Events
High-price hours	HOEP > \$200/MWh	8 hours
Negative-price hours	HOEP < \$0/MWh	224 hours
CMSC Payments	> \$500,000/hour	2 hours
·	> \$1,000,000/day	8 days
OR Payments	> \$100,000/hour	6 hours
IOG Payments	> \$500,000/hour	0 hours
	> \$1,000,000/day	0 days

2 Anomalous HOEP

2.1 Analysis of High-price Hours

High-price hours typically signal tight supply conditions in the province. These conditions arise as a result of relatively high demand or relatively low supply, or a combination of the two. High demand is likely to be driven by weather conditions, as well as by the day of the week and seasonal effects. Low supply conditions may arise in part due to planned or unplanned generator outages, import failures and ramping limitations. Additionally, the real-time supply and demand balance is affected by net exports; imports and exports are scheduled based on pre-dispatch forecasts of supply and demand, and net exports may be sub-optimal if forecasts fail to accurately predict real-time conditions.

Table 2-2 displays the number of hours per month in which the HOEP exceeded\$200/MWh in the Summer 2013 Period and the preceding four Summer Periods.

Chapter 2

Month	2009	2010	2011	2012	2013
May	0	0	2	0	3
June	0	1	3	0	0
July	0	4	0	1	1
August	4	0	1	0	0
September	0	1	0	0	3
October	2	1	0	0	1
Total	6	7	6	1	8

Table 2-2: Number of High-price Hours May – October, 2009 to May – October 2013 (Number of Hours)

During the Summer 2013 Period there were eight high-price hours. This represents an increase over the previous Summer Period, but is consistent with totals observed in earlier Summer Periods.

The following analysis examines the circumstances surrounding four of the eight highprice hours. These events were chosen for further discussion in this report due to the particular conditions that precipitated them. The four high-price hours not analyzed in this report involved conditions frequently observed during high-price events; the effect of these conditions on price has been extensively analyzed in previous Panel reports.¹³

2.1.1 May 24, 2013 Hour Ending 21

On Friday May 24, 2013, the HOEP reached \$510.98/MWh in Hour Ending (HE) 21. Of note is that the day had a relatively low peak demand¹⁴ and there were no major generator outages or import failures.¹⁵

Temperatures in Toronto were mild throughout the day, reaching a high of 11.8°C in HE 16. Mild weather conditions contributed to low demand throughout the day. Real-time Ontario demand averaged 15,801 MW in HE 21, which was consistent with forecasted day-ahead peak demand of 15,855 MW.

¹³ Factors that contributed to the four high-price hours that are not analyzed in this report include: generator outages; import curtailments or failures; and supply and demand forecast discrepancy.

¹⁴ Real-time demand peaked at 15,935 MW in interval 4 of HE 21, which is relatively low for peak demand on any day.

¹⁵ HE 21 refers to the time period from 20:00 to 21:00; in other words, the 'hour ending' at 21:00.

Table 2-3 displays the real-time market clearing price (MCP), Ontario demand and net exports for HE 21; the preceding hour, HE 20, is also shown as the rise in prices began in that hour.

Delivery Hour (HE)	Interval	Real-Time MCP (\$/MWh)	Real-Time Ontario Demand ¹⁶ (OD) (MW)	Real-Time Net Exports (NX) (MW)	Change in OD plus NX from Previous Interval (MW)	Average Change in NX from Previous Hour (MW)
20	1	20.24	15,219	1,645		-464
20	2	26.51	15,176	1,645	-43	-464
20	3	26.51	15,217	1,645	41	-464
20	4	26.51	15,264	1,645	47	-464
20	5	63.83	15,346	1,645	82	-464
20	6	24.27	15,270	1,645	-76	-464
20	7	73.83	15,437	1,645 167		-464
20	8	107.00	15,505	1,645	68	-464
20	9	126.18	15,528	1,645	23	-464
20	10	300.00	15,612	1,645	84	-464
20	11	268.90	15,701	1,645	89	-464
20	12	270.88	15,712	1,645	11	-464
Ave	rage	111.22	15,490	1,645	45	-464
21	1	268.90	15,742	1,600	-15	-45
21	2	490.64	15,867	1,600	125	-45
21	3	500.35	15,875	1,600	8	-45
21	4	1,999.00	15,935	1,600	60	-45
21	5	490.64	15,871	1,600	† -64	-45
21	6	490.64	15,866	1,600	-5	-45
21	7	490.59	15,862	1,600	-4	-45
21	8	487.28	15,840	1,600	-22	-45
21	9	268.90	15,757	1,600	-83	-45
21	10	268.90	15,740	1,600	-17	-45
21	11	260.90	15,697	1,600	-43	-45
21	12	115.00	15,559	1,600	-138	-45
Average		510.98	15.801	1.600	-17	-45

Table 2-3: Real-time MCP, Ontario Demand and Net Exports May 24, 2013, HE 20 & HE 21 (MW & \$/MWh)

Ontario demand reached its peak for the day, 15,935 MW, which coincided with real-time prices reaching \$1,999/MWh in this interval.

Notably, only 60 MW of additional Ontario demand in this interval pushed prices from \$500/MWh to \$1,999/MWh. This is due to the high prices and relative scarcity of supply offered at the top of the supply stack.

Table 2-4 displays pre-dispatch prices, Ontario demand and net exports for the five predispatch hours leading up to HE 21. Pre-dispatch prices are important price signals for

¹⁶ Ontario demand is calculated as: total Ontario generation + imports – exports.

the commitment of non-quick start generation facilities and the scheduling of intertie transactions. Low pre-dispatch prices can have the effect of under-scheduling non-quick start generation facilities and over-scheduling net exports relative to levels that would be optimal in real-time based on the higher real-time prices.

Hours Ahead	Pre-dispatch Price (\$/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
5	16.15	15,367	438	1,865	1,427
4	17.19	15,511	438	1,804	1,366
3	23.16	15,400	644	1,964	1,320
2	30.20	15,423	486	2,098	1,612
1	30.20	15,418	486	2,086	1,600

Table 2-4: Pre-dispatch MCP, Ontario Demand and Net Exports Hours leading up to HE 21 on May 24, 2013 (MW & \$/MWh)

The one-hour ahead forecasted (pre-dispatch) price for HE 21 was \$30.20/MWh, based on a one-hour ahead forecast of Ontario demand that eventually turned out to have underpredicted real-time average Ontario demand for the hour (15,801 MW) by 383 MW.

"Non-quick start" generation facilities (primarily gas-fired generators), which require upwards of three hours' notice to start, rely on pre-dispatch price signals to make start-up and shut-down decisions. In hours such as HE 21 on May 24, 2013, when pre-dispatch prices do not provide a good indication of the eventual tight real-time supply conditions, non-quick start units do not receive accurate signals to come online, thereby limiting the supply that is available to meet demand in real-time. An under-forecast of Ontario demand can also lead to a relative over-scheduling of net exports, further contributing to high prices in real-time. In the case of HE 21 on May 24, 2013, the under-forecast of Ontario demand in pre-dispatch caused a relative over-commitment of net exports and an under-commitment of Ontario generation, which led to a thin supply stack in real-time. These factors were significant in contributing to the rise in real-time prices during HE 21.

Table 2-5 displays pre-dispatch versus real-time Ontario demand, self-scheduling and intermittent supply and net export conditions for each interval in HE 21 on May 24, 2013. Of note is the relatively large forecast discrepancy for Ontario demand and self-

scheduling and intermittent generation. These under-estimates resulted in the need for 822 MW of additional domestic dispatchable generation in interval 4 of HE 21 (relative to the final pre-dispatch forecast), which was the highest demand and price interval of the day.

Table 2-5: Real-time MCP and Pre-dispatch and Real-time Demand and Supply
Conditions
May 24, 2013, HE 21
(MW & \$/MWh)

HE	Interval	MCP (\$/MWh)	Ontario Demand (MW)				Self-Scheduling and Intermittent Supply (MW)			Net Exports (MW)			Total PD vs. RT Discrenancy
			DA	PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	(MW)
21	1	268.90	15,856	15,418	15,742	-324	1,627	1,331	-297	1,600	1,600	0	-621
21	2	490.64	15,856	15,418	15,867	-449	1,627	1,321	-306	1,600	1,600	0	-755
21	3	500.35	15,856	15,418	15,875	-457	1,627	1,319	-308	1,600	1,600	0	-765
21	4	1,999.00	15,856	15,418	15,935	-517	1,627	1,322	-305	1,600	1,600	0	-822
21	5	490.64	15,856	15,418	15,871	-453	1,627	1,323	-304	1,600	1,600	0	-757
21	6	490.64	15,856	15,418	15,866	-448	1,627	1,319	-308	1,600	1,600	0	-756
21	7	490.59	15,856	15,418	15,862	-444	1,627	1,323	-304	1,600	1,600	0	-748
21	8	487.28	15,856	15,418	15,840	-422	1,627	1,325	-302	1,600	1,600	0	-724
21	9	268.90	15,856	15,418	15,757	-339	1,627	1,321	-306	1,600	1,600	0	-645
21	10	268.90	15,856	15,418	15,740	-322	1,627	1,316	-311	1,600	1,600	0	-633
21	11	260.90	15,856	15,418	15,697	-279	1,627	1,312	-315	1,600	1,600	0	-594
21	12	115.00	15,856	15,418	15,559	-141	1,627	1,313	-314	1,600	1,600	0	-455
Average		510.98	15,856	15,418	15,801	-383	1,627	1,320	-307	1,600	1,600	0	-690

In this interval, an additional 822 MW of domestic generation had to be scheduled in order to make up for the discrepancy between pre-dispatch and real-time Ontario demand and self-scheduling and intermittent generation. This helps to explain the difference between the pre-dispatch (one-hour ahead) price (\$30.20/MWh) and the average real-time price for the hour (\$510.98/MWh).

The following figures illustrate the discrepancy between pre-dispatch and real-time scheduled supply that contributed to the high price realized in HE 21 on May 24, 2014. As shown in Table 2-5 above, the total pre-dispatch to real-time discrepancy peaked at 822 MW in interval 4 of HE 21. Figures 2-1 and 2-2 show the changes in scheduled

¹⁷ This column is the change in dispatchable Ontario generation required to meet the change in Ontario demand + the change in self-scheduling and intermittent generation + the change in net exports, between the final pre-dispatch forecast and real-time. A negative number (such as the -822 MW shown in this column for interval 4) signifies more dispatchable Ontario generation was needed, leading to higher real-time vs. pre-dispatch prices.

supply necessitated by the need for the additional 822 MW of Ontario generation in realtime (approximately 5% of peak Ontario demand for the day).

Figure 2-1 shows pre-dispatch scheduled supply one hour ahead of real-time. The table to the right of the chart displays the offer quantity and prices for the marginal resource and the adjacent infra-marginal units along with total scheduled supply. For clarification, the values in the top row of the table are the final offers scheduled in pre-dispatch.



Figure 2-1: One-Hour Ahead Pre-Dispatch Scheduled Supply May 24, 2013, HE 21 (MW & \$/MWh)

Figure 2-2 shows the effects of the discrepancies between the pre-dispatch forecast and real-time level of Ontario demand and supply from self-scheduling and intermittent resources (summarized in Table 2-5, above) in interval 4 of HE 21. The 'low' offer in the scheduled supply stack table corresponds with the 'top' offer from the stack of scheduled supply from the pre-dispatch table shown in Figure 2-1. The discrepancy between the total scheduled supply at a price of \$30.20/MWh or below between pre-dispatch (17,504 MW) and real-time (17,148 MW) is attributable to a decrease in scheduled supply from self-scheduling and intermittent resources between pre-dispatch and real-time. Since net exports remained constant from pre-dispatch to real-time, the

¹⁸ PD-1 refers to the last pre-dispatch run, which occurs one hour before real-time.

¹⁹ The actual offer price for this supply was \$40.25/MWh, not \$30.20/MWh. However, the price was set at \$30.20/MWh because the resource priced at \$40.25/MWh was scheduled to provide operating reserve and, as such, it had to be scheduled to its reserve loading point of 190 MW. The pre-dispatch MCP, which represents the cost of serving the next MW of non-dispatchable load, was actually set by an export bid at \$30.20/MWh.
increase in total scheduled supply of 517 MW (18,021 MW – 17,504 MW) between predispatch and real-time was directly attributable to the 517 MW Ontario demand forecast discrepancy noted in Table 2-5. Real-time demand was not satisfied until the offer of 0.3 MW priced at \$1,999/MWh was scheduled.

Figure 2-2: Real-time Scheduled Supply May 24, 2013, HE 21 Interval 4 (MW & \$/MWh)



This scenario highlights the lack of 'depth' in the supply stack at higher prices in this hour. Accounting for the dual optimization of the energy and operating reserve markets, there was not a single offer available to be scheduled in the energy market at prices between \$201/MWh and \$488.25/MWh or at prices between \$500.35/MWh and \$1,999/MWh.

High Prices during Hours of Low Demand

As discussed at the outset of this section, the high-price hour on May 24, 2013 was notable because it was not associated with any large-scale generator outages or import

curtailments, which would have radically altered supply conditions in the province, nor was there an extreme variation in day-ahead vs. real-time demand.

What is also notable about this particular high-price hour is the absence of offers from non-quick start facilities in the market. Pre-dispatch and day-ahead prices did not signal supply scarcity and, as a result, these units were under-committed relative to eventual real-time market conditions. When high prices materialized in real-time, non-quick start generation units that were not then online were unable to start and increase generation levels in response to the high prices in HE 21. For the day in question, many non-quick start units either did not run at all or had shut down before HE 21, contributing to the steep supply stack.

Also of note is the relatively large effect on price which can result from a discrepancy in the forecasted generation from self-scheduling and intermittent resources versus the generation those resources actually provide in real-time. In interval 4 of HE 21 of this day, that discrepancy accounted for 305 MW of the 822 MW in additional (and higher-priced) dispatchable Ontario generation needed to meet real-time demand. The majority of this discrepancy can be attributed to variations in forecasted versus actual generation from wind resources.

In summary, the pre-dispatch to real-time forecast discrepancy led to the over-scheduling of net exports and an under-commitment of non-quick start generation resources. These factors proved significant enough to result in a high-price hour, despite relatively low demand and abundant hydroelectric generation associated with high springtime water levels.

2.1.2 September 10, 2013, HE 16, HE 17 & HE 20

On this day, the Ontario system went from a state of surplus baseload generation in the early morning to requiring control actions to avoid a supply shortfall in the late afternoon. As a result, the HOEP reached \$475.05/MWh, \$377.69/MWh and \$330.05/MWh in HE 16, HE 17 and HE 20, respectively. The key factors that caused these high prices include: extreme weather conditions in Northern Ontario; outages to key

interconnections; and a large shared activation of reserve²⁰ for a contingency in the Pennsylvania, Jersey, Maryland Interconnection (PJM). Higher than expected temperatures in Ontario contributed to an under-forecast of Ontario demand and affected the broader markets with higher market prices in all of the interconnected jurisdictions and a high level of congestion in the east which resulted in subsequent import/export transaction failures. There was also a planned outage of the IESO's dispatch software related to the Renewable Integration Initiative, which temporarily affected pre-dispatch forecasts and the IESO's ability to send automatic dispatch instructions to market participants; automatic dispatch instructions were not sent to market participants from interval 6 of HE 14 to interval 11 of HE 15. Rather, market participants were advised to maintain generation at the same levels as their previous dispatch instructions unless otherwise verbally dispatched by the IESO. As discussed below, the software outage appears to have had an effect on prices during the late afternoon.

Temperatures in Toronto on September 10, 2013 were much higher than forecast. Dayahead forecast peak demand was predicted to be 20,734 MW in HE 20 and control room logs showed an expected high of 21°C, in line with the average temperatures experienced the previous day. In real-time, however, the temperature rose as high as $30.7^{\circ}C^{21}$ in HE 15, with peak demand reaching 22,596 MW in HE 20, approximately 10% higher than expected day-ahead. Table 2-6 shows the increase in temperatures between September 9 and 10. As a result of this extreme weather variation, the IESO's Ontario demand forecasts for HE 19 and HE 20 were revised up on four separate occasions for a total of 1,200 MW.

²⁰ Shared activation of reserve allows participating members of the Northeast Power Coordinating Council (NPCC) to call upon other members to assist them with recovery from a supply loss of 500 MW or more. In this instance, PJM called upon members for assistance and the IESO provided 400 MW of support.

http://climate.weather.gc.ca/climateData/hourlydata_e.html?timeframe=1&Prov=ONT&StationID=31688&hlyRange=2002-06-04|2014-04-14&Year=2013&Month=9&Day=10

	Temper	Difference	
HE	Sept. 9,	Sept. 10,	(°C)
	2013	2013	
12	19.9	29.7	+9.8
13	18.4	30.6	+12.2
14	18.0	30.7	+12.7
15	19.8	30.1	+10.3
16	19.2	28.9	+9.7
17	18.7	28.8	+10.1
18	17.7	29.3	+11.6
19	17.3	27.9	+10.6
20	17.6	26.6	+9.0
21	17.7	25.9	+8.2
22	18.6	24.3	+5.7
23	18.4	24.3	+5.6

Table 2-6: Hourly Average Toronto Temperatures September 9 & 10, 2013 (°C)

Table 2-7 provides the HOEP, average Ontario demand and net exports for HE 14 to HE 20 on September 10, 2013.

Delivery Hour (HE)	HOEP (\$/MWh)	Real-Time Ontario Demand ²² (OD) (MW)	Real-Time Net Exports (NX) (MW)	Change in OD plus NX from Previous Hour (MW)	Average Change in NX from Previous Hour (MW)
14	38.65	21,073	1,104	752	350
15	191.00 ²³	21,935	943	701	-161
16	475.05	22,358	1,459	7 939	516
17	377.69	22,465	1,404	52	-55
18	50.71	22,266	634	-969	-770
19	110.55	22,331	677	108	43
20	330.05	22,596	278	-134	-399

Table 2-7: HOEP, Real-Time Ontario Demand and Net Exports September 10, 2013, HE 14 to 20 (MW & \$/MWh)

A significant rise in Ontario demand during the mid-afternoon resulted in more expensive generation being scheduled, resulting in higher prices.

Table 2-8 displays the pre-dispatch prices from HE 14 to HE 20. Since intertie transactions are scheduled based on bids and offers one hour ahead of real-time, rising pre-dispatch prices should – and in this case did – result in a decrease in the amount of scheduled net exports.

²² Ontario demand is calculated as: total Ontario generation + imports - exports.

²³ Prices in this hour were based on administered pricing due to a planned outage to the dispatch software associated with the Renewable Integration Initiative. Information on administrative pricing can be found at http://www.ieso.ca/imoweb/pubs/training/QT4_AP.pdf.

Table 2-8: Pre-dispatch MCP, Ontario Demand and Net Exports
September 10, 2013, HE 14 to HE 20
(MW & \$/MWh)

Delivery Hour (HE)	Pre-dispatch Price (PD-1 for the hour) (\$/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)		
14	39.75	21,023	876	2,330	1,454		
15	83.00	21,709	876	2,087	1,211		
16 ²⁴	100.01	22,086	1,066	1,912	846		
17	40.10	22,436	876	2,280	1,404		
18	107.56	22,473	860	1,564	704		
19	34.64	21,929	903	1,457	554		
20	487.09	22,477	1,450	1,427	-23		
When the price in pre-dispatch increased, the scheduled amount of net exports decreased.							

As shown in Tables 2-7 and 2-8, pre-dispatch did not accurately reflect real-time prices or real-time Ontario demand. Table 2-9 identifies the discrepancies between pre-dispatch forecasts and real-time Ontario conditions.

²⁴ Due to the planned outage of the dispatch software, for HE16 the data is from PD-2 rather than PD-1.

Table 2-9: HOEP and Pre-dispatch and Real-time Demand and Supply ConditionsSeptember 10, 2013, HE 14 to HE 20(MW & \$/MWh)

HE	HOEP (\$/M	Ontario Demand (MW)			HOEP (\$/M Ontario Demand (MW) Self-Scheduling and Intermittent (MW)			Net Exports (MW)			Total PD-1 vs. RT Discrepancy	
	Wh)	DA	PD-1	RT	PD-1 - RT	PD-1	RT	RT – PD-1	PD-1	RT	Failed	25 (MW)
14	38.65	19,596	21,023	21,073	-50	1,725	1,586	-139	1,454	1,104	350	161
15	191.00	19,853	21,709	21,935	-226	1,738	1,686	-52	1,211	943	268	-10
16 ²⁷	475.05	20,256	22,086	22,358	-272	1,775	1,738	-38	846	1,459	-613	-922
17	377.69	20,443	22,436	22,465	-29	2,795	1,723	-1,072	1,404	1,404	0	-1,101
18	50.71	20,109	22,473	22,266	207	1,855	1,599	-255	704	634	70	22
19	110.55	20,396	21,929	22,331	-403	1,862	1,487	-376	554	677	-123	-901
20	330.05	20,734	22,477	22,596	-119	1,836	1,530	-306	-23	278	-301	-726
								Ť				

The price peaked in HE 16 with rising Ontario demand, and lowered in HE 18 as Ontario demand decreased.

Prices then rose again in step with Ontario demand in HE 19 and HE 20, exacerbated by the discrepancy between PD and RT Ontario demand and a lack of delivered supply from self-scheduling and intermittent generation.

Precipitated by a steep and unexpected rise in temperatures and challenging system conditions, an under-forecast of Ontario demand, an over-forecast of self-scheduling and intermittent generation and import failures all factored into the need to schedule higher-priced Ontario generation, resulting in the three high-price hours on September 10, 2013 (HE 16, HE 17 and HE 20).

Pre-dispatch forecasts underestimated real-time Ontario demand by an average of 272 MW, 29 MW and 119 MW in HE 16, HE 17 and HE 20, respectively, and this despite

²⁵ This column quantifies the change in dispatchable Ontario generation required to meet real-time Ontario demand compared to the forecasted Ontario generation required to meet forecasted (pre-dispatch) Ontario demand. A negative number signifies that more dispatchable Ontario generation is needed in real-time, leading to higher real-time vs. pre-dispatch prices.
²⁶ A negative net export failure infers that more imports than exports failed or were curtailed. A positive net export

²⁶ A negative net export failure infers that more imports than exports failed or were curtailed. A positive net export failure means that more exports than imports failed or were curtailed.

²⁷ Due to the planned outage of the dispatch software, for HE 16 data is from PD-2 rather than PD-1. Prices in this hour were based on administered pricing due to a planned outage to the dispatch software associated with the Renewable Integration Initiative. Information on administrative pricing can be found at http://www.ieso.ca/imoweb/pubs/training/QT4_AP.pdf.

several demand forecast revisions²⁸ by the IESO during the afternoon of September 10, 2013.

In addition to demand in excess of forecasted levels, self-scheduling and intermittent generation resources under-delivered by an average of 38 MW, 1,072 MW and 306 MW in HE 16, HE 17 and HE 20, respectively. This under-delivery required that more expensive Ontario generation be dispatched, increasing the real-time price relative to the pre-dispatch price.

Real-time net exports in HE 16 were a strong contributor to the discrepancy between predispatch and real-time generation requirements as a result of the failure of 646 MW of imports between pre-dispatch and real-time.²⁹ It should also be noted that there were significant export curtailments throughout HE 17 to HE 20 to address adequacy concerns. Those curtailments are not reflected in the 'failed' column of Table 2-9 as they occurred in the real-time constrained schedule and therefore do not affect price.

As noted earlier, the planned software outage related to the Renewable Integration Initiative did have an effect on prices on the afternoon of September 10, 2013. Table 2-9 shows an anomalously high amount of self-scheduling and intermittent generation (2,795 MW) forecasted for HE 17. This was the first hour in which the upgraded software was in use, and the upgrade appears to have been the cause of the high generation forecasts for the hour. Specifically, for that hour the scheduling algorithm scheduled the intermittent generators based on their nameplate capacity as opposed to the forecasted wind power they could supply. This result was not intended and was an error that was caused by the planned outage. The over-forecast of supply depressed pre-dispatch prices and resulted in the under-scheduling of Ontario generation and over-scheduling of net exports, both of which contributed to the high price in HE 17.

²⁸ Ontario demand forecasts for HE 19 and HE 20 were revised up on four separate occasions, resulting in a 1,200 MW increase.

²⁹ Table 2-9 shows a net export failure of -613 MW for HE 16. This failure amount was comprised of 646 MW of import failures and 33 MW of export failures.

2.2 Analysis of Negative-price Hours

Negative-price hours signal the availability of abundant supply relative to demand, whether due to low demand, relatively abundant supply, or a combination of the two. Similarly to high demand hours, low demand hours are largely driven by weather conditions, with low demand occurring frequently during the mild shoulder seasons (spring and fall). Weekend and overnight hours also regularly experience low demand. Failed export transactions also reduce total market demand and can contribute to negative prices.

The amount of baseload supply is a function of available nuclear, hydroelectric and intermittent generation, as well as scheduled imports. While available generation from nuclear facilities remains fairly constant over time, generation from baseload hydroelectric facilities and wind generators tends to be higher during the shoulder seasons, particularly in the spring.

Table 2-10 displays the number of hours per month in which the HOEP was below \$0/MWh in the Summer 2013 Period and the preceding four Summer Periods.

Month	2009	2010	2011	2012	2013
May	24	0	31	19	27
June	42	0	23	24	26
July	14	0	4	8	25
August	11	0	17	9	40
September	25	9	6	5	91
October	5	10	15	27	15
Total	121	19	96	92	224

Table 2-10: Number of Hours with Negative HOEPs Particular
May to October, 2009 – May to October, 2013
(Number of Hours)

There were 224 negative-price hours in the Summer 2013 Period. This represents a significant increase in the number of negative-price hours relative to the previous four Summer Periods, particularly in the months of July, August and September. Figure 2-3 displays the total monthly supply offered at negative prices by resource type in the Summer 2013 Period and earlier Summer Periods. This figure shows that there was a

large increase in the total supply offered at negative prices by nuclear generation facilities during the Summer 2013 Period relative to the Summer 2012 Period. This increase, and the general increase in the number of negative-price hours in the Summer 2013 Period, can be attributed to the return to service of Bruce A units 1 and 2 in the fall of 2012. Together, those units offer approximately 1,500 MW³⁰ of negative-priced baseload supply, which is substantial enough to account for the large year-over-year increase in negative-price hours during the Summer 2013 Period.

³⁰ http://www.brucepower.com/wp-content/uploads/2013/11/Performance-Review-for-Bruce-A-and-Bruce-B-.pdf.



Figure 2-3: Negative-priced Offers by Month and Resource Type November 2008 – October 2013

The imports included in Figure 2-3 are scheduled quantities, not offered quantities. Imports scheduled in pre-dispatch are priced at -\$2,000/MWh in real-time to ensure that their pre-dispatch schedules are respected. While priced at -\$2,000/MWh for price-setting purposes in real-time, these imports may have been offered at positive prices.

From 2009 to 2012, total negative-priced supply remained relatively constant, averaging 11,200,000 MW per month. As discussed above, however, negative-priced offers from nuclear generation facilities have increased substantially since the fall of 2012, resulting in a rise in the average volume of negative-priced supply per month to approximately 12,100,000 MWh.

Monthly fluctuations in nuclear and hydroelectric supply primarily reflect transient capacity changes associated with outages and seasonal trends (such as high water conditions in the spring and low water conditions in the summer).

3 Anomalous Uplift Payments

The Panel monitors uplift payments associated with the various IESO-administered markets, and has set thresholds to identify uplift events in which anomalous market outcomes or market participant behaviour have resulted in uplift payments that exceed normally observed levels. In the following sections, the Panel reports on several anomalous events that resulted in large Congestion Management Settlement Credit (CMSC) or operating reserve (OR) payments being made in the Summer 2013 Period. There were no instances in which the Panel's thresholds were met in relation to Intertie Offer Guarantee payments in the Summer 2013 Period.

3.1 Congestion Management Settlement Credits

CMSC payments in excess of \$500,000 for a given hour or in excess of \$1,000,000 for a given day are considered anomalous by the Panel. There were eight such days and two such hours during the Summer 2013 Period, with the events spread out over the final four months of the Summer 2013 Period.

On three of the days featuring anomalous CMSC payments, the vast majority of the CMSC payments – almost \$3.9 million of a total of \$5.0 million – were made to one market participant in relation to its dispatchable load facility ("Load A").

3.1.1 Anomalous CMSC payments to Load A, July 8, August 15 & August 16, 2013

On July 8, August 15 and August 16, 2013, Load A received CMSC payments as a result of having been constrained off; that is, in the unconstrained schedule Load A was economically scheduled to consume energy, but was ultimately required by the IESO to consume less energy in the constrained schedule due to system constraints in the form of line outages. The sections below describe how it is that Load A came to receive the constrained-off CMSC payments in question. For the purposes of that discussion, it is important to know that Load A regularly submits two bids into the IESO-administered market, for a total of 100 MW. The first bid is regularly for a quantity of 9 MW priced at \$2,000/MWh. Quantities that are bid at the maximum market clearing price of \$2,000/MWh are considered non-dispatchable by the IESO, and the load is not eligible to receive CMSC payments in relation to that bid. Load A's second bid is regularly for an incremental quantity of 91 MW priced at \$1,999/MWh, the highest bid price that the IESO will treat as dispatchable. As this bid is dispatchable, Load A is eligible for CMSC payments in respect of it.

3.1.1.1 July 8, 2013

On July 8, 2013, Load A received over \$1.5 million in CMSC payments as a result of being constrained off between HE 15 and HE 22. Load A was not able to consume the dispatchable portion of its power requirements (91 MW) between HE 7 and interval 6 in HE 23 due to a planned outage to the transmission lines connecting it to the IESO-controlled grid.

From the start of HE 7 to the end of HE 14, Load A had not submitted the dispatchable portion of its bid (91 MW), meaning that in those hours it was dispatched, both in the unconstrained and constrained schedule, to consume only the non-dispatchable portion of its bid (9 MW). Load A did, however, have dispatchable bids in the market from HE 15 to HE 24 for 91 MW priced at \$1,999/MWh, which as noted above is the highest possible price for a dispatchable bid. As a result, Load A was scheduled in the unconstrained schedule to consume 100 MW, 91 MW of which was dispatchable and eligible for CMSC payments and 9 MW of which was not.

The planned outage of the transmission line connecting Load A to the IESO-controlled grid was scheduled to start in HE 7. It was scheduled to be completed around HE 15, but was not fully resolved until the middle of HE 23. The result for Load A was an unconstrained schedule of 100 MW and a constrained schedule of 5 MW, leading to constrained-off CMSC payments of roughly \$180,000 in each hour from HE 15 to HE 22, and of roughly \$73,000 in HE 23.

Table 2-11 breaks down the schedules applicable to Load A's dispatchable bid quantity and the CMSC payments made to Load A on July 8, 2013.

Table 2-11: CMSC Payment Table for Load A July 8, 2013 (MW, \$/MWh & \$)

Time	Dispatchabl Bid Quantit (MW)	e Y	Bid Price (\$/MWh)	HOEP (\$/MWh)	Unconstrained Schedule for Dispatchable Bid Quantity (MW)		Unconstrained Schedule for Dispatchable Bid Quantity (MW)		Unconstrained Schedule for Dispatchable Bid Quantity (MW)		Unconstrained Schedule for Dispatchable Bid Quantity (MW)		Unconstrained Schedule for Dispatchable Bid Quantity (MW)		Constrained Schedule for Dispatchable Bid Quantity (MW)	CMSC Payment (\$)
HE12	0		N/A	62.98		0	0	0								
HE13	0		N/A	38.90		0	0	0								
HE14	0		N/A	31.73	0		0		0		0		0	0		
HE15	91		1,999	31.52		91	0	179,049								
HE16	91		1,999	30.40		91	0	179,143								
HE17	91		1,999	32.00		91	0	178,996								
HE18	91		1,999	16.06		91	0	180,448								
HE19	91		1,999	14.40		91	0	180,599								
HE20	91		1,999	14.74		91	0	180,567								
HE21	91		1,999	14.54		91	0	180,586								
HE22	91		1,999	15.88		91	0	180,464								
HE23	91		1,999	16.87		91	54.2	72,937								
HE24	91		1,999	19.73		91	91	0								
					Τ		Total CMSC	1,512,789								

As a result of having dispatchable bids in the market at times coincident with when the planned outage was scheduled to be resolved, Load A was scheduled to consume 91 MW in the unconstrained schedule for HE 15. However, as the line outage was not resolved until midway through HE 23, Load A was constrained off for over 8 hours, resulting in large CMSC payments for those hours.

The line outage ended midway through HE 23, and Load A was dispatched in the constrained schedule starting at that time, thus limiting the CMSC payments in HE 23 and eliminating them in HE 24.

Calculating Constrained-Off CMSC Payments

Table 2-11 shows the CMSC payments made to Load A in certain hours on July 8, 2013. The example below uses data for HE 15 from Table 2-11 to demonstrate the calculation of constrained-off CMSC payments, utilizing only the dispatchable portion of Load A's bid.

HE15: Bid Price = \$1,999/MWh HOEP = \$31.52/MWh Unconstrained Schedule = 91 MW Constrained Schedule = 0 MW

CMSC = (Unconstrained Schedule – Constrained Schedule) * (Bid Price – MCP)

= (91 MW - 0 MW) * (\$1,999/MWh - \$31.52/MWh)

CMSC = \$179,049

3.1.1.2 August 15 & August 16, 2013

Load A received CMSC payments in a continuous stream on August 15 and August 16, 2013, totalling over \$2.3 million over the two days. The CMSC payments resulted from Load A being constrained off from HE 19 on August 15 to part-way through HE 8 on August 16. Similar to the event on July 8, 2013, Load A was constrained off as a result of a planned outage to the transmission lines connecting it to the IESO-controlled grid.

From HE 7 to HE 19 on August 15, roughly the expected length of the planned outage, Load A had not submitted the dispatchable portion of its bid (91 MW). Load A did, however, have dispatchable bids in the market from HE 19 on August 15 to HE 24 on August 16 for 91 MW priced at \$1,999/MWh. These bids resulted in Load A being scheduled in the unconstrained schedule to consume 100 MW, 91 MW of which was dispatchable and therefore eligible for CMSC payments and 9 MW of which was not.

Although the line outage was scheduled to be completed around HE 19 on August 15, it was not fully resolved until part way through HE 8 on August 16. The result for Load A

was an unconstrained schedule of 100 MW and a constrained schedule of 5 MW, resulting in constrained-off CMSC payments of roughly \$180,000 each hour from HE 19 on August 15 to HE 7 on August 16, and of roughly \$15,000 in HE 8 on August 16.

Table 2-12 breaks down the schedules applicable to Load A's dispatchable bid quantity and the CMSC payments made to Load A on August 15 and 16.

The Panel has brought this matter to the attention of personnel within the IESO's Market Assessment and Compliance Division that are responsible for enforcing compliance with the Market Rules.

Table 2-12: CMSC Payment Table for Load A August 15 & 16, 2013 (MW, \$/MWh & \$)

Time	Dispatchable Bid Quantity (MW)	e Bid Price y (\$/MWh)	HOEP (\$/MWh)	Unconstrained Schedule for Dispatchable Bid Quantity (MW)	Constrained Schedule for Dispatchable Bid Quantity (MW)	CMSC Payment (\$)
HE17	0	N/A	14.38	0	0	0
HE18	0	N/A	15.79	0	0	0
HE19	91	1,999	28.24	91	0	179,339
HE20	91	1,999	21.61	91	0	179,641
HE21	91	1,999	14.33	91	0	178,799
HE22	91	1,999	13.34	91	0	179,842
HE23	91	1,999	14.82	91	0	180,561
HE24	91	1,999	14.38	91	0	180,600
HE1	91	1,999	13.23	91	0	180,705
HE2	91	1,999	-3.15	91	0	182,196
HE3	91	1,999	-1.94	91	0	182,086
HE4	91	1,999	5.19	91	0	181,437
HE5	91	1,999	14.36	91	0	180,602
HE6	91	1,999	13.00	91	0	180,726
HE7	91	1,999	5.00	91	0	181,454
HE8	91	1,999	12.82	91	83.4	15,192
HE9	91	1,999	14.35	91	91	0
					Total CMSC	\$2,363,180

As a result of having dispatchable bids in the market at times coincident with when the planned outage was scheduled to be resolved, Load A was scheduled to consume 91 MW in the unconstrained schedule for HE 19 on August 15. However, as the line outage was not resolved until early in HE 8 on August 16, Load A was constrained off for almost 14 hours, resulting in large CMSC payments for those hours.

The line outage ended early in HE 8, and Load A was dispatched in the constrained schedule starting at that time, thus limiting the CMSC payments in HE 8 and eliminating them in HE 9.

3.1.2 September 10, 2013

As described in section 2.1.2 of this chapter, September 10, 2013 was a day with several high-price hours. As discussed in previous Panel reports,³¹ high prices generally coincide with large CMSC payments for generation and imports that are constrained off.

Figure 2-4 shows the proportional breakdown of CMSC payments on September 10, 2013 between generation, dispatchable loads and intertie transactions.



Figure 2-4: Proportion of CMSC Payments by Transaction Type September 10, 2013 (%)

3.1.2.1 CMSC Payments to Generators

Of the \$1,344,865 paid to generators on September 10, 2013, \$1,228,456 was for generation that was constrained off and \$116,409 was for constrained-on generation. There were several generators that received large constrained-off CMSC payments, two

³¹ http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf, p. 123

of which were located in the Northwest region of the province. These generation facilities were economic in the unconstrained schedule, but were constrained off as the nodal price associated with their generation facilities was less than their offer price, making them uneconomic compared to other resources in the area. High prices in the afternoon of September 10, 2013 had the effect of increasing these constrained-off payments as the gap between the facilities' offers and the HOEP increased relative to lower-price hours. Table 2-13 shows the CMSC payments made to the two facilities.

 Table 2-13: Large Constrained-off CMSC Payments to Generators in Northwest Zone

 September 10, 2013

	(¢)	
(φ	

Resource	Constrained-Off CMSC Payment
Resource A	\$169,112
Resource B	\$89,724

There were two recipients of large constrained-off CMSC payments in the West zone. Both units had economic offers in real-time and were scheduled in the unconstrained schedule for the majority of the day. The units were constrained off/down throughout the afternoon due to local grid conditions. Table 2-14 shows the payments made to these two generators.

 Table 2-14: Large Constrained-off CMSC Payments to Generators in West Zone

 September 10, 2013

(\$)

Resource	Constrained-Off CMSC Payment
Resource C	\$93,677
Resource D	\$84,343

3.1.2.2 CMSC Payments for Intertie Transactions

There was a total of \$216,432 in CMSC payments made in relation to intertie transactions on September 10, 2013. Table 2-15 provides a breakdown of the CMSC payments, by zone and transaction type.

Intertie Zone	Import		Export		Tatal
	C. Off	C. On	C. Off	C. On	Total
Manitoba	0	0	0	2,404	2,404
Michigan	0	0	465,662	0	465,662
Minnesota	0	0	1,630	16,385	18,015
New York	(4,414)	(35,181)	(493,062)	6,750	(525,907)
Quebec	256,258	0	0	0	256,258
Total	251,884	(35,181)	(25,770)	25,539	216,432

Table 2-15: CMSC Payments by Intertie and Transaction 1	Гуре
<i>September 10, 2013</i>	
(\$)	

There were considerable CMSC payments made for constrained-off exports at the Michigan interface, with the majority of those payments made to a market participant with bids at prices as high as \$1,999/MWh. The participant was constrained off in HE 18, HE 20, HE 21 and HE 22, resulting in payments of \$685,467 during those hours. In other hours, however, the participant (and others) accrued significant negative constrained-off export CMSC payments at the New York intertie, resulting in total net CMSC payments of \$216,432 for all intertie transactions.

3.1.3 September 11, 2013

September 11, 2013 saw the highest level of CMSC payments in the Summer 2013 Period, with payments totalling \$2,918,224. Although prices on this day were not anomalously high (i.e., they were below \$200/MWh), there were several hours where prices were greater than \$100/MWh, with the province experiencing tight supply conditions similar to those that were seen on September 10, particularly in Southern Ontario.

Figure 2-5 shows the breakdown of CMSC payments on September 11, 2013 between generators, dispatchable loads and intertie transactions.

Figure 2-5: Proportion of CMSC Payments by Transaction Type September 11, 2013 (%)



As Figure 2-5 shows, no particular type of transaction received the majority of CMSC payments on this day. However, a significant amount of the CMSC payments were made to intertie traders, which distinguishes this day from other anomalous uplift days in the Summer 2013 Period.

3.1.3.1 CMSC Payments to Generators

Of the \$1,178,463 in CMSC payments made to generators on September 11, 2013, \$704,081 was for constrained-off dispatches and \$474,382 was for constrained-on dispatches. There were only three recipients of large (>\$60,000) CMSC payments on this day despite over \$1 million being paid to generators in the province. Consistently high prices throughout the afternoon and early evening contributed to these large constrainedoff CMSC payments.

Two of the facilities receiving large CMSC payments were located in the Northwest and Northeast regions of the province, both of which are typically supply rich areas. Those generation facilities were economic in the unconstrained schedule, but were constrained off as the nodal price associated with their generation facilities was less than their offer price, making them uneconomic compared to other resources in the area. High prices in the afternoon of September 11, 2013 had the effect of increasing these constrained-off CMSC payments as the gap between the facilities' offers and the HOEP was wider relative to lower-price hours. Table 2-16 shows the amounts of constrained-off CMSC payments made to the two facilities.

Table 2-16: Large Constrained-off CMSC Payments to Generators in Northwest and
Northeast Zones
September 11, 2013

(\$)

Resource	Constrained-Off CMSC Payments (\$)
Resource A ³²	128,298
Resource E	66,890

One resource located in the East zone received \$363,560 in constrained-on CMSC payments. The facility had uneconomic offers for the much of the day, but was constrained on in in HE 3 and produced at levels in the afternoon and evening that were much higher than suggested by its unconstrained schedule. The resource was constrained primarily due to outages at the Outaouais³³ and Beauharnois³⁴ Québec interties. Both interties are regular suppliers of power from Québec into Ontario. With the outages limiting imports from Québec, the resource was required to come online to ensure reliability of supply in Eastern Ontario.

3.1.3.2 CMSC Payments for Intertie Transactions

There was a total of \$1,721,145 in CMSC payments made in relation to intertie transactions on September 11, 2013. Table 2-17 provides a breakdown of the CMSC payments by intertie and transaction type.

³² Resource A in Table 2-16 refers to the same resource as Resource A from Table 2-13.

³³ Outaouais has a regular capacity of 1,250 MW, but was on forced outage eliminating import transactions.

³⁴ Beauharnois was de-rated from 800 MW to 100 MW due to thermal limits on the local transmission system.

Intertie Zone	Import		Export		Tetal
	C. Off	C. On	C. Off	C. On	Totai
Manitoba	0	0	0	1,764	1,764
Michigan	0	351,488	328,309	(292)	679,505
Minnesota	(22,993)	0	0	68,390	45,397
New York	0	331,653	578,788	0	910,441
Quebec	82,862	1,078	98	0	84,038
Total	59,869	684,219	907,195	69,862	1,721,145

Table 2-17: CMSC by Intertie and Transaction Type September 11, 2013 (\$)

The majority of the CMSC payments for intertie transactions were for constrained-off exports and constrained-on imports, reflecting Ontario's relatively tight supply conditions during the afternoon of September 11, 2013. In general, imports at the Michigan and New York interfaces were constrained on while exports at those same interfaces were constrained off. Nodal prices at each of these interfaces were greater than \$200/MWh from HE 13 to HE 20, which explains the considerable amount of constrained-off CMSC payments for transactions on those interties, as exports that were economic in the unconstrained schedule (the HOEP ranged from \$30.69/MWh to \$475.05/MWh between HE 13 and HE 20) were not economic based on nodal prices in the constrained scheduled, and were therefore constrained off. Similarly, import offers that were uneconomic in the unconstrained schedule were economic in the constrained schedule due to high nodal prices.

Specific Item of Interest

There was some notable activity at the Michigan intertie on the afternoon of September 11, 2013. Specifically, one market participant received significant CMSC payments for both constrained-on imports (\$190,756) and constrained-off exports (\$288,473).

For the duration of the afternoon and early evening, the participant was bidding to purchase Ontario power to sell into PJM at prices as high as \$725/MWh. For example, in HE 16 the participant was scheduled to purchase 150 MW of Ontario power at an average bid price of \$707/MWh. In HE 15, the HOEP was forecast in pre-dispatch at \$349/MWh

and settled at \$142/MWh in real-time. The nodal price in the external zone (PJM), which represents the sale price for exports from Ontario into PJM, averaged \$89.92/MWh³⁵ for the hour. Had the participant delivered power as scheduled in the unconstrained schedule, it would have bought power at \$142/MWh and sold it at \$89.92/MWh, resulting in a loss of \$52.08/MWh, for a total of \$7,812 for the 150 MW.³⁶ This loss is modest when compared to the cost that the participant's \$707/MWh bid suggested it was willing to absorb. Had the participant bought power from Ontario at its bid price of \$707/MWh and sold it at \$89.92/MWh in PJM, its losses for 150 MW would have amounted to \$92,562.

Neither of the above hypothetical losses occurred. Instead, with nodal prices at the Ontario-Michigan intertie averaging \$777/MWh, the participant was constrained off and received over \$80,000 in constrained-off CMSC payments for HE 16. CMSC payments in HE 16 were of this magnitude because of the difference between the HOEP (\$142/MWh) and the price the market participant indicated it was prepared to pay to purchase Ontario power (\$707/MWh). In HE 16, the CMSC payments for this market participant were calculated as 150 MW * (\$707/MWh - \$142/MWh), for a total of \$83,412. However, as noted above, had the market participant's transaction flowed as scheduled in the unconstrained schedule, the market participant would have incurred a loss of nearly \$8,000. In this instance, the CMSC payments were therefore more than what was required to return the market participant to the level of operating profit that would have been expected had its transaction not been constrained off.³⁷ In fact, the CMSC payments transformed a losing transaction into a profitable one.

In addition to receiving constrained-off CMSC payments for its export transactions, the same participant also received significant CMSC payments for constrained-on import

 $^{^{35}}$ The actual recorded price was US\$87.14/MWh, which has been converted based on the exchange rate for the day (\$1 CAD = \$0.9691 USD).

³⁶ This figure does not take into account any contractual obligations the participant may have with sellers in Ontario or purchasers in other jurisdictions, and does not include transaction costs such as transmission reservation in external jurisdictions or Ontario export transmission service charges. The value is calculated solely on the basis of the HOEP, the intertie congestion price and the nodal price in the external jurisdiction.

³⁷ As has been noted by the Panel in the past, CMSC payments are designed to compensate a market participant when, based on the constrained schedule, the IESO instructs it to consume or supply electricity in an amount that is less profitable for the participant relative to the operating profit that would have been expected from consuming or supplying at the level indicated for the participant in the unconstrained schedule. In the case of an exporter, the CMSC calculation assumes that the market participant's bid reflects the participant's marginal benefit of consumption.

transactions. The participant had offers to import power into Ontario at relatively high prices for the majority of the afternoon and early evening. For example, in HE 16 the participant's offers averaged \$753/MWh for an import quantity of up to 200 MW. In HE 16, the HOEP was \$142/MWh and the participant was not scheduled to import power in the unconstrained scheduled. However, in the constrained schedule the participant's offers were just below, or equal to, the Ontario-Michigan intertie nodal price of \$777/MWh, resulting in the majority of the offered power (138 MW of 200 MW) being constrained on which in turn resulted in constrained-on CMSC payments of \$82,695. The CMSC calculation assumes that an importer is offering at its marginal cost, in this case represented by the cost of purchasing power in PJM at the \$89.92/MWh price that prevailed at the IMO node in PJM (plus applicable transaction costs such as transmission reservations).

The market participant behaviour described above appears to be another example of behaviour referred to as "chasing the nodal price", which was discussed in the Panel's last monitoring report and which the Panel will continue to monitor.³⁸ In that report, the Panel also reiterated its long-held view that constrained-off CMSC payments, including those for intertie transactions, are susceptible to gaming.³⁹

3.2 *Operating Reserve Payments*

Operating reserve (OR) payments in excess of \$100,000 for a given hour are considered anomalous by the Panel. There were six such hours during the Summer 2013 Period. High OR payments are associated with instances of high OR prices. Due to the joint optimization of the energy and OR markets, energy and OR prices typically move in the same direction as supply and demand conditions change. Instances of high OR prices and payments are typically associated with tight supply conditions in both the energy and OR markets.

In May 2013, OR prices in the 10-minute spinning and 10-minute non-spinning categories reached record high levels. The hour with the highest OR payments in the

³⁸ See the Panel's January 2014 Monitoring Report, at pp. 136-138, available at

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf. ³⁹ *Ibid*, pp. 123-124.

Summer 2013 Period was HE 10 on May 4, 2013, when OR payments totalled \$583,726. During that hour, the prices for 10-minute spinning reserve, 10-minute non-spinning reserve and 30-minute reserve were \$453.95/MWh, \$560.78/MWh and \$445.96/MWh, respectively. The HOEP during that hour was \$583.71/MWh, the highest of the Summer 2013 Period.

Chapter 3 provides further detail as to the factors that led to the record high OR prices during the Summer 2013 Period.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel summarizes notable changes and developments that affect the efficient operation of the IESO-administered markets, and makes recommendations where relevant to promote market objectives. Section 2 provides an update on Panel investigations. In section 3, the Panel discusses two matters: record high operating reserve prices in May 2013; and whether, and the extent to which, Ontario consumers are subsidizing export transactions.

2 Panel Investigations

In July 2014, the Panel released its report on an investigation into possible gaming behaviour by Greenfield Energy Centre LP (GEC) in relation to Congestion Management Settlement Credit (CMSC) payments.⁴⁰ The Panel considered three aspects of GEC's market conduct, and concluded that GEC engaged in gaming in respect of one aspect of its conduct; namely, an increase in its shut down offer price. In so doing, GEC obtained a profit or benefit of approximately \$432,000 in CMSC payments. While disagreeing with the Panel's finding, GEC has voluntarily repaid that amount to the IESO.

The Panel currently has investigations under way in relation to three market participants (one generator and two dispatchable loads), each relating to potential gaming. As each of these investigations is completed, the Panel will submit its investigation report to the Chair of the Ontario Energy Board (OEB) and the report will be published on the OEB's website.⁴¹

⁴⁰ The Panel's report is available at:

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Investigation_Greenfield_20140717.pdf.

⁴¹ The submission and posting of Panel investigation reports is addressed in Article 7 of the OEB's By-law #3 (Market Surveillance Panel), available at:

http://www.ontarioenergyboard.ca/OEB/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf

3 New Matters

3.1 Record High Operating Reserve Prices in May 2013

3.1.1 Introduction

Record high average monthly prices in the IESO-administered market for 10-minute spinning and 10-minute non-spinning operating reserve (OR) occurred in May 2013. The spinning and non-spinning prices were 61% and 53% higher, respectively, than the previous record high prices set in May of 2011. The significant departure of 2013 prices from historical norms led the Panel to review the factors which contributed to the higher 2013 prices.

The IESO administers two types of real-time markets, the energy market and the OR market. OR is standby power that can be called upon to re-establish the balance between supply and demand in the event of a contingency such as a sudden or unexpected increase in demand or a decrease in generation or transmission service.⁴²

There are three classes of standby power in the OR market: 10-minute spinning (10S), 10-minute non-spinning (10N) and 30-minute (30R). The IESO procures OR as a function of its system operator duties. The cost of procuring OR is charged to consumers as part of the hourly uplift charge. The amount of OR the IESO procures is specified in reliability standards set by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council.⁴³ These reliability standards require the IESO to procure enough 10-minute reserve to cover the largest single contingency that can occur on the grid, given the current configuration. A minimum of 25% of the 10-minute reserve. The remainder can be unsynchronized, that is 10-minute non-spinning reserve. Suppliers of 10-minute OR must be able to provide the required energy to the grid within 10 minutes of being dispatched and must be available to provide the energy for up to one hour.

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<sup>43</sup> NPCC Regional Reliability Reference Directory # 5 Reserve, available at
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https://www.npcc.org/Standards/Directories/Directory_5-Full%20Member%20Approved%20Clean-Footer%20Revised-GJD%2020140324.pdf, and NERC Standards TOP-002-2.1b — Normal Operations Planning, available at http://www.nerc.com/files/TOP-002-2_1b.pdf and BAL-002-1 — Disturbance Control Performance, available at http://www.nerc.com/files/BAL-002-1.pdf
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⁴² See the IESO's "Guide to Operating Reserve", Training, Revised: October 2011, available at http://www.ieso.ca/Documents/training/ORGuide.pdf

The IESO's 30-minute requirement is equal to the greater of half of the second largest contingency on the grid or the largest commissioning unit. The suppliers of this class of OR do not have to be synchronized to the grid. 30-minute OR must be provided to the grid within 30 minutes of being dispatched and must be available for up to one hour.

The average requirement for each class of OR during the month of May for each of 2011, 2012 and 2013 is provided in Table 3-1. There was a 10% decrease in the 10-minute non-spinning reserve requirement between May 2011 and May 2013.⁴⁴ A reduction in the OR requirement would tend to put downward pressure on prices.

Table 3-1: Monthly Average Operating Reserve Requirements May 2011, 2012 & 2013 (MW)

	Requirement for 10S	Requirement for 10N	Requirement for 30R
May 2011	259	757	465
May 2012	259	705	450
May 2013	257	680	465

OR can be provided by dispatchable loads, dispatchable generators,⁴⁵ imports and exports;⁴⁶ however, imports and exports cannot provide synchronized reserve. Market participants capable of providing reserve may only offer in the OR market if they also have an offer in the energy market. The quantity offered in the OR market must be less than or equal to the quantity offered or bid in the energy market. As in the energy market, prices and schedules for each class of OR are determined on a 5-minute basis by the dispatch algorithm. The prices and schedules for OR are determined along with those

⁴⁴ The OR requirement is always set to equal the single largest contingency. This can change due to changes in system conditions or available generation units. The reduction in the OR requirement between 2011 and 2013 was due to a change in available generation units.

⁴⁵ At market opening, it was determined that the market for operating reserve was not competitive due to the dominant position of Ontario Power Generation (OPG). OPG entered into an agreement whereby OPG offers operating reserve according to price schedules that contain both thresholds and caps: see section 3.2 of Chapter 1 of the Panel's October 2002 Monitoring Report, available at

http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_071002.pdf . Effective January 1, 2014, the bid-cap agreement between the IESO and OPG that governed OPG offers into the OR market was terminated as noted later in this chapter.

⁴⁶ Imports and exports can only provide OR if there is an agreement with the applicable neighbouring jurisdiction that the transactions may only be used to provide OR in Ontario: see the IESO's "Guide to Operating Reserve", Training, Revised: October 2011, available at http://www.ieso.ca/Documents/training/ORGuide.pdf. There are no exports offered in the OR market at this time as neighbouring jurisdictions will not agree to recallable exports from Ontario. Imports offered for OR must have firm ramp and transmission and the dispatch data must be coded as operating reserve.

for energy through a "joint optimization process". ⁴⁷ In this process, the offers and bids in all markets (energy and the three OR classes) are evaluated at the same time to produce the most cost-effective solution for the market as a whole. This sometimes leads to seemingly anomalous scheduling of resources when observing dispatch outcomes in each market in isolation.

When available supply is insufficient to meet demand and reserve requirements, the IESO may take out-of-market actions to maintain reliability.⁴⁸ The Market Rules allow the IESO to include two such out of market actions, voltage reductions and reductions in the thirty-minute OR requirement, as a substitute for OR offered by market participants.⁴⁹ The megawatts of reserve afforded by these out-of-market actions are known as Control Action Operating Reserve (CAOR), and are placed into the OR market as standing offers.⁵⁰ A total of 800 MW of CAOR can be offered into the OR market at the price/quantity pairs shown in Table 3-2.

Table 3-2: Current Control Action Operating Reserve Offer Laminations(MW & \$/MW per hour)

Quantity (MW)	30R OR Price (\$/MW/h)	10N OR Price (\$/MW/h)
400	30.00	30.10
200	N/A	75.00
200	N/A	100.00

In 2003, the IESO established the pricing of CAOR based on the desired frequency of scheduling. The price for 400 MW of CAOR was established at \$30.00/MW per hour for 30R and \$30.10/MW per hour for 10N such that CAOR would be scheduled at the same

⁴⁷ See the IESO's "Quick Take 20: Joint Optimization", available at

http://www.ieso.ca/Documents/training/QT20_JointOptimization.pdf

⁴⁸ Additional information about the introduction of control action sources of OR can be found in the Panel's June 2004 Monitoring Report, available at

http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_140604.pdf ⁴⁹ Some conditions apply. See section 4.5.6A of Chapter 5 of the Market Rules.

⁵⁰ When the market first opened, the IESO did not price out-of-market actions in the OR market, which led to counterintuitive pricing. As the market approached shortfall conditions, the IESO used out-of-market sources of OR which led to a lowering of reserve prices rather than a rise in the price to scarcity levels, which would have provided a proper price signal for the market.

⁵¹ For more information, see the IESO's "Market Pricing Working Group, Issue Description Paper – v1.0", October 27, 2008, available at http://www.ieso.ca/Documents/consult/mep2/MP_WG-20081029-Item3_Issue13-CAOR_Issue_Paper.pdf

frequency, approximately 7%, at which the IESO had manually reduced OR prior to introducing the standing offers. The price for 30R was set lower than 10N to ensure that CAOR would be scheduled in 30R before 10N. In 2005, an additional 400 MW of CAOR was introduced.

The Market Rules specify the out-of-market control actions that the IESO may include as standing offers in the OR market. The actions that constitute CAOR are:

- a reduction in the 30-minute reserve requirement;
- a 3% voltage reduction; and
- a 5% voltage reduction. ⁵²
- 3.1.2 OR Prices in May 2013

OR prices in May 2013 were significantly higher than the historical norms. Figure 3-1 illustrates the pattern of OR prices from market opening in May 2002 to September 2013. The highest average monthly prices typically occur in the months of May and June during the period of freshet when:

- gas plants may not be available for OR as they may not be online due to the abundance of low-priced hydroelectric supply and to low demand; and
- hydroelectric resources offer energy at low prices and OR at higher prices, or may not be available to provide OR as they are producing at maximum gate, or 100% (full capacity).⁵³

In the spring of 2011 and 2013 the water levels were higher than those in the preceding years of 2010 and 2012. The OR prices in 2011 and 2013 were notably higher than those in 2010 and 2012 when water conditions were less favourable.

⁵² Section 4.5.6A of Chapter 5 of the Market Rules.

⁵³ At times when there is no water storage capacity, the marginal cost is the water rental rate. In order to get scheduled, resources may be offered at less than the water rental rate and potentially at negative prices to ensure that water is used.



Figure 3-1: Monthly Average Operating Reserve Prices May 2002 - September 2013 (\$/MW per hour)

In May 2013, the average monthly price for 10S operating reserve reached \$21.85/MW per hour, an increase of over \$8/MW per hour from the previous high average monthly price in May 2011. The average monthly price for 10N operating reserve was about \$6/MW per hour higher than the average monthly price in May 2011. In contrast with historical OR price trends, the 30R operating reserve price did not track the price of the 10-minute products. The 30R monthly average price of \$3.53 /MW per hour was less than 20% of the 10N price. The monthly average OR prices in May 2011 and May 2013 are provided in Table 3-3.

Table 3-3: Monthly Average Operating Reserve Prices May 2011 & May 2013 (\$/MW per hour)

	10S	10N	30R
May 2011	\$13.54	\$13.41	\$9.09
May 2013	\$21.85	\$20.57	\$3.53

An hour-by-hour examination of OR prices shows increased volatility in the price of the 10S and 10N products and reduced volatility for the 30R product for May 2013 compared to May 2011. Figures 3-2, 3-3, and 3-4 show hourly prices in May 2011 and May 2013 for each class of OR. There are a number of notable differences in the OR prices between the two periods. As discussed below, in 2013 the prices for 10S and 10N reached levels above the price of the first lamination of CAOR (\$30.10/MW per hour) on a more frequent basis than in 2011. Also, in May 2013 there were three hours where the average hourly prices for all three classes of OR exceeded \$100.00/ MW per hour. This compares to only one such hour in May of 2011. These price spikes were not lengthy in duration, but their frequency increased the average monthly price.



Figure 3-2: Average Hourly 10S Prices May 2011 & May 2013 (\$/MW per hour)

Note: Peak prices (all /MW per hour) not shown in the figure are : May 4 2013,HE 10 - \$560.78; May 5 2013,HE 20 - \$415.47; May 11 2011, HE 16, - \$418.56; and May 24 2013, HE 21 - \$467.60.



Figure 3-3: Average Hourly 10N Prices May 2011 & May 2013 (\$/MW per hour)

Note: Peak prices (all /MW per hour) not shown in the figure are: May 4 2013, HE 10 - \$453.95; May 5 2013, HE 20 - \$389.03; May 11 2011, HE 16 - \$410.76; and May 24 2013, HE 21 - \$368.49.



Figure 3-4: Average Hourly 30R Prices May 2011 & May 2013 (\$/MW per hour)

Note: Peak prices (all /MW per hour) not shown on in the figure are: May 4 2013, HE 10 - \$445.96; May 5 2013, HE 20 - \$366.55; May 11 2011, HE 16 \$410.68; and May 24 2013, HE 21 - \$361.07.

Despite the increase in prices in the 10-minute OR classes, the total payment to market participants for OR was almost the same for May 2013 as for May 2011, \$12.8 million and \$12.3 million respectively. The decrease in the 30R price and the 10% reduction in the 10N requirement partially compensates for the increase in 10S and 10N prices. Figure 3-5 shows the contribution of each reserve class to the total cost. It should be noted that payments for CAOR scheduled for 10N and 30R are not charged or paid to any market participant or the IESO. If CAOR was any other offer in the stack, these offers would have resulted in OR payments. The estimated value of these hypothetical payments was determined by multiplying the quantity of CAOR scheduled by the clearing price for the class of OR. The actual payments to market participants for each class of OR and the hypothetical estimates for CAOR are shown in Figure 3-5.




3.1.3 Discussion of Factors Contributing to High Prices for 10S and 10N in May 2013

The Panel reviewed the offer stacks for the three classes of OR in the month of May in the years 2013, 2012 and 2011. All else being equal, a reduction in the number of megawatts offered or an increase in offer prices for OR tends to put upward pressure on reserve prices.⁵⁴ In May 2013, three factors in the reserve offers contributed to higher OR prices. First, compared with May 2012 and May 2011, fewer resources offered for each class of OR in 2013. Second, and consistent with the first observation, in 2013 fewer megawatts were offered in total and fewer megawatts were offered at prices less than the offer price for CAOR. Both of these factors in turn put upward pressure on OR prices. The decreases in question between 2011 and 2013 are shown in Table 3-4.

	Number of Resources Offering		Total Average MW Offered per Hour			MW Offered at Prices Less than the Lowest Lamination of CAOR			
OR Class	10S	10N	30R	10S	10N	30R	10S	10N	30R
2011	102	71	84	4587	5568	6127		1900	2244
2012	100	71	81	4548	5473	6283		3607	3409
2013	91	59	73	3934	4586	4586		1704	2036

Table 3-4: Offer Stack Characteristics for Operating Reserve (MW)

Third, in May 2013 the IESO de-rated CAOR, thereby reducing the number of CAOR megawatts available for scheduling in the OR market. The Panel understands that the de-rating was done to reflect the megawatts of OR that were achievable given the load or demand at the time. As previously described, CAOR can include a 3% or a 5% voltage reduction. A 3% voltage reduction will lead to about a 1.5% energy reduction and a 5% voltage reduction will lead to about a 2.6% energy reduction. If the load is 20,000 MW, this would represent about 300 MW for a 3% voltage reduction and 520 MW for a 5% voltage reduction. In May 2013, the average hourly Ontario demand was about 14,500 MW.⁵⁵ The dispatch scheduling and optimization algorithm recognizes the de-rating of CAOR and, if appropriate, the next lowest cost resource is scheduled. The IESO de-rated CAOR on 24 days in May 2013. Typically, the de-ratings ranged from 100 to 173 MW

⁵⁴ As noted section 3.1.1, OR prices are determined in a joint optimization process with the energy market and changes in the energy market can also influence OR prices.

⁵⁵ Ontario demand is calculated as: Total Ontario generation + imports - exports

and were in place from 08:00 to 22:00. Table 3-5 provides the percentage of intervals where the clearing price for 10N was greater than or equal to \$30.10/MW per hour (the offer price of the first lamination of CAOR). The de-rating of the CAOR (shortening the offer stack) then contributed to a steepening of the OR offer curve, leading to prices which exceeded the first price lamination of CAOR and to the high average monthly prices in May 2013.

Table 3-5: Intervals with 10N Prices Greater Than or Equal to \$30.10/MW per hour(\$/MW per hour & %)

Month of May	Average Price for 10N (\$/MW per hour)	Intervals with Clearing Price Equal to \$30.10	Intervals with Clearing Price Greater than \$30.10
2011	\$13.41	16%	1%
2012	\$0.07	0	0
2013	\$20.57	26%	12%

3.1.4 Conclusions and Recommendations

It appears that the record high prices for 10S and 10R in May 2013 were due to a combination of the factors identified above, namely:

- fewer resources offering into the OR markets;
- fewer megawatts being offered into the OR markets in total and fewer offered below the price of the lowest lamination of CAOR; and
- de-rating of CAOR by the IESO.

In May 2013, water levels were higher contributing to higher OR prices than in May of 2012 when there were less favourable water conditions. Tight supply conditions in the OR market contributed to higher OR prices, as did IESO actions to de-rate CAOR. The de-rating of CAOR during low demand periods is understandable if, for example, the megawatt relief from a 3% or 5% voltage reduction would fail to yield the required megawatts of OR. The Panel considers this rationale sensible. The Panel notes that, in May 2013, the IESO de-rated CAOR for the first time since its introduction into the OR market in 2003. Considering the influence that the de-rating of CAOR had on OR prices

in May 2013, the Panel is of the view that the IESO should provide greater transparency around its practices of de-rating CAOR, including the megawatt quantity and duration of the de-ratings.

Recommendation 3-1

The Panel recommends that the IESO make more information available to market participants about its practices of de-rating Control Action Operating Reserve, including the criteria used to determine the amount and duration of such de-ratings.

The Panel's review of 10N OR pricing also highlighted the frequency with which prices cleared at levels equal to or above CAOR offers, which in May 2013 was above the intended average frequency when CAOR pricing was established in 2003 (as noted earlier, the price of CAOR was established for 10N OR such that CAOR would be scheduled at the same frequency that the IESO had manually reduced OR prior to introducing CAOR). Generators have expressed concern about the pricing of CAOR in the context of the IESO's stakeholder engagement regarding the review of the Hourly Ontario Energy Price (SE-105), noting that CAOR may displace OR offered by market participants at prices that do not necessarily reflect shortage conditions.⁵⁶ As part of an earlier stakeholder engagement in 2011 (SE-72), a proposal had been made to replace CAOR with "Operating Reserve Demand Curves" modelled as supply curve.⁵⁷

The Panel will continue to monitor OR prices to determine if the OR prices and scheduling frequency of CAOR in May of 2013 are anomalous or part of a new and continuing trend and whether revisions to the pricing structure of CAOR appear to be warranted.

In addition, the Panel will also be monitoring the impact on the OR market of the termination of the bid-cap agreement between the IESO and Ontario Power Generation (OPG) that governed OPG's offers into the OR market until the end of 2013. That agreement was put into place at market opening, when it was determined that the market for OR was not sufficiently competitive due to OPG's dominant position. Under the

⁵⁶ See http://www.ieso.ca/Documents/consult/se105/se105-20130118-Stakeholder_Feedback-OPG.pdf.

⁵⁷ See http://www.ieso.ca/Documents/consult/se72/se72-20111011-presentation.pdf.

agreement, OPG offered OR according to price schedules that contain both thresholds and caps. The agreement was terminated effective January 1, 2014, based on the IESO's assessment that the OR market is now effectively competitive.⁵⁸

⁵⁸ See http://www.ieso.ca/Pages/News/NewsItem.aspx?newsID=6714.

3.2 Ontario Consumer Costs and Export Subsidization

Since market opening in 2002, Ontario has participated in, and at times relied heavily upon, inter-jurisdictional energy trading. As the Ontario market has evolved over the years, so too has the trading dynamic between Ontario and its five neighbouring jurisdictions. With Ontario facing tight domestic supply conditions in the early to mid-2000s, imports played a vital role in ensuring that there was adequate supply to meet demand in the province. As the province procured additional generating capacity, Ontario's reliance on import transactions decreased, to the point where Ontario is now a large net exporter of power. With enough generating capacity to meet Ontario demand for the foreseeable future, net exports are likely to be an enduring feature of the Ontario market for some time.

Over the past year, the role of electricity exports in the Ontario market has been the subject of considerable commentary. Questions have arisen about the benefit that export transactions provide to Ontario consumers, and more specifically around the question of whether and the extent to which Ontario ratepayers are subsidizing export transactions. The export subsidization argument, at its simplest, is that Ontario ratepayers pay costs that are incurred as a result of export transactions. To test the merits of this argument, the Panel has analyzed the costs triggered by export transactions and identified who bears those costs. The Panel did not compare the costs paid by exporters with any benefits that exports provide (for example, in the form of transmission service charges or the creation of surpluses for Ontario generators) to arrive at any net benefit of exports to Ontario. Quantification of the benefits provided by exports is difficult, and was outside the scope of the Panel's analysis.

3.2.1 Claims that Ontario Consumers Paid Over \$1 Billion to Subsidize Exports in 2013

Two recent press reports have claimed that Ontarians paid over \$1 billion to subsidize export transactions to neighbouring jurisdictions in 2013.⁵⁹ In both of those reports, the

⁵⁹ See https://web.archive.org/web/20140411041544/http://ontariondp.com/en/electricity-exporting-cost-ontariansover-1-billion-in-2013 (issued in January 2014) and http://opinion.financialpost.com/2013/12/02/ontarios-power-tripprovince-lost-1-2-billion-this-year-exporting-power/ (published in December 2013).

average revenue received from export sales⁶⁰ was compared with the average all-in cost per kWh of generation.⁶¹ The average all-in cost of generation, as measured in both press reports, includes the Hourly Ontario Energy Price (HOEP), the Global Adjustment (GA) and uplift. While the average export revenue methodology reflected in both reports provides a fairly accurate estimate of revenues, the Panel believes that their approach to estimating average cost is overly simplistic, and does not appropriately assign costs to their causation.

All of the costs associated with procuring, generating and delivering electricity are recovered from end-users; for present purposes, these end-users can be categorized into Ontario consumers (i.e., those with physical load in the province), and exporters.

The various costs incurred to serve demand are not created equal, and to treat them as such when allocating costs would itself lead to cross-subsidization amongst groups. The costs associated with building and operating a reliable and sustainable electricity system are incurred over various timeframes and for a number of different reasons. In industries such as electricity that require long lead times and large capital investments, the distinction between capital costs and variable costs is particularly important. Decisions on capital costs, such as the procurement of capacity, are made irrespective of short-term variable conditions. Similarly, decisions on variable costs, such as unit commitment, are made independent of sunk capital costs.

The Panel reviewed both the capital and variable costs associated with serving demand, and asked: "Would these costs have been incurred had there been no export transactions?" The subsidization of exports only becomes an issue if export transactions induce a cost that is not fully covered by the market price or any out-of-market charges paid by exporters. The Panel's analysis suggests that there is no cross-subsidization associated with exporters not paying the GA, nor is there cross-subsidization in relation to the HOEP. However, the Panel has found that exporters do not bear the full cost of starting generators under the IESO's generation cost guarantee programs to meet export

⁶⁰ The average revenue from export sales was calculated to be 2.54 cents per kWh in one press report, and 2.65 cents per kWh in the other.

⁶¹ The average all-in cost of generation was calculated to be 8.55 cents per kWh in one press report, and 10.5 cents per kWh in the other.

demand. The Panel estimates that, without taking into account any benefit that exports provide, Ontario consumers paid an average of approximately \$43 million in such costs in each of 2012 and 2013. This cost subsidization from Ontario consumers to exporters goes towards offsetting any such benefit.

3.2.2 Major Cost Recovery Categories

The vast majority of costs incurred to serve market demand are recovered from Ontario consumers and exporters through a combination of three major charges: the HOEP, the GA and uplift. The sections that follow examine whether or not costs recovered through these charges are incurred as a result of export demand. Costs which are incurred as a result of exports, but that are not charged to exporters, would give rise to cross-subsidization amongst Ontario consumers and exporters and to potentially inefficient levels of exports.

Hourly Ontario Energy Price

Export demand requires the scheduling of incremental supply above the level needed to serve Ontario demand. The variable cost of the incremental supply is reflected in a higher HOEP. As exporters pay the HOEP, there is no subsidization of this variable cost across Ontario consumers and exporters.

All else being equal, export demand does raise the HOEP for Ontario consumers; while there is no cost subsidization amongst Ontario consumers and exporters, there is a transfer of wealth from consumers to producers. This wealth transfer, to the degree that it is induced by efficient consumption from Ontario consumers or exporters, generates surpluses for electricity producers, a fundamental aspect of a competitive market design.⁶²

⁶² Under the contract and regulation structure applicable to generation in the province, most of this surplus flows back to Ontario consumers through reductions in GA charges.

Global Adjustment

The GA primarily accounts for the difference between the HOEP and the rates paid to regulated and contracted generators.⁶³

In Ontario, the vast majority of generators are compensated on the basis of either a regulated rate set by the Ontario Energy Board (OEB)⁶⁴ or a contractual rate primarily negotiated with, or set by, the Ontario Power Authority. Payments to these generators are made in part through the HOEP and, when the HOEP is less than the regulated or contracted rate, in part through payments recovered from Ontario consumers through the GA.⁶⁵ In principle, generators are guaranteed a fixed, or near fixed, stream of future revenues.⁶⁶

Contracted and regulated rates paid to generators generally cover the capital costs of building and maintaining a generation facility, plus a reasonable rate of return. Decisions on whether or not to build additional generation, and to incur the associated costs, are based solely on Ontario's forecasted domestic demand needs (plus a reliability cushion), and not on export demand. Consequently, the GA applies to Ontario consumers only; exporters do not pay the GA.

There are a number of regulated and contracted rates. Some of these rates are paid based on available capacity, and are unaffected by the level of demand. The presence or absence of exports has no effect on the level of payments made to these generators. However, to the extent that export demand causes the HOEP to rise, more of a generator's payment is derived from the HOEP and less from payments recovered via the GA.

⁶³ For more information on the GA, see http://ieso-public.sharepoint.com/Pages/Ontario's-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx

⁶⁴ The OEB sets rates only for facilities owned by Ontario Power Generation Inc.

⁶⁵ The GA is normally a charge to Ontario consumers, but when the HOEP is greater than the contracted or regulated rates, generators return the differential to the market, in which case the GA can be a rebate to Ontario consumers. Generally, as the HOEP increases, GA charges decrease, and vice versa.

⁶⁶ Generators that are compensated on a "per MWh of production" basis have payment streams that vary with the level of production. Generators with these rates are either baseload, self-scheduling, wind or solar resources.

Some resources with contracted rates, as well as those with regulated rates receive a flat rate per MWh of production. In such cases, where an export is the cause of a generator being scheduled, resulting in an increase in the GA that would otherwise not have occurred, cross-subsidization would arise since, as noted earlier, exporters do not pay the GA. While, in theory, payments of the "per MWh of production" type can be attributable to increasing export demand, in practice the payments to be recovered through the GA are incurred whether exports are present or not. Only baseload, self-scheduling and intermittent resources receive contracted or regulated rates that compensate on a per MWh of production basis. The operational nature of these resources dictates that they are the first sources of generation to be turned on, and the last to be shut down. Since Ontario consumers are modelled in the market as having the highest willingness to consume (priced at \$2,000/MWh, the Maximum Market Clearing Price), baseload, selfscheduling and intermittent resources are usually generating to serve Ontario demand. When generation from these units exceeds Ontario demand, and is going to serve exports, payments to be recovered through the GA are still unlikely to increase due to the contract structure of some generators (those that are compensated for foregone energy production), and the operational nature of others. In light of the above considerations, the Panel is of the view that there is no subsidization of GA across Ontario consumers and exporters.

Appendix 3-A sets out a detailed analysis of why the payments recovered through the GA do not increase with increased export demand, including a breakdown of the various payment structures that underlie generation costs that are recovered through the GA.

Uplift

Uplift is charged to Ontario consumers and exporters in order to recover costs associated with the operation of the market that are not recovered through the HOEP, including the costs of reliability programs and congestion payments, among others. Uplift charges generally fall into two categories, hourly and non-hourly (often daily or monthly); Ontario consumers are subject to nearly all uplift charges, while exporters are subject to most, but not all.

Hourly Uplift

Hourly uplift is comprised of various costs that are variable on an hourly or interval (5minute) basis. The cost components recovered through the hourly uplift are:

- Congestion Management Settlement Credit (CMSC) payments;
- Intertie Offer Guarantee (IOG) payments;
- Operating Reserve (OR) payments; and
- Line losses.

Ontario consumers and exporters are charged a portion of total hourly uplift based on their proportion of total real-time market demand during the relevant hour. Some costs recovered through hourly uplift charges are incurred on behalf of Ontario consumers and exporters, such as OR payments, and are thus appropriately allocated to both Ontario consumers and exporters. Other costs recovered through hourly uplift charges could be attributable to or induced by a single market participant or group of market participants, but those market participants are not easily identifiable and there is no practice of allocating these costs directly to them. To the extent that there is any subsidization from Ontario consumers to exporters, or vice versa, related to hourly uplift using the current allocation methodology, it is not readily determinable.

Non-hourly Uplift

Generally, non-hourly uplift is comprised of various costs that are variable over multiple hours, a day or longer. In some cases, charges to recover specific costs can remain constant over the course of one or more years; such is the case for the final three charges on the list below. The components of non-hourly uplift include:

- Day-ahead Production Cost Guarantee (DA-PCG) payments;
- Real-time Generation Cost Guarantee (RT-GCG) payments;
- Monthly ancillary service charge;
- Export transmission service charge (exporters only);
- Debt Retirement Charge (Ontario consumers only); and
- Rural and remote settlement charge (Ontario consumers only).

Non-hourly uplift charges that do not apply to exporters, such as the Debt Retirement Charge and the rural and remote settlement charge (to pay down the Ontario Hydro residual stranded debt and to help off-set the higher cost of serving Ontario consumers in rural and remote areas, respectively) relate to costs that are incurred regardless of whether exports are present. The bulk of the remaining non-hourly uplift charges are levied on both Ontario consumers and exporters on the basis of their respective share of total real-time market demand.

Just as with hourly uplift, some costs recovered through non-hourly uplift cannot be easily linked to those who induced the costs, making cross-subsidization difficult to avoid. However, the Panel has identified two cost components of non-hourly uplift, RT-GCG and DA-PCG payments, where (i) the costs can be linked to the group that induced them, and (ii) the current allocation methodology can give rise to cross-subsidization.

3.2.3 Allocation of Uplift to Recover Payments under Generation Cost Guarantee Programs⁶⁷

3.2.3.1 Real-time Generation Cost Guarantee Uplift

The RT-GCG program is a generation commitment program that ensures that non-quick start generators (primarily gas-fired units) will recover the costs associated with starting their unit and operating at their minimum generation level for their minimum run-time.⁶⁸ Absent a start-up cost recovery mechanism, such generators may be unable to recover these costs through market revenues, making them hesitant to run their units for risk of incurring a loss. Currently, market participants with eligible RT-GCG units recover their start-up costs by submitting the total costs that were incurred during start-up; if market revenues earned during start-up and operating profits earned during minimum run-time following ramp-up (up to the unit's minimum generation point) are less than the unit's start-up costs, a top-up payment will be made to the market participant. As discussed below, units are committed under the RT-GCG program to meet a need for additional

⁶⁷ For a detailed discussion of the IESO's generation cost guarantee programs, see Chapter 3 of the Panel's January 2014 Monitoring Report, available at

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf. ⁶⁸ Both minimum generation and minimum run-time levels are determined by the unit's technical limitations. The unit cannot operate safely or efficiently at lesser generation levels and durations.

generation that appears in real-time due to changes in supply or demand relative to dayahead forecasts.

Top-up payments made to units under the RT-GCG program are recovered from both Ontario consumers and exporters through a monthly uplift charge that is allocated based on their respective share of total real-time market demand. As discussed below, this allocation methodology does not necessarily reflect the extent to which consumers and exporters respectively cause RT-GCG top-up payments to be incurred. The Panel believes that the introduction of the Enhanced Day-ahead Commitment (EDAC) process in 2011 allows for an alternate allocation methodology, also discussed below, that would improve the link between cost causality and cost recovery, reducing some crosssubsidization between Ontario consumers and exporters.

Using a forecast of Ontario demand and output from self-scheduling and intermittent resources, as well as offers and bids from dispatchable resources, EDAC attempts to schedule sufficient generation to meet total forecast market demand for the next day. While all resources are subject to scheduling day-ahead, only non-quick start generators, importers and exporters receive financially binding schedules.⁶⁹ When scheduling to meet total forecast market demand, EDAC attempts to minimize total system costs by considering not only the variable operating costs of each unit, but also the start-up and speed no-load⁷⁰ costs of non-quick start generators. In this sense, EDAC is designed to satisfy total forecast market demand at least cost.

While EDAC satisfies day-ahead demand at least cost, more or less generation may be needed in real-time due to changes between day-ahead and real-time conditions. From day-ahead to real-time, supply and demand conditions may change for any of the following reasons:

Supply Side Changes

- Self-scheduling and intermittent forecast error; and
- Generator outages.

⁶⁹ Other resources are not penalized for not meeting their day-ahead schedules in real-time.

⁷⁰ Speed no-load costs are costs associated with a generator remaining synchronized to the electricity grid, but injecting no power.

Demand Side Changes

- Ontario demand forecast error; and
- Changes in net exports.

The change in the need for generation from day-ahead to real-time manifests itself in two ways based on whether the change is the result of a supply side factor or a demand side factor. On the demand side, real-time Ontario demand that exceeds day-ahead forecasted demand, and increases in net exports in real-time relative to day-ahead, require the scheduling of additional generation in real-time. On the supply side, self-scheduling and intermittent resources that generate less in real-time than forecasted day-ahead, and generator outages that affect real-time but were not foreseen day-ahead, also require the scheduling of additional generation in real-time.

Table 3-6 shows the total need for increased generation from day-ahead to real-time in 2012 and 2013, broken down by source of the day-ahead to real-time change. Note that positive supply side numbers represent decreased supply, in other words, the need for more real-time generation.

Table 3-6: Day-ahead to Real-time change in the need for Additional Supply2012 - 2013(Average hourly MW change)

Supply			Dem	Total	
Vear	Avg. Change	Avg.	Avg. Change	Avg.	Change
1 cai	in SS and Int.	Generator	in Ontario	Change in	DA to
	Generation	Outages	Demand	Net Exports	RT
2012	1	125	-4	1,177	1,299
2013	-23	80	8	1,554	1,619

Increased net exports from day-ahead to real-time have far and away been the primary source of change in terms of the need for additional generation since the implementation of EDAC in 2011. On average, increased net exports accounted for 90.6% of the total average hourly change in 2012, and 95.9% in 2013.⁷¹

⁷¹ While the data in Table 3-6 very strongly suggests that the vast majority of RT-GCG starts were for the purpose of serving incremental exports, a definitive conclusion cannot be reached solely on the basis of the real-time data in Table 3-6 due to the fact that commitments are made in pre-dispatch, not in real-time. See footnote 73 for additional information.

Such large increases in net exports from day-ahead to real-time arise due to the treatment of imports and exports in day-ahead relative to real-time. When committed day-ahead, importers are provided a guarantee (in the form of an Intertie Offer Guarantee) that they will recover their scheduled cost no matter the real-time price. They therefore have an incentive to participate day-ahead, and many do. As a result, incremental imports from day-ahead to real-time are modest. Conversely, there is no incentive for exporters to participate day-ahead; in fact, if they participate day-ahead they are financially penalized for not following their day-ahead schedule. With no upside and considerable downside, exporters rarely participate day-ahead to real-time. Table 3-7 displays average hourly exports scheduled day-ahead and in real-time in 2012 and 2013, and illustrates the large change in exports from day-ahead to real-time.

Table 3-7: Day-Ahead and Real-Time Scheduled Exports 2012 - 2013 (Average hourly MW)

Year	Day-Ahead	Real-Time	Change from DA to RT
2012	15	1,665	1,650
2013	3	2,090	2,087

Day-ahead to Real-time changes: An Illustrative Day

On January 4, 2013, nine fossil-fired units qualified to start under the RT-GCG program; these nine units had total combined guaranteed costs of \$506,000. For all nine starts, market revenues were insufficient to cover guaranteed costs, resulting in \$322,000 in RT-GCG top-up payments. These top-up payments were recovered from all market participants based on their respective share of total real-time demand, with Ontario consumers paying approximately \$285,850 of the bill, and exporters paying the remaining \$36,150.

But why were those units needed in the first place? As discussed earlier, there are four sources of day-ahead to real-time discrepancy which may necessitate the commitment of additional generation in real-time.

	Suj	oply	Dem	Total	
	Avg. Change	Avg.	Avg. Change	Avg.	Change
January 4,	in SS and Int.	Generator	in Ontario	Change in	DA to
2013	Generation	Outages	Demand	Net Exports	RT
	(MW)	(MW)	(MW)	(MW)	(MW)
	-251	41	-444	2,138	1,485

On the supply side, there was an hourly average of 41 MW of generation scheduled day-ahead that was unavailable in real-time. These modest incremental supply outages were more than offset by self-scheduling and intermittent generators, which produced more than forecasted in every hour, averaging 251 MW of additional generation throughout the day. On the demand side, actual Ontario demand was less than forecasted in every hour, averaging 444 MW less than forecasted day-ahead. In all, these three sources of day-ahead to real-time change accounted for an average of 654 MW of spare supply or unrealized demand in real-time; despite this, nine units were started under the RT-GCG program.

On this day, incremental net exports necessitated the commitment of RT-GCG units. Day-ahead there were no exports scheduled in any hour, while real-time exports averaged 2,186 MW per hour. After accounting for offsetting import transactions, the average change in net exports from day-ahead to real-time was 2,138 MW; this influx in demand represented a 12% increase in market demand from day-ahead.

With all other sources of day-ahead to real-time change, in aggregate, reducing the need for additional real-time generation, generators were committed under the RT-GCG program primarily for the purpose of supplying incremental net exports. Despite this, Ontario consumers were responsible for paying \$285,850, or 89% of the costs associated with these starts, with exporters paying the remaining \$36,150, or 11%. Using the alternate allocation methodology discussed below, exporters would have been responsible for paying virtually all of the \$322,000 in RT-GCG top-up payments.

If all four sources of potential day-ahead to real time change remain the same from dayahead to real-time, one would expect the real-time market to settle almost exactly as it did day-ahead.⁷² To the extent that any of these sources do change, and additional generation needs to be scheduled in real-time, that need can be met in one of the following ways:

- Increased supply from day-ahead committed resources;
- Increased supply from quick-start resources that were not scheduled, or were only partially scheduled, day-ahead; or
- Increased supply from non-quick start resources under the RT-GCG program for units that were not committed day-ahead.

Where the need for additional generation is met from the first two sources, scheduling is done based solely on variable operating costs (day-ahead committed resources have sunk start-up costs and quick-start resources have no start-up costs), and the costs are recovered from Ontario consumers and exporters via the HOEP. When RT-GCG units are scheduled to meet the need for additional generation, additional start-up costs are incurred and will be recovered from the market through uplift charges if market revenues are not sufficient to cover those costs.

As noted earlier, RT-GCG top-up payments are recovered through a monthly uplift charge paid by Ontario consumers and exporters based on their respective share of total real-time market demand. RT-GCG units are only brought online where required as a result of one of the four day-ahead to real-time changes identified earlier. Since EDAC settles the entirety of the market day-ahead, it is possible to delineate between costs induced by day-ahead demand and those induced by incremental real-time demand.

In order to limit cost subsidization amongst day-ahead and real-time sources of demand (and by extension Ontario consumers and exporters), costs incurred to meet day-ahead demand would need to be allocated to day-ahead Ontario consumers and exporters only; additional costs incurred to meet demand incremental to day-ahead would be allocated

⁷² Provided that generators offer at cost in both day-ahead and real-time, and that costs and/or opportunity costs do not change from day-ahead to real-time.

only to Ontario consumers and exporters that caused that incremental demand. In jurisdictions that have day-ahead markets, costs are allocated in this manner using a twostage settlement system (settling day-ahead and real-time separately). If the IESO were to adopt a full day-ahead market with standard two-stage settlement, subsidization of RT-GCG costs amongst day-ahead and real-time sources of demand would no longer be an issue, as the costs would be allocated to the respective market in respect of which they were incurred.

By separating costs induced by real-time demand from those induced day-ahead, it is possible to identify any subsidization that occurs between day-ahead and real-time sources of demand as well as any subsidization that occurs between Ontario consumers and exporters.

As noted earlier, RT-GCG top-up payments are triggered by starting units to meet a change in the need for generation from day-ahead to real-time, whether that change is the result of supply side factors or demand side factors. Changes in supply side factors affect Ontario consumers and exporters equally, including all sources of demand scheduled day-ahead. For that reason, allocating RT-GCG top-up payments associated with supply side changes on the basis of an Ontario consumer's or an exporter's share of total real-time market demand would not give rise to cross-subsidization.

Where cross-subsidization between Ontario consumers and exporters can occur is when RT-GCG units are brought online to meet demand side changes. To avoid crosssubsidization, the top-up payments associated with an RT-GCG unit committed to serve increases in Ontario demand from day-ahead to real-time would need to be charged to Ontario consumers only. Conversely, when RT-GCG resources are committed to meet increases in export demand, exporters would need to pay the associated top-up payments. In other words, in order to limit cross-subsidization RT-GCG top-up payments would need to be recovered based on an Ontario consumer's or an exporter's share of (or responsibility for) the change in the need for generation from day-ahead to real-time, rather than on their share of total real-time market demand.⁷³

⁷³ RT-GCG commitments are not made in real-time, but in pre-dispatch, up to three hours ahead of real-time. Despite providing a good indicator, real-time numbers do not necessarily reflect the pre-dispatch conditions at the time of unit

Under the IESO's current practice of allocating RT-GCG costs based on an Ontario consumer's or an exporter's share of total real-time market demand, rather than on the basis of the extent to which these costs were induced by the Ontario consumer or exporter, cost recovery is not directly linked to cost causality.

While it is not possible to completely link cost recovery to cost causation, the subsidization of RT-GCG costs between Ontario consumers and exporters can be limited by using a settlement approach similar in principle to the two-stage settlement system used in jurisdictions that have day-ahead markets. This alternative settlement approach would involve using the proportional cost allocation methodology already employed by the IESO, but allocating costs based on the Ontario consumer's or the exporter's share of the changes in demand from day-ahead to real-time rather than on their share of total real-time market demand. Using this approach, the Panel calculated how much of the RT-GCG costs in 2012 and 2013 would have been allocated to Ontario consumers and how much would have been allocated to exporters on an annual basis. The results are shown in Table 3-8, which also includes the actual RT-GCG top-up payments recovered from Ontario consumers and exporters for those years so that the total cross-subsidization may be calculated.⁷⁴

Table 3-8: Estimated Cross-subsidization of RT-GCG Costs Associated with Top-up Payments 2012 - 2013 (\$ millions)

	Total RT-	Actual Allocation		Alternate Allocation		Salaidine tion .	
Year GCG Costs Year Associated with Top-up Payments	GCG Costs Associated with Top-up Payments	Ontario Consumer Share	Exporter Share	Ontario Consumer Share	Expor ter Share	Ontario Subsidizing Exports	
2012	78.4	69.8	8.6	18.3	60.1	51.5	
2013	63.5	55.4	8.1	13.4	50.1	42.0	
Total	141.9	125.2	16.7	31.7	110.2	93.5	

commitment. This means that allocating RT-GCG uplift charges based on changes from day-ahead to real-time could still result in some cross-subsidization, due to changes from pre-dispatch to real-time. Nevertheless, allocating RT-GCG uplift charges based on changes in the need for generation from day-ahead to real-time would still represent a significant improvement over the current allocation methodology.⁷⁴ Note that the allocated costs do not equal the share of total change in Table 3-6 multiplied by the "Total RT-GCG

⁷⁴ Note that the allocated costs do not equal the share of total change in Table 3-6 multiplied by the "Total RT-GCG Costs Associated with Top-up Payments" in Table 3-8. This is because, for greater accuracy, the values in Table 3-8 were calculated on a daily average basis, whereas Table 3-6 presents yearly average data for summary purposes.

Total RT-GCG top-up payments were \$141.9 million combined in 2012 and 2013, of which \$125.2 million was recovered from Ontario consumers, and \$16.7 million from exporters. Based on the alternate allocation methodology, exporters would have paid approximately \$110.2 million over the same time period, with Ontario consumers paying \$31.7 million. The Panel estimates that, under the current cost allocation methodology, \$93.5 million in RT-GCG uplift charges were paid by Ontario consumers over the two-year period that should more appropriately have been paid by exporters. However, as discussed below, there is cross-subsidization in the opposite direction under the day-ahead production cost guarantee program that partially off-sets this amount.

3.2.3.2 Day-ahead Production Cost Guarantee Uplift

As is the case under the RT-GCG program, top-up payments under the DA-PCG program are made to non-quick start generators whose real-time market revenues are not sufficient to cover their guaranteed costs. In this case, however, DA-PCG top-up payments are made to generators that are committed day-ahead, as opposed to those that are committed in pre-dispatch. Just as with RT-GCG payments, the current cost allocation methodology recovers DA-PCG top-up payments from Ontario consumers and exporters based on their respective share of total real-time market demand. To limit subsidization between Ontario consumers and exporters, the costs associated with meeting day-ahead demand would need to be borne by those scheduled to consume power day-ahead.

As discussed earlier, exports have no incentive to participate day-ahead. As a result, exports accounted for far less than 1% of total day-ahead market demand in both 2012 and 2013. Despite their negligible contribution to day-ahead demand, 10.7% of total DA-PCG top-up payments were recovered from exporters over the two-year period. Using the alternate allocation methodology under which DA-PCG costs would be allocated based on share of day-ahead demand, the Panel calculated how much of the DA-PCG costs would be allocated to Ontario consumers and how much to exporters. The results are shown in Table 3-9, as are the actual DA-PCG top-up payments recovered from each group so that the total cross-subsidization may be calculated. Note that the subsidization column measures subsidization of exporter costs by Ontario consumers,

Table 3-9: Estimated Cross-subsidization of DA-GCG Costs Associated with Top-up Payments 2012 - 2013 (\$ millions)

Total DA-		Actual Allocation		Alternate A	Subsidization:	
Year	Year Associated with Top-up Payments	Ontario Consumer Share	Exporter Share	Ontario Consumer Share	Exporter Share	Ontario Subsidizing Exports
2012	58.7	52.5	6.2	58.7	0.0*	-6.2
2013	10.6	9.4	1.2	10.6	0.0*	-1.2
Total	69.3	61.9	7.4	69.3	0.0*	-7.4

*These numbers were positive, but rounded to zero.

Total DA-PCG top-up payments were \$69.3 million combined in 2012 and 2013, of which \$61.9 million was recovered from Ontario consumers, and \$7.4 million from exporters. Based on the alternate allocation methodology, exporters would have paid approximately \$42,669 over the same time period, with Ontario consumers paying the remaining \$69.3 million. The Panel estimates that, under the current cost allocation methodology, \$7.4 million in DA-PCG uplift charges were paid by exporters over the two-year period that should have been paid by Ontario consumers.

Table 3-10 displays the total cross-subsidization associated with the RT-GCG and DA-PCG programs in 2012 and 2013.

Table 3-10: Estimated Cross-subsidization of RT-GCG and DA-PCG Costs Associated with Top-up Payments 2012 – 2013 (\$ millions)

Total RT-		Actual Allocation		Alternate A	Subsidization	
Year	GCG and DA-PCG Top-up Payments	Ontario Consumer Share	Exporter Share	Ontario Consumer Share	Exporter Share	Ontario Subsidizing Exports
2012	137.1	122.3	14.8	77.0	60.1	45.3
2013	74.1	64.7	9.4	24.0	50.1	40.7
Total	211.2	187.0	24.2	101.0	110.2	86.0

In total, the top-up payments associated with the RT-GCG and DA-PCG programs totaled \$211.2 million combined in 2012 and 2013. The Panel estimates that, of the \$211.2 million, \$86 million – on average \$43 million per year – in exporter-induced costs were allocated to, and paid by, Ontario consumers. This cost subsidization from Ontario consumers to exporters goes towards offsetting any benefit that exports provide to Ontario. Had costs been allocated on the basis of the alternate allocation methodology, the all-in cost charged to Ontario consumers⁷⁵ would have fallen from \$71.77/MWh to \$71.48/MWh in 2012 (0.4% reduction), and from \$83.07/MWh to \$82.75/MWh in 2013 (0.4% reduction).⁷⁶

Although the level of cross-subsidization found by the Panel is far lower than the \$1 billion claimed by some commentators, it is nonetheless material. In the Panel's view, the IESO should address this issue by revising the manner in which it allocates RT-GCG and DA-PCG uplift charges between Ontario consumers and exporters.

Recommendation 3-2

The Panel recommends that the IESO revise the way it allocates uplift charges associated with top-up payments under the real-time generation cost guarantee and day-ahead production cost guarantee programs so that the charges to Ontario consumers and to exporters better reflect the extent to which each group causes those payments to be incurred.

The Panel recognizes that changes to the allocation of uplift can affect the bidding behavior of price sensitive market participants as they adjust to the cost implications of the alternate uplift allocation. In any market where market participants must account exante for out-of-market costs, in this case uplift charges, there may be efficiency implications. The current methodology for allocating RT-GCG costs and the Panel's alternate methodology both allocate out-of-market costs ex-post, which have associated

⁷⁵ Unlike in Chapter 1 where the all-in cost to Ontario consumers is broken down by Class A and Class B consumers (plus embedded Class A), the calculation of all-in cost to Ontario consumers in this section does not differentiate between Class A and Class B.

⁷⁶ If the IESO were to adopt the alternate allocation methodology, the Panel would expect some reduction in export transactions due to the increase in export costs. To the degree that this occurs, the benefit realized by Ontario consumers in the form of a reduction in cross-subsidization would be partially offset by reductions in the transmission service charges collected from exporters.

efficiency implications, but the benefit of the Panel's alternate methodology is that it more closely aligns cost recovery with cost causality than does the current methodology.

The Panel also notes that in its June 2014 Monitoring Report, it recommended that the IESO re-examine the integration of exports into EDAC, to reduce the need to commit additional generation in real-time to meet export demand that currently only appears after day-ahead. As noted in Chapter 4 of this report, the IESO has indicated that it will assess the feasibility of developing an export forecast to integrate into EDAC. While the Panel notes that the better integration of exports day-ahead should contribute to attenuating the subsidization issue that the above recommendation is aimed at addressing, subsidization will persist absent a change in the allocation methodology.

3.2.4 Conclusion

The Panel's analysis indicates that the subsidization of exports by Ontario consumers is largely limited to a subset of uplift payments; specifically, the allocation of uplift payments related to RT-GCG and DA-PCG top-up payments. This cost subsidization from Ontario consumers to exporters goes to offset any benefit that exporters provide to Ontario. Costs that are recovered through the GA are either insensitive to export demand, or decrease as exports increase. Accordingly, the Panel does not believe that cross-subsidization has occurred as a result of exporters not paying the GA.

As noted above, Ontario consumers paid an average of approximately \$43 million per year over the past two years for exporter-induced costs. The Panel's analysis therefore does not support recently made claims that export transactions cost Ontario consumers \$1 billion annually.

While the cross-subsidization of uplift charges associated with RT-GCG and DA-PCG top-up payments represents a direct cost to Ontario consumers, exporters contributed an average of \$34 million per year in transmission service charges over the same period, costs that would otherwise have been borne by Ontario consumers. Additionally, large volumes of export transactions generated operating surpluses for Ontario generators,

which offset GA payments. The Panel did not compare the costs paid by exporters with any benefits they provide to arrive at any net benefit of exports to Ontario.

An area that requires further study is the efficiency of RT-GCG starts when units are committed to serve export demand. While the Panel's analysis examined whether or not there was subsidization between Ontario consumers and exporters in terms of uplift associated with RT-GCG top-up payments, it does not answer the question of whether these RT-GCG commitments and associated costs should have been incurred in the first place. For instance, committing an RT-GCG unit based on an exporter's willingness to pay and the variable operating cost of the RT-GCG unit may appear to be efficient, but in fact may not be when the start-up costs submitted after the fact by the RT-GCG unit are known and included in the calculation. The IESO is examining this issue as part of its stakeholder engagement on the generation cost guarantee programs.⁷⁷ The Panel notes that, even with perfectly efficient RT-GCG scheduling, the RT-GCG and DA-PCG cross-subsidization issue described above would persist absent a change in the allocation methodology.

⁷⁷ For more information, see http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-111.aspx

Appendix 3-A

Review of the Costs Recovered Through the Global Adjustment

The Global Adjustment (GA) primarily accounts for the difference between the Hourly Ontario Energy Price (HOEP) and the rates paid to regulated and contracted generators. Contracted and regulated rates generally cover the cost of building and maintaining a generation facility (capital costs) plus a reasonable rate of return; in some cases, they also cover a facility's variable operating costs (variable costs).

The GA will be a charge to Ontario consumers when market revenues⁷⁸ are less than the rates payable to generation facilities under the terms of contracts or, in the case of Ontario Power Generation Inc. (OPG), are less than the payment amounts set by the Ontario Energy Board (OEB). In 2013, the GA made up approximately 65% of the all-in cost of electricity paid by Ontario consumers.

As noted in the main body of this chapter, the GA is charged to Ontario consumers; exporters do not pay the GA. Accordingly, to the extent that any costs that are recovered through the GA are incurred as a result of export demand, or increase as a result of export demand, there would be concerns about cross-subsidization.

The GA can be broken down into several sub-categories based on contract structures that are common to different resource groups and on the OEB payment amount regime applicable to OPG's facilities. The following identifies these various sub-categories and examines the reasons for which the associated costs are incurred as well as the sensitivity of each sub-category to increased export demand. The contract structures and regulated payment regimes are in many cases considerably more complex than described below, but the descriptions provided are sufficient for purposes of the issue being examined.

3A.1 Take or Pay Resources

These resources have contracts under which they are paid a flat rate per megawatt of available capacity, meaning that they are paid regardless of whether or not they generate

⁷⁸ Market revenues that offset contracted or regulated rate payments vary by contract or regulation structure, but typically include actual or imputed revenue from HOEP, as well as Congestion Management Settlement Credit payments. In some instances other forms of market revenue are considered.

electricity. Long-term payment commitments made to facilities that are available but are not necessarily producing power are akin to capacity payments; this is especially true for baseload resources as they do not reserve spare capacity for regulation service or operating reserve. As discussed in the main body of this chapter, capital costs for capacity are incurred irrespective of export demand.

The following are considered take or pay resources:

- Bruce nuclear units (A and B);
- Resources with contracts under the Feed-in Tariff (FIT) and micro-FIT programs (primarily wind and solar);⁷⁹ and
- Resources with Renewable Energy Supply (RES) contracts.⁸⁰

When these resources produce power they receive the HOEP, and that revenue goes to offset the amount of their contract payments. These resources are more likely to be scheduled when demand is higher. As a result, costs recovered through the GA in relation to these resources will likely decrease as more exports are scheduled.

3A.2 Minimum Net Revenue Resources

These resources are guaranteed to receive a minimum net revenue level, with imputed net revenues⁸¹ going to offset the amount of their payments under the contract. The minimum net revenue level ensures that the market participant will recover the capital costs of building the facility plus a reasonable rate of return, as well as fixed operating and maintenance costs. All variable operating costs are intended to be recovered through the electricity market, including under generation cost guarantee programs. Accordingly, payments made to resources in this sub-category that are recovered through the GA are

⁷⁹ In terms of contracted wind and solar resources that are paid for each megawatt of available capacity, available capacity refers to available capacity based on fuel availability (wind, sun), not installed capacity. While it is true that resources that have a FIT or RES contract can now be dispatched off without compensation, this only applies to the first 20 hours of a resource's yearly constrained-off dispatches. The small proportion of non-take or pay hours, combined with the use of strategic offer behaviours aimed at avoiding uncompensated constrained-off dispatches, has led the Panel to conclude that these resources are nonetheless best classified under the take or pay category. ⁸⁰ *Ibid.*

⁸¹ A generation unit is deemed to have received imputed net revenues when the pre-dispatch and/or real-time market prices are higher than the unit's variable energy cost of production as set out in the contract. In such hours, the payments under the contract are reduced by an amount determined based on the generation facility's contract capacity times the HOEP minus the unit's contracted variable cost.

also appropriately characterized as payments for capacity; as discussed earlier, capacity is procured to meet Ontario demand, not export demand.

The following are considered minimum net revenue resources:

- Resources with Clean Energy Supply contracts, including the so-called "early movers";
- Resources with Accelerated Clean Energy Supply contracts; and
- Resources with Combined Heat and Power contracts.

When these resources are imputed to run, the imputed revenues (net of variable operating costs) go to offset the amount of their payments under contract. All else being equal, these resources are more likely to be imputed to run when demand is higher. As a result, costs recovered through the GA in relation to these resources are likely to decrease as more exports are scheduled.

3A.3 Self-scheduling Resources paid a Flat Rate per MWh of Production

These resources are paid a flat rate per megawatt hour of generation that they provide to the market. These resources schedule themselves irrespective of demand, in whatever manner they see fit; as such, GA costs associated with self-scheduling generators are not a function of the presence or volume of export demand.

Only the so-called non-utility (NUG) generators fall within this sub-category of resources. NUG generators have been under contract since before market opening, and many of the contracts are currently being renegotiated with the Ontario Power Authority (the contracts are currently held by the Ontario Electricity Financial Corporation). Early indications suggest that the renegotiated contracts will resemble the contracts that are currently applicable to minimum net revenue resources.

3A.4 Dispatchable Resources paid a Flat Rate per MWh of Production

These resources are paid a flat rate per megawatt hour of generation that they provide to the market. The total compensation to these resources is variable from hour to hour depending on their production, with total compensation determined by whether or not they are dispatched to meet demand. In theory, increasing demand would result in increased scheduling of these resources, in turn increasing the GA. In reality, however, the offer behaviour of these resources is such that they rarely go unscheduled when prices are low and they rarely require additional compensation beyond market revenues when prices are high. In fact, market revenues in excess of regulated rates will be rebated to Ontario consumers through decreased GA charges.

The following are considered dispatchable flat rate resources:

- OPG's nuclear facilities;
- OPG's baseload hydroelectric facilities;⁸²
- Resources with contracts under the Hydroelectric Contract Initiative; and

• Resources with contracts under the Hydroelectric Energy Supply Agreement program.

Baseload facilities, such as nuclear units and baseload hydroelectric facilities, must run for a number of environmental, regulatory and safety reasons. While still actively participating in the market and, in theory, sensitive to market prices, these units are offered at negative prices that ensure that they are economic in the unconstrained sequence. As a result, these facilities are in effect becoming self-scheduling units, planning their generation schedules to respect the various operating limitations applicable to them. Accordingly, payments that are recovered through the GA in relation to these facilities are unchanged by the presence of exports in the same way as are payments in relation to self-scheduling facilities.

The remaining available capacity at hydroelectric facilities is offered as opportunity water. That is to say, there is limited water available to generate electricity, which can either be used at a given time or stored for later use. To reflect the opportunity cost of using water as opposed to storing it and using it at a later time, this water-backed generation is offered at projected future prices; the longer the storage horizon, the higher the opportunity cost. The power backed by opportunity water is regularly offered above

⁸² As a result of amendments that were made to Ontario Regulation 53/05 in 2013, payments for output from OPG's non-baseload hydroelectric facilities will, as of July 1, 2014, also become subject to regulation by the OEB.

the flat rates stipulated in the contracts. If the power backed by opportunity water is being scheduled to meet export demand, the HOEP (together with Congestion Management Settlement Credit payments where applicable) likely exceeds the contracted or regulated flat rates, meaning that, not only are there no payments to be recovered through the GA, but the market revenues earned above the regulated rate will be returned to Ontario consumers in the form of a reduction in GA charges.

Baseload hydroelectric units with limited storage capability and high water levels will offer laminations of water-backed power at positive prices, but below contracted or regulated rates. To the degree that these resources are scheduled to meet export demand in a given hour, the amount to be recovered through the GA will increase for that hour. However, had that production not been scheduled, and had the water been stored, the water storage horizon would begin to decrease. As the storage horizon approaches zero, hydroelectric facilities would re-price their production to a price where they will only spill the water (and receive no revenue) if the market price is so negative that it exceeds their positive contracted or regulated price (net of any variable operating costs, such as water rental charges). For example, a hydroelectric facility with a \$40/MWh contracted or regulated rate and no storage horizon would offer that power to the market at -\$40/MWh, and be willing to produce at any price equal to or greater than -\$40/MWh. With contracted or regulated rates that allow hydroelectric facilities to offer at negative prices without operating at a loss, these facilities can ensure that their production is scheduled in the unconstrained sequence. All of which is to say that hydroelectric production that is subject to a contracted or regulated rate will make it to market at one time or another, regardless of whether or not there is export demand.

3A.5 Resources paid for Demand Response

Demand Response 3 (DR3) is a program under which large Ontario consumers agree to reduce their consumption during tight supply conditions. In exchange, they receive both stand-by payments and payments to reduce consumption when called upon to do so. Both types of payments are recovered through the GA. The DR3 program is activated when the supply cushion drops below a certain percentage. Because the supply cushion

is calculated based on Ontario demand, exports have no effect on whether the program is activated or not.

3A.6 Conclusion and GA Charges by Sub-category

For the reasons set out above, the vast majority of payments recovered through the GA are related to capacity procurement, which are incurred irrespective of export demand. Additionally, variable payments recovered through the GA are either unaffected by, or decrease with, export demand.

Table 3A-1 displays annual GA charges for 2012 and 2013, broken down by the subcategories described above.

Table 3A-1: Global Adjustment 2012 – 2013 (\$ millions)

Year	Take or Pay	Minimum Net Revenue	Self- Scheduling Paid Flat Rate	Dispatchable Paid Flat Rate	Demand Response	Total
2012	2,001	762	1,090	2,046	35	5,934
2013	2,984	834	1,132	2,026	42	7,018
Total	4,986	1,596	2,223	4,073	78	12,956

Chapter 4: Panel Recommendations

This chapter sets out the IESO's responses to recommendations made by the Panel in its last monitoring report, and the Panel's comments on some of those responses. It also repeats the recommendations made in earlier chapters of this report.

Consistent with the Panel's streamlined approach to Summer Period (May to October) reporting, the Panel is deferring its assessment of the state of the IESO-administered markets to its next monitoring report (covering the winter period from November 2013 to April 2014).

1 Response to Panel Recommendations in the January 2014 Report

Following the release of each of the Panel's semi-annual monitoring reports, the Ontario Energy Board posts on its website the IESO's responses to any Panel recommendations that have been directed to it.⁸³

The Panel's January 2014 Monitoring Report⁸⁴ contained four recommendations, one of which related to constrained-off Congestion Management Settlement Credit (CMSC) payments and three of which related to the IESO's generation cost guarantee programs. All four recommendations were directed to the IESO. The IESO's responses to those recommendations are set out in Table 4-1 below.

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_Letter_MSP_Report_20140131.pdf. The IESO historically maintained an updated listing of its responses to Panel recommendations. This has been integrated into the annual update that the IESO is now required, as a condition of licence, to provide the Ontario Energy Board. The annual update describes the status of the IESO's work on Panel recommendations made within the past five years. The first such annual update was filed with the Ontario Energy Board in December 2013, and is available on the IESO's website at http://ieso-public.sharepoint.com/Pages/Participate/Market-Oversight/Monitoring.aspx.

⁸³ The IESO's response to the recommendations in the Panel's January 2014 Monitoring Report are set out in a letter available on the Ontario Energy Board's website at

⁸⁴ Available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

Table 4-1: IESO Responses to Recommendations in the Panel'sJanuary 2014 Monitoring Report

Recommendation	IESO Response ⁸⁵
Recommendation 2-1 The Panel recommends that the IESO eliminate constrained-off Congestion Management Settlement Credit (CMSC) payments for all intertie transactions, with due consideration to the interplay between the elimination of negative CMSC payments and Intertie Offer Guarantee payments.	"The IESO has previously assessed that constrained-off payments for import transactions into designated chronically congested zones are not consistent with justifications outlined in the MSP's discussion paper, Congestion Management Settlement Credits in the IMO Administered Electricity Market. The market rules were subsequently amended to eliminate these payments. However, the remaining CMSC payments continue to play an important role in the existing Ontario market structure. The IESO has launched a review of the energy market pricing system under Stakeholder Engagement 114 to identify the potential for a more efficient approach, and this effort could result in changes to, or potentially elimination of all CMSC payments. The results of SE-114 will provide input into a broader IESO consultation that will prioritize potential enhancements to improve the efficiency and effectiveness of Ontario's electricity market."
Recommendation 3-1 The Panel recommends that the IESO provide a detailed analysis to confirm whether the real-time generation cost guarantee (RT-GCG) program continues to be needed in light of the implementation of the enhanced day-ahead commitment process (EDAC), of changes in Ontario's generation capacity, and of other changes in the market since the RT-GCG program was introduced.	 "The IESO has considered, and reported through Stakeholder Engagement 111: Review of Generation Guarantee Programs, that a mechanism to ensure resource availability to meet the change in demand between day-ahead and real-time is both desirable and consistent with industry practice. The current mechanism for this purpose is the real-time generator cost guarantee. The IESO holds the obligation to produce and assess day-ahead and real-time operating plans and those plans are used to position the system for reliable real-time operation. The IESO uses the Day Ahead Commitment Process, the Real Time Generator Cost Guarantee, and Intertie Offer Guarantees to ensure a good starting position for operations as the system moves from day-ahead, to pre- dispatch, and then to real-time. The change in import offers and export bids between the day-ahead and real-time along with changes to other key inputs such as forced outages to generation and transmission elements, demand forecast errors, and variable generation forecast errors can all drive the need to commit additional generation in real-time. A majority of Independent System Operators (ISO) and Regional Transmission Organizations have a process in place to commit non- quick start generating capacity in real-time through real-time commitments and/or guarantees to supplement the day-ahead process. A review of these processes at the Midcontinent ISO (previously Midwest ISO), California ISO, PJM and New York ISO was included in Scott Harvey's <i>Review of the Efficiency of the Hourly Ontario Energy Price</i>. The IESO's real-time generator cost guarantee program serves this purpose in Ontario.

⁸⁵ Footnotes in the IESO's responses that provide links to reference documents have been omitted.

Recommendation	IESO Response ⁸⁵
	not provide financially binding prices and schedules for any day- [a]head participants – which makes the IESO more dependent on real-time processes to manage the gap from day-ahead to real-time. The IESO is concerned that removal of the real-time generator cost guarantee would increase the frequency with which the IESO must constrain on units for reliability and take other out of market control actions to manage the gap. The removal of the real-time guarantee program would also mean greater uncertainty in the IESO's process for managing the transition from day-ahead to real-time operation, impacting the current proactive approach to planning and executing power system operations. Taking all of these factors into account, the IESO is unwilling at this time to eliminate the program, but is committed to considering improvements to its structure and implementation, including the expansion of offsetting revenues proposed in Recommendation 3-2 below."
Recommendation 3-2 If the IESO, after performing its detailed analysis, determines that the RT-GCG program continues to be needed, the Panel recommends that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any profit (revenues less incremental operating costs) earned (a) on output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and (b) on output generated after the end of the facility's MGBRT.	"The IESO will assess this proposal in 2014, including whether this change would materially impact the incentive for generators to participate in the real-time generation cost guarantee program rather than the day-ahead commitment process."
Recommendation 3-3 The Panel recommends that the IESO re-examine the question of integrating exports into EDAC to reduce the need to commit additional generation in real-time to meet export demand that currently only appears in the market in real-time. While the Panel is not recommending a specific approach for integrating exports, the following have been identified as potential options: a) introduce a mechanism that encourages exports to bid in EDAC; or b) include a forecast of exports when commitments are made under EDAC.	"The IESO has explored options to induce exports to participate in the day-ahead commitment process while assessing the advantages and disadvantages to the market along with the attractiveness of potential options to exporters. The IESO determined and reported its findings through Stakeholder Engagement 21: Day-Ahead Market Evolution that it was not feasible to develop a mechanism to incent exports to participate in the day-ahead process." The IESO agrees that there could be benefits realized for real-time operations with the inclusion of an export forecast during the day- ahead process (option 'b' of this recommendation). The IESO will assess the feasibility of developing an export forecast to integrate into the day-ahead commitment process in 2014."

2 Panel Commentary on IESO Responses

Recommendation 2-1

The Panel acknowledges the positive steps taken by the IESO to eliminate constrainedoff CMSC payments for import transactions into designated chronically congested zones. As discussed in the Panel's June 2014 Monitoring Report, this change has not only reduced uplift charges but has also discouraged inefficient offer behaviour. However, as also noted in the June 2014 Monitoring Report, in the Panel's view the rationale for the elimination of constrained-off CMSC payments for import transactions into designated chronically congested zones applies equally to constrained-off CMSC payments for all intertie transactions. The IESO has not, in its response to the Panel's recommendation, specifically identified why this particular class of CMSC payments is warranted, even if others might be.

Although the Panel recognizes that the issue will be considered further as part of the IESO's SE-114 stakeholder engagement process, the Panel expects that any market design changes emanating from that process will likely take a number of years to implement. The Panel believes that the elimination of constrained-off CMSC payments for intertie transactions can and should be done independently of other market design changes that might eventually result from the SE-114 consultations.

Recommendations 3-1 and 3-2

The Panel acknowledges that the IESO is considering various aspects of the real-time generation cost guarantee (RT-GCG) program through its SE-111 stakeholder engagement process. However, the Panel notes that the IESO's response does not specifically address the Panel's recommendation that the IESO conduct a detailed analysis to confirm whether the RT-GCG program continues to be needed. The Panel remains of the view that the IESO should consider this more fundamental question before moving to a consideration of refinements that might be made to that program.

The Panel is nevertheless supportive of efforts made to date as part of the SE-111 process, including the IESO's analysis of whether generators are "overcommitted" and of

whether they are committed efficiently against export demand under the RT-GCG program. The Panel anticipates that analyses of this nature will support the need to evolve the IESO's generation cost guarantee programs such that the enhanced day-ahead commitment process (EDAC) can deliver on the benefits that it was intended to provide.

The Panel understands that one approach being considered by the IESO as a means of eliminating concerns around after-the-fact cost submissions under the current RT-GCG program is to implement three-part offers similar to those that apply under EDAC. The Panel expects that implementation of this approach would likely take some time, and believes that the IESO should consider more immediate action to expand the revenue offsets under the RT-GCG program as recommended by the Panel. The Panel further believes that such a change to the RT-GCG program will be most effective if export demand is included in EDAC (see below), and encourages the IESO to implement both changes at the same time.

Recommendation 3-3

The Panel is supportive of the IESO's efforts to assess the feasibility of including a forecast of exports in EDAC, which the Panel believes can serve to reduce the IESO's reliance on the RT-GCG program as a mechanism for ensuring resource availability to meet changes in demand between day-ahead and real-time. The better integration of exports into EDAC can also assist in addressing the cross-subsidization issue that is discussed in Chapter 3 of this report.

3 Recommendations in this Report

The Panel groups its recommendations into four categories: price fidelity, efficiency, transparency and uplift payments. Some recommendations may have impacts in more than one category (for example, a scheduling change could affect prices as well as uplift) and, where this is the case, the recommendation is included in the category of its primary effect.

The first recommendation in this report relates to transparency as well as price fidelity in the operating reserve markets. The second relates primarily to uplift and other payments.

Recommendation 3-1

The Panel recommends that the IESO make more information available to market participants about its practices of de-rating Control Action Operating Reserve, including the criteria used to determine the amount and duration of such de-ratings.

Recommendation 3-2

The Panel recommends that the IESO revise the way it allocates uplift charges associated with top-up payments under the real-time generation cost guarantee and day-ahead production cost guarantee programs so that the charges to Ontario consumers and to exporters better reflect the extent to which each group causes those payments to be incurred.