Ontario Energy Board   Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2015 – April 2016

May 2017

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board. Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The Panel monitors, evaluates and analyzes activities related to the IESO-administered markets and the conduct of market participants to identify:

- inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
- activities of the IESO that may have an impact on market efficiencies or effective competition;
- actual or potential design or other flaws and inefficiencies in market rules and procedures; and
- actual or potential design or other flaws in the overall structure of the IESO-administered markets and assess consistency of that structure with the efficient and fair operation of a competitive market.

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations, making recommendations for remedial action as it considers appropriate.

Executive Summary

Market Overview and Developments

In Chapter 1 the Panel provides its general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness. Given some of the limiting features of Ontario's hybrid market design, competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to other North American jurisdictions. There remain significant opportunities to unlock competition and drive more efficient production, delivery, consumption and investment decisions.

To that end, the Independent Electricity System Operator (IESO) launched the Market Renewal stakeholder engagement in March 2016. Engagement participants and the IESO are critically examining the foundations of Ontario's electricity market; in doing so, identifying current market design issues and considering fundamental changes.

The Panel strongly supports the IESO exploring market design alternatives and will continue to support the initiative through its participation in the Market Renewal stakeholder initiatives.

In addition to Market Renewal, the Panel provides brief updates on a number of IESO and broader industry initiatives, including: the expansion of the Industrial Conservation Initiative, Ontario's energy trade deal with Québec, the Province's Greenhouse Gas Cap and Trade program and the IESO's capacity export initiative.

In the Panel's November 2016 Monitoring Report it made two recommendations related to the Real-Time Generation Cost Guarantee (RT-GCG) program. In addition, the Panel made three submissions to the IESO's *RT-GCG Program Cost Recovery Framework* stakeholder engagement. In each case, the Panel stated its concern with the cost of the RT-GCG program, as well as its uncertain benefits. The Panel's own analysis demonstrated that the program was necessary less than 1% of the time it was used.

The IESO has yet to address these concerns in a meaningful way.

The Panel believes that a new approach is needed that balances the competing priorities of reliability and cost and ensures that decisions are supported by objective analysis that considers whether lower cost alternatives are feasible. To guard against a "reliability at all costs" approach, other jurisdictions have developed objective and open processes for assessing these competing priorities. A similar approach should be considered in Ontario.

Matters to Report in the Ontario Electricity Marketplace

Assessment of the IESO's Demand Response Auction

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods. Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none. DR resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers by uplift charges.

The resources procured through the DR auction are intended to help meet the Ministry of Energy's conservation policy goals. However, for the reasons explained in detail in Chapter 4 of this Report, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

Having said that, the Panel also questions the need for peak shaving DR capacity at this time as Ontario has sufficient resources to meet peak demand in the province for the foreseeable future.

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated

preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

Improving the Allocation of Disbursements from the Transmission Rights Clearing Account

When an intertie becomes congested, the price used to settle intertie transactions can differ from the province-wide Market Clearing Price (MCP). This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the intertie price, while the corresponding domestic transaction is settled at the MCP. The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent. Congestion rent reflects the value of scarce transmission capacity. The more valuable access to a transmission path is to those who wish to utilize it, the higher the congestion rent collected.

Given intertie traders are willing to pay for scarce transmission capacity in the form of congestion rent, it follows that the owner of transmission capacity would benefit from making that transmission capacity available. In Ontario, the companies that own transmission capacity are rate regulated. Any congestion rent revenue these companies receive would go to offset their revenue requirements, thus reducing the regulated rates charged to their transmission customers. It follows that transmission customers benefit from congestion rent.

Congestion introduces financial risk to intertie traders. In order to provide the opportunity to hedge against that risk, the IESO operates a Transmission Rights (TR) market. TRs provide a financial hedge against price differences between the intertie price and the MCP. TR payments are designed as a full hedge against paying congestion rents; accordingly, TR payments and congestion rents collected should be approximately equal. By purchasing a TR, the owner has essentially purchased the right to the congestion rents on that intertie.

In return for relinquishing congestion rents, transmission customers receive the proceeds generated from the sale of TRs; these proceeds are known as “auction revenues”. Auction revenues accrue in the TR Clearing Account and are periodically disbursed to transmission customers to offset the transmission charges they pay. The manner in which these funds are disbursed has no impact on market efficiency or reliability, therefore the Panel looked to its other mandated principle, namely fairness, to assess the appropriateness of the existing methodology.

Considering that disbursements are intended to offset transmission charges, they are effectively a rebate on costs paid. The Panel believes that a fair allocation would have each customer receive a rebate proportionate to its share of costs paid. Unfortunately the current allocation methodology has not resulted in what the Panel considers to be a fair allocation of disbursements. Ontario transmission customers have paid in excess of 98% of all transmission charges, but received only 86% of disbursements; exporters received 14% of disbursements despite paying less than 2% of total transmission charges.

This misalignment stems from the fact that disbursements are allocated based on each customer's share of demand over the previous months, not its share of transmission service charges paid. The transmission charge associated with a megawatt-hour of Ontario based demand is significantly higher than the transmission charge associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand.

To date, the IESO has disbursed $58 million from the TR Clearing Account to exporters, $51 million of which the Panel believes ought to have been paid to Ontario transmission customers. Given the ongoing and material nature of this issue, future transfers will be significant if the current disbursement allocation methodology is left unremedied.

Recommendation 4-1

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

Market Outcomes and Anomalous Events

The Panel's review and analysis of market outcomes covers the period from November 2015 to April 2016 (the Current Reporting Period). The Panel's analysis revealed the following items of interest.

Dispatchable Loads and Unavailable Operating Reserves

Operating Reserve (OR) is standby capacity intended to respond and recover from a contingency on the grid, such as a forced generator or transmission outage. A dispatchable load (DL) may provide OR standby capacity; when it is activated to help recover from a contingency, the DL provides relief by reducing its consumption. To be able to provide the required relief (and fulfill its OR activation), a DL must be consuming at least the activation amount prior to being activated.

In Chapter 3, the Panel examines an hour in which two DLs got paid for OR they were technically incapable of providing. These resources were compensated $25,760 for 29 MWh of standby capacity, despite not consuming sufficient electricity to provide that OR if called upon. This outcome is inappropriate: not only were the DLs potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour.

This unavailable OR issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that DLs received approximately $12.5 million in OR payments for reserves that they were incapable of providing. DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of all intervals during the Current Reporting Period.

Recommendation 3-1

The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.

Ramp-Down CMSC Payments and Market Rule Implementation Constraints

A generator signals its intent to come offline at the end of its run by raising its energy offer price above the local nodal price, thus becoming uneconomic in the constrained sequence. Due to the three-times ramp rate assumption used in the unconstrained sequence, a generator’s unconstrained schedule ramps down faster than its constrained schedule. As a result, there is a divergence between the two schedules during the ramp-down period, resulting in constrained-on

Congestion Management Settlement Credit (CMSC) payments. In Chapter 3, the Panel examines one such payment to a gas-fired generator, totalling $160,000 over the course of one hour.

In past reports, the Panel has highlighted the inappropriate nature of CMSC payments caused by ramping, and recommended that the IESO eliminate them; CMSC is not intended to provide a revenue stream for generators that take a voluntary action.

In response to the Panel's concerns, the IESO recommended and its Board of Directors approved a Market Rule amendment to mitigate the cost of CMSC payments caused by ramping. This amendment was approved in June 2015 contingent on implementation of necessary IT system changes. Due to the complexity of these changes, they were not implemented until December 2016. The Panel estimates that CMSC payments caused by ramping would have been reduced by $1.9 million had the rule changes been effective immediately upon approval. In the future, the Panel suggests that the IESO consider providing for retrospective application of such changes to the date they are approved.

Export Failures and Congestion Rent Shortfalls

When an intertie is congested and a transaction fails following the final pre-dispatch run, the congestion rent collected may not be sufficient to cover the TR payments made, resulting in congestion rent shortfall.[1] Congestion rent shortfall results in a transfer of funds from Ontario consumers to TR owners, who are often intertie traders themselves.

When an intertie trader fails a transaction for reasons within its control (such as failing to acquire the proper transmission), it may be levied an intertie failure charge. The current intertie failure charge fails to account for the congestion rent shortfall created by the failure, leaving Ontario consumers to pay for the shortfall. This outcome is clearly inappropriate.

In Chapter 3, the Panel examines a day in which an intertie trader failed 7,456 MWh worth of exports, all for reasons within its control. For these failures, the intertie trader was charged a $466 intertie failure charge, despite causing over $12,000 in congestion rent shortfalls. This same

[1] For a quick overview of congestion rent and TRs, see the *Improving the Allocation of Disbursements from the Transmission Rights Clearing Account* section of the Executive Summary.

intertie trader profited from these intentional failures due to the TRs it owned, netting over $14,000 in TR payments.

The congestion rent shortfall issue is much larger than the aforementioned example: from January 2010 to April 2016, the Panel estimates that intertie failures within the control of market participants have resulted in congestion rent shortfalls of approximately $11 million.

Recommendation 3-2:

The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.

Demand and Supply Conditions

Due to the mild winter weather, demand was down for all months of the Current Reporting Period relative to the same months from the previous year.

On the supply side, approximately 550 MW of nameplate generating capacity was added to the IESO-controlled grid during the Current Reporting Period. The new generating stations were all from renewable fuel sources, including 400 MW of wind capacity and 100 MW of solar capacity. Over the same period, 130 MW of distribution connected generating capacity was added, the majority of which was solar generation.

Market Prices and Effective Electricity Prices

The average Hourly Ontario Energy Price was less than $10/MWh during the Current Reporting Period, the lowest average of any six month period since market opening. Approximately one third of all hours during the Current Reporting Period experienced a price of $0/MWh or less.

Despite the low market prices, the average effective electricity price remained stable at $60.07/MWh for Direct Class A consumers, and increased $7.48/MWh to $112.25/MWh for Class B and Embedded Class A consumers. The higher average effective electricity prices for Class B and Embedded Class A consumers reflects an increase in Global Adjustment (GA) payments made to contracted and regulated resources. In January 2016 monthly total system costs, which reflects the effective electricity prices paid by all classes of consumers combined, reached an all-time high of just over $1.2 billion.

Chapter 1: Market Overview and Developments

1 *General Assessment*

Once annually, the Panel is required to provide a general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness.

Since market opening in 2002, and particularly since the advent of the hybrid market in 2005, the Panel has assessed the state of the markets with regard to several design features and policy decisions that affect market participant behaviour and market outcomes. As noted frequently in past Panel reports, these features include:

- Ontario's two-schedule pricing and dispatch system: under this system, the prices faced by wholesale market participants can diverge (sometimes significantly) from the incremental cost of supplying another megawatt of energy at a particular location.
- Investment decisions are not driven by market dynamics: virtually all generation in Ontario is subject to long-term contracts with government agencies, or rate regulation by the Ontario Energy Board. Additionally, incentives under the contracts and regulation can result in offer prices that deviate from the generators' short-run marginal cost.
- The 3-times ramp rate multiplier: the use of the multiplier in the unconstrained sequence artificially depresses the market clearing price and distorts production and consumption decisions.

At market opening, some of the aforementioned features and impacts were expected to be temporary, while others were never envisioned at all; all have persisted over a number of years. The Panel has a long history of reporting on the systemic issues associated with these features, including: extended periods of deeply negative prices, inefficient trade on the interties and inappropriate wealth transfers.

Though the Panel has been critical of these features, it recognized them as ingrained parts of the current market design. In that context, the Panel's past assessments of the competitiveness and efficiency of the IESO-administered markets have been made with regard to the inherent limitations created by those features. In other words, the Panel made its assessments "within the Ontario context". On that limited basis, the Panel has said that the IESO-administered markets operated in a reasonably satisfactory manner.

Stepping out of the Ontario context, it is clear that competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to other North American jurisdictions. There remain significant avenues to unlock competition and drive more efficient production, consumption and investment decisions.

The IESO acknowledges the deficiencies in the current system and recognizes the benefits that market reform could bring to the sector. To that end, the IESO launched the Market Renewal stakeholder engagement in March 2016. Engagement participants and the IESO are critically examining the foundations of Ontario's electricity market; in doing so, identifying current market design issues and considering fundamental changes.

The IESO's Market Renewal initiative represents a significant opportunity to address many of the issues identified by the Panel over the years. Broad market reform has the potential to foster competition in existing markets, while introducing new competitive markets and mechanisms; all with the goal of improving efficiency. Market reform may include: the replacement of the two-schedule system with locational marginal pricing, a financially binding day-ahead market, unit commitment using multi-hour optimization, more frequent intertie scheduling and competitive procurement through technology neutral capacity auctions.

The Panel strongly supports the IESO exploring these market design alternatives and will continue to support the initiative through its participation in the Market Renewal stakeholder engagement process.

While important change is on the horizon, both the Panel and IESO recognize the long timelines associated with implementing Market Renewal. Between now and the completion of the initiative, the Panel will continue to identify deficiencies in the current market design and market rules that impact the efficient and fair operation of competitive markets. In cases where the impacts are too costly to go unaddressed until Market Renewal, or where Market Renewal will not address the issue, the Panel will continue to recommend expeditious changes, as it has done in this report.

2 *Future Development of the Market*

The IESO is currently undertaking a number of significant initiatives; they are discussed in the sections that follow.

Market Renewal

As discussed in the *General Assessment* section above, the IESO launched its Market Renewal stakeholder engagement initiative in March 2016. This initiative allows the IESO and stakeholders to address known challenges with the existing market design, and create a foundation for a more dynamic energy market to meet future needs.

The initiative will consider fundamental design changes in three categories: energy production and scheduling, capacity and operability. Specifically, the IESO has proposed the following projects in the Market Renewal work plan:

- Two schedule replacement - moving to a pricing approach reflective of actual costs
- Day-ahead market - introducing a day-ahead market to provide greater certainty to market participants and the IESO
- Real-time unit commitment - improving real-time unit commitment to optimize supply and demand over multiple hours with known costs
- Interties - enhancing intertie scheduling to improve efficiency and flexibility
- Demand response auction – establishing a workable and useful demand response auction
- Capacity trade - develop a system to enable the sale of capacity to other jurisdictions
- Capacity auction - develop an auction for incremental capacity needs.

In pursuit of these proposed changes, the IESO has retained the Brattle Group to complete a benefits case for Market Renewal. In the interim, the IESO presented the preliminary findings of its benefits case at its December 19, 2016 stakeholder engagement meeting. The preliminary findings suggest that the efficiency benefits of Market Renewal would be significant: approximately $3.7 billion from 2021 through 2030; with consumers benefitting $3.1 billion. These benefits far exceed expected implementation costs of $155 million. The final report summarizing the findings of the benefits case is expected to be published by the end of Q1 2017.

Expansion of the Industrial Conservation Initiative

On January 1, 2017 the Ontario Government expanded the Industrial Conservation Initiative (ICI) to allow customers with peak demand exceeding 1 MW to opt into the program. When introduced in 2010, only customers with peak demand greater than 5 MW were eligible to participate; the eligibility criteria was first reduced to 3 MW in 2015.

ICI customers' share of Global Adjustment charges varies based on their consumption during the five coincident peak demand hours during a year. The expansion of the ICI program will most likely mean higher Global Adjustment charges for lower volume customers, as more ICI customers shift consumption to avoid Global Adjustment charges.

Energy Trade Agreement with Québec

The provincial governments of Ontario and Québec recently signed a seven year energy trade agreement running from 2017 through 2023.[2] The general structure of the agreement includes the following elements:

- Québec will provide Ontario with 2 TWh of electricity each year,
- Ontario will reserve 500 MW of generating capacity to meet Québec's winter peak demand, and
- Ontario may provide electricity to Québec during times of surplus, part of which gets returned to Ontario during non-surplus hours.

The Panel will monitor for the impacts of the agreement on trade flows and efficiency in Ontario's wholesale electricity market.

Greenhouse Gas Cap and Trade Program

Effective January 1, 2017, greenhouse gas emitters from the energy sector are subject to the Government of Ontario's new cap and trade program. Participants in the program must have enough emission allowances to cover their emissions by the end of each compliance period. Emission allowances can be purchased at one of the quarterly auctions, or on the secondary market.[3]

Among Ontario's greenhouse gas emitters is its fleet of natural gas-fired generators. Unlike most emitters under the program, natural gas-fired generators supplied by an Ontario Energy Board (OEB) regulated gas distributor will not be obligated to acquire emissions allowances directly. Instead, the natural gas distributor will be responsible for acquiring the necessary emission allowances and complying with the program. The cost of purchasing the allowances will be

[2] For more information see the Government of Ontario's backgrounder, available at: https://news.ontario.ca/opo/en/2016/10/agreement-between-the-government-of-ontario-and-the-gouvernement-du-quebec-concerning-electricity.html

[3] For an overview of Ontario's greenhouse gas cap and trade program, see the Government of Ontario's webpage, available at: https://www.ontario.ca/page/cap-and-trade-ontario. Ontario Regulation 144/16, which passed the cap and trade program into law, is available at: https://www.ontario.ca/laws/regulation/r16144?_ga=1.105770058.816112800.1484255410

passed along to the emitters themselves, the natural gas-fired generators, in the form of a volumetric charge on natural gas purchased.[4]

The Panel expects this new volumetric charge to be included in the incremental energy offers of natural gas-fired generators. It follows that, when one of these generators is the marginal unit setting the Market Clearing Price (which was the case 19% of the time in 2016), the price will be higher. An increase in the MCP will have numerous impacts throughout the market, most notably on intertie flows and the proportion of the all-in cost of electricity recovered through the market versus the Global Adjustment.[5]

Imports from jurisdictions that typically have greenhouse gas emitting technologies on the margin are now subject to the cap and trade program. Importers will need to purchase emission allowances based on the quantity of imports and the Default Emission Factor (DEF) that applies to the source jurisdiction. Jurisdictions with heavily emitting supply mixes face higher DEFs and therefore must purchase more allowances for the same import quantity. To that end, imports from PJM, NYISO, ISO-NE and MISO will be subject to positive DEFs, while imports from Manitoba and Québec, which are primarily backed by hydroelectric generation, will not.[6] This has the effect of decreasing the competitiveness of imports from high emitting jurisdictions, while increasing the competitiveness of imports from cleaner ones.

The Panel will continue to monitor for the impacts of the cap and trade program on Ontario's wholesale electricity market.

Capacity Exports

In February 2015 the IESO launched its *Capacity Exports* stakeholder engagement to investigate the potential for allowing Ontario generators to export their capacity to other jurisdictions.[7]

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[4] See the OEB's *Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities* report, page 30, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0363/Report_Cap_and_Trade_Framework_20160926.pdf

[5] Generally, the MCP and the Global Adjustment are inversely related, meaning when one increases the other tends to decrease, and vice versa.

[6] The DEFs are posted on the Government of Ontario's webpage, available at: http://www.energy.gov.on.ca/en/ontarios-electricity-system/climate-change/

[7] For more information see the IESO's *Capacity Exports* stakeholder engagement webpage, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/capacity-exports

By facilitating the export of generating capacity that is not needed for reliability in Ontario, the IESO is providing an opportunity for participants to monetize capacity that would otherwise go idle or decommission. This additional revenue stream for generators could also benefit Ontario consumers: if the exporting generator has an Ontario supply contract or is subject to rate regulation, some of the additional capacity revenues would go to offset payments under those frameworks.

As part of the engagement process, market participants were asked to contact the IESO to discuss specific export opportunities of interest. While there was general interest in capacity export opportunities to New York and Québec, only one stakeholder expressed a strong interest in pursuing a specific near term project, and demonstrated readiness. The IESO successfully implemented the necessary procedures and agreements, allowing the aforementioned market participant to offer its capacity into the New York 2016-2017 winter capacity auction.

In the longer term, the IESO intends to incorporate the capacity export initiative in to Market Renewal. In doing so, the IESO is looking to evolve capacity export opportunities by adding additional export markets, automating the participation process and integrating capacity exports into the planned incremental capacity auction in Ontario.

3 *IESO Responses to Most Recent Panel Recommendations*

Recommendation	IESO Response
Recommendation 2-1 *Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.*	The IESO will undertake the recommended review in the new year to assess the issues with the current CAOR structure and identify potential options. I anticipate that IESO staff will complete the review and report back to the MSP by late Q1 2017.

<table>
<tr><th>Recommendation</th><th>IESO Response</th></tr>
<tr><td>Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with:
a) incremental operating costs for start-up and ramp to minimum loading point; and
b) incremental maintenance costs for start-up and ramp to minimum loading point.</td><td rowspan="2"><u>Background</u>
Mandatory North American reliability standards require that the IESO's daily Operating Plan demonstrate that adequate resources will be available to meet the expected load plus operating reserve. The RT-GCG program is a key element of the mechanisms that the IESO relies on in developing its daily Operating Plan and preparing for reliable real-time operations.

In particular, the RT-GCG program helps meet daily reliability requirements by incenting participants to start their facilities, be available and offer real-time supply to the market. The incentive is available for generation facilities that meet eligibility criteria to ensure recovery of certain incremental start-up costs, subject to defined revenue offsets.

As noted, the primary goal of the IESO's RT-GCG program is to ensure that generators are available when needed. The IESO is concerned that the Panel's recommendations, which would significantly reduce the incentive structure under the program, could have negative impacts on the program's overall reliability goals, in that the output from some gas-fired units might not be offered into the market in real time, which would, in turn, impact market dynamics and reliability, potentially impairing the IESO's ability to address changing conditions over the day.

The Panel's recommendation to eliminate guarantees under the RT-GCG program for incremental operating and maintenance costs is based in part on earlier versions of the program where eligible payments were limited to fuel-only costs. However, at the time those earlier versions relied heavily on flexible generation to provide the vast majority of the starts under the program (about 80% of starts - of which over half were coal). By 2009, coal fired generation was being replaced by natural gas-fired generation facilities, which have very different operating characteristics and risk profiles. This change in the underlying characteristics of the supply mix was amongst the factors that prompted the IESO to make changes to the RT-GCG program, to include the guarantee of certain start-up operating and maintenance (O&M) costs, impose more stringent program eligibility criteria, and place limitations on eligible fuel costs - all aimed at improving the overall efficiency of the commitments.

<u>Proposed Improvements to the Commitment Process</u>
Given our concerns regarding the potential impact of the MSP recommendations, the IESO is proposing interim adjustments to the processes around unit commitments pending the market renewal initiative outlined below. These proposed changes would ensure that resources scheduled to provide Operating Reserve (OR) in the day-ahead timeframe continue to offer this OR in real-time.

Currently some resources that are anticipated to provide OR based on day-ahead optimization withdraw their offers for OR closer to real-time. This</td></tr>
<tr><td>Recommendation 3-2

The Panel recommends that the IESO modify the Real-time Generation Cost Guarantee program such that the revenues that are used to offset guaranteed costs under the program are expanded to include any net energy and operating reserve revenues earned, as well as all Congestion Management Settlement Credit payments received, on:
a) output above a generation facility's minimum loading point during its minimum generation block run time (MGBRT), and
b) output generated after the end of the facility's MGBRT.</td></tr>
</table>

	results in the IESO having to commit additional units in real time, many under the RT-GCG, to meet OR requirements. Introducing a mechanism to maintain scheduled OR offers from Day-Ahead into real-time should result in resources with limited real-time OR capability reducing the quantity they offer into the DACP, giving more confidence that the remaining quantities will in fact be available in real-time. This should result in the necessary units needed for OR to be committed more efficiently through the DACP, instead of through the RT-GCG Program. At the same time, the changes proposed in the current RT-GCG Cost Recovery Framework stakeholder engagement initiative will limit the initial O&M payments referenced in the Panel report by introducing pre-approved cost values that will ensure greater clarity and transparency in the recovery of eligible costs, and reduce the need for time consuming after-the-fact audits and recovery of ineligible costs. To date, these recoveries have amounted to about 25% of the initial amounts claimed under the program. The IESO expects that the proposed interim improvements to the commitment process can be implemented in 2017, recognizing that they will need to be formally reviewed under the IESO's stakeholder engagement processes. <u>Market Renewal</u> The MSP work, both on GCG and other issues, has driven increased focus on the need for market renewal. Simply put, the market design developed in the early 2000's needs to be modernized to support the very different technologies, services and participants in our fast-changing sector. Accordingly, in considering the balance between investing key resources in our current market (for example in working through major changes to programs such as GCG) or in renewing our market design to meet pressing current and future needs, our market renewal program is being given priority. The Market Renewal Program will introduce fundamental changes to the energy market, including a re-design of its real-time unit commitment process to achieve reliability objectives in a more efficient manner. Consistent with the feedback that the IESO received from the Panel, all the energy initiatives (Single Schedule, Day-Ahead Market and enhanced real-time unit commitment process) will be undertaken as a single cohesive project rather than as sequenced projects, as originally proposed. That approach will ensure earlier implementation of all components. Market renewal will be a significant project for the sector and we are looking forward to working with the MSP as it proceeds.

4 *Panel Commentary on IESO Response*

The IESO's response to the Panel's concerns about the cost and uncertain benefits of the RT-GCG program largely ignores the substance of those concerns. This is consistent with the IESO's reaction to the Panel's previous recommendations and its submissions to the IESO's recent stakeholder engagement on this subject. The IESO has largely adopted a "reliability at any cost" approach notwithstanding that the Panel's own analysis demonstrated that the program was actually needed in less than 1% of the time it was used.

The Panel continues to believe that an objective and rigorous cost/benefit analysis that considers the feasibility of less costly alternatives is required.

Other jurisdictions have developed processes for assessing the competing priorities of reliability and cost.[8] The Panel believes a similar approach should be considered in Ontario.

The IESO has proposed interim adjustments to the scheduling of operating reserve that could, if adopted, reduce the number of RT-GCG commitments. This would be a positive step. However, it does not account for the fact that RT-GCG commitments are largely driven by export demand, not operating reserve requirements.

Recommendation from the Panel's February 2015 Investigation Report

In late August 2010, the IESO passed an Urgent Market Rule Amendment to suspend all Congestion Management Settlement Credit (CMSC) payments to constrained-off dispatchable loads. These CMSC payments were suspended because significant amounts had been paid to two dispatchable loads; payments the IESO believed to be inconsistent with the intent of the CMSC regime. Following stakeholder consultation, the suspension of these payments was lifted, replaced by targeted Market Rules that withheld CMSC when specific behaviours were observed.

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[8] A recent example involves the National Electricity Market in Australia where, following a period of unprecedented power disruptions in the state of South Australia, including a state-wide blackout, the South Australian government proposed market rule changes to enhance reliability. The Australian Energy Market Commission, the agency responsible for making rule changes, recognized that the proposed reliability enhancements will support security of supply for consumers but that they must also be delivered at the lowest possible cost. Even with the sector in a state of heightened concern over reliable supply, the passing of the proposed reliability enhancements remain subject to a robust cost benefit process. See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen#

In the course of its investigation into the possible gaming behaviour of the two aforementioned dispatchable loads, the Panel observed that despite the new Market Rules, significant CMSC continued to be paid.[9] The Panel recommended that the IESO review the CMSC payments being made to dispatchable loads, and if necessary, make further amendments to eliminate unwarranted CMSC payments.

The IESO conducted the recommended review and found what the Panel considers to be a material amount of unwarranted CMSC still being paid. While the IESO believes it has the appropriate authority under the Market Rules to address these CMSC payments,[10] its settlement processes do not prevent or recover these payments. The Panel encourages the IESO to implement the necessary changes to prevent or recover these unwarranted payments.

[9] For more information see the Panel's *Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.*, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf

[10] See the IESO's response to the recommendation contained in the Panel's investigation report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_MSP_20150918.pdf

Chapter 2: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between November 1, 2015 and April 30, 2016 ("Current Reporting Period"), with comparisons to the period between May 1, 2015 and October 31, 2015 ("Previous Reporting Period"), as well as other periods where relevant.

1 *Pricing*

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment (GA) and uplift charges), operating reserve (OR) prices, and Transmission Rights (TR) auction prices.

Table 2-1: Average Effective Electricity Price by Consumer Class
May 2015 – October 2015 & November 2015 – April 2016
($/MWh)

Description:

Table 2-1 summarizes the average effective electricity price[11] in dollars per megawatt hour by consumer class for the Current Reporting Period and the Previous Reporting Period. The effective electricity price is the sum of the average load-weighted HOEP, the GA, and uplift charges. Results are reported for three consumer groups: "Direct Class A consumers" (Class A consumers that are directly connected to the IESO-controlled grid); "Class B & Embedded Class A consumers" (Embedded Class A consumers being Class A consumers that are connected at the distribution level);[12] and "All Consumers", which represents what the effective electricity price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. Information pertaining to Embedded Class A consumers is aggregated with information pertaining to Class B consumers because information regarding hourly consumption by Embedded Class A consumers is not readily available. Accordingly, effective price information pertaining to Class A consumers relates only to Direct Class A consumers.

[11] This price reflects the commodity cost of electricity and does not include delivery, regulatory, and debt retirement charges.
[12] Although the Panel does not have visibility over the data, it is reasonable to assume that Embedded Class A consumers likely pay an effective electricity price similar to Direct Class A consumers. Therefore, aggregating Class B consumers and Embedded Class A consumers within a single price category likely understates the effective electricity price for Class B consumers and likely overstates the effective electricity price for Embedded Class A consumers.

Customer Class	Weighted HOEP	Average Global Adjustment	Average Uplift	Effective Price
Direct Class A - Current	10.12	48.38	1.57	60.07
Direct Class A - Previous	21.07	36.53	2.40	60.00
Class B & Embedded Class A - Current	11.15	99.47	1.63	112.25
Class B & Embedded Class A - Previous	22.76	79.53	2.48	104.77
All Consumers - Current	11.03	93.28	1.62	105.93
All Consumers - Previous	22.56	74.38	2.47	99.41

*All references to "Current" in tables and figures in this report mean the Current Reporting Period. Similarly, all references to "Previous" mean the Previous Reporting Period.

Relevance:

In Ontario, different consumer classes pay different effective electricity prices. Consumers are divided into two groups: Class A—consumers with an average peak demand above 3 MW; [13,14] and Class B—all other consumers (including, for example, all small commercial and residential consumers).[15]

Many Class B consumers—those that use less than 250,000 kWh of electricity per year are and some others—are eligible for the Regulated Price Plan ("RPP") prices set by the Ontario Energy Board ("OEB"). They pay the RPP price unless they choose to enter into a contract with an electricity retailer (in which case they pay the contract price) or they choose to opt out of the RPP. The commodity price payable by Class B consumers that are not eligible for the RPP or that opt out of the RPP depends on their meter. If they have an interval meter, they pay the HOEP. If they do not have an interval meter, they pay a weighted average HOEP based on the net system load profile in their distributor's service area. For consumers that are not on the RPP or that have signed up with a retailer the GA appears as a separate line item on their electricity bill. Since RPP prices include a forecast of the GA, the GA is not a separate item on RPP consumer bills.

[13] Effective July 1, 2015, the government of Ontario expanded the definition of Class A from consumers with a peak demand of 5 MW or greater to include a subset of consumers with a peak demand greater than 3 MW but less than or equal to 5 MW. See IESO's Industrial Conservation Initiative Backgrounder, available at: http://iesoqa-public.sharepoint.com/Documents/Expansion%20of%20the%20ICI%20Backgrounder%20-%20June%202014%20(2).pdf .
[14] As the expansion of the Class A definition occurred mid-reporting period, a weighted average of the calculation was used for the Current Reporting Period results.
[15] See Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998,* available at: http://www.ontario.ca/laws/regulation/040429.

For reference purposes, the table displays the average effective electricity price for "all consumers," which is calculated using the previous GA allocation methodology under which all consumers were allocated the GA based on their pro rata share of total consumption during the period. As of January 2011, the GA payable by Class A consumers is determined based on their peak demand factor, which is the ratio of the consumer's electricity consumption during the five peak hours[16] in a year relative to total consumption by all consumers in each of those hours. The GA continues to be charged to Class B consumers based on their total consumption during the period.[17]

In the Panel's April 2015 Monitoring Report,[18] the need to obtain generation and consumption data at an hourly level of granularity was discussed, specifically pertaining to embedded generation, behind-the-meter generation and embedded Class A consumers. While there is data on installed capacity of IESO-contracted embedded generation, the Panel noted that assessing the impacts of certain market changes is difficult, if not impossible, without generation and consumption data at the hourly level for these subsets of the Ontario electricity sector.

In a broader context, assessing the province's overall demand for electricity becomes increasingly difficult as a larger portion of that demand is no longer measured at the level of the high-voltage power system.

In particular, the Panel is interested in ascertaining the impacts of the GA allocation methodology on Class A consumption patterns for consumers that qualify for the Industrial Conservation Initiative ("ICI"). In order to more accurately calculate the effective commodity price for each consumer class in Ontario and quantify the impact of the ICI, access to hourly meter data for embedded Class A consumers and behind-the-meter generation is required. The Panel understands that the IESO is currently investigating means of collecting such information.

Commentary and Market Considerations:

[16] The five peak demand hours must occur on different days.

[17] For more information on the GA allocation methodology and its effect on each consumer class see the Panel's June 2013 Monitoring Report, pages 69-92, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

[18] For more information on this topic see the Panel's April 2015 Monitoring Report, pages 105-109, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

The average effective electricity price increased for both Direct Class A consumers and Class B & Embedded Class A consumers during the Current Reporting Period relative to the Previous Reporting Period. The GA was the primary driver behind increases in the effective electricity price, having increased for all consumers. The GA is primarily composed of payments to contracted and regulated generating resources that are intended to make up for shortfalls between market revenues and the contracted or regulated rates of those resources. As a consequence, the HOEP and the GA often exhibit an inverse relationship. This explains in part why the HOEP during the Current Reporting Period is less than half of what it was during the Previous Reporting Period.[19]

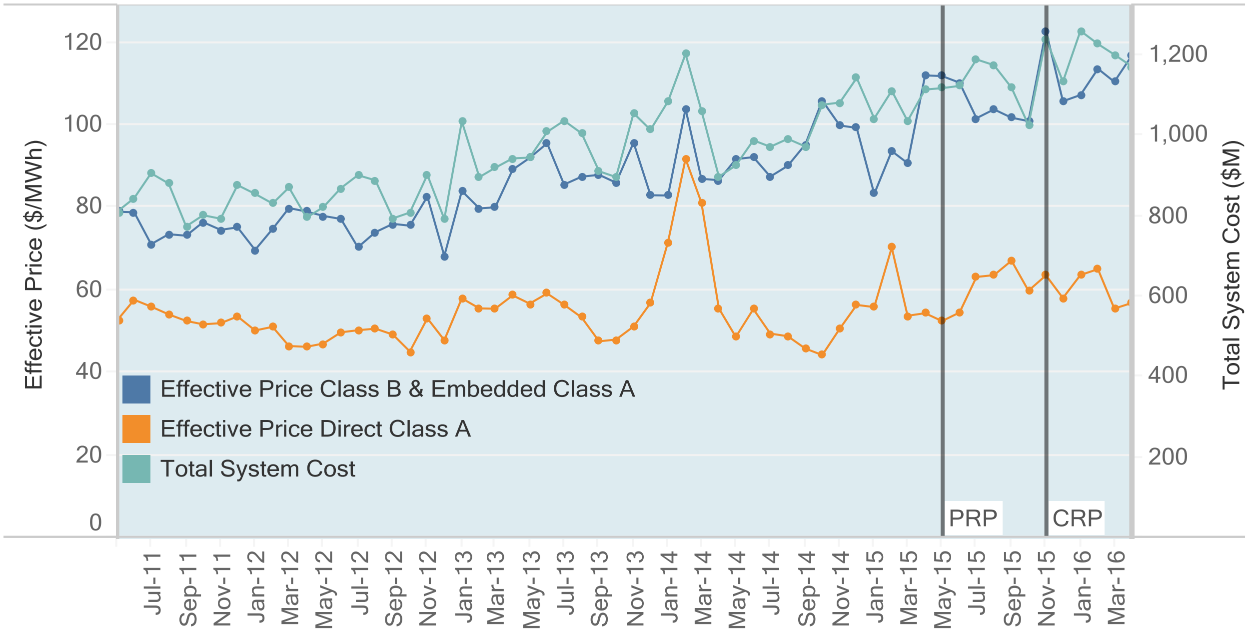
Direct Class A consumers saw the average GA increase by about $12/MWh while Class B & Embedded Class A consumers experienced an average GA increase of about $20/MWh. The average effective electricity price for both consumer classes was about $6/MWh greater in the Current Reporting Period than in the Previous Reporting Period.

Figure 2-1: Monthly Average Effective Electricity Price and System Costs May 2011 – April 2016 ($/MWh & $)

Description:

Figure 2-1 plots the monthly average effective electricity price for Direct Class A and Class B & Embedded Class A consumers, as well as the monthly average system cost (System Cost), for the previous five years.

[19] The costs associated with compensating loads under the IESO's demand response programs and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/global-adjustment-components-and-costs



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure highlights the changes in the effective electricity price paid by each consumer class over the past five years, as well as the changes in System Cost.

Commentary and Market Considerations:

In the Current Reporting Period, there were both record high total System Costs (January 2016 at $1.17B) and record high average effective electricity prices (April 2016 at $116.64/MWh) for Class B & Embedded Class A consumers. Effective electricity prices for Direct Class A consumers were little changed.

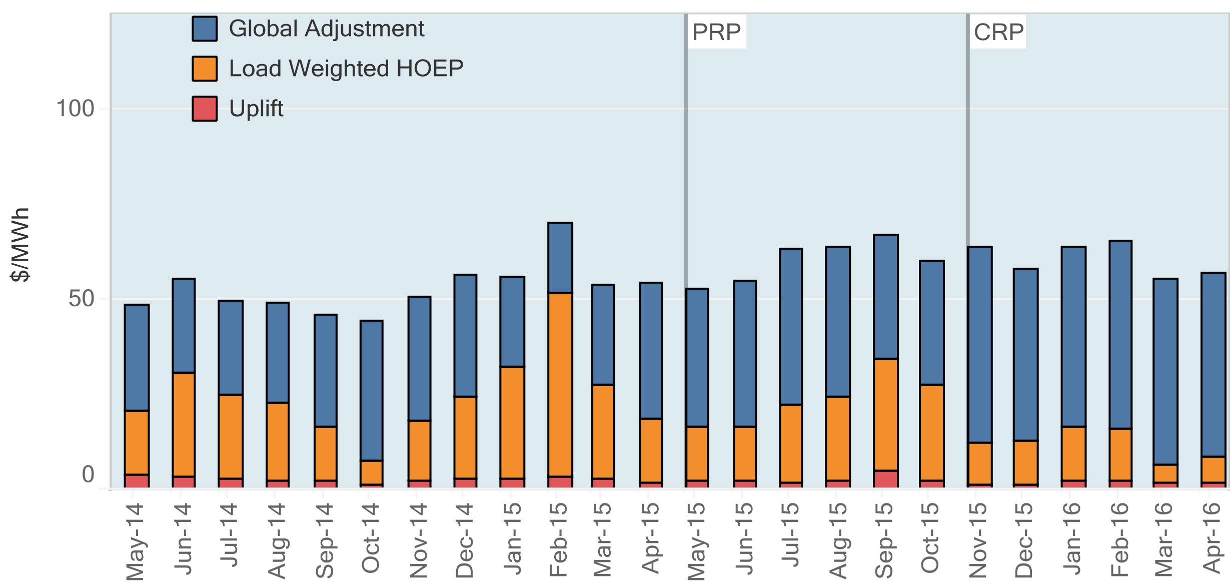
Figures 2-2A & 2-2B: Average Effective Electricity Price by Consumer Class and by Component

Description:

Figures 2-2A and 2-2B divide the monthly average effective electricity price into its three components (average HOEP, average GA, and average uplift charges) for Direct Class A consumers and Class B & Embedded Class A consumers for the previous two years.

As noted previously, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A consumers respond to that methodology are responsible for the significant difference in the average effective electricity price paid by each consumer group. As the GA is charged to Class A consumers based on their share of peak load during the five hours with the highest total demand in a 12-month base period,[20] Class A consumers can substantially reduce or even eliminate their GA by reducing their consumption from the IESO-controlled grid during these hours. When the average GA makes up an increasing portion of System Cost the average effective price paid by Class B consumers increases proportionately more than that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

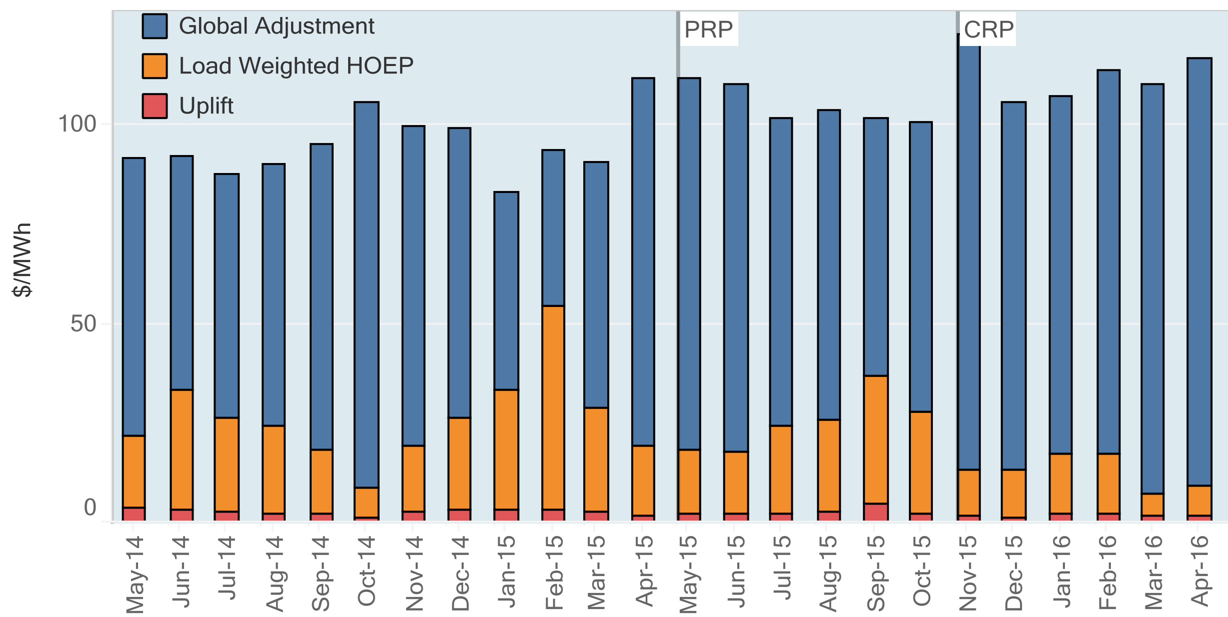
Figure 2-2a: Average Effective Electricity Price for Direct Class A Consumers by Component May 2014 – April 2016 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

[20] Each base period runs from May 1 in one year to April 30 in the following year. The GA allocation for the Current Reporting Period is based on the base period from May 2015 to April 2016.

Figure 2-2b: Average Effective Electricity Price for Class B & Embedded Class A Consumers by Component May 2014 – April 2016 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

These two figures illustrate how changes in the individual components of the effective electricity price affect the average effective electricity price paid by each consumer group.

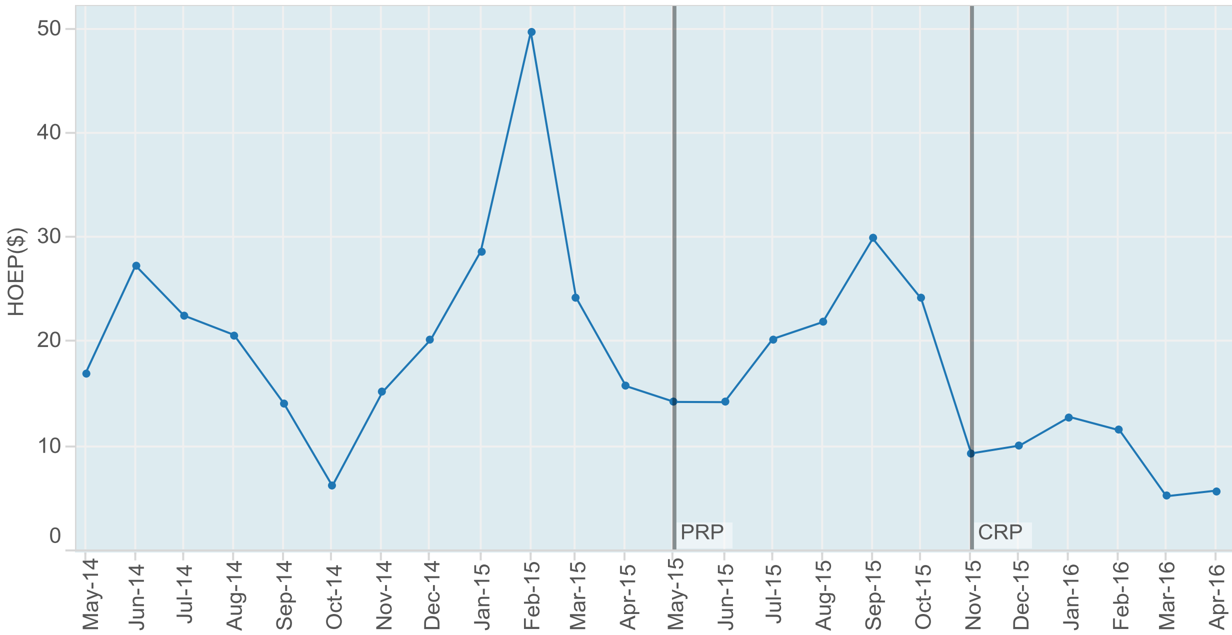
Commentary and Market Considerations:

The average effective electricity price for Class B & Embedded Class A consumers was significantly higher than that of Direct Class A consumers, as the former pay more GA compared to the latter. The GA also contributed to a record high share of the effective price in the Current Reporting Period.

Figure 2-3: Monthly (Simple) Average Hourly Ontario Energy Price (HOEP) May 2014 – April 2016 ($/MWh)

Description:

Figure 2-3 displays the simple monthly average HOEP for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The HOEP is the market price for a given hour and is one component of the effective electricity price paid by consumers. The HOEP is the simple average of the twelve Market Clearing Prices ("MCP") within the hour and that are set every five minutes. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's RPP.

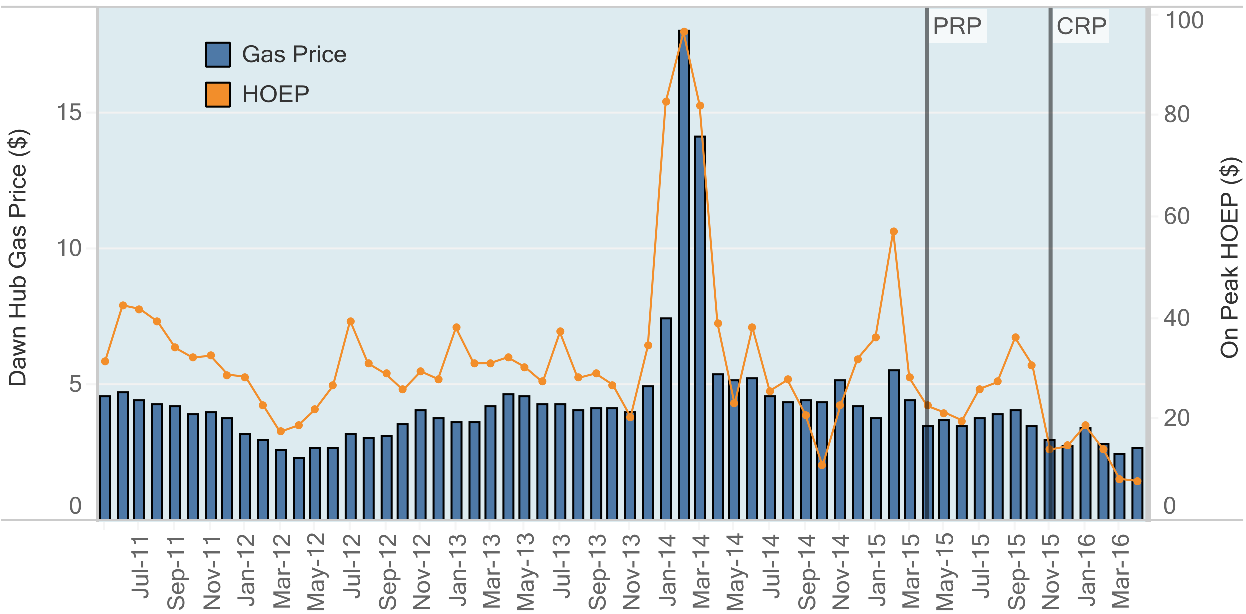
Commentary and Market Considerations:

The average HOEP of $9.09/MWh during the Current Reporting Period was significantly lower than that of both the Previous Reporting Period and the Winter 2015 Period: this is attributed to low demand and abundant supply, as nuclear units out of service in September 2015 and October 2015 were back online by the start of the Current Reporting Period and additional low marginal cost wind and solar capacity came online. The relatively low HOEP also reflects relatively low demand, owing to milder temperatures. Low demand also contributed to the Market Clearing Price ("MCP") often being set by resources offering at low prices such as wind, nuclear, and hydroelectric generation.

Figure 2-4: Natural Gas Price and On-peak Hourly Ontario Energy Price June 2011 – April 2016 ($/MWh & $/MMBtu)

Description:

Figure 2-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours, for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario and has the largest gas storage facility in the province. Gas-fired facilities can typically purchase gas day-ahead in order to ensure sufficient time to arrange for transportation; for that reason, the Dawn Hub day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the HOEP during on-peak hours, as gas-fired facilities frequently set the price during these hours.

Commentary and Market Considerations:

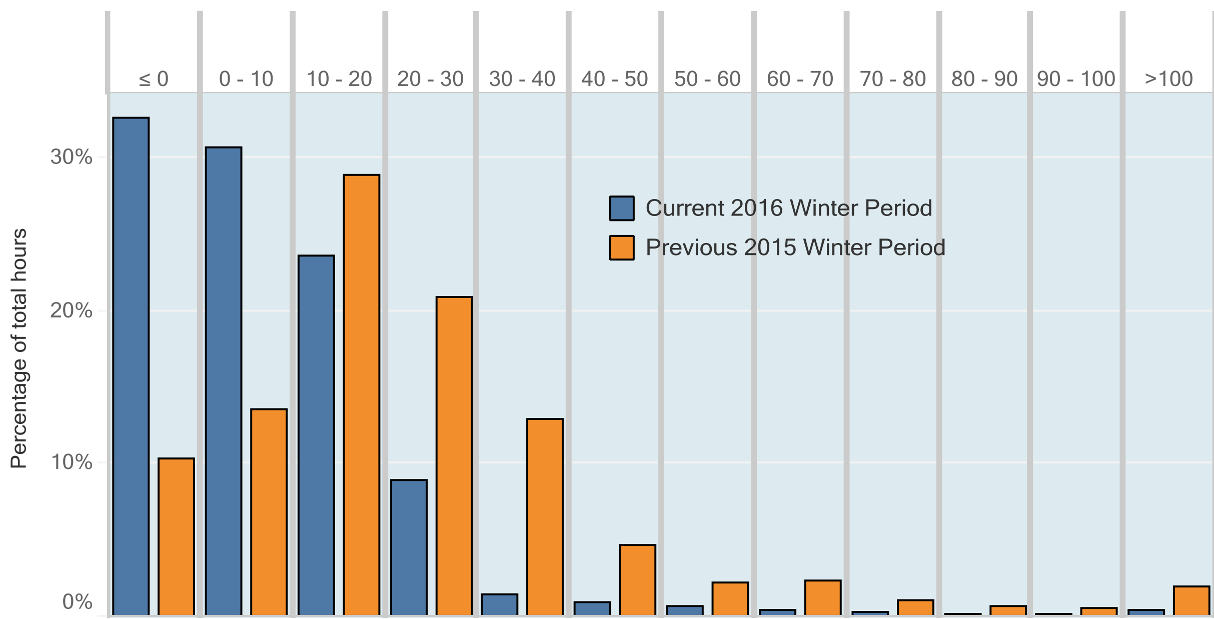
Dawn Hub gas prices have been declining since the Winter 2014 period: the Current Reporting Period had an average day-ahead gas price of $2.84/MMBtu, which was lower than that of the Previous Reporting Period at $3.72/MMBtu.

Daily changes in natural gas prices historically have been more strongly correlated with movements in the on-peak HOEP, with a correlation coefficient of 0.7069 for daily average prices from May 2011 to October 2015. The two prices have been weakly correlated in the Current Reporting Period, with a correlation coefficient of 0.3726. A contributing factor to the weak correlation is the lack of volatility in the daily average Dawn Hub gas price relative to the average on-peak HOEP.

Figure 2-5: Frequency Distribution of Hourly Ontario Energy Price November 2014 – April 2015 & November 2015 – April 2016 (% of hours, $/MWh)

Description:

Figure 2-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Current 2016 Winter Period (the same as the Current Reporting Period) and the Previous 2015 Winter Period (the same period from the previous year). The HOEP is grouped in $10/MWh increments; for example, the fourth price interval from the left counts all HOEPs greater than $20/MWh and less than or equal to $30/MWh. The negative-price hours are grouped together with all $0/MWh values in the category of HOEP less than or equal to $0/MWh.



Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, providing information on the frequency of extremely high or low prices.

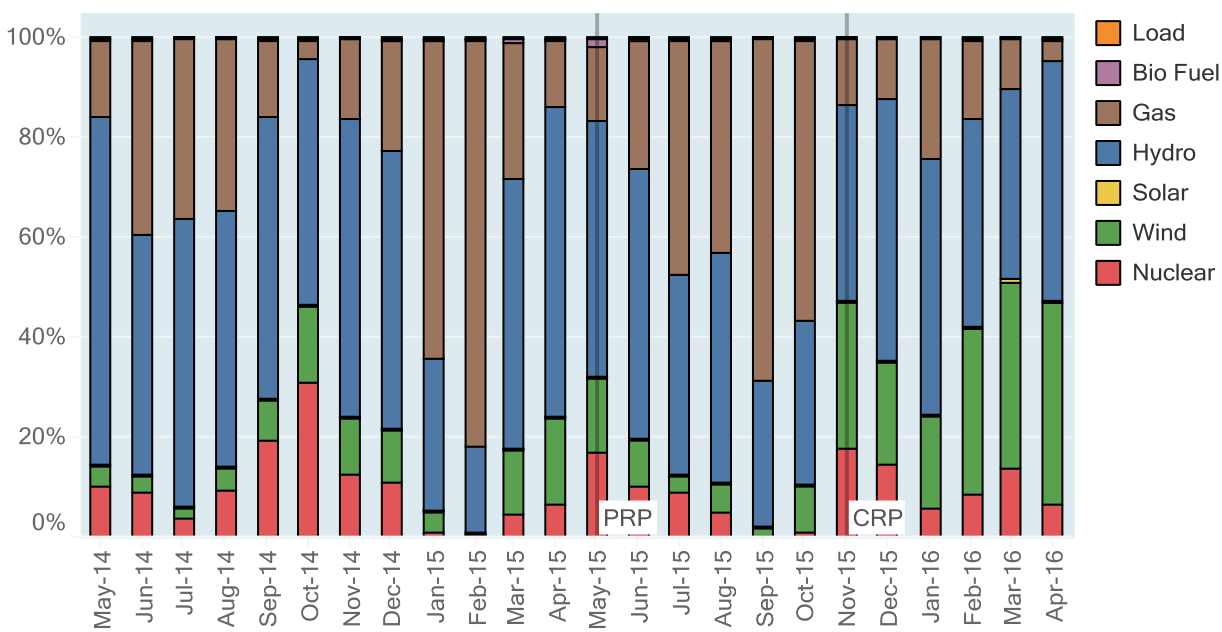
Commentary and Market Considerations:

The frequency distribution of prices illustrates a large increase in the amount of non-positive price hours (zero and negative) compared to the Winter 2015 Period. The HOEP was non-positive in 33% of hours in the Current Reporting Period. This is likely a result of the relatively low demand observed during the period, precipitated by mild weather conditions. The addition of approximately 400 MW of renewable energy capacity (which frequently offers at negative prices) was also a factor in causing lower prices. Chapter 2 examines the increase in non-positive price hours in greater detail.

Figure 2-6: Share of Resource Type setting Real-Time Market Clearing Price
May 2014 – April 2016
(% of intervals)

Description:

Figure 2-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

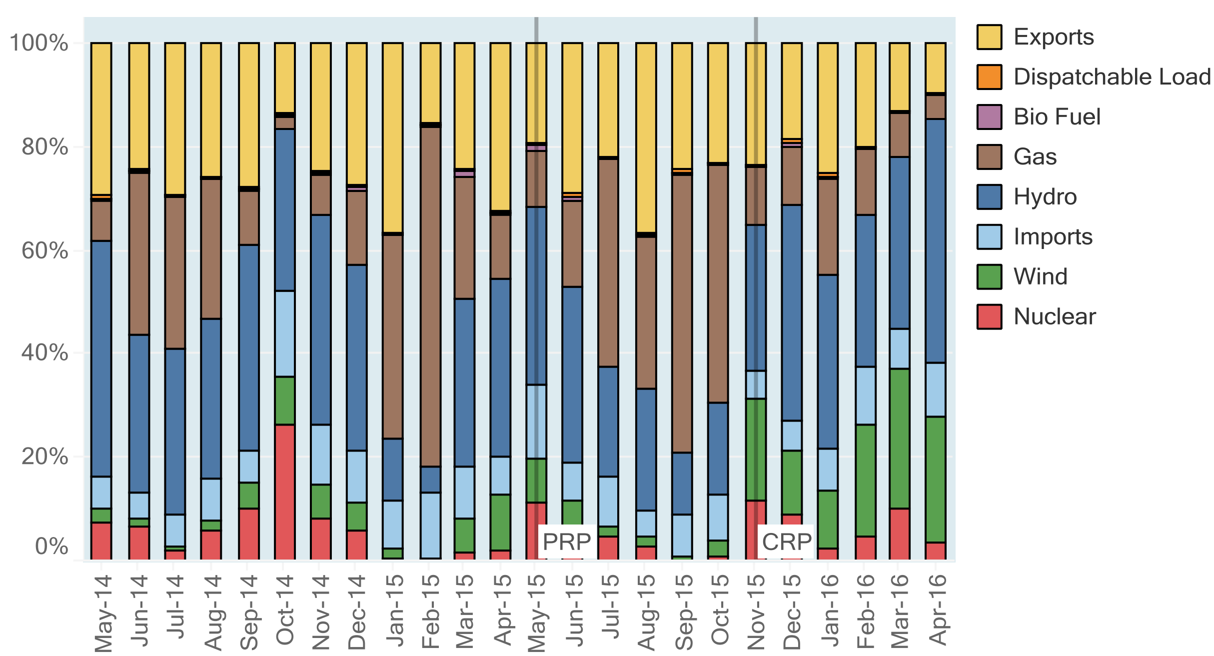
Commentary and Market Considerations:

Wind set the MCP in 30% of all intervals in the Current Reporting Period, which is more frequent than ever before. As installed wind capacity continues to increase in Ontario, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. There has also been a significant reduction in the share of gas generators setting the market clearing price compared to the Previous Reporting Period (from 42.7% to 13.5% of all intervals) as well as compared to the Winter 2015 Period (from 37% to 13.5% of all intervals), because of mild temperatures and higher available capacity from nuclear generation.

***Figure 2-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price
May 2014 – April 2016
(% of hours)***

Description:

Figure 2-7 presents the monthly share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

When compared with Figure 2-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[21] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Similar to the Commentary for Figure 2-6, two notable observations relate to changes in the share of hours in which wind and gas-fired generators set the PD-1 price. The share of wind setting the PD-1 MCP increased from 3.6% in the Previous Reporting Period to 19.3% in the Current Reporting Period. The share of gas decreased from 33.0% in the Previous Reporting Period and from 27.0% in the 2015 Winter Period to 11.4% in the Current Reporting Period.

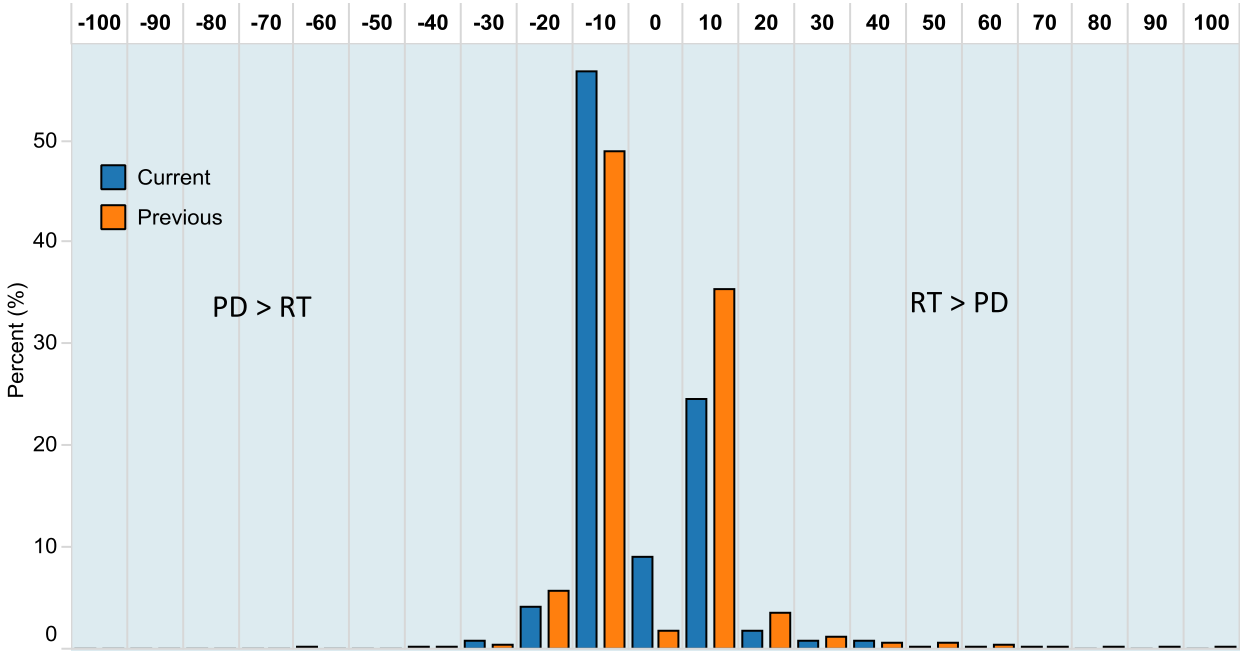
Figure 2-8: Difference between the Hourly Ontario Energy Price and the One-Hour Ahead Pre-Dispatch Price May 2015 – October 2015 & November 2015 – April 2016 (% of hours)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $100/MWh is negligible and so is not included in Figure 2-8, and the same is true of Figure 2-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

[21] Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour and their prices are adjusted in real-time to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time.

Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

Consistent with the Previous Reporting Period, the pre-dispatch sequence over-estimated the HOEP by less than $10/MWh in more than half of all the hours. Almost 10% of the hours had no change in price between the pre-dispatch and real-time frames. The average absolute difference is $5.22/MWh in the Current Reporting Period. As this was $1.36/MWh less than that of the

Previous Reporting Period, this means PD-1 prices in the Current Reporting Period were a more accurate predictor of real-time prices.

Table 2-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices May 2015 – October 2015 & November 2015 – April 2016 (MWh & % of Ontario demand)

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

Supply

- Self-scheduling and intermittent generation forecast deviation (other than wind);
- Wind generation forecast deviation;
- Generator outages; and
- Import failures/curtailments.

Demand

- Pre-dispatch to real-time demand forecast deviation; and
- Export failures/ curtailments.

Metrics for all but one of these factors are presented in Table 2-2 as the average absolute difference between PD-1 and real-time. The effect of generator outages is not shown in this table as they tend to be infrequent, although short-notice outages can have significant price effects.

Factor	Current		Previous		Winter 2015	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	15,435		15,205		16,461	
Pre-dispatch to Real-time Demand Forecast Deviation	219	1.42	211	1.39	213	1.29
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	65	0.42	81	0.53	55	0.33
Wind Deviation	114	0.74	112	0.74	126	0.77
Net Export Failures/Curtailments	90	0.59	82	0.54	76	0.61

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of price risks that participants, particularly importers and exporters, face as they enter offers and bids into the market.

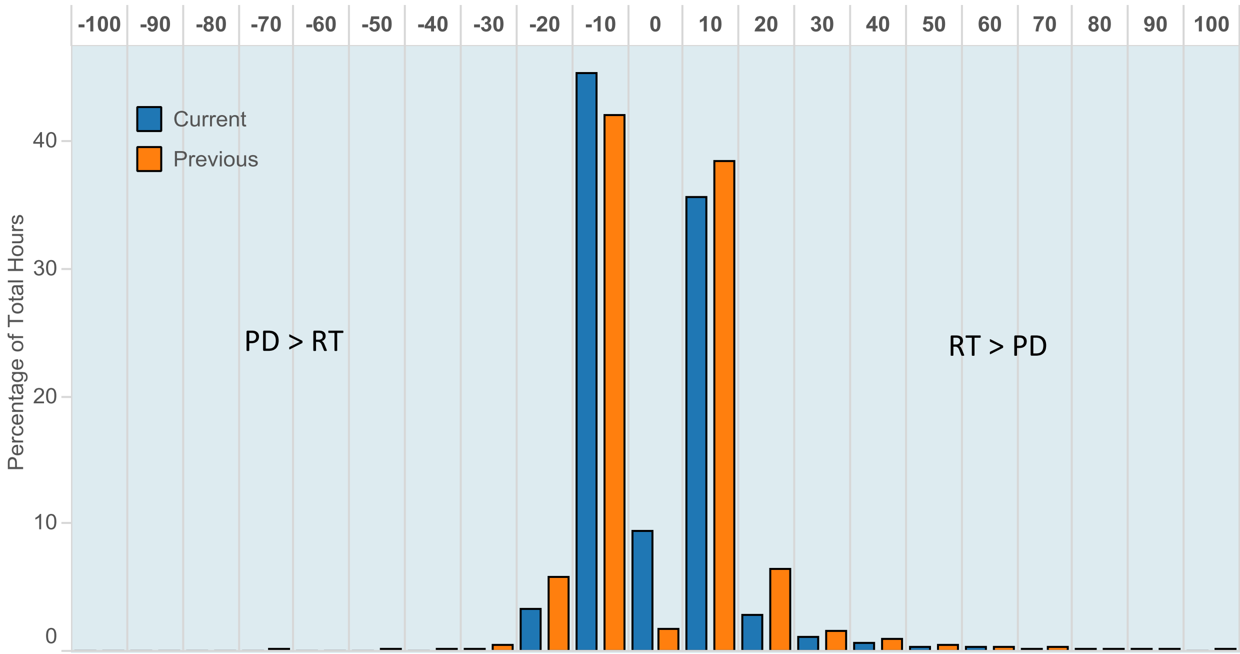
Commentary & Market Considerations:

Demand forecast deviation continues to be the largest source of price deviation, while wind forecast deviation remains the second largest factor. Compared to the Previous Reporting Period, the demand forecast deviation and wind forecast deviation remained largely unchanged.

Figure 2-9: Difference between the Hourly Ontario Energy Price and the Three-Hour Ahead Pre-Dispatch Price May 2015 – October 2015 & November 2015 – April 2016 (% of hours)

Description:

Figure 2-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP for the Current and Previous Reporting Periods. The price differences are grouped in \$10/MWh increments, save for the \$0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed with the approval of the IESO. Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[22] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

The frequency distribution of differences is similar between the PD-3 MCP and the PD-1 MCP. Compared to the Previous Reporting Period, PD-3 prices were better predictors of real-time prices, with smaller average and absolute average differences along with their associated standard deviations. In addition, 90% of hours observed an absolute difference smaller than

[22] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

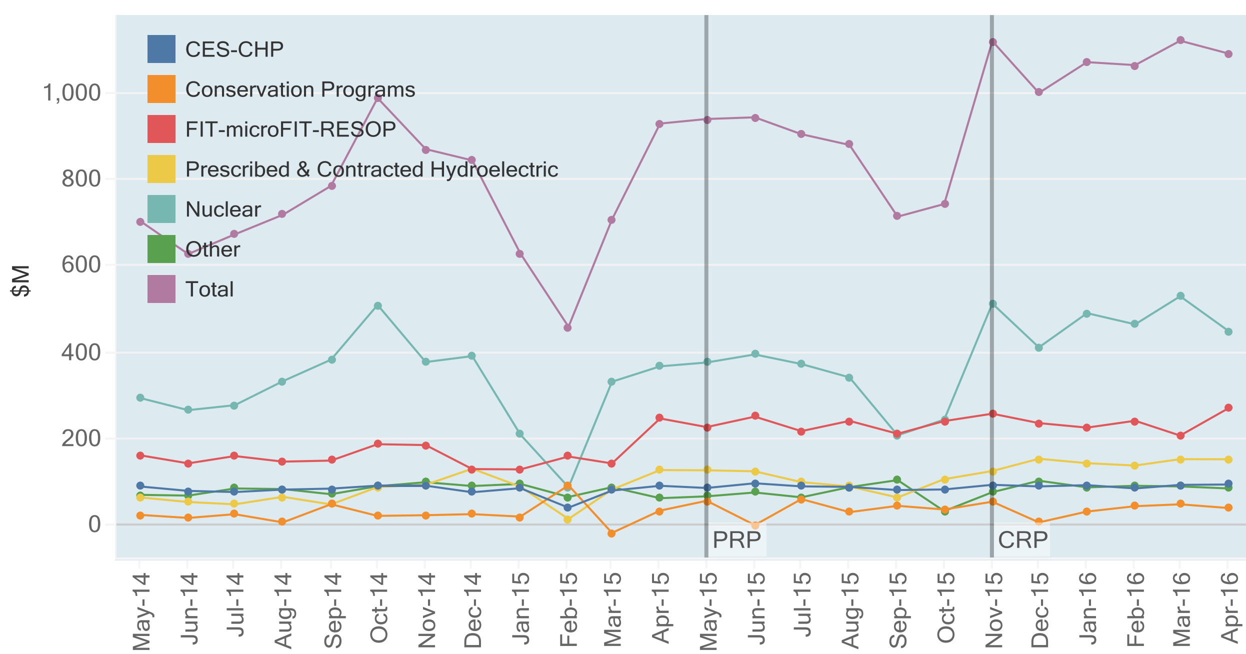
$10/MWh in the Current Reporting Period, compared to approximately 82% in the Previous Reporting Period.

Figure 2-10: Monthly Global Adjustment by Components
May 2014 – April 2016
($)

Description:

Figure 2-10 plots the revenue recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG's) nuclear assets);
- Payments to holders of Clean Energy Supply and Combined Heat and Power contracts;
- Payments to prescribed or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff ("FIT"), microFIT and the Renewable Energy Standard Offer Program);
- Payments related to the IESO's conservation programs; and
- Payments to others (including the IESO's demand response programs, non-utility generators, and OPG's Lennox Generating Station).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

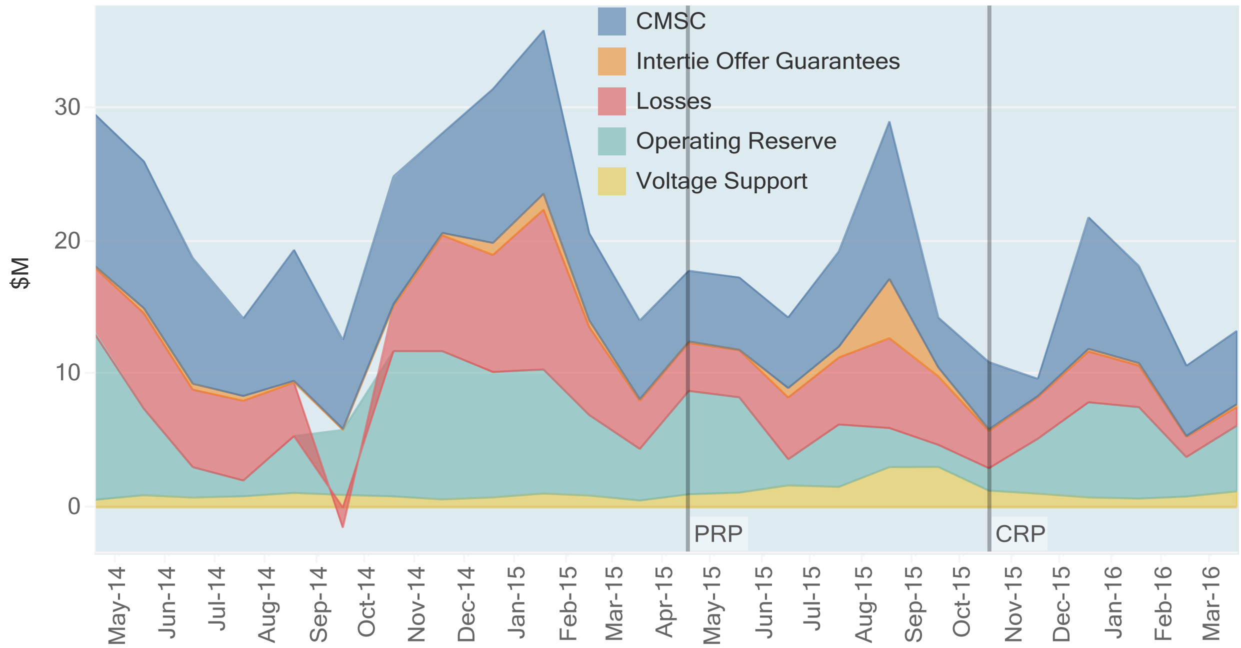
Commentary and Market Considerations:

The overall GA reached a record high of about $6.5 billion in the Current Reporting Period, owing to a comparatively mild winter resulting in lower demand and relatively low HOEP. The increase in GA is also largely attributed to the differential in nuclear payouts, which were much higher in the Current Reporting Period ($2.9 billion) compared to the Previous Reporting Period ($1.9 billion) because of a reduction in nuclear outages. Total FIT and microFIT GA payments also reached new highs ($1.4 billion) during the Current Reporting Period, reflecting an increase of approximately another 400 MW of wind and solar capacity in conjunction with the lower average HOEP.

Figure 2-11: Total Hourly Uplift Charge
By Component and Month
May 2014 – April 2016
($)

Description:

Figure 2-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement Credit (CMSC) payments, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, Operating Reserve (OR) payments, voltage support payments, and losses.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Hourly Uplift is a component of the effective electricity price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

The Current Reporting Period had a lower peak hourly uplift than the Previous Reporting Period or the Winter 2015 Period, with negligible intertie offer guarantee payments. CMSC and OR were the largest sources of uplift. The relatively high OR payouts from January to February 2016 are largely attributed to increases in OR prices resulting from scarcity conditions, the mechanics of which were described by the Panel in its November 2016 Monitoring Report[23] and are mentioned in the commentary for Figure 2-13 below.

[23] Refer to MSP 27, Chapter 2.

Figure 2-12: Total Monthly Uplift Charge by Component and Month May 2014 – April 2016 ($)[24]

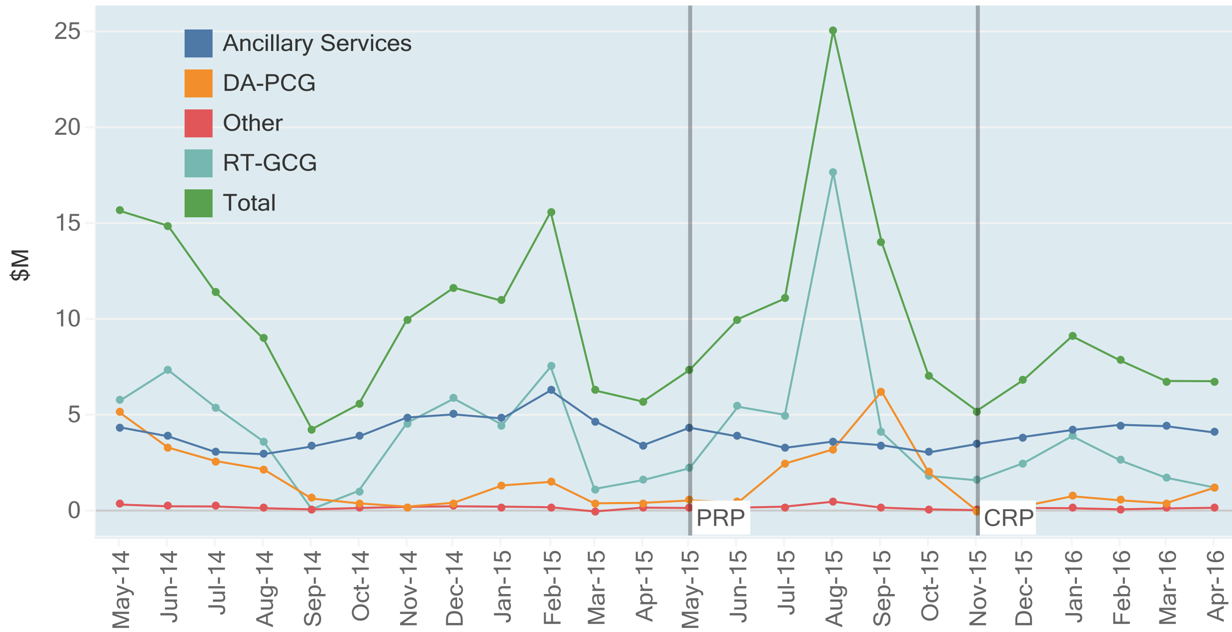
Description:

Figure 2-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:[25]

- Payments for ancillary services (i.e., regulation service, black start capability, monthly voltage support);
- Payments for demand response capacity obligations under the DR auction;
- Guarantee payments to generators — Day-Ahead Production Cost Guarantee (DA-PCG) payments made under the IESO's Day-Ahead Commitment Program and Real-Time Generation Cost Guarantee (RT-GCG) payments made under the IESO's RT-GCG program; and
- Other, which includes charges and rebates such as compensation for administrative pricing, the local market power rebate, among others.

[24] The Panel has amended the manner in which it classifies monthly uplift charges to more closely align reported costs with the month in which they were incurred rather than the month in which they were settled. This primarily impacts the monthly reported totals for GCG payments. For example, in Figure 1-12 below, all costs submissions to the GCG program for starts occurring between August 11 and September 9, 2015 were settled at the end of September. However, the bulk of the settlements pertain to starts that occurred in August 2015. As such, the Panel reports these costs below to have occurred in August 2015, rather than September 2015. As a result of this change, monthly totals reported in this report will not match those previously reported by the Panel.

[25] The Monthly Uplifts in this figure are all uplifts that are charged other than on an hourly basis.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Monthly Uplift is a component of the effective electricity price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

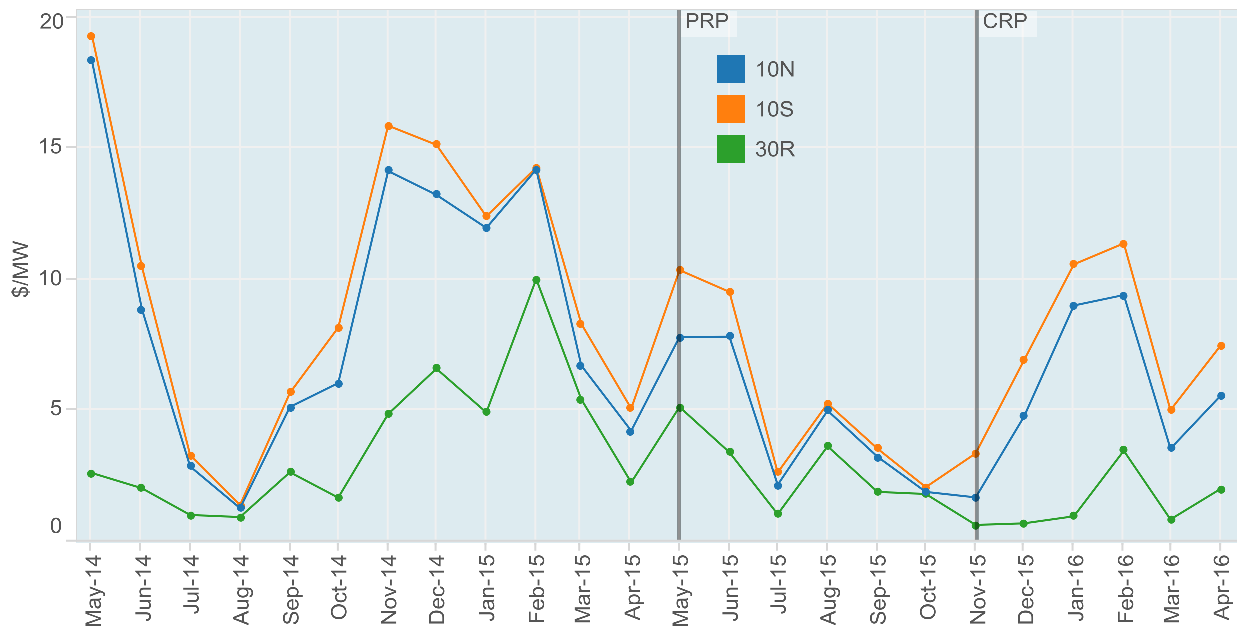
Commentary and Market Considerations:

The Current Reporting Period had relatively low monthly uplifts compared to the Previous Reporting Period. The highest monthly uplift figure during this period was $9.1 million, whereas the highest monthly uplift in the Previous Reporting Period was $25 million. The decline in Monthly Uplift over the Current Reporting Period is partially due to the decline in RT-GCG payments, from a total of $36.3 million in the Previous Reporting Period to a total of $13.7 million in the Current Reporting Period.

Figure 2-13: Average Monthly Operating Reserve Prices, by Category May 2014 – April 2016 ($/MWh)

Description:

Figure 2-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30 minute (30R).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The total OR requirement, as specified in the reliability standards adopted by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council, is sufficient megawatts to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. These requirements ensure that the IESO-controlled grid can operate reliably.

Commentary and Market Considerations:

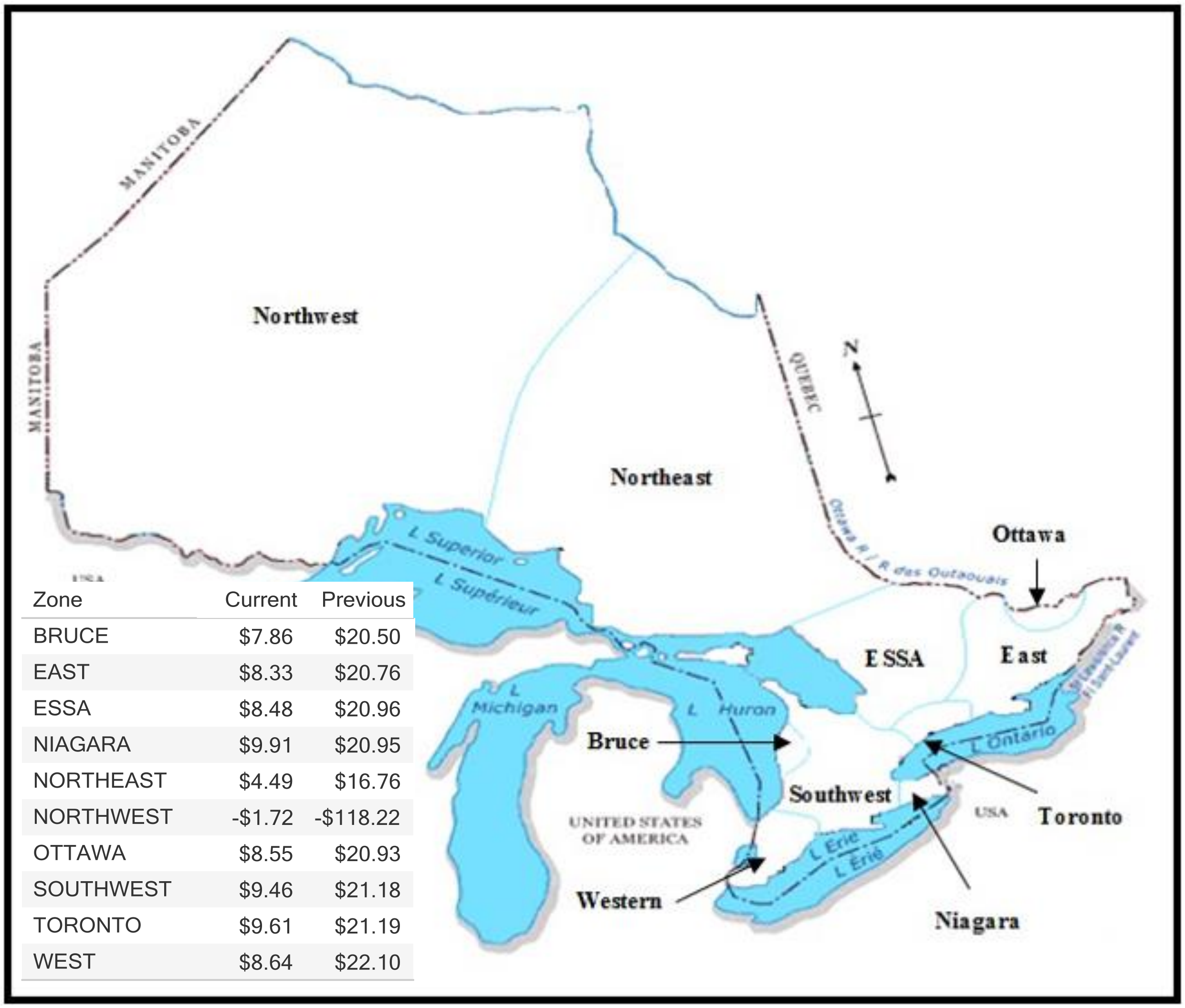
OR prices are higher relative to the Previous Reporting Period but are lower compared to the Winter 2015 period. January and February 2016 experienced relatively higher OR prices due to OR scarcity. While the majority of OR is offered by gas-fired and hydro-electric facilities, two factors have contributed to their decline. First, OR offers from hydroelectric resources have been decreasing for several years; this may be because OR revenue received by Ontario Power Generation's hydro-electric facilities is subtracted from the facilities' revenue requirement.[26] Therefore, OPG may not have a significant incentive to maximize OR revenues. The other contributor relates to Ontario's supply mix: abundant low marginal-cost supply in the form of nuclear, wind, and solar more frequently represent the marginal resource in Ontario; however, none of these resources can provide OR. When those low marginal cost resources are marginal, most non-quick start gas-fired facilities are not online, and therefore are not available to provide 10-minute operating reserve. This can result in short supply in the OR market, which generally results in higher OR prices and the increased potential of OR shortfalls. The Panel expects that higher OR prices will become more prevalent as even more renewable capacity is contracted and brought online.

Figure 2-14: Average Internal Nodal Prices by Zone
May 2015– October 2015 & November 2015 – April 2016
($/MWh)

Description:

Figure 2-14 illustrates the average nodal price of Ontario's ten internal zones for the Current and Previous Reporting Periods. In principle, nodal prices represent the cost of supplying the next megawatt of power at a given location.

[26] Refer to section 2.6 of MSP 27 Chapter 2 to examine in greater details the reasons for declining OR offers.



Zone	Current	Previous
BRUCE	$7.86	$20.50
EAST	$8.33	$20.76
ESSA	$8.48	$20.96
NIAGARA	$9.91	$20.95
NORTHEAST	$4.49	$16.76
NORTHWEST	-$1.72	-$118.22
OTTAWA	$8.55	$20.93
SOUTHWEST	$9.46	$21.18
TORONTO	$9.61	$21.19
WEST	$8.64	$22.10

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal value of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, the supply conditions are relatively tight; in zones in which average nodal prices are low, the supply conditions are relatively more abundant.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is surplus low-cost generation (in excess of local demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Nodal prices decreased among all zones, with the exception of the Northwest zone, where prices increased but were still negative. In line with changes in the HOEP attributed to milder winter conditions, relatively low demand during the Current Reporting Period resulted in lower nodal prices. In general, most zonal prices tend to move together, expect when there are outages on major transmission lines. With respect to the Northwest, however, increased net exports to Manitoba and Minnesota, as noted in Figure 2-26, were likely contributors to the price increase.

Figures 2-15 & 2-16: Congestion by Interface Group

Description:

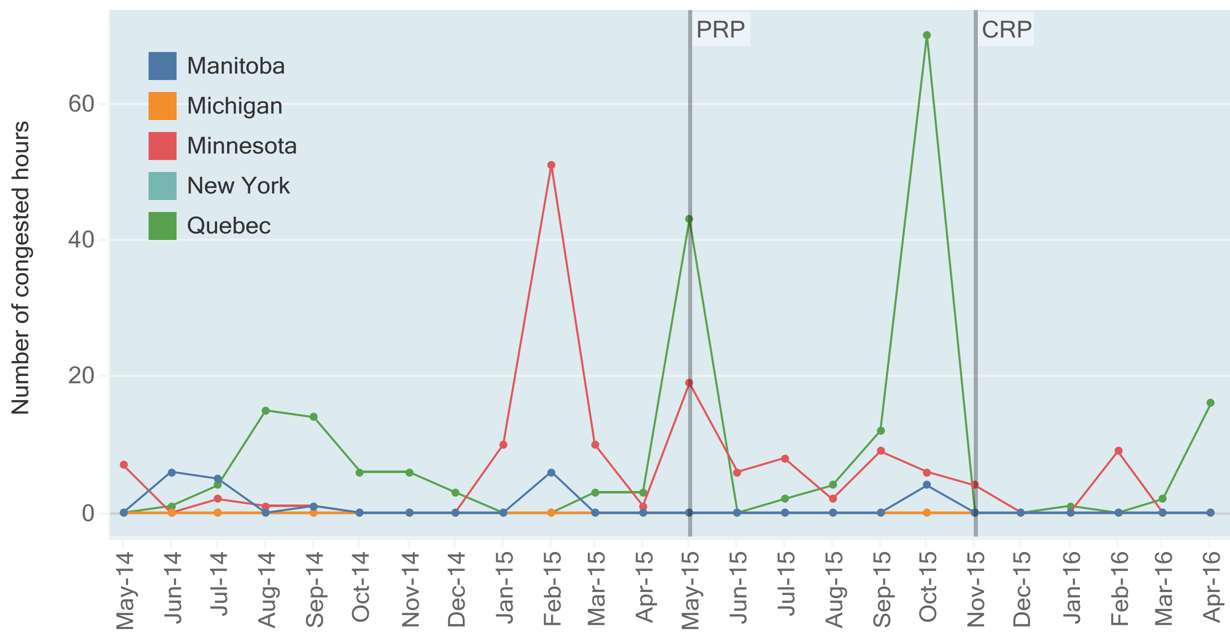
Figures 2-15 and 2-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. When an intertie has a greater amount of economic net import offers (or economic net export bids) than its one-hour ahead pre-dispatch transfer capability, the intertie will be import (or export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions.

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. When there is import congestion, importers receive less for the energy they supply while exporters (if any) pay less for the energy they purchase—the intertie zonal price is lower than the MCP. When there is export congestion, importers (if any) receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zonal price is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has more energy transactions than the intertie transmission lines can withstand. The ICP is positive when there is export congestion and negative when there is import congestion. This is discussed in more detail in the "Relevance" section associated with Figure 2-17.

Figure 2-15: Import Congestion by Interface Group
May 2014 – April 2016
(number of hours in the unconstrained schedule)

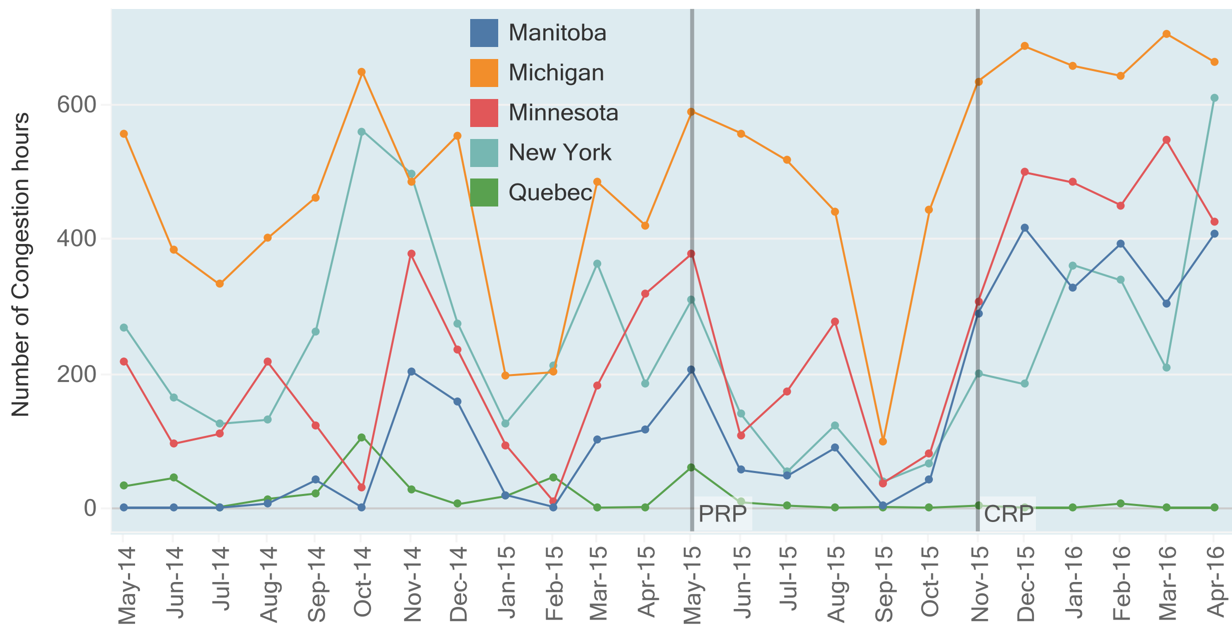


*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Overall there were fewer import congestion hours compared to the Previous Reporting Period. Low HOEP in the Current Reporting Period resulted in relatively few imports. A depreciation of the Canadian dollar compared to the US dollar also has the effect of decreasing the profitability of importing power.

Figure 2-16: Export Congestion by Interface Group
May 2014 – April 2016
(number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Export congestion increased for every intertie with the exception of Quebec. Low HOEP relative to the price in other jurisdictions had led to greater export opportunities relative to intertie capacity, leading to increased intertie congestion. Depreciation of the Canadian dollar compared to the US dollar also has the effect of increasing the profitability of exporting power.

The significant increase in export congestion hours on the New York intertie from March 2016 to April 2016 is due to transmission line limitations having restricted the New York intertie limit by at least 600 MW for approximately 66% of all hours in April.

Table 2-3: Monthly Average Hourly Wholesale Electricity Prices
in Ontario and Surrounding Jurisdictions
November 2015 – April 2016
($/MWh)

Description:

Table 2-3 lists the average hourly real-time wholesale prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in

Ontario commonly trade. The Ontario price reported is the HOEP. Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario.

The external prices reported are the real-time location-marginal prices (“LMPs”) that correspond with the node on the other side of Ontario’s interface with each jurisdiction. A proxy price was calculated for Manitoba as it does not operate a market. Quebéc is a frequent trading partner, but also does not operate a market. No proxy price was calculated for Quebéc. All prices are listed in Canadian dollars.

Month	Ontario (HOEP)[27]	Manitoba[28]	Michigan (MISO)[29]	Minnesota (MISO)[30]	New York (NYISO)[31]	Pennsylvania New Jersey Maryland Operator (PJM)[32]
Nov	9.29	19.26	22.72	31.27	16.91	30.50
Dec	10.04	24.15	25.65	29.90	17.90	29.67
Jan	12.78	29.22	30.55	31.56	23.69	35.90
Feb	11.5	24.41	26.43	29.46	19.19	31.79
Mar	5.19	19.24	21.99	26.65	10.45	18.06
Apr	5.73	17.98	21.00	28.18	24.77	27.71

Relevance:

One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.[33]

[27] All prices listed for each jurisdiction reflect the marginal price of energy. Costs associated with capacity, such as Ontario`s global adjustment or NYISO, PJM, or MISO’s capacity markets, are not considered in inter-jurisdictional trade.
[28] The Panel assumed that the real-time LMPs at the ‘MHEB’ node published by MISO are representative of the external prices at the Manitoba interface.
[29] The Panel assumed that the real-time LMPs at the ‘ONT_DECO_PSOUT’ node published by MISO are representative of the external prices at the Michigan interface.
[30] The Panel assumed that the real-time LMPs at the ‘ONT_W’ node published by MISO are representative of the external prices at the Minnesota interface.
[31] The Panel assumed that the real-time LMPs at the ‘OH’ node published by NYISO are representative of the external prices at the New York interface.
[32] The Panel assumed that the real-time LMPs at the ‘IMO’ node published by PJM are representative of the external prices in PJM that exporters can capture by wheeling through New York or Michigan.
[33] Differences exist in terms of the specific costs that are included in the spot price of electricity between jurisdictions. For example, in Ontario, the HOEP is not reflective of a gas-fired generation unit’s start-up costs, as these costs are a component of uplift, which is settled out-of-market. The specific components that comprise the spot price will vary from jurisdiction to jurisdiction, but they are still the most accurate and readily available indicators of economic decision making in real-time for intertie traders.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will impact the direction of energy trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions can lead to energy trade that appeared efficient ex-ante but ends up being inefficient or unprofitable ex-post. However, average prices over longer time horizons should be informative on trends in the direction of energy trade between jurisdictions. Over the course of a month if the average energy price in Ontario is lower than another jurisdiction, energy trade should flow from Ontario to that jurisdiction in that month on a net basis.

Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction's price. However, the two key pieces of information in determining whether to import to or export from Ontario are the HOEP and the spot price in the external jurisdiction.

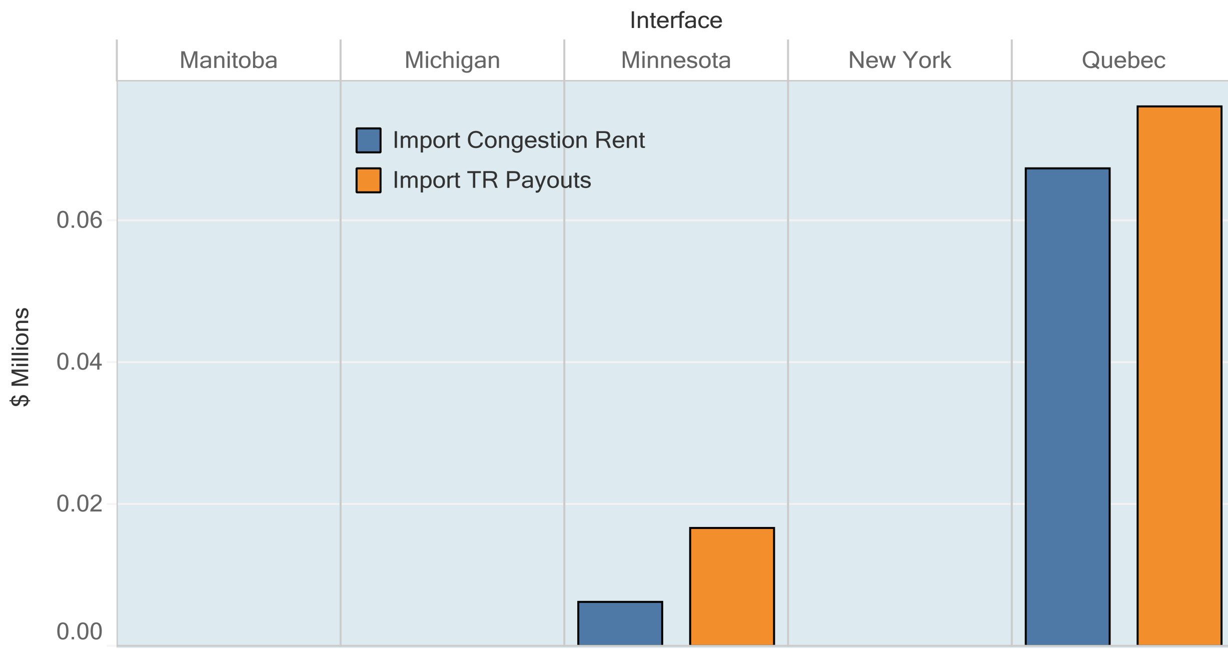
Commentary and Market Considerations:

In line with observations from Figures 2-15 and 2-16, Ontario's HOEP was significantly lower than the energy price in all of the surrounding jurisdictions; hence it was a net exporter during the Current Reporting Period.

Figure 2-17: Import Congestion Rent &
Transmission Rights Payouts by Interface Group
November 2015 – April 2016
($)

Description:

Figure 2-17 compares the total collection of import congestion rent to total TR payments by interface group for the Current Reporting Period.



Relevance:

As discussed in the relevance section associated with Figures 2-15 and 2-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1 intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import "congestion rent". Congestion rent accrues to the IESO's TR Clearing Account. This account is discussed in greater detail in the Relevance section associated with Figure 2-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or "payout") equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion, as TR payouts will exactly offset price differences between the Ontario price and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is seldom the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[34] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.[35] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers. The IESO has recently made changes to its TR auction process to address recurring congestion rent shortfalls, which is discussed further in the Relevance section associated with Figure 2-19.

Note that interties with a high frequency of import congestion hours (see Figure 2-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

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[34] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree that the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (*e.g.,* import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.,* export). In this case, import TR payouts are made and negative import congestion rents are "collected".

[35] If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate-regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see the Panel's January 2013 Monitoring Report, pages 146-160, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

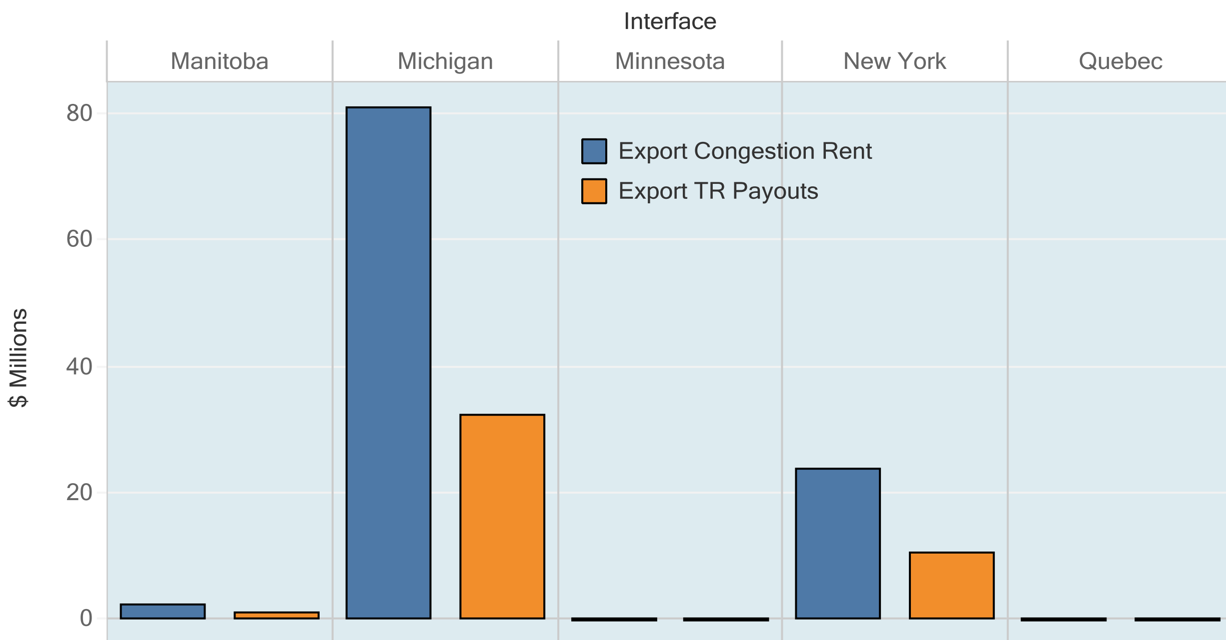
Commentary and Market Consideration:

There were very little import congestion rents paid out during the Current Reporting Period. This is because the HOEP was considerably less than the market prices in neighbouring jurisdictions, meaning there were fewer opportunities to import.

Figure 2-18: Export Congestion Rent & TR Payouts by Interface Group November 2015 – April 2016 ($)

Description:

Figure 2-18 compares the total collection of export congestion rent to total TR payouts by interface group for the Current Reporting Period.



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 2-17 that describes the relationship between congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR Clearing Account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

Compared to the Previous Reporting Period, export congestion rents for the New York and Michigan interties more than doubled, while TR payouts effectively remained unchanged between the Current and Previous Reporting Periods. The New York and Michigan interfaces were the primary contributors to congestion rent, with the latter being the most heavily export congested interface in the Current Reporting Period, as seen in Figure 2-16. The average hourly export capacity of the interface exceeded average hourly export TR ownership over the Current Reporting period by 346 MW and 99 MW for Michigan and New York respectively. In general, TRs can be undersold relative to the intertie capacity owing to line and equipment outages or system security requirements that suppress the IESO's forecast of the intertie's capacity.

Table 2-4: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction May 2015 – February 2016 ($/MW)

Description:

Table 2-4 lists the weighted average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since May 2015 (these TRs would have been valid during the Current Reporting Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Quebec
Import	May-15	Jul-15 to May-16	3,294	511	5,306	456	2,454
	Aug-15	Oct-15 to Aug-16	2,844	505	4,445	404	1,106
	Nov-15	Jan-16 to Dec-16	1,735	389	3,707	224	1,850
	Feb-16	Apr-16 to Mar-17	1,796	339	3,487	208	1,118
Export	May-15	Jul-15 to May-16	15,883	62,961	26,374	42,910	6,745
	Aug-15	Oct-15 to Aug-16	12,605	72,534	21,850	51,193	9,865
	Nov-15	Jan-16 to Dec-16	8,828	61,875	19,034	29,036	4,383
	Feb-16	Apr-16 to Mar-17	19,595	78,135	25,276	34,165	2,980

Relevance:

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal the market's expectation of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

Given Ontario's position as a net exporter of energy, auctions prices for long-term TRs were generally higher for exports than for imports across all interties. There has been a decrease in long-term import TR prices from the Previous Reporting Period to the Current Reporting Period across all interties: this may be indicative of market participants' expectations that import congestion will not be as prominent in the upcoming winter. With the exception of the New York and Michigan interties, there were no major price fluctuations for long term TR's between the Current and Previous Reporting Periods. The relatively material decrease in long-term export TR prices at New York is predictive of fewer export congestion hours in subsequent monitoring periods. Michigan is the only intertie with long-term TR prices that have increased, albeit slightly, from the Previous to the Current Reporting Period: the high occurrence of export congestion on the Michigan intertie is expected to persist.

***Table 2-5: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction
May 2015 – April 2016
($/MW)***

Description:

Table 2-5 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during the Previous and Current Reporting Periods.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Quebec
Import	May-15	310	55	418	90	135
	Jun-15	317	16	-	16	90
	Jul-15	387	12	-	11	81
	Aug-15	417	30	201	7	79
	Sep-15	202	12	164	7	0
	Oct-15	135	19	290	15	118
	Nov-15	165	15	122	15	5
	Dec-15	117	0	201	0	28
	Jan-16	103	0	327	1	20
	Feb-16	121	0	143	0	28
	Mar-16	98	0	126	0	40
	Apr-16	113	14	130	0	82
Export	May-15	810	4,494	1,735	2,262	179
	Jun-15	1,300	5,575	-	2,520	27
	Jul-15	751	6,897	-	2,645	82
	Aug-15	459	7,462	-	930	37
	Sep-15	580	5,947	-	1,125	6
	Oct-15	393	2,701	-	671	123
	Nov-15	310	4,009	-	2,297	72
	Dec-15	457	4,494	-	1,208	220
	Jan-16	1,001	4,621	-	1,305	826
	Feb-16	1,510	6,145	-	1,655	355
	Mar-16	2,612	7,373	-	2,875	186
	Apr-16	2,320	6,586	-	1,523	10

Relevance:

As discussed in the relevance section associated with Table 2-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

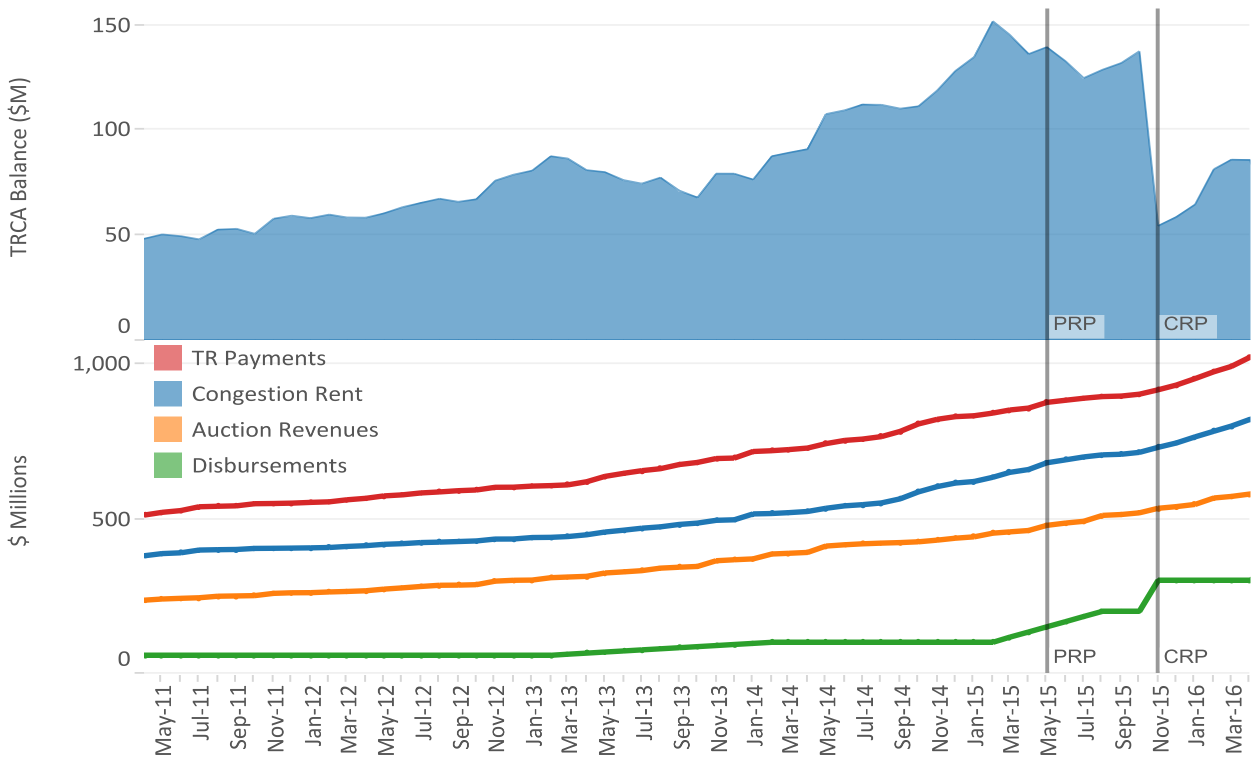
Commentary and Market Consideration:

Short-term import TR prices were consistent with the long-term TR auction. Regarding short-term export TR's, none were sold to Minnesota in this monitoring period. The short-term export TR prices at the Manitoba intertie almost tripled from the Previous to Current Reporting Period, which indicates a correct anticipation for the increased occurrence of export congestion hours at the Manitoba intertie, as illustrated in Figure 2-16. Trends in short-term export TR prices were consistent with the long-term TR auction for New York and Michigan.

Figure 2-19: Transmission Rights Clearing Account
May 2011 – April 2016
($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 2-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as a breakdown by its component transactions.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The TR Clearing Account balance is affected by five types of transactions:

<u>Credits</u>

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

<u>Debits</u>

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million set by the IESO Board of Directors; funds in excess of this threshold can be disbursed to wholesale loads and exporters at the discretion of the IESO Board of Directors.

Commentary & Market Considerations:

In the Current Reporting Period, the balance in the TR Clearing Account decreased by $51.78 million; from $137.31 million at the end of the Previous Reporting Period to $85.53 million at the end of the Current Reporting Period, thus ending $65.53 million above the Reserve Threshold. This change was composed of:

- $168.26 million in revenues
  - $107 million in congestion rent collected
  - $60.96 million in auction revenues
  - $0.30 million in interest (this was negligible and was therefore removed from the figure)
- $220.5 million in disbursements
  - $120.05 million in TR payments to rights holders
  - $100 million in disbursement to Ontario consumers in November 2015
    - This particular disbursement is discussed in more detail in Chapter 3 of this report

Total auction revenues increased by $4 million from the Previous Reporting Period to the Current Reporting Period. This change is likely attributed to a net increase in export TR prices coupled with relatively immaterial fluctuations in import TR prices, as summarized in Table 2-4 and Table 2-5.

Congestions rents increased by $52 million, while TR payouts increased by $75 million from the Previous Reporting Period to the Current Reporting Period. As noted in Figure 2-16, depreciation in the Canadian dollar relative to the US dollar had the effect of increasing the profitability of exporting power. This has contributed to an increase in the number of export congestion hours in all interties from the Previous Reporting Period to the Current Reporting Period, which in turn has increased the opportunity to collect congestion rents and make TR payments.

The Panel expands on the interdependencies between each component of the TR Clearing Account from section 3.1.1 to section 3.1.2 of Chapter 4.

Table 2-6: Demand Response Auction Results in December 2015 (MW, $/MW-day)

Description

Table 1-6 summarizes the results of the IESO's inaugural Demand Response (DR) Auction, completed in December 2015 for the subsequent summer (May 1, 2016 to October 31, 2016) and winter (November 1, 2016 – April 30, 2017) commitment periods. In general, DR consists of programs that encourage customers to reduce demand during times of tight supply conditions. DR is meant to reduce the total peak demand, or be used at other times to assist with maintaining reliability, as an alternative to calling on generators to produce more energy. As specified by the capacity obligation within each zone, resources committed through the DR auction are available to provide relief by reducing their consumption when called upon. Successful resources from the DR auction receive the auction clearing price for each MW of DR capacity.[36]

Zone	Summer Commitment Period (May 1, 2016 - Oct 31, 2016)		Winter Commitment Period (Nov 1, 2016 - Apr 30, 2017)	
	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)
BRUCE	-	-	-	-
EAST	24.7	378.21	25.4	359.87
ESSA	13.7	378.21	13.8	359.87
NIAGARA	15.9	348.45	15.9	332.71
NORTHEAST	56.3	378.21	56.3	359.87
NORTHWEST	51	378.21	50	359.87
OTTAWA	10.8	378.21	11.2	359.87
SOUTHWEST	40	378.21	55.3	359.87
TORONTO	159.4	378.21	159.2	359.87
WEST	19.7	378.21	16.6	359.87
Total MW	**391.5**	**-**	**403.7**	**-**
Weighted Average Price	**-**	**377.00**	**-**	**358.80**

[36] See Chapter 3 for an in-depth explanation of the DR auction process.

Relevance

The DR Auction is part of the IESO's transitional program to migrate the procurement of demand response from previous multi-year, contracted programs into a more competitive, near-term market mechanism within the IESO-administered markets. Instituting the DR Auction is viewed by the IESO as a foundational step to introduce a market-based mechanism to procure capacity, with the aim to allow for the entry of new, cost-effective demand response providers, enable system flexibility, and evolve the demand response sector to eventually compete with conventional forms of capacity such as supply or import resources. The DR Auction is also one of the key instruments the IESO is using to work towards the policy goal set forth in the 2013 Long Term Energy Plan of reducing peak demand by 10% in 2025.

Commentary

As Ontario has 10 electrical zones with varying supply and demand conditions, the auction took place on a zonal level by creating limits for the amount of DR procured in each zone. Zones with more generation than load would require less DR, while zones with more load than generation can have DR playing a greater role in matching supply and demand. For these reasons, Toronto was the zone with the greatest capacity obligation, holding 40.7% and 39.4% of the total capacity obligation in the summer and winter commitment periods, respectively. There was no cleared capacity in Bruce because no participant submitted offers into the auction. See section 3.2 of Chapter 4 for an in-depth discussion of the DR auction.

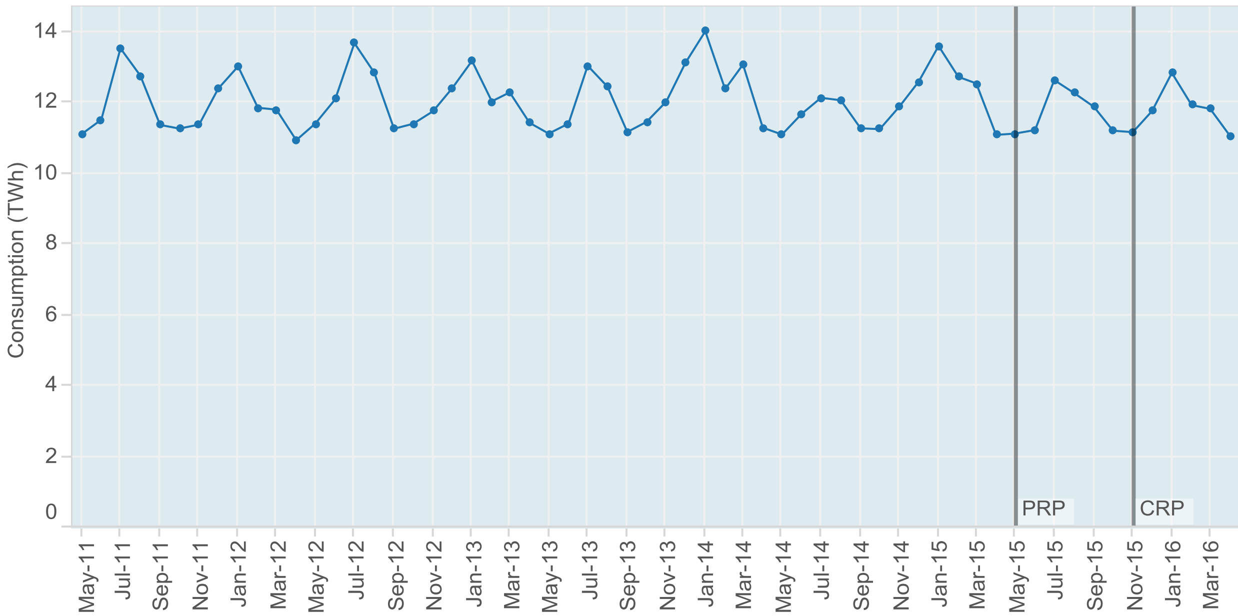
2 *Demand*

This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand
May 2011 – April 2016
(TWh)

Description:

Figure 2-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns.

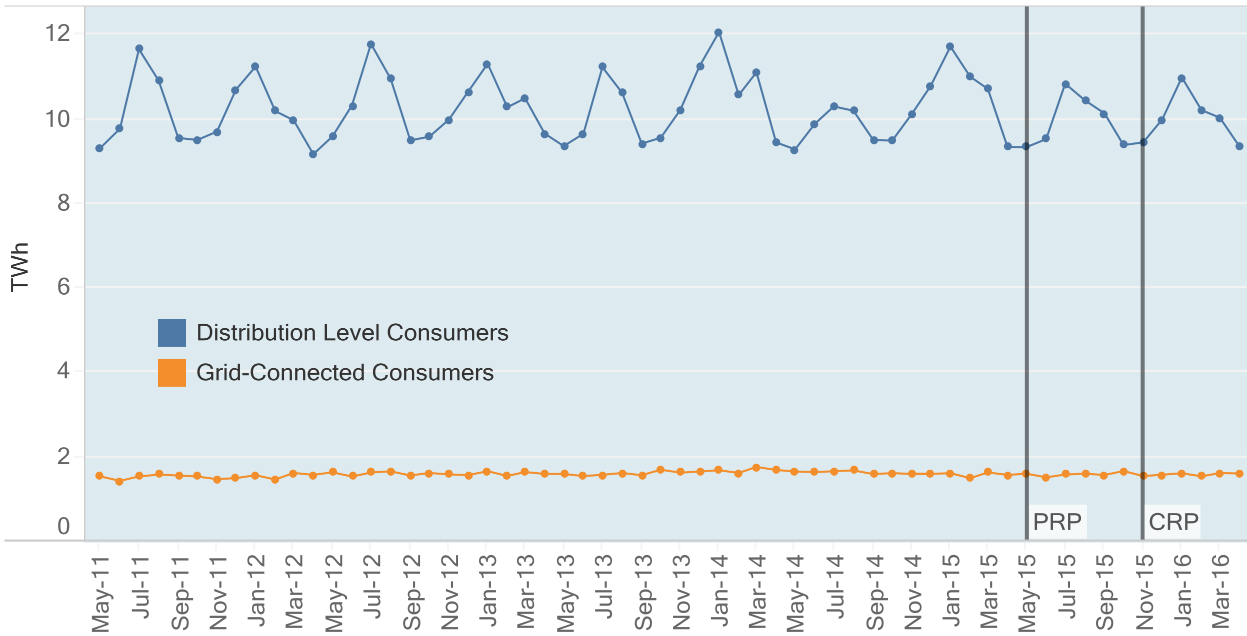
Commentary and Market Consideration:

The peak consumption during the Current Reporting Period was 12.82 TWh, which was lower than the peak consumption during the Winter 2015 and Winter 2014 Periods. In fact, monthly demand in the Current Reporting Period was less than it was for each corresponding month in the Winter 2015 Period. The relatively mild winter weather contributed to the reduction in demand.

Figure 2-21: Monthly Total Energy Withdrawals, Distributors and Wholesale Loads May 2011 – April 2016 (TWh)

Description:

Figure 2-21 charts the demand of two categories of consumers: market participants that are directly connected to the IESO-controlled grid other than distributors (Grid-Connected Consumers), and consumers connected to distribution systems (Distribution Level Consumers).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The breakdown of consumers into these two categories helps identify their respective monthly demand profiles.

Commentary and Market Consideration:

Seasonal changes in Ontario demand are attributed almost entirely to Distribution Level Consumers, which include residential, small and medium commercial, and small industrial loads. Demand from Grid-connected consumers, a group primarily composed of industrial loads and large commercial consumers, exhibit little of the seasonality evident of distribution-level consumption.

3 *Supply*[37]

During the fourth quarter of 2015 and the first quarter of 2016, 549.7 MW of nameplate generating capacity completed commissioning and was added to the IESO-controlled grid's total installed generator capacity. This new grid-connected capacity consisted of wind (409.7 MW) biomass (40 MW) and solar (100 MW) generation. At the end of the first quarter of 2016, grid

[37] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in March 2016 and available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18-month-outlook--2016mar.zip

connected generation capacity totalled 35,731 MW, consisting of nuclear (12,978 MW), gas-fired (9,942 MW), hydroelectric (8,432 MW), wind (3,643 MW), biofuel (495 MW) and solar generation (240 MW)[38].

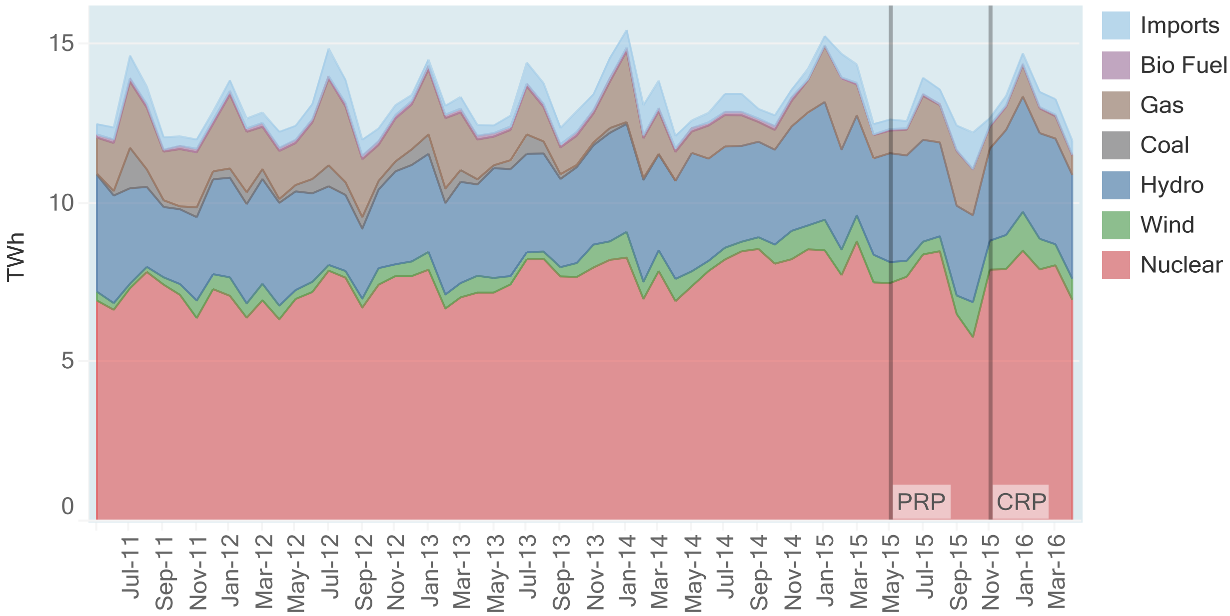
During the fourth quarter of 2015 and the first quarter of 2016, 130 MW of nameplate IESO contracted generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of solar (110 MW), wind (14 MW), biofuel (1 MW), hydroelectric (5 MW), and gas-fired and combined heat and power (4 MW). At the end of the first quarter of 2016, IESO contracted embedded capacity totalled 2,970 MW, consisting of solar (1,876 MW), wind (498 MW), hydroelectric (269 MW), gas-fired and combined heat and power (213 MW), biofuel (108 MW) and energy from waste (10 MW).[39]

Figure 2-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule by Reporting Period May 2011 – April 2016 (TWh)

Description:

Figure 2-22 illustrates the cumulative share of energy in the real-time unconstrained schedule for the past five years by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear, and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.

[38] Capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php
[39] Embedded capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added embedded capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

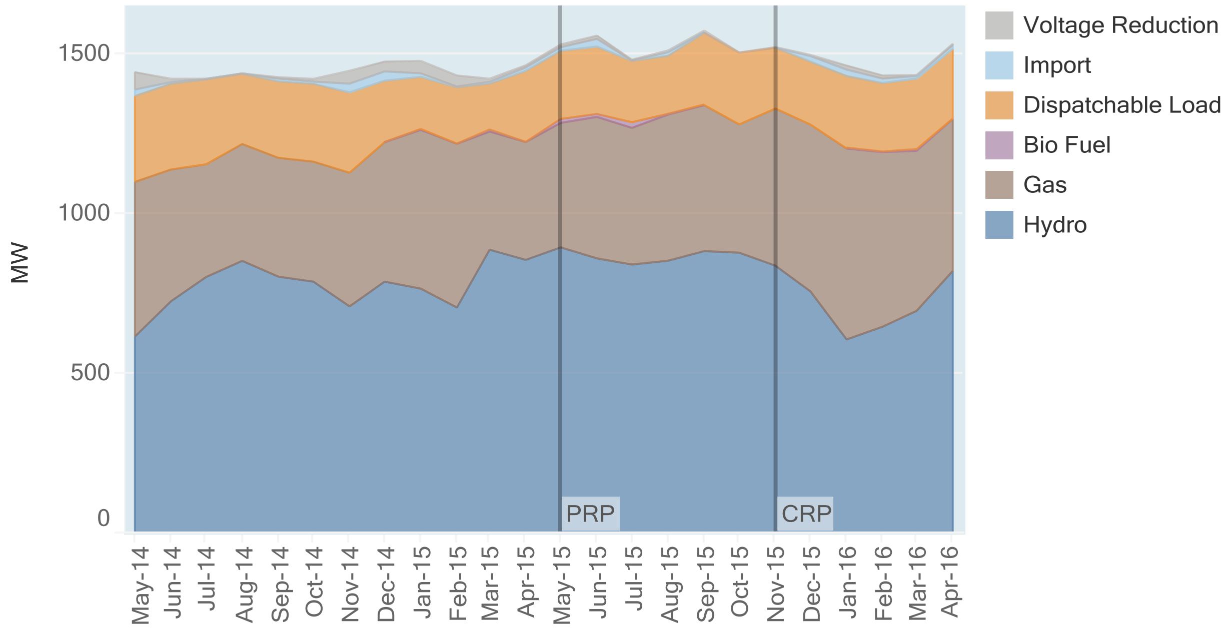
Commentary and Market Considerations:

Nuclear and hydroelectric resources continued to be the main sources of generation in Ontario. Wind resources were scheduled to produce more than gas-fired facilities for the first time (5.5 TWh for wind, 4.5 TWh for gas) in the Current Reporting Period.

Figure 2-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type May 2014 – April 2016 (MW per hour)

Description:

Figure 2-23 plots the average hourly amount of OR in the unconstrained schedule for the past two years by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads and voltage reduction.[40] Changes in the total average hourly operating reserve scheduled reflect changes in the OR quantity requirements.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors. [41]

Commentary and Market Considerations:

The amount of OR scheduled in the Current Reporting Period (6.4 TWh) decreased relative to the Previous Reporting Period (6.7 TWh) but slightly increased relative to the 2015 Winter Period (6.3 TWh): this corresponded to changes in the total OR requirement between monitoring periods. Factors such as increased power flows on a major 500 kV circuit – connecting supply in the Northeast to demand in the South – and an instance of nuclear commissioning tests in April

[40] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only used in real-time, never in pre-dispatch. Voltage reduction is an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.

[41] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency in Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.

2016 have contributed to the total OR requirement increasing beyond 1500 MW for more than 50% of all hours in the Current Reporting Period. In contrast, the Previous Reporting Period had approximately 90% of all such hours: this is likely attributed to seasonal freshet that increased the flow of hydroelectric power from the Northeast during May and June 2015. Between the Winter 2015 Period and Current Reporting Period, the slight increase in total OR requirement is likely attributed to anticipated changes in the operational profile of various nuclear facilities – a notable example being the nuclear commissioning tests that took place in April 2016.

The share of OR provided by hydro went down to an average of 48.9% during the Current Reporting Period compared to 56.8% from the Previous Reporting Period and 54.0% from the Winter 2015 Period. The share of OR provided by gas went up to 35.4% compared to 28.1% from the Previous Reporting Period and 30.0% from the Winter 2015 Period. The remainder of OR were supplied by voltage reduction, dispatchable loads, and imports.

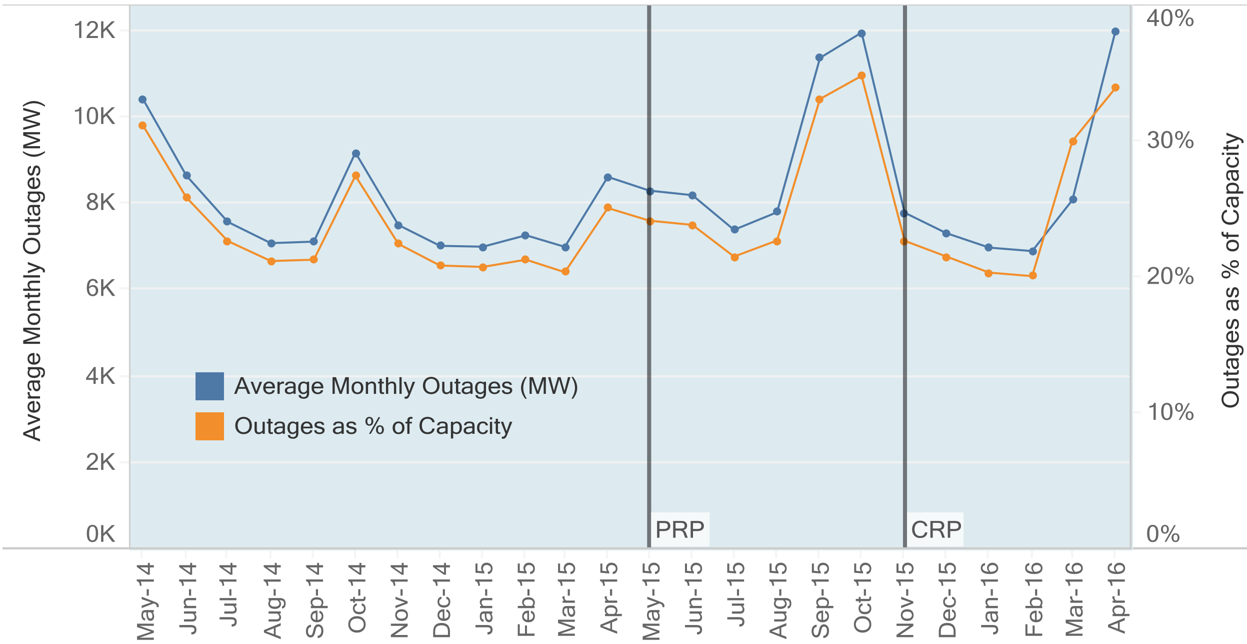
Figure 2-24: Unavailable Generation Relative to Installed Capacity
May 2014 – April 2016
(% of capacity) [42]

Description:

Figure 2-24 plots the monthly averages of the hourly sums of unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and derates, along with unscheduled capacity from intermittent, self-scheduling and transitional generators and constrained generation capacity due to operating security limits, as a percentage of total grid-connected installed generation capacity from May 2014 – April 2016.[43]

[42] In Previous Panel Reports, Figure 1-24 reported planned and forced outages and derates relative to capacity. The Panel has decided to report on all unavailable generation capacity. As such, the data reported in Figure 1-24 will not align with similar data published in previous Panel Reports for the period of November 2013 through April 2015. The Panel did this intentionally as it has revised the methodology by which it reports on unavailable generation capacity to also include unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid, in addition to planned and forced outages and derates.

[43] Unavailable generation capacity data was obtained from System Status Reports published daily by the IESO. A simple monthly average was calculated using the most recently reported totals for each hour of each trade date. Daily, weekly and monthly market summaries published by the IESO can be found here: http://www.ieso.ca/Pages/Power-Data/Market-Summaries-Archive.aspx.



*PRP: Previous Reporting Period. CRP: Current Reporting Period

Relevance:

Statistics regarding unavailable generation capacity provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices.

Commentary and Market Considerations:

Until March and April 2016, average monthly outages had decreased significantly from the Previous Reporting Period. The spike in outages in March and April are primarily attributed to nuclear refurbishments and refueling procedures that accounted for 65% of all unavailable capacity. Furthermore, planned outages with hydroelectric generation stations, for reasons such as transmission upgrades, accounted for 24% of all unavailable capacity.

4 *Imports, Exports and Net Exports*

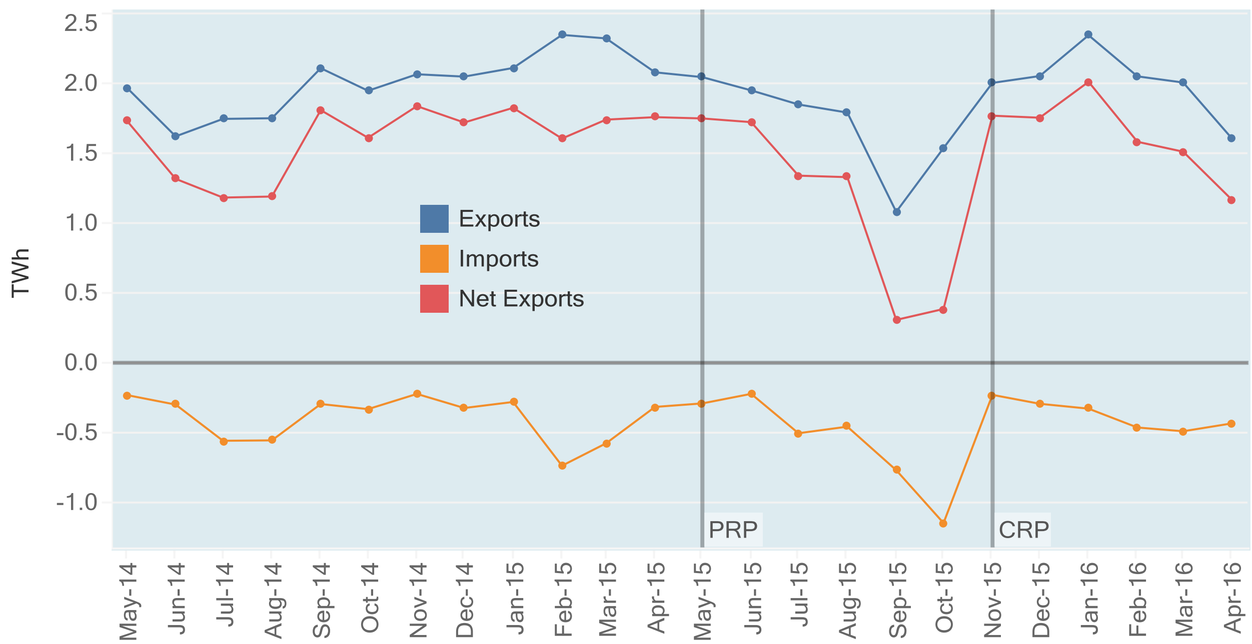
The data used in this section are based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.[44]

[44] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or the Ontario uniform price (either in pre-dispatch or in real-time).

Figure 2-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) May 2014 – April 2016 (TWh)

Description:

Figure 2-25 plots total monthly energy imports, exports and net exports from May 2014 to April 2016. Exports are represented by positive values while imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Current Reporting Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

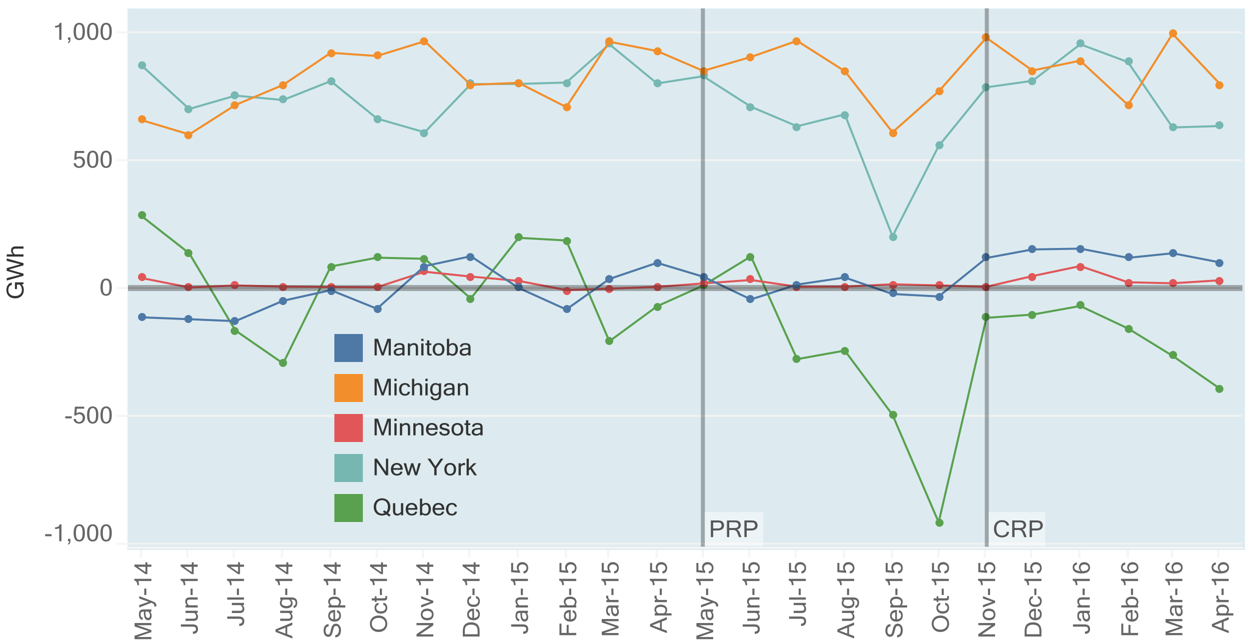
Commentary and Market Considerations:

There were higher net exports in the Current Reporting Period, which totalled 9.76 TWh, compared to the previous reporting Period, which totalled 6.80 TWh. The combination of low demand, low HOEP, and a weak Canadian dollar has contributed to stronger net exports.

Figure 2-26: Net Exports by Interface Group
May 2014 – April 2016
(GWh)

Description:

Figure 2-26 presents a breakdown of net energy exports from May 2014 to April 2016 to each of Ontario's five neighbouring jurisdictions: Manitoba, Michigan, Minnesota, New York and Quebec. Net exports are represented by positive values while net imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure shows how Ontario's energy trade evolves over time with each external jurisdiction.

Commentary and Market Considerations:

Net exports increased in every interface (except Québec) compared to previous monitoring periods, which was incentivized by the lower Ontario HOEP in the Current Reporting Period. The New York intertie experienced the largest increase in net exports by 1.09 TWh. While Québec's net imports dropped by 0.69 TWh in the Current Reporting Period, it remained a net importer across all months, totalling 1.11 TWh.

Table 2-7: Average Monthly Export Failures by Interface Group and Cause May 2015 – October 2015 & November 2015 – April 2016 (GWh and %)

Interface Group	Average Monthly Exports GWh		Average Monthly Export Failure and Curtailment GWh				Export Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	386.3	289.1	1.8	1.5	8.3	5.9	0.5	0.5	2.1	2.0
Michigan	348.1	333.8	1.5	1.2	3.2	4.7	0.4	0.4	0.9	1.4
Manitoba	79.9	37.4	2.6	3.2	16.3	11.7	3.2	8.5	20.4	31.1
Minnesota	6.0	8.2	0.2	0.4	0.2	0.2	2.7	5.0	3.7	2.9
Quebec	93.2	92.5	4.2	1.4	1.3	0.4	4.5	1.5	1.4	0.4

Description:

Table 2-6 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[45]

Relevance:

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails due to a failure on the part of a market participant (such as a failure to obtain transmission service).

MP Failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to SBG conditions. The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

[45] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

Commentary and Market Considerations:

Average export failures caused by market participants increased in volume on the Manitoba intertie; such failures accounted for 20% of export transactions. Manitoba continues to be an outlier with respect to the percentage and absolute volume of monthly exports that are curtailed due to MP failure.

Table 2-8: Average Monthly Import Failures by Interface Group and Cause May 2015 – October 2015 & November 2015 – April 2016 (GWh and %)

Interface Group	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	1.4	13.1	0.0	0.1	0.1	0.4	0.6	0.6	3.8	3.0
Michigan	1.2	5.4	0.2	0.1	0.4	0.6	16.6	1.6	34.7	10.4
Manitoba	34.8	21.0	5.9	3.5	0.3	0.1	16.9	16.8	0.8	0.5
Minnesota	8.2	1.4	0.9	0.1	0.7	0.1	11.5	4.9	8.8	4.2
Quebec	85.7	136.1	2.6	5.9	0.1	0.5	3.1	4.3	0.1	0.3

Description:

Table 2-7 reports average monthly import failures and curtailments over the Current and Previous Reporting Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for MP Failures and ISO Curtailments.

Commentary and Market Considerations:

Except Québec, the percentage of ISO Curtailments and MP Failures increased at all interfaces relative to the Previous Reporting Period, albeit on a relatively low volume of imports

Chapter 3: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments during the Current Reporting Period, from November 1, 2015 to April 30, 2016.

Typically, the Panel's analysis of anomalous events focusses on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of high uplift, such as Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments, and payments made through the IESO's Real-Time Generation Cost Guarantee (RT-GCG) program and the Day-Ahead Commitment Program (DACP). Payments made through the DACP are referred to as Day-Ahead Production Cost Guarantee (DA-PCG) payments. All of the aforementioned payments are recovered from consumers through uplift charges.

In the past, the Panel has defined anomalous events using several thresholds, such as the HOEP being greater than $200/MWh or daily CMSC payments being in excess of $1 million. Table 3-1 displays the number of events that exceeded the Panel's thresholds during the Current Reporting Period.

Table 3-1: Summary of Anomalous Events
November 2015 – April 2016
(Number of Events)

Anomalous Event Threshold	Number of Events
HOEP > $200	5
HOEP ≤ $0	1,427
Energy CMSC > $1 million/day	0
Energy CMSC > $500,000/hour	0
OR Payments > $100,000/hour	5
IOG > $1 million/day	0
IOG > $500,000/hour	0

During the Current Reporting Period, there were five hours when the HOEP was greater than $200/MWh; during these five hours there were also operating reserve (OR) payments in excess of $100,000. Having analyzed these hours, the Panel has concluded that they were largely the result of variable generation shortfall and demand forecast errors. In these hours, ample supply conditions in pre-dispatch resulted in relatively low prices and few gas-fired facilities being committed to generate. With few gas-fired facilities online to provide relatively inexpensive ramping capability and OR, the system had limited ability to absorb the loss of variable generation and excess demand in real time, resulting in high HOEP and OR payments. High prices related to limited ramp capability were examined in detail in the Panel's November 2016 Monitoring Report.[46] In one of the five aforementioned hours, the supply shortfall and excess demand conditions were exacerbated by an unforeseen nuclear outage.

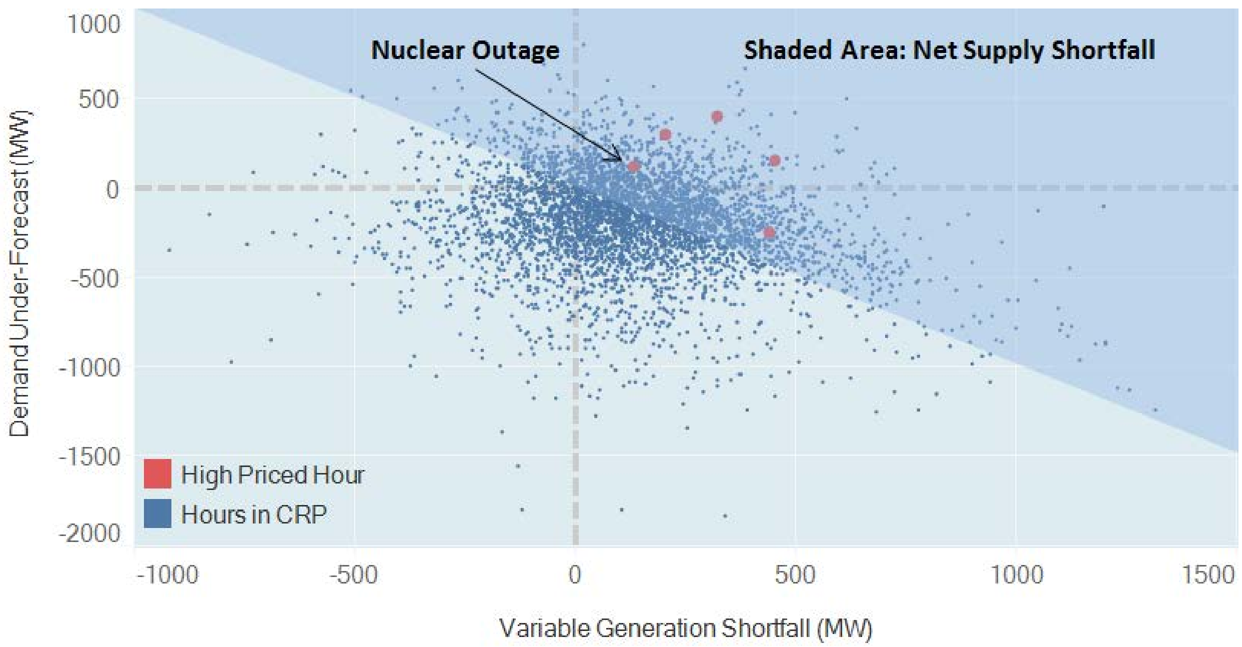
There were no days or hours during the Current Reporting Period that exceeded the Panel's CMSC or IOG thresholds.

There were 1,427 hours when HOEP was non-positive: an all-time high number of non-positive hours during a 6-month reporting period. Non-positive HOEPs are the result of increasingly common conditions, such as: low Ontario demand, abundant supply offered at negative prices, and failed export transactions, among other causes. The Panel examines the conditions surrounding non-positive hours in greater detail in section 3 of this chapter.

As has been described above, a high or low price, or a large uplift payment, does not necessarily indicate that there was something amiss; the regularity with which variable generation shortfall and/or demand under-forecast are contributors to high HOEP events is one such example. Figure 3-1 shows that all five high price hours in the Current Reporting Period, marked in red, occurred during net supply shortfall (defined as hours in which the sum of demand under-forecast and variable generation shortfall are positive, creating tighter supply conditions in real-time relative to pre-dispatch).

[46] See pages 69 –71 of the Panel's November 2016 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf

Figure 3-1: HOEP by Net Supply Conditions
November 2015 – April 2016
(MW)



Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. In this chapter, the Panel has expanded its analysis of anomalous events beyond those which meet or exceed pre-determined thresholds. Other criteria for assessing events include: the appropriateness of the market outcome relative to the Market Objective[47] and the Market Rules; the novelty and frequency of an unexpected event, as well as the relevance of the outcome to current IESO initiatives and stakeholder engagements. The Panel's approach will be informed by the historic thresholds, but will broaden the analysis to include other relevant events as appropriate.

2 *Analysis of Anomalous Events*

In the sections that follow, the Panel reports on three anomalous events that occurred during the Current Reporting Period. These events resulted in inappropriate payments or outcomes related to: dispatchable loads in the OR markets, ramp-down CMSC payments, and export failures.

[47] The Market Objective of the IESO-administered markets is to promote an efficient, competitive, and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

2.1 *Dispatchable Loads and Unavailable Operating Reserves in February 2016*

Relevance

From January 2010 to April 2016, the Panel estimates that dispatchable loads (DLs) received approximately $12.5 million in OR payments for reserves that they were incapable of providing. Such instances are of concern, not only for the significant inappropriate payments themselves, but also for the corresponding reliability issues. To highlight these concerns, the Panel analyzes one such event that occurred in the ten-minute OR markets during hour ending (HE) 19 on February 21, 2016.

Analysis

OR is standby capacity intended to respond to, and recover from, a contingency on the grid. Such a contingency could take the form of a sudden, unexpected increase in demand, a forced outage of generation or transmission equipment, or significant dispatch deviations from generators or DLs, among other possibilities. Resources scheduled to provide standby capacity in the ten-minute OR market must provide the entirety of that capacity within ten minutes of receiving an OR activation, and must be able to provide the activated capacity for at least one hour.[48] When a DL's standby capacity is activated to help recover from a contingency, the DL provides relief by reducing its consumption. To be able to provide the required relief (and fulfill its OR activation), a DL must be consuming at least the activation amount prior to being activated.

Table 3-2 summarizes the dispatch schedules, actual MW consumption, OR price, and corresponding OR payments for two DLs on HE 19 of February 21, 2016.

[48] Refer to the Market Rules, Chapter 5 Appendices, Section 1.2

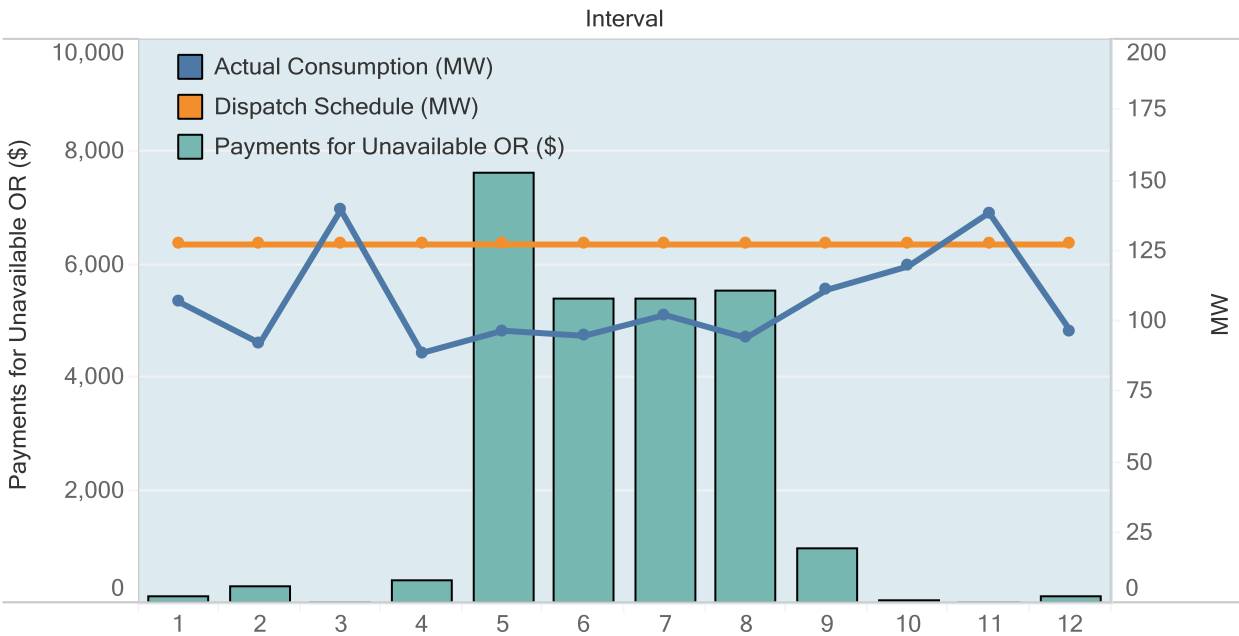
Table 3-2: Participation of Two Dispatchable Loads in the Ten-Minute OR Markets February 21, 2016, HE 19

Interval	OR Schedule (MW)	Actual Consumption (MW)	Unavailable OR (MW)[49]	OR Price ($/MWh)	Payment for Unavailable OR ($)
1	127	107	36	30	91
2	127	92	43	75	270
3	127	139	0	91	0
4	127	89	48	96	386
5	127	96	46	2,000	7,613
6	127	95	32	2,000	5,403
7	127	102	32	2,000	5,386
8	127	94	33	2,000	5,523
9	127	111	29	396	956
10	127	119	16	30	39
11	127	138	0	30	0
12	127	96	37	30	93
Total	-	-	-	-	**25,760**

As illustrated in Figure 3-2, during numerous intervals within the hour these DLs consumed less than their scheduled OR standby capacity. Had these DLs been activated to recover from a contingency, they would have been unable to provide the relief they were paid for.

[49] Because Table 3-2 aggregates the data of two DLs, the unavailable OR in a given interval is not necessarily equal to the difference between the total OR schedule and the total consumption shown in the table. The OR schedule represents the maximum OR a DL can provide, therefore any over consumption by one DL does not offset the under consumption of another when determining how much OR is available.

Figure 3-2: OR Schedule, Energy Consumption, and Excess Compensation for Two Dispatchable Loads on February 21, 2016, HE 19 (MW, $)



In totality these resources were compensated for 29 MWh[50] of OR they were unable to provide. This hour experienced the highest average ten-minute OR price of the Current Reporting Period ($1,050/MW), signalling a premium on reliability. Since DLs are compensated according to their OR schedule, not the OR they were able to provide, the two DLs received $25,760 for OR that they were incapable of providing.

DLs scheduled for ten-minute OR were capable of providing the entirety of their OR schedule in only 9.6% of intervals during the Current Reporting Period. In the remaining 90.4% of intervals, DLs had an average OR schedule of 122 MW, but only consumed an average of 57 MW. Accordingly, there was an average of 65 MW of unavailable OR from DLs, or approximately 6.5% of the average ten-minute OR requirement. This outcome is inappropriate: not only were the DLs potentially compromising the reliability of the grid by operating in a manner which rendered them unable to meet their OR obligation, but they were compensated for such behaviour. This is a recurring outcome (across several DLs) that has resulted in approximately

[50] This number is calculated by adding the unavailable OR values in each interval from Table 3-2 and dividing the sum by 12 to generate the corresponding MWh value.

$12.5 million being paid for scheduled OR that were not actually provided (from January 2010 through April 2016).

The Panel recognizes that provisions exist in the Market Rules to recover payments made to DLs for unavailable OR. While the Panel encourages the IESO to pursue any and all available avenues for recovering such payments, the IESO should also pursue a more fundamental solution that prevents the payments from being made in the first instance.

Recommendation 3-1:

The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.

2.2 *Ramp-Down CMSC Payments for a Gas-Fired Generator on January 4, 2016*

Relevance

A generator signals its intent to come offline at the end of its run by raising its energy offer price above the local nodal price, thus becoming uneconomic in the constrained sequence. Due to the three-times ramp rate assumption used in the unconstrained sequence,[51] a generator's unconstrained schedule ramps down faster than its constrained schedule. As a result, there is a divergence between the two schedules during the ramp-down period, resulting in constrained-on CMSC payments.

In past reports, the Panel has highlighted the inappropriate nature of CMSC payments caused by ramping, and recommended that the IESO eliminate them; CMSC is not intended to provide a revenue stream for generators that take a voluntary action.

The IESO conducted a stakeholder engagement on the matter, introducing Market Rule Amendment MR-00414 to mitigate CMSC payments caused by ramping. While the rule was

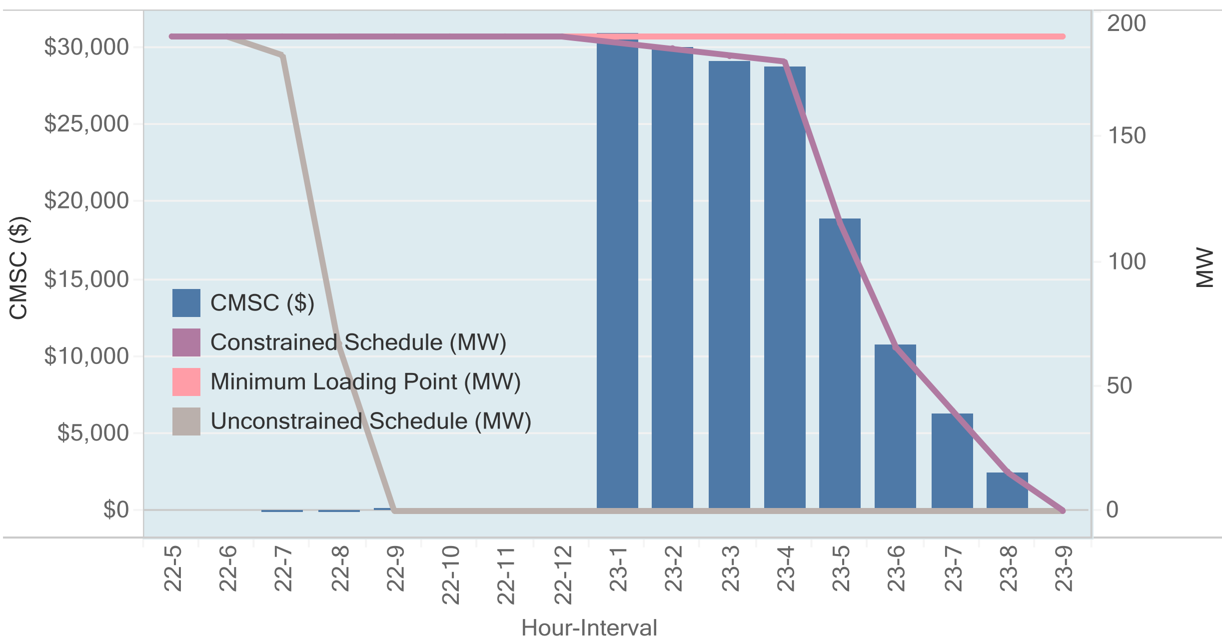
[51] The "three-times ramp rate assumption" refers to the IESO's unconstrained dispatch algorithm's assumption that a generator can ramp down three times faster than is technically feasible. The constrained dispatch algorithm must respect the physical limitations of generators in order to produce a feasible schedule, and thus does not employ the three-times ramp rate assumption. The result is a divergence between a generator's constrained and unconstrained schedules any time the unit is ramping, which results in CMSC payments.

approved by the IESO Board of Directors on June 24, 2015,[52] it was not implemented by the IESO until a year and half later on December 8, 2016. To highlight the ramp-down CMSC payments that were ongoing during the period between the rule approval and its implementation, the following section examines the operation of a gas-fired facility in January 2016.

Analysis

On January 4, 2016, a gas-fired facility offered its full capacity at $2,000/MWh in HE 23 in order to signal its intent to ramp down and come offline. As illustrated in Figure 2-3, the facility ramped down from interval 1 to 8 in HE 23 and generated approximately $160,000 in CMSC payments.

Figure 3-3: Gas-Fired Generator's Ramp-Down Profile and CMSC
January 4, 2016
(MW, $)



The CMSC payments were self-induced by the market participant's decision to come offline and exacerbated by the participant's choice of a $2,000/MWh offer price; which was well in excess of the price required to ensure a ramp down was achieved.

[52] For more information on Market Rule 414, see the IESO's SE-111 stakeholder webpage, available at: http://www.iemo.com/Pages/Participate/Stakeholder-Engagement/SE-111.aspx

While the IESO Board of Directors had already approved a Market Rule to limit ramp-down CMSC payments, the effective date of the Market Rule was contingent on the implementation of the required IT system changes, which were not yet in place.[53] Had the rule been put in effect when passed, ramp-down CMSC payments for the gas-fired facility would have been reduced from $160,000 to $4,000.

The Panel estimates that CMSC payments caused by ramping would have been reduced by $1.9 million market wide from June 25, 2015 to December 7, 2016 had the Market Rule amendment been effective from the date the amendment was approved.

The Panel understands that the implementation of the Market Rule amendment was delayed due to the relative complexity of the required solution. The decision not to make the market rule amendment effective immediately or to recommend retroactive adjustment was also due to the intricacy of the IT solutions. The Panel recognizes that while the implementation of the Market Rule amendment represented a complex IT process, that relative difficulty should not preclude the IESO from making retroactive adjustments pursuant to the appropriate Market Rule, which in this case could have clawed back approximately $1.9 million.

The Panel believes that the IESO should make all reasonable efforts to allow future Market Rule amendments to be effective immediately upon approval by the Board of Directors. This would allow the IESO to retroactively apply adjustments in accordance with the Market Rules, regardless of implementation constraints.

2.3 *Export Failures on the New York Intertie on February 20, 2016*

Relevance

Transmission lines can only accommodate a certain amount of electricity flow at a given time; this limit is referred to as the scheduling limit. Congestion occurs when the quantity of electricity scheduled to flow over the transmission line exceeds the scheduling limit.

When an intertie becomes congested, the Intertie Zonal Price (IZP) – the price at which intertie traders are settled – will differ from the Market Clearing Price (MCP). The IZP will be higher

[53] For more information on the IESO Board of Directors decision on MR-00414, see the Market Rule Amendment Proposal, available:
http://www.ieso.ca/Documents/Amend/mr2015/MR_00414_R00_Amendment_Proposal_Ramp_Down_CMSC_v5.0.pdf , page 1

than the MCP when there is export congestion and lower than the MCP when there is import congestion. This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the IZP, while the corresponding domestic transaction is settled at the MCP.[54] The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent.

Intertie congestion can be difficult to predict and can significantly impact the profitability of an intertie transaction; congestion introduces financial risk to intertie traders. Accordingly, the IESO auctions off Transmission Rights (TRs), which provide a financial hedge against congestion by paying out the difference between the IZP and the MCP when the intertie is congested.

TR payments are based on the level of intertie congestion in pre-dispatch, whereas congestion rent is based on the amount of energy dispatched an hour later in real-time. Intertie traders contribute to congestion, and thus TR payments, when they are scheduled in pre-dispatch.

After pre-dispatch but before real-time, an intertie trader may fail a scheduled transaction for reasons within its control, in which case the transaction does not flow and no congestion rent is collected. The result is TR payments (based on conditions anticipated in pre-dispatch) in excess of congestion rents collected (based on real-time conditions). TR payments in excess of congestion rent collected are referred to as a "congestion rent shortfall"; the shortfall is funded by diverting auction revenues from transmission customers to TR owners. As discussed in Chapter 4, this transfer of funds from transmission customers to TR owners is inappropriate and ultimately to the detriment of Ontario consumers.

The IESO may levy an intertie failure charge on intertie traders that fail transactions for reasons within their control. The amount of the failure charge, if any, is calculated pursuant to a pre-set formula and that only take into account the impact of the failure on the MCP.[55] The failure

[54] For instance, an exporter pays the IZP, while the Ontario generator that supplies that export is paid the MCP. In the case of export congestion, the exporter pays the higher IZP and the Ontario generator is paid the lower MCP: the difference in payments accrues as congestion rent. For more information on congestion rent, see section 3.1.1 of Chapter 4.
[55] The intertie failure charge is calculated on the basis of the spread between the pre-dispatch and real-time Ontario MCP multiplied by the number of failed megawatts.

charge does not capture the impact of the congestion rent shortfall that the failure creates.[56] Consequently, when there is congestion on the intertie, the failure charge is incommensurate with the congestion rent shortfall the failure created, leaving Ontario consumers to pay for the shortfall.[57]

From January 2010 to April 2016, the Panel estimates that intertie failures within the control of market participants have resulted in congestion rent shortfalls of approximately $11 million. To highlight this behaviour, the Panel examines an exporter's activity at the New York intertie on February 20, 2016.

Analysis

On February 20, 2016, an intertie trader bid to export 400 MW from Ontario to New York in every hour of the day, with an average weighted hourly bid price of $33.98/MWh. Pre-dispatch prices were below $5/MWh in all hours of the day, so the intertie trader's exports were continually economic, resulting in a total daily pre-dispatch export schedule of 9,600 MWh. However, following pre-dispatch but before real-time, the intertie trader failed a total of 7,456 MWh (78%) of its exports from Ontario to New York. These export failures were within the intertie trader's control, resulting from the participant's failure to economically schedule the corresponding import transactions in the New York electricity market. The intertie trader was subject to export failure charges totalling $466.

In 10 of the 22 hours when the intertie trader failed an export transaction, the New York intertie was export congested, with an average intertie congestion price of $3.51/MWh. By failing its export transactions throughout the day, the intertie trader contributed to higher congestion prices and greater TR payments, but avoided paying congestion rents, leaving Ontario consumers to pay for the shortfall.

In this particular instance, the intertie trader who failed the exports also owned 400 MW of New York export TRs, meaning it was the beneficiary of the congestion it helped create. All told, the

[56] Export failure on the intertie could result in other impacts unaccounted for by the failure charge, such as the need to constrain off domestic generation. In particular, export failures can exacerbate surplus baseload generation conditions and could potentially lead to costly nuclear maneuvers.

[57] Not accounting for congestion rent shortfall in the failure charge may incent traders that own TRs to create congestion in order to receive TR payments, only to intentionally fail its transactions and avoid paying congestion rents.

intertie trader paid $1,537 in congestion rent, but collected $14,044 in TR payments, for a total profit to the intertie trader (and congestion rent shortfall to the Ontario consumer) of $12,507.

Table 3-3: Intertie Trader's Activities during Hours with Intertie Congestion February 20, 2016

Export Congestion Hour	Exports Scheduled in Pre-Dispatch (MW)	Exports Flowed in Real-Time (MW)	Congestion Rents Paid ($)	TR Payments Received ($)	Benefit to Intertie Trader (Congestion Rent Shortfall) ($)
1	400	57	163	1,144	981
2	400	164	800	1,952	1,152
4	400	0	0	1,200	1,200
6	400	38	114	1,200	1,086
10	400	0	0	104	104
11	400	0	0	3,000	3,000
15	400	0	0	404	404
17	400	0	0	1,600	1,600
22	400	200	460	920	460
23	400	0	0	2,520	2,520
Total	**4,000**	**459**	**1,537**	**14,044**	**12,507**

From January 2010 to April 2016, Ontario consumers have paid for approximately $11 million in congestion rent shortfall induced by intertie failures within the participant's control. This outcome is clearly inappropriate.

The Panel recognizes that the IESO has the authority within the Market Rules to adjust settlement amounts attributable to intertie failures within the market participant's control. While the Panel encourages the IESO to pursue any appropriate actions available to it via the Market Rules, it suggests that the IESO should also pursue a more fundamental solution that prevents situations like the one described above from occurring in the first instance. The Panel believes an appropriate failure charge should include congestion rents avoided.[58]

[58] In 2005, the IESO's Intertie Transaction Failure Working Group considered such an approach to calculating the intertie failure charge, but ultimately recommended the current methodology. In consideration of publicly available materials on the views and concerns of the working group and stakeholders at that time, the Panel found no compelling reason not to include the congestion rents avoided.

Recommendation 3-2:

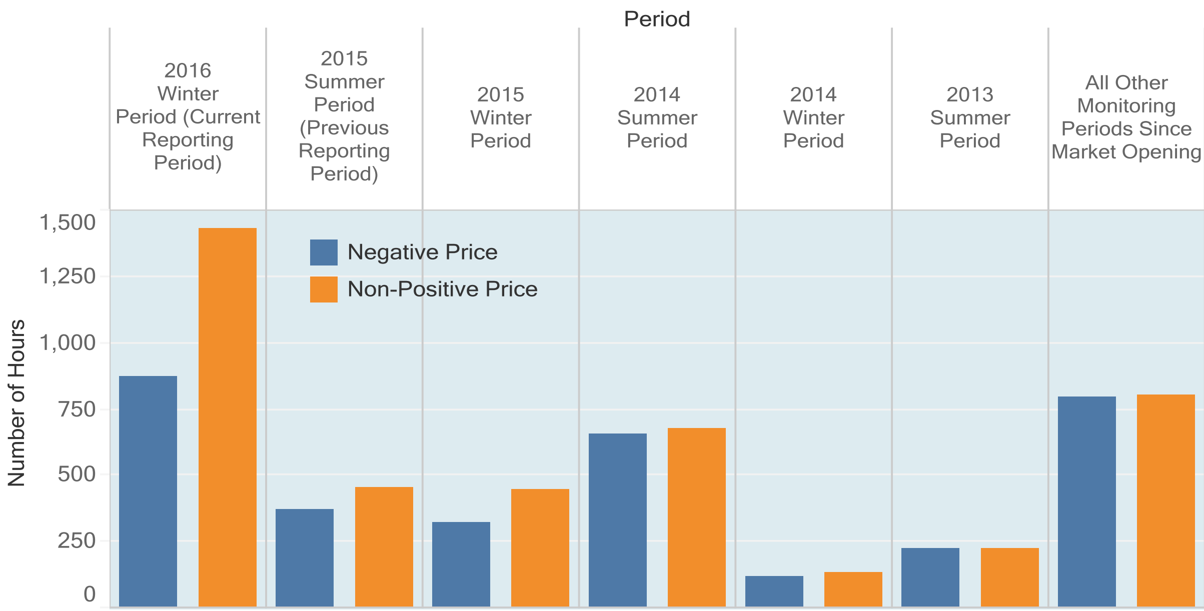
The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.

2.4 *Examination of Non-Positive Price Hours*

The Panel has traditionally monitored low price hours when the HOEP is negative as a means to identify and report on potentially anomalous market outcomes. In recent reporting periods, there has been a significant increase in the frequency of zero-price HOEPs; the Panel has therefore altered its monitoring threshold to be non-positive HOEPs. Non-positive price hours typically signal an abundance of supply relative to demand, with contributing factors that include: low Ontario demand, failed export transactions, and an abundance of supply offered at non-positive prices.

During the Current Reporting Period there were 1,427 non-positive HOEPs, a significant increase from the corresponding period in the previous year when there were 447. As illustrated in Figure 3-4, the Current Reporting Period had the highest occurrence of non-positive HOEPs of all reporting periods since market opening; approximately 33% of all HOEPS during the Current Reporting Period were non-positive.

Figure 3-4: Non-Positive HOEPs by Reporting Period (Number of Hours)

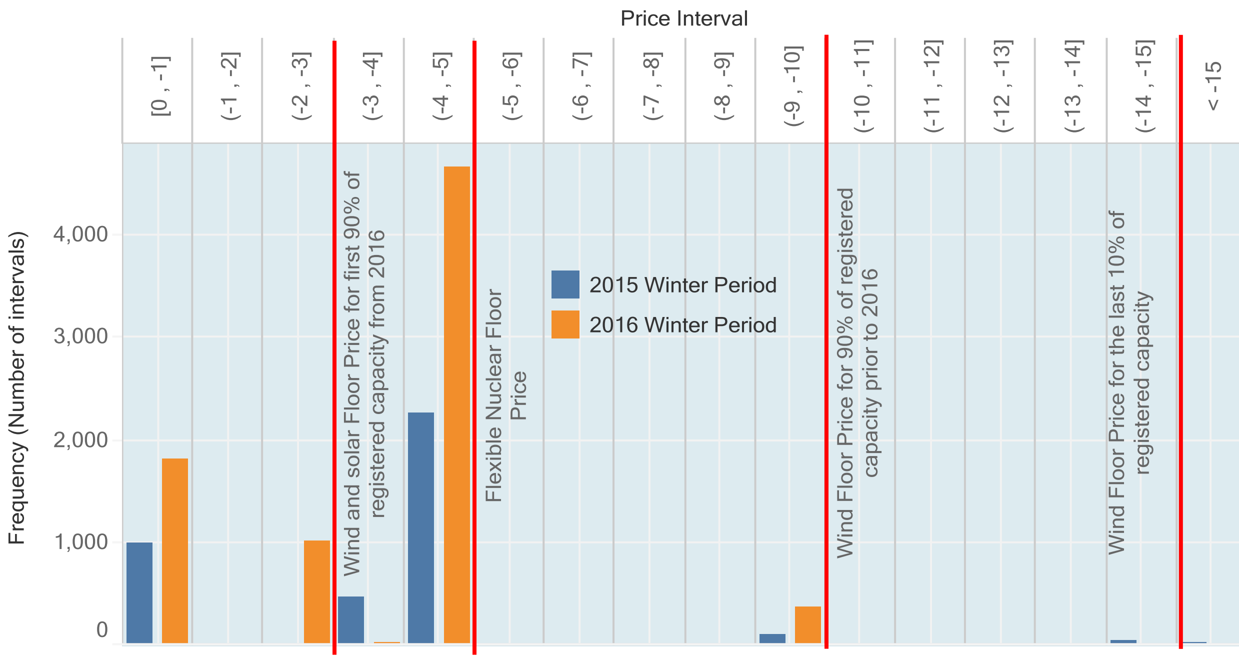


Non-positive HOEPs are prominent during periods of relatively low market demand, such as the early morning prior to 8:00 am or the late evenings after 10:00 pm. While non-positive HOEPs are particularly prevalent during weekends, they are becoming increasingly prominent during weekdays as well.

Figure 3-5 illustrates the frequency distribution for non-positive MCP's during the Current Reporting Period and the 2015 Winter Period, across $1/MWh price increments. The red vertical lines indicate the offer price floors imposed by the Market Rules for various resource types[59]. The price intervals demarcated by the offer price floors present the frequency with which certain resources go unscheduled in the unconstrained sequence. For example, any intervals to the right of the Flexible Nuclear Floor Price line indicate how often (375 intervals in the 2016 Winter Period) flexible nuclear went unscheduled in the Current Reporting Period.

[59] For more information on the offer price floors, see Market Manual 4 Part 4.2: Submission of Dispatch Data in the Real-Time Energy and OR Markets, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/67f665f95aa94954b4a1d4504c772460.ashx

Figure 3-5: Frequency Distribution of Non-Positive MCPs November 2015 – April 2015 & November 2015 – April 2016 (Number of Intervals)[60]



The unprecedented frequency of non-positive prices reflects consistent surplus baseload generation. This is in line with expectations given relatively stable demand and the changes in Ontario's underlying supply mix. On September 27, 2016, the Minister of Energy directed the suspension of the IESO's second round of the Large Renewable Procurement (LRP II) process, citing Ontario's strong supply situation. LRP II had targeted the procurement of up to 600 MW of wind and 250 MW of solar, among other renewable resources. Reducing the amount of future grid-connected baseload capacity should help mitigate additional downward pressure on market prices. However, the Panel notes that according to the Ontario Planning Outlook (OPO), there is an additional 1,050 MW of wind and solar to be installed by 2017 (1,500 MW by 2020).[61] The Panel expects the addition of these low marginal cost resources will further suppress market prices.

[60] On the horizontal axis of Figure 2-5, a square bracket indicates the number beside it is included in the MCP range while a round bracket indicates the number beside it is excluded.

[61] For more information on the Ontario supply outlook, see Module 4 of the Ontario Planning Outlook, available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/module-4-supply-outlook-20160901-pdf.pdf?la=en

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

1 *Introduction*

In this chapter, the Panel presents its analysis of two aspects of the IESO-administered markets. The Panel's analysis considers the results and implications of the IESO's Demand Response Auction and examines disbursements made from the IESO's Transmission Rights (TR) Clearing Account.

2 *Panel Investigations*

The Panel may conduct an investigation into the conduct of market participants, including in relation to inappropriate or anomalous market conduct, when it considers such an investigation is warranted. The Panel currently has one gaming investigation under way in relation to a generator.

3 *New Matters*

3.1 *Improving the Allocation of Disbursements from the Transmission Rights Clearing Account*

Exporters have disproportionately benefited from disbursements from the TR Clearing Account, to the detriment of Ontario transmission customers. This disproportionate benefit is the result of the allocation methodology currently used to disburse funds from the account, and has resulted in $51 million being paid to exporters that the Panel believes ought to have been paid to Ontario transmission customers. Given the ongoing and material nature of the issue, future transfers will be significant if the current disbursement allocation methodology continues.

In support of an alternate disbursement allocation methodology, the sections that follow provide an overview of Ontario's intertie pricing system, the TR market and the IESO's administration of the TR Clearing Account. The sections conclude with a recommendation to the IESO to revise the disbursement methodology to what the Panel considers to be a fairer allocation.

3.1.1 Overview of the Transmission Rights Market and Clearing Account

Intertie Congestion and Congestion Pricing

Ontario's wholesale electricity market employs a uniform price design in which Ontario consumers and producers buy and sell electricity at the same price province-wide: this price is known as the Market Clearing Price (MCP). The uniform price design does not apply to the interties that connect Ontario to its neighbouring jurisdictions; exporters and importers pay, or are paid, the relevant Intertie Zonal Price (IZP). The IZP differs from the MCP when there is congestion on the intertie. When there is no congestion the IZP is equal to the MCP.

Transmission lines can only accommodate a certain amount of electricity flow at a given time; this limit is referred to as the scheduling limit. Congestion occurs when the quantity of electricity scheduled to flow over the transmission line exceeds the scheduling limit.

When intertie traders collectively offer to buy or sell a net quantity[62] of economic imports or exports that exceeds the scheduling limit of the intertie, the intertie becomes congested. Under such circumstances there are more economic transactions on offer than there is transmission capacity, and the IESO must determine which transactions are scheduled and which are not: this is done through economic selection.

The IESO's dispatch algorithm schedules transactions based on their economic merit: from low-cost to high-cost for importers, and from high-price to low-price for exporters.[63] Transactions are scheduled in this manner until the intertie's scheduling limit is reached, or until there are no further economic transactions. In doing so the algorithm looks to maximize the gains from trade.

If intertie traders, on a net basis, offer to sell imported electricity to Ontario at a cost below the MCP and in excess of the intertie's scheduling limit, the intertie becomes import congested. Under such circumstances there is an oversupply of electricity at the intertie: this abundance is reflected in an IZP that is less than the MCP.

Import Congestion = Intertie Zonal Price < Market Clearing Price

If intertie traders, on a net basis, bid to buy and export electricity from Ontario at a price above the MCP and in excess of the intertie's scheduling limit, the intertie becomes export congested. Under such circumstances there is excess demand for electricity at the intertie: this scarcity is reflected in an IZP that is greater than the MCP.

Export Congestion = Intertie Zonal Price > Market Clearing Price

[62] Interties are scheduled on a net basis, meaning gross import transactions can exceed the scheduling limit if there are offsetting exports scheduled in the opposite direction, and vice versa. Net imports (or net exports) cannot exceed the scheduling limit.
[63] For example, an importer willing to sell electricity to Ontario at $20/MWh is scheduled ahead of an importer willing to sell at $30/MWh. Conversely, an exporter willing to buy electricity from Ontario at $50/MWh is scheduled ahead of an exporter willing to pay $40/MWh.

Congestion Rents

Importers are paid the IZP and exporters pay the IZP, which as discussed above, is higher or lower than the MCP when there is intertie congestion. This produces a situation in which either side of the same transaction is settled at different prices: the intertie transaction is settled at the IZP, while the corresponding domestic transaction is settled at the MCP. For instance, an exporter from Ontario pays the IZP, while the Ontario generator that supplies that export is paid the MCP. Likewise, an import into Ontario is paid the IZP, while the corresponding Ontario consumer pays the MCP. The difference in the money collected from the buyer and paid to the seller is referred to as congestion rent. Total congestion rent at a given intertie for a given hour is equal to the difference in prices multiplied by the net electricity flow in that direction.

Import Congestion Rent = (MCP – IZP) * Net Import Schedule

Export Congestion Rent = (IZP – MCP) * Net Export Schedule

Congestion rent reflects the value of scarce transmission capacity. The more valuable access to a transmission path is to those who wish to utilize it, the higher the congestion rent collected. Given intertie traders are willing to pay for scarce transmission capacity in the form of congestion rent, it follows that the owner of transmission capacity would benefit from making that transmission capacity available.

There are five companies which own and operate transmission lines in Ontario. Each of those five companies is subject to rate regulation by the Ontario Energy Board (OEB) which approves the rates they charge to their transmission customers. The regulated rates are derived from the revenue requirements of the companies, which is the revenue level at which they recover their costs including a return on equity.[64] Any congestion rent collected by the IESO and paid to transmission owners would go to offset the revenue requirement of those companies, thus reducing the regulated rates charged to their transmission customers. It follows that, in Ontario, transmission customers benefit from congestion rent.

[64] For a brief overview of the OEB's role in energy sector regulation and rate setting, see its Backgrounder on Energy Sector Regulation, at available at: http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Energy_Sector_Regulation-Overview.pdf

Transmission Rights

As explained above, the price intertie traders are settled at (the IZP) differs from the uniform Ontario price (the MCP) when there is intertie congestion. Intertie congestion can be difficult to predict and can significantly impact the profitability of an intertie transaction; congestion introduces financial risk to intertie traders. In order to provide the opportunity to hedge against that risk, the IESO operates a TR market.

TRs provide a financial hedge against price differences between the IZP and the MCP. The IESO offers an array of different TRs at monthly and quarterly auctions. The IESO auctions TRs by the megawatt, with each TR being specific to an intertie, a trade direction (import or export) and a length of time (1-month or 1-year). For example, a prospective exporter looking to hedge against congestion risk may purchase a TR for the New York intertie, in the export direction, that is valid for April 2017.

The owner of a one megawatt TR is entitled to a payment equal to the difference between the IZP and MCP every time there is congestion on the relevant intertie, in the relevant direction, and during the relevant time period:

> When import congested, the Import TR Payment = (MCP – IZP) * Import TRs owned
> When export congested, the Export TR Payment = (IZP – MCP) * Export TRs owned

Extending the New York export TR example from above, the owner of 100 MWs of the aforementioned TRs would receive a TR payment of $1,500 under the following conditions:

> MCP = $30/MWh
> IZP = $45/MWh
> Export TRs Owned = 100 MW
> TR Payment = (IZP – MCP) * Export TRs Owned
> TR Payment = ($45 – $30) * 100
> TR Payment = $1,500

The exporter, who pays $4,500 to purchase 100 MW at the $45/MWh IZP, receives a $1,500 TR payment. The TR payment makes the net cost of the export $3,000; equivalent to having purchased 100 MW at the $30/MWh MCP. Effectively, an intertie trader that hedges their transaction with TRs ensures that they can purchase power at the MCP, as opposed to the IZP, regardless of whether or not there is congestion.

TR payments are designed as a full hedge against congestion rents; accordingly, TR payments and congestion rents collected should be approximately equal. By purchasing a TR, the owner has essentially purchased the right to the congestion rents on that intertie.

Transmission Rights Auction Revenues

By selling TRs the IESO transfers the benefit of congestion rents from transmission customers to the purchasers of TRs. In return for relinquishing that benefit, transmission customers receive the proceeds generated from the sale of TRs; these proceeds are known as “auction revenues”. If transmission customers did not receive TR auction revenues then, in the Panel’s view, they would be made worse off by the IESO’s sale of TRs.

Transmission Rights Clearing Account

The IESO administers Ontario’s TR market and manages the flows of money through the TR Clearing Account. There are five flows of money into or out of the account, three credits and two debits:

Credits

- Congestion Rents
- Auction Revenues
- Interest accrued on funds in the account

Debits

- TR Payments
- Disbursements

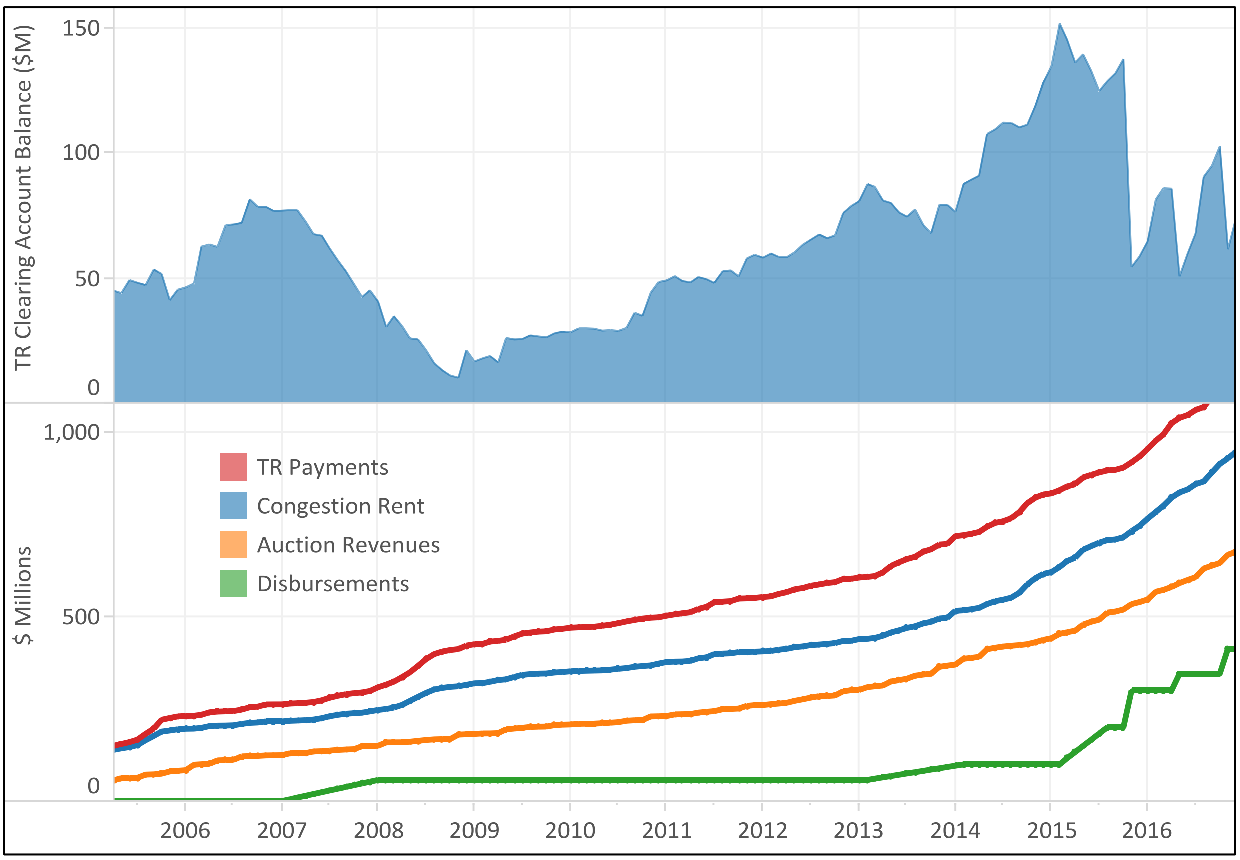
As discussed in the Transmission Rights section above, congestion rents and TR payments should be approximately equal, and thus offset one another in terms of the balance of the TR Clearing Account. The account’s remaining credits, auction revenues and any accrued interest, are remitted to transmission customers through the disbursement debit transaction. It follows that, over time one would expect:

1) TR payments and congestion rents would be approximately equal, and

2) Auction revenues (plus interest) and disbursements would be approximately equal.

Figure 4-1 below shows the cumulative total of each of the TR Clearing Account's line items (excluding interest) since market opening, as well as the balance of the TR Clearing Account over time.

Figure 4-1: Transmission Rights Clearing Account Balance
May 2005 – December 2016
($ millions)



At the end of 2016, the TR Clearing Account had a balance of $74 million. For reasons discussed in the following section, neither of the aforementioned equalities materialized over time: TR payments have exceeded congestion rents, and auction revenues have exceeded disbursements, both by significant margins.[65]

Disbursements from the Transmission Rights Clearing Account

The IESO Board of Directors (the "IESO Board") authorizes disbursements from the TR Clearing Account.[66] From market opening in May 2002, to the beginning of 2013, the IESO authorized one disbursement totalling $57 million; yet, had collected $302 million in auction revenues. Of the $245 million in undisbursed auction revenues, $85 million was in the TR Clearing Account at that time. The remaining $160 million had been paid to TR owners in order to fund TR payments in excess of congestion rents (see Figure 3-1). These excess TR payments represent money that could have been disbursed to transmission customers, but that was instead diverted to TR owners.

This considerable transfer from transmission customers to TR owners was primarily the result of an IESO Board decision in 2003. The decision permitted the IESO to intentionally over-sell TRs so that TR payments would exceed congestion rents collected, thus depleting the TR Clearing Account of auction revenues and paying them to TR owners.[67] In doing so, the IESO believed it was providing liquidity to the TR market and encouraging trade.

In its January 2013 Monitoring Report, the Panel examined the impacts of the IESO Board's decision and recommended a policy change. The Panel's proposed change would balance TR payments and congestion rents collected; stopping the transfer of funds to TR owners and allowing for all auction revenues to be disbursed to transmission customers.[68] The IESO adopted the Panel's recommendation and changed its policy; it is now in the process of implementing those changes.

[65] Further to the aforementioned equalities, one would expect that each of TR payments, congestion rents, auction revenues and disbursements would be approximately equal over time. Prospective TR owners should be willing to pay (in the form of auction revenues) the expected value of congestion rents for TRs; TR payments are intended to be a full hedge against congestion rents and should thus be equal to congestion rents; all auction revenues would be disbursed to transmission customers.
[66] See Chapter 8, Section 4.18.2 of the IESO's Market Rules, available at:
http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx
[67] For more information see the IESO's MR-00242 Market Rule Amendment Proposal, available at:
http://www.theimo.com/Documents/Amend/mr/mr_00242_Q00.pdf
[68] For more information see pages 146-161 of the Panel's January 2013 Monitoring Report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

In addition to the aforementioned policy change, the Panel recommended that the IESO disburse the funds in the TR Clearing Account at that time, as well as formalize a process for disbursing funds once annually.[69] In response to these recommendations the IESO disbursed $42 million to transmission customers in 2013, and formalized a process to review the balance in the account on a semi-annual basis to determine whether a disbursement should be made.[70] Since the Panel's 2013 recommendations, the IESO has disbursed $355 million from the TR Clearing Account to transmission customers.

3.1.2 Allocating Disbursements to Transmission Customers

Through a series of rules and definitions, the Market Rules dictate the methodology for disbursing funds from the TR Clearing Account.

> *Subject to section 4.18.3 [which establishes the TR Clearing Account reserve threshold], the IESO Board may, at such times as it determines appropriate, authorize the debit of funds from the TR clearing account for the purpose of using those funds to offset the transmission services charges referred to in section 3.6.3 of Chapter 9 [which references the disbursement formula].*[71] (emphasis added)

All consumers, both domestic and exporters, pay some form of transmission service charge, thus entitling them to disbursements under the Panel's reading of the above Market Rule.[72] While the rule establishes to whom and why disbursements are to be paid, it does not establish how much each transmission customer ought to receive.

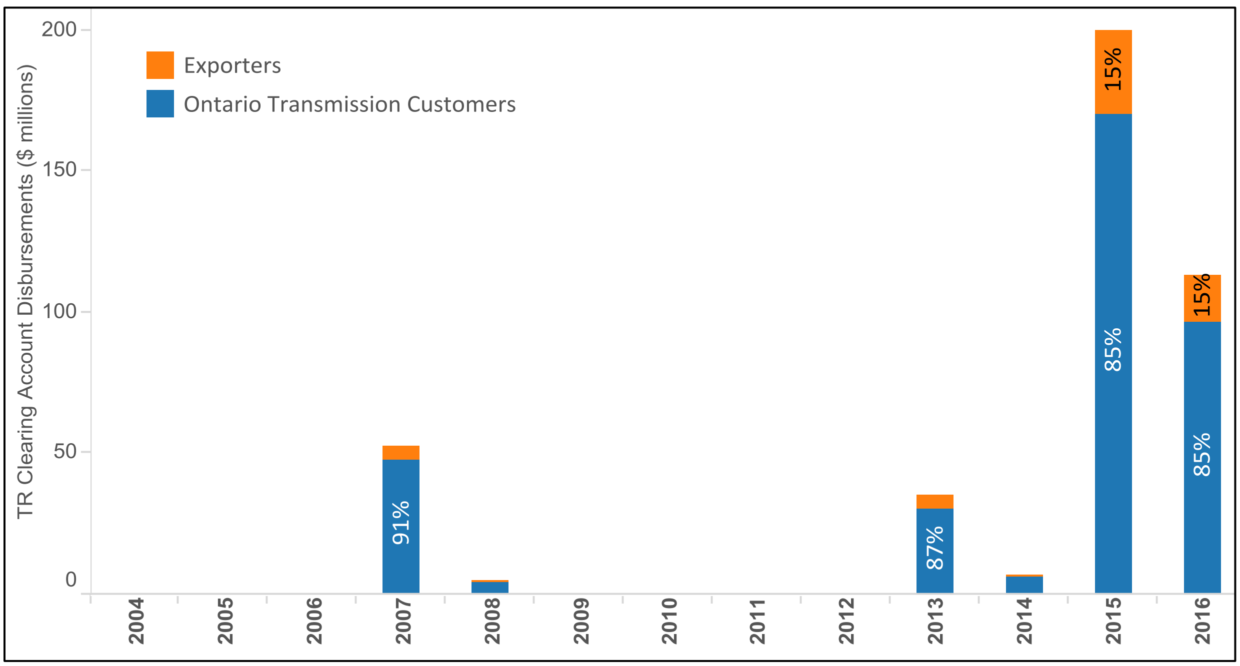
The formula for determining each transmission customer's share of disbursements from the TR Clearing Account is found in Chapter 9, Section 4.7 of the Market Rules. This formula dictates

[69] *Ibid.*
[70] For more information see the IESO's MR-00421 Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr2015/MR_00421_TRCA_Amendment_Proposal%20v5_0.pdf
[71] See Chapter 8, Section 4.18.2 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/586603f319a04df9a08fcea9f8705b32.ashx
[72] See the definition for "Transmission Service Charges" and "Transmission Services" in Chapter 10 of the IESO's Market Rules, available at: available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/4278d372760e4e719f78019aa2953c6e.ashx

that disbursements are proportionally allocated to consumers based on their share of total demand over the previous six months.[73]

Since market opening, the IESO Board has approved, and the IESO has made, six disbursements from the TR Clearing Account, totalling $412 million. These disbursements were allocated amongst Ontario transmission customers and exporters based on their proportion of demand over the month prior to disbursement, or six months in the case of the three most recent disbursements. Figure 4-2 displays disbursements to Ontario transmission customers and exporters by year from 2004 to 2016.

Figure 4-2: Disbursements from the TR Clearing Account
2004 – 2016
($ millions)



From 2004 to 2016, Ontario transmission customers received $354 million in disbursements from the TR Clearing Account (86% of total disbursements), while exporters received $58 million (14%).

[73] See Chapter 9, Section 4.7 of the IESO's Market Rules, available at: http://www.ieso.ca/Sector%20Participants/Market%20Operations/-/media/bfddf5699fdd4cce9fde8822336e747b.ashx.Earlier disbursements were allocated based on shares of total demand during the month prior to disbursement.

The decision to allocate disbursements based on shares of demand appears to date back to a Technical Panel decision in July of 2000. At that time, the Technical Panel was presented with a number of options for disbursing funds from the TR Clearing Account, including: disbursing funds to Ontario consumers only, exporters only, or both based on shares of demand. The Technical Panel ultimately endorsed disbursing funds based on shares of demand; this methodology was adopted for market opening and continues today. Unfortunately, the Technical Panel's rationale for selecting this option is not well-documented.

When the Panel assesses elements of market design, market rules or procedures, it considers the impacts of different options across various measures and principles. As dictated by its mandate, the Panel's primary considerations involve the impact on the efficient and fair operation of competitive markets.[74] While the Panel is not mandated to monitor or report on the reliability of the grid, it also considers potential reliability impacts when making its assessments.

In the Panel's assessment, there are no efficiency or reliability impacts associated with choosing one reasonable allocation methodology over another. In order for such impacts to occur, the real-time consumption decisions of market participants must be meaningfully influenced by disbursement considerations. For instance, under the current design an exporter could conceivably increase its trade activity in order to increase its share of disbursements. That said, any meaningful link between real-time consumption decisions and disbursement considerations is unlikely. Not only are future disbursements distant and unknown, but any additional disbursement revenue associated with increasing demand would most likely be far outweighed by the additional costs of the increased consumption. In other words, real-time incentives remain the driver of real-time behaviour, not disbursements.

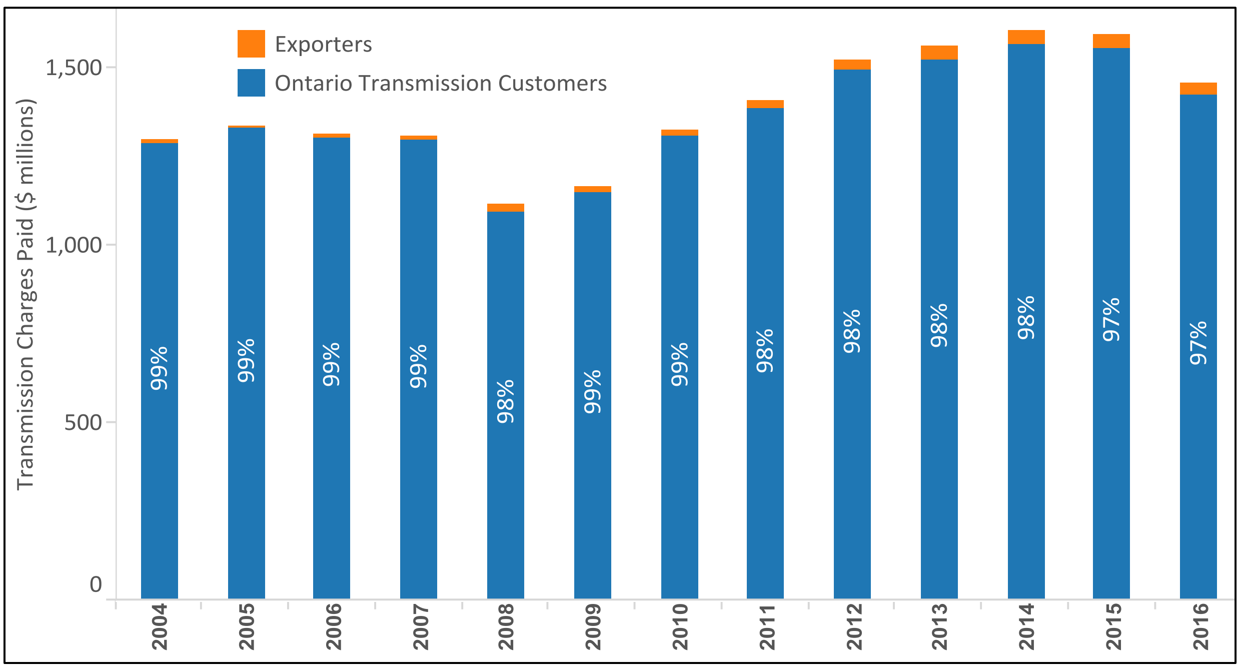
With no impact on efficiency or reliability, the Panel looked to its other mandated principle, namely fairness, to assess disbursement options. As stated in Chapter 8, Section 4.18.2 of the Market Rules, the purpose of disbursements from the TR Clearing Account is to offset transmission service charges; the disbursement is a rebate on costs paid. Accordingly, the Panel believes that a fair allocation would have each customer receive a rebate proportionate to its

[74] See the Ontario Energy Board's Bylaw #3, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf

share of costs paid. For instance, a transmission customer that paid 1% of the total transmission service charges over the accrual period would receive 1% of the disbursements at the end of that period. Unfortunately, the current allocation methodology has not resulted in what the Panel considers to be a fair allocation of disbursements.

Figure 4-3 displays the transmission service charges paid by Ontario transmission customers and exporters by year from 2004 to 2016.

Figure 4-3: Transmission Charges Paid
2004 – 2016
($ millions)



From 2004 to 2016, Ontario transmission customers paid $17.7 billion in transmission charges (98.3% of total charges), while exporters paid $304 million (1.7%). Despite paying 98.3% of total transmission charges, Ontario transmission customers received only 86% of disbursements from the TR Clearing Account (see Figure 3-3); exporters received 14% of disbursements despite paying only 1.7% of total transmission charges.

The misalignment stems from the fact that disbursements are allocated based on shares of demand, not shares of transmission service charges paid. The transmission charge associated with a megawatt-hour of Ontario demand is significantly higher than the transmission charge associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand; such a methodology does not result in what the Panel considers to be a fair allocation.[75]

Had disbursements been allocated in line with the Panel's view on fairness, Ontario transmission customers would have received disbursements totalling $405 million while exporters would have received $7 million. Under such an allocation, Ontario transmission customers would have received an additional $51 million in disbursements that was actually paid to exporters.

Given the IESO's revised TR Clearing Account policies aimed at balancing congestion rents and TR payments, the Panel expects all future auction revenues to be disbursed to transmission customers. Since 2010, auction revenues have increased each year, eclipsing $100 million per year in 2015 and 2016. Left unremedied, the disbursement allocation methodology will continue to be a significant issue going forward.

Recommendation 4-1:

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

3.2 *Assessment of the IESO's Demand Response Auction*

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods.[76] Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

[75] The transmission charges applicable to Ontario transmission customers are broken down into three separate OEB approved rates: Network Service Charge, Line Connection Service Charge and Transformation Connection Service Charge. Together these rates currently total $8.97/MWh. Exporters are subject to the Export Transmission Service (ETS) charge, which is currently set at $1.85/MWh. Both the rates charged to Ontario transmission customers and exporters are set annually and have varied over time, though the rates applicable to Ontario transmission customers have always been higher than the ETS charge.

[76] The Ministry of Energy's *Conservation First: A Renewed Vision for Energy Conservation in Ontario* report states that, "Ontario's vision is to invest in conservation first, before new generation, where cost-effective." The report is available at: http://www.energy.gov.on.ca/en/files/2013/07/conservation-first-en.pdf

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none.

The DR auction occurs once annually and procures DR resources for a period of one year. As part of the auction process eligible resources submit the quantity of DR capacity they are willing to provide, and the price at which they are willing to provide it; the IESO uses those offers to build a supply curve. The DR auction clearing price is set where the supply curve intersects the administratively determined demand curve; all resources selected in the DR auction receive the clearing price.[77] To be paid, resources procured through the DR auction must be made available to reduce consumption during specified periods, and must actually reduce consumption when certain activation criteria are met. For this service, resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers through an uplift charge.[78]

Two types of resources are permitted to participate in the DR auction: dispatchable loads and hourly demand response (HDR) resources. Dispatchable loads already participate in the energy market, changing their consumption in response to five-minute price signals; participating in the DR auction should not materially change the behaviour of these resources. For that reason, the following sections focus on HDR resources, unless otherwise stated. HDR resources are not willing or able to respond to five-minute price signals, and would not participate in the energy market absent some incentive, such as the payments received through the DR auction. To date, approximately 72% of all DR procured through the DR auction has been from HDR resources.

[77] Given the differences in supply and demand in different areas of the province, the IESO limits the amount of DR procured in each zone. If the limit is reached in a given zone, the clearing price in that zone may differ from the others.

[78] While auction payments are technically recovered from Ontario consumers via uplift, the uplift is allocated in the exact same manner as the Global Adjustment. In other words, a consumer's share of this uplift is based on whether they are Class A or Class B customers: Class A customers are charged based on their share of consumption during the five coincident peak demand hours during a year, Class B customers based on their volumetric consumption on all days. Exporters do not pay this uplift.

The IESO has stated that the DR auction is part of a suite of programs and incentives that will help meet the Ministry of Energy's conservation related policy goals.[79] However, for the reasons explained in this section, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

3.2.1 Meeting the Ministry of Energy's Policy Goal

Having said that, it is worth noting that the IESO views the DR auction as an initial step towards the evolution of capacity procurement in the province; one in which all generating and DR capacity is procured through an integrated auction.[80] The Panel supports this longer-term objective.

In 2013, the Ministry of Energy issued its most recent conservation related policy goal: use DR to meet 10% of peak demand by 2025 (approximately 2,400 MW under then forecasted conditions).[81] The IESO views the DR auction as a means of achieving the Ministry's policy goal:

> *Creating a DR auction will support the province's objective for DR to meet 10 per cent of Ontario's peak demand by 2025 and encourage new competitive DR resources to help meet that goal for Ontario's electricity system.*[82] – IESO

In order for the IESO's suite of DR programs and incentives to achieve peak demand reductions, DR not only needs to be available during periods of peak demand, but must also be activated during those periods. As such, it is important to understand the difference between the procurement of DR capacity (i.e. DR availability), and achieving peak demand reductions (i.e.

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[79] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

[80] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

[81] For more information on the Ministry of Energy's policy goal see pages 20-27 of the *2013 Long Term Energy Plan* report, available at: http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf

[82] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

DR activations). A program that procures DR capacity, but does not result in DR activations during peak demand, will not help achieve the Ministry of Energy's policy goal.

As currently designed, DR procured through the IESO's DR auction is unlikely to be activated during periods of peak demand. To understand why that is, it is necessary to understand both the availability obligation placed on DR resources and the criteria under which they are activated.

Availability Obligation

DR resources procured through the DR auction are required to participate in the energy market for certain pre-determined commitment periods and availability windows. The availability window applies to business days only: 12 PM to 9 PM from May to October (Summer Commitment Period) and 4 PM to 9 PM from November to April (Winter Commitment Period).

During the availability windows DR resources must enter bids into the energy market at prices between $100/MWh and $2,000/MWh. These bids represent the price at which the resource is willing to be activated for DR. The bids must be entered into the market before the IESO's day-ahead process starts, and remain in the market until the IESO determines the resource will not be activated, or until an activation is completed.

Activation Criteria

In order for a DR resource to be activated during the applicable availability window, it must receive both a standby notice and an activation notice from the IESO.

First, a DR resource will receive a standby notice at or before 7 AM if the pre-dispatch nodal price at its location is above its bid price for four consecutive hours within the availability window. Second, if the resource receives a standby notice, it may next receive an activation notice 2.5 hours prior to activation, so long as the price remains above its bid price for four consecutive hours within the availability window. If a DR resource receives an activation notice it must reduce its consumption for a period of four hours, beginning with the first hour included in the activation notice.

Consider the following example: a DR resource is procured for the Winter Commitment Period; to fulfill its availability obligation it bids $1,999/MWh into the energy market during all hours of the availability window. For simplicity, assume that any activation will start at 4 PM and conclude at 8 PM.[83]

Under these conditions the DR resource will receive a standby notice if, during any of the hours before 7 AM, the pre-dispatch nodal prices for the 4 PM to 8 PM activation period exceed the resource's $1,999/MWh bid. To then receive an activation notice, the same conditions must persist at 1:30 PM, in which case the resource must reduce its consumption for the 4 PM to 8 PM activation period.

Prospect of Being Activated

Given the activation criteria described above, the likelihood of an activation is remote. This is borne out by events since the Current Reporting Period; since the first commitment period started in May 2016, no HDR resource has been activated.

Under the program rules DR resources can bid into the energy market at any price between $100/MWh and $2,000/MWh; the higher the bid price, the lower the likelihood of being activated. Table 4-1 contains the prices used to date by HDR resources when submitting their bids to the energy market.

Table 4-1: HDR Resources' Bids into the Energy Market
May 2016 – December 2016

Observed Bid Prices	HDR Capacity Bid at Observed Price
$1,999/MWh	82%
$500/MWh	18%

Since the start of the first commitment period 82% of all DR capacity has been bid into the energy market at the program's maximum allowable price. While the Panel supports DR resources being able to bid into the energy market at any price, bidding at the maximum allowable price, in conjunction with the current activation criteria, means that HDR resources will not be activated. Indeed, the Panel's analysis indicates that any bid price over $220/MWh would not have been activated during the period.

[83] During the Winter Commitment Period, a DR resource may also have an activation period from 5 PM to 9 PM. During the Summer Commitment Period an activation period may span any four consecutive hours between noon and 9 PM.

Given Ontario's current surplus supply conditions and the prices that persisted over the period, it is not surprising that there were no activations.

That said the province has not always been flush with surplus supply. In 2005 and 2006 all-time demand records were being set in Ontario, and in the winter of 2014 the "polar vortex" weather event increased demand and constrained supply. To get a sense of the likelihood of an activation given the current activation criteria, the Panel applied the same criteria to all hours dating back to the high demand conditions experienced in 2005. Table 4-2 displays the number of HDR activations that would have occurred at various bid prices since 2005.

Table 4-2: Hypothetical HDR Activations by Bid Price
2005 – 2016
(Number of Activations)

Energy Bid Price ($/MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100 - 200	552	152	199	188	1	26	18	16	4	168	66	88
200 - 300	65	16	7	4	-	3	4	-	5	51	-	33
300 - 400	27	9	-	4	-	-	-	-	-	6	-	-
400 - 500	27	9	-	-	-	-	-	-	-	-	-	-
500 - 600	25	3	-	-	-	-	-	-	-	-	-	-
600 - 700	15	1	-	-	-	-	-	-	-	-	-	-
700 - 800	8	1	-	-	-	-	-	-	-	-	-	-
800 - 900	4	-	-	-	-	-	-	-	-	-	-	-
900 - 1,000	1	-	-	-	-	-	-	-	-	-	-	-
1,000+	-	-	-	-	-	-	-	-	-	-	-	-

Since 2005, no bid price above $1,000/MWh would have been activated, yet most HDR resources bid at twice that price. Any bid price over $400/MWh would not have been activated since 2006.[84]

Even under the most aggressive of demand projections, peak demand is not expected to return to record 2005 and 2006 levels until 2029.[85] Ontario is also in a better supply situation than it was during those years, having added thousands of megawatts of capacity to the grid.[86]

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[84] Going forward, new HDR resources may emerge at different locations on the grid; their likelihood of activation may differ.
[85] See the IESO's most recent *Ontario Planning Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[86] See *The Need for Capacity* section below for a summary of Ontario's current supply and demand conditions.

The Panel is mindful that reducing consumption during periods of peak demand is a means to an end, and should not be a goal unto itself. A DR resource may wish to consume during periods of high demand, but may be incented to abstain in order to alleviate the need to build additional supply. In this way, DR programs incur short-term costs (i.e. curtailing otherwise efficient energy consumption) in order to avoid long-term costs (i.e. reducing the need for additional peak generation capacity). As long as the avoided long-term costs exceed the incurred short-term costs, reducing peak demand can be efficient.

Ontario is currently flush with supply, and will continue to be for the foreseeable future (see *The Need for Capacity* section below). Even with considerable demand growth, there is little need to build new capacity. Consequently, consumption during peak periods results in no additional long-term capacity costs, meaning demand reductions during these periods are unnecessary and likely inefficient. It follows that payments to procure DR, such as those provided by the DR auction, are also unnecessary and inefficient.

3.2.2 Meeting the IESO's Capacity Objective

As mentioned in the previous section, the IESO's DR auction is unlikely to provide energy through DR activations given the current activation criteria.

The notion that the DR auction is procuring capacity only is consistent with the program's availability obligations, as well as the manner in which DR resources are compensated. Specifically, DR resources are paid to be available for activation, not to be activated; there are no minimum requirements on the number of times a resource must be activated. In furtherance of this idea, the IESO plans to integrate the DR auction and its participants into the broader capacity auction currently being developed through the IESO's Market Renewal initiative.[87] In the sections that follow, the Panel assesses the appropriateness of the DR auction as a means to procure capacity.

[87] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

Availability Obligation and Activation Criteria

Unlike meeting the Ministry of Energy's policy goal of using DR to reduce peak demand, procuring capacity does not necessarily come with the expectation that it will be utilised regularly or predictably. The IESO must procure enough capacity to ensure that Ontario's electricity needs are met, plus some additional capacity to ensure reliability. On that basis, one would expect there to be a portion of capacity that is rarely if ever used. Specifically, capacity resources with high bids in the energy market, such as those procured to date through the DR auction, are the last to be activated and are likely only needed on rare occasions. For DR capacity to be of use, the activation criteria needs to result in consumption reductions on those infrequent occasions when those resources are needed.

As noted earlier, HDR resources bidding at the maximum allowable energy market price (82% of all HDR resources to date) would not have been activated from 2005 onwards; resources bid above $400/MWh would not have been activated since 2006. There have been occasions since 2005, including during the very tight supply conditions experienced during the winter of 2014, when DR activations could have been beneficial.[88] To that end, the Panel encourages the IESO to assess whether changes to the current availability obligations and activation criteria should be made in order to facilitate activations when needed.

Technology-Specific Procurement

In terms of satisfying the need for capacity, capacity from DR is no different than capacity from other resources, such as gas-fired generators. Given the substitutability of capacity from different technologies, the procurement process should be technology neutral, not favouring one technology over another. Technological neutrality allows the procurement mechanism to select the lowest cost capacity, no matter the resource type. In order for the procurement mechanism to be technologically neutral it must permit all resources to compete against one another to supply capacity, and place identical obligations on all resources procured. The need for technology-neutral procurement was recently supported by the Minister of Energy, Glenn Thibeault:

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[88] The Panel finds it instructive that, over the same period, there were numerous other DR programs with differing activation criteria that resulted in activations, including activations under the program the DR auction is effectively replacing.

> *Upon taking this office, I was interested to learn that our previous procurements were essentially segmented into "technology-specific" allotments. In this day and age, with the level of innovation, pace of technological change – as well as the clear benefit to ratepayers from competitively procured resources; it is essential that we begin moving towards more "technology-agnostic" procurements.*
>
> *Too often we have sought to impose strict requirements on the system operator. Rather, as we seek to undertake future procurements – we should be focused on outcomes, rather than contracting with specific technologies. Moving to become technology-agnostic will provide new opportunities for innovation and modernization. We must unleash the electricity sector and our system operator to find the appropriate mix to fulfil a capacity auction would ensure that ratepayers receive the best prices possible.*[89]

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> *Allocating the precise mix of technology types has largely been arbitrary and led to suboptimal siting, uncompetitive prices and heightened community concerns.*[90]

The DR policy goal set by the Ministry of Energy in 2013 is technology specific, as was the IESO's corresponding procurement. Currently, DR is the only capacity procured through an auction process. By limiting competitive procurement to one resource type, the IESO is limiting its ability to procure capacity at least cost. Fortunately, the IESO is considering the introduction of a technology-neutral capacity market, allowing for DR resources to compete against other technologies to provide capacity at least cost in the future.

The Need for Capacity

The quantity of DR capacity procured through the DR auction is determined by the intersection of the participant-offered supply curve and the IESO determined demand curve. The demand curve sets the bounds for how much DR capacity will be procured at different prices, including the maximum quantity at the auction's lowest price, and the minimum quantity at its highest price.

[89] Speech delivered by Glenn Thibeault (Minister of Energy) to the Empire Club of Canada on November 28, 2016.
[90] Comments made by Glenn Thibeault following his speech to the Economic Club of Canada on February 24, 2017, as reported in the Globe and Mail's article: *Ontario Liberals Eye Electricity Market Overhaul to Lower Rates*, available at: http://www.theglobeandmail.com/news/ontario-liberals-eye-electricity-market-overhaul-to-lower-rates/article34128778/

The IESO sets the position of the demand curve (i.e. how much DR will be bought at different prices) by setting a target quantity and price for procuring DR capacity. Recall that prior to the auction, DR was procured through bilateral contracting; those legacy contracts expire at different times, the last of these expires in 2018.[91] For the first DR auction, the IESO set the target quantity equal to the capacity that was expiring under those legacy contracts.[92] The IESO set the target price equal to the agreed upon price in those expiring contracts. In effect, the quantity of DR procured for 2016, and the price at which it was procured, was largely determined by market conditions that prevailed when those legacy contracts were signed (upwards of five years prior in some cases).[93] The IESO plans to increase DR capacity targets in future auctions by 7% per year, with additional increases as more legacy DR contracts expire.[94] In the Panel's view, the procurement of capacity for future periods should not be based on administratively determined growth rates or the volume of contract expirations, but rather on a reasonable expectation of capacity needs during the commitment period.

Regardless of the procurement mechanism, the decision on how much capacity to procure, if any, should be directly tied to the need for capacity. The IESO recently assessed the long-term need for capacity in Ontario, noting the province's strong capacity position in its *Ontario Power Outlook* report, "Ontario will have sufficient resources to meet demand requirements generally over the next decade across all [demand] outlooks".[95] This assessment is consistent with the IESO's most recent *18-month Outlook*.[96] Indeed, even without the expected capacity contributions of resources procured through the DR auction,[97] Ontario has sufficient capacity to

[91] See slide 4 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

[92] See page 3 of the IESO's approved Market Rule Amendment Proposal (MR-00416-R01), available at: http://ieso.ca/Documents/Amend/mr2015/MR_00416_R01_Amendment_Proposal%20v5.0.pdf

[93] See slide 10 of the Ontario Power Authority's April 2014 presentation: *Demand Response Programs in Ontario*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/drwg-20140403-DRWG-OPA-Presentation.pdf

[94] See slide 3 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

[95] See page 11 of the IESO's *Ontario Power Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf

[96] See page ii of the IESO's *18-Month Outlook,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2016sep.pdf

[97] The IESO's target procurement capacity for the DR auction is 648 MW in 2018, growing to 1,246 MW in 2025. For more information see the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at:

meet its needs for many years. Based on the IESO's most aggressive demand outlook (plus a reserve margin), and without any contribution from the DR auction, Ontario has sufficient capacity to meet its capacity needs until 2021. Under the most conservative demand outlook, Ontario has sufficient capacity until 2025.

Accordingly, the IESO is procuring capacity through the DR auction at a time when capacity is not needed. This procurement comes at a significant cost: resources procured through the 2016 and 2017 DR auctions will be paid upwards of $73 million in total. Under the most aggressive of assumptions, additional capacity is not needed until 2021. Fortuitously, the technology-neutral capacity auction in development is expected to have its first capacity auction in 2020 to procure capacity for future years.[98] Not only is the technology-neutral capacity auction a more cost effective way to procure capacity, but the timing of its implementation aligns far better with Ontario's capacity needs. [99]

In this regard it is noteworthy that various other capacity procurement projects have been cancelled or scaled back in recent years, including round two of the Large Renewal Procurement process,[100] and rounds five and six of the Feed-In Tariff program.[101]

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

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http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

[98] See slide 44 of the Brattle Group's December 2016 presentation: *IESO Market Renewal Benefits Case: Preliminary Benefits Case Findings*, available at: http://ieso.ca/-/media/files/ieso/document-library/engage/me/me-20161219-preliminary-benefits.pdf?la=en

[99] As part of its reasoning for implementing the DR auction, the IESO stated the auction will, "Provide a stable transition [from bilateral DR contracts] that offers a learning opportunity for DR providers to be able to successfully compete in a full capacity auction." While that may be true, that learning opportunity comes at a cost that will well exceed $100 million, all the while providing little benefit. For more information on the IESO's justification for the DR auction, see its Market Rule Amendment Submission (MR-416-Q00), available at: http://www.ieso.ca/Documents/Amend/mr2015/MR-00416-Q00.pdf

[100] See the Minister of Energy's Letter to the IESO, dated September 27, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-lrpii-efwsop-20160927.pdf?la=en

[101] See the Minister of Energy's Letter to the IESO, dated December 16, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-nug-20161216.pdf?la=en