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

Market Surveillance Panel Report 37

MONITORING REPORT ON THE IESO-ADMINISTERED ELECTRICITY MARKETS

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board (OEB). 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:

1. inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
2. activities of the IESO that may have an impact on market efficiencies or effective competition;
3. actual or potential design or other flaws and inefficiencies in the Market Rules and procedures; and
4. 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. The Panel does not have the legislative mandate to impose sanctions or other remedies in response to inappropriate conduct or market defects, but it does make recommendations for remedial action as it considers appropriate.

Executive Summary

This is the 37th Market Surveillance Panel Monitoring Report published since market opening in 2002. The report notes recent electricity sector events (Chapter 1) and events in the monitoring period May 1, 2021 to October 31, 2021 – referred to as the Summer 2021 Period (Chapter 2 and Appendix A), and provides an analysis of anomalous events in the Northwest (Chapter 3).

This Monitoring Report is broken down into three chapters and two appendices:

- Chapter 1: Market Developments
- Chapter 2: Analysis of Anomalous Market Outcomes
- Chapter 3: Matters to Report in the Ontario Electricity Marketplace
- Appendix A: Market Outcomes for the Summer 2021 Period
- Appendix B: MSP Submission on Reconsideration of Dispatchable Load Exemptions

Chapter 1: Market Developments

Six recent market developments are considered noteworthy: the Market Assessment and Compliance Division investigation into the IESO's actions to adjust Northwest intertie limits due to IESO-identified reliability concerns; amendment to the Market Rules to improve accessibility of operating reserve; the IESO's reconsideration of exemptions for four electric arc furnace dispatchable load resources in the energy and operating reserve markets; a registry for clean energy credits; the suspension of the Lake Erie connector project; and updates on the IESO's resource adequacy and acquisition framework.

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter deals with events in the Summer 2021 Period that exceed predefined thresholds established to identify outcomes considered anomalous and are therefore potentially significant for the IESO-administered markets. Of particular note is the $1,150 Hourly Ontario Energy Price in hour ending 12 on October 10, 2021. A contributing factor to the high hourly price was the IESO's derating of control action operating reserve in real-time.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

This chapter provides an in-depth review of actions taken by the IESO to address the issues of high congestion management settlement credit payments on the Manitoba and Minnesota interties between the Winter 2020-21 Period and the Summer 2021 Period. This chapter also contains the Panel's observations and opinions on related issues with Ontario's two-schedule system.

In summary, the Panel believes that the IESO should have a process in place for ex-ante (best efforts given the relative urgency of the situation) and ex-post analysis of IESO actions to determine that an action to manage reliability is indeed required and that the action has been analyzed across all possible actions and deemed to be the least cost means to address the reliability concern. Also, there should be IESO stakeholder engagement to review both processes to promote transparency and foster improvements.

Chapter 1: Market Developments

1.1 Developments Related to the IESO-Administered Markets

This chapter contains an update on recent developments related to the IESO-administered markets since Monitoring Report 36.

1.1.1 Northwest Intertie Flow Limits

In Monitoring Report 36 the Panel noted recent decisions by the IESO to limit exports in the Northwest due to IESO-identified reliability concerns. The IESO adjusted the intertie limits used in both the dispatch and market schedules. The IESO then proposed market rule amendments that would align market rules to their actions. The IESO describes these amendments as adding clarifying language to the Market Rules specifying when internal transmission constraints will be considered by the IESO in setting intertie limits. In November 2021, the IESO commenced a stakeholder engagement on the topic. At the February 15, 2022 Technical Panel meeting, members voted to post the amended rules, however no stakeholder feedback was received.[1] The Technical Panel subsequently recommended the rule amendments proceed to the IESO Board of Directors and in their August 2022 meeting the Board approved the rule amendments.[2]

The IESO's Market Assessment and Compliance Division (MACD) was concurrently investigating the actions of the IESO. It was determined by MACD that the IESO actions were not authorized under the then-current Market Rules and the IESO was issued a letter of non-compliance and a financial penalty in July 2022.[3]

[1] IESO, "Minutes of the IESO Technical Panel Meeting, 15/February/2022", page 12, https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2022/iesotp-20220215-minutes.ashx.

[2] IESO, "Resolution of the Board of Directors", August 24, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2022/iesotp-20220822-mr-00468-draft-board-resolution.ashx

[3] IESO, "Compliance Enforcement: Sanctions", https://www.ieso.ca/en/Sector-Participants/Market-Oversight/Compliance-Enforcement/Sanctions.

1.1.2 Improving Accessibility of Operating Reserve

In June 2022, the Technical Panel passed a motion to recommend a proposed amendment (MR-00467-R00) to the Market Rules that would add a settlement charge to help efficiently claw back operating reserve (OR) payments when participants fail to maintain adequate unused generation (or load reduction) capacity during intervals where they are scheduled for OR.[4] The IESO initiated this amendment in response to the Panel's Recommendation 3-1 in Monitoring Report 28, which called for dispatchable loads to be compensated only for the amount of operating reserve they were capable of providing in real time.[5] However, the IESO is considering whether the very dispatchable loads that are of primary concern with respect to the Panel's Recommendation 3-1 will be exempt from the new settlement charge (see section 1.1.3 below). The Panel views this proposal as running counter to the its original recommendation. The amendment was adopted by the IESO Board on March 8, 2023 with an effective date concurrent with the implementation of the Replacement of the IESO Settlement System Market Rules (MR-00475-R00).[6] The effective date for the implementation of MR-00475-R00, as outlined in the Board's decision, is May 1, 2023.[7] This is also the same effective date for Dofasco and Ivaco's exemption reconsiderations.

[4] IESO, "Minutes of the IESO Technical Panel Meeting", June 14, 2022, page 13, https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2022/iesotp-20220614-minutes.ashx.

[5] Market Surveillance Panel Monitoring Report 28, page 6, https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf.

[6] IESO, "Reasons of the IESO Board in respect of an amendment to the market rules", https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2023/iesotp-20230309-mr-00467-board-reason-form.ashx.

[7] IESO, "Reasons of the IESO Board in respect of an amendment to the market rules", https://ieso.ca/-/media/Files/IESO/Document-Library/tp/2023/iesotp-20230309-mr-00475-board-reason-form.ashx.

1.1.3 Dispatchable Load Exemption Reconsiderations

The IESO reconsidered the exemptions for four electric arc furnace dispatchable load resources in the energy and OR markets. Exemptions were originally granted to these dispatchable loads in the early years of the markets due to the variable operating nature of their electric arc furnaces. The exemption review process began in August 2021 and IESO staff recommendations were posted in June 2022.[8] The IESO indicated these reconsiderations are needed to effectively address the Panel's Recommendation 3-1 in Monitoring Report 28 in a manner that aligns with the unique operating characteristics of an electric arc furnace. The Panel sent a letter to the Markets Committee of the IESO Board of Directors, in its capacity as the Exemption Panel, in July 2022. That letter, reproduced in 3.1.5Appendix B:, was made publicly available. The Panel received letters from one of the dispatchable loads (ArcelorMittal Dofasco) in August 2022 and November 2022, and was copied on a letter sent to the Exemption Panel by another of the dispatchable loads (Gerdau Long Steel North America) in December 2022. These letters expanded on their views regarding the need for the exemptions. The Panel received a letter from the IESO in November 2022, which provided some more background for their recommendations related to the reconsiderations. While the Panel appreciates that these letters were provided to add clarity to the factors that in the IESO's view support the reconsideration of these exemptions, this is precisely the type of information that should have been part of the initial IESO staff assessment in support of their recommendations to the Exemption Panel so that a well informed decision can be made.

The Panel does not believe the IESO adequately responded to the concerns set out in the Panel's July 2022 letter, and remains of the view that the IESO has not provided sufficient rationale for whether the exemptions are required, cost effective or appropriately quantified.

[8] IESO, "Active Exemption Applications", https://www.ieso.ca/en/Sector-Participants/Change-Management/Exemptions/Active-Exemption-Applications.

In March 2023 the Exemption Panel granted the exemption reconsiderations to Ivaco and Dofasco, which will take effect on the same date as the proposed market rule amendments contained within MR-00467-R00 (Improving Accessibility of Operating Reserve) on May 1, 2023[9]. At time of writing, there were no new updates for both of Gerdau's exemption reconsiderations (1304,1305). The Panel will continue to review this matter.

1.1.4 A Registry for Clean Energy Credits

On January 26, 2022, the Ministry of Energy asked the IESO to assess options for the establishment, management, and operation of a voluntary clean energy credit (CEC) registry for trading in Ontario.[10] The registry is intended to support the creation, recognition, trading, and retirement of CECs. The IESO was requested to report back to the Ministry with recommendations, detailed design options, potential benefits, and cost estimates of the project. The IESO report has not been made public as of February 2023. In August 2022, the Ministry published a proposal for the development of a CEC registry.[11] Amendments have now been made to the *Electricity Act, 1998* that will come into force on March 15, 2023 and establish a framework for the recognition of environmental attributes as clean energy credits on a clean energy credit registry that is established or designated by the IESO.[12] The Panel will continue to monitor this item for impacts on the effective operation of the markets.

[9] IESO, "Decision of the Independent Panel – Exemption Reconsideration #1308", https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/1308-Dofasco-Decision-of-the-Exemption-Panel.ashx.

IESO, "Decision of the Independent Panel – Exemption Reconsideration #1164", https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/1164-Ivaco-Decision-of-the-Exemption-Panel.ashx.

[10] Ministry of Energy, MC-994-2022-17, https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20220126.ashx.

[11] Ministry of Energy, "Development of a Clean Energy Credit Registry", https://www.ontariocanada.com/registry/view.do?postingId=42188&language=en

[12] See the new Part II.1 of the *Electricity Act, 1998.*

1.1.5 Lake Erie Connector Project Suspension

On March 31, 2022, the Minister of Energy directed the IESO to negotiate and enter into a procurement contract with Lake Erie LP by August 15, 2022.[13] The contract was slated to procure the construction of the Lake Erie Connector Project, a 1,000 MW bi-directional 320 kV transmission line under Lake Erie, connecting the IESO with PJM wholesale electricity markets. In August 2022 ITC Investments Holdings Inc., the project sponsor, suspended all project development activities and commercial negotiations on the Lake Erie Connector project.[14]

1.1.6 Resource Adequacy and Acquisition

The IESO launched its Resource Adequacy Engagements in September 2020 with their stated goal of using competitive mechanisms to meet short, medium and long term resource and capacity needs. The Capacity Auction serves as the short term balancing mechanism in the framework, securing the capacity needed to meet Ontario's short-term resource adequacy needs[15]. The Medium-Term RFP serves medium term resource needs by acquiring five-year commitments from resources in the province. The Expedited Process (E-LT1 RFP) and Long-Term RFP address emerging system needs driven by the long term concerns of rising Ontario demand and nuclear unit retirements and refurbishments[16].

In 2022, the IESO continued efforts to support Ministry directed procurement including the Medium-Term RFP and Long-Term RFP. Other recent engagements following from ministerial

[13] Minister's Directive, Order in Council 877/2022, https://www.ontario.ca/page/ministers-directive-order-council-8772022.

[14] ITC Investment Holdings Inc., Lake Erie Connector Project Homepage, https://www.itclakeerieconnector.com/

[15] IESO, "Capacity Auction", February 9, 2023, https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Capacity-Auction.

[16] IESO, "Long-Term RFP and Expedited Process", February 9, 2023, https://www.ieso.ca/en/Sector-Participants/Resource-Acquisition-and-Contracts/Long-Term-RFP-and-Expedited-Process.

directives include Capacity Auction enhancements, and the small hydro project, a program to provide new contracts for existing small hydroelectric generation facilities with a capacity of under 10 MW. In April, the IESO released its 2022 Annual Acquisition Report. In September the Ontario government announced plans to extend operations at the Pickering nuclear station.

Monitoring Report 36 summarized updates on the Medium-Term RFP, including the January 2022 directive from the Ministry of Energy to proceed with the first Medium-Term RFP.[17] The winners of the Medium-Term RFP were announced in August 2022.[18]

In October 2022 the Ministry issued a directive instructing the IESO to procure 4,000 MW of additional (new build or expansion) capacity by 2027 through three separate processes; 1,500 MW from the Expedited Process, 300 MW from the Same Technology Upgrades, and 2,200 MW from the Long-Term RFP. Across all three procurement efforts, natural gas is targeted for up to 1,500 MW and storage for about 2,500 MW.[19]

In Fall 2022 the IESO has held engagements to aid in drafting the E-LT1 RFP and Contract. Schedules have been repeatedly pushed back, extending the targeted E-LT1 RFP contract offer date from December 2022 until at least March 31, 2023.[20] The E-LT1 is a contract for capacity and offers financial incentives for resources to achieve commercial operation by as early as May 2025. The E-LT1 Contracts will expire by 2047, a duration of up to 22 years. Gas-fired resources'

[17] Ministry of Energy, January 28 2022 Directive, https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20220128.ashx

[18] IESO, "MT1 RFP Results", https://www.ieso.ca/-/media/Files/IESO/Document-Library/medium-term-rfp/MT-I-RFP-results.ashx

[19] IESO, "Expedited Process Procurement Update: Overview of Updated draft E-LT1 RFP and Contract", October 18, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/long-term-rfp/ltrfp-20221018-presentation.ashx

[20] IESO, "Expedited Process Procurement Update", November 7, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/long-term-rfp/ltrfp-20221107-presentation.ashx

contracts will expire by 2040. Gas facilities which are forced closed due to an inability to comply with the Clean Electricity Standard in 2035 will continue to receive contracted payments.[21] The (non-expedited) Long-Term RFP also aims to award contracts in 2023.

The IESO is considering allowing projects which are not selected in the Expedited Long-Term RFP to bid in the regular Long-Term RFP.[22]

In MSP Report 35 the Panel's recommendation 3-1 called for the development of stronger penalties and other structural solutions to address resource performance failures in the capacity auction[23] and starting in February 2022, Resource Adequancy Engagement sessions took place around design changes for the 2022 Capacity Auction. These changes include dropping Performance Adjustment Factors for the December 2022 Capacity Auction,[24] increasing flexibility around capacity testing procedures, and adding a tenfold increase in the charge for non-performance during system emergency advisories.[25] The IESO suggested that the Technical Panel vote to recommend the proposed market rule amendment MR-00469-R00 to

[21] IESO, "Revised Draft E-LT1 Contract", November 8, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/ieso-E-LT1-20221108-Expedited-Long-Term-Reliability-Services-Contract-Draft.ashx

[22] IESO, "LT1 RFP and Additional Mechanisms Engagement", slide 9-13, https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/long-term-rfp/ltrfp-20220609-presentation.ashx.

[23] Market Surveillance Panel Monitoring Report 35, page 51, published August 2021: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202108.pdf.

[24] Performance Adjustment Factors will return in the 2024 Capacity Auction based on performance during the 2023-2024 period.

[25] IESO, "Guidance Document – Log of Key Updates to the Draft 2022 Capacity Auction Design Document", https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20220224-ca-de-guidance-document.ashx.

the IESO Board of Directors with a proposed effective date of July 20, 2022. The vote was held at the June 14, 2022 Technical Panel meeting and the motion was defeated.[26]

Since the Minister's January 2022 directive, the IESO has held engagements discussing high level design concepts for the Small and Large Hydro Programs. The Small Hydro program will focus on contracting existing facilities with capacities of 10MW and below, and the Large Hydro program will focus on contracting existing facilities over 10MW. Some high-level design goals include incenting resources to be responsive to system needs and providing financial security for planning and investment.[27]

In April, the IESO published its 2022 Annual Acquisition Report (AAR). The second annual report outlines how current planning will meet capacity needs through 2024, but starting in 2025 and 2026 more supply is needed. The IESO intends to meet this need through the Hydro-Québec Capacity Sharing Agreement among other options outlined in the report. The IESO is also initiating the LT RFP for supply needs starting in the late 2020s.[28]

In September, the Ontario government announced plans to keep Pickering "B" units in operation until September 2026, pending approval by Canadian Nuclear Safety Commission. The units were previously scheduled to shut down in 2025. The province has also asked

[26] IESO, "Minutes of the IESO Technical Panel Meeting", June 14, 2022", page 12, https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2022/iesotp-20220614-minutes.ashx; also see IESO, "Memorandum Re: MR-00469-R00 – 2022 Capacity Auction Enhancements", page 3, https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2022/iesotp-20220614-mr-00469-r00-capacity-auction-enhancements-cover-memo.ashx.

[27] IESO, "Hydroelectric Program Development & Assessment IESO Stakeholder Engagement Days", https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20220420-presentation.ashx.

[28] IESO, "2022 Annual Acquisition Report", page 5, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx.

Ontario Power Generation to undertake a study assessing the feasibility of refurbishing the units which could allow the plant to operate for another 30 years.[29]

[29] Government of Ontario, "Ontario Supports Plan to Safely Continue Operating the Pickering Nuclear Generating Station", September 29, 2022, https://news.ontario.ca/en/release/1002338/ontario-supports-plan-to-safely-continue-operating-the-pickering-nuclear-generating-station.

Ontario Power Generation, "A message from Ken Hartwick, OPG's President & CEO about Pickering Nuclear Generating Station", https://www.opg.com/powering-ontario/our-generation/nuclear/pickering-nuclear-generation-station/.

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter provides data and analysis of the 6-month monitoring period from May 1, 2021 to October 31, 2021, referred to as the Summer 2021 Period, making comparisons to previous periods as appropriate.

A primary responsibility of the Panel is to monitor for anomalies in the IESO-administered markets. The Panel has established several thresholds, described below, that identify statistical outliers where additional analysis would be warranted to determine if they are anomalous and whether they require further action.

Anomalous event thresholds are defined for: energy prices, Congestion Management Settlement Credit (CMSC) payments, Operating Reserve (OR) payments and Intertie Offer Guarantee (IOG) payments. The energy price thresholds are the Hourly Ontario Energy Prices (HOEP) greater than $200/MWh, or less than or equal to $0/MWh.[30] The CMSC threshold is defined as days where total CMSC settled exceeds $1 million/day and/or hours where CMSC exceeds $500,000/hour. The OR threshold is any payment that exceeds $100,000/hour.[31] The IOG threshold is any payment that exceeds $1 million/day and/or $500,000/hour. These payments are recovered from Ontario consumers and exporters through uplift charges.

2.1 Summer 2021 Period Overview

Figure 2-1 and Table 2-1 provide context to the energy price thresholds by presenting recent price trends for the median, top 5%, top 0.5%, and the maximum HOEP from the Summer 2019 Period through to Summer 2021 Period.

[30] A new market clearing price (MCP) is set every five minutes. The average of the twelve MCPs set in each hour is called the Hourly Ontario Energy Price (HOEP). Electricity consumers in Ontario pay this price either directly (if they are wholesale market participants) or indirectly through the Regulated Price Plan prices set by the Ontario Energy Board (residential and small business consumers) or market-based pricing charged by their electricity distributor. The small number of consumers that have a contract with an electricity retailer pay the contract price.

[31] An hourly OR payment of $100,000/hour equates to an OR price of ~$70/MWh for the typical amount of 1,418 MW of OR scheduled in an hour.

Figure 2-1: HOEP Thresholds Exceedances by Price, 5 Periods

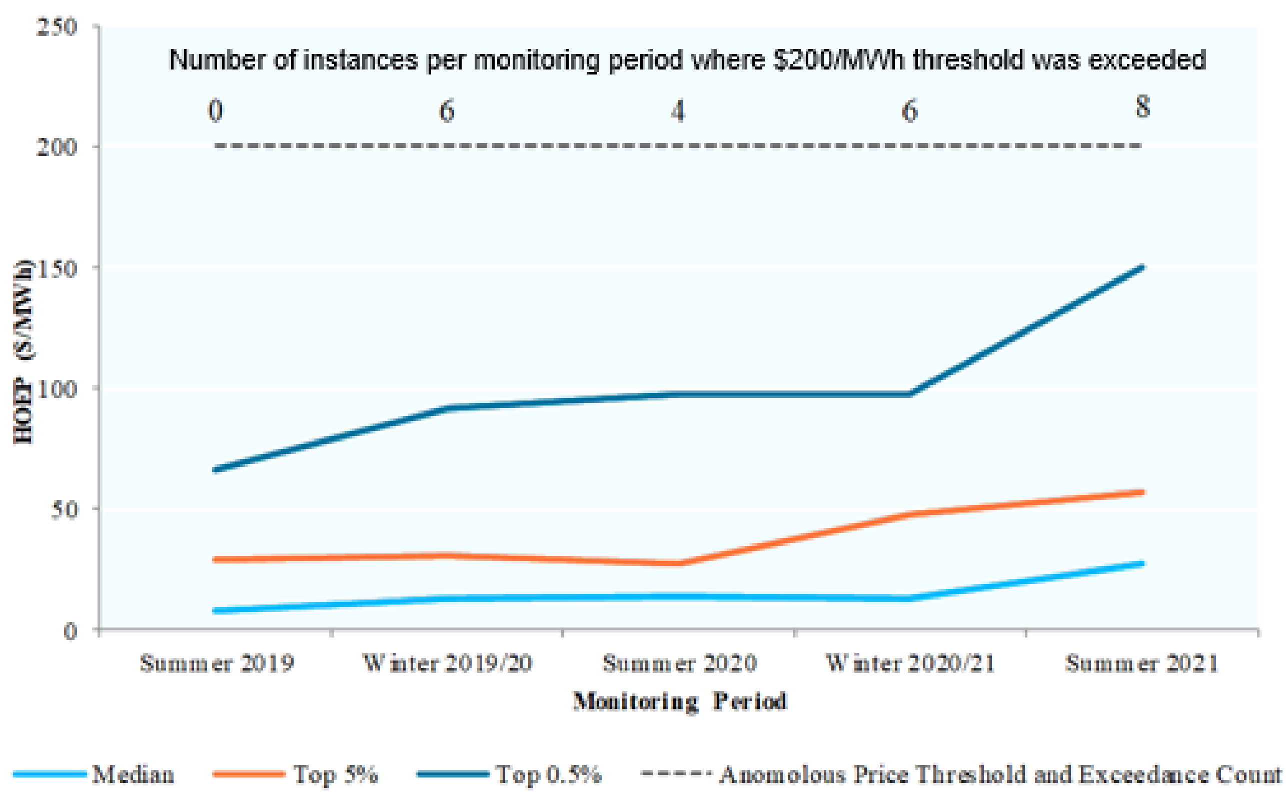


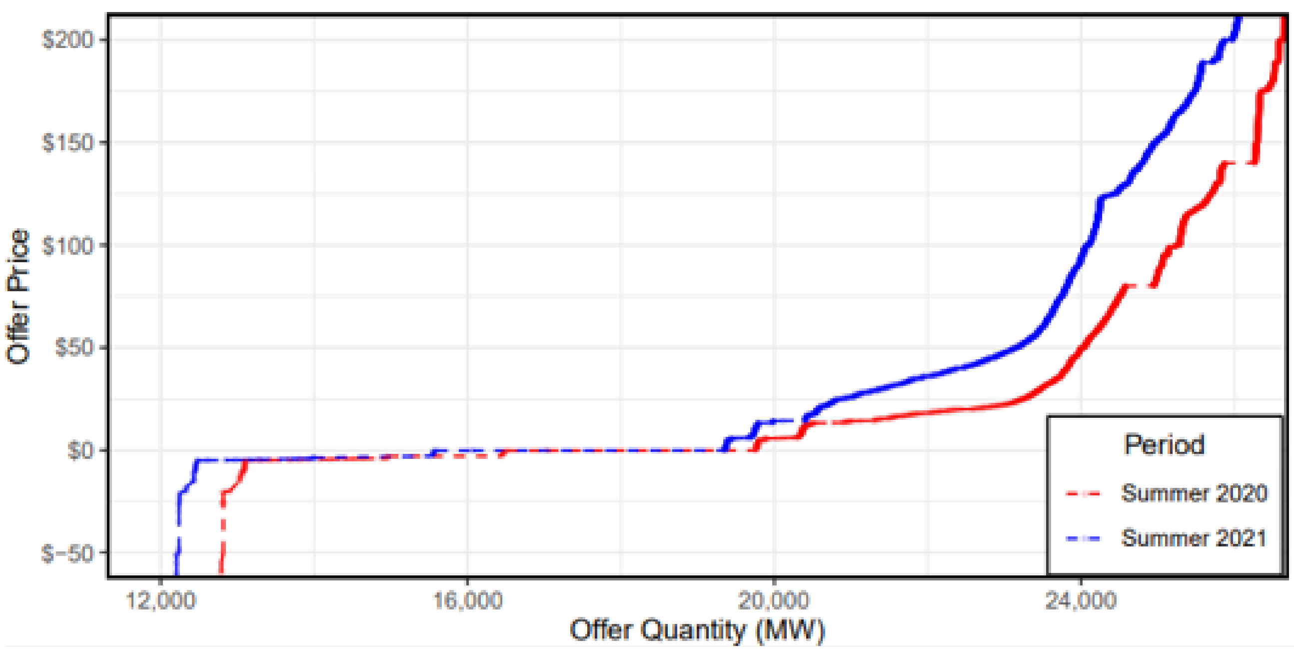
Table 2-1: Summary of HOEP Percentiles Summer 2019 Period to Summer 2021 Period, 5 Periods

Period	Median HOEP ($/MWh)	Average HOEP ($/MWh)	Top 5% HOEP ($/MWh)	Top 0.5% HOEP ($/MWh)	Maximum HOEP ($/MWh)	Hours at or below $0/MWh (hours)	Hours above $200/MWh (hours)	Total Hours in Periods (hours)
Summer 2019	$8	$11	$29	$66	$181	1,281	-	4,416
Winter 2019/20	$13	$15	$31	$92	$1,258	747	6	4,368
Summer 2020	$13	$13	$28	$98	$381	662	4	4,416
Winter 2020/21	$13	$16	$48	$97	$1,661	552	6	4,344
Summer 2021	**$27**	**$29**	**$57**	**$150**	**$1,150**	**295**	**8**	**4,416**

The average HOEP more than doubled from $13.29/MWh in the Summer 2020 Period to $28.75/MWh in the Summer 2021 Period. This represents a significant increase compared to the HOEP trend of the preceding four monitoring periods. The Summer 2021 Period experienced 8 hours where the HOEP exceeded $200/MWh compared to 4 hours experienced in the Summer

2020 Period. The number of hours when the HOEP was less than or equal to $0/MWh declined by 55% from 15.0% of all hours during the Summer 2020 Period (662 hours) to 6.7% of hours (295 hours) in the Summer 2021 Period.

Figure 2-2: Average Offer Curve Comparison between the Summer 2020 Period and Summer 2021 Period



The significant increase in the average HOEP in the Summer 2021 Period appears to be largely driven by supply side factors. Figure 2-2 illustrates this with average offer curves for each period. The average natural gas price in Summer 2021 Period was about double the price of the previous Summer Period (see Figure A-7 for details). This increase in generation costs likely pushed the right-hand portion of the curve upwards. Additionally, there were increased outages and reduced generation in nuclear and hydro in the Summer 2021 Period (see Figure A-16), resulting in less availability of lower cost offers and shifting the curve for 2021 to the left of the 2020 curve. This resulted in an increase in the use of gas resources with the total hours where gas set the real-time MCP, increasing to 62%, up from 53% in the previous Summer Period (see Table A-1). In the Summer 2021 Period, the average Ontario demand was also marginally higher at 15,173 MW compared to the Summer 2020 Period average Ontario demand of 15,043 (see Table A-2). Net exports were about 35% lower in the Summer 2021 Period (see Figure A-19) which simultaneously may have reflected the higher supply prices while somewhat mitigating the upward pressure on the HOEP.

Table 2-2 presents a comparison of CMSC, OR and IOG average payments and the number of hours thresholds were exceeded during the Summer 2021 Period. This is presented alongside the corresponding 6-month Summer 2020 Period from the year prior (May 1, 2020 to October 31, 2020).[32]

Table 2-2: Summary of Threshold Exceedances for the Summer 2020 Period and Summer 2021 Period

Payments Threshold	Summer 2020 Period (May 2020 to Oct 2020)		**Summer 2021 Period (May 2021 to Oct 2021)**	
	Average Payment	Threshold Exceedances	**Average Payment**	**Threshold Exceedances**
Daily Energy CMSC[33]	~$246,000/day	4 instances >$1 million/day	**~$419,000/day**	**7 instances >$1 million/day**
Hourly Energy CMSC	~$10,200/hour	0 instances >$500,000/hour	**~$17,500/hour**	**1 instances >$500,000/hour**
Hourly OR	~$4,700/hour	6 instances >$100,000/hour	**~$2,400/hour**	**6 instances >$100,000/hour**
Daily IOG	~$75,000/day	1 instance >$1 million/day	**~$151,000/day**	**3 instances >$1 million/day**
Hourly IOG	~$3,100/hour	0 instances >$500,000/hour	**$6,300/hour**	**0 instances >$500,000/hour**

The total CMSC paid in the Summer 2021 Period was $77 million, significantly higher than the CMSC paid in the Summer 2020 Period ($42 million). As shown in Figure 2-3, the increase in CMSC during the Summer 2021 period was largely driven by increased payments to generators in the Niagara region ($12.9 million or 16.9% of total CMSC in the Summer 2021 Period compared to $2.9 million or 7.2% of total CMSC in the Summer 2020 Period) and imports and

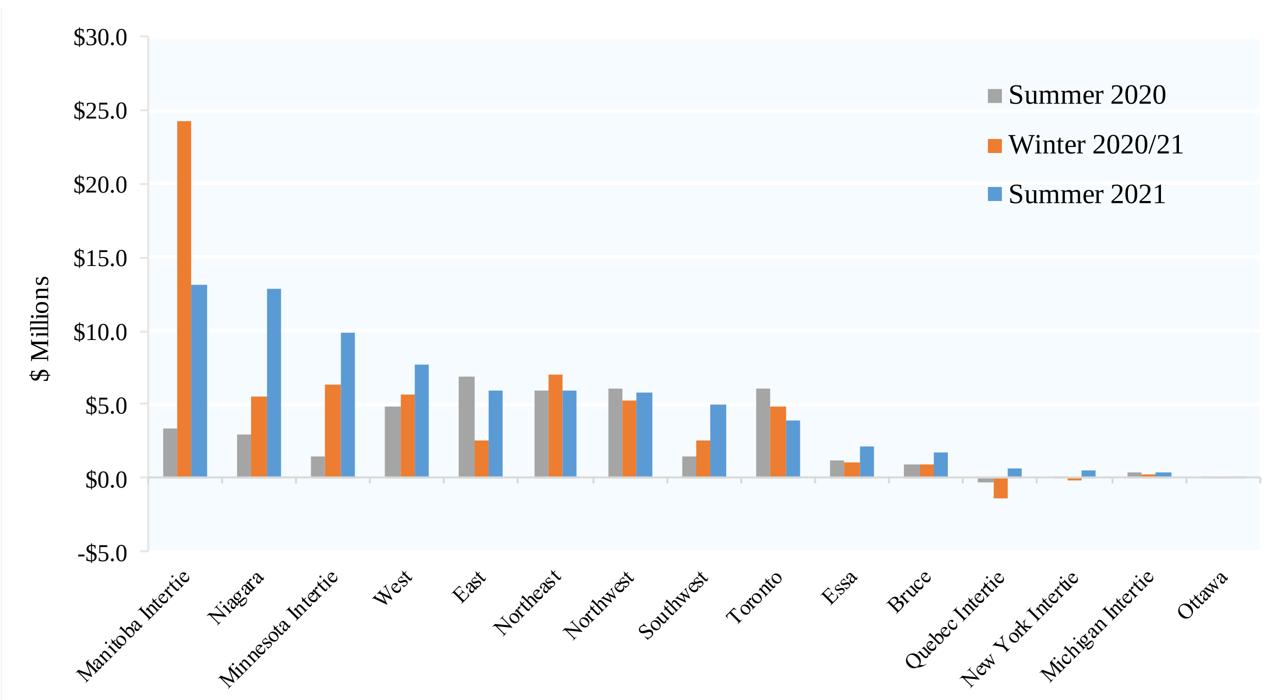
[32] Due to seasonal variations, the Panel compares instances of anomalous events occurring in the same 6-month monitoring period year over year.

[33] This considers CMSC net payment after any applicable claw backs.

exports on the Manitoba intertie ($13.2 million or 17.4% of total CMSC in the Summer 2021 Period compared to $3.3 million or 8% of total CMSC in Summer 2020).

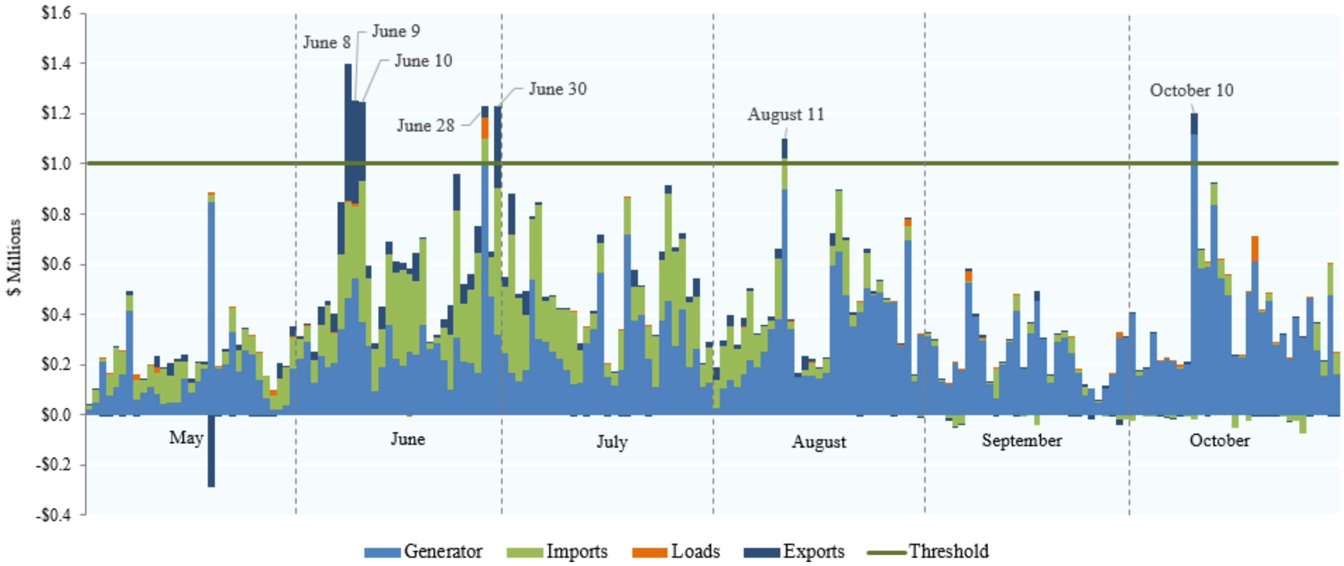
Most CMSC payments to traders on the Manitoba and Minnesota interties were part of a sequence of events that continued from the Winter 2020/21 Period that saw increased payments in an environment with tight supply conditions and transmission limitations. This issue was initially discussed in Monitoring Report 36.[34] On August 23, 2021, the IESO implemented transmission constraints that limited net exports from Manitoba and Minnesota, subsequently reducing the CMSC payments to resources in this region, as seen in Figure 2-4. This topic is further discussed in Chapter 3: Matters to Report in the Ontario Electricity Marketplace.

Figure 2-3: Total CMSC by Zone, 3 Periods



[34] Market Surveillance Panel Monitoring Report 36 published March 2022: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202203.pdf.

Figure 2-4: Daily CMSC by Facility Type, Summer 2021 Period



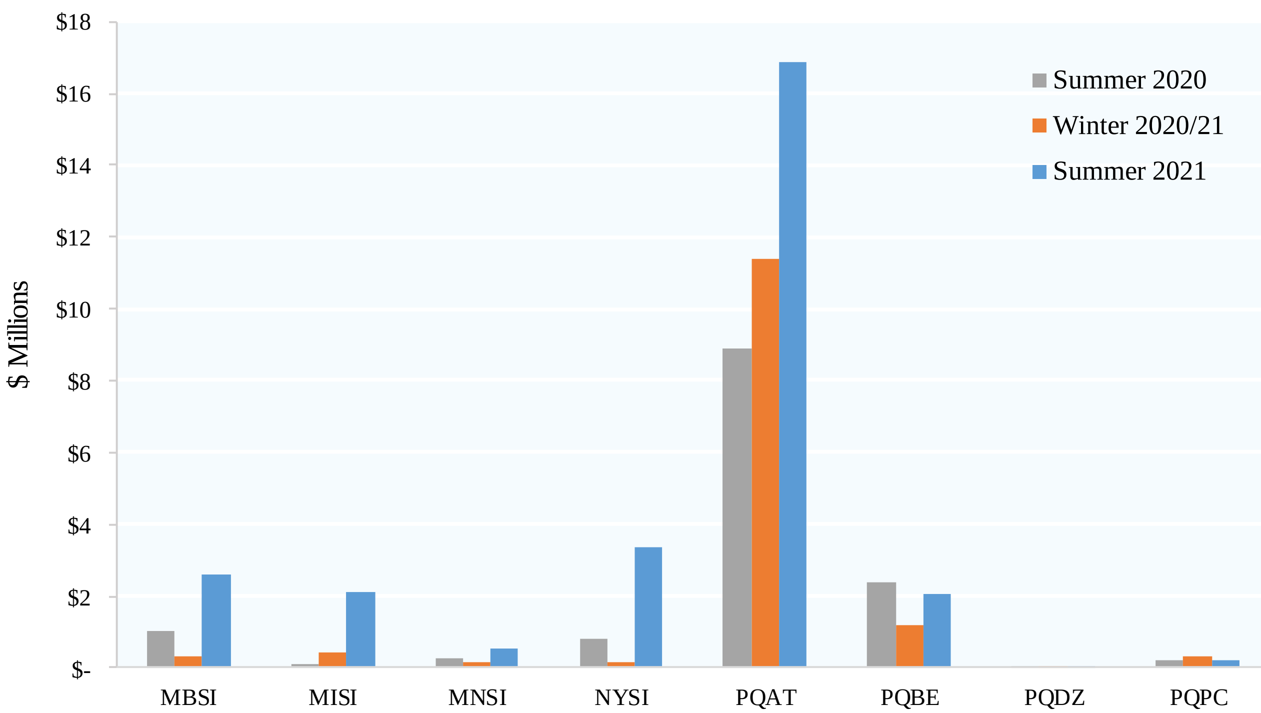
The number of days when CMSC was greater than $1 million/day increased to seven in the Summer 2021 Period from 4 days in the Summer 2020 Period. The average CMSC payment was approximately $419,000/day in the Summer 2021 Period, a 68% increase in average payment from the Summer 2020 Period (average ~$246,000/day).[35] There was one instance in the Summer 2021 Period where CMSC exceeded the $500,000/hour threshold.

The total OR payment in the Summer 2021 Period was $10.8 million (average of approximately $2,400/hour). The total OR payment for the Summer 2020 Period was significantly higher at $20.6 million (average of approximately $4,700/hour). Both the Summer 2020 and 2021 Period experienced six instances where OR payments surpassed the $100,000/hour threshold. The highest OR payment for a single hour was $1.2 million on October 10, 2021; prices during this hour were $1050/MWh for 10-minute non-spinning and 30-minute reserve, and $1099 for 10-minute spinning reserve. Further discussion on energy prices and OR payments on October 10 are included in Section 2.1.1.

[35] Market Surveillance Panel Monitoring Report 35 published August 2021: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202108.pdf.

Total IOG payments in the Summer 2021 Period were $27.7 million, which was significantly higher than the $13.8 million IOG payments in Summer 2020. As shown in Figure 2-5, most of the payments were to traders using the Québec interties. IOG payments to imports using the Québec interties in the Summer 2021 Period represented 69% of the total IOG payments ($19.1 million of $27.7 million). The high proportion of IOG payments to imports using the Québec interties is a trend that began in 2017, when the IESO's seven-year electricity trade agreement with Hydro-Québec took effect[36].

Figure 2-5: Total IOG by Zone, 3 Periods



The average IOG payment was approximately $151,000/day in the Summer 2021 Period, double the average payment of $75,000/day in the Summer 2020 Period. There were three instances in the Summer 2021 Period where the IOG payments surpassed $1 million/day. There were no

[36] Ibid.

instances in the Summer 2021 Period where the IOG payments exceeded the $500,000/hour threshold. Further discussion on specific IOG threshold exceedances in this period is included in Section 2.1.3.

Table 2-3 below presents the dates and, where applicable, times when the threshold exceedances occurred during the Summer 2021 Period.

Table 2-3: Date and Time of Threshold Exceedances for the Summer 2021 Period

High HOEP	High OR	Daily CMSC	Hourly CMSC	Daily IOG	Hourly IOG
May 19 | HE 18	May 19 | HE 18				No Events
		Jun 8			
		Jun 9			
		Jun 10			
Jun 28 | HE 11		Jun 28			
Jun 28 | HE 18					
		Jun 30			
		Aug 11			
				Aug 19	
				Aug 23	
				Aug 26	
Sept 18 | HE 12	Sept 18 | HE 12				
Sept 29 | HE 8	Sept 29 | HE 8				
Sept 29 | HE 9	Sept 29 | HE 9				
Oct 9 | HE 17	Oct 9 | HE 17				
Oct 10 | HE 12	Oct 10 | HE 12	Oct 10	Oct 10 | HE 12		

2.1.1 Energy Prices and OR Payments Above Threshold

The Panel reviews hours in which the HOEP exceeds $200/MWh and days in which OR payments exceed $100,000/hour to determine if the relatively high prices and payments can be attributable to known supply and demand or market design factors, or are a result of potential inappropriate or anomalous market conduct that warrants further review. Known factors that contribute to relatively high prices and payments include demand and variable generation forecast errors, planned and forced outages, import/export transaction failures, offer/bid changes close to the dispatch hour, lack of spare capacity, OR shortfalls, control action operating reserve (CAOR) derates, and changes in OR requirements[37].

Table 2-4 lists the factors contributing to the HOEP above $200/MWh or OR payments above $100,000/hour. OR payments are calculated by multiplying the price of OR with the amount of OR scheduled in an hour. Threshold exceedances are listed in bold text in the table below.

Table 2-4: Causes of High HOEP and OR Payments for the Summer 2021 Period

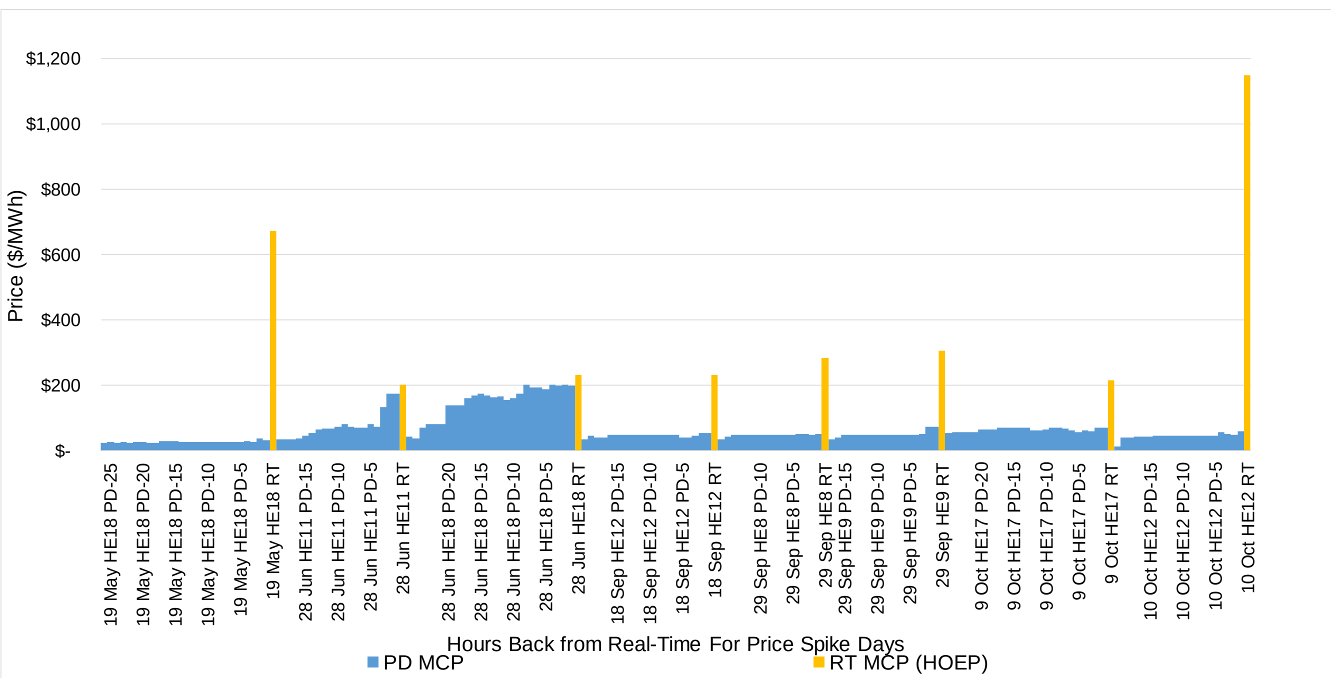
Event Date	Event Hour Ending	HOEP ($/MWh)	OR ($/hour)	Main Causes	Anomalous? (Yes/No)
May 19	18	**$674**	**$703,451**	- Outages (multiple gas units unavailable) - CAOR derate to 1 MW - OR shortfall	No
Jun 28	11	**$201**	$38,272	- Under forecasted demand - Lack of spare capacity	No
Jun 28	18	**$233**	$76,591	- Under forecasted demand - Lack of spare capacity	No
Sep 18	12	**$233**	**$104,426**	- Under forecasted demand - Over forecasted variable generation	No
Sep 29	8	**$285**	**$171,305**	- Under forecasted demand - Over forecasted variable generation	No

[37] CAOR 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. 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. CAOR is offered as OR at about $30 but has a corresponding energy offer of $2,000/MWh that ensures that the control action operating reserve is activated after all other scheduled reserve and are only used in real-time, never in pre-dispatch.

Sep 29	9	**$307**	**$271,950**	- Under forecasted demand - Over forecasted variable generation	No
Oct 9	17	**$216**	**$133,968**	- Under forecasted demand - Over forecasted variable generation	No
Oct 10	12	**$1,150**	**$1,240,743**	- Under forecasted demand - Over forecasted variable generation - OR shortfall - CAOR derate to 1 MW *Discussed in detail in this section.*	No

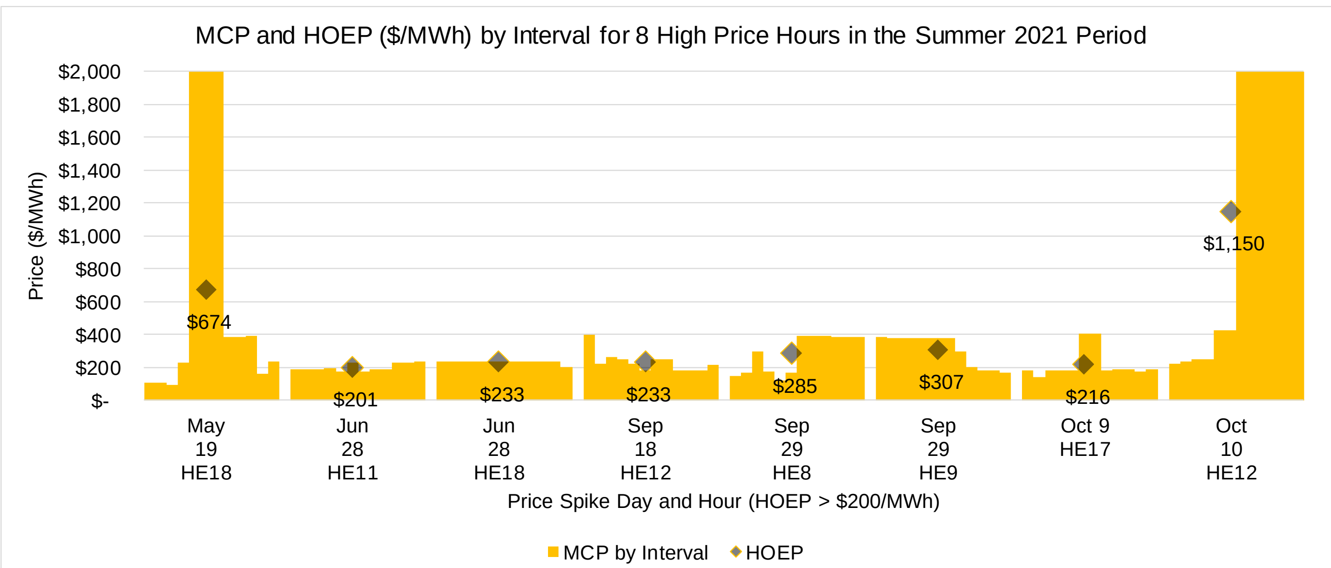
For the Summer 2021 Period, 6 of the 8 high priced HOEP were not projected in pre-dispatch (i.e., forecast prices stayed below ~$75/MWh), as shown in Figure 2-6.

Figure 2-6: Pre-Dispatch and Real-Time MCP for 8 High Price Hours



Intra-hour price changes can be the result of fluctuations in demand and variable generation output with a lack of flexible resources available to quickly respond intra-hour. While most high price hours did not have any MCP intervals above $400/MWh, 2 of the 8 hours had MCPs of $2,000/MWh for several intervals, May 19 and October 10. For both hours, the OR price also reached $2,000/MWh, well above the highest price for OR offers, indicating a shortfall in the amount of OR scheduled relative to the OR requirement of available OR. The real-time MCP by interval for the 8 high price hours is shown in Figure 2-7.

Figure 2-7: Real-Time MCP by Interval for 8 High Price Hours



A factor driving price discrepancies between pre-dispatch and real-time is the change in demand. For the 8 high price hours in this monitoring period, the change in unconstrained market demand from pre-dispatch to real-time was up to 300 MW.

Interventions by the IESO can also influence the HOEP. Two actions in particular influence how much OR is scheduled in real-time – adding 200 MW of OR in pre-dispatch to enhance flexibility and scheduling/derating CAOR.

The lack of flexible intra-hour supply was previously discussed in the Panel's Monitoring Report 32, which recommended that the IESO improve the criteria used to enable its flexibility solution of increasing the scheduled 30-minute OR by 200 MW.[38] The flexibility solution was not enabled by the IESO for any of the days where the HOEP exceeded $200/MWh and was rarely in effect during the Summer 2021 Period.

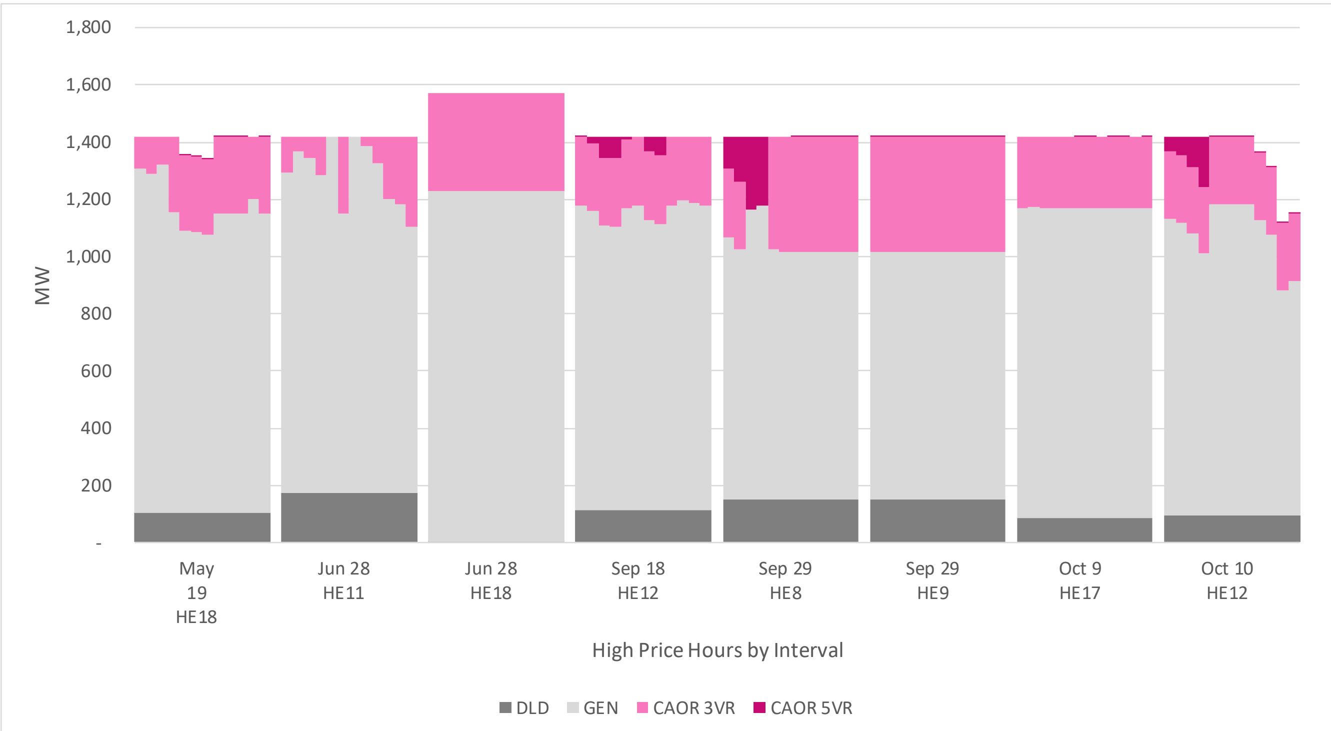
The IESO continues to use CAOR in the real-time OR offer stack, at prices that do not reflect the IESO's intention of relying on voltage reductions. This issue was discussed in the Panel's Monitoring Report 27 published November 2016, with a recommendation from the Panel that remains unaddressed.[39]

Figure 2-7 shows the MCP by interval for the 8 hours in which the $200/MWh HOEP threshold was exceeded. On May 19 and October 10, the 5-minute market clearing price reached the maximum market clearing price of $2,000/MWh in several intervals. During both of those hours, there were OR shortfalls, as shown in Figure 2-8. The IESO identified the OR shortfall by derating CAOR, which, by reducing OR supply, also contributes to the shortfall as well. The IESO's derating of the CAOR resource RICHVIEW-230.G_5VR to 1 MW in real-time resulted in MCP spikes to $2,000/MWh. Had CAOR been scheduled, the price could have been less volatile and may not have resulted in a threshold exceedance.

[38] See the Panel's Monitoring Report 32, Section 3.2, "Defining and Addressing the System Flexibility Need", published July 2020: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf.

[39] See the Panel's Monitoring Report 27, published November 2016, Section 2.7 "Control Action Operating Reserves are Scheduled More Frequently", page 77: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf.

Figure 2-8: OR Schedule (Unconstrained) by Interval for 8 High Price Hours



In HE12 on October 10, 2021, the HOEP spiked to $1,150/MWh and the price of all three OR types spiked to between $1,050/MWh and $1,100/MWh[40]. These prices deviated significantly from prices projected in PD-1, which were $59.67/MWh for the HOEP and $1.24/MWh for each of the OR types[41]. There were a number of factors that contributed to these price spikes.

Starting in the previous hour on this day, HE11, the IESO disabled the 5-minute Variable Generation (VG) forecast for Multi-Interval Optimization (MIO) to incorporate current wind output instead of forecasted wind output to determine future dispatches. MIO is a feature of the dispatch scheduling optimizer (DSO) software that considers several future intervals to determine optimal dispatch instructions, rather than considering just a single interval. At the time, wind generation

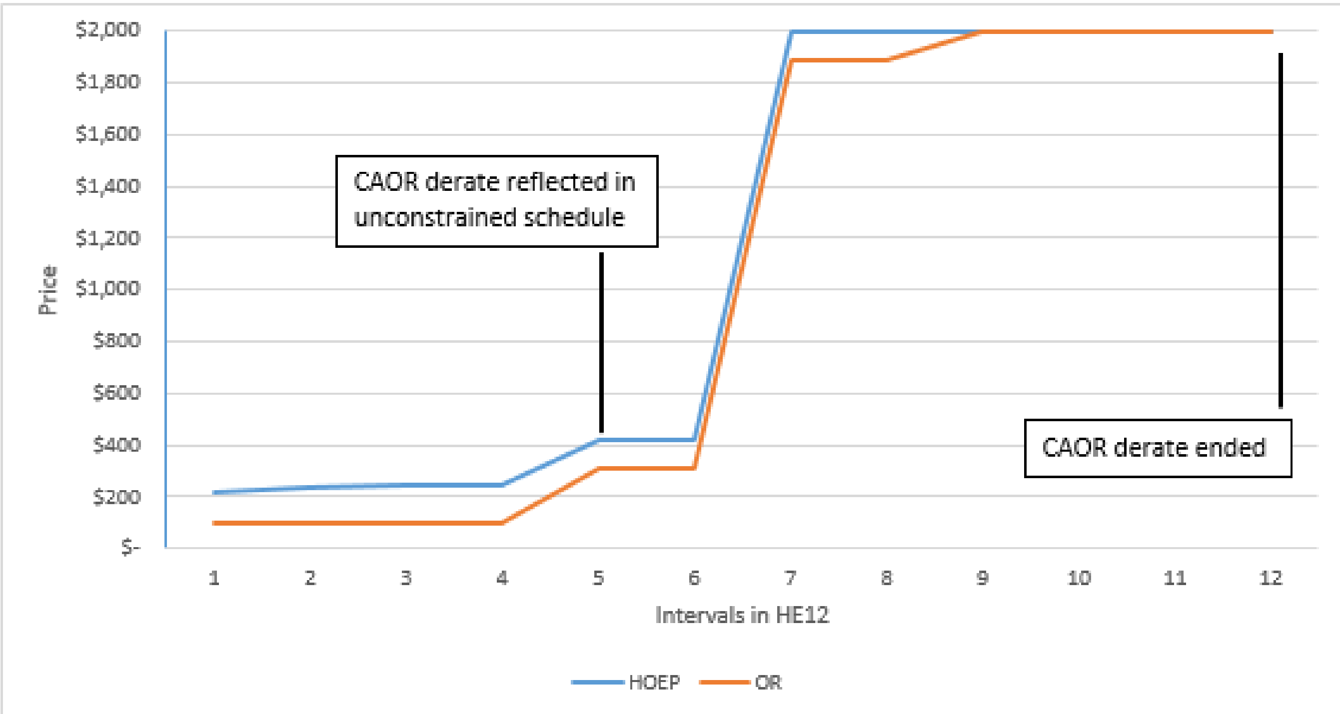
[40] The IESO uses the "Hour Ending" naming convention for the hours in a day. HE12 refers to the time between 11am to 12pm EST.

[41] The last run of pre-dispatch before the dispatch hour is commonly referred to as PD-1.

output was 300 MW under the 5-minute forecast and solar generation was under the forecast by 50-100 MW as a storm front was passing through South-Western Ontario. In this hour, storms in Northwest Ontario required generation reduction to respect reduced transmission limits that are applied under the high-risk conditions brought on by the storm.

By HE12, the DSO was scheduling over 250 MW of CAOR on the RICHVIEW-230.G_5VR resource due to real-time wind output dropping ~400 MW. The DSO's scheduling of the CAOR potentially indicated a shortfall of other resources to supply OR. In order to determine if an actual reserve shortfall existed the IESO control room derated the RICHVIEW-230.G_5VR resource to 1 MW to confirm if other resources were able to satisfy the requirement. IESO operators have the discretion for how long, up to an hour, to derate the 5VR resource and depending on system conditions, it may take a few intervals to see the impacts of the derate stabilize, which is required to make an absolute determination of shortage conditions. The increase in prices coincides with the derating of CAOR, as evident in the Figure 2-9 below, as more expensive generation had to provide operating reserve. Due to the joint optimization of energy and OR, the price in one market can reflect the opportunity cost in the other when the total capacity (including ramping capability) has been exhausted. The MCP remained at $2,000 for a total of four intervals. If the IESO had reinstated the CAOR, prices should have gone down to ~$300 to $400 (as in interval 6) for the last 4 or 5 intervals all else being equal.

Figure 2-9: HOEP and OR prices in HE12 on October 10, 2021



2.1.2 CMSC Payments Above Threshold

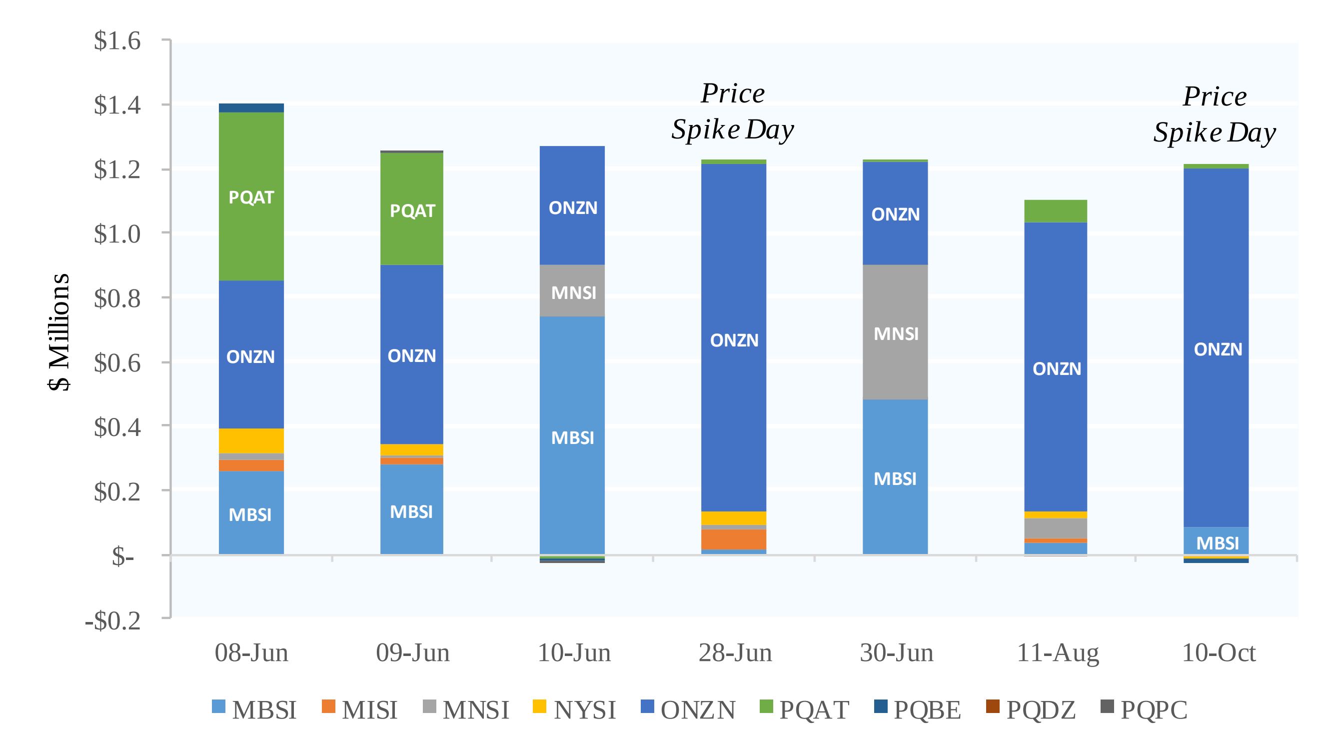
Congestion Management Settlement Credits are intended to keep market participants whole based on their offers or bids, when they are instructed to generate or consume electricity differently from the unconstrained schedule. In most situations, this is a payment to the participant with the cost of CMSC payments being passed on to electricity consumers as a settlement charge.[42]

[42] See the IESO's Training Material "Introduction to Ontario's Physical Markets", page 49: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/WB-Intro-Ontario-Physical-Markets.ashx.

The following is a review of the CMSC payments associated with the events that exceeded the threshold set out in Table 2-2 above.

Figure 2-10 presents the distribution of CMSC payments by zone on the threshold exceedances days in the Summer 2021 Period with the ONZN code representing the Ontario control area and all other codes representing interties with neighbouring control areas[43].

Figure 2-10: Distribution of CMSC by Zone, Summer 2021 Period Threshold Exceedance Days



On June 8, 2021, a majority of the CMSC payments were paid to exporters on the Outaouais intertie as a result of the IESO curtailing transactions due to internal system conditions.

[43] See the IESO's Training Material "Interjurisdictional Energy Trading", page 12: https://www.ieso.ca/-/media/Files/IESO/Document-Library/training/WB-Interjurisdictional-Energy-Trading.ashx.

On June 9, 2021, a biomass power plant was constrained-on due to forecasted high risk conditions and multiple elements forced out of service.

Payments to traders in the Northwest area constituted the majority of CMSC payments on the threshold exceedance days of June 10, 2021 and June 30, 2021.

On June 28, 2021, a gas generator was constrained-on for reliability for reasons including limited imports, demand running 1,000 MW above forecast, and several forced generator outages. With numerous other out-of-market actions taken, the IESO issued an Extreme Conditions Alert at HE11. Forty-five minutes later, the IESO issued an Energy Emergency Alert 1 with a message stating that all available resources were in service, with the IESO as a net importer with little capability to import additional energy. On August 11, 2021, the same gas generator was constrained-on for reliability due to 900 MW of derates across the gas fleet from high ambient temperatures. There was also limited spare energy available over peak and limited generation in certain areas due to a tornado warning.

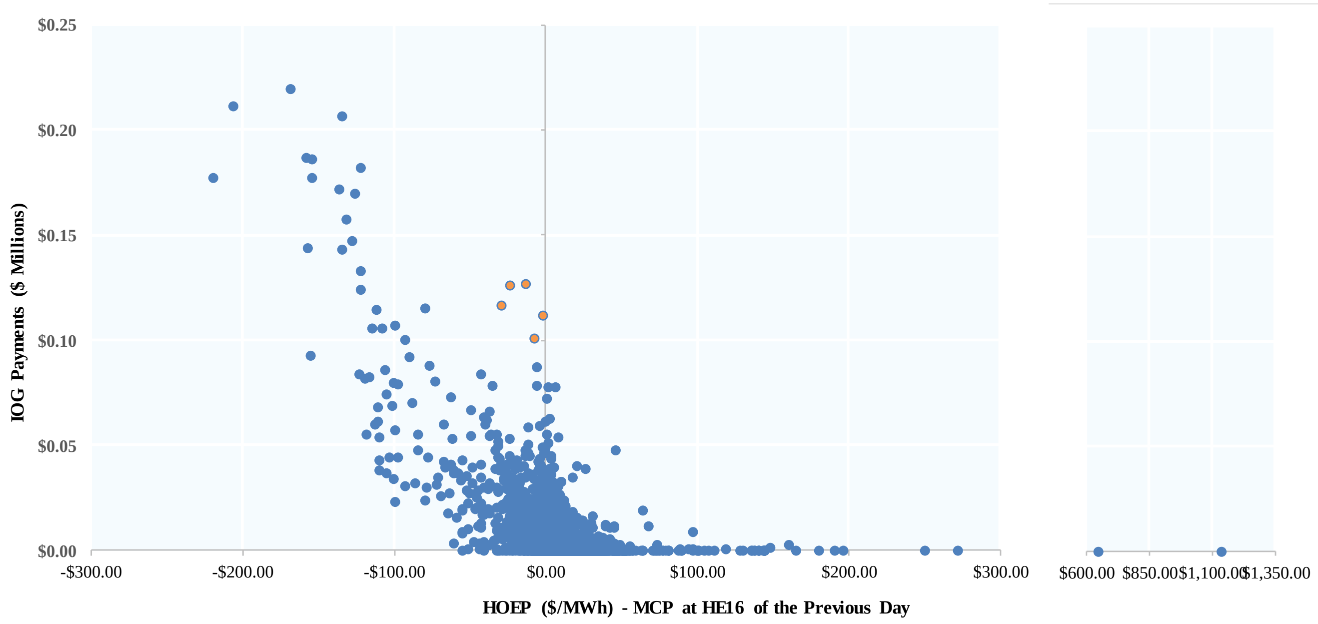
On October 10, 2021, $1.1 million of CMSC was paid and a significant portion of this amount went to hydroelectric facilities in the Niagara region. On October 9, 2021, an insulator failed in the switchyard of a hydroelectric facility due to Hydro One switching. The constraint ended on October 16, 2021.

2.1.3 IOG Payments Above Threshold

The Panel monitors IOG payments for both Day Ahead (DA) and Real Time (RT) to understand the frequency of high out-of-market payments and to understand the variability between pre-dispatch (or DA) schedules and real-time commitment of imports at intertie zones. IOG payments are provided to cover the risk when the final settlement price falls below the importer’s DA or RT offer price. For DA imports, this incentivizes traders to lower offers after imports have been scheduled in DA to increase the probability that the energy will flow in real-time because they are guaranteed to, at minimum, recover their as-offered prices on import transactions.

In the Summer 2021 Period, all interties experienced significant increases in IOG payments.

Figure 2-11: Distribution of Hourly Total IOG Payments by Price Spread & MWh, Summer 2021 Period



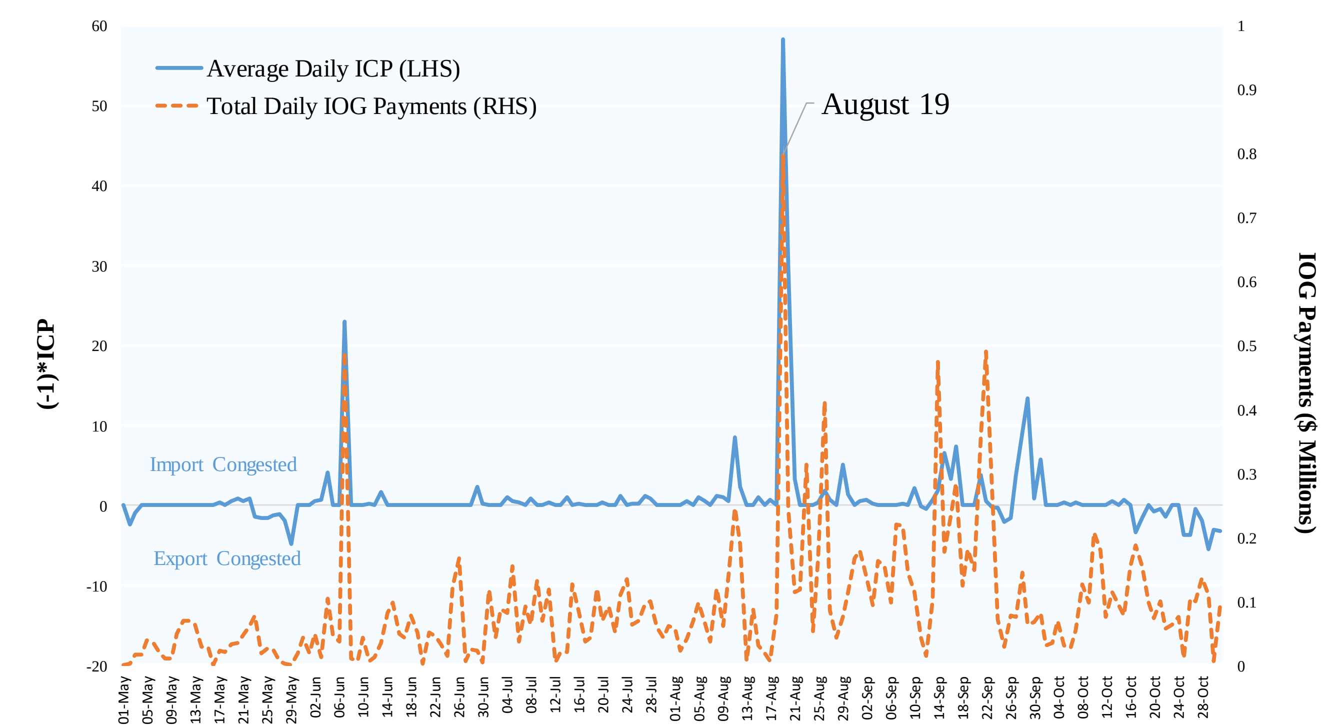
The first pre-dispatch projection of HOEP which is made at HE16 of the previous day can act as an estimate for the importers' DA offer prices. As IOG payments are provided to recover importers' offer prices, increased deviations between the real-time HOEP and the first pre-dispatch price estimate of the hour can contribute to higher IOG payments, as shown in Figure 2-11. Two of the IOG threshold exceedance days – August 23, 2021 and August 26, 2021 – experienced high average price deviations relative to the period average (see Table 2-5), indicating that the high payments on these threshold exceedance days were likely driven by high price deviations.

Table 2-5: Distribution of Hourly Total IOG Payments by Price Spread & MWh, Summer 2021 Period

	Total IOG Payment	Average Day-Ahead Price Deviation ($/MWh)
August 19, 2021	$1.0 million	5.31
August 23, 2021	**$1.8 million**	**-86.88**
August 26, 2021	**$1.1 million**	**-38.00**
Summer 2021 Period	$27.7 million	4.51
Summer 2020 Period	$13.8 million	6.31

On August 19, 2021, $1.0 million in IOG payments were paid, approximately $0.9 million of which were paid to importers on the Outaouais and Beauharnois interties. The highlighted hours in Figure 2-11 above are IOG payments predominantly to a single market participant on August 19, 2021 in the hours of HE13 to HE17. As shown in Figure 2-12, August 19, 2021, also experienced high import congestion on the Québec intertie.

Figure 2-12: Daily Total IOG Payments and Average Intertie Congestion Price, Summer 2021 Period



High import congestion means that the Intertie Zonal Prices (IZP) – the prices at which intertie traders are paid for selling energy – are lower than the MCP. In these conditions, scheduled day-ahead imports that flow can be subject to IZPs that are lower than the trader's original day-ahead offers. In some cases, traders intending on fulfilling their schedule may even be forced to offer energy at a negative price depending on expected pre-dispatch prices to ensure being scheduled. The trader would then receive an IOG payment to make up for the negative operating profit. The high IOG payments to a single market participant on August 19, 2021, occurred as a result of the Québec interties being heavily import congested and not as a result of the low apparent price spreads between the pre-dispatch projected HOEP and real-time HOEP.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

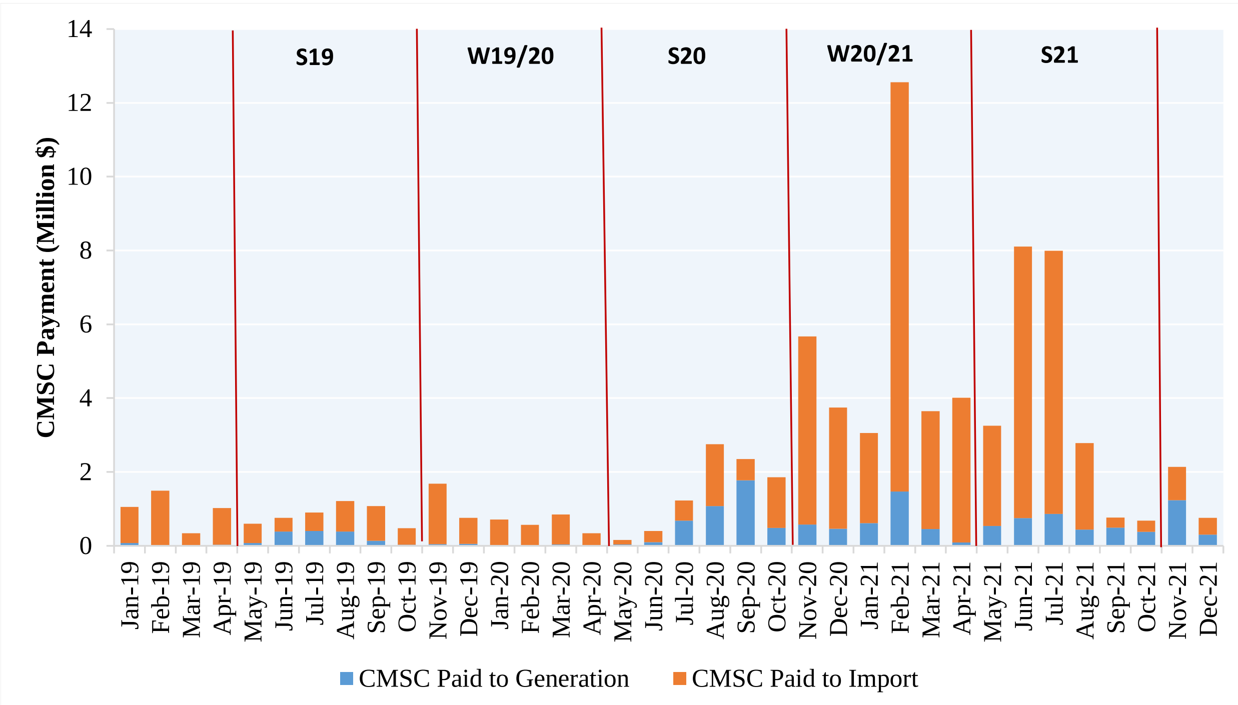
3.1 An Analysis of Anomalous Events in the Northwest

3.1.1 Introduction

During the Winter 2020-21 Period and Summer 2021 Period, Congestion Management Settlement Credit (CMSC) payments made to traders at the Manitoba (MB) and Minnesota (MN) interties increased significantly compared to previous periods (see Figure 3-1). The MB and MN interties connect the Northwest (NW) zone, one of the ten internal electrical zones within Ontario's transmission system, to the Midcontinent Independent System Operator's (MISO) control area.[44]

[44] The IESO-controlled grid is divided into ten electrical zones, with the boundaries of the zones chosen to correspond with the major internal transmission interfaces. The NW zone boundary is marked on the east by the East-West Transfer East (EWTE) interface and on the west by the Manitoba-Ontario and Minnesota-Ontario borders. The East-West Transfer West (EWTW) interface is identical to EWTE, but the transfers are measured in reverse direction.

Figure 3-1: CMSC paid to Generation and Imports in the Northwest Zone (2019-2021)



In Market Surveillance Panel Report 36, the Panel highlighted the high CMSC payments in the NW as anomalous events and indicated that it would provide further analysis of the event in its next report. The Panel's analysis is presented in this chapter, starting with a description of the trends in demand and supply in the NW zone from January 2019 to December 2021, referred to in this Chapter as the review period. A relative scarcity of domestic supply available to the NW zone emerged in the Summer 2020 Period due to reduced available energy from hydroelectric generation located within the NW zone and reduced transfer capability on the East-West Transfer west interface (East-West Tie[45]) that limited supply from the rest of the province. Section 3.1.3 describes how a flaw in Ontario's current market design induced inefficient exports

[45] The East-West Tie is an exisiting transmission corridor. Before the construction of the NextBridge East-West Transmission Project, which expanded the East-West Tie, the corridor consisted of a double-circuit 230 kV transmission line. See the IESO's Northwest Ontario Bulk Planning Initatives webpage at https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northwest-Ontario/bulk-planning#eastwest.

from the NW zone to MISO, and a shortcoming of the current design failed to optimize the use of daily energy-limited hydroelectric output. The market design flaw and design shortcoming, coupled with the scarcity of hydroelectric generation and limited East-West Tie transfer capability, presented operational challenges for the IESO. At several points during the three years, the IESO acted in response to the operational challenges, which affected import and export flows over the MB and MN interties and CMSC payments. Section 3.1.4 discusses the different actions taken by the IESO to manage the challenges in the NW zone, and the effect each action had on import and export flows and CMSC. Section 3.1.5 provides the Panel's overall observations on the causes of the event, high CMSC payments, and the IESO's approach of intervening in the market to manage the operational challenges rather than allowing the market to solve the situation.

3.1.2 Demand and Supply Trends and the NW Zone Supply Scarcity

Electricity supply for the NW zone is provided through three sources: generation facilities located in the NW zone, imports from the MISO control area through MB and MN interties, and electricity transferred from the rest of Ontario over the East-West Tie.

There is roughly 1,400 MW of generation capacity[46] located in the NW zone. Hydroelectric generation accounts for roughly 920 MW or 67% of the capacity in the NW zone (see Figure 3-2, right axis). However, the amount of electricity produced by hydroelectric generation each year relies on annual precipitation and stream flows. In 2019, hydroelectric generation produced 4,000 GWh of electricity in the NW zone. In 2021, with declining water levels, hydroelectric generation's output fell by 32% to only 2,500 GWh (See Figure 3-2, left axis).

[46] The IESO collects data on the capable generation capacity of resources through the registration process. Figure 3-2 reports registered generation capacity for the summer, defined as the Maximum Generator Unit Capability during specified ambient conditions without station service being supplied by the unit (35ºC ambient (at or south of Barrie) or 30ºC ambient (north of Barrie)). Biofuel capacity is limited by fuel availability.

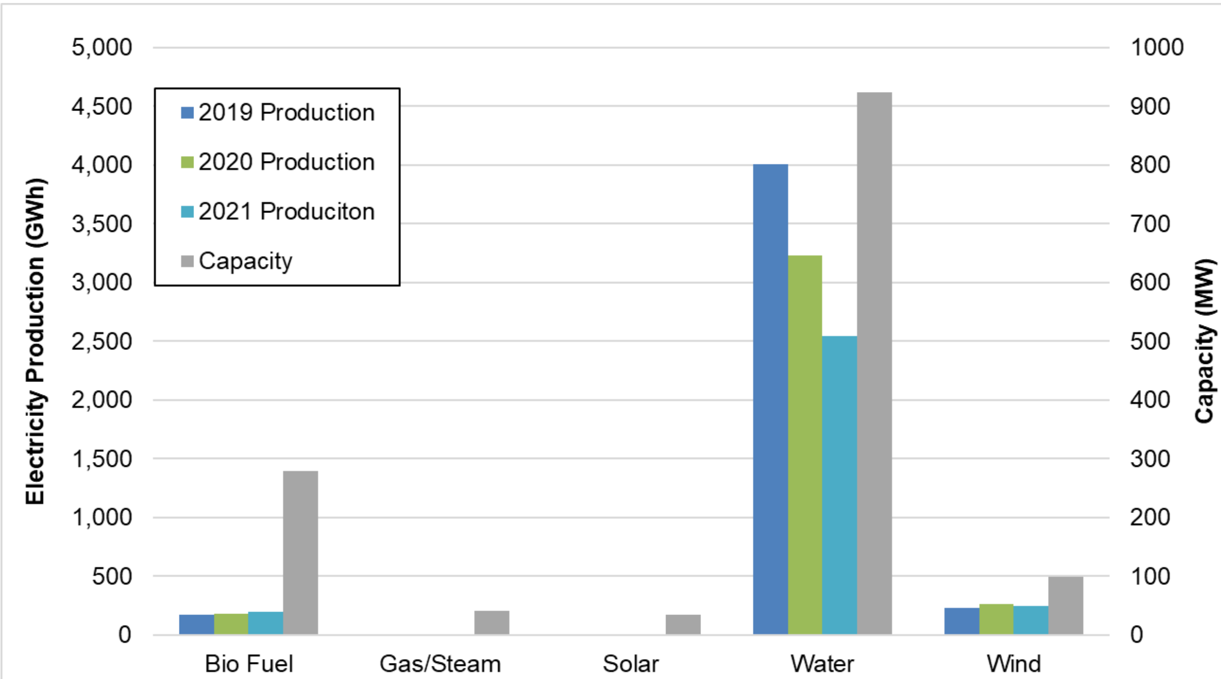
Up to March 2022, the East-West Tie, which connects the NW zone with the rest of the Ontario grid, was nominally rated at 325 MW.[47] However, during the three years, the transfer capability of the East-West Tie was often reduced below 325 MW due to planned outages to transformer stations that were needed to accommodate the construction of a new 230 kV transmission line running roughly parallel to the existing East-West Tie line (the NextBridge East-West Tie Transmission Project)[48] or line derates caused by storms in the area (See Figure 3-3).[49] This limited the flow of energy into the NW from the rest of the provincial grid.

[47] East-West Tie operating limits are included in the "Transmission Facility All in Service Limits Report (Days 0 to 34)" available at http://reports.ieso.ca/public/TxLimitsAllInService0to34Days/.

[48] The NextBridge East-West Tie Transmission Project line, which went into service on March 31, 2022, increased the potential electricity transfer capability to 650 MW. See NextBridge Infrastructure website at https://www.nextbridge.ca/.

[49] Figure 3-3 presents data on the actual electricity transfers over the East-West Tie. This amount can often be less than the transfer limits placed on the tie line. Accurate data on the transfer limits were not available.

Figure 3-2: Generation Capacity and Electricity Production in the Northwest Zone by Fuel Type (2019-2021)

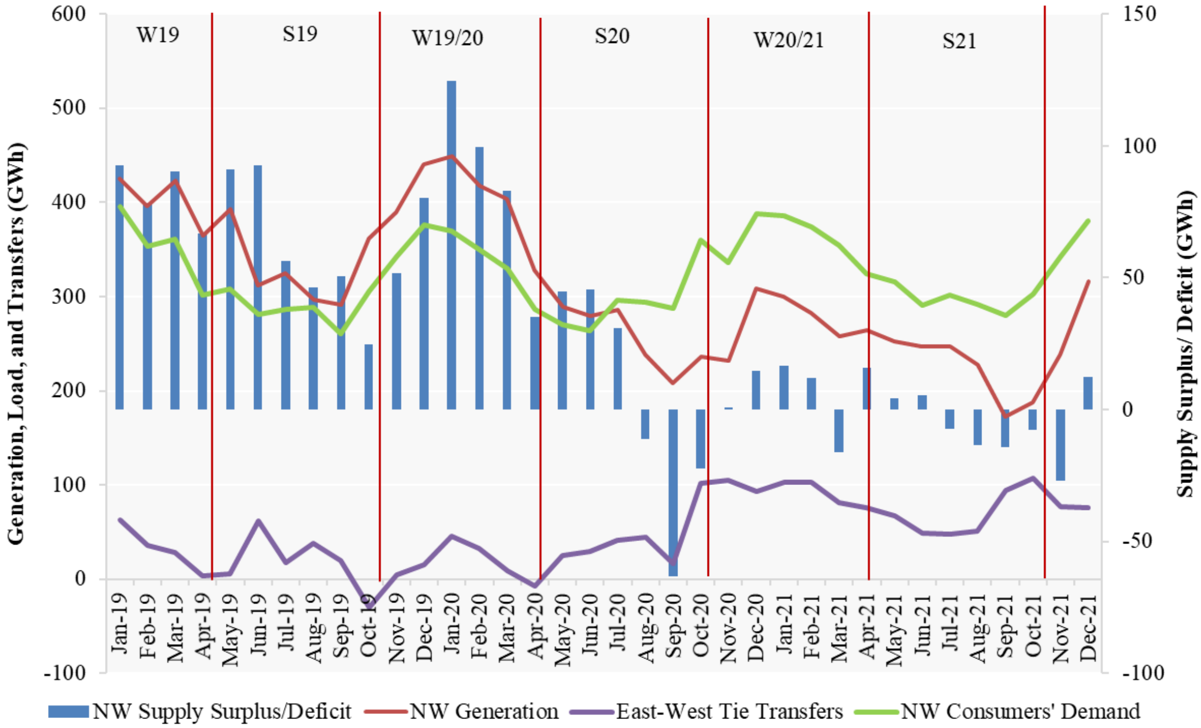


Electricity demand in the NW zone includes demand from consumers located in the NW zone[50] and export demand from MISO (and possibly locations beyond). NW zone consumers' demand varies by season depending on weather conditions with demand being the highest during the winter heating months. Over the three-year review period, NW consumers' demand was as high as 400 GWh per month and as low as 260 GWh per month (See Figure 3-3).

As much as 250 MW and 80 MW of electricity imports or exports can be transferred between Ontario and MB and MN respectively, although the transfer capabilities can be reduced under certain summer operating conditions. The amount of electricity imports or exports varies by hours depending on prevailing price levels in the region. This is discussed in more detail in Section 3.1.3.

[50] When there is surplus generation within the NW zone, this surplus can be transferred to demand in other parts of the province over the East-West Tie.

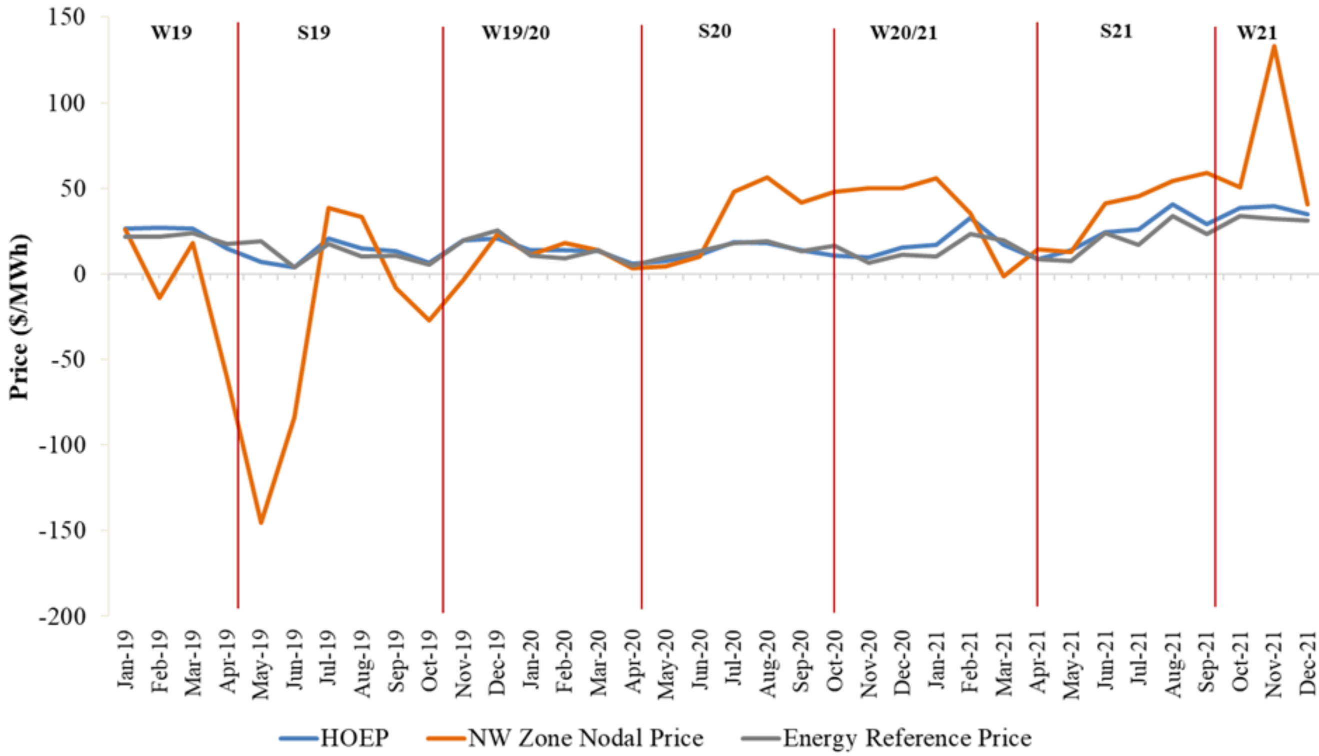
Figure 3-3: Electricity Generation, East West Tie Transfers and Electricity Demand in the NW Zone, Monthly (Jan 2019 - Dec 2021)



Over the last couple of years, the NW zone has experienced a drop in river system water levels and stream flow resulting in a decline in available hydroelectric electricity generation. Furthermore, periodic maintenance and derates to the East-West Tie limited access to supply from the rest of Ontario for several hours during the same period. These two factors gradually contributed to deficits of domestic supply (generation located in the NW zone plus supply from the rest of the province over the East-West Tie) to meet NW zone consumers' demand beginning in the Summer 2020 Period (see the blue bars in Figure 3-3).[51] Note, these are supply deficits internal to the NW zone before considering net imports; at no time during the review period did the IESO fail to meet its reserve requirements or need to shed load within the NW zone.

[51] The generation and load data presented in Figure 3-3 are derived by summing the metered load across all the metered locations within the NW zone.

Figure 3-4: Monthly Average NW Zone Nodal Price, Energy Reference Price and HOEP, (Jan 2019 - Dec 2021)



In a competitive market, supply scarcity is reflected in higher market clearing prices. Furthermore, if there is limited transmission transfer capability between two regions (i.e., limits on the East-West Tie which connects the NW zone to the rest of Ontario), scarcity conditions affecting one region (i.e., the NW zone) but not another (i.e., the rest of the province) can lead to differences in regional prices. This is the situation that occurred in Ontario between 2019 to 2021 as reflected in the difference between the monthly average NW zone nodal price[52] and the nodal prices east of the East-West Tie as shown by the monthly average Ontario energy

[52] The nodal price in Figure 3-4 represents an average of the nodal prices in the NW zone.

reference price (see Figure 3-4).[53] The difference between the monthly average NW zone nodal price and the monthly average HOEP is also presented for comparison.[54] Note, during the period, the monthly average reference price and the monthly average HOEP were relatively similar, and starting in the Summer 2020 Period, were consistently lower than the monthly average NW zone nodal price.

3.1.3 Market Design Implications

Intertie trade is based on regional price differences, with traders seeking to profit from moving electricity from a low-price region to a high-price region. This trade can promote regional efficiency by ensuring the lowest cost sources of supply are used to meet overall regional demand. Furthermore, efficient trade supports the reliable operation of the grid by ameliorating location-specific scarcity. For example, in a competitive market, if one region is experiencing a relative scarcity of supply when other regions are not, prices in the region experiencing scarcity (at least initially) are relatively higher than the prices in the other regions. The price differences encourage imports to flow from the low-price regions to the high-price region experiencing scarcity and discourage exports from the high-price region with scarcity to the low-price regions. Absent limits on intertie transmission capacity, these trade flows continue until prices across the regions converge, with remaining regional price differences reflecting only the traders' transaction costs, such as transmission tariffs or the cost to reserve physical transmission rights.

[53] The energy reference price is the cost of consuming an additional MW of electricity at a specific location on the transmission system known as the "reference location." The energy reference price is a necessary constant in the calculation of system nodal prices. The nodal price at any location is equal to the energy reference price plus the energy congestion price and the energy loss price. At the reference location, losses and congestion are both equal to zero so the nodal price at the reference location is equal to the energy reference price. To establish the energy reference price, a single reference location must be used. While a change in reference price would mean that the breakdown of the nodal price components at each location could change, the overall nodal price at each location would remain the same. In Ontario, the reference location is the Richview Transformer Station in the Greater Toronto Area (Etobicoke).

Figure 3-5: Monthly Average Regional Price Trends, (Jan 2019 - Dec 2021)

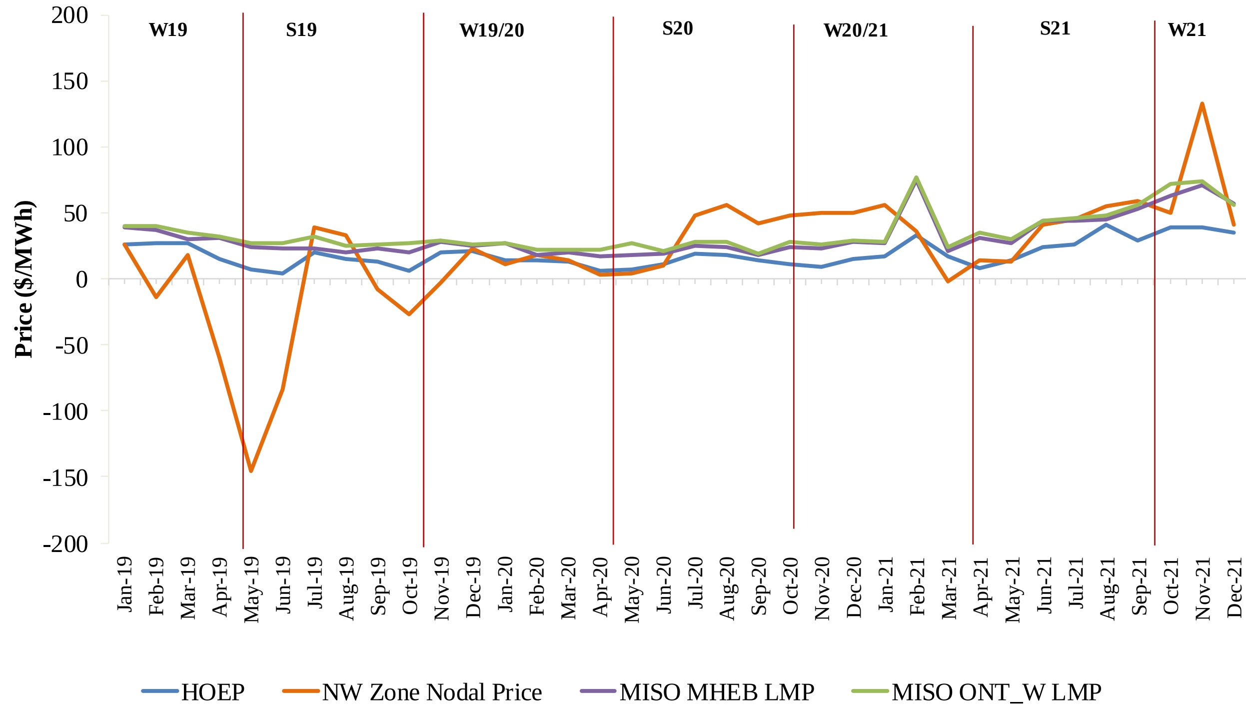
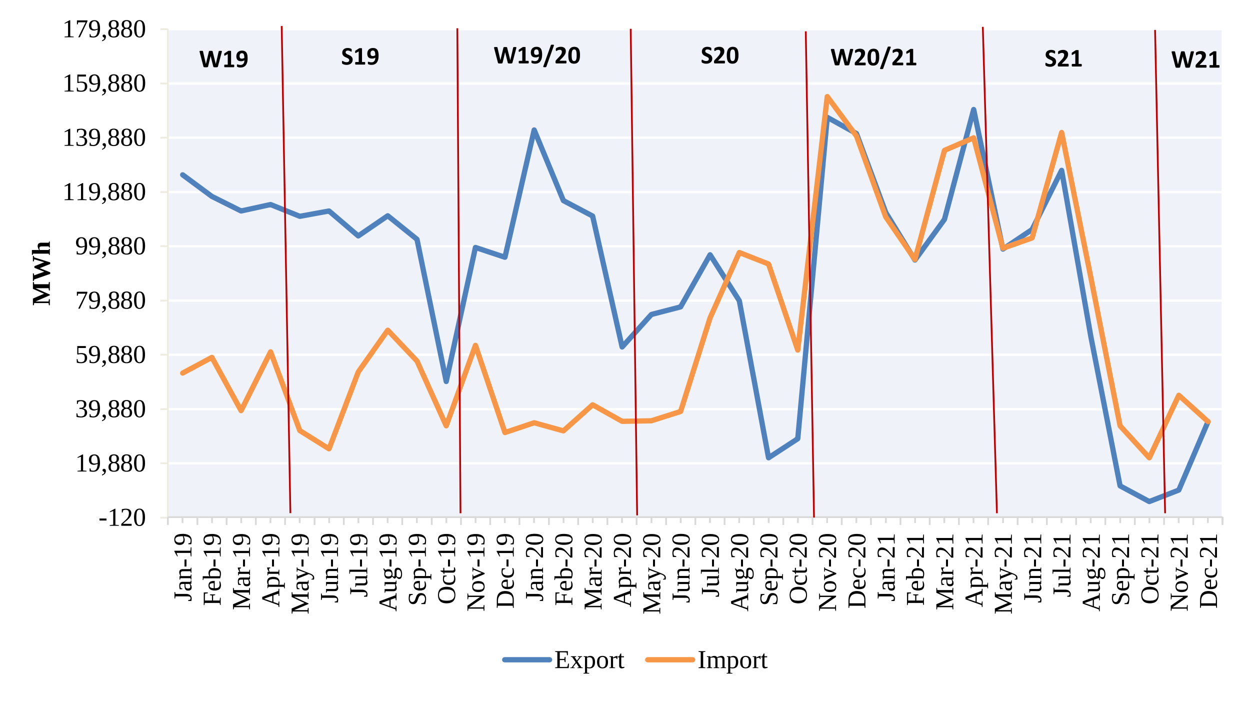


Figure 3-5 outlines the regional price trends for Ontario (HOEP), the NW zone, MISO MHEB location, and MISO ONT_W location for the 3 years.[55] The monthly average locational prices, which reflect the supply and demand conditions in North Dakota (MHEB LMP) and Minnesota (ONT_W LMP) were relatively stable over the 3 years. They were consistently higher than the monthly average HOEP, but often much less than the monthly average NW zone nodal price.

[55] Prices for MISO locations were accessed from the MISO website and reflect the monthly average real-time locational marginal price (LMP) at the MHEB location and ONT_W location. LMP is the cost of providing the next MW of electrical energy at a specific location on the grid. ONT_W location is in Minnesota bordering Ontario and MHEB is in North Dakota bordering Manitoba. There is no wholesale electricity market in Manitoba. Electricity can be purchased in Ontario and sold to North Dakota via Manitoba. Manitoba can also export its own surplus energy to MISO and Ontario.

Figure 3-6: Monthly Average Exports and Imports between MISO and Ontario's NW Zone, (Jan 2019 - Dec 2021)



In theory, given the significant regional price differences, we might expect that Ontario was a net importer into the NW zone in most months as the high prices would attract imports to the NW zone from MISO and deter exports from the NW zone to MISO. However, this was not the case during the review period. As Figure 3-6 shows, for most of the period, Ontario was a net exporter of electricity from the NW zone, and when it was a net importer, the volume of imports was marginally higher than the volume of exports.

The relatively high volumes of exports to MISO from the NW zone when the prices in the NW zone were consistently higher than prices in MISO is an anomaly that can be explained with reference to a market design flaw inherent in Ontario's two-schedule system.[56] To understand this, consider the following discussion on the incentives for traders to import and export in a hypothetical competitive market with a single schedule and locational pricing, compared to the incentives created under Ontario's current market design. In a competitive market with locational pricing, traders that import to Ontario from MISO would offer to import at a price equal to the purchase price of electricity to be exported from MISO (plus any transaction costs). This is the competitive import offer price. By offering at the competitive import price, the trader would avoid receiving a negative profit margin on the trade as it would be scheduled only if the locational market clearing price, the price it would receive from Ontario for the import, was higher than the purchase price of electricity plus transaction costs.[57]

During the 3 years, the import purchase price in MISO (the competitive import offer price) was generally above the HOEP but below the NW zone price (see Figure 3-5). Under Ontario's two-schedule system, an import offered at the competitive price would be too expensive to be economically scheduled in the unconstrained schedule (the competitive offer price would be

[56] Ontario uses a two-schedule system to dispatch generation and demand resources and to determine market clearing prices. The unconstrained schedule minimizes the cost of supply to meet demand, but in doing so, ignores certain physical characteristics of the electric grid such as transmission limits and resource specific losses (and other physical limits on the grid, including generator ramp rates and minimum generation loading points). The unconstrained schedule determines the Ontario uniform market price – the HOEP – which reflects the marginal cost of the last unit of supply used to meet demand assuming a total system loss and no transmission constraints. The constrained schedule minimizes the cost of supply to meet demand but considers the physical characteristics of the grid to reliably dispatch generation and demand resources. The constrained schedule also determines prices at various (injection and withdrawal) points or nodes on the grid. Nodal prices offer an indication of local area supply and demand conditions, reflecting the physical constraints on local area supply or demand caused by limits on transmission and the effects of transmission losses. Nodal prices reflect the marginal cost of supply to meet demand at each node on the grid and can differ by its location depending on transmission congestion and transmission line losses.

[57] Note, in practice traders buy power in real-time or day-ahead markets and from locations beyond those adjacent to Ontario. For this discussion, we assume the purchase price to be the real-time price in the external market adjacent to Ontario. This assumption does not detract from the general point made in this section regarding efficient trade flows.

above the HOEP). However, because of limited transmission capability from the East-West Tie, it would be economically scheduled in the constrained schedule (competitive offer price below the NW zone nodal price). The import would be constrained-on (scheduled in the constrained schedule but not the unconstrained schedule). The importer would receive the HOEP for each MWh scheduled in the constrained schedule, which is less than its competitive import offer price. However, the import would also be eligible for a constrained-on CMSC payment that pays the difference between the import offer price and the HOEP for each MWh scheduled in the constrained schedule. The CMSC payment would ensure the trader would not incur a negative gross profit margin.

As a result, traders that imported into Ontario from MISO during the 3 years should in theory have had an incentive to offer at the competitive price. In theory, traders' incentives under the two-schedule system should be consistent with the incentives to efficiently import under an effectively competitive market with locational pricing.[58]

In contrast, consider the incentives to export. In a competitive market with a single schedule system and locational pricing, traders that export from Ontario to MISO would want to bid, to purchase electricity from the Ontario market, at the price they would receive by selling electricity in MISO minus transaction costs (i.e., the competitive export bid price). By bidding at the competitive export bid price, the trader limits the risk of earning a negative profit margin.[59]

[58] Note that import traders aware of these pricing and payment conditions have an incentive to offer at a price that is as close as possible to the relevant nodal price in the NW zone to maximize their CMSC payment. This strategy is referred to as pay-as-bid or nodal price-chasing behaviour. While the strategy does not undermine the efficient scheduling of imports (unless the importer incorrectly guesses the nodal price and offers above it), it can lead to larger CMSC payments and a transfer of wealth from those that pay CMSC (Ontario consumers and exporters) to the import traders.

[59] In Ontario, imports and exports are scheduled one hour in advance of real-time. Traders do not know the actual price that they will have to pay to export or receive for their import until after the real-time market has concluded. For an export, bidding at the competitive export bid price does not eliminate the risk that the real-time price will rise above what the trader expected causing the trader to earn a negative profit margin on the trade. Imports are protected from real-time price uncertainty through the Import Offer Guarantee.

During the 3 years, the MISO prices were consistently above the HOEP but below the NW zone nodal price. Under the current two-schedule system, bidding at the MISO price (the competitive price bid) would mean the exports would be economically scheduled in the unconstrained schedule but not in the constrained schedule (i.e., the exports would be constrained-off). Before 2015, the export would have been eligible for a constrained-off CMSC payment that paid the difference between the export bid price and the HOEP for each MWh scheduled in the unconstrained schedule. That is, while the export would not flow, the trader would be compensated for the lost opportunity to buy at the lower HOEP and sell to MISO at the higher MISO price. Under this payment structure, the trader would be incentivized to bid the competitive bid price and not flow. This would be the efficient market outcome as it would avoid having power flow from the high-price, high marginal-cost NW zone, to a lower-price, lower marginal-cost region.

In 2015, the IESO eliminated constrained-off CMSC payments for exporters to address the Panel's concern that, under certain market conditions, traders could increase the amount of their constrained-off payments by bidding a price just below the relevant nodal price, a strategy referred to as "nodal price chasing."[60] Evidence of nodal price chasing and the transfer of wealth from consumers to traders through CMSC payments was the primary reason for the Panel's recommendation to eliminate constrained-off payments to exports. While the elimination of constrained-off payments eliminated this behaviour and the corresponding high constrained-off CMSC payments, it created an incentive for traders under certain market conditions to increase their bid prices ***above*** the competitive bid price and ***above*** the relevant nodal price to ensure

[60] Note again that traders aware of these pricing and payment conditions would have an incentive to bid at a price that is as close as possible to the relevant nodal price in the NW zone to maximize their constrained off CMSC payment. While the strategy does not undermine the efficient scheduling of exports (unless the exporter incorrectly guesses the nodal price and bids above it), it can lead to larger CMSC payments and a transfer of wealth from those that pay CMSC (Ontario consumers and other exporters) to the export traders. Evidence of nodal price chasing and the extraction of wealth through CMSC payments was the primary reason for the Panel's recommendation to eliminate constrained-off payments to exports.

the export was scheduled in the unconstrained and constrained schedule.[61] That is, whenever the anticipated MISO price is higher than the HOEP plus transaction costs, bidding above the nodal prices and competitive levels results in the export being scheduled in both the unconstrained and constrained schedule. However, since the trader only pays the HOEP, they have ensured a positive gross profit margin. This however also means that at times, electricity flows from the high-price region to the low-price, which is inefficient.

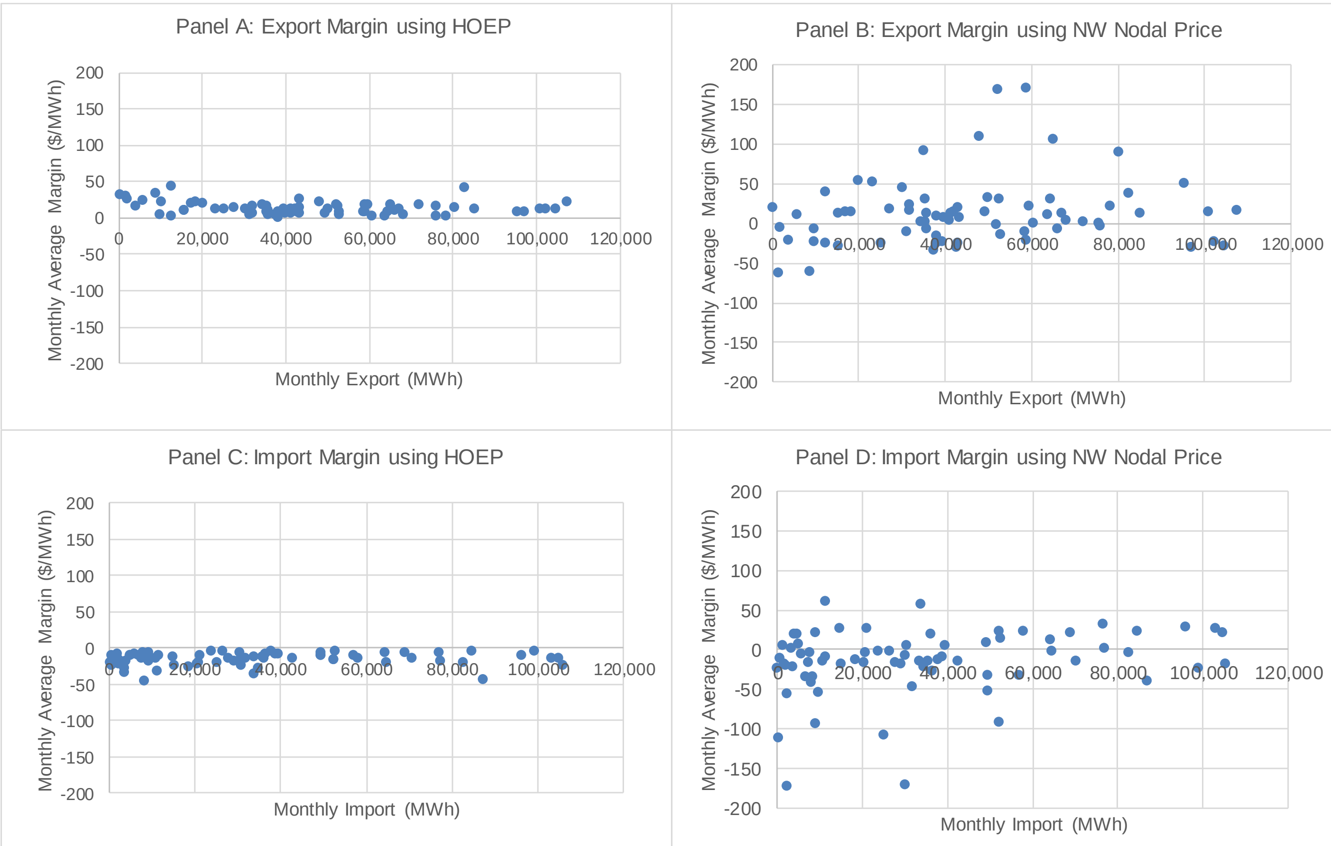
Figure 3-7 illustrates how the Ontario market design, specifically the two-schedule system can induce inefficient intertie trades. Panels A and B plot the implied monthly average gross profit margin[62] per MWh of export and monthly export flows to MISO (through MB or MN interties) during the 3 years (so there are 12 months*2 interties*3 years = 72 points in each panel), using either the HOEP or the NW zone nodal price as the assumed export purchase price from Ontario. Panel A indicates that on average, exports would have realized a positive gross margin for trades based on the HOEP and Panel B shows frequent negative gross profit margin for trades based on the NW zone nodal price. Since traders are in the business of making profits, it seems apparent that traders targeted the HOEP when submitting their export bids. To realize positive export flows and positive margins, these traders would have had to bid above the NW zone nodal price and above the delivered price in MISO (the competitive bid price).[63] While this strategy leads to privately profitable outcomes for the trader, it results in socially inefficient electricity flows from a high-cost region to a low-cost region.

[61] This incentive can be present on all interties depending on the market conditions, including the relationship between HOEP, relevant nodal price, and the external jurisdiction price.

[62] The gross profit margin is calculated as the difference between the price that a trader is paid to inject electricity in the import jurisdiction, and the price the trader pays to withdraw electricity from the export jurisdiction. The gross profit margin does not net out other variable costs (e.g., transmission tariff fees) of the transaction or any of the trader's fixed costs from maintaining its trading business.

[63] Note that there is a risk to the traders following this strategy. If the intertie were congested by exports bids more than can be accommodated by the intertie flow limit, the export could be unprofitable when the Intertie Zone Price (IZP) is greater than the delivered price in MISO. The traders can hedge this risk by purchasing transmission rights (TRs). TR ownership at MB and MN interties are very low relative to export flow, suggesting the perceived risk of congestion is low.

Figure 3-7: Implied Monthly Average Gross Profit Margins for Exports and Imports using the HOEP and NW Nodal Price, (Jan 2019 - Dec 2021)



Panels C and D plot the implied monthly average gross profit margin for imports from MISO during the 3 years, using either the HOEP or the NW zone nodal price as the assumed import delivered price to Ontario. A comparison of Panels C and D shows that traders were incented to target the NW zone nodal price when offering imports since import margin using the HOEP tend to be negative, so the market design on average induced efficient import flows.

Perhaps a more important observation is that exporters' incentives to inefficiently export electricity can be inconsistent with the reliable operation of the grid during periods of locational supply scarcity such as the supply scarcity experienced within the NW zone beginning in the Summer 2020 Period. Under the current market design, exporters can be encouraged to export from a supply-constrained zone, potentially exacerbating the supply scarcity conditions and creating operational concerns for the system operator.

For example, a key concern of the IESO in its management of the scarcity conditions and operation concerns in the NW zone in 2020 and 2021 was the effect that the demand for net exports from the NW zone to MISO (i.e., exports minus imports) had on the allocation of energy-limited hydroelectric generation.[64]

Hydroelectric resources in the NW zone are, for the most part, energy limited; the amount of electricity that can be produced from a hydroelectric resource is limited by the availability of water in the river systems. When water levels are low, hydroelectric resources may be able to generate electricity at full capacity in only a few hours a day. These resources typically can store water in forebays for short periods, which allows the operators of these resources to target which hours of the day they want to use the limited water to generate. Efficient use of energy-limited hydroelectric resources targets production in the hours when the output is expected to have the highest value, which are typically the peak demand hours. In a period of supply scarcity, if the hydroelectric generation is allocated inefficiently (i.e., used in hours when it does not have the highest value), there may be insufficient supply to meet peak demand, creating a reliability concern for the system operator.[65]

During the review period, the IESO grew concerned that net export demand, if not managed, could induce a misallocation of the energy-limited hydroelectric generation. In particular, the use of the limited hydroelectric output in the off-peak hours to supply positive amounts of net exports could lead to insufficient hydroelectric generation to supply NW zone consumers' demand during peak demand hours.

[64] See https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/aifl/adjustments-to-intertie-flow-20211112-presentation.ashx, and the recorded presentation at https://youtu.be/EPfRDlzh2gE for a summary of the IESO's perspective on the issues in the NW zone.

[65] In the presentation mentioned in Footnote 64, the IESO says "In order to manage reliability, the IESO applied transmission limits that limited the net export of power from the region". Section 3.1.4 discusses the actions.

The IESO's concern was further complicated by a shortcoming in the current pre-dispatch scheduling process. The IESO's pre-dispatch scheduling process currently optimizes supply and demand on an hour-by-hour basis. It does not optimize supply and demand intertemporally across several hours on a forward-looking schedule nor does it consider the daily energy limits of hydroelectric generation resources when scheduling output from these resources. If the IESO's pre-dispatch scheduling process was designed to optimize supply and demand across the 24 hours in a day and to recognize the daily energy limits of hydroelectric generation resources, the process would have limited the scheduling of positive net export volumes in off-peak hours to preserve energy-limited resources and avoid shortages of supply to meet internal demand in future peak hours.[66]

In summary, there was a relative scarcity of domestic supply to the NW zone during the Summer 2020 Period and continuing through 2021. The relative scarcity of supply was due to the reduced availability of hydroelectric generation within the NW zone and reduced supply to the NW zone from the rest of Ontario due to limited transfer capability over the East-West Tie. The scarcity conditions were exacerbated by a market design flaw that induced inefficient exports from the NW zone and was further complicated by a shortcoming in the IESO's pre-dispatch process, which does not recognize daily energy limits on hydroelectric generation output and optimize supply and demand intertemporally across the hours in a day.

During the review period, the IESO took specific actions to limit net exports from the NW zone to MISO to manage operational concerns created by the scarcity conditions and further complicated by the market design flaw. The implications of each of the IESO's actions for import and export schedules and CMSC payments are discussed in the next section.

[66] Furthermore, the IESO considers supply from imports to be "non-firm." As a result, while there may have been sufficient net imports offered to supply NW zone demand in the peak hours, the IESO would not rely on the availability of these non-firm imports to manage perceived resource adequacy issues such as the ones present in the NW zone in 2020 and 2021.

3.1.4 IESO's Approaches to Managing the Operational Challenges

Rather than allowing the market to allocate resources and maintain system balance and security, the IESO used three different approaches to manage its concern of a misallocation of energy-limited hydroelectric generation output during the review period rather than allowing the market to respond to its concern. First, the IESO curtailed exports, which is one of the actions on the Emergency Operating State Control Actions list outlined in Market Manual 7. This type of control action is used fairly frequently to deal with perceived reliability events but is usually a short-term action, typically lasting only a few hours at a time.

Figure 3-8: Monthly Average OSL on Northwest Net Export (Jan 2019 - Aug 2021)

By the early part of the Summer 2020 Period, export curtailments were a frequent occurrence. Export curtailments are a manual action, and the increased frequency of curtailments placed a burden on the workload of IESO control room staff. From August 2020, the IESO started to rely less on curtailing exports and more on a second approach to managing its reliability concerns.

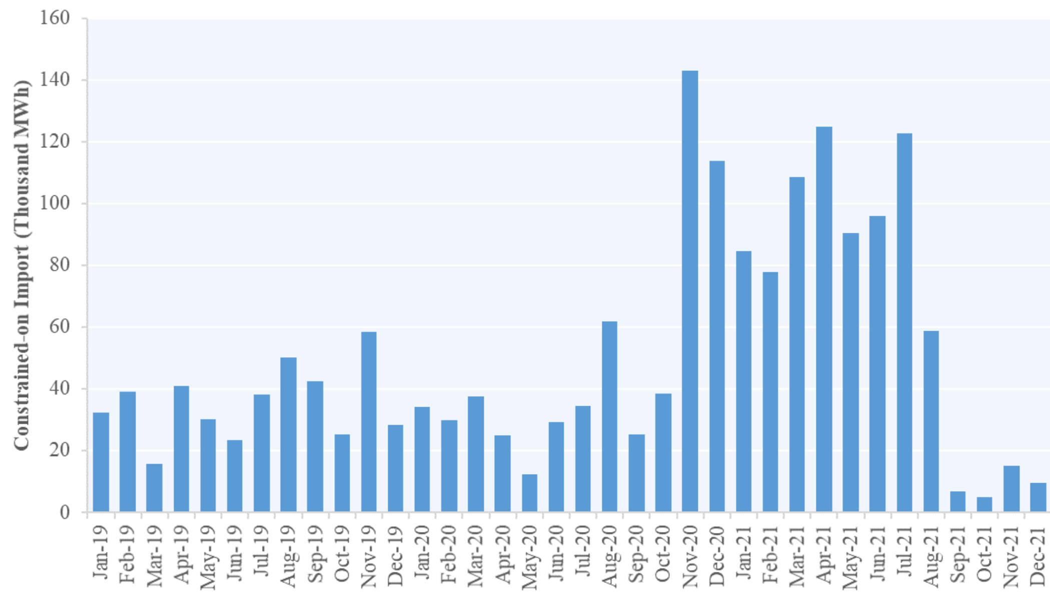
This automated approach, which began in the spring of 2020, involved the use of a unique operating security limit (OSL)[67] to address system adequacy issues internal to Ontario. This unique OSL identifies the amount of available spare generation within the NW zone over and above what the IESO believes is needed to supply NW zone demand and also considers the transfer capability of the East-West Tie. The IESO then imposes a constraint on the maximum volume of net exports to MISO from the NW zone.

As Figure 3-8 illustrates, beginning in the spring of 2020 the IESO began to gradually lower the OSL to restrict the use of internal generation to supply net exports. Changes to OSLs affect the constrained schedule but do not affect the unconstrained schedule. A consequence of the IESO's gradual reduction in the OSL was that the IESO's scheduling optimization process considered it optimal to constrain on relatively high-priced imports to offset the even higher bid exports. Figure 3-9 illustrates how beginning in November 2020, and ending in September 2021, there was a marked increase in the amount of constrained-on imports. A comparison of Figure 3-9 to Figure 3-1 (in section 3.1.1) shows that the marked increase in constrained on imports coincided with the marked increase in CMSC payments paid on import trades in the NW zone.[68]

[67] The use of unique OSLs to address provincial adequacy concerns was introduced in 2015.

[68] Note that the use of the OSL, coupled with the market design flaw that incentivizes inefficient exports, could have also induced inefficient imports, by scheduling the flow of electricity from a high-priced jurisdiction (i.e., MN) to a low-priced jurisdiction (i.e., MB). Furthermore, the use of the OSL, by design, made imports the primary supplier for inefficiently bid export demand (i.e., restricted potential competition for the export from suppliers within the NW zone). This could have made a strategy of nodal price chasing even more possible, contributing to higher CMSC payments.

Figure 3-9: Monthly Constrained-on Imports into the Northwest (Jan 2019 - Dec 2021)



The use of the OSL effectively addressed the IESO's reliability concerns regarding the potential misallocation of energy-limited hydroelectric resources. However, it induced a new concern related to the use of constrained-on imports to supply export demand and the corresponding high CMSC payments. In August 2021, the IESO deviated from the OSL approach and implemented a new procedure restricting the intertie scheduling limits. Under the procedure, the control room operators determine the total allowable MW schedule across both MB and MN interties and set each intertie scheduling limit to half of the allowable MW.[69]

The procedure is implemented in an IESO tool called INPARM (i.e., input parameters) which, in contrast to the OSLs, affects the inputs used in both the constrained and unconstrained schedules. The introduction of the new procedure limited the volume of net exports scheduled

[69] Unequal allocation of the total allowable MW is allowed based on system conditions.

from the NW zone to an amount the IESO deemed could be supplied by generation within the NW zone in both the constrained schedule and the unconstrained schedule. This limited the amount of export demand in the market[70] and as a result, reduced both the export and import volumes and correspondingly the CMSC payments.

Figure 3-10: Monthly Average INPARM Limit on Net Exports from the Northwest (Jan 2019 - Dec 2021)

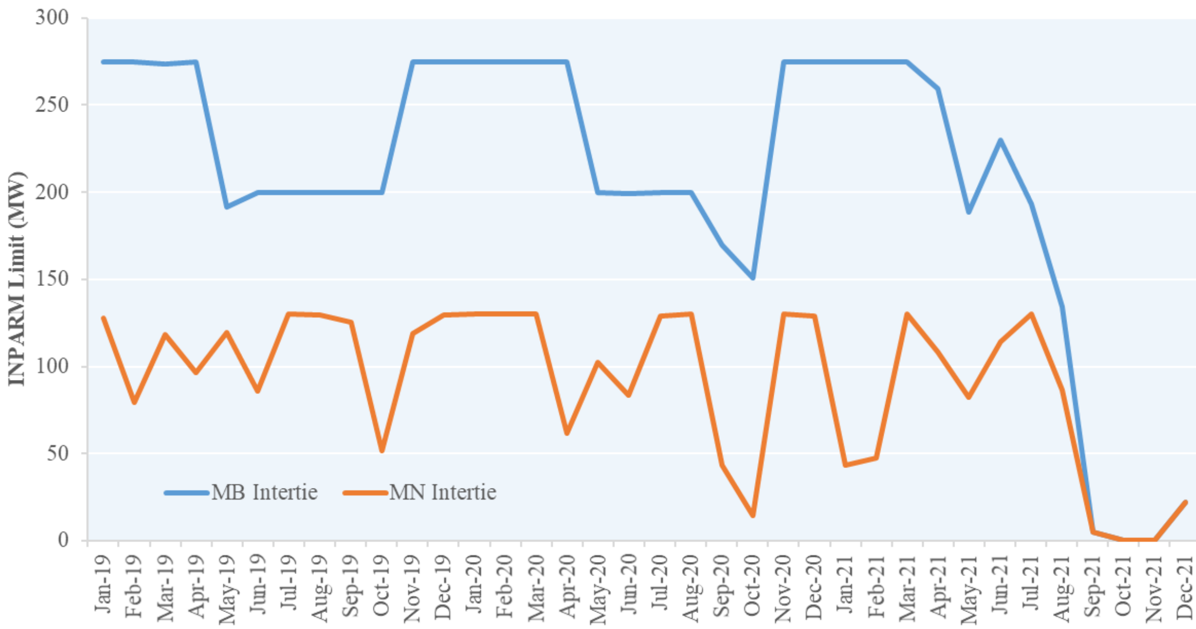


Figure 3-10 shows how the monthly average INPARM limits on net exports changed over the three years. There was a marked decline in the limits in August 2021. A comparison of Figure 3-10 with Figure 3-9 and Figure 3-1 shows that the reduction in INPARM limits in August 2021

[70] The reduced intertie scheduling limits make export congestion more likely than before, dampening the demand for exports. Footnote 63 explains the risk to exporters associated with congestion.

coincided with a significant reduction in constrained-on imports and CMSC payments paid to imports.[71]

3.1.5 The Panel's Overall Observations

The Panel makes the following observations from its analysis of the causes of the anomalously high CMSC payments paid to traders in the NW zone in the Winter 2020/21 Period and Summer 2021 Period.

The IESO has not substantiated its stated reliability concerns with a determinative analysis of the existence and magnitude of a reliability issue. The Panel's observations are premised on the existence of a bona fide reliability issue warranting an initial IESO intervention.

The flaws inherent in Ontario's two-schedule system induced inefficient exports from the NW zone during the Winter 2020-21 and Summer 2021 Periods. These inefficient exports occurred at a time when there was a relative scarcity of supply from within the NW zone due to limited hydroelectric generation output, and limited supply from the rest of Ontario due to reductions in the transfer capability of the East-West Tie. The inefficient exports exacerbated the supply scarcity issue within the NW zone by drawing on supply from energy-limited hydroelectric resources during non-peak demand hours risking the depletion of these resources before peak demand hours when the supply may have been needed to meet peak NW consumers' demand. The IESO's current pre-dispatch scheduling process which optimizes supply and demand on an hour-by-hour basis rather than intertemporally across many hours in the day exacerbated the situation. The inefficient exports and the lack of multi-hour optimization in the pre-dispatch scheduling process was perceived as a reliability issue for the IESO that triggered the IESO to

[71] As described above in section 1.1.1 of this report, the Market Assessment and Compliance Division determined that in imposing of limits on intertie flows based on internal transmission constraints the IESO was in non-compliance with the market rules then in force and assessed a penalty against the IESO. The IESO has since amended the Market Rules to align with their actions.

intervene in the market to manage the operating conditions in the NW zone rather than allowing the market to supply energy.

The inefficient exports from the NW zone to MISO and the shortcoming of the current market design failing to optimize the use of daily energy-limited hydroelectric output during the review period highlights the need to implement the single schedule system with locational marginal pricing and multi-hour optimization in the day-ahead and pre-dispatch time frames that among other things account for hydroelectric generation daily energy limits as contemplated under the IESO's Market Renewal Program. If export transactions were settled on locational marginal prices for electricity purchased from Ontario through the NW zone, rather than the HOEP, there would have been considerably fewer inefficient net exports which would have alleviated the IESO's concerns regarding reliability due to the misallocation of energy-limited hydroelectric generation. Furthermore, multi-hour optimization in the day-ahead and pre-dispatch time frames that respects hydroelectric generation daily energy limits would have more automatically addressed the IESO's concern regarding the misallocation of energy-limited hydroelectric generation, even in the face of inefficient net exports.

The IESO's response to operational challenges in the NW zone during the review period illustrate how the IESO's actions to intervene in the market to manage what they perceived to be reliability concerns can have material impacts on market outcomes and the cost to Ontario electricity consumers. The IESO's action to limit the OSLs on net exports from the NW zone in the spring of 2020 addressed the IESO's perceived reliability and operational concerns but led to a substantial increase in CMSC payments for imports. Its decision to adjust intertie flow limits through IMPARM, which impacts the unconstrained schedule and so could not have had a reliability purpose, nonetheless substantially reduced CMSC payments.

The IESO's actions can have a material effect on market outcomes and consumer costs. As such, it is prudent for the IESO to have a process in place to ensure that before an action is taken to manage reliability, an ex-ante assessment is conducted to determine that the action is indeed required and was analyzed across all possible actions and deemed to be the least cost means to address the reliability concern. The Panel understands that such an assessment may be impossible under urgent situations and in these cases the ex-ante assessment should be performed on a best efforts basis. Furthermore, an ex-post assessment of the IESO's action should also be undertaken after the IESO has addressed the need for the required action. The ex-post assessment should 1) provide a follow-up analysis of whether the IESO actions were the least costly means to achieve the desired outcome, 2) aim to inform market participants of the ex-ante analysis used by the IESO and, if applicable, an explanation of why an ex-ante analysis was not performed, and 3) aim to establish best practices to improve future IESO decision-making around reliability actions. The ex-post assessment should be made public and the IESO should host a stakeholder engagement to review the assessments to promote transparency and foster improvements to future assessments.

Appendix A:Market Outcomes for the Summer 2021 Period

This Appendix reports on outcomes in the IESO-administered markets for the Summer 2021 Period (May 1, 2021 to October 31, 2021), with comparisons to previous reporting periods as appropriate.

Prices, Charges, and Rates in IESO-Administered Markets

Prices, charges, and rates have specific and distinct meanings in the context of IESO-administered markets. These terms are used distinctly in Appendix A.

Prices are determined in the Energy (e.g. MCP, HOEP, and nodal prices), Operating Reserve (e.g. OR prices), and Transmission Right markets (e.g. TR auction prices) and develop through each market's competitive processes. Generally, the prices in energy and OR markets are used to determine payments to market participants providing products and services to each market. They can be a component of the charges paid by consumers.

Charges, which include the commodity charge HOEP (total of the sum of [HOEP multiplied by hourly consumption]), Global Adjustment, and uplift, are fees paid by market participants consuming power. Some charges are levied based on different factors such as energy volume and/or contribution to peak. For example, the commodity *charge* HOEP is based on the Hourly Ontario Energy *Price*, and is levied based on a market participant's energy consumption.

Rates for various categories are the total payments in those categories divided by the categories' total consumption expressed per unit of consumption over a period of time. These are meant to provide an illustration of the average fees incurred in that category.

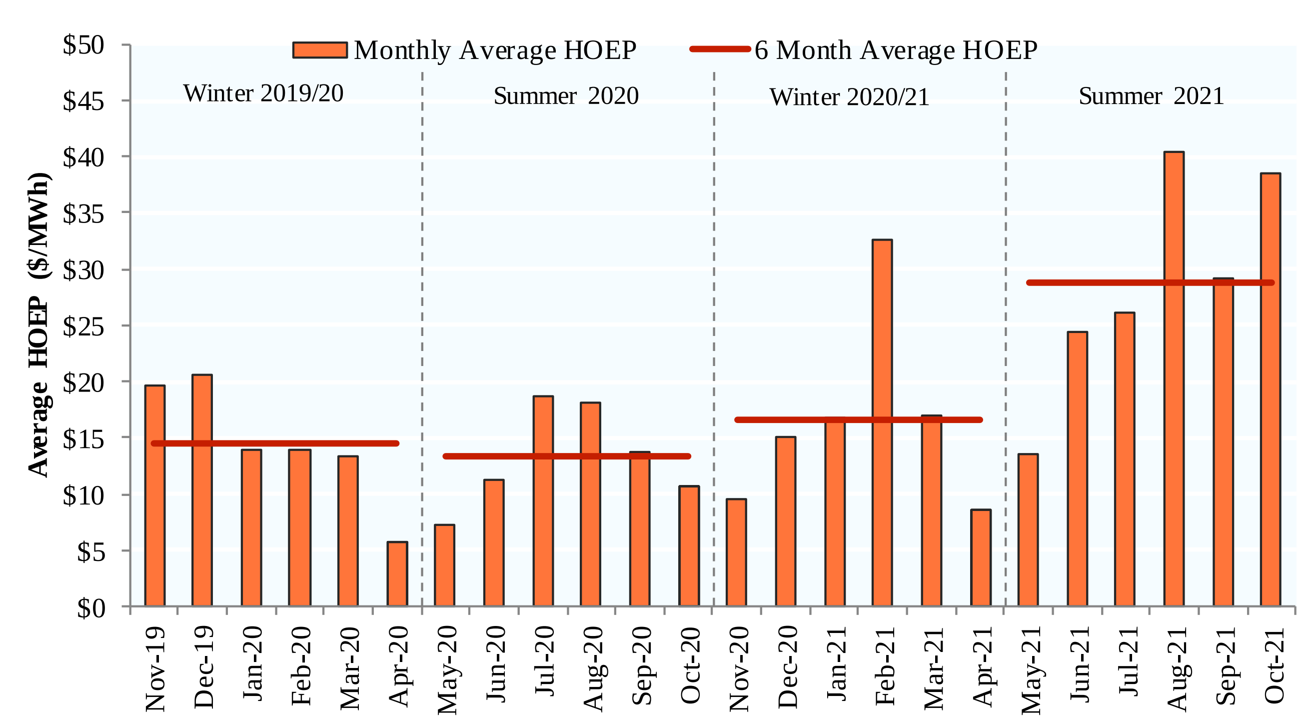
A.1 Pricing

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), Operating Reserve (OR) prices, and Transmission Rights (TR) auction prices.

A.1.1 Hourly Ontario Energy Price (HOEP)

Figure A-1 displays the monthly unweighted average HOEP and the 6-month period average since November 2019. During the Summer 2021 Period, there was a significant increase in the unweighted 6-month average HOEP compared to the Summer 2020 Period, rising from $13.29/MWh to $28.73/MWh.

Figure A-1: Monthly & 6 Month (Simple) Average HOEP, 2 Years



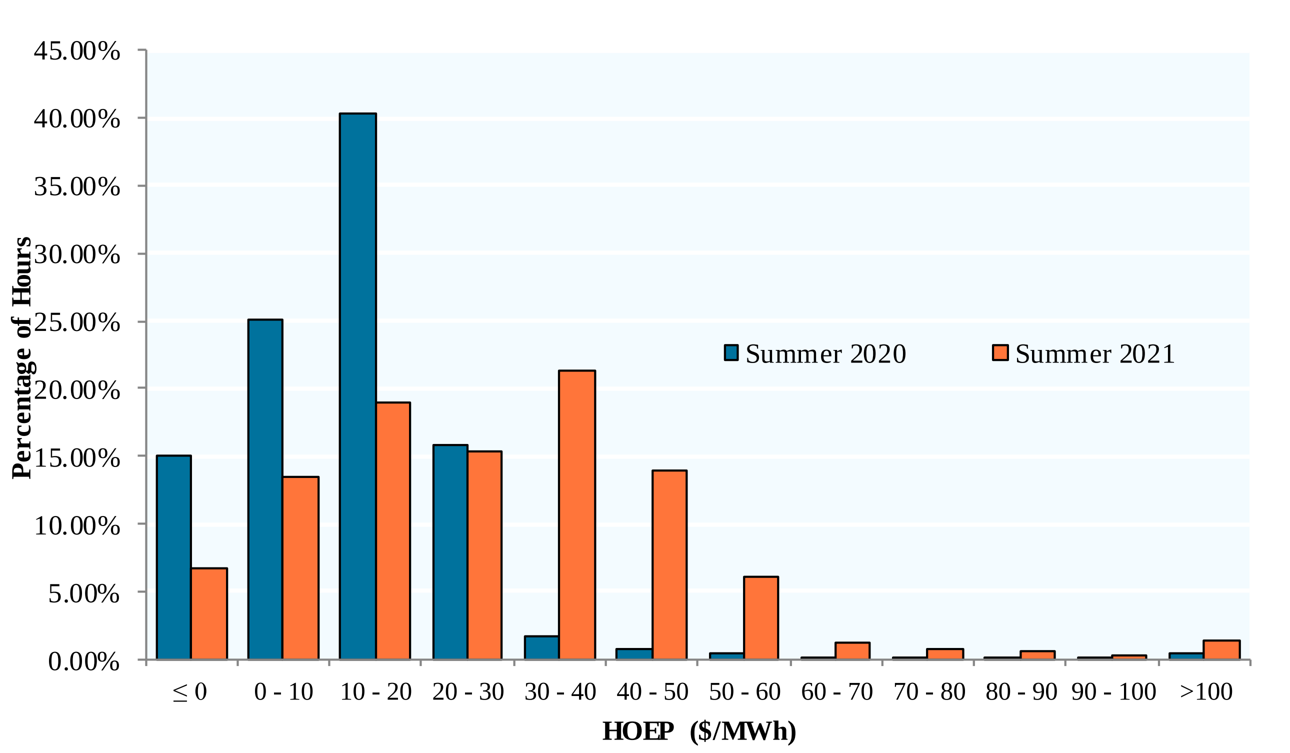
While intra-day prices usually rise and fall with the normal daily cycle of demand causing more or fewer of the higher-priced resources to be scheduled, period to period changes can be affected by changes in both supply and demand. Demand was about the same in the Summer

2021 Period as compared to the Summer 2020 Period. Decreased available capacity due to nuclear and hydro outages – which can indicate tighter supply conditions and result in more expensive resources setting the MCP more frequently – likely contributed to the increase in the HOEP during the Summer 2021 Period (see Figure A-18). To replace the lower cost nuclear and hydro resources on outages, gas resources were on the margin more frequently in the Summer 2021 Period at 62% of the time (up from 53% in the Summer 2020 Period) (see Table A-1).

An additional factor increasing the HOEP was higher gas prices in the Summer 2021 Period (see Figure A-7).

Figure A-2 compares the frequency distribution of the HOEP as a percentage of total hours for the Summer 2020 and Summer 2021 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh hours.

Figure A-2: Frequency Distribution of the HOEP, 2 Periods



During the Summer 2021 Period, the HOEP was negative for about 7% of hours, compared to 15% in the Summer 2020 Period. The HOEP was at least $20/MWh for 61% of hours in the Summer 2021 Period, up from 20% in the Summer 2020 Period, likely due to the increased gas prices and the share of intervals where gas set the MCP.

Table A-1 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch MCP, including imports and exports, and the share of hours in which each resource type set the real-time MCP in the Summer 2020, Winter 2020/21, and Summer 2021 Periods. The shares do not add up to 100% as more than one resource can set the MCP at any given hour.

Table A-1: Share of Hours of Resource Type Setting the Pre-Dispatch and Real-Time MCP, 3 Periods

Resource	Summer 2020		Winter 2020/21		Summer 2021	
	PD-1	RT	PD-1	RT	PD-1	RT
Hydro	23%	39%	19%	49%	17%	43%
Wind	11%	21%	9%	20%	5%	11%
Gas	36%	53%	32%	42%	41%	62%
Nuclear	0%	1%	0%	0%	0%	0%
Solar	1%	0%	1%	0%	0%	0%
Biofuel	1%	2%	1%	2%	0%	0%
Imports	13%	-	30%	-	27%	-
Exports	31%	-	23%	-	23%	-
Loads	1%	-	2%	-	1%	-

Figure A-3 presents the share of hours in which each resource type set the real-time MCP during the Summer 2020, Winter 2020/21, and Summer 2021 Periods. Figure A-4 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP during the Summer 2020, Winter 2020/21, and Summer 2021 Periods. When compared with Figure A-3, Figure A-4 shows how the marginal resource mix changes from pre-dispatch to real-time.

Figure A-3: Share of Resource Type Setting the Real-Time MCP, 3 Periods

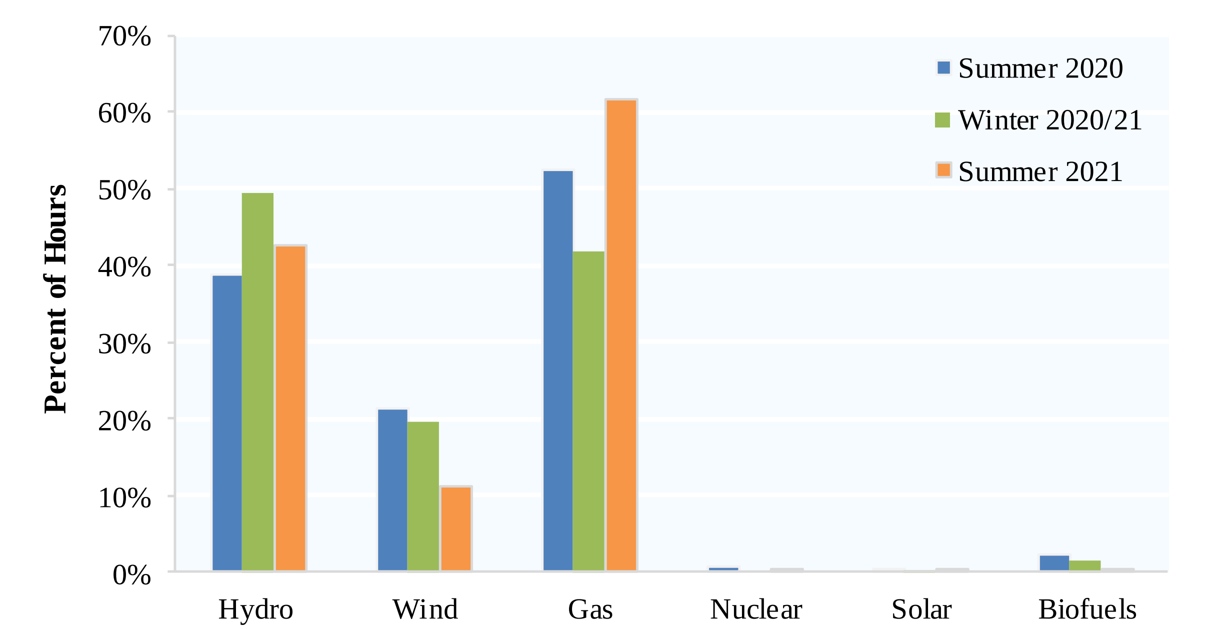
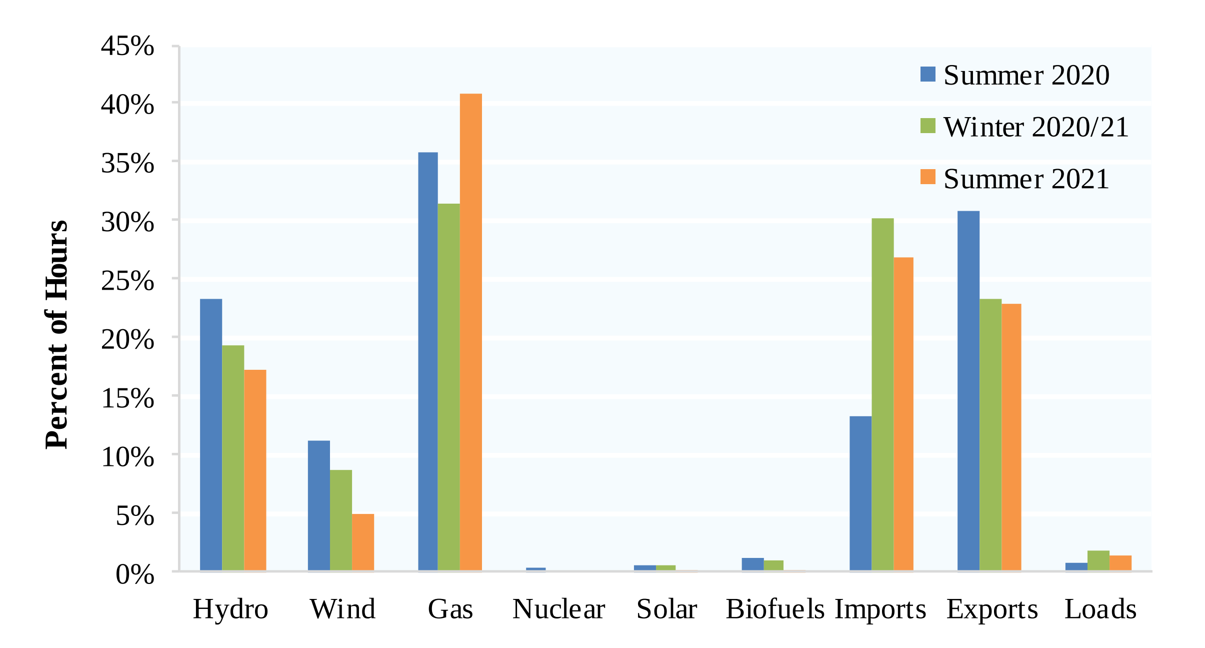


Figure A-4: Share of Resource Type Setting the One-Hour Ahead Pre-Dispatch MCP, 3 Periods



The percentage of intervals where wind set the real-time MCP decreased significantly to 11% in the Summer 2021 Period from 21% in the Summer 2020 Period. With less lower-priced wind, and with nuclear and solar on the margin, natural gas resources set the real-time MCP more frequently at 62% in the Summer 2021 Period, up from 53% in the Summer 2020 Period. Gas resources set the real-time MCP more often in the month of August 2021 than in any other month in the past two years. August 2021 experienced the peak demand in the Summer 2021 Period, likely necessitating the increase in output from more expensive gas resources and resulting in the increase in the percentage of hours where gas set the real-time MCP.

The frequency with which imports and exports set the pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[72] 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. Imports set the PD-1 MCP in 27% of hours in the Summer 2021 Period, compared to 13% in the Summer 2020 Period, likely contributing to the increase in the divergence between the pre-dispatch and real-time MCPs (see Figure A-5 and Figure A-6). Similar to the real-time marginal resource mix, gas resources set the pre-dispatch MCP more often in the month of August 2021 than in any other month in past two years, likely due to increased demand.

The (PD-3) MCP is the last price signal seen by the market prior to the closing of the offer and bid window. Changes in price between PD-3 and the HOEP are particularly relevant to non-quick start facilities and energy limited resources, both of which rely on pre-dispatch prices to make

[72] Due to scheduling protocols, imports and exports are scheduled hour-ahead. In real-time, imports and exports are fixed for any given hour and are treated as non-dispatchable resources by the dispatch scheduling optimizer (DSO). The DSO treats the offers and bids as -$2000/MWh and $2000/MWh for imports and exports respectively as they are scheduled to flow for the entire hour regardless of the price, though their schedules may be curtailed within an hour to maintain reliability.

operational decisions.[73] Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

The PD-1 MCP and the PD-1 schedules are used for import and export transactions for real-time delivery. While intertie transactions are scheduled based on the PD-1 MCP, they are settled based on the Intertie Zonal Price (IZP). 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 real-time MCP.

Figure A-5 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Summer 2020, Winter 2020/21, and Summer 2021 Periods. Figure A-6 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2020, Winter 2020/21, and Summer 2021 Periods. [74] Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.

[73] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day but can optimize their production over their storage horizons. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

[74] The price differences for Figure A-5 and Figure A-6 are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP, as well as the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$20/MWh.

Figure A-5: Difference between the HOEP and PD-3 MCP, 3 Periods

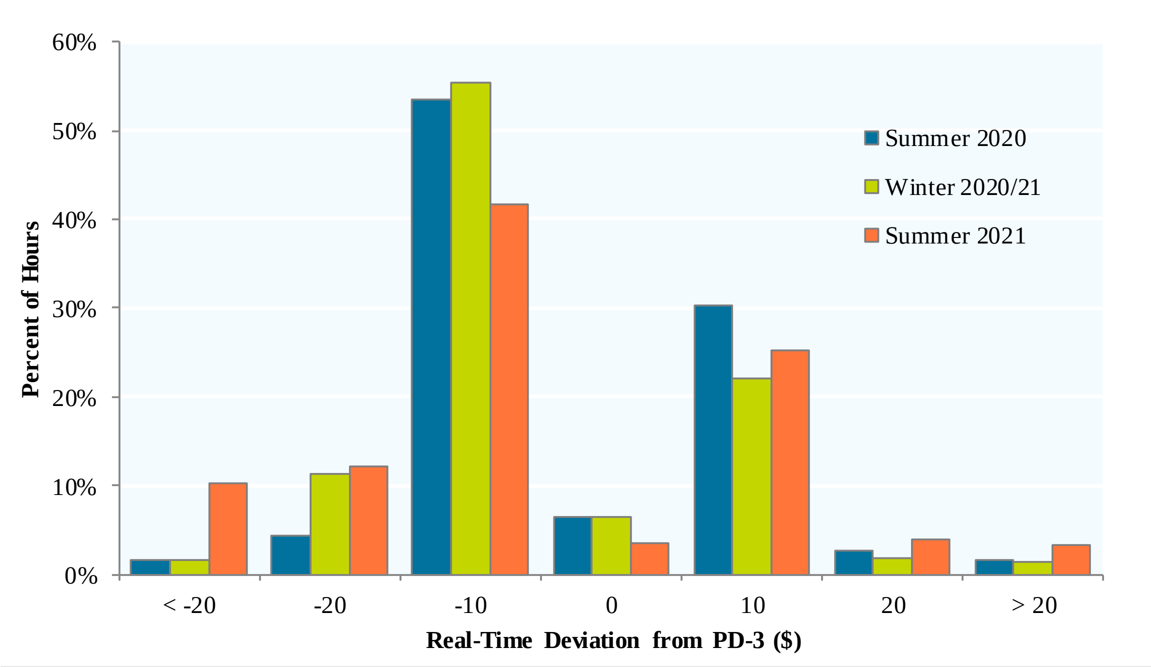
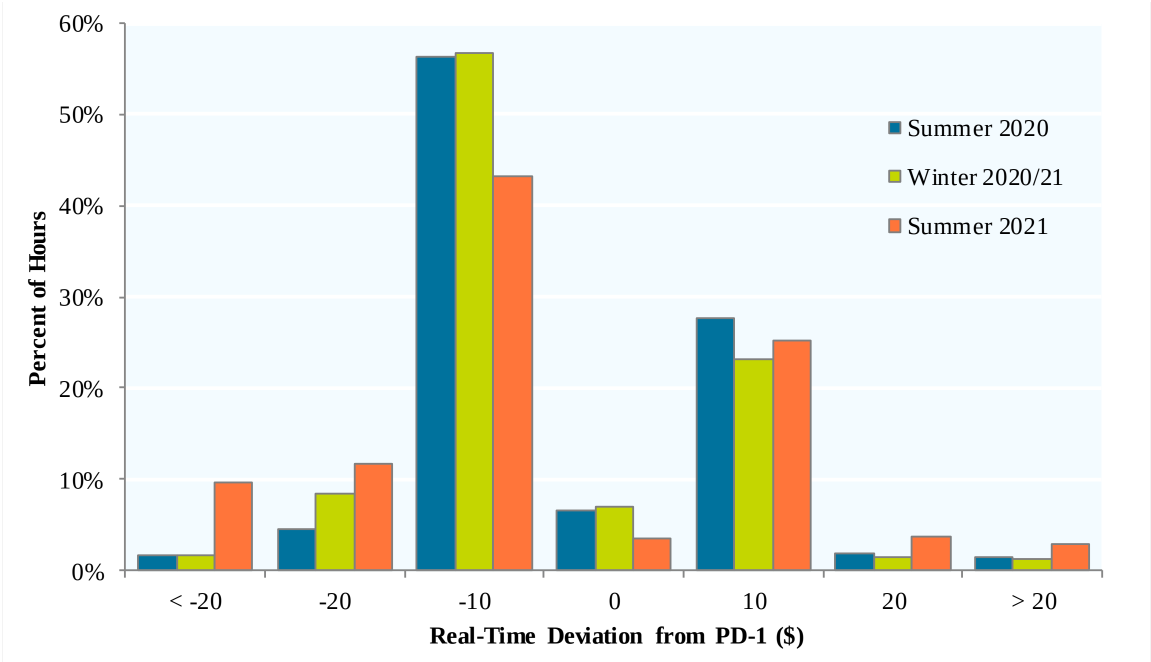


Figure A-6: Difference between the HOEP and PD-1 MCP, 3 Periods



The PD-1 and PD-3 prices were closely aligned, both showing increased deviations from the real-time MCPs in the Summer 2021 Period. The average absolute deviation between the PD-3 and real-time MCPs approximately doubled in the Summer 2021 Period from the Summer 2020 Period ($10.16/MWh compared to $4.96/MWh). The average absolute deviation between PD-1 and real-time prices comparably doubled in the Summer 2021 Period from the Summer 2020 Period ($9.47/MWh compared to $4.77/MWh).

Real-time prices diverge from PD-1 prices because of changing conditions from pre-dispatch to real-time.[75,76] Identifying the factors that lead to deviations between the PD-1 MCP and the real-time MCP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as they enter offers and bids into the market.

Table A-2 displays the average absolute difference between PD-1 and real-time for all factors identified by the Panel as contributing to the difference between PD-1 and real-time, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

Table A-2: Factors Contributing to Differences between the PD-1 MCP and HOEP, 3 Periods

Factor	Summer 2020: Absolute Difference		Winter 2020/21: Absolute Difference		Summer 2021: Absolute Difference	
	Average (MW)	Maximum (MW)	Average (MW)	Maximum (MW)	Average (MW)	Maximum (MW)

[75] 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**: i) Self-scheduling and intermittent generation forecast deviation (other than wind), ii) wind generation forecast deviation, iii) generator outages and iv) import failures/curtailments. **Demand**: v) Pre-dispatch to real-time demand forecast deviation and vi) export failures/curtailments. Imports or exports setting the PD-1 MCP can also result in price divergences as these transactions cannot set the price in real-time.

[76] Intertie transactions can set PD-1 prices and are fixed for any given hour in real-time, which can cause a price deviation from pre-dispatch to real-time.

Ontario Demand	15,043	24,990	15,395	20,554	15,173	22,877
Forecast Demand Deviation	242	2,213	242	1,461	255	1,497
Self-Scheduling Generation and Intermittent Forecast Deviation (Excluding Wind)	15	81	12	70	13	83
Wind Generation Forecast Deviation	156	1,430	172	1,427	157	1,079
Net Export Failures/Curtailments	68	951	64	968	50	817

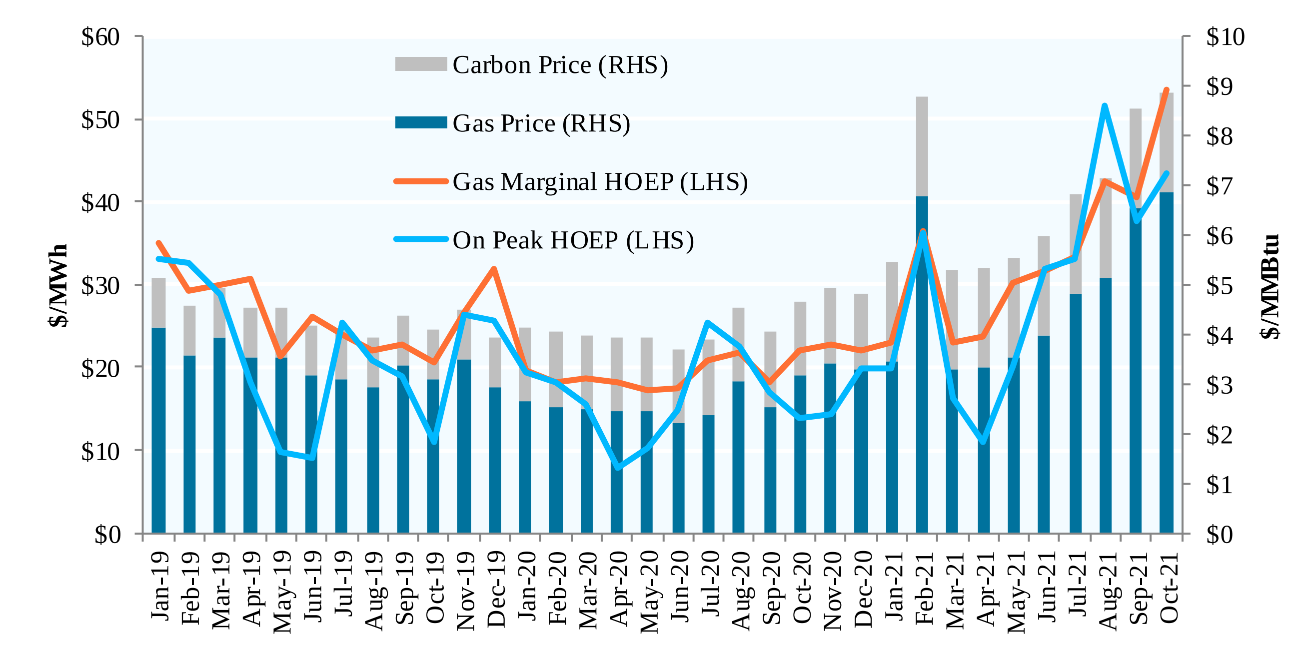
Figure A-7 compares the average monthly on-peak HOEP and the average monthly HOEP during hours where gas is the marginal resource to the sum of the monthly average of Henry Hub natural gas spot prices and the monthly carbon price.[77,78] When the supply of baseload generation is low, or when the demand for energy is high, higher cost natural gas resources often set the MCP. When these conditions occur, there is likely to be a stronger positive correlation between the on-peak HOEP and the price of natural gas.

Figure A-7: Natural Gas Price, Carbon Price, and HOEP during Peak Hours & during Hours where Gas is the

[77] On-peak hours are defined as 7:00 AM to 11:00 PM EST, Monday to Friday (excluding holidays). Off-peak hours are all other hours. Henry Hub spot gas price data is available from the U.S. Energy Information Administration: https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm.

[78] Carbon prices are represented in Figure A-7 as the contribution of the carbon price to fuel costs is becoming increasingly significant. Carbon prices were $20/tonne for 2019, $30/tonne for 2020, and $40/tonne for 2021. For additional information, see the following: https://www.canada.ca/en/services/environment/weather/climatechange/climate-action/pricing-carbon-pollution/output-based-pricing-system.html.

Marginal Resource, 3 Years[79]



The average gas price was $5.14/MMBtu in the Summer 2021 Period, nearly double the price of $2.63/MMBtu in the Summer 2020 Period.

A.1.2 Operating Reserve Prices

The three OR markets are co-optimized with the energy market, so prices in these markets tend to be positively correlated. The resulting schedule indicates the resources (MW) that are selected to be on standby/reserve and paid the price in the respective OR market. If and when a contingency occurs they are activated (up to the amount scheduled and at their offered ramp rate and energy price offer) and receive revenue that is the equivalent of the MCP or their energy price offer, whichever is greater. The OR demand is based primarily on reliability standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). At minimum, the IESO must schedule sufficient OR to allow the

[79] Refer to the right hand side (RHS) axis for carbon price and gas prices and refer to the left hand side (LHS) for gas marginal HOEP and on-peak HOEP.

grid to recover from the single largest contingency (such as loss of the largest generator) within 10 minutes, plus additional OR to recover from half of the second largest contingency or the loss of the largest commissioning generating unit within 30 minutes. In 2018, the IESO made a Market Rule change to enable increases to the 30-minute OR requirement, which has mainly been used to increase the scheduled amount of 30-minute OR by 200 MW to enable system flexibility.[80,81]

The Summer 2021 Period experienced lower OR prices than the Summer 2020 Period. Uplift from OR was $10.8 million for Summer 2021 Period, about half as much as the cost of OR in the Summer 2020 Period ($20.6 million). The 10-minute spinning price ($2.75/MW) and 10-minute non-spinning price ($1.86/MW) decreased by 44% and 48% compared to the Summer 2020 Period. The 30-minute reserve decreased by 36% compared to the Summer 2020 Period. While the supply mix did not change significantly in the Summer 2021 Period, less expensive resources like hydro set the price more often, and at lower prices than in the previous Summer Period. There was also an increase in gas supply in the Summer 2021 Period, resulting in a larger amount of spinning reserve which was scheduled in the OR market at lower prices.

Table A-3 reports the average operating reserve prices for the previous two years and Figure A-8 illustrates the monthly fluctuations of OR prices.

Table A-3: Average Operating Reserve Prices by Period, 2 Years

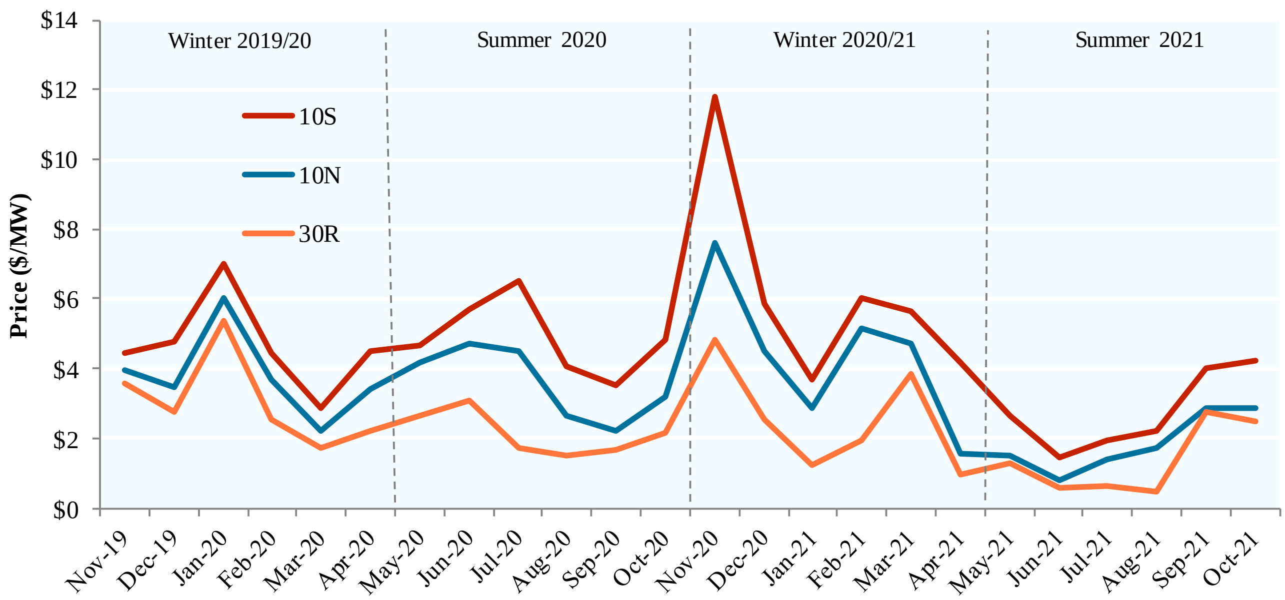
Operating Reserve Markets	Winter 2019/20 ($/MW)	Summer 2020 ($/MW)	Winter 2020/21 ($/MW)	Summer 2021 ($/MW)
10-minute spinning (10S)	4.67	4.88	6.20	2.75

[80] See the Market Rule Amendment “MR-00436: Enabling System Flexibility – Thirty-Minute OR”, approved by the IESO Board April 11, 2018: http://www.ieso.ca/-/media/Files/IESO/Document-Library/mr-amendments/mr2018/MR-00436-R00-Enabling-Flexibility-Amendment-Proposal-v5-0.pdf?la=en.

[81] This Market Rule Amendment and its justification was discussed in the Panel’s Monitoring Report 32, Chapter 3, published July 30, 2020: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf.

10-minute non-spinning (10N)	3.79	3.57	4.41	1.86
30-minute reserve (30R)	3.04	2.13	2.55	1.37

Figure A-8: Average Monthly OR Prices by Category, 2 Years



A.1.3 Nodal Prices

Nodal prices approximate the marginal cost of electricity in each location and reflect Ontario's internal transmission constraints. High average nodal prices are generally caused by expensive or limited supply while low average nodal prices are generally caused by cheaper or abundant supply. Differences in nodal prices across zones reflect transmission line losses and congestion.

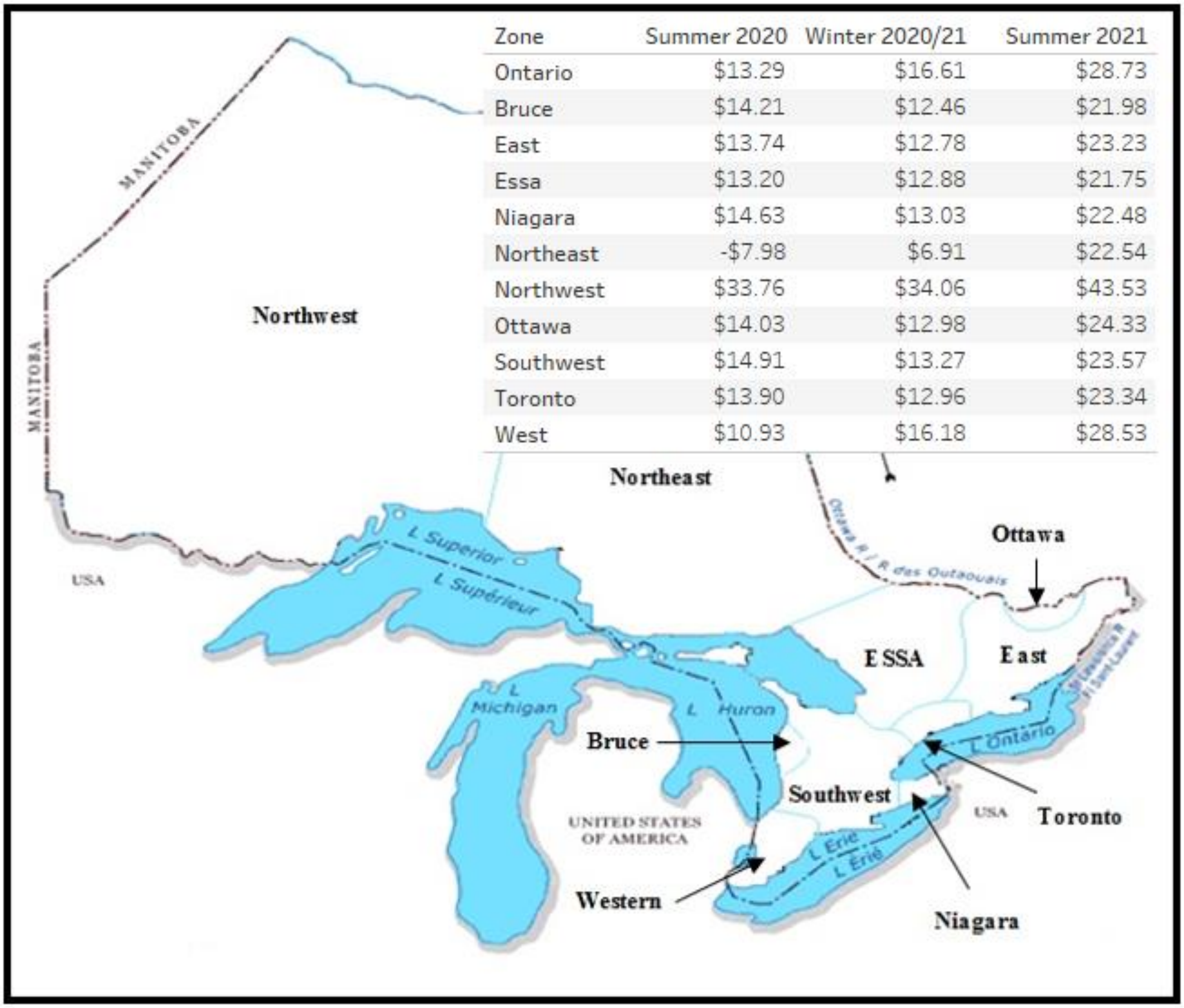
As shown in Figure A-9, most zones had higher average prices in the Summer 2021 Period compared to the previous Summer Period. The West and Northwest had higher prices than the other zones.

In general, monthly average nodal prices outside the two northern zones are similar and move together. Most of the time, the nodal prices in the Northwest and Northeast zones are significantly lower than in the rest of the province because there is more low-cost generation (typically hydroelectric supply) than there is demand in these zones, as well as insufficient transmission to transfer this low-cost surplus power to the southern parts of the province. While this generally leads to lower nodal prices in the Northwest and Northeast, this limited transmission capacity could also lead to high nodal prices. For these reasons, nodal prices in the Northwest and Northeast zones are generally highly sensitive to changes in demand and hydroelectric supply.

In addition, some hydroelectric facilities are required to operate at certain levels of output for safety, environmental or regulatory reasons. Under such conditions, market participants offer the energy at negative prices to ensure that the units are economically selected and scheduled as required. A surplus of water during a given period will likely increase production from hydroelectric facilities. The limited demand in the Northwest and Northeast, means that an increase in production from hydroelectric facilities could create local surpluses of power that exceed the capability of transmission lines required to move this power into southern load centres. The opposite of this effect occurred in the Northwest since the region's hydroelectric supply decreased and the nodal price increased substantially in the Summer 2021 Period, relative to historical averages and other zones in Ontario. The average monthly demand in Northwest did not experience significant changes in the Summer 2021 Period relative to the Summer 2020 Period. However, supply from hydroelectric generators in the Northwest fell by 19% in the Summer 2021 Period, relative to the Summer 2020 Period.[82]

[82] Hydroelectric supply conditions in the Northwest were evaluated by comparing the total hydroelectric supply available during a 6-month period across summer seasons. Winter seasonal totals were not compared.

Figure A-9: Average Internal Nodal Prices by Zone, 3 Periods[83]



Zone	Summer 2020	Winter 2020/21	Summer 2021
Ontario	$13.29	$16.61	$28.73
Bruce	$14.21	$12.46	$21.98
East	$13.74	$12.78	$23.23
Essa	$13.20	$12.88	$21.75
Niagara	$14.63	$13.03	$22.48
Northeast	-$7.98	$6.91	$22.54
Northwest	$33.76	$34.06	$43.53
Ottawa	$14.03	$12.98	$24.33
Southwest	$14.91	$13.27	$23.57
Toronto	$13.90	$12.96	$23.34
West	$10.93	$16.18	$28.53

[83] Each zone has a series of nodes, with each node having its own shadow price. The average price for each zone is calculated by taking the simple average of the nodes within that zone over every hour in the monitoring period, and then taking a simple average of the price calculated for each hour in the monitoring period associated with that particular zone.

A.1.4 Regional Prices

Table A-4 lists the average hourly real-time spot 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 reflects only the HOEP and does not include the Global Adjustment (GA) or uplift. Québec is not included in Table A-4 as it does not operate a wholesale market and does not publish prices.

Table A-4: Monthly Electricity Spot Prices – Ontario & Surrounding Jurisdictions, Summer 2021 Period[84]

Date	Ontario (HOEP) ($/MWh)	Manitoba[85] (MISO[86]) ($/MWh)	Michigan (MISO) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO[87]) ($/MWh)	PJM[88] ($/MWh)
May 2021	13.57	26.93	31.66	30.43	19.41	30.43
June 2021	24.42	43.41	40.46	44.16	33.24	36.74
July 2021	26.08	43.51	45.19	45.44	30.71	43.03
Aug 2021	40.48	45.24	51.67	48.47	47.78	52.51
Sept 2021	29.24	52.96	48.28	55.75	38.11	55.01
Oct 2021	38.61	62.92	66.19	71.63	47.24	64.95

hour in the monitoring period associated with that particular zone.

[85] The $/MWh values reported in Table A-4 Operator (MISO), but is its own Planning Coordinator and Balancing Authority for Manitoba. As such, there is no energy market in the province and therefore, no electricity spot price for Manitoba. The price shown in this table is the MISO price associated with importing/exporting between MISO and Manitoba and also wheelthroughs across Manitoba between Ontario and MISO. This price is for illustrative purposes only. For more information about Manitoba Hydro, see the NERC "2022 Long-Term Reliability Assessment", December 2022: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

[86] Midcontinent Independent System Operator

[87] New York Independent System Operator

[88] PJM Interconnection

The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs. The external prices reported are the real-time locational-marginal prices that correspond with the node on the other side of Ontario's intertie with each jurisdiction.

The average HOEP in Ontario continued to be the lowest market price compared to Manitoba, Michigan, Minnesota, New York and PJM. Manitoba, Michigan, Minnesota, and PJM had the highest average seasonal market prices relative to Ontario's HOEP, with New York experiencing the most significant price spread increase of 61%.

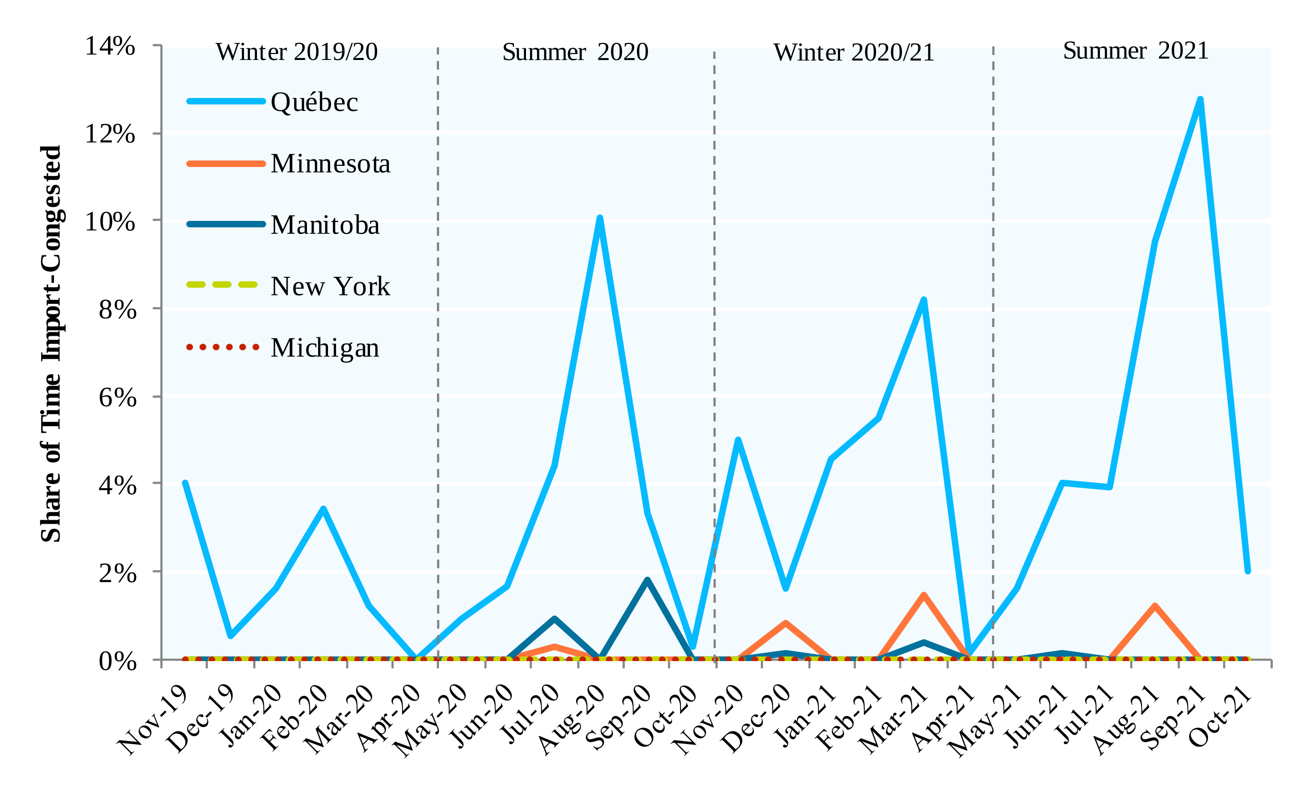
A.1.5 Import/Export Congestion and Transmission Rights

When an intertie has a greater amount of economic net import offers (or economic net export bids) than its pre-dispatch (PD-1) transfer capability, the intertie will be import (or export) congested.

For a given intertie, importers are paid the Intertie Zonal Price (IZP), while exporters pay the IZP. The difference between the IZP and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 and signals when there are more economic transactions than the intertie transmission lines can accommodate (if there is no congestion the ICP is zero). The ICP is positive when there is export congestion and negative when there is import congestion.

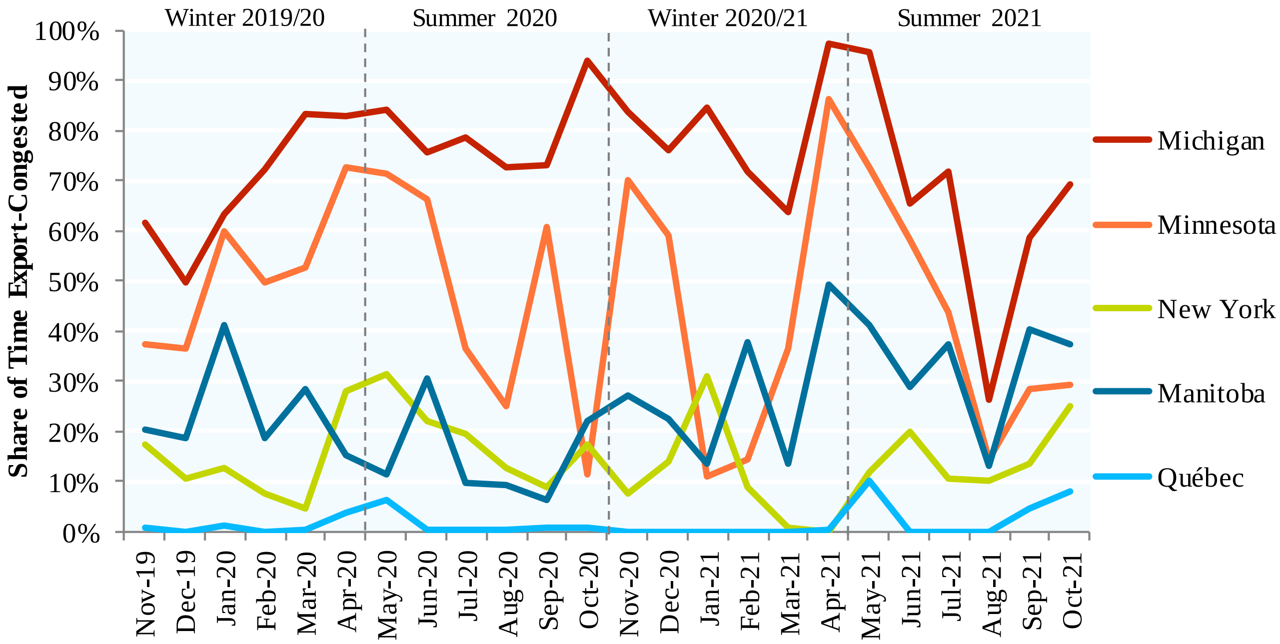
Figure A-10 reports the number of hours per month of import congestion by intertie and Figure A-11 reports the number of hours per month of export congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

Figure A-10: Import Congestion by Intertie, 2 Years



There were 258 hours of import congestion during the Summer 2021 Period, a 47% increase compared to the Summer 2020 Period. For the Summer 2021 Period, Québec experienced the highest number of import-congested hours. The Québec intertie experienced a 62% increase in the number of import-congested hours relative to the Summer 2020 Period.

Figure A-11: Export Congestion by Intertie, 2 Years



There were 6,967 hours of export congestion in the Summer 2021 Period, approximately the same amount of hours as the previous Summer Period. The number of export-congested hours decreased on Michigan, Minnesota, and New York, and increased on Manitoba and Québec during the Summer 2021 Period in comparison to the Summer 2020 Period. The Québec intertie experienced the greatest increase in export-congested hours, from 66 hours in the Summer 2020 Period to 170 hours in the Summer 2021 Period. Exports to all jurisdictions dipped in August 2021 (Table A-9).

An IZP 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 pre-dispatch PD-1 MCP and the PD-1 IZP. While the importer is paid the lower IZP, the purchaser in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer in such a case is import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TRCA).

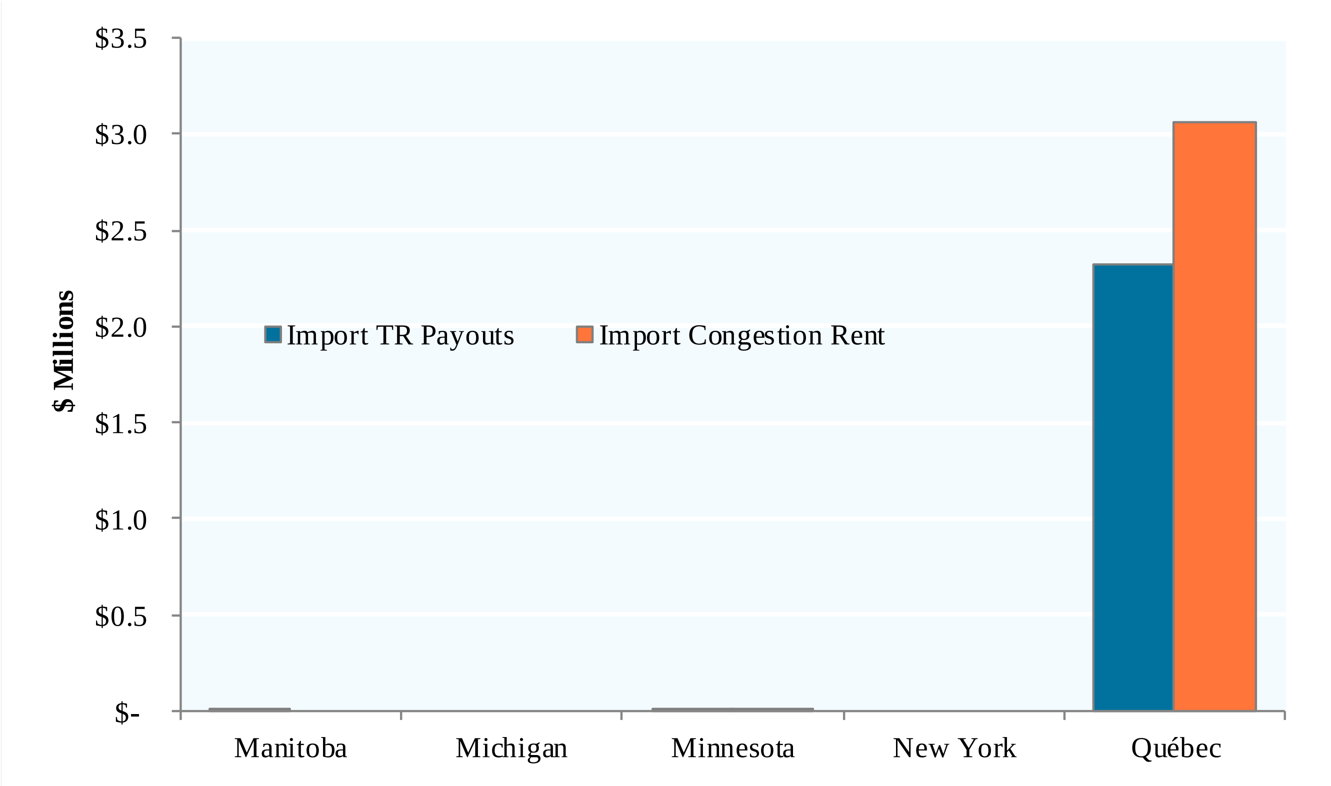
To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month (short-term) or one year (long-term). Short-term TR auctions occur between the 1st and the 15th day of each month and sell TRs that are valid for the one-month period. Long-term auctions are held between 30 to 90 days prior to the beginning of the quarter for which long-term TRs are being auctioned. Long-term TRs are valid for a period of one year, beginning on the first day of the quarter.[89] The owner of a TR is entitled to a payment (or "payout") equal to the ICP multiplied by the amount of TRs the owner holds every time congestion occurs on the intertie in the direction for which a TR is owned.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. Any congestion rent shortfalls, which occur when TR payouts exceed the congestion rent collected, are generally covered primarily by TR auction revenues, (proceeds from selling TRs, a payment into the TRCA).

Figure A-12 compares the total import congestion rent collected to total TR payouts by intertie for the Summer 2021 Period and Figure A-13 compares the total export congestion rent collected to total TR payouts by intertie for the same period.

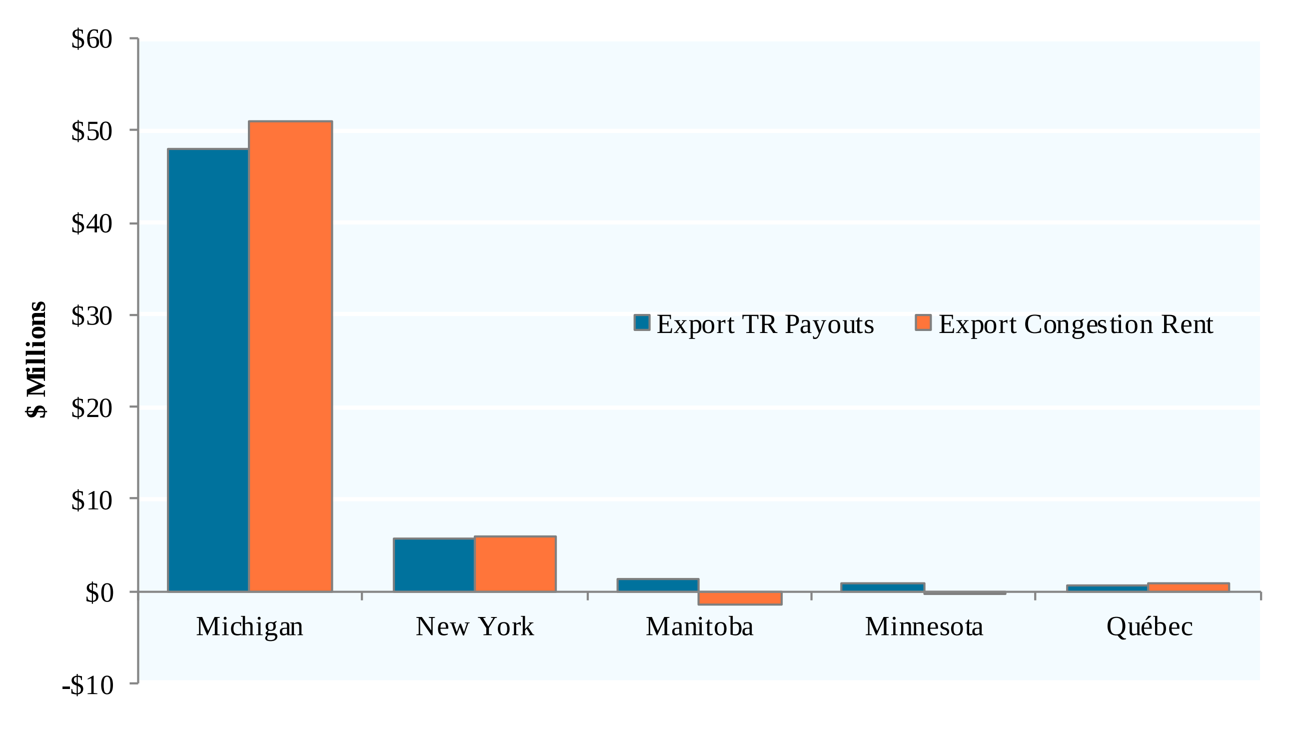
[89] For more information on the short-term and long-term TR auctions held by the IESO, see page 11 of: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-TransmissionRights.ashx.

Figure A-12: Import Congestion Rent & Transmission Rights (TR) Payouts by Intertie, Summer 2021 Period



Total import TR payouts in the Summer 2021 Period were $2.3 million, while total import congestion rent was $3.1 million, creating a congestion rent surplus of $0.7 million. This congestion rent surplus was essentially all on the Québec intertie.

Figure A-13: Export Congestion Rent & TR Payouts by Intertie, Summer 2021 Period



Export TR payouts in the Summer 2021 Period totalled $56.6 million, while export congestion rent totalled $56.2 million to offset it, resulting in a $0.35 million congestion rent shortfall. The shortfall was driven by congestion rent shortfalls on the Manitoba and Minnesota interties. These shortfalls were partially offset by congestion rent surpluses on the Michigan, New York, and Québec interties.

Of note, the Manitoba and Minnesota interties experienced negative export congestion rent during the Summer 2021 Period. Congestion rent is calculated by the ICP, as determined in pre-dispatch, multiplied by the real-time net constrained schedule. Negative congestion rent is experienced when the congestion direction indicated by the ICP sign is opposite to the net schedule. For example, an intertie may have a negative ICP in pre-dispatch which would indicate import congestion in the unconstrained sequence. However, in real-time, the power may flow out of Ontario (i.e. net export) and this would result in a negative congestion rent for the hour.

Table A-5 lists the average auction prices for 1 MW of long-term (12-month) TRs for each intertie in either direction for each auction since November 2020 and Table A-6 lists the auction prices for 1 MW of short-term (one-month) TRs for each intertie in either direction for each auction during the Winter 2020/21 and Summer 2021 Periods.

Auction prices signal market participant expectations of intertie congestion conditions for the forward period. If an auction is efficient, the price paid for 1 MW of TRs should reflect the expected payout from owning that TR for the period. Prices signal market participant expectations of intertie congestion conditions for the forward period.

Generally, when long-term import and export TR prices increase from auction to auction – as the 12-month term shifts ahead by 3 months – it indicates that traders expect import congestion to increase, and vice versa. Long-term import TR prices for the August 2021 auction decreased for all interties except for Manitoba and New York when compared to the Nov 2020 auction, indicating that traders expected the import congestion on the Michigan, Minnesota, and Québec interties to decrease. Similarly, long-term export TR prices for New York and Québec also decreased, indicating that traders expected export congestion to decrease as well. Long-term export TRs on the Manitoba and Minnesota interties were not offered in the August 2021 auction due to the IESO's application of operational constraints that imposed a limit on Northwest exports to Minnesota and Manitoba.

Table A-5: Average 12-Month TR Auction Prices by Intertie & Direction, One Year Period

Direction	Month	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	Nov-20	Jan-21 to Dec-21	512	210	875	267	8,854
	Feb-21	Apr-21 to Mar-22	325	175	462	195	4,952
	Apr-21	Jul-21 to Jun-22	519	97	654	232	6,829
	Aug-21	Oct-21 to Sep-22	655	169	774	309	5,019
Export	Nov-20	Jan-21 to Dec-21	8,652	77,684	37,471	13,849	1,758
	Feb-21	Apr-21 to Mar-22	4,730	86,072	31,063	15,184	766

	Apr-21	Jul-21 to Jun-22	25,000	92,514	38,851	8,639	937
	Aug-21	Oct-21 to Sep-22	-	95,981	-	10,377	1,293

Short-term import TR prices continued to be volatile from month-to-month for New York and Québec.

Table A-6: Average One-Month TR Auction Prices by Intertie & Direction, 1 Year

Direction	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	Nov-20	-	2	-	6	185
	Dec-20	-	5.58	-	14	96.72
	Jan-21	-	0.08	-	15	134
	Feb-21	-	3	-	15	250
	Mar-21	-	4	-	8	306
	Apr-21	-	0.1	-	3	302
	May-21	-	0.02	-	4	150
	Jun-21	-	0.01	-	7	500
	Jul-21	-	0.04	-	10	714
	Aug-21	-	0.11	-	0.1	714
	Sep-21	-	0.01	-	0.1	303
	Oct-21	-	0.05	-	0.2	71
Export	Nov-20	-	-	-	1,663	70
	Dec-20	-	6,555	-	558	46
	Jan-21	-	3,758	-	1,049	312
	Feb-21	-	4,704	-	1,344	309
	Mar-21	-	7,633	-	1,488	112
	Apr-21	-	7,956	-	1,221	79
	May-21	-	12,023	-	700	100
	Jun-21	-	9,180	-	720	87
	Jul-21	-	5,100	-	752	151
	Aug-21	-	6,335	-	448	105
	Sep-21	-	9,223	-	468	79

	Oct-21	-	10,349	-	930	116

Figure A-14 shows the estimated balance in the TRCA at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account. The balance of the TRCA decreased from $77.0 million at the end of the Winter 2021/21 Period (April 2021) to $73.2 million at the end of the Summer 2021 Period (October 2021).[90, 91] The April 2022 balance was $53.2 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:[92]

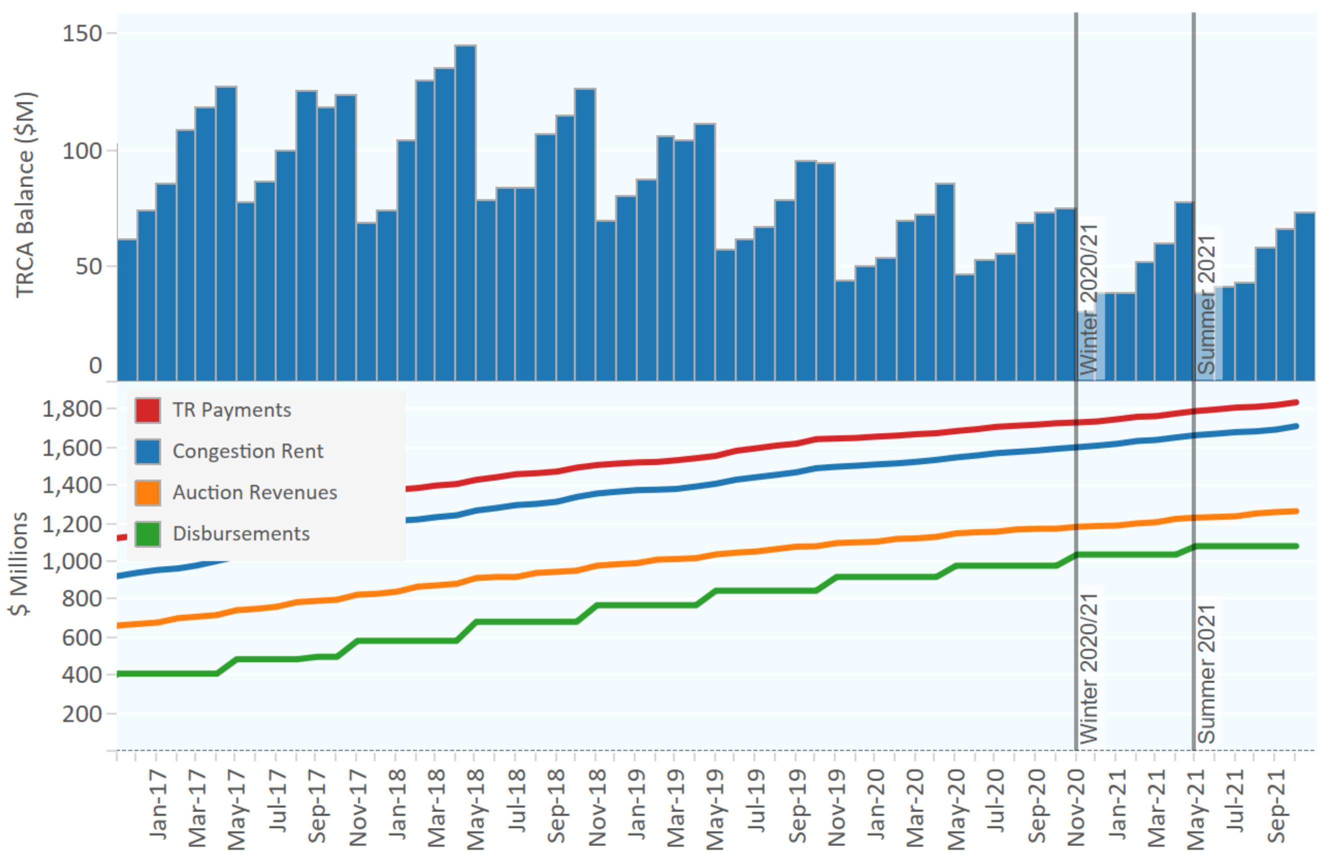
1. $99.5 million in revenue, specifically:
    - $59.3 million in congestion rent
    - $40.1 million in auction revenues
    - $0.1 million in interest
2. $103.2 million in debits, specifically:
    - $58.9 million in TR payouts
    - $44.3 million in disbursements to Ontario consumers and exporters.

90 The balances given here differ from balances in the IESO Monthly Market Reports. This is because the IESO accounts for auction revenues on an accrual basis (long-term auction rights revenue allocated evenly over the relevant 12-month period, with revenue allocated for future months excluded) whereas the balances given here reflect the total amounts, including auction revenues, received and paid out on a cash flow basis in the reporting period.

91 For reference, the balance at the end of the Summer 2020 Period (October 2020) was $75.0 million.

92 Disbursement and interest amounts are referenced from the IESO's Monthly Market Report. Congestion rent, total auction revenue and TR payments are referenced from the IESO's settlements database and may differ from the IESO's Monthly Market Reports because the settlement database records revenue on a cash flow basis and not an accrual basis.

Figure A-14: Transmission Rights Clearing Account Balance & Cumulative In/Outflows, 5 Years



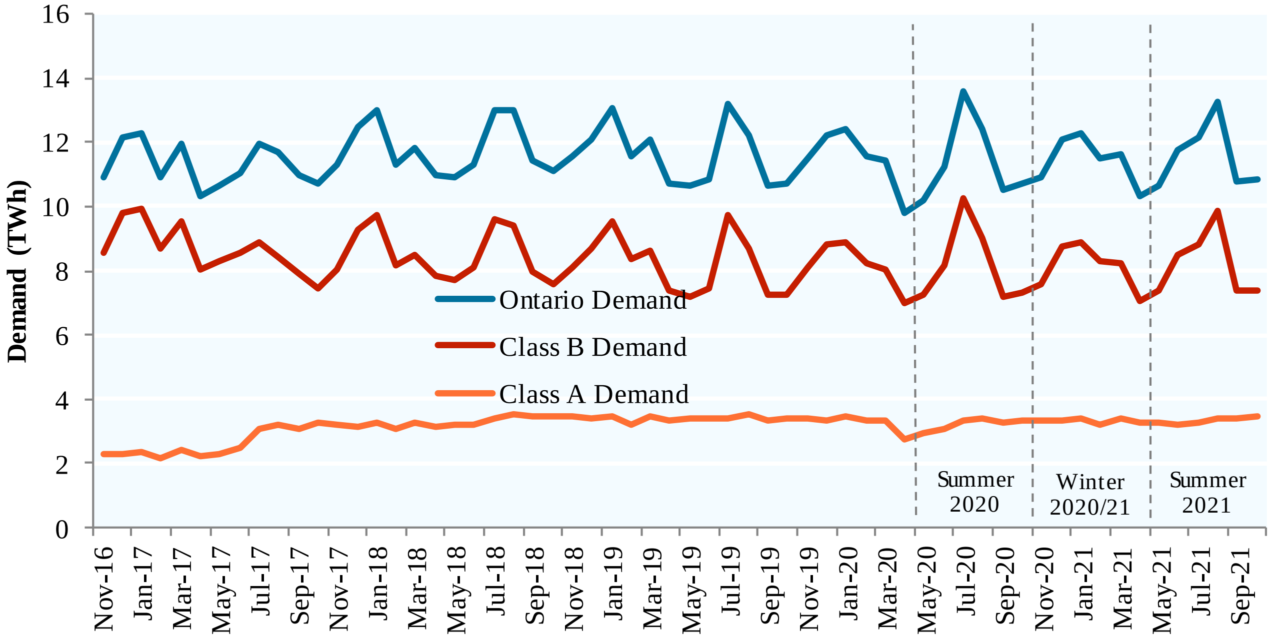
A.2 Demand

Figure A-15 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand – not just grid-connected demand – in that it includes demand satisfied by embedded generators.[93]

Total demand in the Summer 2021 Period was 69.4 TWh – 1% higher than the total demand of 68.7 TWh in the Summer 2020 Period. In reference to the total seasonal demand, demand from Class A consumers in the Summer 2021 Period was 20.0 TWh – a 3.1% increase compared to the Summer 2020 Period. The Class B demand for the Summer 2021 Period was 49.3 TWh – approximately the same as the demand during the Summer 2020 Period. The pandemic and associated restrictions during Summer 2021 Period do not appear to have had any effect on Class A and Class B demand.

[93] Class A demand may be understated as the Panel does not have access to behind-the-meter generation data, which serves to offset demand from the grid. For more information, see the Panel's Monitoring Report 24 published April 2015, pages 105-109, and the Panel's Industrial Conservation Initiative Report published December 2018: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf and https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.

Figure A-15: Monthly Ontario Energy Demand by Class A & Class B Consumers, 5 Years



A.3 Supply

This section presents data on generating capacity, actual generation, and Operating Reserve (OR) supply for the Summer 2021 Period relative to previous years.

Table A-7 lists the quantity of nameplate generating capacity that completed commissioning and was added to and/or removed from the IESO-controlled grid's total capacity during the second and third quarters of 2021, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level. Total capacity of each type at the end of the third quarter of 2021 is also shown.

Table A-7: Changes in Generating Capacity, Q2 2021 to Q3 2021

Generation Type	Grid-connected		Distribution-level ("Embedded")	
	Changes in capacity (MW)	Total (MW)	Changes in capacity (MW)	Total (MW)
Nuclear	80	13,089	-	-
Natural Gas	-802	10,515	-	-
Hydro	-142	8,918	27	333
Wind	-3	4,783	-	591
Solar	-	478	-	2,172
Biofuel	1	296	-	110
Gas-Fired and Combined Heat and Power (CHP)	-	-	-	320
Energy from Waste	-	-	-	24
Total	-866	38,079	27	3,550

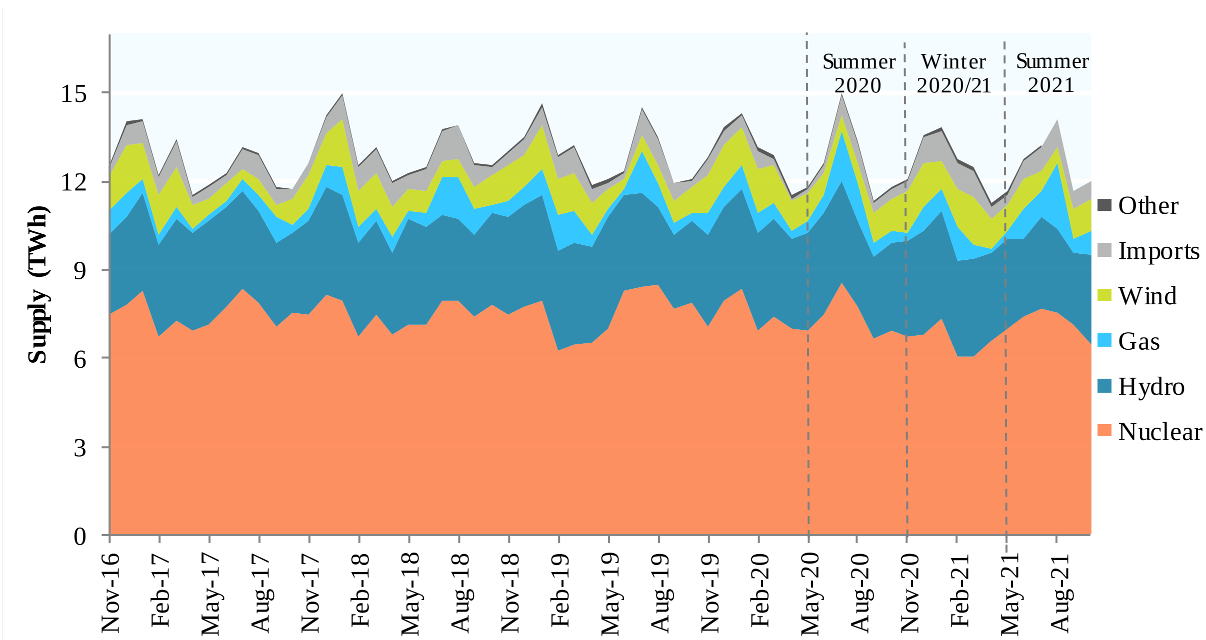
The 866 MW difference in grid-connected capacity is a result of the IESO's change in accounting method and does not reflect changes in amount of available supply.[94] All of the IESO-controlled

[94] Starting with the Reliability Outlook report (July 2021 to December 22), released June 2021, the IESO has changed its accounting method of capacity to better align the reliability outlook (RO) methodology with the annual planning outlook (APO), as well as factoring the latest information and ongoing change at individual facilities. The inconsistencies between the short-term RO and long-term APO reports were discussed in Monitoring Report 33 published December 2020, pages 53-54: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf.

grid's added capacity is variable generation that generally offers into the energy market at low prices, potentially contributing to the continuation of low wholesale spot prices in Ontario.

Figure A-16 displays the real-time unconstrained schedules from November 2016 to October 2021 by resource or transaction type: imports, wind, gas-fired, hydroelectric, nuclear, and other (biofuel and solar). Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand or seasonal fuel variations (for example, during the spring snowmelt or freshet when hydroelectric plants have an abundant supply of water).

Figure A-16: Resources Scheduled in the Real-Time Market (Unconstrained), 5 Years[95]



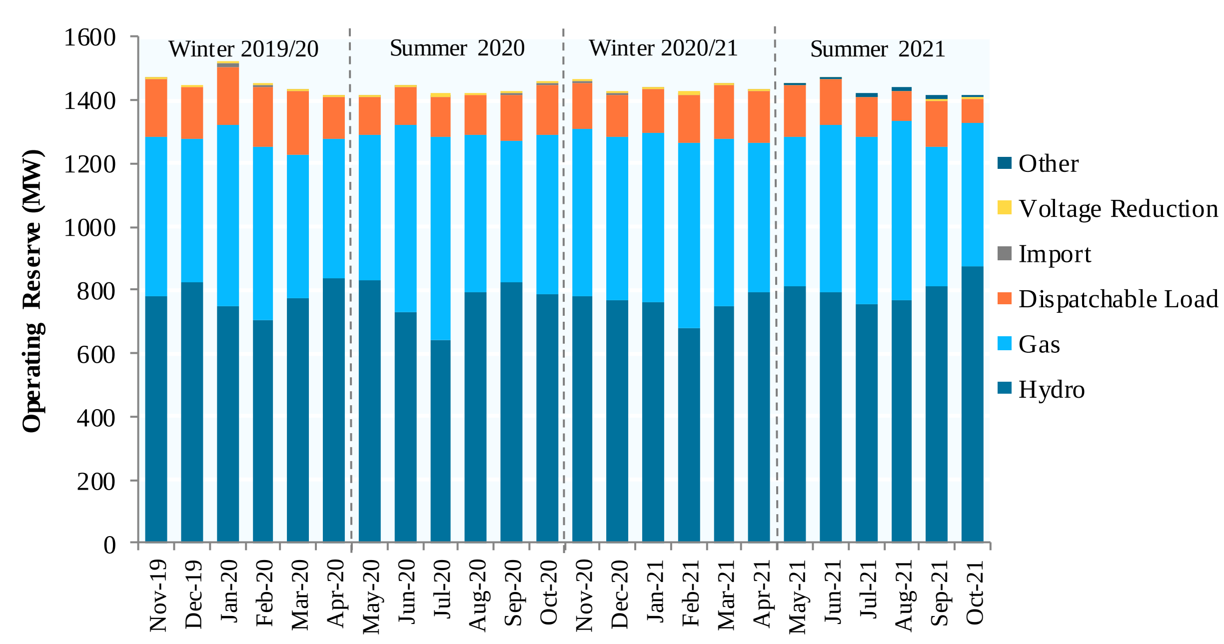
Compared to the Summer 2020 Period, the Summer 2021 Period showed minor changes in nuclear, hydro, and wind capacity. Scheduled imports increased by 61% from 2.5 TWh to

[95] "Other" refers to the sum of biofuel and solar supply scheduled in the real-time market

4.0 TWh, and gas capacity increased by 17% from 4.9 TWh to 5.1 TWh, likely driven by increased outages in hydro, nuclear, wind, and solar generation (see Figure A-18).

Figure A-17 displays the real-time unconstrained OR schedules from November 2019 to October 2021 by resource or transaction type: voltage reduction[96], imports, dispatchable loads, gas-fired, and hydroelectric. Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time. There were no significant changes in the distribution of OR by resource type in the Summer 2021 Period compared to the previous two years. Total hourly scheduled OR exceeded the mode value of 1,418 MW in 11% of the hours in both the Summer 2020 and 2021 Periods.

Figure A-17: Average Hourly OR Scheduled by Resource Type, 2 Years



96 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 scheduled in real-time, never in pre-dispatch. Voltage reductions are an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.

Table A-8 reports the seasonal average quantity of hourly OR scheduled and the fraction of total OR that is provided by resource or transaction type. There were no significant changes to the fraction and average quantity of OR for the previous three periods.

Table A-8: Average Hourly OR Scheduled by Resource Type and Season, 3 Periods

Quantity	Summer 2020	Winter 2020/21	Summer 2021
Average OR Scheduled (MW)	1,435	1,445	1,441
Dispatchable Load Share (%)	9%	10%	9%
Natural Gas Share (%)	37%	36%	35%
Hydro Share (%)	53%	52%	56%
Other Share (%)[97]	1%	1%	1%

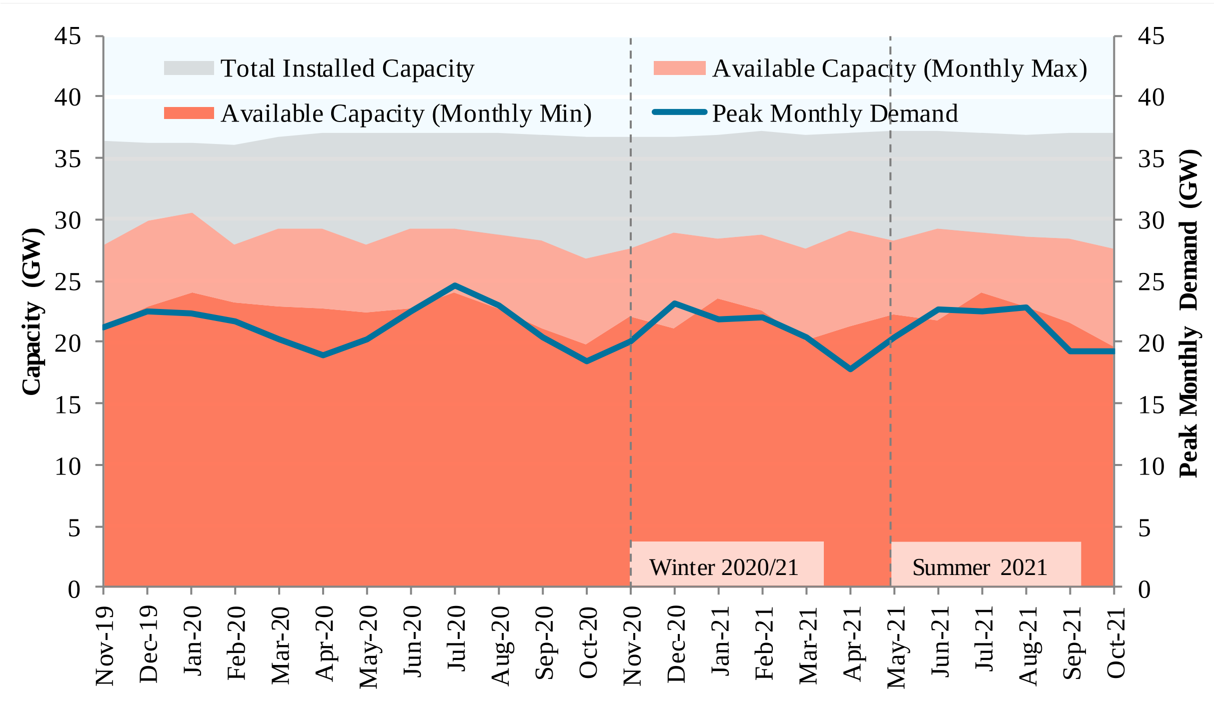
Figure A-18 plots the monthly minimum and maximum available generation capacity, accounting for unavailable capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from November 2019 to October 2021.[98] For a given month, the maximum megawatts on outage can be observed by comparing the total installed capacity to the minimum available capacity, and the minimum megawatts on outage can be observed by comparing the total installed capacity to the maximum available capacity. For reference, the figure also includes the monthly peak market demand, excluding demand served by imports.[99]

[97] "Other" refers to the sum of the share of OR from imports and voltage reduction.

[98] This figure is created using the final version of each day's Adequacy Report, available at: http://reports.ieso.ca/public/Adequacy2/.

[99] Unavailable generation capacity data was obtained from adequacy reports published daily by the IESO. Daily average unavailable capacity data can also be found in the IESO Monthly Market Report, available at: https://www.ieso.ca/en/Power-Data/Monthly-Market-Report.

Figure A-18: Monthly Installed Capacity, Available Capacity and Peak Demand, 2 Years



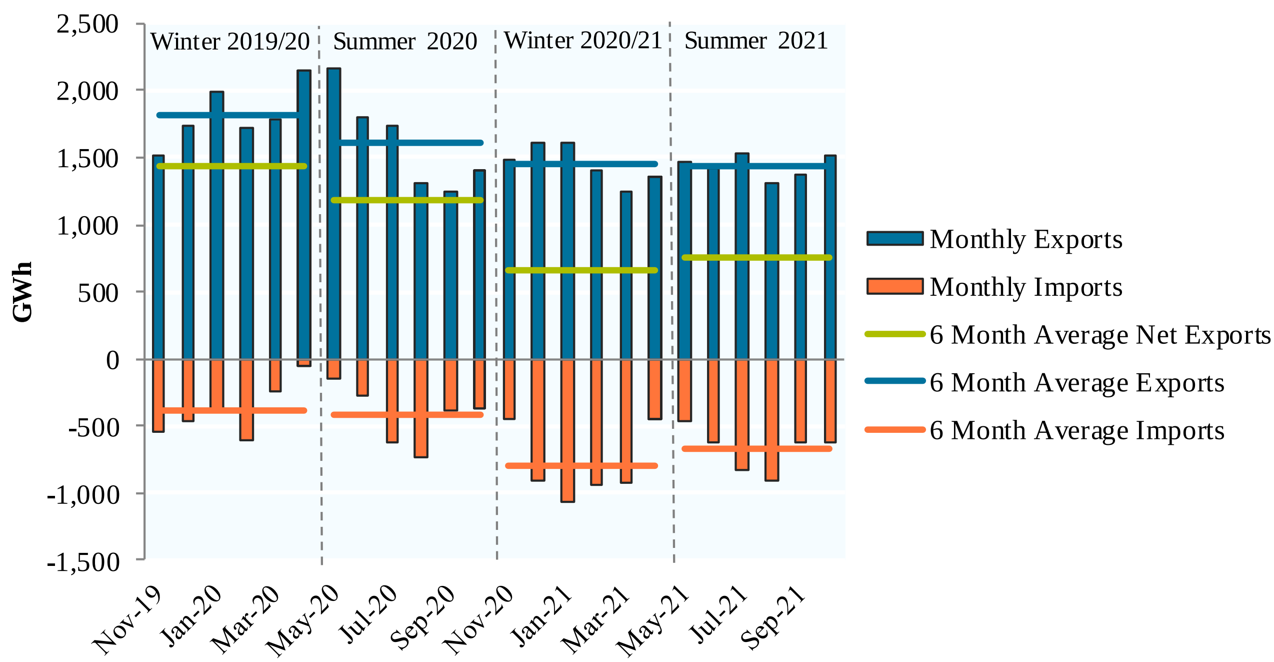
As a whole, the Summer 2021 Period had, on average, 12.2 GW of unavailable capacity, which is 2% more than the average of 11.9 GW of capacity that was unavailable in the Winter 2020/21 Period. The increase in unavailable capacity was primarily driven by minor increases in hydro, nuclear, wind, and solar outages and offset by a 58% decrease in gas outages and a 30% decrease in biofuel outages.

A.4 Imports, Exports and Net Exports

This section examines import and export transactions in the constrained sequence, as schedules in this sequence most closely reflect actual power flows.[100]

Figure A-19 plots total monthly imports and exports from November 2019 to October 2021, as well as the average monthly imports, exports and net exports calculated over each 6-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Figure A-19: Monthly Imports and Exports, and Average Net Exports, 2 Years

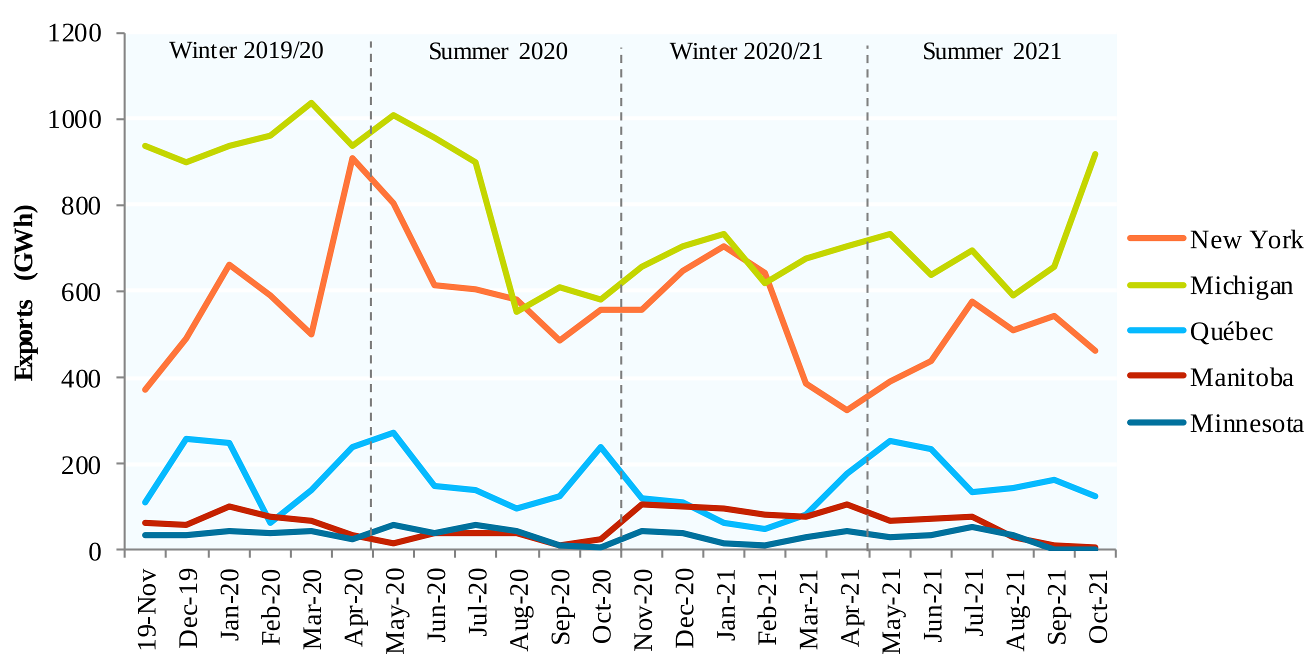


Ontario remained a net exporter in the Summer 2021 Period, with net exports of 4.6 TWh over the six months, down from 7.1 TWh in the Summer 2020 Period. Compared to the Summer 2020 Period, exports fell by 1.0 TWh and imports increased by 1.5 TWh.

[100] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not impact ICPs or the Ontario uniform price.

Figure A-20 presents a breakdown of exports from November 2019 to October 2021 to each of Ontario's five neighboring jurisdictions.

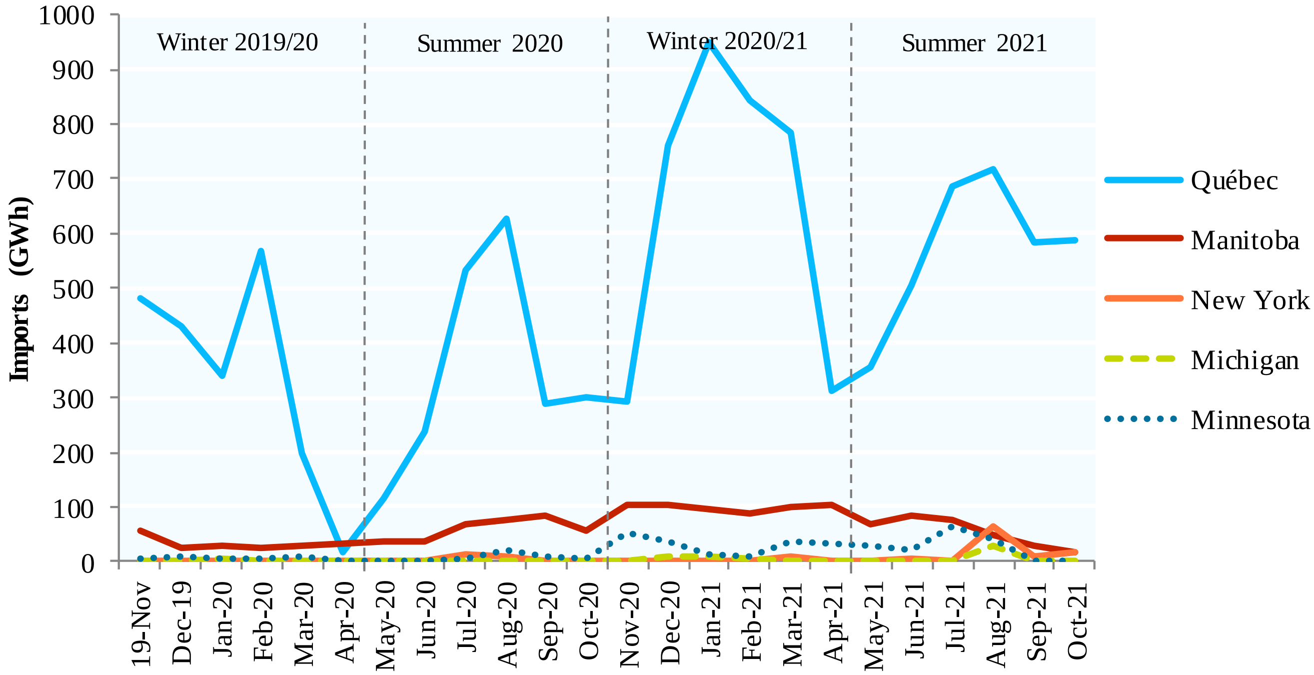
Figure A-20: Exports by Intertie, 2 Years



Exports fell across all jurisdictions except Manitoba and Québec. Exports on the Manitoba intertie increased significantly by 56%. Exports on the New York intertie fell by 20% from an average of 607 GWh per month in the Summer 2020 Period to an average of 487 GWh per month in the Summer 2021 Period.

Figure A-21 presents a breakdown of imports from November 2019 to October 2021 from each of Ontario's five neighboring jurisdictions. The average monthly import quantities over the Winter 2020/21 and Summer 2021 Periods are given for each intertie in Table A-10.

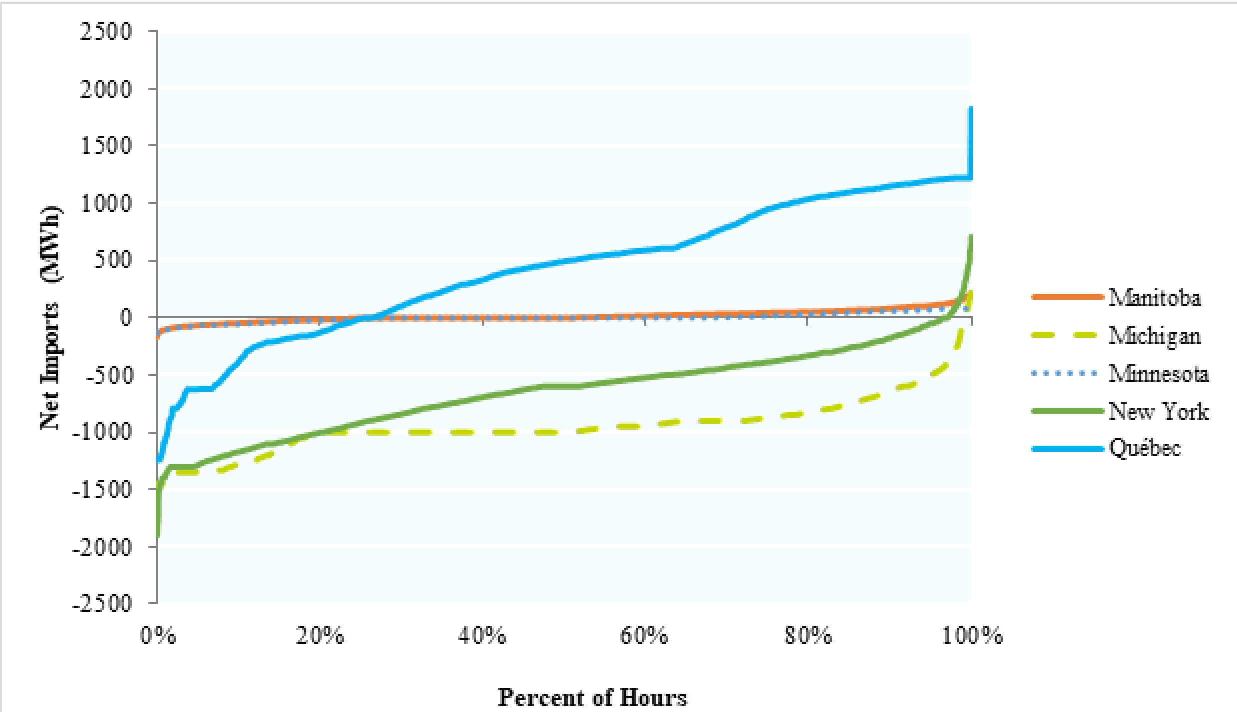
Figure A-21: Imports by Intertie, 2 Years



Imports from all jurisdictions increased in the Summer 2021 Period compared to the Summer 2020 Period except for Manitoba. New York, Michigan, and Minnesota supplied the largest percentage increase in imports. Imports from Québec also increased from an average of 351 GWh per month in the Summer 2020 Period to an average of 574 GWh per month in the Summer 2021 Period. Overall imports peaked in August 2021.

Figure A-22 presents the profile of energy flow to Ontario's five neighbouring jurisdictions in the Summer 2021 Period.

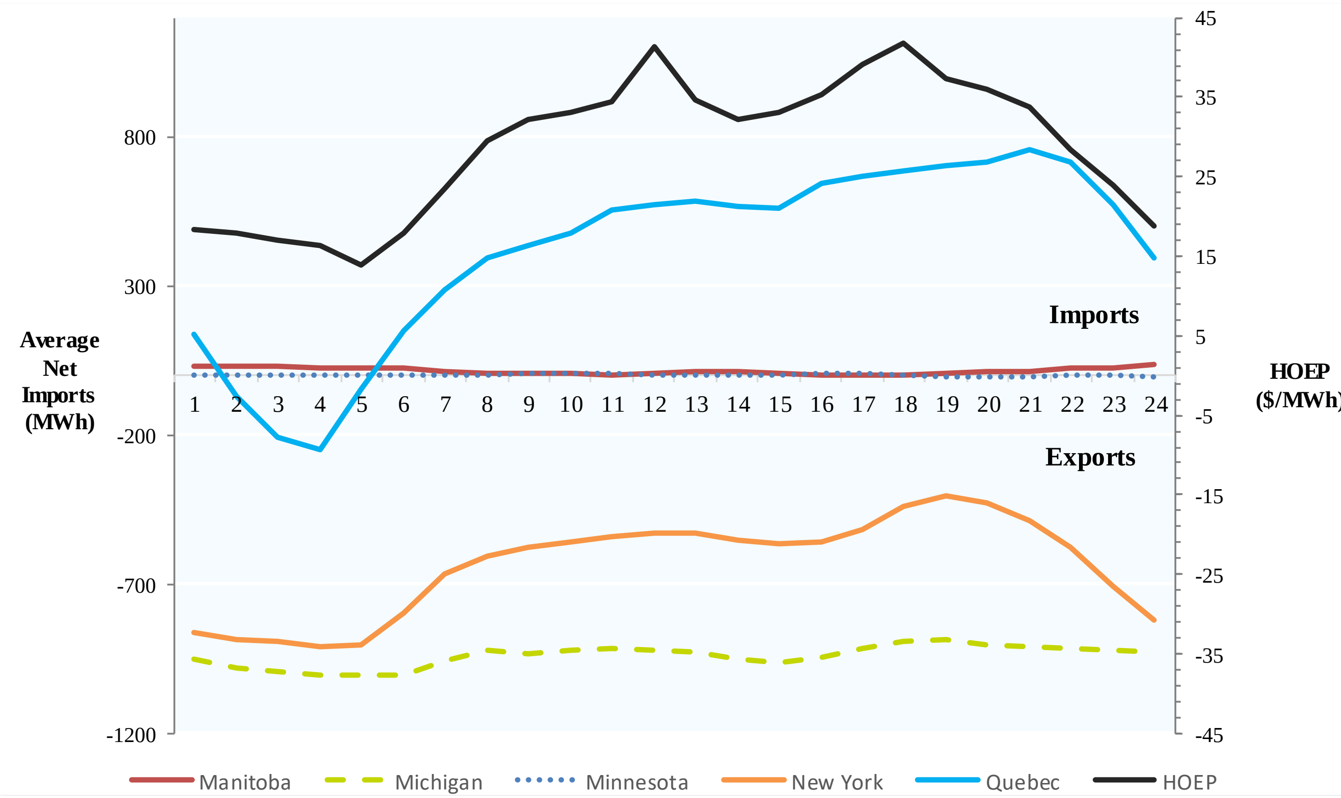
Figure A-22: Profile of Energy Flow by Intertie, Summer 2021 Period



Québec is a net importer in 73.6% of the hours. Minnesota and Manitoba experience a net intertie flow of 0 MWh in 24% and 39% of all hours, and New York and Michigan are net exporters for the majority of the Summer 2021 Period.

Figure A-23 presents the average daily activity by intertie. Daily activity on the Québec, Michigan, and New York interties follow HOEP and reach local maximums around HE12 and HE 18.

Figure A-23: Average Daily Activity by Intertie, Summer 2021 Period[101]



Flows on the Québec interties net as imports during the daylight hours, and transitions into nets exports overnight, while flow on the New York and Michigan interties net as exports throughout the entire day. Flow on the Minnesota and Manitoba interties are mostly net imports and do not appear to follow HOEP in the Summer 2021 Period.

Table A-9 reports average monthly export curtailments and failures over the Winter 2020/21 and Summer 2021 Periods by intertie and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each intertie, excluding linked wheel transactions. Curtailment (Independent System Operator (ISO) Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Market Participant (MP)

[101] This figure shows the average daily activity of net energy flow both into Ontario (imports) and out of Ontario (exports).

Failure refers to a transaction that fails for reasons within the control of the market participant such as a failure to obtain transmission service. Failed or curtailed exports reduce demand between pre-dispatch (PD-1) and real-time.

Table A-9: Average Monthly Exports and Export Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Exports GWh		Average Monthly Export Failure and Curtailment GWh				Export Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure[102]	
	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021
New York	553	492	0.7	0.9	9.0	5.7	0.1%	0.2%	1.6%	1.2%
Michigan	687	707	1.4	0.8	6.7	7.9	0.2%	0.1%	1.0%	1.1%
Manitoba	121	61	1.4	1.6	23.9	15.7	1.2%	2.6%	19.8%	25.9%
Minnesota	32	27	0.4	1.0	0.7	0.3	1.4%	3.6%	2.1%	1.2%
Québec	96	172	2.3	1.6	1.5	1.7	2.3%	0.9%	1.6%	1.0%

The market participant percentage failure rate of exports decreased in the Summer 2021 Period on all interties except Michigan and Minnesota. This rate continues to follow a seasonal pattern for Manitoba, with significantly higher failure rates in the Summer Period and lower failure rates in the Winter Period. As in previous periods, the market participant failure percentage rate for Manitoba is much higher than for other interties in both periods. The rate of ISO-curtailed exports in the Summer 2021 Period was relatively low for all of Ontario's interties. This rate tends to follow a seasonal pattern for Manitoba and Minnesota, with higher curtailment rates in the Summer Period and lower rates in the Winter Period.

102 MP Failure includes OTH and MrNH failure codes. The OTH reason code denotes other (OTH) constraining events at the interties and the MrNH reason code denotes MISO Ramp / Transmission Service or NYISO HAM protocol (MrNh) constraining events at the interties. Other codes are classified as ISO Curtailment.

Table A-10 reports average monthly import failures and curtailments the Winter 2020/21 and Summer 2021 Periods by intertie and cause. The market participant failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions. Failed or curtailed imports reduce supply between the PD-1 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 market participant failures and ISO Curtailments.

Table A-10: Average Monthly Imports and Import Failures by Intertie and Cause, 2 Periods

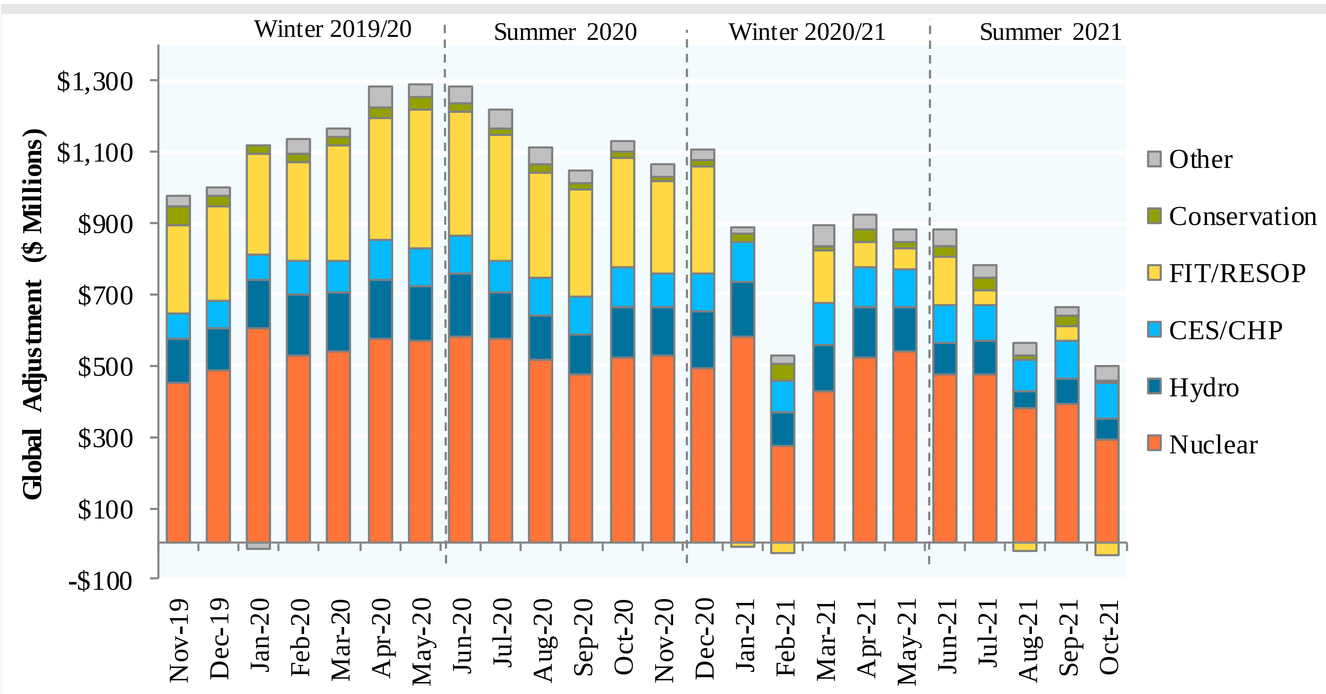
Intertie	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021	Winter 2020/21	Summer 2021
New York	2	17	0.0	0.1	0.1	0.2	0.0%	0.7%	3.4%	1.1%
Michigan	5	6	0.3	0.0	0.3	0.6	6.2%	0.0%	5.4%	8.7%
Manitoba	104	58	2.0	2.2	2.8	1.1	1.9%	3.8%	2.7%	1.9%
Minnesota	33	31	0.2	0.7	2.3	3.9	0.7%	2.4%	7.1%	12.4%
Québec	651	564	3.6	4.1	0.4	0.6	0.6%	0.7%	0.1%	0.1%

The MP Failure rate of imports significantly increased on the Michigan and Minnesota interties in the Summer 2021 Period compared to the Winter 2020/21 Period, aligning with seasonal patterns in the past with higher failure rates in the Summer Period and lower failure rates in the winter. The rate of ISO-curtailed exports in the Summer 2021 Period was relatively low for all of Ontario's interties, following a seasonal pattern where with higher failure rates in the Summer Period and increasing slightly on all interties except for Michigan.

A.5 Out-of-Market Commodity Charges

Figure A-24 plots the payments to or from various resources that are recovered through the GA, by month and by component, for the previous two years.

Figure A-24: Monthly Global Adjustment (GA) by Component, 2 Years



Total GA is divided into six components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation Inc.'s (OPG) nuclear assets);
- Payments to holders of Clean Energy Supply (CES) and Combined Heat and Power (CHP) contracts;
- Payments to regulated or contracted hydroelectric generation;

- Payments to holders of contracts for renewable power (Feed-in Tariff, including microFIT (collectively FIT), and the Renewable Energy Standard Offer Program (RESOP)); [103]
- Payments related to the IESO's conservation programs; and
- Payments to others (including to holders of Non-Utility Generator (NUG) contracts and Ontario Power Generation Inc.'s (OPG's) Lennox Generating Station)

The total GA throughout the Summer 2021 Period was about 40% less than the total GA during the Summer 2020 Period, decreasing from $7.1 billion to $4.2 billion. Most of the change is due to the introduction of the Non-Hydro Renewables Funding Amount in January 2021 that effectively reduces the GA costs for consumers by having taxpayers pay these costs instead. For the Summer 2021 Period, the Non-Hydro Renewables Funding Amount contributed to a $1.56 billion decrease in the GA cost compared to the Summer 2020 Period.

Wholesale market service charges include the cost of services provided by the IESO to operate the wholesale electricity market and maintain the reliability of the high voltage power grid. These charges are included in the "Regulatory Charges" line item of low-volume consumer bills, and are recovered from wholesale market participants through "uplift" charges that are captured by the IESO under the rubric of "wholesale market service charges".[104] Regulatory charges include both amounts set or approved by the Ontario Energy Board (OEB) (e.g. IESO Administration Charge and the Rural or Remote Electricity Rate Protection (RRRP) charge) and amounts that

[103] A new regulation effective on January 2021 specifies the renewable contract costs that can be funded by the Province rather than being funded by ratepayers through the GA, resulting in a decrease in FIT/RESOP payments. For more information regarding the Non-Hydro Renewables Funding Amount, see the IESO's webpage "Monthly Market Report": https://www.ieso.ca/en/Power-Data/Monthly-Market-Report.
[104] The OEB sets a "wholesale market service rate" that electricity distributors charge their customers to recover the cost of services provided by the IESO to administer the wholesale market and maintain reliability of the grid. This rate is captured in the "Regulatory Charges" line item.

are not set or approved by the OEB such as charges associated with reliability or transmission losses.[105]

Hourly uplift components are charged to wholesale consumers (including distributors) based on their share of total hourly demand, while monthly uplift components are charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand.[106]

Table A-11 below summarizes a number of components of the IESO's of Wholesale Market Service Charge, the majority of which are "uplift" costs for wholesale market participants.[107] Charges are split into hourly charges (including Congestion Management Settlement Credits (CMSC), transmission losses, Intertie Offer Guarantee (IOG), Operating Reserve (OR), and hourly reactive support and voltage control) and monthly charges (including the Day Ahead Production Cost Guarantee (DA-PCG)[108] and Real-Time Generation Cost Guarantee (RT-GCG) programs, ancillary services, Demand Response (DR), IESO Administration Charge, Rural or Remote Electricity Rate Protection and other charges). Figure A-25 shows the Wholesale Market Service Charges by month.[109]

Total Wholesale Market Service Charges in the Summer 2021 Period were $383 million, a 21% increase from the Summer 2020 Period of $317 million. Notable increases compared to the previous Summer Period include: CMSC (71% increase or $32 million), IOG (101% increase or

[105] See the OEB's webpage "Understanding Your Electricity Bill": https://www.oeb.ca/rates-and-your-bill/electricity-rates/understanding-your-electricity-bill.

[106] This applies to all monthly and daily uplifts with the exception of costs associated with DR. These costs are allocated with the same methodology as the GA, where Class A consumers pay the fraction of costs corresponding to their fraction of Ontario demand during the five highest demand peaks of the year, and Class B consumers are billed the remaining sum volumetrically.

[107] The table separates previously aggregated charges and considers two other Wholesale Market Service Charges previously omitted from Panel reports: IESO Administration Charge and the Rural and Remote Electricity Rate Protection Charge.

[108] Although the settlement resolution for the DA-PCG program is daily, it has been grouped with monthly charges as all other charges considered are hourly or monthly.

[109] For consistency with previous reports, the Intertie Failure Charge Rebate, the IESO Administration Charge and the Rural and Remote Electricity Rate Protection Charge were omitted from Figure A-25.

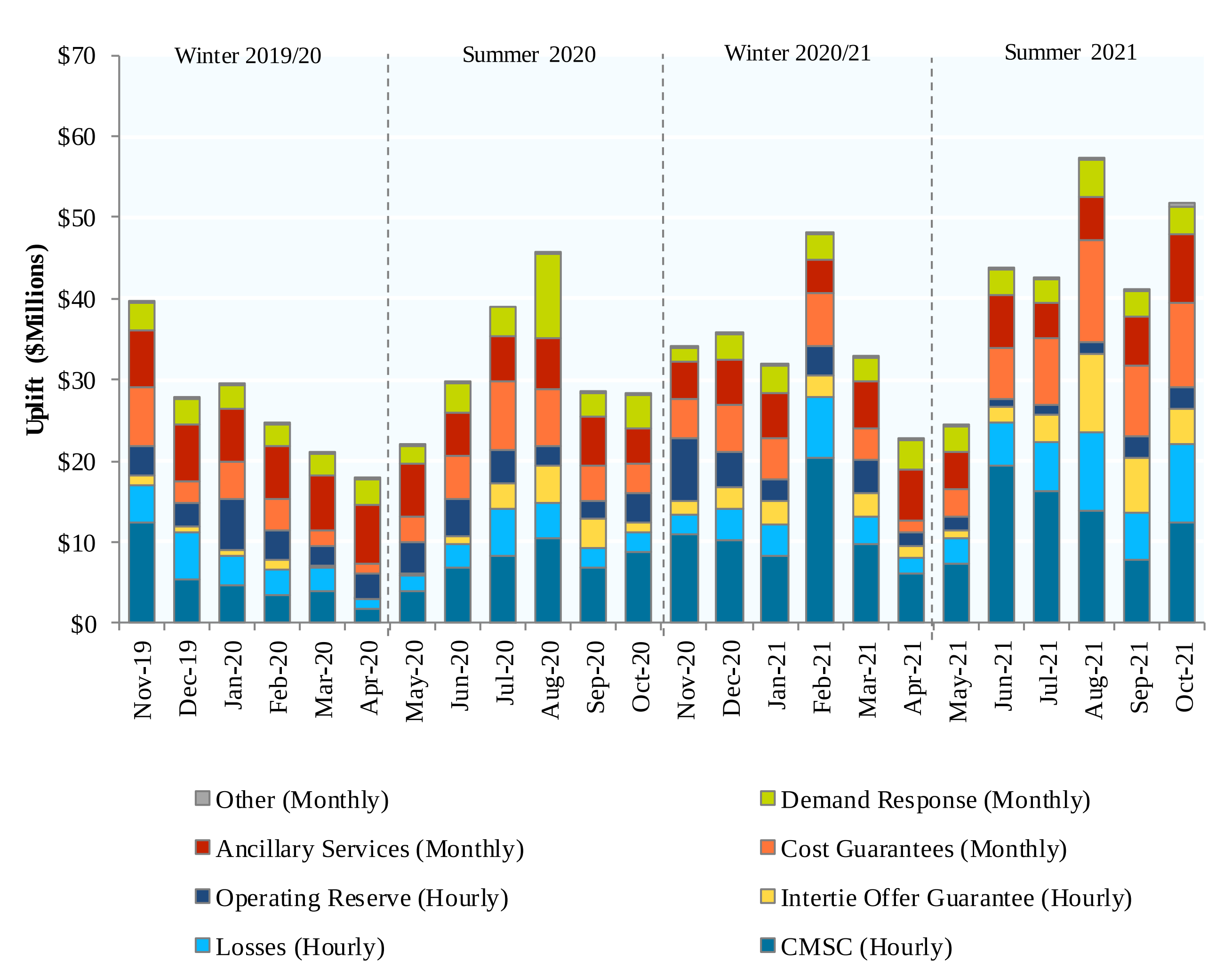
$14 million), DA-PCG (111% increase or $16 million) and ancillary monthly reactive support and voltage control charges (606% increase of $6 million). The significant increases in CMSC and IOG are addressed in Chapter 2. The increase in DA-PCG is likely attributed to the increase in gas scheduled in the Summer 2021 Period.

Table A-11: Wholesale Market Service Charges by Charge Type and Period, 3 Periods

Settlement Resolution	Wholesale Market Service Charges	Summer 2020 ($ million)	Winter 2020/21 ($ million)	Summer 2021 ($ million)
Hourly	Congestion Management Settlement Credits (CMSC)	45.18	65.43	77.10
	Transmission Losses	19.93	23.35	39.14
	Intertie Offer Guarantee (IOG)	13.80	14.13	27.75
	Intertie Failure Charge Rebate	-0.51	-0.46	-0.63
	Operating Reserve: 10-minute spinning reserve	9.68	11.05	4.28
	Operating Reserve: 10-minute non-spinning reserve	6.65	8.37	4.35
	Operating Reserve: 30-minute reserve	4.25	4.79	2.18
	Hourly Reactive Support and Voltage Control	11.46	8.39	13.28
	Hourly Charges Subtotal	**110.43**	**135.05**	**167.46**
Monthly	Cost Guarantee: RT-GCG program	17.73	20.54	19.08
	Cost Guarantee: PCG program	14.24	6.90	30.03
	Ancillary Services: Black Start	0.83	0.87	0.71
	Ancillary Services: Regulation	20.69	20.02	14.95
	Ancillary Services: Monthly Reactive Support and Voltage Control	0.92	2.73	6.47
	Demand Response Capacity Payments	27.03	17.77	20.09
	IESO Administration Charge	89.67	89.28	89.55

	Rural or Remote Electricity Rate Protection	32.56	32.79	32.94
	Other (163, 169, 170)	2.46	1.39	1.76
	Monthly Charges Subtotal	**206.11**	**192.30**	**215.57**
Total Regulatory Charges		**316.54**	**327.36**	**383.03**

Figure A-25: Total Uplift Charge by Component on a Monthly Basis, 2 Years



A.6 Total Customer Commodity Charges

Table A-12 presents the wholesale electricity commodity charges for the Summer 2020, Winter 2020/21, and Summer 2021 periods.

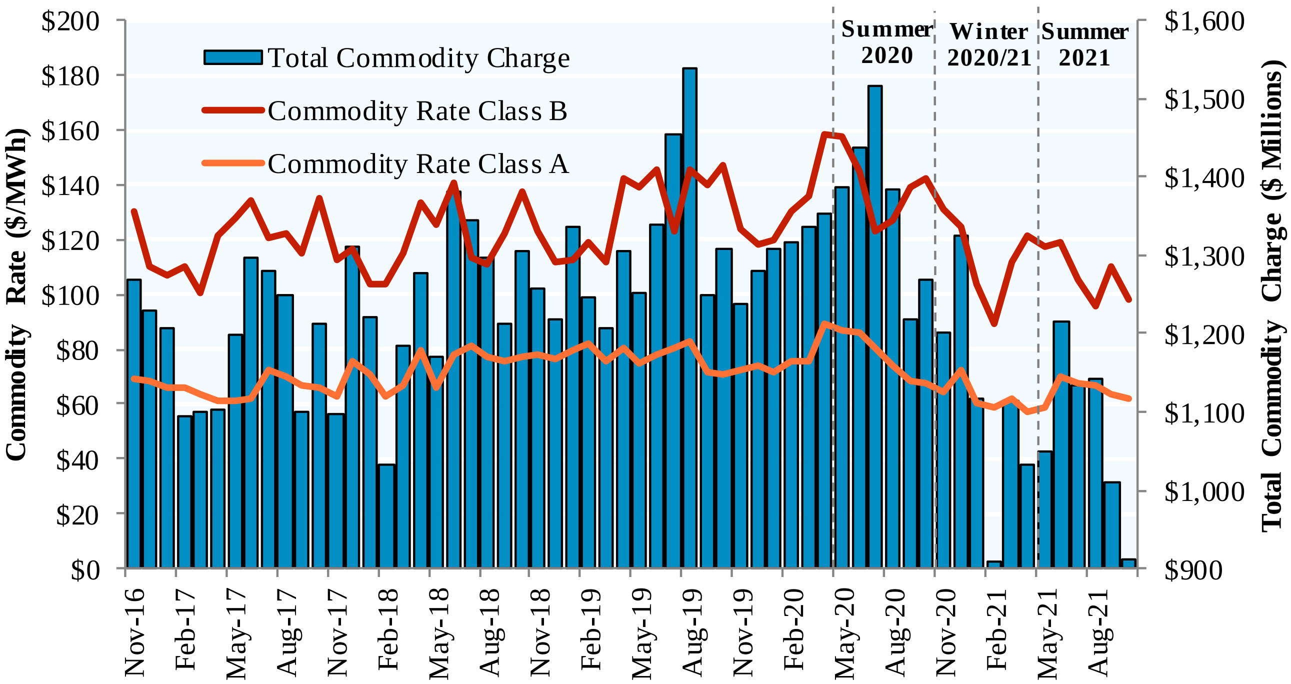
Table A-12: Wholesale Electricity Commodity Charges, 3 Periods[110]

	Summer 2020	Winter 2020/21	Summer 2021
Commodity Charge HOEP ($ millions)	955	1,141	**2,015**
Total Global Adjustment ($ millions)	7,089	5,377	**4,220**
Total Uplift ($ millions)	170	184	**231**
Total Commodity Charge ($ millions)	8,213	6,702	**6,466**

Figure A-26 plots the monthly average commodity rate for Class A and Class B consumers, as well as the total monthly commodity charges for the previous five years.

[110] The Panel defines the total commodity charge as the sum of charges related to the HOEP, the GA and uplift components. The total commodity charge presented within this Appendix does not consider all charges reflected in the total cost settled by the IESO, such as charges related to transmission and distribution.

Figure A-26: Monthly Average Commodity Rate & Commodity Charges, 5 Years



The total commodity charge borne by Ontario consumers fell by about 21.3% ($1.7 billion) between the Summer 2021 Period and the Summer 2020 Period. This decrease in total commodity charge was due mostly to a $2.9 billion decrease in GA that was somewhat offset by an increase of about $1.1 billion in the commodity charge HOEP and a small increase of $61 million in the uplift charges.

Table A-13 presents the illustrative average commodity rate for different consumer classes in the Summer 2020, Winter 2020/21, and Summer 2021 Periods. The average commodity rate is calculated as the sum of the average weighted energy rate[111], GA rate, and uplift rate in dollars

[111] The average weighted energy rate reported for each class is an average of the HOEP values in the monitoring period weighted by that class's consumption during each hour in the period. It was assumed that embedded Class A follows the same load profile as directly connected Class A consumers.

per MWh, reported for three consumer groups: "Class A consumers", "Class B consumers" and "All Consumers."[112,113]

Table A-13: Average Commodity Rate by Consumer Class and Period ($/MWh), 3 Periods

	Consumer Class	Summer 2020	Winter 2020/21	Summer 2021
Average Weighted Energy Rate ($/MWh)	Class A	12.22	15.08	**26.06**
	Class B	15.70	18.40	**32.57**
Average Global Adjustment ($/MWh)	Class A	62.28	44.84	**35.62**
	Class B	119.45	91.98	**71.14**
Average Uplift ($/MWh)	Class A	2.33	2.63	**3.23**
	Class B	2.69	2.87	**3.60**
Average Commodity Rate ($/MWh)	Class A	76.83	62.54	**64.91**
	Class B	137.84	113.25	**107.31**
	All Consumers	120.55	98.48	**94.98**

The average commodity rate for both Class A and B consumers decreased in the Summer 2021 Period compared to the Summer 2020 Period. The average commodity rate for Class A consumers decreased by 16%, while the average commodity rate for Class B consumers

[112] Consumers are divided into two groups: Class A, being consumers with an average monthly peak demand less than 5 MW but greater than 1 MW (or 500 kW for some sectors) that have opted into the class as well as consumers with an average monthly peak demand greater than 5 MW that have not opted out of the class, and Class B, being all other consumers. For more information, see Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*: http://www.ontario.ca/laws/regulation/040429.

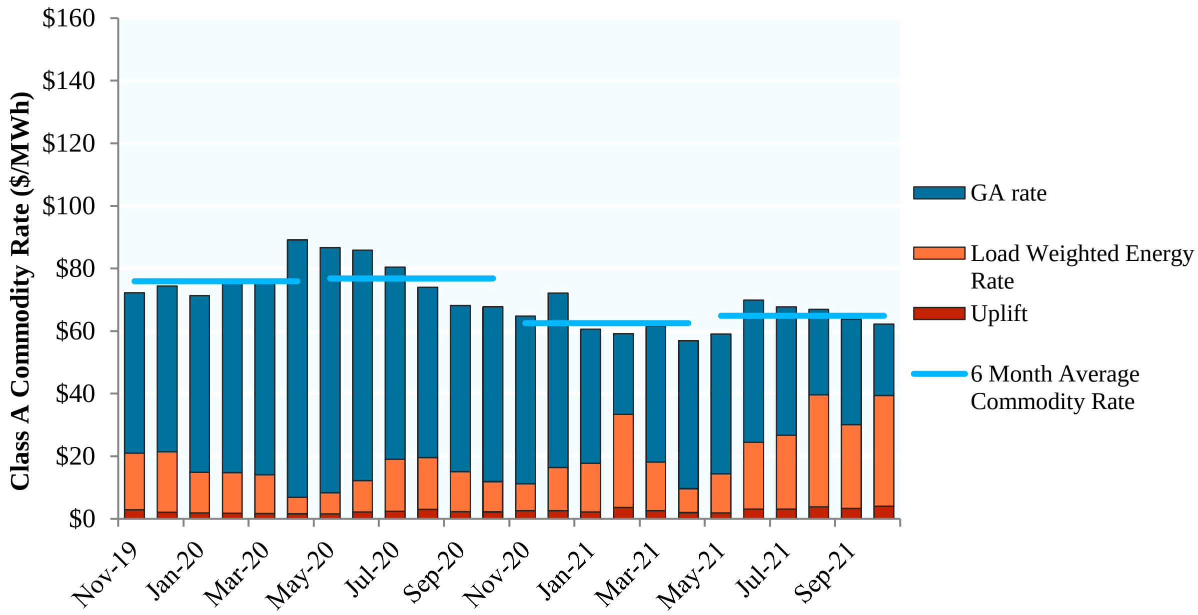
[113] Since January 2011, the GA payable by Class A consumers has been based on the ratio of their electricity consumption during the five peak hours in a year relative to the total consumption by all consumers in each of those hours. This ratio for Class A consumers is calculated for a given year and is applied to the Total GA for each month of the following year. To the extent that Class A consumers reduce their demand during peak hours, their share of GA is reduced in the next year. Once the Class A portion of the monthly GA is allocated, the remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel's Industrial Conservation Initiative (ICI) Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.

decreased by 22%. Despite the high HOEP, the Summer 2021 Period commodity rates decreased due to the Non-Hydro Renewables Funding Amount.

While the GA and the HOEP have an inverse relationship, this is not necessarily a one-for-one relationship nor does it impact each consumer class equally. A higher GA tends to increase the commodity rate more for Class B than Class A consumers because the current GA allocation methodology allocates to Class A consumers a lower share of GA per MWh consumed than to Class B consumers. Conversely, a lower GA tends to decrease the commodity rate more for Class B than Class A consumers. In the Summer 2021 Period, Class B consumers experienced a greater decrease in commodity rate than Class A consumers, indicating that changes in GA continued to have a greater impact on the average commodity rate for Class B consumers as compared to Class A consumers.

Figure A-27 separates the monthly average commodity rate into its three components (average load weighted energy rate, average GA rate, and average uplift rate) for Class A consumers for the previous two years. The figure also shows the total commodity rate averaged over each 6-month period.

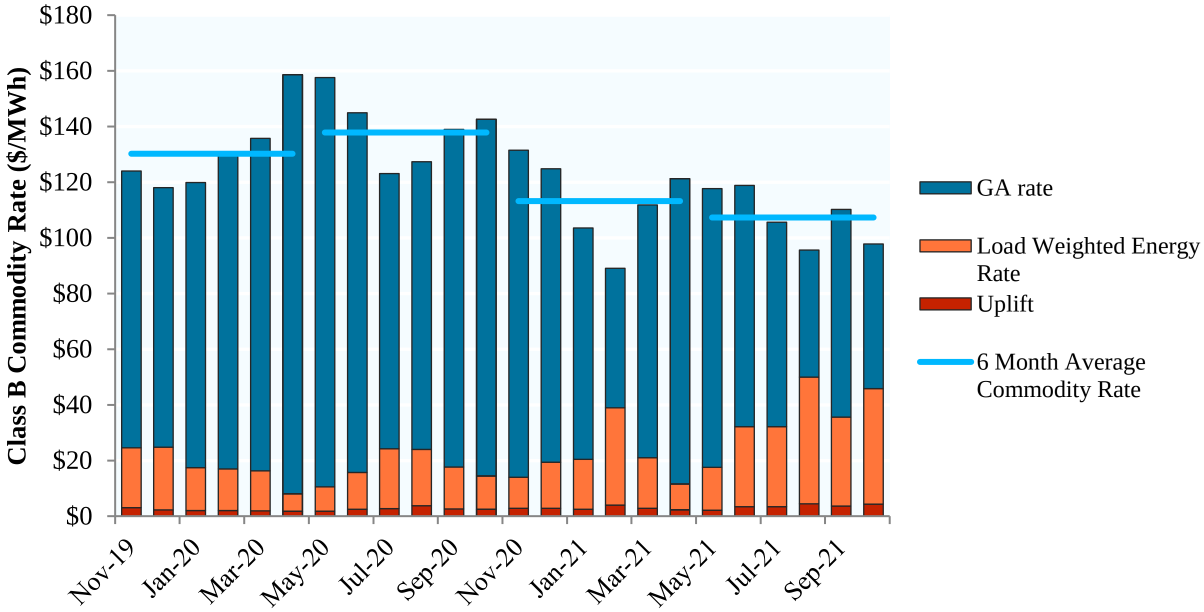
Figure A-27: Average Commodity Rate for Class A Consumers by Component, 2 Years



The 6-month average commodity rate for Class A consumers decreased significantly from $77/MWh in the Summer 2020 Period to $64/MWh in the Summer 2021 Period.

Figure A-28 separates the monthly average commodity rate into its three components (average load weighted energy rate, average GA rate, and average uplift rate) for Class B consumers for the previous two years. The figure also shows the total commodity rate averaged over each 6-month period.

Figure A-28: Average Commodity Rate for Class B Consumers by Component, 2 Years



The 6-month average commodity rate for Class B consumers decreased from $137/MWh in the Summer 2020 Period to $107/MWh in the Summer 2021 Period.

Appendix B: MSP Submission on Reconsideration of Dispatchable Load Exemptions

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

Ontario

Market Surveillance Panel I Comité de surveillance du marché

BY E-MAIL

July 26, 2022

To: Markets Committee of the IESO Board of Directors, in their capacity as the Exemption Panel
Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1

RE: IESO Recommendations to Reconsider Existing Exemptions for Dispatchable Loads

The Market Surveillance Panel (MSP)[1] understands that the Markets Committee of the IESO Board of Directors has been assigned as the panel (Exemption Panel) to reconsider existing exemptions for ArcelorMittal Dofasco Inc. (Dofasco), Gerdau Long Steel (Gerdau), and Ivaco Rolling Mills (Ivaco) (collectively, the Exempt Loads) from certain obligations and standards required by the market rules. The exemption reconsideration process for these Exempt Loads was initiated in 2021 by IESO staff. In June of 2022 the IESO published documents with their recommendations relating to these reconsiderations. These documents state that the IESO staff requested these reconsiderations due to a change in circumstances, one of which, according to the documents, is the MSP report that discussed inaccessible operating reserve. Specifically,

[1] The MSP has a mandate to monitor, evaluate and analyze activities related to the IESO-administered markets and the conduct of market participants with a view to identifying, among other things, aspects of the underlying design and structure of the IESO-administered markets that are inconsistent with the efficient and fair operation of a competitive market.

the documents state that "{I}n order to effectively address the MSPs recommendations…it is necessary to reconsider the existing exemptions".

The MSP is writing to the Exemption Panel, with a copy to the IESO, the Ontario Energy Board (OEB) and the Exempt Loads, to ensure that the MSP's views on the effectiveness of the reconsidered exemptions at addressing the MSP's concerns are clear, timely and transparent. The MSP intends to post this letter on the OEB website and encourages the IESO to post the letter on their website.

In this letter, we provide our understanding of the contextual background for the proposed reconsidered exemptions and present the MSP's observations on the IESO staff recommendations on these exemptions as they relate to the efficient and fair operation of a competitive market.

While the MSP understands that exemptions may be required in certain circumstances, they should be developed based on appropriate and robust analysis and with regard to viable alternative approaches. In short, the MSP believes that IESO staff have not provided sufficient evidence to support their recommendations for these exemptions. We describe the areas that are at issue and that would benefit from further evidence.

The Existing Exemptions

Exemptions are addressed in section 36.1 of the *Electricity Act, 1998* (Act), and the IESO's *Market Manual 2: Administration - Part 2.2: Exemption Application and Assessment* provides details related to the process and criteria for assessing the merits of exemption applications, including exemption reconsiderations.

In 2002, a panel (referred to at the time as the "Independent Panel") considered Ivaco's application for exemption from the requirement to comply with dispatch instructions for the real-time energy market and from the requirement to notify the IESO if there is an expected material difference in operations from those dispatch instructions. IESO staff recommended[2] approval of the exemption, under certain conditions on the bidding and operating strategies of Ivaco's

[2] "IMO Staff Recommendation to Panel on Exemption Application (General)", IESO, March 11, 2002, http://www.ieso.ca/Documents/exemptions/ex_011164_rec.pdf. Also see "Waiver Application (General Process)", IESO, October 11, 2001, http://www.ieso.ca/Documents/exemptions/ex_011164.pdf and "Part 3: Submissions in Support of Waiver Application", IESO, March 8, 2002, http://www.ieso.ca/Documents/exemptions/ex_011164_att.pdf.

facilities during the term of the exemption. These conditions are listed in the attached Appendix A.

The exemption panel granted the exemptions on the conditions recommended by IESO staff, concluding that they “provide a least-cost means of allowing [Ivaco] to become dispatchable and to participate in the market for Operating Reserve.”[3]

In 2004, Gerdau and Dofasco applied for exemptions similar to those granted to Ivaco.[4] The applications included a condition to submit operating reserve offer quantities equal to average consumption of the process when running, not including zero consumption time periods; a less restrictive requirement than the Ivaco condition which requires the average to include zero consumption periods. IESO staff considered operating reserve to be outside the scope of the recommendation and a matter best addressed through the facility registration process. The exemption panel granted the exemptions for participation by these Exempt Loads in the energy market on the conditions recommended by IESO staff, which did not include exemptions for operating reserve offers as requested by these two Exempt Loads. As such, when they offer operating reserve, they are not exempt from compliance in the way that Ivaco is.

The MSP’s Monitoring Report and Later Developments

In its Monitoring Report released in May 2017, the MSP reported that during the period January 2010 to April 2016, the IESO scheduled operating reserve from dispatchable loads when their facilities were incapable of providing the stand-by energy reduction required under the market rules, and per North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) reliability standards. The MSP estimated that dispatchable loads received approximately $12 million in inappropriate stand-by payments during the identified period for providing reserve that was unavailable for energy activation, noting that these

[3] Decision of the Independent Panel -Application No. 01-1146,” IESO, June 17, 2002, http://www.ieso.ca/Documents/exemptions/ex_PanelDecision_011164_02Jun06.pdf.

[4] “Gerdau Exemption Application, ID#: 1304”, IESO, March 31, 2004, http://www.ieso.ca/Documents/exemptions/ex_1304.pdf;

“Gerdau Exemption Application, ID#: 1305”, IESO, March 31, 2004, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/ex_1305.ashx.

“Dofasco Exemption Application, ID#: 1308”, IESO, April 30, 2004, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/ex_1308.ashx;

“Part 4 – Submissions in Support of Exemption Application”, IESO, 2004, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/ex_1308_Att1.ashx.

instances were of concern not only for the payments themselves but for the corresponding reliability issues. The MSP recommended that the IESO ensure that dispatchable loads are compensated only for the amount of operating reserve that they were capable of providing in real-time and, more fundamentally, that the IESO should explore options for ensuring that unavailable operating reserve is not scheduled in the first place.

Since May 2017, the IESO has continued to schedule unavailable operating reserve from dispatchable loads and dispatchable loads have continued to receive inappropriate stand-by payments, although the IESO has begun to recover some of the payments as allowed by the market rules. The IESO has recently taken additional actions that are relevant to the MSP's concerns. First, the IESO has proposed a market rule amendment to add a settlement charge (called the "non-accessibility charge") to automatically recover operating reserve payments from market participants where the market participant fails to maintain adequate unused generation (or load reduction) capacity during all intervals in which they were scheduled for operating reserve.[5] The IESO expects that this rule amendment will make the process for recovery more efficient than the current process. Second, the IESO commenced a process to reconsider the exemptions provided to the Exempt Loads, which is the focus of this letter.[6]

IESO Staff Recommendations for Reconsideration of Exemptions

On June 10, 2022, the IESO posted "IESO Staff Recommendations to Panel on Exemption Reconsideration" in relation to the existing exemptions for Ivaco, Gerdau and Dofasco. These documents cite the MSP's compensation and reliability concerns regarding unavailable operating reserve from dispatchable loads as one of the causes for reconsideration. Attached

[5] "Market Rule Amendment Proposal Form (Subject: Improving Accessibility of Operating Reserve)", IESO, May 31, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2022/iesotp-20220614-mr-00467-r00-improving-accessibility-of-operating-reserve-amendment-proposal.ashx.

[6] "Notice of Reconsideration 1164: Ivaco Rolling Mills", IESO, June 10, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/web-IESO-Staff-Recommendation-Ivaco-1164.ashx;

"Notice of Reconsideration 1304: Gerdau Long Steel", IESO, June 10, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/web-IESO-Staff-Recommendation-Gerdau-Whitby-1304.ashx;
"Notice of Reconsideration 1305: Gerdau Long Steel", IESO, June 10, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/web-IESO-Staff-Recommendation-Gerdau-Cambridge-1305.ashx.

"Notice of Reconsideration 1308: ArcelorMittal Dofasco Inc.", IESO, June 10, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/exemptions/web-IESO-Staff-Recommendation-AMD-1308.ashx as Appendix B is Table 1, which presents the main conditions for exemption proposed by IESO staff in relation to the reconsideration, alongside the conditions that apply under the existing exemptions.

MSP Observations

The MSP offers the following observations on IESO staff's recommendations.

First, the IESO staff recommendations do not clearly explain why the existing exemptions are deficient or unworkable. The existing exemptions appear to be designed to specifically limit the amount of unavailable operating reserve scheduled from these dispatchable loads and hence the associated inappropriate payments. Specifically, under the 2002 and 2004 exemptions, the dispatchable loads are required to load to full or zero consumption in response to an IESO energy dispatch instruction within 5 minutes, but at most within 15 minutes per their normal consumption pattern. If the dispatchable loads are not capable of responding to dispatch instructions, they are required to notify the IESO so that corrective action can be taken. These two exemption conditions should limit the number of intervals with potential unavailable operating reserve to no more than three or four intervals per hour. The condition applicable to Ivaco for the operating reserve market requiring it to submit a maximum reserve offer quantity equal to average consumption per dispatch hour, including zero consumption time periods, should further reduce the amount of unavailable reserve scheduled and the associated inappropriate payments. The MSP suggests that a more detailed explanation and quantification of the deficiencies of the conditions in the existing exemptions is needed to better understand why the status quo is not acceptable and why a set of potentially <u>less</u> stringent exemption conditions are being put forth by IESO staff.

Second, the IESO staff recommendations compare the revised conditions for exemption against the status quo when discussing the exemption approval criteria set out in Manual 2: Part 2.2. However, comparing the outcomes under the IESO staff recommendations to the status quo would be inappropriate ***if*** the previous conditions for exemption are proven to be deficient or unworkable and hence an untenable solution moving forward. In that case, when evaluating the criteria for the exemption the proper comparison is to the next best *feasible* alternative. If the current conditions for exemption are deficient (a conclusion that the IESO staff discussion does not substantiate per our first observation above), then the more appropriate comparison is likely the situation where the Exempt Loads are *ineligible* to be dispatchable loads. This was the comparison properly applied by IESO staff and the exemption panel to evaluate the criteria for approval for the existing exemptions.

Third, a factor to be considered in the evaluation of the reconsidered conditions for exemption is whether the conditions for exemption provide the Exempt Loads with an undue preference[7] or a competitive advantage in the supply of operating reserve relative to other operating reserve providers, including generators. This is not addressed in the IESO staff recommendation. The proposed conditions *could* provide the Exempt Loads with an undue preference or competitive advantage *if* they permit the Exempt Loads to be scheduled for an amount of unavailable operating reserve proportional to the offered amount that is materially greater than what is allowed from other providers of operating reserve (e.g., generators) under the market rules. Providing an undue preference or competitive advantage to the Exempt Loads could lead to short-term inefficient dispatch and over the long run, less efficient investment in operating reserve capability, and would be inconsistent with the efficient and fair operation of a competitive market. The MSP has not formed an opinion on this issue but believes that it requires consideration and that the IESO should provide an analysis of it in support of their recommendations.

Fourth, the IESO staff recommendation proposes to exempt the Exempt Loads from the pending non-accessibility charge (if approved by the IESO Board of Directors). As noted above, the pending market rule amendment would allow the IESO to automatically claw-back operating reserve payments from market participants when they fail to maintain adequate unused generation (or load reduction) capacity when scheduled for operating reserve. Exempting the Exempt Loads from the charge would provide them with an undue preference or competitive advantage over other operating reserve providers that will be subject to the charge in the sense that the Exempt Loads would receive a higher payment for an inferior product. As discussed above, this would be inconsistent with the efficient and fair operation of a competitive market. The IESO staff recommendation offers no justification for why the Exempt Loads should be exempt from this charge while their competitors are subject to the charge.

In conclusion, the MSP believes that IESO staff has not provided sufficient information or evidence to support a conclusion that the threshold criteria for exemption, as set out in the Market Manual referred to above, have been met.

We trust you will find the MSP’s observations helpful in your consideration of this matter.

Respectfully,

The Market Surveillance Panel

[7] See Section 1.4.2 of *Market Manual 2: Administration - Part 2.2: Exemption Application and Assessment*.

cc

Michael Lyle, Vice-President, Legal Resources and Corporate Governance, IESO

Carolyn Calwell, Chief Corporate Services Officer and General Counsel, OEB

Exempt Loads:

Victor Stranges, ArcelorMittal Dofasco, G.P., ArcelorMittal Dofasco Inc.

Sam Harper, Director of Energy, Gerdau Long Steel North America

François Abdelnour P.Eng., Energy Director, Ivaco Rolling Mills

Appendix A

In 2002, IESO staff recommended approval of the exemption for Ivaco, under the following conditions:

1) submit a maximum energy bid quantity at average consumption of the process while running, not including zero consumption time periods, and with ramp rates that allow the facilities to go from minimum to maximum load bid within 5 minutes, to reduce the amount of non-compliance alarms and the number of dispatch instructions;
2) submit a maximum operating reserve offer quantity at average consumption per dispatch hour, with the average including zero consumption periods to ensure fairness of payments to the successful bidders into the Operating Reserve Market;
3) when offering in the operating reserve market,
    a) dispatch to or remain at full consumption if it receives an energy dispatch instruction that is to 50% or greater of its energy bid quantity and dispatch to or remain at minimum consumption if the energy dispatch instruction is to less than 50% of its maximum bid quantity;
    b) if at zero load and dispatched to full consumption but unable to comply within the five-minute interval because of operating characteristics, notify the IESO that it cannot comply and remain at zero consumption until the next dispatch interval; and
    c) report equipment outages of four or more consecutive dispatch intervals to the IESO when unable to operate as per normal operations (occasional equipment outages of up to four consecutive dispatch intervals).

Appendix B

Table 1: Main Conditions of Existing Exemptions (2002 and 2004), and Proposed Conditions on Reconsideration (2022)

	Conditions for Existing Ivaco Exemptions (2002)	Conditions for Existing Gerdau, Dofasco Exemptions (2004)	Conditions Proposed by IESO Staff for Exemption Reconsideration (2022)
Normal Consumption Pattern	Mentioned but not officially defined	During production cycle can respond to energy dispatch instruction in 15 minutes or less	Defined but not publicly available
Maximum Energy Bid Quantity	Average consumption of the process while running, ***not including*** zero consumption time periods	Average consumption of the process while running, ***not including*** zero consumption time periods	Hourly average consumption over applicable 6 month period (***including*** zero consumption period) when metered consumption exceeds 1MW
Energy Bid Adjustment	Not addressed	Not addressed	If reasonably expect dispatchable load to decrease by more than 10% then max energy bid decrease by same percentage
Energy Dispatch	Dispatch to full consumption if dispatch instruction is to 50% or more of maximum bid, and dispatch to zero consumption otherwise	Dispatch to full consumption if dispatch instruction is to 50% or more of energy bid, and dispatch to zero consumption otherwise	If instructed to dispatch to zero, dispatch to 1MW or less in 5 minutes, if the instruction is to 50% or more of energy bid, dispatch to normal consumption pattern, and dispatch to 1MW or less otherwise
Operating Reserve Offer	Average consumption per dispatch hour, ***including*** zero consumption time periods	Not addressed	Hourly average dispatchable consumption (***including*** zero consumption period) in all settlement hours that an offer for operating reserve was submitted during applicable 6 month period
Operating Reserve Adjustment	Not addressed	Not addressed	If reasonably expect dispatchable load to decrease by more than 10% but within normal consumption pattern for 5 hours or more, then max reserve offer decrease by same percentage
Operating Reserve Activation	Not addressed	Not addressed	If dispatchable load at 1MW, accept ORA and remain at or below 1MW until deactivated, otherwise got to 1MW or less regardless of value of ORA until deactivated
IESO Notifications	If cannot comply with dispatch instruction within the five-minute interval	If operating outside normal consumption pattern and cannot comply with dispatch instruction	If expect to operate in manner that, for any reason differs materially from dispatch instruction and operating parameters of the exemption
Non-accessibility charge	Not applicable	Not applicable	Exempt if compliant with terms and conditions of Exemption