ONTARIO ENERGY BOARD

Market Surveillance Panel

State of the Market Report 2023

September 2024

Ontario Energy Board

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2SS	Two-Schedule System
CER	Clean Electricity Regulations
CSMC	Congestion Management Settlement Credits
DA-PCG	Day-Ahead Production Cost Guarantee
DAM	Day-Ahead Market
EEA-1	Energy Emergency Alert Level 1
ELT-1	Expedited Long-Term Procurement
ERA	*Electricity Restructuring Act, 2004*
ERCOT	Electricity Reliability Council of Texas
ERUC	Enhanced Real-Time Unit Commitment
FERC	Federal Energy Regulatory Commission
FIT	Feed-In-Tariff
GA	Global Adjustment
HDR	Hourly Demand Response
HHI	Herfindahl-Hirschman Index
HIM	Hydro Incentive Mechanism
HOEP	Hourly Ontario Energy Price
IAM	IESO-Administered Markets
ICP	Intertie Congestion Price
IESO	Independent Electricity System Operator
IOG	Intertie Offer Guarantee
IZP	Intertie Zonal Price
LMP	Locational Marginal Pricing
MCP	Market Clearing Price
MMCP	Maximum Market Clearing Price
MOCA	Must-Offer Condition Agreement
MPMA	Market Power Mitigation Agreement
MRP	Market Renewal Program
MSP	Market Surveillance Panel
NERC	North American Electric Reliability Corporation

OEB	Ontario Energy Board
OER	Ontario Electricity Rebate
OPG	Ontario Power Generation Inc.
OR	Operating Reserve
PD	Pre-Dispatch
RFP	Request for Proposals
RSI	Residual Supplier Index
RT-GCG	Real-Time Generation Cost Guarantee
TR	Transmission Rights
TRCA	Transmission Rights Clearing Account

1 EXECUTIVE SUMMARY

The Market Surveillance Panel (MSP or Panel) serves as the market monitor for the Ontario wholesale electricity markets, which are administered by the Independent Electricity System Operator (IESO). Mandated to monitor, evaluate and report on the efficiency and competitiveness of the wholesale electricity markets, the Panel is an integral part of the oversight framework. The Panel provides independent evaluation and analysis of the wholesale electricity markets – which includes authoring public reports and making recommendations to other oversight authorities in alignment with its mandate. Appendix A provides a more detailed description of the Panel's role. The work of the Panel is supported by the Market Assessment Unit within the IESO, in accordance with a Protocol between the IESO and the Ontario Energy Board.

The *State of the Market Report 2023* reviews the performance of the IESO-Administered Markets (IAM) in the calendar year 2023. The main findings of the review include the following:

- The all-in cost of electricity decreased slightly from $23.6 billion in 2022 to $23.4 billion in 2023. Government cost mitigation programs reduced the all-in cost to Ontario consumers by $5.8 billion in 2023, down from $6.2 billion in 2022. The all-in unit cost of electricity fell by 0.7% from $162/MWh in 2022 to $161/MWh in 2023, while Ontario demand slightly decreased from 145.4 TWh in 2022 to 145.2 TWh in 2023 (see also, Chapter 3 – Market Outcomes).
- Ontario Power Generation Inc. (OPG) and its subsidiary, Atura Power, collectively maintained a dominant market share by controlling 51% of the province's generating capacity and 68% of price sensitive generating capacity[1] - a figure unchanged since last year's report. Ontario continues to rely upon regulatory mechanisms and the Must Offer Conditions Agreement to contain the exercise of market power by OPG and its subsidiary and to promote dispatch efficiency (see also, Chapter 4 – Competitiveness and Contracting).

[1] Price-sensitive capacity refers to most hydroelectric (excluding self-scheduling), gas/oil and biofuel generation within the IAM. Market shares include capacity at generators where OPG has the majority ownership interest and operational control.

- There continues to be a dichotomy between the relative economic efficiency of Ontario's import and export trade. In previous reports, the Panel has highlighted the systemic differences between hour-ahead pre-dispatch (PD-1) prices, which facilitate intertie scheduling, and real-time prices. Imports scheduled in the hour-ahead pre-dispatch are provided an Intertie Offer Guarantee (IOG), which ensures the import receives the higher of its offer price or the real-time price. In contrast, exports pay the real-time price, which may be higher than their bid price. The IOG was implemented prior to the start of the market in 2002 to "encourage imports, helping to ensure adequate supply in Ontario".[2] The Panel is concerned that the persistent difference between the PD-1 price, and the real-time price combined with the price assurances provided to imports but not exports through the IOG, contributes to the relatively higher percentage of scheduling inefficiencies for imports. The planned implementation of the Market Renewal Program (MRP) will provide an opportunity to review the trade-off between the potential reliability benefits and the scheduling inefficiency costs of the IOG. The Panel recommends that the IESO conduct this review following the implementation of MRP (see also, Chapter 6 – External Transactions).

  Recommendation 2024-1-1

  The Panel recommends that the IESO review the benefits and costs of continuing the Intertie Offer Guarantee (IOG) in the real-time market after the deployment of the Market Renewal Program, once sufficient data is accumulated, but no later than one year after implementation. The review should consider imports arranged outside of the Day-Ahead Market and quantify the extent to which the IOG:

  - ***enhances the reliability or adequacy of the electricity system;***
  - ***contributes to inefficient import schedules; and***
  - ***dampens real-time market prices thus contributing to other potential real-time scheduling inefficiencies.***

[2] See the IESO Quick Takes, Intertie Offer Guarantee, 2007.

- The IESO issued three Energy Emergency Alert Level 1 (EEA-1) advisories in 2023,[3] largely precipitated by weather conditions and unplanned nuclear outages. EEA-1 advisories serve as notice to neighbouring jurisdictions that supply and demand conditions are such that additional measures (such as limiting exports or calling on emergency energy) may be needed if those conditions persist or worsen. Prices that accurately reflect system conditions can play an important role in encouraging efficient and effective responses from market participants under extreme supply and demand conditions. These responses also support grid reliability. The Panel notes that wholesale market prices understated the relative scarcity of supply during the three EEA-1 advisories. The Panel further notes that following the activation of Hourly Demand Response (HDR) resources, wholesale market prices were well below the HDR bid prices (the highest price these consumers are willing to pay before having their consumption curtailed) as an indication of how prices understated the relative scarcity conditions (see also, Chapter 3 – Market Outcomes).
- The IESO is embarking on a new Resource Adequacy framework with a regularized publication of long-term planning outlooks and an attendant *Annual Acquisition Report* (AAR). The 2022 AAR sets out the need for new-build capacity totaling 2,500 MW by 2027 and another 1,500 MW by 2030 (4,000 MW total).[4] In 2023, the IESO secured 1,463 MW (winter contract capacity) and 1,424 MW (summer contract capacity) of new supply through its Expedited Long-Term Procurement (E-LT1) and Same Technology Upgrade Solicitation, and articulated the need for future procurement efforts through two additional long-term RFPs (LT1 and LT2). Many of these projects have faced the challenge of securing the necessary municipal support in order to proceed and this could affect both the level of certainty and ultimate outcomes of these efforts (see also, Chapter 5 – Investment and Long-Term Procurement).

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[3] Under NERC Emergency Operations standard EOP-011-1, an Energy Emergency Alert Level 1 situation is defined as follows:

1. EEA-1 — All available generation resources in use.

Circumstances:

1. *The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.*
2. *Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.*

[4] See the IESO's 2022 Annual Acquisition Report, pages 39-40.

- Public policy has the potential to influence the long-run dynamic efficiency of any market. A wide range of policy choices ranging from technological selection to major infrastructure investment can affect the construct of the long-run average cost curve. This has been the case over the entire span of the historic development of Ontario's electricity system. The Panel has observed that the IESO's procurement efforts have taken place alongside an increasingly active trend of Ministerial directives and policy measures at both the federal and provincial levels. Over the course of 2023, the IESO received 15 directives or letters from the Minister of Energy, some of which set the stage for both long-term capacity procurement and exploration for the potential of non-competitive procurements of both generation and storage resources of material size. In some cases, such as the government's announced nuclear building programs spanning the additional small modular reactors at Darlington and the Bruce Power Expansion, the ultimate source of funding and structuring of these projects remains presently unclear and potentially material to the future competition and efficiency of the electricity markets (see also Chapter 5 – Investment and Long-Term Procurement and Chapter 9 – Policy, Government and Community Influences).
- The Panel more specifically notes where environmental policy measures of the "energy transition" are now presenting a potential future impact on long-term procurements in the electricity market. At the federal level, the discourse over the proposal Clean Electricity Regulations also poses the potential to influence both the value of fossil-based generation investment, and the Ministerial-directed provisional guarantees against this policy risk afforded to natural gas generators in the IESO's procurement program (see also, Chapter 9 – Policy Government and Community Influences).[5] In this year's report, the Panel also notes the increased utilization of Ontario's natural gas fleet and its increased role as a price-setting resource, in the face of lower natural gas prices (see also, Chapter 3 – Market Outcomes).

As noted in Chapter 10 – Future of Ontario Market Design, the Panel is increasingly turning its attention towards the implementation of MRP planned for mid-2025. The Panel has made numerous past recommendations for improvements to market efficiency, which directly intersect with the stated objectives of MRP's constituent design components. In this context, many of the observations in this *State of the Market Report 2023* set the stage for future analysis by the Panel, as Ontario embarks on the largest, single stepwise change to the wholesale electricity market since its inception.

[5] A natural gas facility can suspend operations for the remainder of the contract term while retaining payments under the E-LT1 and LT1 contracts in the event that the project is, despite commercially reasonable efforts, unable to comply with such laws or regulations (see also, Ministerial Directive to the IESO, Order-in-Council 1348 /2022, October, 6, 2022, Sections 2 g. and 9).

2 INTRODUCTION

The MSP is a panel of the Ontario Energy Board (OEB) providing independent evaluation and analysis of the wholesale electricity markets administered by the IESO. This *State of the Market 2023* report provides the Panel's general observations on the state of the IESO-Administered Markets (IAM).[6] The Panel publishes its annual state of the market report to increase public awareness of the markets' overall performance and to highlight areas of potential improvement. The Panel's previous report, the *State of the Market Report 2022*, was published in December 2023.[7]

Monitoring the competitiveness and efficiency of a market is an essential part of all competitive electricity markets. Competition protects the interests of consumers by encouraging suppliers to minimize production costs, maximize resource availability, invest in new innovative technologies, and offer in the market at prices reflective of their cost. When competition is effective, it ensures that the sector functions efficiently and that consumers are provided with a reliable supply of electricity.

The Ontario electricity industry operates as a hybrid market where government policies and programs play a significant role in securing assets that participate in the wholesale market. While electricity is traded competitively in the wholesale market, capacity and supply are mostly procured through long-term contracts and central planning. The hybrid market features regulated prices for certain consumers and for many of Ontario Power Generation Inc.'s (OPG) generation assets.[8] The Government of Ontario also plays a key role in the hybrid market through Ministerial directive powers. At times, government policy objectives will affect the goals of efficiency and competitiveness. The Panel conducts its assessment of the efficiency and competitiveness of the IAM with recognition of the stated objectives of government policies.

The remainder of this report is organized as follows:

- Chapter 3 provides detail on all-in costs paid for electricity.
- Chapter 4 covers competitiveness and contracting within the energy markets.
- Chapter 5 offers an assessment of investment and long-term efficiency.
- Chapter 6 provides an assessment of intertie trading.
- Chapter 7 explores the performance of the financial Transmission Rights market in 2023 and discusses transmission development in the province.

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[6] The IESO administers several separate but related markets, including the energy market, the Operating Reserve market, capacity markets, and transmissions rights auctions. IESO procurements may also indirectly affect the IAM.

[7] See the [Panel's *State of the Market Report 2022* (*Monitoring Report 38*)](#).

[8] Consumers that pay electricity prices set by the OEB do not directly participate in the wholesale market. However, those prices are based on a forecast of wholesale market prices (and the Global Adjustment), and other market costs charged to electricity distributors. Distributors then pass the costs through to these consumers.

- Chapter 8 offers a brief overview of the Operating Reserve and Ancillary Services markets.
- Chapter 9 covers key government policies and community influences in 2023 that intersected with market efficiency and competition.
- Chapter 10 highlights key inefficiencies in the current market design.

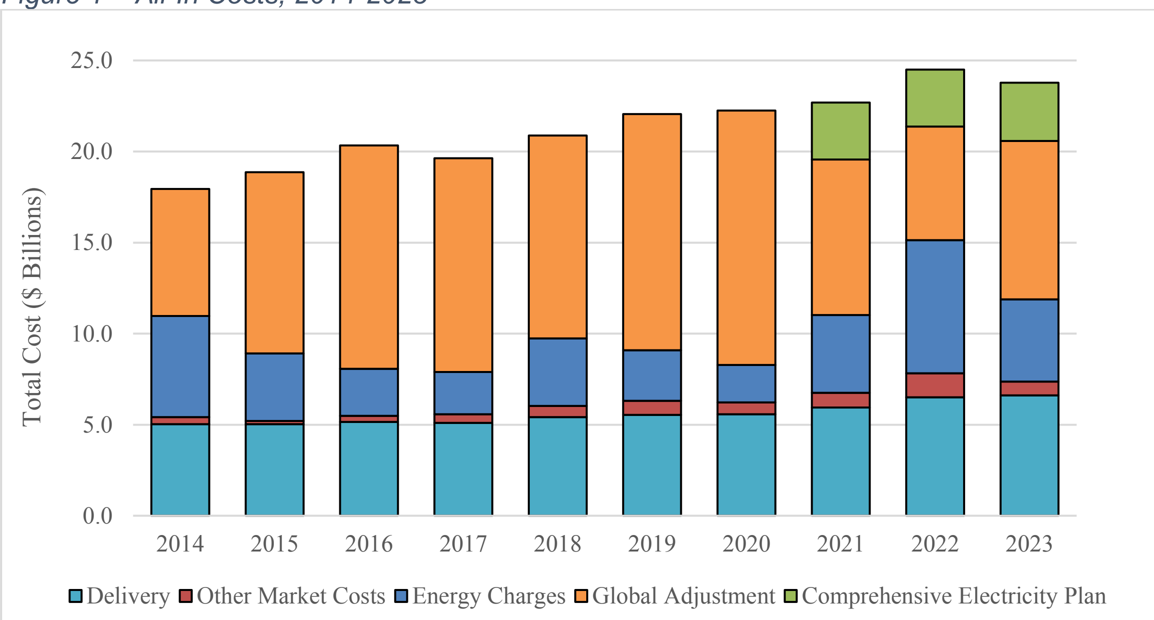
3 MARKET OUTCOMES

The "all-in cost" of electricity reflects the total cost of serving electricity consumers in Ontario. In 2023, the all-in cost was $23.4 billion. This chapter provides an overview of the components of the all-in cost, an analysis of cost trends, and a summary of government cost mitigation programs. Additionally, this chapter provides key context for topics covered in the later chapters of this report.

3.1 All-In Cost and All-In Unit Cost

Figure 1 displays the annual all-in cost, which is the total amount paid into the electricity system by Ontario consumers and through government funding for the period 2014 to 2023. Figure 2 presents the annual "all-in unit cost", which is the all-in cost per MWh of Ontario demand consumption for the same period. In 2023, the all-in unit cost was $161/MWh. A figure showing monthly breakouts of all-in unit costs is available in Appendix B.[9]

Figure 1 – All-In Costs, 2014-2023[10]



[9] See Figure 37 – All-In Unit Cost, Monthly 2022-2023.

[10] Specific items under "Other Market Costs" are provided in Table 1.

Figure 2 – All-In Unit Cost, 2014-2023

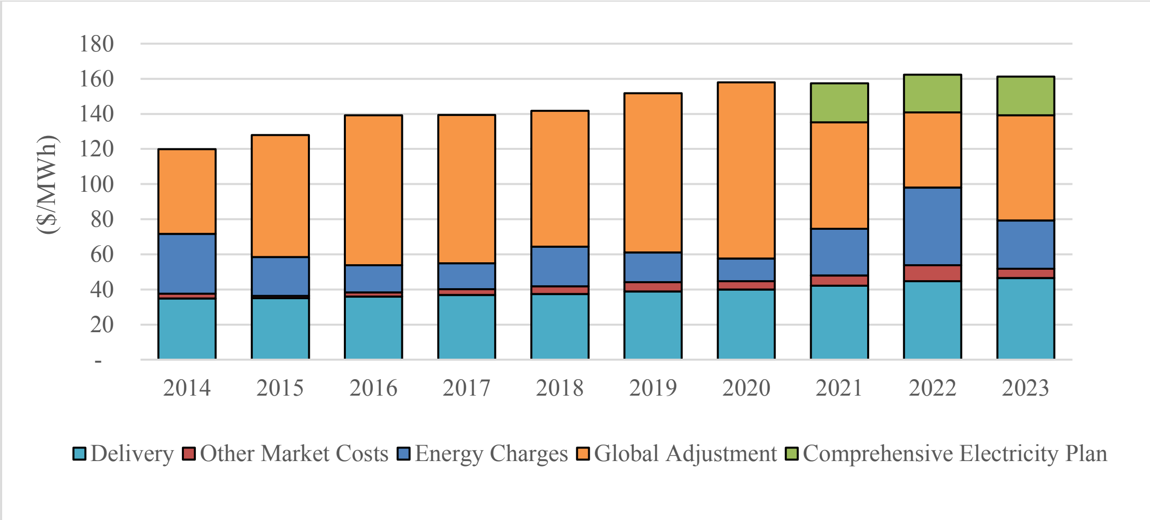


Table 1 below provides a detailed breakdown of the all-in cost and all-in unit cost by components for 2023. [11,12]

The all-in unit cost of electricity in Ontario fell by 0.7% in 2023 compared to 2022, from $162/MWh to $161/MWh. Over the last ten years, all-in unit costs have increased by 34%, from $120/MWh in 2014. In real terms, the increase over the last ten years is 0.7% (adjusting for inflation).

Energy traded at the wholesale market price and the Global Adjustment are the first two components of the all-in cost. These elements principally represent the amounts paid to generators for electricity production and capacity availability.

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[11] The 2022 all-in cost number is higher by $530 million (2.2%) than that reported in the State of the Market 2022 report due to changes to the methodology for the following line items:

1) inclusion of generator station service use in the line, "Energy Traded at the Wholesale Market Price" – impact is an additional $49 million
2) inclusion of complete cost arising from losses in the sub-item "Other" under "Other Market Costs" – impact is an additional $244 million
3) the methodology of estimating sub-item "Distribution Cost" under "Delivery" by assuming previous year's value is equal to current year (due to the lag time in the availability of distribution-level data), further adjusted by the average annual distribution cost growth rate in the last five years – impact is an additional $234 million.

These changes in methodology also apply to the 2023 all-in cost numbers.

[12] Government Program costs are published by the Ontario government (see also, The Public Accounts of Ontario 2022–23). Sub-item "Other" under "Government Programs" is composed of the Ontario Electricity Support Program, Distribution Rate Protection, the Rural or Remote Electricity Rate Protection, the Northern Energy Advantage Program, the Fair Hydro Plan and the First Nations On-Reserve Delivery Credit.

Delivery costs come from the OEB (see also, Natural gas and electricity utility yearbooks | Ontario Energy Board (oeb.ca)). All other costs are compiled from IESO settlements data and may differ slightly from other publications due to adjustments and groupings.

Table 1 – All-In Cost and All-In Unit Cost Components, 2022-2023

All-in Costs	2022 All-in Cost ($m)	2022 All-in Unit Cost ($ per MWh)*	2023 All-in Cost ($m)	2023 All-in Unit Cost ($ per MWh)*
Energy Traded at the Wholesale Market Price	**6,434**	**44.25**	**3,989**	**27.47**
Global Adjustment	**6,227**	**42.83**	**8,705**	**59.94**
Contracts	2,740	18.84	3,879	26.71
OPG Regulated Assets	2,146	14.76	3,476	23.93
LDC FIT/MicroFIT Contracts	1,183	8.14	1,204	8.29
Conservation	158	1.09	147	1.01
Comprehensive Electricity Plan	**3,131**	**21.53**	**3,190**	**21.96**
Other Market Costs	**1,311**	**9.02**	**760**	**5.23**
IESO Administration Charge	207	1.42	205	1.41
Congestion Management	277	1.91	106	0.73
Ancillary Services	60	0.41	81	0.55
Operating Reserve	80	0.55	47	0.33
Capacity Auction	35	0.24	67	0.46
Production Cost Guarantee	94	0.65	53	0.37
Generator Cost Guarantee	52	0.36	45	0.31
Intertie Offer Guarantee	95	0.65	43	0.30
Other	411	2.83	113	0.78
Delivery	**6,511**	**44.78**	**6,769**	**46.61**
Distribution	4,325	29.75	4,488 est	30.90
Transmission	2,186	15.03	2,281	15.71
All-in Cost Total	**23,615**	**162.41**	**23,413**	**161.21**
Government Programs	**-6,164**	**-42.39**	**-5,793**	**-39.89**
Comprehensive Electricity Plan	-3,131	-21.53	-3,190	-21.96
Ontario Electricity Rebate	-1,998	-13.74	-1,547	-10.65
Other	-1,035	-7.12	-1,056	-7.27
Consumer Cost (All-in Cost Net of Government Programs)	**17,450**	**120.01**	**17,620**	**121.32**

** Ontario gross demand in 2023 was 145.2 TWh. It was 145.4 TWh in 2022.*

Energy Traded at the Wholesale Market Price

Energy is traded in the IAM at the wholesale market price. This wholesale price is determined in the IESO's wholesale energy market by the forces of supply and demand. The wholesale Market Clearing Price (MCP) is determined every five minutes. The Hourly Ontario Energy Price (HOEP) is calculated as the average of the twelve five-minute MCPs within the hour. These prices should ideally reflect the marginal cost of producing electricity in Ontario.

Global Adjustment

The Global Adjustment (GA) is the mechanism used to (i) reconcile differences between payments made to generators at the wholesale market price and payments made at regulated rates or under contracts that differ from the wholesale market price; and (ii) fund the province's conservation and demand management programs. In Ontario, most generators are provided price or revenue guarantees through contracts with the IESO or, in the case of provincially-owned OPG, through payments regulated by the Ontario Energy Board (OEB). The price or revenue guarantees provide generators with protection from low wholesale market prices and offer some assurance that generators will recover the cost of building, operating, and maintaining their assets.

Comprehensive Electricity Plan

Contractual payments owed to non-hydro generators have been transferred from the GA to the tax base as part of a government program referred to as the Comprehensive Electricity Plan. This is described in more detail in Section 3.4.

Other Market Costs

Other market costs include payments to generators and bulk loads (i.e. dispatchable loads and demand response resources) for reliability and ancillary services. They also include payments for congestion management, IESO administration charges, out-of-market commitment programs, including the Intertie Offer Guarantee (IOG), Day-Ahead Production Cost Guarantee (DA-PCG) and Real-Time Generation Cost Guarantee (RT-GCG) programs, as well as the debt retirement charge which was phased out by 2018.

Delivery

The delivery cost represents the amount paid to transmission and distribution companies to cover the cost to build, maintain and operate the high voltage (transmission) and low voltage (distribution) power lines which conduct electricity from the generation stations to consumers. The delivery component of the all-in unit cost grew by 4.1% in 2023, slightly higher than the ten-year average growth rate of 3.3%.

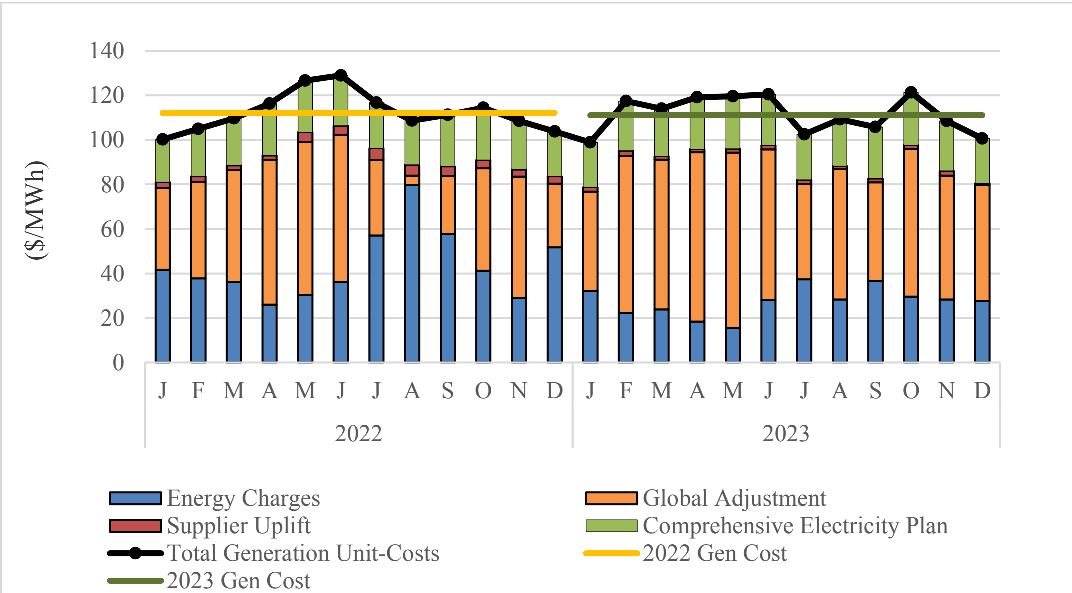
Consumer Costs

Consumer costs are the costs paid by Ontario electricity consumers. Consumer cost is the difference between the all-in cost and the costs covered by Ontario government funding programs.

3.2 Analysis of All-In Unit Cost

While all-in unit costs have risen annually by 3.4% on average over the last ten years, it fell by 0.7% in 2023 compared to 2022. This is due primarily to a decline in the generation cost components which are (i) energy traded at the wholesale market price, (ii) supplier uplift, and (iii) the Comprehensive Electricity Plan.[13] Together, these costs decreased by 0.9% in 2023, compared to a ten-year annual average increase of 3.1%. Figure 3 shows the monthly generation unit-costs in 2022 and 2023.[14]

Figure 3 – Generation Unit-Costs, Monthly 2022-2023



Although it is a small component of total generation costs, supplier uplift in particular fell by 52% year-over-year. The decline in generation costs and supplier uplift (which includes gas generation start-up costs) is largely driven by a decline in natural gas prices which fell nearly 60% year-over-year.

As described above, generators primarily earn revenues by selling their energy in the wholesale electricity market and through contractual (or regulated) payments made under the GA or the Comprehensive Electricity Plan. Sales made in the wholesale electricity market are dependent on the wholesale market price which will rise or fall depending on supply and demand dynamics. Most contracts and regulated rates are designed to insulate generator cost recovery from variations in the wholesale market price, most commonly by defining a fixed total price to be paid per MWh of generation. When a generator earns less than this total price in the market, GA payments make up the shortfall.[15] This means that the effect of changes in the wholesale market price on the all-in unit cost are largely offset by the counterbalancing changes to GA payments. That said,

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[13] Supplier uplift includes select components of the "Other Market Costs"; the Real-Time Generation Cost Guarantee, the Day-Ahead Production Cost Guarantee, the Intertie Offer Guarantee and Congestion Management Settlement Credits.

[14] Appendix B provides additional figure (i.e. Figure 39 – Generation Unit-Costs, 2014-2023) showing annual figures.

[15] If more than the total price is earned in the market, the GA will similarly act as a claw back.

changes in natural gas prices can affect specific market cost components paid through uplifts that are not covered through contract and the GA. The RT-GCG program, for example, provides start-up cost recovery guarantees to gas generators if market revenues from the wholesale market price are insufficient for cost recovery. Changes in gas prices affect start-up costs, with higher gas prices generally leading to larger RT-GCG payments, and higher all-in costs.

The role of wholesale market prices is discussed in Section 3.3. Contracts and rate regulation are discussed in more detail in Chapter 4.2.1.

The all-in unit cost is influenced by long-run and short-run factors. Long-run factors include investment, retirement, and contracting decisions. These factors are discussed more in Chapter 5. Short-run factors include supply side factors such as fuel prices and generation mix, and demand side factors such as industry growth and weather. The short-run factors will be discussed more in Sections 3.2.1 and 3.2.2.

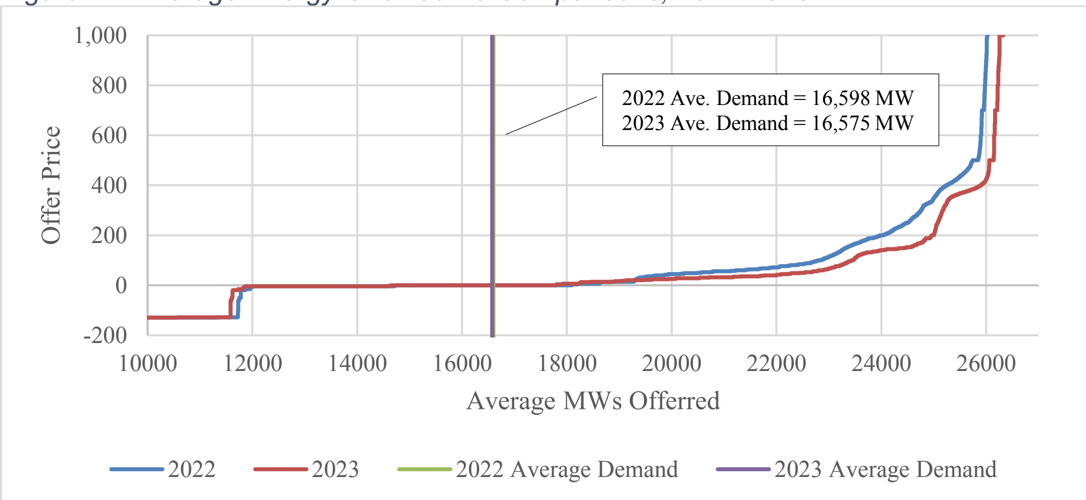
3.2.1 Supply Side Factors

The supply side of the wholesale market includes generation and imports, represented as the quantity of generation and imports offered into the market and the cost (or price) of quantities offered. Supply factors played a key role in the reduction in all-in costs in 2023. The drop in natural gas prices was a particularly important driver of lower costs.

Figure 4 below illustrates the average energy offer curve in 2023 compared to 2022.[16] In the IAMs, an energy offer curve is compiled on an hourly basis and illustrates the increasing marginal (as offered) costs of generation across the system. The rightward shift of the offer curve in 2023 was due to the increased availability of gas resources (only slightly offset by the decrease in hydro resource availability), while the downward shift in the offer curve in 2023 was largely a reflection of lower natural gas prices, as reflected in the offers of natural gas generators.

[16] The figure is zoomed in to show offers between -200 and +1000 CAD. The full offer curve is illustrated in Appendix B, Figure 45 – Average Energy Offer Curve Comparisons, 2022-2023.

Figure 4 – Average Energy Offer Curve Comparisons, 2022-2023

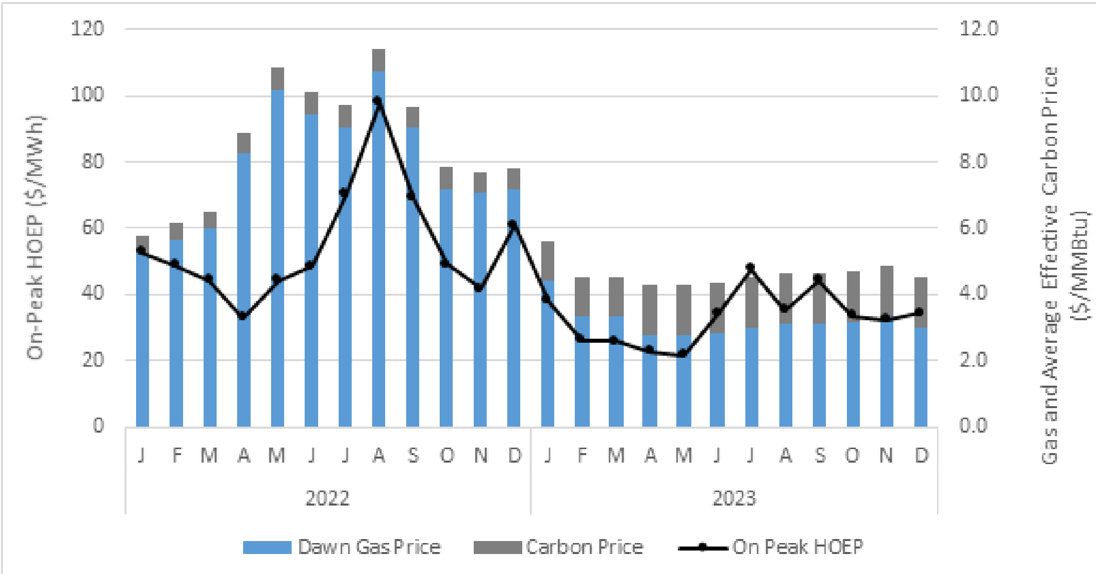


Natural gas generators hold a unique position among the energy suppliers participating in the IAM due to their cost structure. Natural gas generators have largely unrestricted fuel availability and relatively high variable costs, and their variable costs fluctuate according to prices determined in broader markets for natural gas. These characteristics dictate the key role gas generation currently plays setting wholesale market prices in the IAM. In 2023, gas generation set the price in 65% of intervals.

During intervals where natural gas generation sets the price, the HOEP should reflect natural gas prices as these are the key determinant of gas generators' marginal costs and offer prices. Figure *5* below shows the close relationship between on-peak HOEP (when gas is most often the marginal resource) and the Dawn Hub natural gas price (including the Canadian Carbon Price[17]). We see that in 2023, the average on-peak HOEP was lower than in 2022, reflecting the reduction in natural gas costs.

[17] Electricity production is considered an emission-intensive, trade-exposed (EITE) industry which means its carbon price is only applied to emissions above a benchmark of 310tCO_2e/GWh in 2023 (370tCO_2e/GWh in 2022) as set out in Ontario's Emission Performance Standards. On average, Ontario's gas fleet performs at 390tCO_2e/GWh and is responsible for the carbon price for 80tCO_2e/GWh. In the period between 2022 and 2023, the average effective carbon price ranged from \$0.53/mmbtu to \$1.52/mmbtu.

Figure 5 – Average On-Peak HOEP compared to the Dawn Hub Natural Gas Price and the Canadian Carbon Price, 2022-2023



In addition to its direct role setting prices, gas generation also largely affects the offer prices and supply of other resources such as imports, exports, and energy-limited hydroelectricity offering according to opportunity costs. When these other resources are the price setting resources, the resulting wholesale market prices generally reflect the prevailing price of natural gas.

While most supply is insulated from variations in wholesale market prices, some supply remains exposed to varying degrees. When natural gas prices decline, the cost of gas generators will also decline, and all-in unit costs will fall. In 2023, Dawn Hub natural gas prices fell 59% compared to 2022, which contributed to the 36% decline in wholesale market prices and a 0.7% decline in all-in unit costs.

Changes to the supply mix can drive changes to the all-in unit cost, as the relative share of higher and lower cost resources vary.

Table *2* shows the supply mix in 2022 and 2023. Capacity and energy output levels remained approximately consistent with 2022 with 4 TWh more utilization from natural gas resources. This translated into a higher capacity factor for natural gas resources in 2023. Additionally, the share of five-minute intervals where natural gas generators set the real-time MCP for energy rose from 58% to 65%.

Table 2 – Capacity, Energy Output, Capacity Factor and Price Setting by Fuel Type in Pre-Dispatch (PD) and Real-Time (RT), 2022-2023

Fuel Type	Available Capacity				Energy Output				Price Setting			
	Total MW		Share %		Total TWh		Share %		PD MCP Share %		RT MCP Share %	
	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
Hydro	9358	9288	22.3%	22.1%	38.0	37.4	27.7%	27.3%	14.7%	13.0%	35.0%	30.3%
Wind	5311	5311	12.7%	12.6%	13.8	12.2	10.0%	8.9%	1.7%	1.0%	6.3%	3.7%
Gas	11398	11636	27.2%	27.6%	15.2	19.1	11.1%	14.0%	37.6%	48.0%	57.7%	64.7%
Nuclear	13928	13966	33.3%	33.2%	78.8	79.3	57.4%	58.0%	0.0%	0.0%	0.0%	0.1%
Solar	1566	1566	3.7%	3.7%	0.7	0.7	0.5%	0.5%	0.0%	0.0%	0.0%	0.0%
Biofuels	327	327	0.8%	0.8%	0.3	0.4	0.2%	0.3%	0.4%	0.7%	0.7%	1.0%
Imports	-	-	-	-	7.9	4.1	5.7%	3.0%	18.8%	10.0%	-	-
Exports	-	-	-	-	-17.5	-16.5	-12.8%	-12.0%	26.0%	26.6%	-	-
Total	*41,887*	*42,094*	-	-	*137.2*	*136.7*	-	-	-	-	-	-

In conclusion, supply factors played a key role in the reduction in all-in costs in 2023. The drop in natural gas prices was a particularly important driver of lower costs.

3.2.2 Demand Side Factors

Demand side factors refer to the consumption and export side of the IAMs. These factors include the load profile along with the bid prices of dispatchable loads and exports.

Figure 6 below shows the gross Ontario demand over the last 24 months. The gross Ontario demand includes the Ontario wholesale demand and embedded generation. The gross Ontario demand in 2023 was 145.2 TWh, down slightly from 2022.[18] Heating and Cooling Degree Days, a measure of heating and cooling demand were 8% and 12% lower in 2023 compared to 2022 (see Figure 7 below).[19] The reduction in heating and cooling requirements was offset by Ontario's positive GDP growth in 2023[20] (indicating increased economic activities) and an increase in the Ontario population[21] resulting in unchanged demand for the year. While conservation efforts in 2023 resulted in 24.8 TWh lower consumption for the province,[22] overall demand level was maintained due to economic and population growth.

[18] Ontario demand was 145.4 TWh in 2022, compared to 145.2 TWh in 2023.

[19] Degree days are based on a 15.5 degree Celsius base temperature.

[20] See Ontario's 2023-24 Third Quarter Finances.

[21] Ontario's population also reached 15,500,632 on April 1, 2023 with an increase of 114,225 people during the first quarter of 2023 more than double the recorded number in the same quarter of 2022 (see also, Ontario Demographic Quarterly: Highlights of first quarter | ontario.ca).

[22] See the IESO's 2024 Annual Planning Outlook Data Tables, in sheet Figure 6.

Figure 6 – Ontario Gross Demand, Monthly 2022-2023

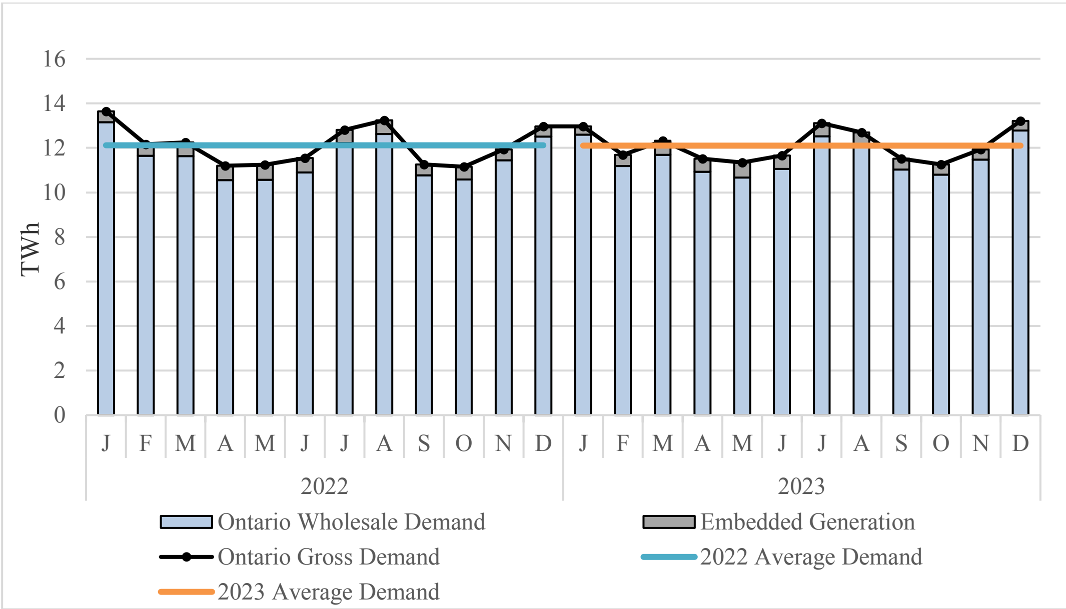
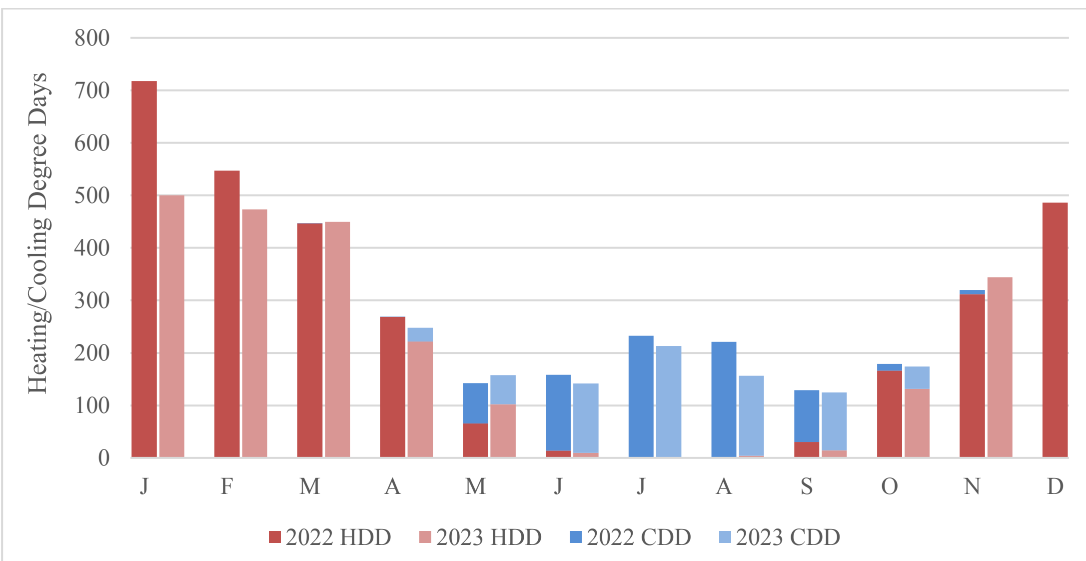


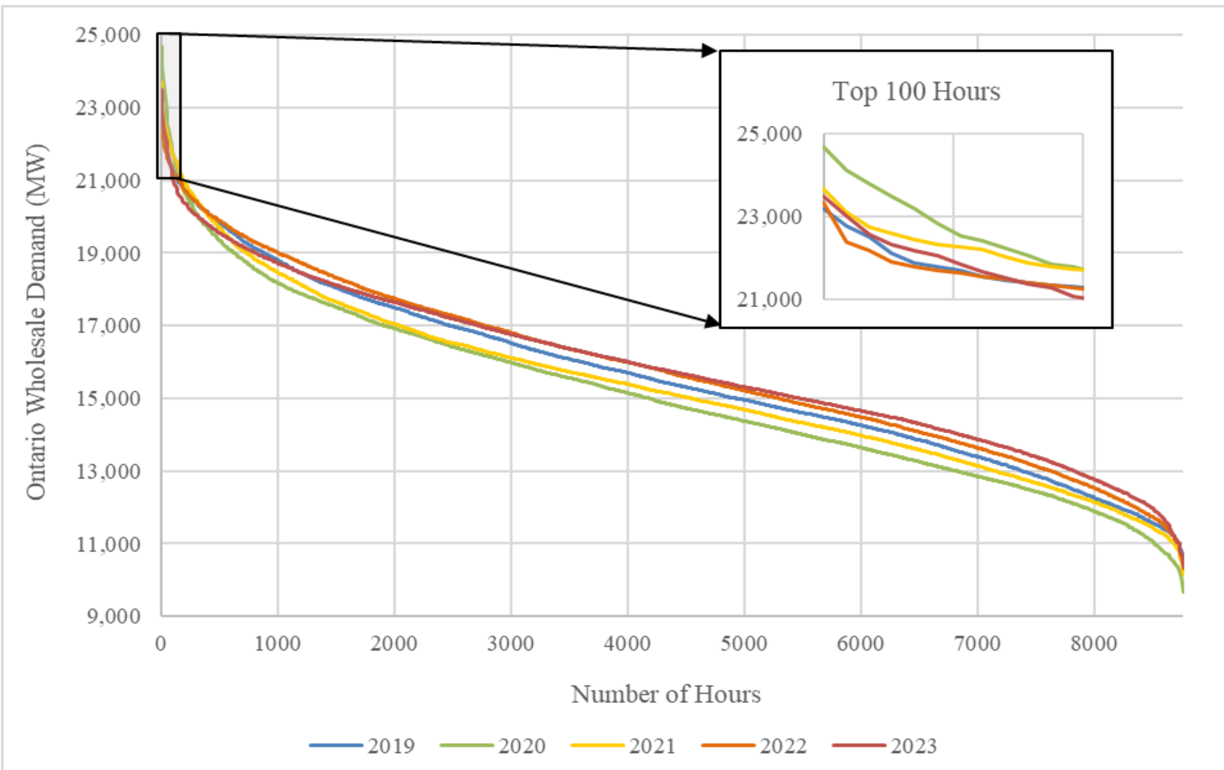
Figure 7 – Heating and Cooling Degree Days, Monthly 2022-2023



In the IAMs, the relationship between demand and all-in unit costs may differ from that typically found in other competitive wholesale markets with less contracting.[23] In other markets, higher demand will typically push up market prices and all-in unit costs. In the IAMs, higher demand can lead to lower all-in unit costs in the short-run. Higher energy demand allows for the disbursement of Global Adjustment contractual costs across a wider base, thus reducing all-in unit costs.

Figure 8 illustrates Ontario's wholesale demand duration curves over the last five years. While gross Ontario demand in 2023 was consistent with 2022, the duration curves show increasing wholesale demand during the low demand hours (the lowest 3,000 hours). The curve also illustrates that demand during system peaks (the top 100 hours) was consistent with 2022 and below the highs of 2020.

Figure 8 – Annual Ontario Wholesale Demand Duration Curves, 2019-2023



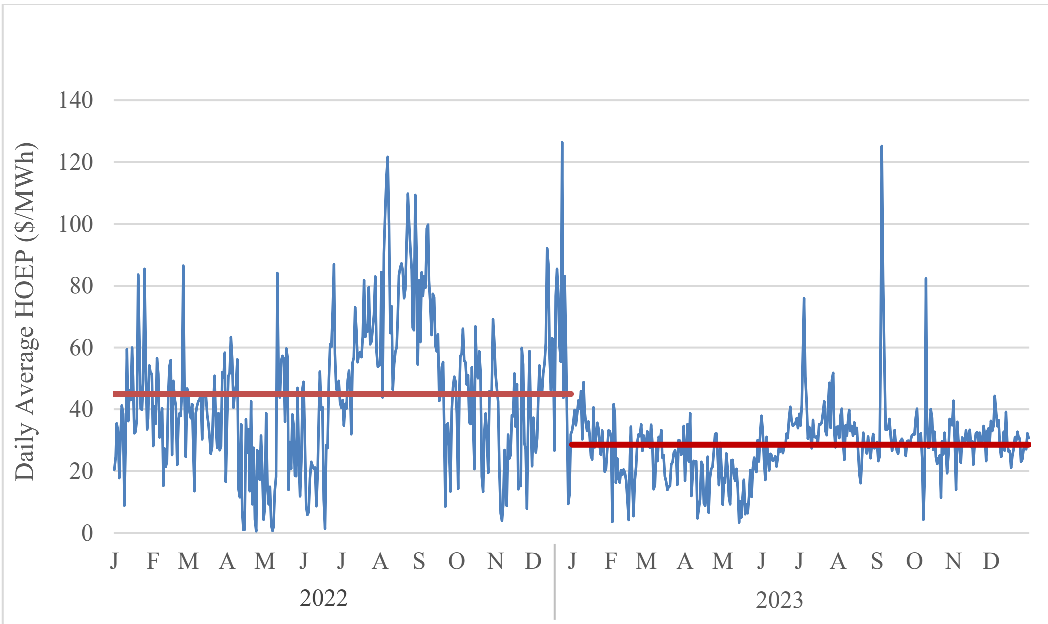
[23] While not exactly similar, the cost of the capacity markets in the US power pools resemble the Global Adjustment cost in Ontario. In 2023, the portion of all-in electricity cost attributed to capacity market took up an average of 14% in the Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO), Pennsylvania-New Jersey-Maryland Interconnection (PJM), New York Independent System Operator (NYISO), ISO-New England (ISO-NE) and Southwest Power Pool (SPP). This is in contrast with the 37% share of the Global Adjustment in Ontario's 2023 all-in cost.

In conclusion, Ontario demand in 2023 was consistent with 2022 and did not appear to be a major contributor to changes in all-in unit cost.

3.3 Wholesale Market Prices

Figure 9 shows daily average HOEP over the last two years. Daily average HOEP prices were $29/MWh in 2023, compared to $45/MWh in 2022.

Figure 9 – Daily Average HOEP, 2022-2023



Market prices are intended to guide and incentivize efficient behavior by market participants. In the short-term, competition and market clearing prices encourage generators to offer at marginal costs knowing they will receive the market price.[24] When resources offer at marginal cost, the IESO can efficiently dispatch the least-cost resources to meet demand. In the long-run, prices offer signals which support efficient investment and retirement decisions.

While the Panel anticipates that central planning (i.e., the IESO's *Annual Planning Outlook* (APO) report, and government policies) will continue to be the primary driver of investment decisions, real-time market prices can also play an important role. Any competitive procurement for contracts which offers exposure to market prices (i.e., the recent Expedited Long-Term Procurement or E-LT1) allows for clear and transparent market signals to help guide efficient investment decisions. As a result of this exposure to market prices, the proponents in these procurements can earn marginal net revenues in the

[24] In contrast, pay-as-offer arrangements can incentivize participants to offer above costs as they are paid according to their offer.

wholesale market, which can contribute to the recovery of their fixed investment costs. The proponents should reflect these expected net revenues in their procurement bid price, which can affect their likelihood of being selected in the procurement.[25] If real-time prices accurately reflect the cost of operating the system in real-time, then the projects which anticipate greater wholesale market net revenues (and hence greater investment cost recovery) will become relatively more cost effective in the procurement than if the real-time prices understated the cost of operating the grid in real-time. This should lead to a more efficient selection of resources in the procurement. Put another way, if proponents of a procurement are not exposed to real-time market prices or if real-time market prices understate the actual cost of operating the system in real-time, the more efficient investments will be inherently disadvantaged in the competitive procurement.

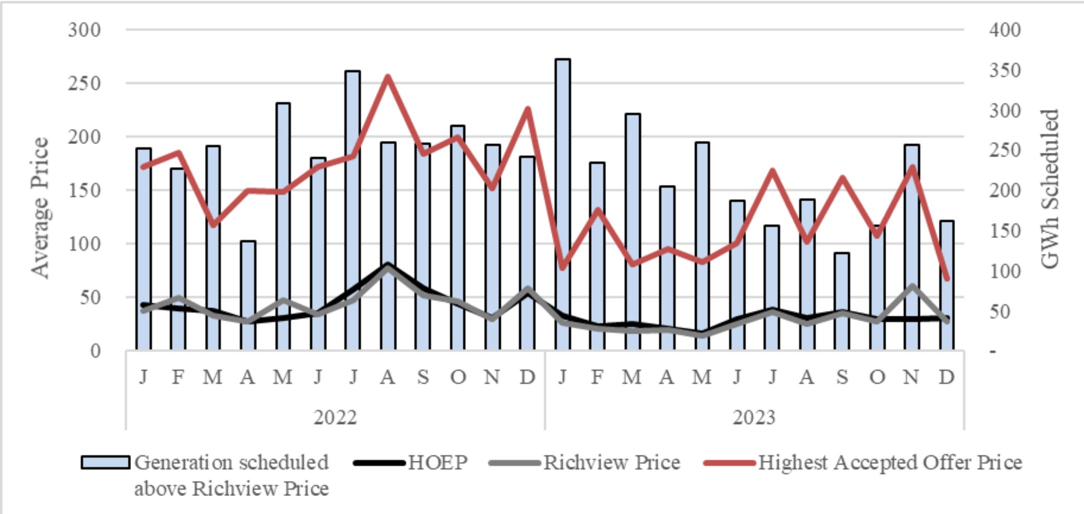
There are several indications that the current wholesale market design and operational procedures contribute to an understatement of the actual cost to operate the grid in real-time. Figure 10 illustrates monthly average highest accepted offer price (equal to the highest offer price of resources scheduled in the constrained schedule), HOEP, and Richview price.26 In 2023, the monthly average highest accepted offer price exceeded the Richview price by an average of $87. Additionally, an average of 202 GWh of generation were scheduled per month with offer prices that exceeded the Richview price (an average of 271 MW per hour).27 Section 3.5 discusses this further in the context of the three Energy Emergency Alert Level 1 events that took place in 2023. Several features of the IESO’s Market Renewal Program, including locational pricing, and enhanced unit commitment are intended to address the current design inefficiencies. These changes are discussed further in Chapter 10.

[25] While bid prices are often framed as a payment for “capacity”, these payments primarily serve to help proponents recover fixed investment costs.

[26] Richview price is a locational price within the load center of Ontario.

[27] Annual figures are presented in Appendix B, Figure 46 – Highest Accepted Offer Price vs HOEP and Richview Price, 2019-2023.

Figure 10 – Highest Accepted Offer Price, HOEP and Richview Price, Monthly 2022-2023



3.4 Government Cost Mitigation

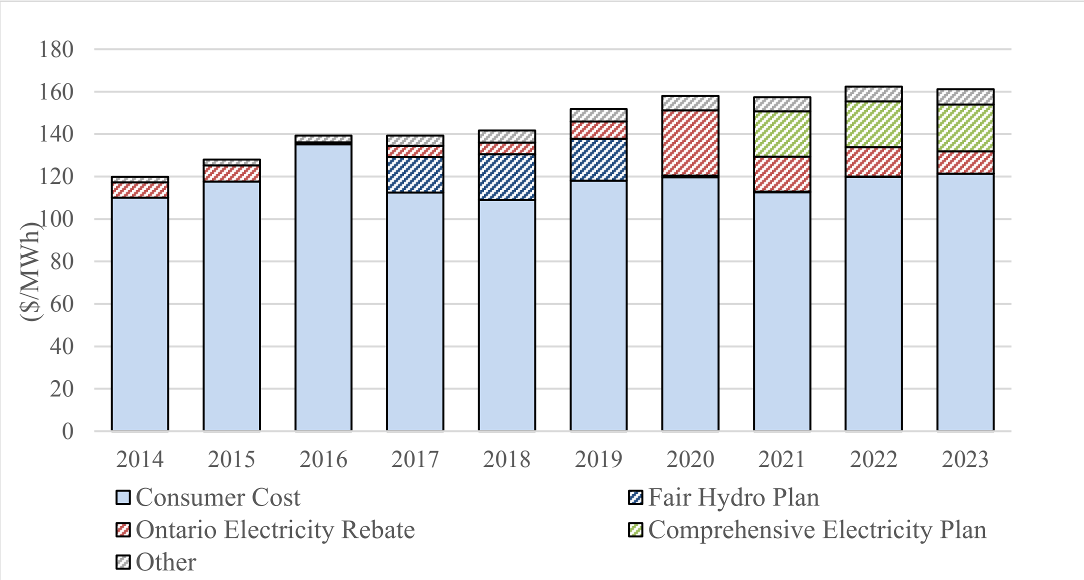
While the all-in costs have been increasing since 2014, the Ontario government's programs have helped to moderate the effects of these cost increases on consumers. Government programs were expanded significantly in 2017, leading to a year-over-year reduction in the average consumer's bill. In the following years, several programs have helped sustain the reduction in average annual consumer costs and continue to hold them below 2016 levels. In 2023, government spending on electricity cost mitigation was roughly $6 billion.

The two largest programs are the Comprehensive Electricity Plan and the Ontario Electricity Rebate (OER). The Comprehensive Electricity Plan transfers roughly 85% of the costs of non-hydro renewable energy contracts from electricity ratepayers to provincial taxpayers. The OER provides eligible residential customers, small businesses, farms, and long-term care homes a rebate on the pre-tax subtotal of their electricity bill and is intended to reduce their overall cost.[28] Together, the two programs represent over 80% of the annual government cost mitigation program in 2023. In 2023, the government programs held total consumer costs to $121/MWh, roughly 25% below the total all-in unit cost of $161/MWh.

[28] For ease of reference, references in this report to the Ontario Electricity Rebate, introduced in 2019, includes predecessor programs under the *Ontario Rebate for Electricity Consumers Act, 2016* and the *Ontario Clean Energy Benefit Act, 2010*. The total bill impact for individual customers across the province may vary depending on the customer's electricity usage and utility that serves them. From January to October 2023, the OER was 11.7%. On November 1, 2023, the OER was reset at 19.3%.

Figure 11 illustrates the effect of these government programs on total consumer costs (as noted by the solid blue bars). The total height of the bars in Figure 11 are the all-in unit costs.[29]

Figure 11 – Government Program Spending and Consumer Cost in ($/ MWh), 2014-2023



3.5 Energy Emergency Alert Level 1 Events

In 2023, the IESO issued three Energy Emergency Alert Level 1 (EEA-1) advisories. An EEA-1 is issued when the IESO control area has (or expects to have) all available resources in use. The EEA-1 events took place during the summer on July 27, September 6, and 7 and were largely precipitated by:

- Extreme hot weather driving high demand:
    - On July 27 demand peaked at 21,558 MW in HE18;
    - On September 6 demand peaked at 22,966 MW in HE17 placing second in the top five peaks for 2023;[30] and
    - On September 7 demand peaked at 21,166 MW in HE17
- Coincident, major nuclear outages:
    - On July 25th, Darlington units G2 and G3 were not available within 19 hours of each other, for a combined capacity loss of 1,890 MW. Darlington

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[29] Government program spending totals are illustrated in Appendix B, Figure 43 – Government Program Spending, 2014-2023.

[30] See the IESO's Top 5 Peaks: Hours & System-wide Consumption (Base Period: May 1, 2023 to April 30, 2024).

G3 (945 MW) returned to service on July 28 and Darlington G2 (945 MW) returned to service on July 31.

- On September 6, Bruce units G1 and G8 were not available within 22 hours of each other, for a combined capacity loss of 1,746 MW. Bruce G8 (872 MW) returned to service on September 8 and Bruce G1 (874 MW) on September 11.

Efficient markets should signal short-run supply shortages, such as the shortages experienced during the summer 2023 EEA-1 events, through relatively higher equilibrium prices. This high level of pricing in turn should incent competitive conduct by suppliers and efficient participation by demand response resources. Economic theory also dictates that recurring shortages and high prices should signal long-run investment opportunities in new resources or transmission where it is needed most.[31]

The high level of prices during supply shortage is observed in other markets. For example, the EEA events of Alberta in January 2024 due to extreme cold weather and of Texas in February 2021 (during winter storm Uri) resulted in prices reaching their respective Maximum Market Clearing Price (MMCP) for a sustained period.[32] From January 12-15, 2024, the Alberta pool price trended upwards due to extreme winter weather reaching the price cap of $1,000/MWh for several hours. The Alberta supply cushion thinned out but did not reach a point where the Alberta Electricity System Operator (AESO) needed to shed load. Also, an urgent appeal issued by the provincial government for Albertans to conserve electricity during this time was met by a 100 MW drop in electricity demand.

In Texas, winter storm Uri hit the ERCOT region from February 13-19, 2021, resulting in natural gas supply interruptions and widespread outages of generation causing a severe supply and demand imbalance that required the curtailment of load to maintain the operation of the bulk electric system. An EEA-3 was in effect from February 15 to 19, 2021 and prices in ERCOT's day-ahead and real-time markets remained at or near the offer cap of $9,000/MWh.

Figure 12 illustrates the trend of HOEP level during all Ontario EEA-1 events since 2016, while Figure 13 shows the HOEP duration curve for the same years. The highest HOEP reached in the 2023 EEA-1 events was $298/MWh in HE17 on September 6. As Figure 12 shows, this price outcome is like other EEA-1 events since 2016: the $298/MWh price on September 6 was also lower than the HOEP in other lower demand hours in 2023 in which supply conditions were more favorable (see Figure 13).

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[31] See "Electricity Market Design and Efficient Pricing: Applications for New England and Beyond" by William Hogan (2014).

[32] It should be noted that both Alberta and Texas markets are largely energy-only markets and neither have a capacity auction or capacity and energy procurements to the extent Ontario does.

Figure 12 – HOEP trend during EEA-1 events, 2016-2023

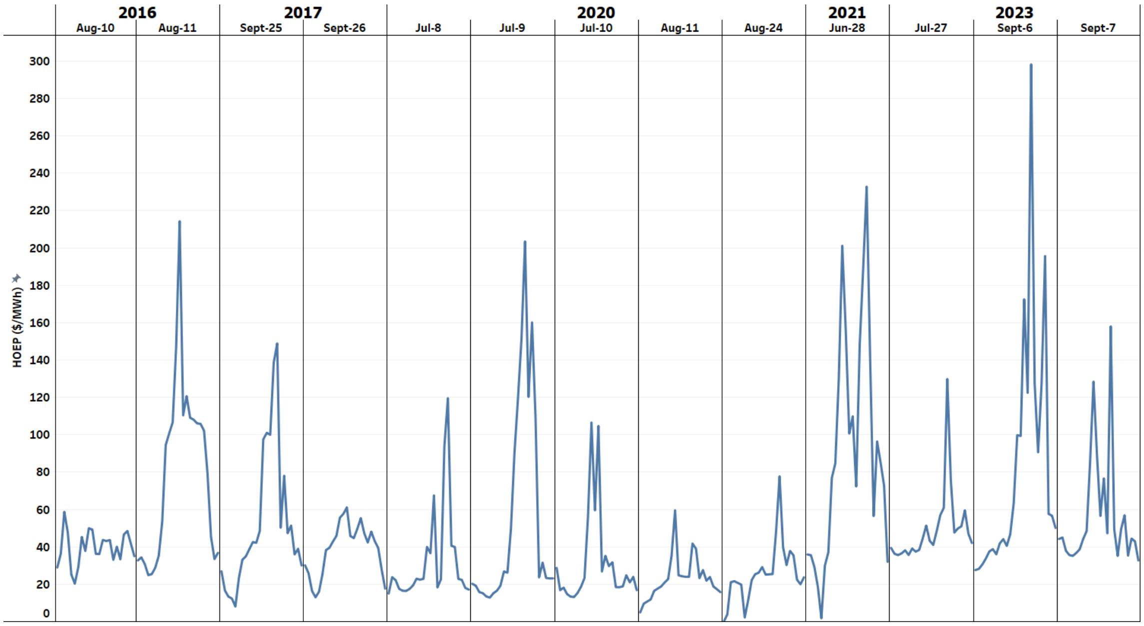
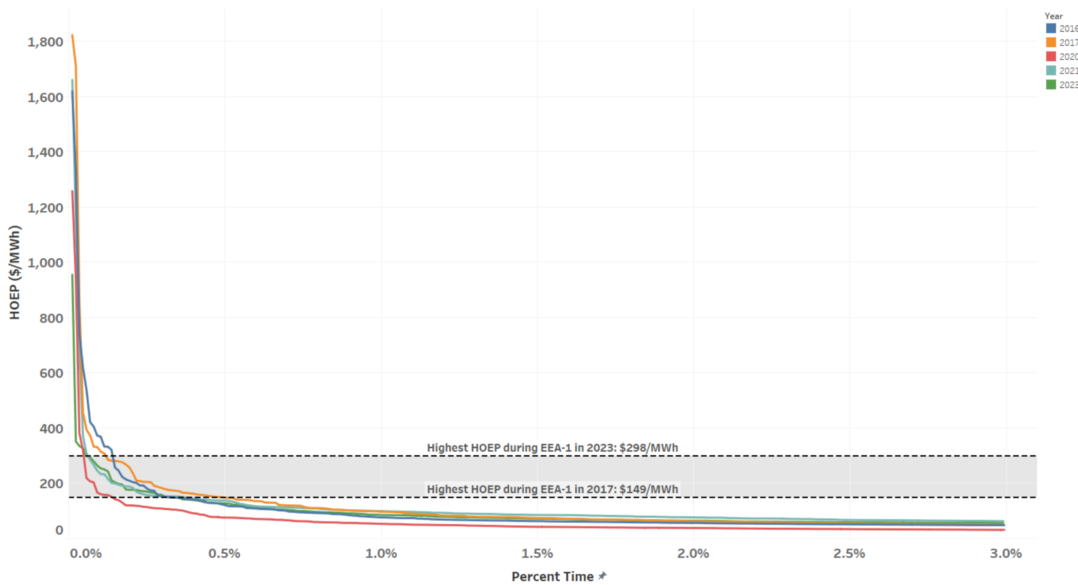


Figure 13 – HOEP duration curve in years with EEA-1 events, truncated at top 3%



During all three 2023 EEA-1 events, the IESO activated over 700 MW of Hourly Demand Response (HDR) resources, of which only 70-75% was delivered in actual load reduction.[33] HDR resources generally bid into the energy market at or near Ontario's MMCP,[34] meaning it is unlikely these resources will be economically activated to curtail load. However, in accordance with the IESO's Market Manual 4.3, these HDR resources are placed on standby when Pre-Dispatch (PD) prices reach $200/MWh. HDR resources can also be manually placed on standby and manually activated at PD-3 (i.e. three hours ahead of real-time). Manual activation of the HDR fleet took place during the three 2023 EEA-1 events. As a result, while the bid prices of most HDR resources activated during the 2023 EEA-1 events were at or near the MMCP, they did not contribute to price formation in real-time.

The IESO also took other out-of-market actions during the three 2023 EEA-1 events to address adequacy and security risks such as pre-emptively constraining-on expensive natural gas resources in anticipation of issuing the EEA-1 advisory. In addition, the IESO committed a relatively higher level of capacity in the day-ahead to ensure reliability. These manual interventions put downward pressure on price by adding to the supply stack of energy and operating reserve via the dispatch of out-of-merit resources.

The Panel recognizes that the IESO must work with the prevailing market design that exists at any point in time, while ensuring reliability of the bulk electricity system. In the case of the 2023 EEA-1 events, the IESO may have had good reason to activate HDR resources and take other actions – though the inescapable fact is that market prices did not seem to reflect a similar sense of urgency to bring resources to bear on the problem.

A recurrent theme in Panel reports from market opening until 2005 is the Panel's assessment of manual implementation of out-of-market actions that distort market price signals by reducing real-time prices and, at the same time, create production inefficiencies where lower-cost resources are underutilized. The Federal Energy Regulatory Commission (FERC) has also noted in recent years, the risk of resorting to paying for loading relief using mechanisms funded by uplift payments, as opposed to reflecting in market prices. On a sustained basis (like the Congestion Management Settlement Credits in Ontario), these mechanisms can undermine the market's ability to send actionable price signals. FERC further remarked that services from these resources should be priced in the market or opened to competition.[35]

While the implementation of MRP is expected to improve the dispatch and commitment of resources, the Panel will continue to monitor scarcity price formation during supply shortage events, including the number of out-of-market interventions and their effects on prices.

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[33] See the IESO Presentation on November 22, 2023: "2023 Performance Results and Future Enhancements to the Capacity Auction".

[34] See Brattle report, "Energy Market Payment Options for Demand Response in Ontario", prepared for the IESO.

[35] See FERC Order No. 825, 831 & 844.

3.6 Conclusion

The Ontario wholesale market price in 2023 has declined driven largely by lower natural gas prices. This, however, had limited effect on the all-in unit cost as most contracts as well as rate regulation are designed to insulate generator cost recovery from variations in the wholesale market price. Government programs have continued to play a role in reducing consumer cost in 2023 by approximately 25%.

During the three EEA-1 events in 2023, the market price remained relatively low considering the attendant resource adequacy risks in the system and likely understated the actual cost of operating the grid during these hours. The understatement of costs during scarcity conditions limits effective responses from market participants and contributes to short-term and long-term inefficiencies.

4 COMPETITIVENESS AND CONTRACTING

Since market opening, Ontario Power Generation Inc. (OPG) has owned and controlled a large share of the generation assets in Ontario. Within this concentrated structure, the market has relied on rate regulation and contracting to guide market participant behavior, mitigate market power, and promote dispatch efficiency.

Initially, the Market Power Mitigation Agreement (MPMA) was used to limit OPG's market power by capping prices paid to it and laying out plans for its capacity divestment. This resulted in the lease of the Bruce nuclear operations and the divestment of 490 MW of hydro assets by 2002. The MPMA, however, was later rescinded in 2004 with the enactment of the *Electricity Restructuring Act*, *2004* (ERA).[36] The ERA made provision for payment regulation of OPG's baseload hydroelectric and nuclear assets, and the divesture targets envisioned under the MPMA were revoked at the end of 2005. In 2014, most of OPG's remaining hydroelectric facilities became rate-regulated.

In 2019 and 2020, Atura Power, a wholly-owned subsidiary of OPG, acquired full ownership of four natural gas generators – including Portlands Energy Centre and Brighton Beach Generation Station[37] in which OPG previously had a 50% stake – increasing OPG's ownership share of the generation capacity and electricity production in Ontario. In the Ontario Energy Board's (OEB) review of the 2020 transaction, it noted that "the acquisition of additional generation assets by OPG raises concerns about the competitiveness of Ontario's wholesale electricity market and the potential implications for electricity consumers."

To alleviate the competitive concerns around OPG's dominant position, OEB licence conditions have been implemented. These conditions include provisions which guide OPG offer behavior (i.e. the "must offer" condition, operationalized through the Must-Offer Condition Agreement (MOCA) with the IESO) and ring-fence operations at the acquired gas plants.[38] These conditions are intended to mitigate the exercise of market power and to encourage OPG to offer its facilities into the market at prices that reflect their marginal production cost.

Today, OPG is the largest capacity, energy, and operating reserve provider in the IAM. The market share analysis in Section 4.1 demonstrates that OPG controls 51% of the total generation capacity and 68% of the total price-sensitive capacity in the energy market. This level of concentration in a market generally raises concerns from competition

[36] See *Electricity Restructuring Act, 2004*.

[37] As part of the acquisition, Shell would retain marketing and operational control of Brighton Beach until July 2024.

[38] See the OEB Decision and Order EB-2019-0258 / EB-2020-0110.

authorities regarding market power.[39] As discussed, this concern is intended to be addressed through regulatory measures imposed on OPG by the OEB and operationalized through MOCA.[40] Details on these regulatory measures and other contracts are covered in Section 4.2.[41]

While rate regulation and contracts largely promote efficient short-run market behaviours, they do not act as a perfect replacement for competition. Generally, competition authorities view regulation as a poor alternative for true (structural) competition.[42] In electricity markets, regulation is well suited to replicate some benefits of competition but not others. For example, it has been found that regulation can be effective in reducing market power but less effective at driving plant-level efficiencies.[43] Given its large market share and diverse generation portfolio, OPG has an informational advantage over all other market participants by virtue of being able to see, on average, a majority of the offer prices in the supply curve which are not viewable by other market participants.

The foreseen resource adequacy needs over the coming years and decades will be an opportunity to usher in improvements in the structural competitiveness of the Ontario market. While the Panel acknowledges that the abilities and experience of OPG makes it a strong candidate for new investment projects, it also sees potential benefits from new entrants invigorating competition within the markets.[44] When designing procurements, the Panel believes there is merit in considering the additional value new entrants could provide to the energy market through increased competition. The Panel notes that 28% of the capacity awarded under both the new build storage projects and the Same

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[39] For example, the Canadian Competition Bureau uses market shares as an initial screening mechanism to assess allegations of abuse of dominance. A single firm market share of 50% or more or a combined market share of 65% of a group of firms alleged to be jointly dominant prompts further examination for anti-competitive outcomes. See "Abuse of Dominance Enforcement Guidelines" by Competition Bureau Canada, 2019.

[40] Market power concerns are also addressed through a Memorandum of Agreement in September 2021 between the OPG and its sole shareholder, the Government of Ontario.

[41] The Panel is also monitoring the finalization of the Market Power Mitigation framework under the IESO's Market Renewal Program, including how the mitigating measures in this framework may overlap or interact with similar contract and regulatory provisions.

[42] The Competition Bureau notes that structural remedies (i.e., asset divestitures that reduce market share) are preferred over behavioral remedies as they are "more clear and certain, less costly to administer, and readily enforceable". The costs of behavioral remedies include the cost of monitoring the participant's behavior, the cost of uncertainty for other market participants, and costs of the participant's efforts to circumvent the remedy. They also note behavioral remedies may prevent efficient responses to changing market conditions and restrain pro-competitive behavior by market participants. See "Information Bulletin on Merger Remedies in Canada" by Competition Bureau Canada, 2006.

[43] Fabrizio et al. (2007) found that plant operating expenses decreased 3-5% in anticipation of increased competition following deregulation, or 6-12% compared to government owned plants.

[44] Incumbents may be preferred over new entrants due to risks around project delays or incompletion. A study of US interconnection queues found that only 19% of proposed projects from 2000-2018 had reached commercial operations by 2023. See Queued Up: 2024 Edition by Berkeley Lab.

Technology Upgrades Solicitation announced by the IESO in June 2023 went to OPG.[45] The percentage slightly increases with the addition of the non-competitive bilateral contract entered into by the IESO and Atura Power in April 2023 for the continued operation of the Brighton Beach Generation Station that includes a 42.5 MW expansion.[46]

4.1 Competition Measures

Monitoring the structural competitiveness of the markets is important as strong competition amongst suppliers helps ensure that market and reliability needs are met while minimizing costs. Competition protects the interests of consumers by encouraging suppliers to minimize production costs, maximize resource availability, invest in new innovative technologies, and offer in the market at prices reflective of their cost.

One of the most common indicators used by economists and anti-trust agencies to help measure the structural competitiveness of a market are market shares. The market share of a firm is the percentage share of total market capacity or output owned (or controlled) by the firm. In 2023, OPG controlled 51% of total capacity, and 68% of total price sensitive capacity in Ontario.[47] In unregulated markets, these market shares would likely raise competitive concerns and prompt further examination by competition regulators.

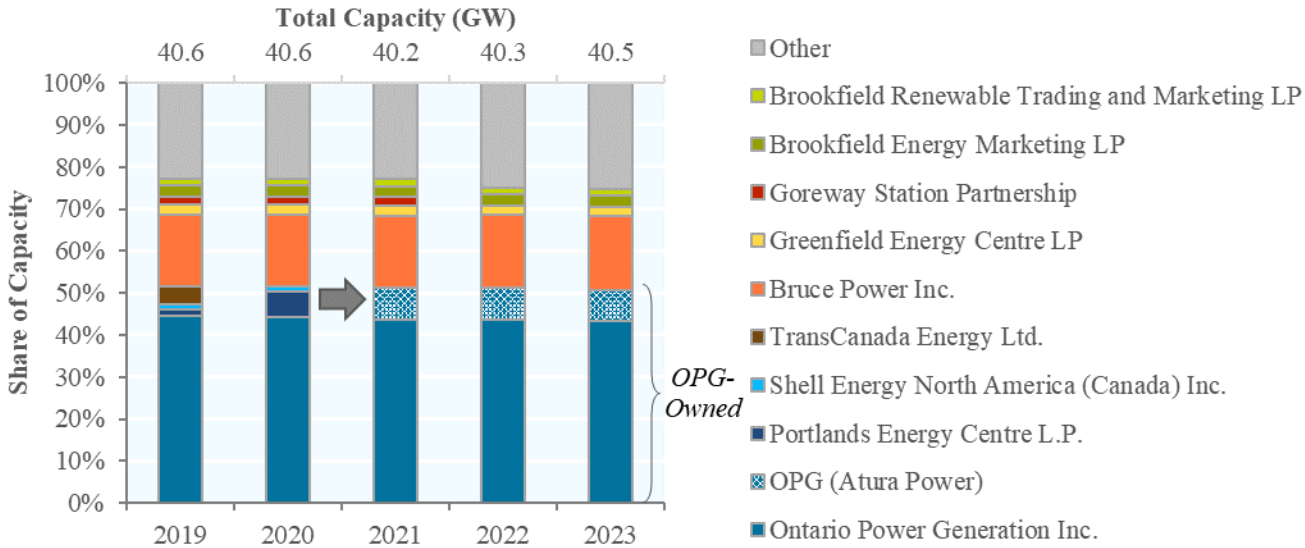
Figure 14 depicts shares of capacity since 2019.

[45] The Expedited procurements conducted by IESO in 2023 resulted in 930 MW new storage capacity and 286 MW upgraded capacity from gas resources where OPG holds 265 MW and 81.5 MW, respectively. Boralex Inc. and Capital Power Corporation shared between them 59% in new storage capacity while St. Claire Energy Centre follows OPG in the largest shares in same technology upgrade with at 24%.

[46] This report refers to “non-competitive bilateral contracts” as contracts entered into without a competitive procurement process.

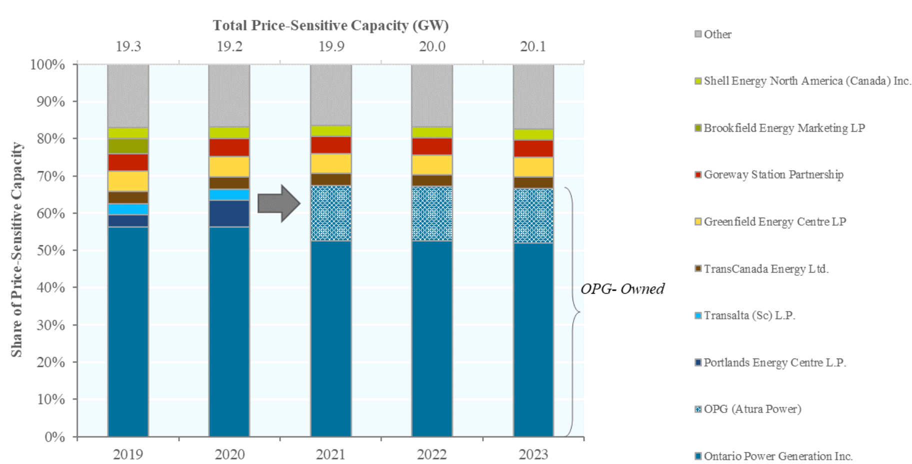
[47] Market shares include capacity at generators where OPG holds the majority ownership interest and operational control.

Figure 14 – Registered Capacity by Market Participant, 2019-2023



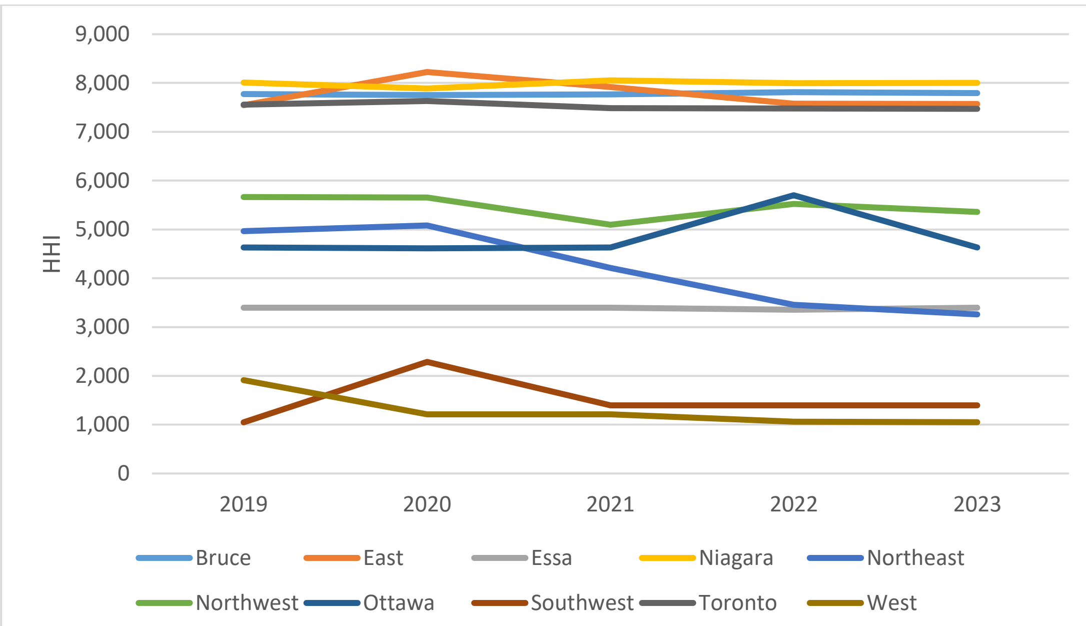
OPG controlled 51% of the capacity in the IAM in 2023. OPG has held this level of dominance since the major natural gas generation acquisitions in 2020. Figure 15 demonstrates that OPG controls an even larger share of the price-sensitive capacity, which includes natural gas, some energy limited hydroelectric, oil, and biofuel. Within this concentrated structure, the market relies on rate regulation of OPG payments and the OEB licence conditions, including the MOCA, to mitigate OPG's incentive to exercise market power.

Figure 15 – Price-Sensitive Generation Registered Capacity by Market Participant, 2019-2023



By the standards of the Herfindahl-Hirschman Index (HHI), this level of market share from one participant would already indicate a highly concentrated market.[48] Figure 16 further illustrates similar HHI scenarios when calculated per zone. The West zone registered the lowest HHI score while the Niagara and Bruce zones are noted to have the highest for the period 2019-2023. Except for the West and Southwest zones, HHI scores for all other zones were greater than 1,800 all throughout the period, indicating highly concentrated zones.

Figure 16 – Yearly HHI of Registered Capacity per Zone, 2019-2023



When supply is tight in the market and demand is highly (almost perfectly) inelastic, there is greater opportunity and incentives for market participants to exercise market power and influence market prices.[49] Supply is also typically more inelastic at high levels of demand, meaning a small change in offers could have a relatively large impact on market prices. At these times, generators are more assured their supply will be needed. The pivotal role

[48] HHI is a commonly accepted measure of market concentration calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. The US Department of Justice and the Federal Trade Commission regard markets with an HHI greater than 1,800 as highly concentrated. See [US DOJ & FTC, Merger Guidelines, 2023: 2023 Merger Guidelines].

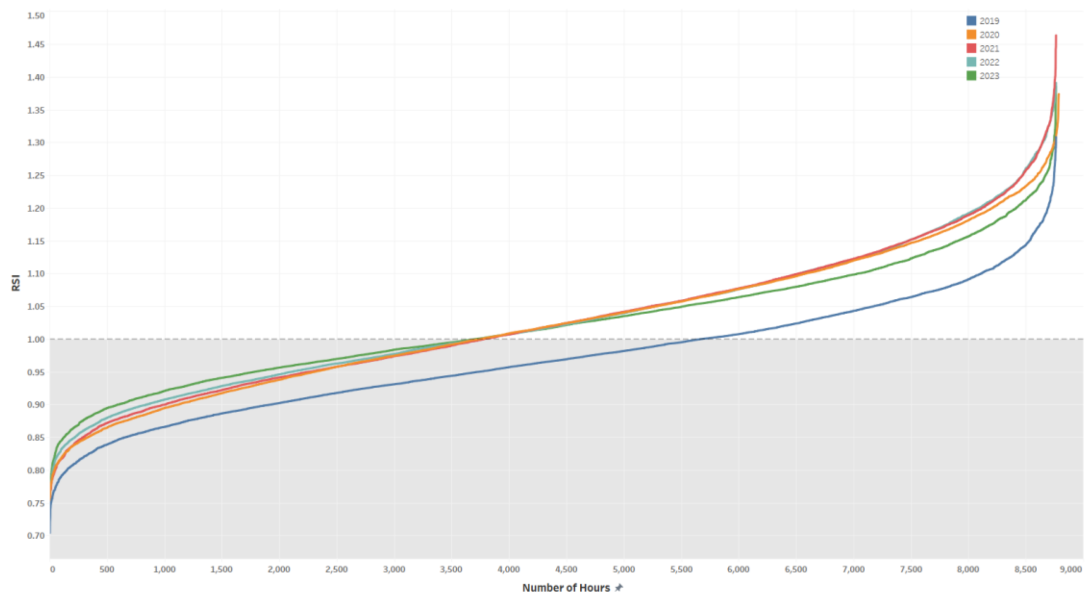
[49] There are several IESO mechanisms that enable demand responses and foster demand elasticity such as dispatchable load market participation, the ICI program, and demand response procured through the capacity auction. Time-of-use pricing from residential and small commercial consumers can also enable demand response.

Ontario Energy Board

of a single supplier in a given interval creates a significant incentive to exercise market power absent contracts and regulation.

The Residual Supplier Index (RSI) captures this essence by calculating the ratio of hourly supply from non-pivotal suppliers to demand. An RSI score of less than one indicates that demand cannot be satisfied without a given supplier (pivotal). Figure 17 illustrates that during 2023 there were about 3,700 hours (42%) where the RSI was less than one. OPG's concentrated ownership of diverse generation assets is the contributing factor towards it being the pivotal supplier so frequently.

Figure 17 – RSI, 2019-2023



While contracts and regulation do help mitigate concerns of market power, demand side participation also has an important role in mitigating the potential negative effects of this structural issue. Demand response, i.e., modifying electricity consumption in response to changes in electricity prices, mitigates the incentives for suppliers to exercise market power.[50] To a degree, intertie transactions also contribute to mitigating market power within the province by adding another source of supply that can compete with domestic resources.

In summary, the market shares analysis illustrates the high degree of concentration in the Ontario electricity market. Particularly noteworthy is the leading position of OPG, which

[50] See "The role of demand response in mitigating market power: a quantitative analysis using a stochastic market equilibrium model" by Devine D & Bertsch V (2019).

See also, "A review of market power-mitigation mechanisms in electricity markets" by Lin X, et al (2022): Energy Conversion and Economics Volume 3(5): 304-318.

controls just over half of the capacity and an even higher percentage of the price-sensitive generation in the province.

While OEB licence conditions including the MOCA may reduce OPG's incentives or ability to increase offer prices and push up market prices, they do not act as a perfect replacement for competition. While OPG may not earn supra-competitive profits in the wholesale market due to contract and regulatory measures, Ontario consumers may not be realizing the full benefits that a more diverse set of suppliers and more effective competition could provide. Effective competition provides more direct incentives for suppliers to minimize production costs, maximize resource availability, invest in new innovative technologies, and offer in the market at prices reflective of their cost.[51]

4.2 The Role of Contracting and Rate Regulation

In Ontario, most generators are subject to contracts or rate regulation which influence their participation in the IAM.[52] Well-designed contracts can be an effective way to incentivize competitive offers and to promote efficiency in highly concentrated markets. The terms of these contracts should aim to mimic the incentives faced in a competitive market, while rewarding competition and efficiency enhancing behaviors.

In the short-run, well-designed contracts should encourage generators to offer at marginal costs as they would in a perfectly competitive market. This will ensure that demand is met by the lowest cost resources (productive efficiency). It also ensures that any demand willing to pay above cost will be served (allocative efficiency). Contracts which lessen the incentives for generators to offer at marginal costs may lead to inefficiencies in the short-run.

In the long-run, well-designed contracts should support optimal and timely decisions around investment, technology choice, upgrades, maintenance, and retirements. Contracts should reward low cost and adept generators. In the long-term, efficiency is achieved when the industry long-term average cost is minimized and price is equal to marginal cost.

In Ontario's hybrid market, contracts play a key role in providing generators the opportunity to earn sufficient revenues to cover their fixed capital and operating costs, and a competitive rate of return on investment. Centrally procured contracts have become increasingly necessary to attract generation capacity investment, as low wholesale market prices have provided insufficient revenues.

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[51] For a broader discussion, see "Strengths and Weaknesses of Traditional Arrangements for Electricity Supply" by Schmalensee, 2021.

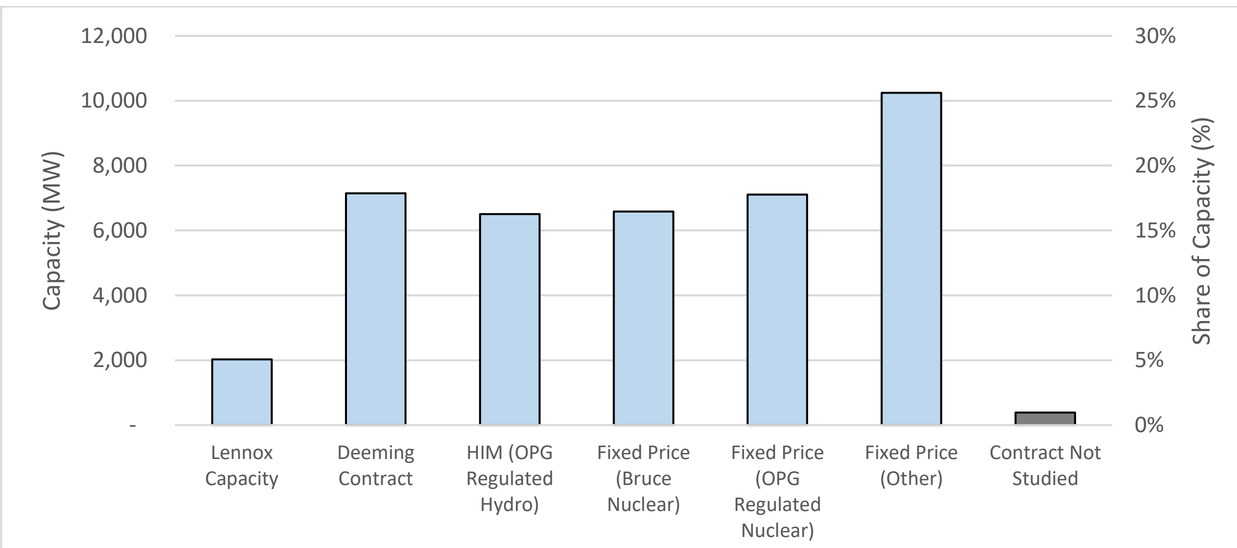
[52] See the IESO's "A Progress Report on Contracted Electricity Supply", First Quarter 2024. A small number of contracts continue to be held with the Ontario Electricity Financial Corporation (OEFC), see OEFC's 2023 Annual Report.

4.2.1 Overview of Contract Types

The IESO currently manages over 33,000 contracts with a combined 27 GW of capacity. About 98 of these contracts are for transmission-connected resources including the 6.5 GW Bruce Nuclear facility, 9.1 GW of natural gas, 2.1 GW of hydroelectric, and 5.4 GW of wind and solar.[53] The remaining contracts totals 2.6 GW of distribution connected resources, of which small FIT (Feed-In-Tariff) and microFIT solar projects comprise about 1.6 GW. More than half of the natural gas generation contracts will expire by mid-2030s. Most of the wind and solar generation are under 20-year contracts set to expire in the 2030s. The OEB regulates 6.4 GW of OPG hydroelectric assets and the entirety of OPG's 7 GW nuclear capacity. In 2023, less than 1% of wholesale energy generation came from non-rate-regulated resources without a contract or rate regulation (not including imports).

Figure 18 illustrates generation capacity under rate regulation and each type of contract. The IESO contracts have been categorized into six groups in addition to a "Contract Not Studied"[54] group. Additional details on each group are provided below.

Figure 18 – Regulated and Contracted Capacity by Type, 2023



Lennox Capacity Contract

The Lennox Generating Station holds a unique position within the IAM. The 2,160 MW gas and oil facility is owned and operated by OPG. In 2022, the IESO re-contracted 1,657 MW of capacity from the facility through 2029. The "capacity-style" contract is largely

[53] ibid.

[54] "Contracts not Studied" include Atikokan Biomass Energy Supply Agreement (ABESA), Chaudière Falls Contract (CFC), Hydroelectric Standard Offer Program (HESOP) and Non-Utility Generator Enhanced Dispatch Contract (NUGEDC).

defined by a fixed $9 million monthly payment. The contract also includes smaller provisions to compensate for select costs and share net revenues.[55]

In general, capacity style contracts offer fixed monthly payments that contribute to the recovery of fixed operating costs and capital costs, but otherwise contract holders earn revenues according to market prices. These contracts preserve financial incentives to respond to market signals in the short run but do not mitigate the potential to exercise market power, as generators under a capacity contract can benefit from higher market prices.

Deeming Contracts

Most natural gas plants in Ontario operate under deeming contracts.[56] These contracts are designed to incentivize generators to offer energy in the wholesale market at their marginal cost, attempting to mimic the outcome that would be induced if the market was perfectly competitive. Under deeming contracts, generators receive a monthly payment called a net revenue requirement. The net revenue requirement is considered the amount the generator needs to recover each month to cover fixed operating costs and capital costs, assuming no other revenue was earned in the month. Additionally, deeming contracts stipulate that when wholesale market prices rise above the generator's deemed marginal variable costs, as described in the contract, they are deemed to have run in the market and collected revenue at the market price. Deemed net revenues (deemed revenues above the deemed variable costs, including deemed marginal cost and start-up cost) are clawed back from the net revenue requirement each month. This claw-back occurs regardless of whether the generator actually ran or not.[57] Since the monthly payments are determined irrespective of actual operations, short-term incentives in the market remain as they would absent a contract under perfect competition. These incentives promote efficient market outcomes by guiding generators to offer at marginal cost.

While there are short-run efficiency benefits under the deeming contract, uncertainties around contract renewal and renegotiation may raise generators' cost of capital and these costs are passed on to consumers. Incentives for efficient retirement decisions are also attenuated as deeming contracts continue to provide generators net revenue opportunities, regardless of market trends, even when some facilities are no longer

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[55] See the Amended and Restated Lennox Energy Supply Agreement, 2021.

[56] Over 70% gas capacity in 2022 operated under deeming contracts. Deeming contracts include the Accelerated Clean Energy Supply Contract or ACES (2,030 MW), the Clean Energy Supply Contract or CES (2,886 MW), the Combined Heat and Power or CHP (419 MW), the Combined Heat and Power Standard Offer Program or CHPSOP (79 MW), the Early Mover Clean Energy Supply Contract or EMCES (997 MW) and the Northern York Region Peaking Generation Contract or NYRP (393 MW).

[57] A generator's deemed operating profit is calculated as Generator's Deemed Output x (HOEP - Generator's Deemed Variable Costs).

economical within the overall supply mix. Larger (costlier) facility upgrades are also unlikely to arise under the contract structure and typically require additional revenue streams. For example, in the IESO's recent Same Technology Upgrades Solicitation procurement, long-term contracts were needed to motivate gas generators to invest in capacity upgrades.

Hydro Incentive Mechanism (OPG Regulated Hydroelectric)

The Hydro Incentive Mechanism (HIM) is designed to encourage OPG to operate its energy-limited hydroelectric stations efficiently by offering its limited energy output in the hours with the highest expected market prices. The mechanism applies to the majority of OPG's hydroelectric generation. The HIM is preferred over fixed regulated rates per MWh of production, which offer no incentives to adjust production according to market conditions.[58] The HIM is designed to encourage OPG's hydroelectric generators with a limited supply of water to hold back production in low-price hours and shift that production to high-price hours. The HIM provides OPG an incentive to offer supply at the opportunity cost of the limited water while providing the generator revenue security like a fixed-price contract.[59] Approximately 80% of the transmission-connected hydroelectric capacity in Ontario operates under the HIM.[60]

Fixed Price

Most of the remaining generation in Ontario operates under a fixed-price structure. These contracts guarantee a price per MWh of generation which removes incentives to respond to market signals.

Fixed-price contracts incent generators to produce output in hours when the contracted fixed-price exceeds the generators marginal production cost. They do this by offering into the market at a sufficiently low price (below the expected market price). In hours when the generator's marginal cost exceeds the contracted fixed-price, the generator avoids producing by not offering or by offering at a sufficiently high price (above the expected market price). A fixed-price contract leads to inefficiencies when it induces the contracted

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[58] 54 of OPG's 66 hydroelectric stations are rate-regulated and subject to the HIM. In 2023, the rate-regulated price for hydro was $44.91 – base regulated price plus deferral and variance account rate riders (see also, [OPG 2023 Financial Results](#)).

[59] The Panel noted in Monitoring Report 32 that the intended objective of the OPG HIM may be muted by an OEB prescribed sharing arrangement which distributes revenue OPG earns above its regulatory approved forecast HIM revenue equally between OPG and Ontario consumers.

[60] The remaining 20% of transmission-connected hydroelectric capacity in Ontario is not rate-regulated and holds a contract with the IESO. Roughly 1,000 MW of this capacity operates under a hydroelectric contract incentive (HCI) which pays a fixed price but provides some incentives to produce in peak hours through the application of a peak performance factor. Some smaller hydroelectric generators (approximately 70 MW) also operate under an early fixed-price Feed-In-Tariff or renewable energy supply contracts. OPG operates six new hydroelectric units (approximately 438 MW of capacity) on the Lower Mattagami River under a hydroelectric energy supply agreement (HESA) with the IESO.

generator to produce instead of a generator with a lower marginal cost, or induces the contracted generator not to produce, requiring a generator with a higher marginal cost to produce. Fixed-price contracts mitigate the incentives to exercise market power as the generators do not benefit from higher market prices under these contracts.

Nuclear generation in Ontario operates under a fixed-price structure. These include fixed-price contracts for Bruce Nuclear and fixed-price rate regulation for OPG's Pickering and Darlington nuclear stations.[61] Nuclear units are largely offered to continuously generate at maximum output, excepting for outages, and adhere to rigid operating requirements. This lessens the likelihood that fixed-price contracts induce short-run inefficiencies.

Fixed-price contracts are also used for transmission-connected wind and solar plants, and some hydroelectric stations.[62] The marginal production cost of these resources is very low (effectively zero) and well below the contracted fix-price. Dispatch inefficiencies can occur when these facilities are scheduled to operate while others with lower (or negative) marginal costs, specifically available nuclear facilities are not. Prior to 2012, these outcomes would sometimes occur during low demand hours when there was a surplus of baseload supply (i.e., periods with surplus baseload generation) and wind production would force nuclear generators to reduce output or shutdown. This was not only inefficient, but it also created potential reliability issues as nuclear plants, when shutdown, are required to remain out of service for several hours before returning to service.

To reduce the potential for dispatch inefficiency during hours of surplus baseload generation, the IESO amended the market rules in 2013 to imposed price floors on nuclear, wind and solar generators, to induce offers that establish a merit order consistent with expected efficient dispatch.

Finally, these fixed-price may induce inefficient investment over the longer-term when the fixed-price is higher than the average market price.

4.3 Conclusions

OPG continues to own and control the majority of the province's generation assets, and has grown its market share through recent gas plant acquisitions. Contracts and regulation are used to address these competition concerns and encourage OPG and other generators to offer at marginal costs.

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[61] Bruce Nuclear is contracted under the [Amended and Restated Bruce Power Rehabilitation Refurbishment Implementation Agreement (ABPRIA), 2015.]

[62] Wind and solar contract types include the Feed-in-Tariff Program or FIT, the Green Energy Investment Agreement Power Purchase or GEIA, the Large Renewable Procurement Program or LRP, the microFIT, the Renewable Energy Supply Contract or RES and the Renewal Energy Standard Offer Program or RESOP. Hydro-electric fixed price contracts include the Hydroelectric Contract Initiative or HCI, and the Hydroelectric Energy Supply Agreement or HESA.

The Panel will continue to closely monitor market developments and their implications for the dynamic and long-term efficiency of the market. While the Panel anticipates that central planning will continue to play a key role in guiding longer-term decisions around investment and innovation, the Panel believes that leveraging competition to drive efficiency whenever possible will be beneficial to the interests of Ontario electricity consumers. Over the longer-term, competition can help keep costs down, drive innovation, and reduce investment risk to ratepayers through mechanisms such as capacity auctions.

5 INVESTMENT AND LONG-TERM EFFICIENCY

Long-term (or dynamic) efficiency in electricity markets is about making optimal and timely investment, maintenance, and retirement decisions. In a competitive market, prices guide these decisions for market participants. Efficiency is achieved as industry average costs are minimized. Consumers benefit when the market is efficient in the long term as it leads to the lowest all-in average unit price.

The Panel acknowledges that the hybrid market structure in Ontario differs from many other competitive electricity markets in North America. In those markets, investment and retirement decisions are largely driven by market prices for electricity and capacity.[63] In contrast, most generation investment in Ontario is determined through centralized planning and government policies. Projects are then secured through procurements and long-term contracting. The Panel monitors the province's long-term planning and procurement processes to assess the implications on the competitiveness and efficiency of the wholesale market, and to identify opportunities to use competitive drivers, whenever possible, to promote those outcomes.

5.1 Current Investment Needs and Efforts

Over the next two decades, the IESO predicts a significant increase in Ontario's overall electricity demand.[64] The IESO's *Pathways to Decarbonization Report* explores an even greater demand growth under a high electrification scenario characterized by a switch from fossil fuel powered to electric powered transportation, heating, and production processes, and economic growth in the agricultural greenhouse and electric vehicle manufacturing sectors. In addition, capacity reductions in Ontario's nuclear fleet due to scheduled refurbishments and the expected decline in the utilization of gas plants in furtherance of clean energy policies add further pressure to the projected supply crunch. To address the anticipated shortfalls, significant capital investments in new generation and transmission assets will be required.

In response to the projected supply crunch, several procurement activities have been undertaken in recent years. In October 2022, the Minister of Energy issued a directive instructing the IESO to procure 4,000 MW of additional (new build or expansion) capacity by 2027. In addition, through the Medium-Term (MT) RFP initiative, the IESO executed

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[63] Alberta (AESO) and Texas (ERCOT) use an energy-only market, meaning there is no separate auction for capacity. All other major U.S. RTOs principally rely on a capacity auction to incent investment and retirement decisions which are not facilitated by the energy market alone. Increasingly, however, investment and retirement decisions are being influenced by the renewable energy policies within each jurisdiction.

[64] See the IESO's Annual Planning Outlook 2024 (Released March 19, 2024).

contracts in September 2023 with five existing generators that were coming off contracts whose capacities will now be available between 2024-2026.[65, 66]

These recent procurement efforts have contributed to improvements in the 2023 North American Electric Reliability Corporation (NERC) reliability outlook for Ontario.[67] For the past five years, the Ontario bulk power system had been regarded by NERC as a high-risk area not being able to meet the resource adequacy criteria based on its long-term horizon outlook.[68] Through a mix of procurement approaches (i.e., expedited, long-term and medium-term RFPs) for new builds and expansion of existing resources including the annual capacity auction and capacity sharing agreement with Hydro-Québec, the IESO was able to address the previous shortfall forecasts by NERC with adequate reserve margins until 2030.

Figure 19 illustrates monthly minimum and maximum available generation capacity, and monthly peak market demand (excluding demand served by imports).[69] The market enjoyed an average supply cushion of over 6,000 MW in 2023, but this level has been on a decline for the last five years with the highest reaching an average of about 8,000 MW in 2020.[70] This is largely driven by the growing gap between the installed and available capacities due to increased 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. While conservation efforts, energy efficiency improvements and increased embedded generation deployment have all contributed in shaving the province's peak demand, the figure also illustrates that the low points of peak demand, particularly in 2023, have not been as low historically. This is a sign of upward pressure on the demand trend and aligns with forecasted supply need.

[65] See Minister of Energy's directive to the IESO dated January 27, 2022.

[66] Original MT1-RFP targets for 750 MW of unforced capacity (UCAP) were not met, instead only about half this target was procured (see also, IESO's MT-1 RFP Results).

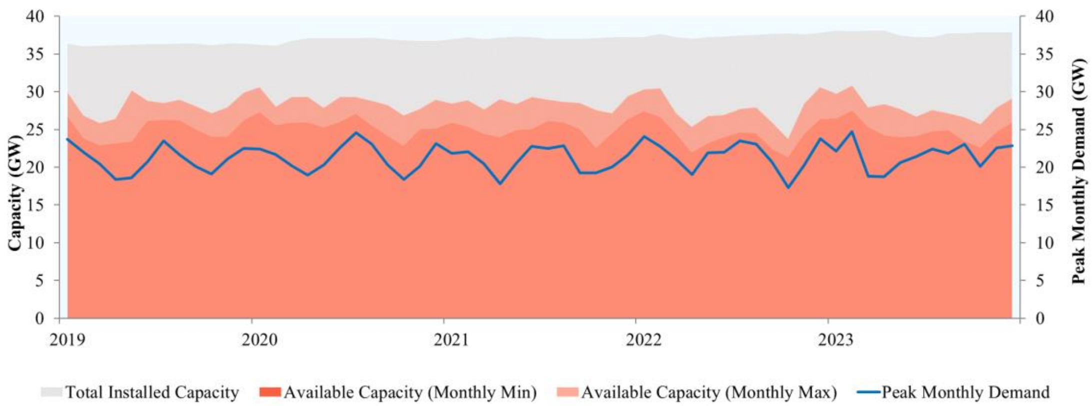
[67] See NERC's 2023 Long-Term Reliability Assessment (2023), at page 66-70.

[68] See NERC's Long-Term Reliability Outlook Assessment (2019, 2020, 2021 & 2022).

[69] Available generation accounts for unavailable capacity due to planned and forced (i.e., unforeseen) outages and de-rates, and unavailable capacity from intermittent and self-scheduling generators.

[70] Supply cushion here simply refers to the difference between the non-coincidental highest monthly available capacity and demand.

Figure 19 – Installed Capacity, Available Capacity, and Peak Demand, 2019-2023



Investments within the Ontario system should be made in consideration of the demand profile. Capacity resources are best suited to address system peaks, while baseload and intermittent generation may better address energy needs. Even in a hybrid framework, market prices can provide valuable signals to help guide investments which best serve the needs of consumers. While the Panel acknowledges the IESO may need to plan for and procure generation capacity to ensure reliability, this exercise must be imbued with economic discipline. The role and efficacy of wholesale market prices are discussed further in Section 3.3.

5.1.1 New build investments and future procurements

With the stated objective of ensuring that Ontario has a reliable and affordable electricity system while continuing to find further cost efficiencies in the electricity sector, the Minister of Energy directed the IESO in October 2022 to undertake the Expedited Long-Term Procurement (E-LT1). Its intent was to acquire 1,500 MW from new build resources and Same Technology Upgrades Solicitation that can commence operation prior to 2027.[71] E-LT1 was concluded in September 2023 and achieved a 95%-98% success rate with respect to the target capacity. The storage category of E-LT1 was procured in a competitive manner through a two-round bidding process[72], while the same technology upgrade category was based on a targeted call for new cost-effective capacity upgrades from existing contracted natural gas facilities that can supply energy for at least eight consecutive hours.

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[71] See Ministerial Directive to the IESO in October 2022. The October 2022 directive originally set the target commercial operation date as no later than May 2026 but was subsequently changed to 2027.

[72] The two-round bidding process in the E-LT1 storage category is driven by a parameter termed as "Storage Threshold Price" set by the IESO which is unknown to proponents. All price bids lower than the threshold win the first round. In the next, the remaining proponents can then revise their bids incorporating the investment offer from the Canada Infrastructure Bank with the goal of price reduction.

Table 3 shows the summary of the actual MW capacity awarded in each category including the corresponding average contract prices. Storage capacities totaled 882 MW, while natural gas capacities reached 581 MW in both new build and upgrades.[73] Across the procurement categories, the Panel notes that OPG represents around 28% in new storage capacities and announced upgrades. The percentage slightly increases if we also account for the non-competitive bilateral contract entered into by the IESO and Atura Power dated as of April 2023 for the continued operation of Brighton Beach Generation Station that includes a 42.5 MW expansion. This level of market share in the forthcoming additional capacities further bolsters OPG's dominance and preserves the high market concentration in the IAM.

Table 3 – Summary of Expedited Procurement Result[74]

Procurement	Target (MW)	Actual (MW)	No. of Facilities	Avg. Contract Price ($/MW-Business Day)
E-LT1 – Storage	1,200	882	15	881.09
E-LT1 – Non-Storage		295 (Winter) 256 (Summer)	2	1,093.22
Same Technology Upgrade	300	286	7	537
Total	***1,500***	***1,463 (Winter) 1,424 (Summer)***		

The listed contract prices for E-LT1 in both the storage and non-storage categories are fixed capacity payments that will be on top of what the facilities can potentially earn from the market. The contract price for the Same Technology Upgrade Solicitation category, on the other hand, will form part of an amendment to the respective existing contracts of these natural gas facilities that will see an increase in contract capacity as well as modification in the current net revenue requirement for eligible facilities.[75]

[73] This calculation is based on Winter Contract Capacity for Storage and Non-Storage plus Same Technology Upgrade Solicitation. Storage: 882 MW (E-LT1 Storage), Gas: 295 (E-LT1 Non-storage) + 286 (Same Tech Upgrade) = 581 MW. Gas capacity total is slightly lower at 542 MW if based on Summer Contract Capacity: 256 (E-LT1 Non-storage) + 286 (Same Tech Upgrade) = 542 MW.

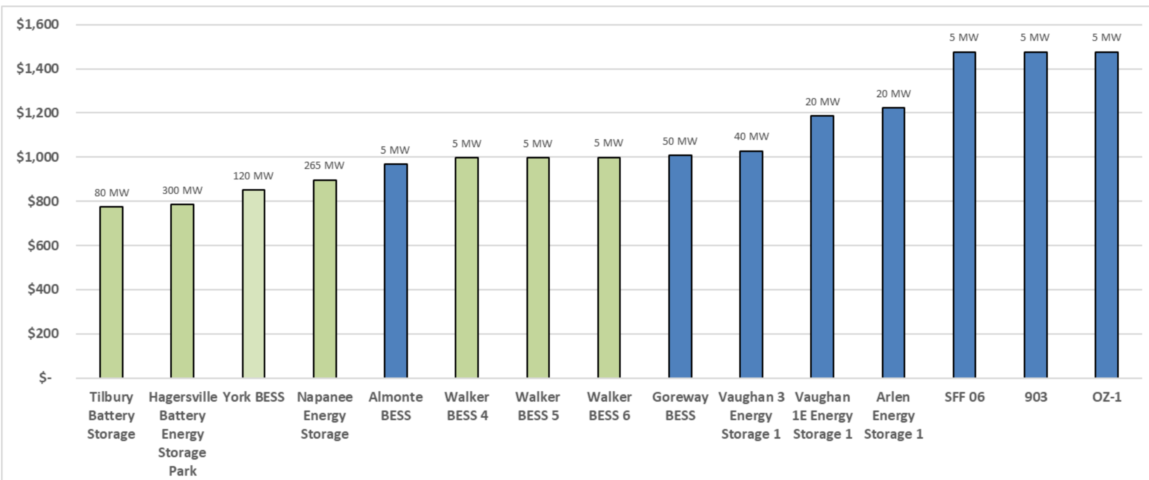
[74] Further details can be found in Appendix B, Table 7 to Table 9.

[75] See Item 8 Upgrade Amendments of the IESO's Same Technology Upgrades Solicitation – Final Call for Submission, at page 7.

Notwithstanding, the features of a deeming contract as discussed in the previous chapter will generally continue for these facilities.[76]

Figure 20 displays the spread of contract prices for the awarded battery storage proponents. Seven projects, noted in green bars, won in the first stage of bidding while an additional eight storage projects, the blue bars, were successful in the second bidding round. Due to a price threshold that served as cut-off criteria in the first round, contract prices in this stage are distinctly lower than that of the second. Moreover, the size of the battery storage also seems to play a role as projects with capacity above 50 MW yielded an average price of $827.5/MW-business day, whereas those equal or below have an average contract price of $1,167.2/MW-business day.

Figure 20 – IESO Battery Procurements Fixed Capacity Payment ($/MW-Business Day)[77]



In addition to the E-LT1 and the Same Technology Upgrades Solicitation, the Ministerial directive in October 2022 also mentioned a long-term procurement (LT1) designed to competitively contract new capacity able to go online no later than May 2027. LT1 was launched by the IESO in May 2023 and as of the end of 2023 was at the proposal evaluation stage after the passing of the submission deadline on December 12, 2023. The IESO expects to acquire 2,518 MW of year-round effective capacity from dispatchable new build resources out of LT1. If successful, this would bring the numbers closer to the overall target of 4,000 MW that the Minister of Energy set out for the IESO in the October 2022 directive.

[76] Specifically, these deeming contracts are the Accelerated Clean Energy Supply contracts (ACES), Clean Energy Supply contracts (CES), Combined Heat and Power (CHP) and Early Mover Clean Energy Supply Contract (EMCES).

[77] See the IESO's Expedited Long-Term Procurement (E-LT1) – Final Results.

Recognizing that new laws or regulations may effectively restrict greenhouse gas emissions of a project, the directive stipulated that a natural gas facility can suspend operations for the remainder of the contract term while retaining payments under the E-LT1 and LT1 contracts in the event that the project is, despite commercially reasonable efforts, unable to comply with such laws or regulations.[78]

At the end of 2023, the federal Government of Canada was continuing to engage stakeholders on the draft Clean Electricity Regulations (CER) aimed to achieve a net-zero grid by 2035. The IESO submitted its comments to the federal government on the draft CER on November 2, 2023, recommending to allow more of Ontario's natural gas generators to operate without restrictions beyond 2035, to modify the approach to the 450 annual operating hour exception for gas turbines that reach their prescribed life threshold and to update the CER to conform with North American reliability standards.[79] Following the consultation period, the federal government is considering several changes to the draft including changes to the emissions limit approach and end of prescribed life. Final regulations are expected to be posted in 2024.

Building off of the earlier 2023 procurement efforts, the IESO released a supply adequacy report on December 11, 2023, outlining its plan to acquire 2,000 MW more of new energy-producing resources with a target commercial operation date of 2030 (through LT2), with another 1,500 MW targeted for 2032 (LT3) and an additional 1,500 MW targeted for 2034 (LT4). This cadenced approach is intended to allow for a regular reassessment of needs as time progresses, and for ongoing technological advances to occur that may reduce associated costs.[80] For these procurements, the IESO plans to run a technology agnostic competitive procurement focusing on non-emitting supply.

Informed by the *Pathways to Decarbonization* report, the Minister of Energy made a key announcement in July 2023 on several other capacity investments that are forthcoming. This is contained in the government's *Powering Ontario's Growth* report which includes the expansion of the Darlington and Bruce Nuclear generating stations and the plan to advance the Meaford and Marmora pumped storage projects, among others. When completed, the additional nuclear capacity will bring up the province's supply by 6,000 MW, while the long-storage duration pump projects will give it another 1,400 MW boost.[81] Chapter 9 discusses this in detail. More recently, the Minister of Energy confirmed the Ontario government's plan to refurbish Pickering B (2,192 MW) to keep the nuclear plant operating for at least another 30 years.

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[78] See Sections 2.g (ii) and 9.b of the Minister of Energy's directive to the IESO dated October 6th, 2022.

[79] See the IESO's Response to draft Clean Electricity Regulations.

[80] See "Evaluating Procurement Options for Supply Adequacy: A Resource Adequacy Update to the Minister of Energy" December 11, 2023.

[81] Marmora is a 400 MW pump storage project under the partnership of OPG and Northland. Meaford is a 1,000 MW pump storage project under the partnership of TC Energy and Saugeen Ojibway Nation.

As major procurement activities were underway in 2023, a couple of challenges were encountered by aspiring proponents particularly in the areas of municipal support and the deliverability test. Both are requirements under the procurement process.[82] A number of prospective LT1 projects were noted to have faced issues in garnering support from their respective host communities.[83] As a way to contribute to informed decisions by community councils on potential energy projects in their jurisdictions, in late 2023, the Minister of Energy requested that the IESO make itself available to municipal councils and their officials on an ongoing basis, including outreach to municipal forums and organizations, to address queries regarding the needs of the Ontario electricity system.[84]

The deliverability test, on the other hand, is an assessment of whether there are any transmission constraints that would prevent a project from providing the reliability service for which it was procured. For LT1, the IESO carried out deliverability tests on 388 projects where 265 passed (68%) as “Deliverable but Competing”.[85] Due to shortage in available connection, projects west of London mostly failed this evaluation (i.e. designated as “Not Deliverable”) such as the proposed Enniskillen BESS located in Wyoming, Ontario with a potential capacity of 350 MW. In the U.S., only about 20% of projects requesting grid interconnection ultimately reached commercial operations.[86]

5.1.2 Other contracting and agreements

In addition to the foregoing competitive procurements, the IESO, pursuant to the Minister of Energy’s directives, also entered into a number of bilateral contracts, as follows:

1. Atura Power’s Brighton Beach Generation Station[87]
    - A natural gas combined cycle facility with a capacity of 541.25 MW and facility upgrade that will increase its total capability by 42.5 MW.
    - Its contract type is Early Mover Clean Energy Supply (EMCES) that runs from July 16, 2024, to July 15, 2034.

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[82] Community support through the submission of a council resolution by a proponent is a requirement outlined in the October 2022 Ministerial Directive and December 2022 Minister of Energy’s Letter of clarification to the IESO. Deliverability test and community support are eligibility requirements are set out in Section 2.1 of the LT1 RFP document.

[83] Some of the prospective projects (not an exhaustive list) that did not obtain community support were: Picton BESS, Thorold gas project, Halton Hills gas expansion, Kingston Cogen expansion & BESS projects, Elizabethtown-Kitley BESS and South Fronterac BESS.

[84] See Minister of Energy’s letter to the IESO dated November 14, 2023.

[85] This represents 44,917 MW of the 67,783 MW for all of the projects. See the IESO Report on Deliverability Test Results for LT1 (September 29, 2023).

[86] See Berkeley Lab’s Queued up: 2024 Edition. It is noted that the grid interconnection process in the U.S. is different from Ontario’s as merchant projects in the former can submit interconnection requests even at early pre-development stages. In Ontario, the timing of the connection request is most often aligned with procurement where resources are a subject of a procurement process.

[87] See Minister of Energy’s Directive to the IESO dated April 27, 2023.

2. Resolute FP Canada Inc's Thunder Bay Biomass Condensing Turbine Project[88]
   - A biomass-based electricity generation facility whose biomass fuel consists primarily of by-products from Resolute FP's Northern Ontario sawmills. It has a capacity of 40 MW.
   - Its contract type is Combined Heat and Power Agreement III (CHPIII) that runs from November 1, 2023 to September 20, 2028.

3. Tembec Industries Inc's Chapleau Biomass GS[89]
   - A biomass-based electricity generation facility whose biomass fuel consists primarily of by-products from the Chapleau sawmill. It has a capacity of 5 MW.
   - Its contract type is Non-Utility Generator agreement (NUG) that runs from January 1, 2023 to December 31, 2027.

It should be noted that there are potential pump storage projects at Meaford and Marmora (combined capacity of 1,400 MW). These potential projects are the subject of the Minister of Energy's letter to the IESO requesting a cost-benefit study on the two potential projects.[90] In January 2024, the "Minister has asked the IESO and the proponents of pumped storage projects in Meaford and Marmora to continue to update and refine their proposals".[91]

On August 30, 2023, the IESO and Hydro-Québec (HQ) entered into a memorandum of understanding to support a new 600 MW trade agreement from November 1, 2024 to October 31, 2031. This period may be extended for three more years.[92] Based on the agreement, the IESO will ensure that 600 MW capacity shall be committed for exports to Québec during each hour of the winter period. Similarly, HQ will return the 600 MW committed capacity in the summer period with the IESO having the option to bank a portion of the capacity for use in subsequent years. It should be noted, however, that the swap essentially only secures the portion of that energy that is already imported on a regular basis, guaranteeing 600 MW of supply will be available at the most critical time. The trade agreement is a continuation of a previous interregional collaboration between the two provinces which originally involved a 500 MW capacity swap with no monetary exchange in 2015.[93]

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[88] See Minister of Energy's Directive to the IESO dated October 19, 2023.

[89] See Minister of Energy's Directive dated October 7, 2022.

[90] See Minister of Energy's letter to the IESO dated July 10, 2023.

[91] See Minister of Energy's letter to the IESO dated January 9, 2024.

[92] See Article 3.2 of the Memorandum of Understanding between the IESO and HQ.

[93] The previous capacity sharing agreement between Ontario and Québec started in 2015 that saw a straight swap of 500 MW on a like for like basis. This was later amended by the Electricity Trade Agreement in the fall of 2016 which introduced components of electricity purchases, electricity cycling and capacity sales.

The complementary opposing seasonal peak in electricity demand of Ontario and Québec is instrumental in facilitating this agreement. This arrangement will have to be revisited in a future time as Ontario could evolve from summer-peaking into dual summer-and-winter peaking in the 2030s due to the ongoing energy transition and electrification of the Ontario economy. While the capacity sharing arrangement injects a degree of operational comfort and planning assurance that align with the clean energy goals of Ontario, it is a decision that impacts consumers and, hence, moving forward should require a proper consideration of the cost and benefit of all potential alternative options. Further, as this type of transaction is generally an extension of a previous one, future decisions to carry on should ideally be informed by an evaluation of the first agreement. Finally, any such assessments in the future can also benefit from a public stakeholdering process.

5.1.3 Capacity Auction

The fourth annual capacity auction was held in December 2023. The auction is designed to ensure that there is sufficient available capacity[94] of off-contract generators, demand response, energy storage, or system/generator-backed imports to meet the IESO's resource adequacy reliability standards for the following calendar year. The auction provides the successful resources with an "availability" payment for up to two six-month obligation period, summer and/or winter, to be available to produce energy.

In 2023, the IESO introduced several amendments to the capacity auction rules that help ensure that only reliable capacities are enrolled and duly compensated.[95] The 2023 auction participants qualified on the basis of their unforced capacity (UCAP), a discounted version of installed capacity that accounts for historical availability and performance. New resources without historical data will be applied with fleet average availability de-rating factor. For HDR resources, an in-period UCAP adjustment has been implemented that would essentially bring down the contractual obligation and payment for an HDR resource if it fails to meet the new and tighter performance dead band. This is in addition to applicable penalty charges that may also be imposed.

In *Monitoring Report 35*, the Panel made several recommendations around the capacity auction. In particular, the Panel recommended using strong penalties to ensure auction participants do not have an incentive to over-represent the capacity contributions or ignore dispatch instructions.[96] Hence, the enhanced measures implemented by the IESO should provide a financial incentive for auction participants to improve performance and much stronger financial consequences for poor performance.

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[94] This is capacity availability that is not rate-regulated, or beyond what has already been committed to the IESO through long-term IESO contracts.

[95] See the IESO Capacity Auction Stream 1 Enhancements approved by the IESO Board on June 26, 2023 and the Stream 2 Enhancements effective as of November 29, 2023.

[96] See MSP 35 Recommendation 3.2, page 52.

In the 2023 auction, 1,812 MW of capacity was acquired for the summer 2024 period at a clearing price of $367/MW-day and 1,311 MW was acquired for the winter 2024/2025 period at $147/MW-day. The procured capacity for summer is about 412 MW more than the set target of 1,400 MW, while winter capacity is 460 MW more than the target of 850 MW. The resulting prices were also noted to be higher than last year. Two factors that may have contributed to the increased prices were the introduction of UCAP that effectively reduced the amount of qualified MW bids and the changes in the auction demand curve parameters such as the target capacity which led to 17% higher prices for summer obligation and 12% for winter.[97] The IESO uses a capacity auction forward guidance to inform its auction targets and this was the basis for setting the parameters in the 2023 capacity auction. This guidance, however, is focused on achieving market predictability to grow the auction; it is less clear how it ties in with the reliability requirement of the province.[98]

5.2 Conclusions

The Panel considers it important for the IESO, when using contracts, to design contracts that not only encourage dispatch efficiency, but also incentivize efficient investment in facility maintenance, capacity upgrades and expansions. The Panel also remains of the view that a transparent and independent regulatory review of the IESO’s system needs assessments and decisions around choice of competitive versus bilateral procurements would improve the level of accountability over future system investments and promote overall investment efficiency. Finally, the Panel supports the IESO’s use of competitive procurement processes to address system needs whenever possible, to achieve efficiencies and cost savings for electricity consumers.

[97] The capacity auction demand curve represents the IESO’s willingness to pay for varying quantities of capacity along a curve. There are two price parameters and three quantity parameters that establish the shape of the curve which includes target capacity. For details of the demand curve, see the IESO Market Manual 12.

[98] See the IESO’s Annual Acquisition Report (2021) at pages 26-27 and Annual Planning Outlook (2024) at pages 78-80.

6 EXTERNAL TRANSACTIONS

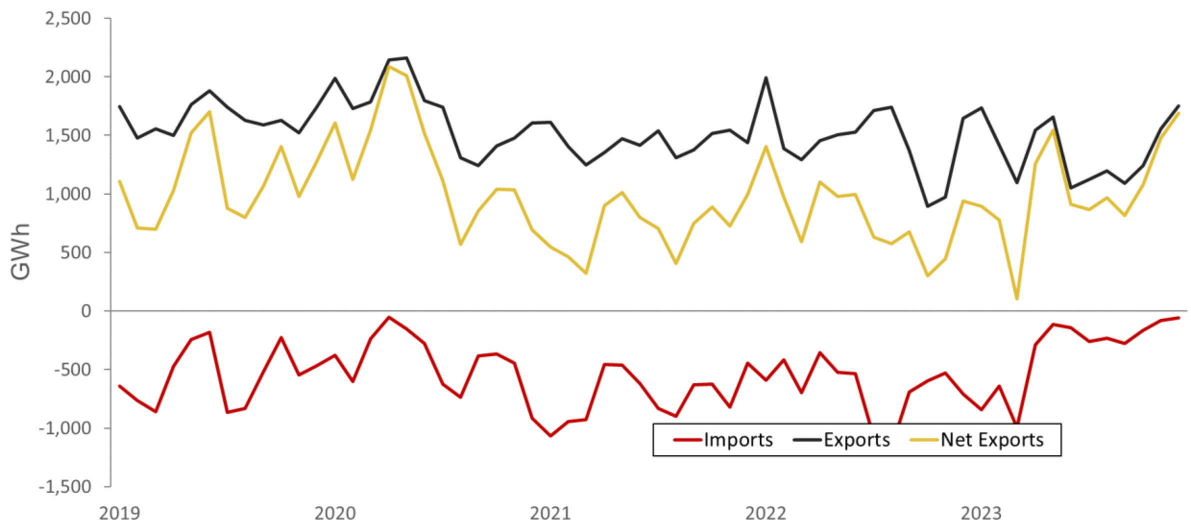
Intertie trading can facilitate the efficient use of the transmission interfaces that connect Ontario and its neighboring jurisdictions. Intertie trading allows low-cost resources in one jurisdiction to compete to serve consumers in neighboring jurisdictions with higher cost resources. It also allows the IESO to draw on other jurisdictions to provide emergency power, reserves, and capacity to meet reliability standards.

Ontario is interconnected with five other jurisdictions: New York, Michigan, Québec, Manitoba and Minnesota. These interties provide direct connections to two open wholesale electricity markets, MISO and NYISO, and indirect connections to two additional markets, PJM and ISO-NE. Ontario interties also provide direct connections to Hydro-Québec and Manitoba Hydro's jurisdictions which do not have wholesale electricity markets.[99]

Historically, Ontario has been a net exporter of electricity. Figure 21 shows monthly imports, exports, and net exports since January 2019. In 2023, Ontario exported 16 TWh and imported 4 TWh (12 TWh of net exports).

[99] Note that Manitoba Hydro joined MISO in September 2001 "through the execution of a Coordination Agreement with MISO (and not the Transmission Owners' Agreement) which sets out the various rights and obligations of the parties related to transmission service and pricing, tariff administration, generation and transmission outage coordination, transmission planning coordination, sharing of contingency reserves and reliability coordination. In addition to participating in MISO as the Coordinating Owner, Manitoba Hydro also participates in the MISO Capacity, ASM, Energy and FTR markets through which it delivers to the MISO footprint approximately 1,000 MW of capacity and 10 TWh of energy on an annual basis" (see also, MISO Sector Profile).

Figure 21 – Monthly Imports, Exports, and Net Exports, 2019-2023[100]



6.1 Efficiency Assessment

Intertie trading can improve regional efficiency when traders are incented to export energy from regions with a relative excess of low-cost energy (and lower market prices) and import that energy to regions with a relative scarcity of low-cost energy (and higher market prices).

This section examines the relative efficiency of intertie trading between 2019 and 2023. Intertie trading efficiency is assessed on an ex-post basis by comparing the hourly average real-time locational marginal price (LMP) at the neighbouring control areas with the real-time IESO nodal shadow prices at buses near the interties of the corresponding transactions.[101] For simplicity, the transaction costs associated with trading (i.e., transmission tariffs) are not accounted for in the efficiency assessment. Furthermore, intertie trading is only assessed with neighbouring U.S. control areas where historical price data are readily available, namely MISO, NYISO, PJM and ISO-NE.[102] In 2023, imports from and exports to these four control areas represented 10% and 82.7% of the

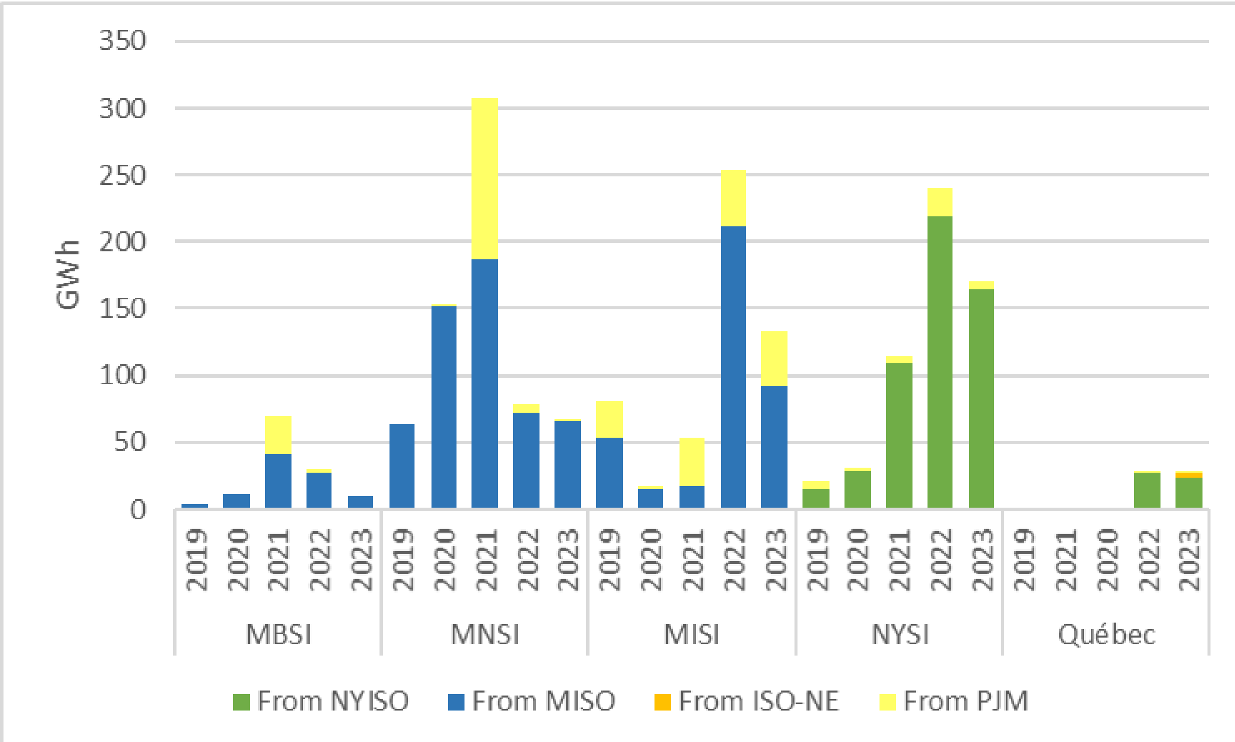
[100] In this figure, import quantities are assigned a negative value, export quantities are assigned a positive value and net exports are calculated as the sum of the two values.

[101] IESO nodal shadow prices, produced by the constrained mode of the dispatch algorithm, represent the marginal cost of energy at a location and thus are appropriate for the efficiency assessment. However, intertie traders are settled based on unconstrained prices and thus the profitability of a trade can be different from the efficiency of the trade. To be clear, the profitability of traders is not the main subject of this section.

[102] There are no wholesale electricity markets in the provinces of Manitoba and Québec and thus no real-time electricity prices, which are needed for the efficiency analysis. Only imports into Ontario and exports from Ontario are considered, i.e., the wheel-through is excluded from the assessment.

total import and total export of Ontario, respectively. Figure 22 presents a breakdown of imports from the four US control areas from 2019 to 2023.

Figure 22 – Imports from the U.S. Control Areas by Intertie, 5 Years[103]



Among the four control areas, Ontario imported the most energy from MISO through three interties, i.e., the Manitoba intertie (MBSI), the Minnesota intertie (MNSI), and the Michigan intertie (MISI), followed by that from NYISO through the New York intertie (NYSI).[104]

Figure 23 presents a breakdown of exports to the four U.S. control areas from 2019 to 2023. Ontario exported the most energy to MISO mainly through MISI, followed by NYISO through NYSI.

[103] The import volumes from ISO-NE are minimal, rendering them virtually imperceptible on the chart.

[104] The high volumes of PJM imports through MBSI and MNSI in 2021 were attracted by the availability of high CMSC payments in the Northwest. For more discussion on these events see Chapter 3 of MSP Report 37 (2023).

Figure 23 – Exports to the U.S. Control Areas by Intertie, 5 Years

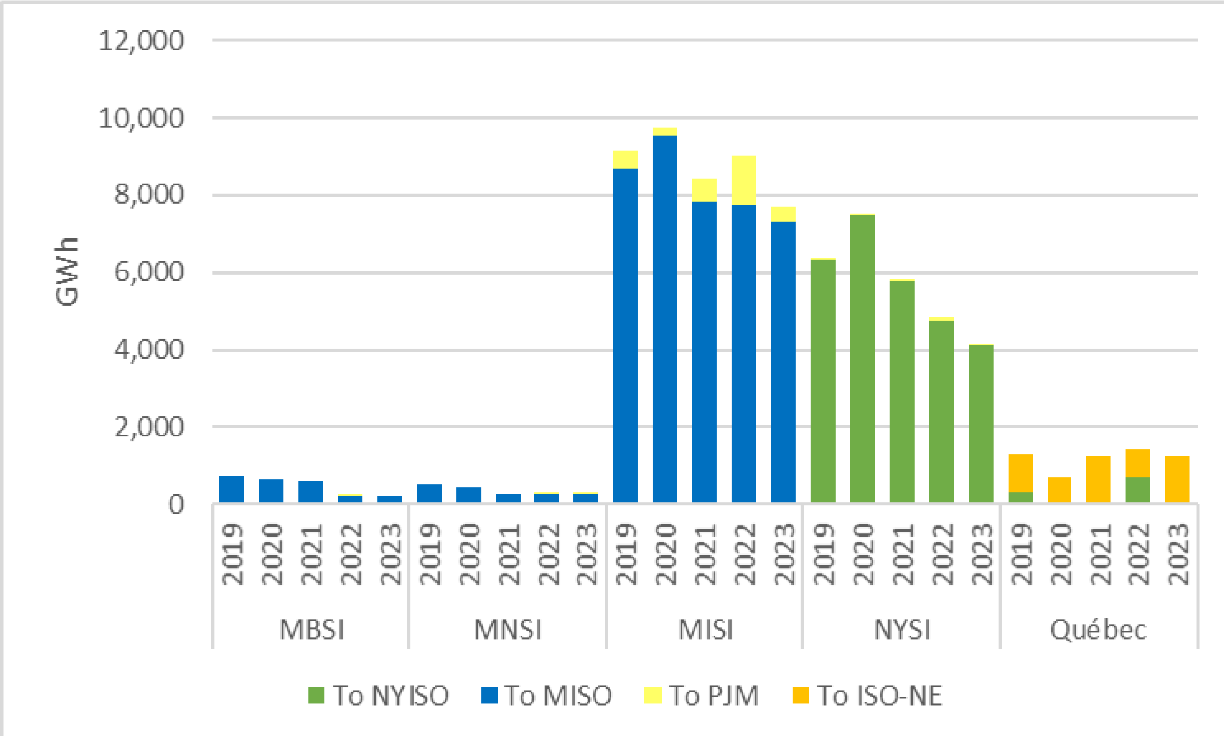


Figure 24 presents the percentage of import energy flows from the four U.S. control areas that were ex-post efficient from 2019 to 2023.[105] An import energy flow is considered efficient ex-post if the real-time LMP at the source control area is lower than the real-time IESO nodal shadow price near the relevant intertie.[106]

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[105] Not all imports are assessed. Imports from PJM via MBSI and MNSI are excluded because of zero volume in some years. Import from PJM via NYSI, and from NYISO via Québec are excluded because of consistently low volume.

Externally, MISO real-time LMPs of locations MHEB, ONT_W, and ONT_DECO.PSOUT are used for assessing MBSI, MNSI, and MISI intertie transactions with MISO. PJM real-time IMO interface price is used for assessing MISI intertie transactions with PJM. NYISO real-time IESO interface price (Zone OH) is used for assessing NYSI intertie transactions with NYISO.

Internally, the IESO's real-time nodal shadow prices for Kenora, Fort Frances, and Beck2 are used for assessing MBSI, MNSI, NYSI intertie transactions, respectively. Average nodal shadow prices of Keith and Sarnia are used for assessing MISI intertie transactions.

[106] Intertie transactions are scheduled on an hourly basis and do not change during the hour (unless a change is needed for reliability reasons). Therefore, the trading efficiency is assessed using the hourly average prices.

Figure 24 – Efficiency of Energy Imports, 5 Years

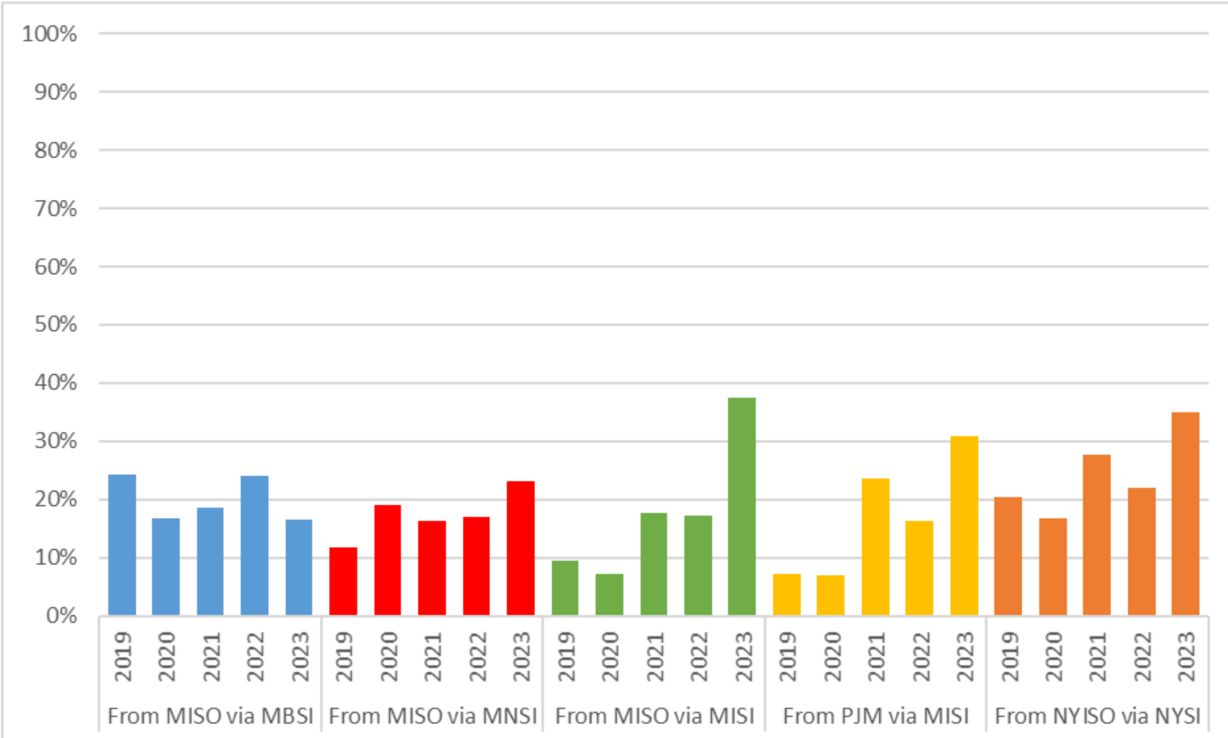
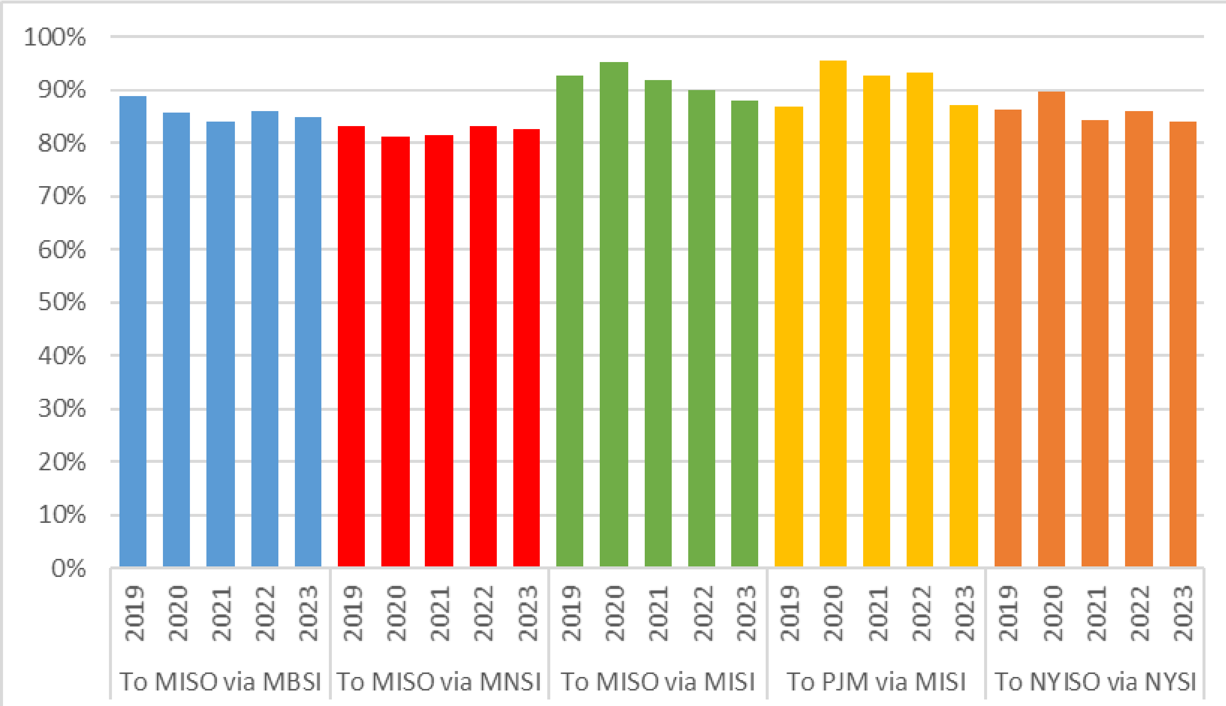


Figure 25 presents the percentage of export energy flows to the three U.S. control areas that were ex-post efficient from 2019 to 2023. An export energy flow is considered efficient ex-post if the real-time LMP at the destination ("sink") control area is higher than the real-time IESO nodal shadow price near the relevant intertie.

Figure 25 – Efficiency of Energy Exports, 5 Years



During the five years studied, the percentage of ex-post efficient exports was consistently above 80% across the interties and the destinations ("sinks") these transactions were intended for. This was especially high at the Michigan intertie. In contrast, the percentage of ex-post efficient imports was less than 40% across the interties and source areas, implying that the majority of energy imports were dispatched when the U.S. control areas had higher real-time marginal cost than that of Ontario.

The lower percentage of ex-post efficient import energy flows may be explained by the fact that intertie transactions are scheduled in the hour-ahead pre-dispatch (PD-1), and the nodal shadow price in the hour-ahead timeframe (PD-1) tends to be higher than in real-time. That is, imports may appear efficient ex-ante when scheduled in PD-1, but then become inefficient ex-post in real-time, when Ontario real-time prices are lower than the PD-1 prices.[107] Figure *26* presents a hypothetical import efficiency assessment comparing the real-time LMP at the neighboring control areas with the PD-1 IESO nodal shadow prices near the interties. The efficiency of imports would be higher across the interties and source areas if the real-time IESO nodal shadow prices were the same as the PD-1 prices.

[107] As discussed further below, the tendency for real-time prices to be lower than PD-1 prices may contribute to the higher ex-post efficiency of export energy flows.

Figure 26 – Hypothetical Efficiency of Energy Imports using PD-1 Nodal Shadow Prices, 5 Years

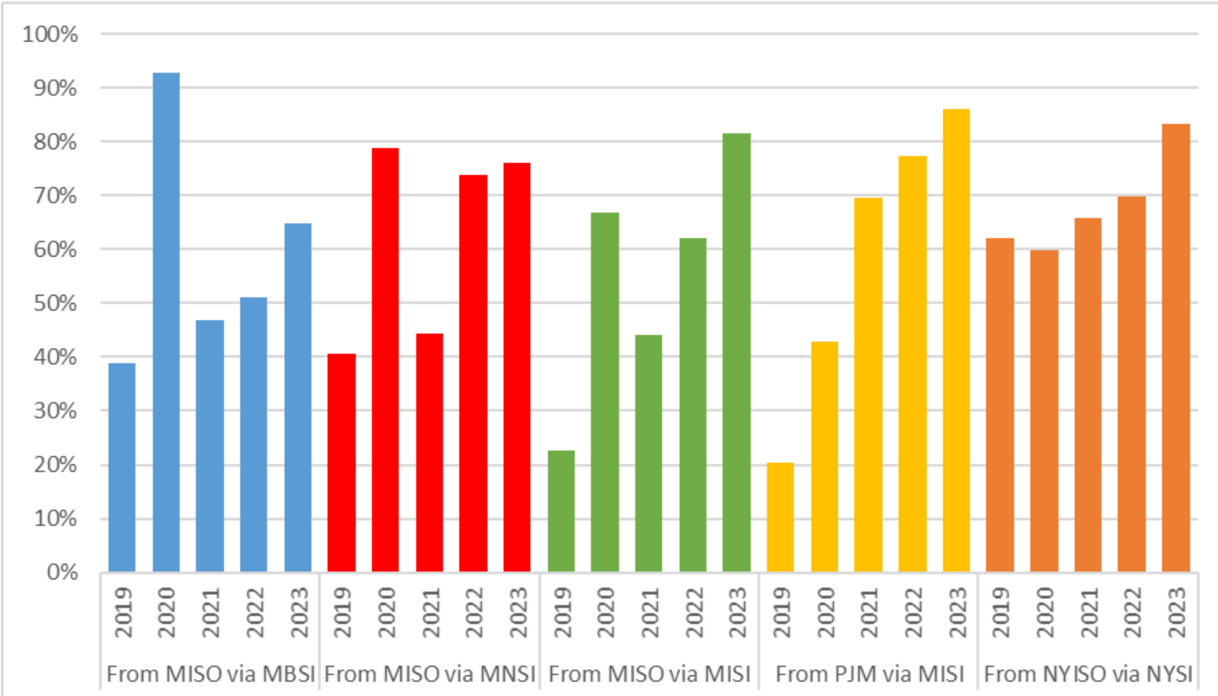
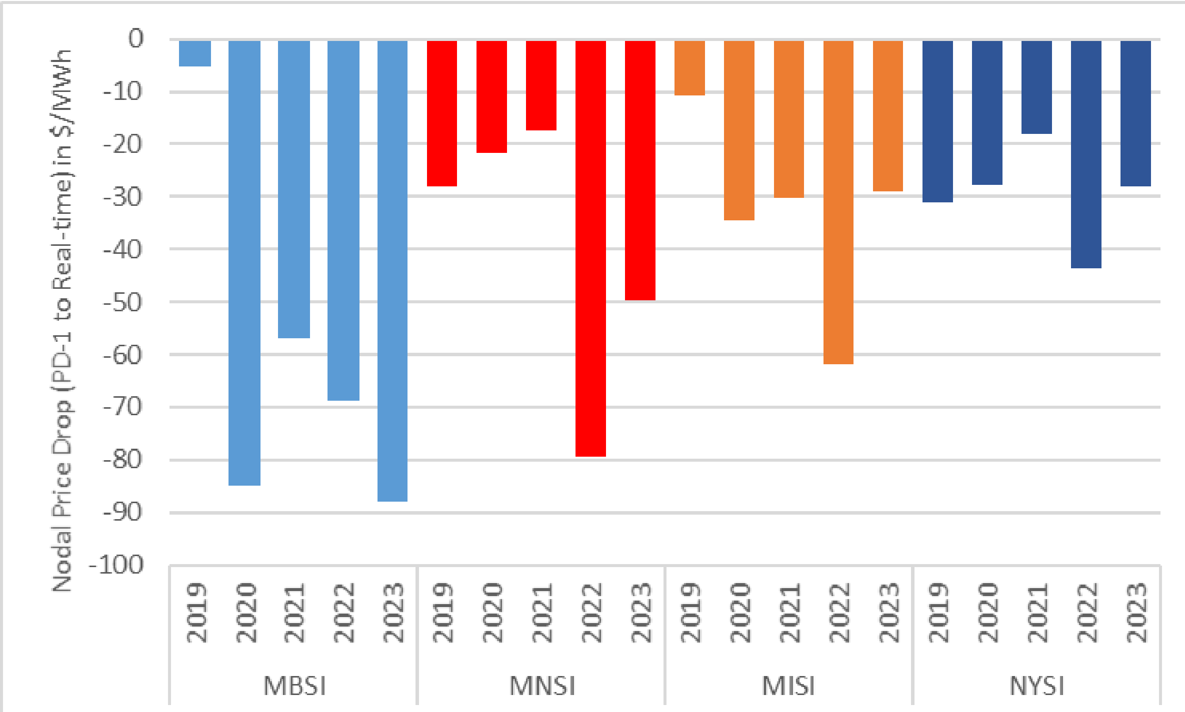


Figure 27 illustrates the average IESO nodal shadow price discrepancy between PD-1 and real-time near the four interties when there were imports scheduled on the interties from the U.S. control areas. Excluding MBSI, which had the least energy imports among the four interties,[108] the real-time prices were lower than the PD-1 prices by around $60/MWh in 2022, and around $35/MWh in 2023.

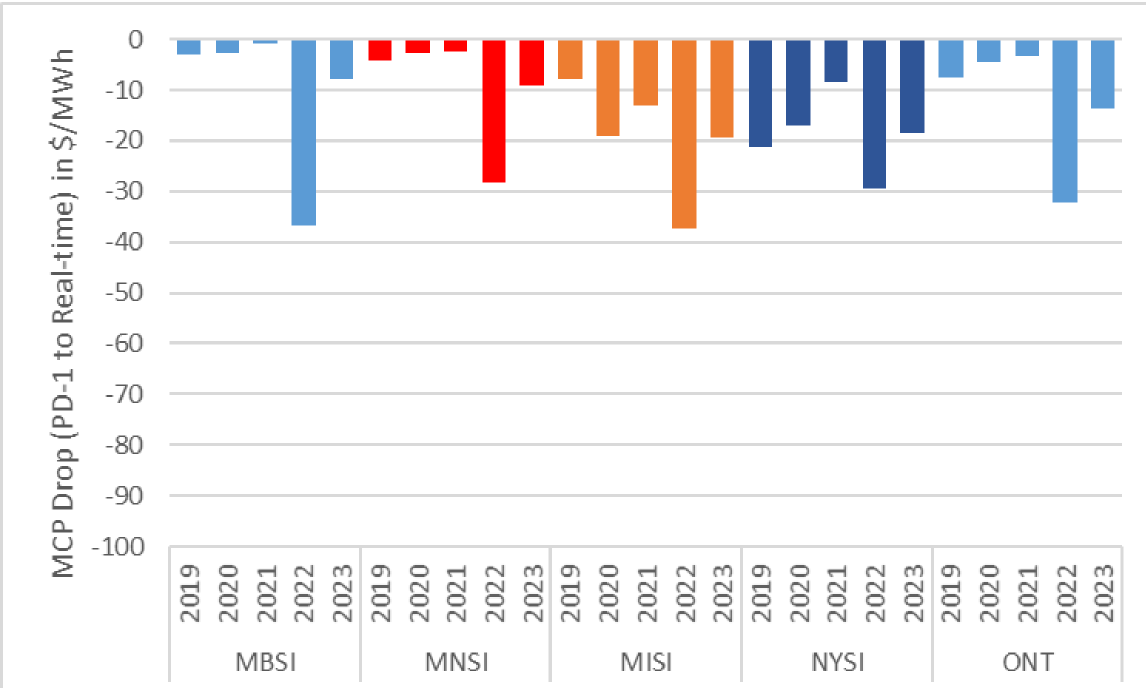
[108] Not counting energy imports from the province of Manitoba.

Figure 27 – Average IESO Nodal Shadow Price Discrepancy Between PD-1 and Real-Time Near the Interties during Importing Hours, 5 Years



Consistent with what was observed in the nodal shadow prices, intertie zone MCPs (the basis of intertie transaction settlement) also tend to be lower in real-time than in PD-1. Figure 28 presents the average MCP discrepancy between PD-1 and real-time at the four intertie zones when there were imports scheduled on the interties from the U.S. control areas. For reference, the average Ontario MCP discrepancy between PD-1 and real-time during the same hours is also shown.

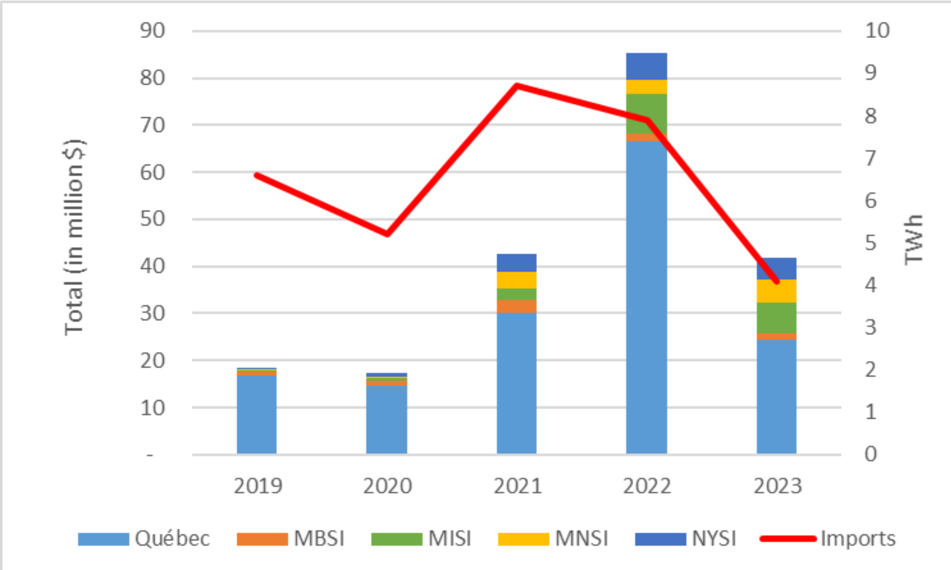
Figure 28 – Average MCP Discrepancy Between PD-1 and Real-Time during Importing Hours, 5 Years



Previous MSP reports have discussed the divergence between the Pre-Dispatch and the real-time MCP. Demand forecast deviation and wind generation forecast deviation between PD-1 and real-time have been identified as the two main contributing factors. When demand is over-forecasted and wind generation is under-forecasted in the Pre-Dispatch, PD-1 MCP will be higher than real-time MCP and imports could be over-scheduled.

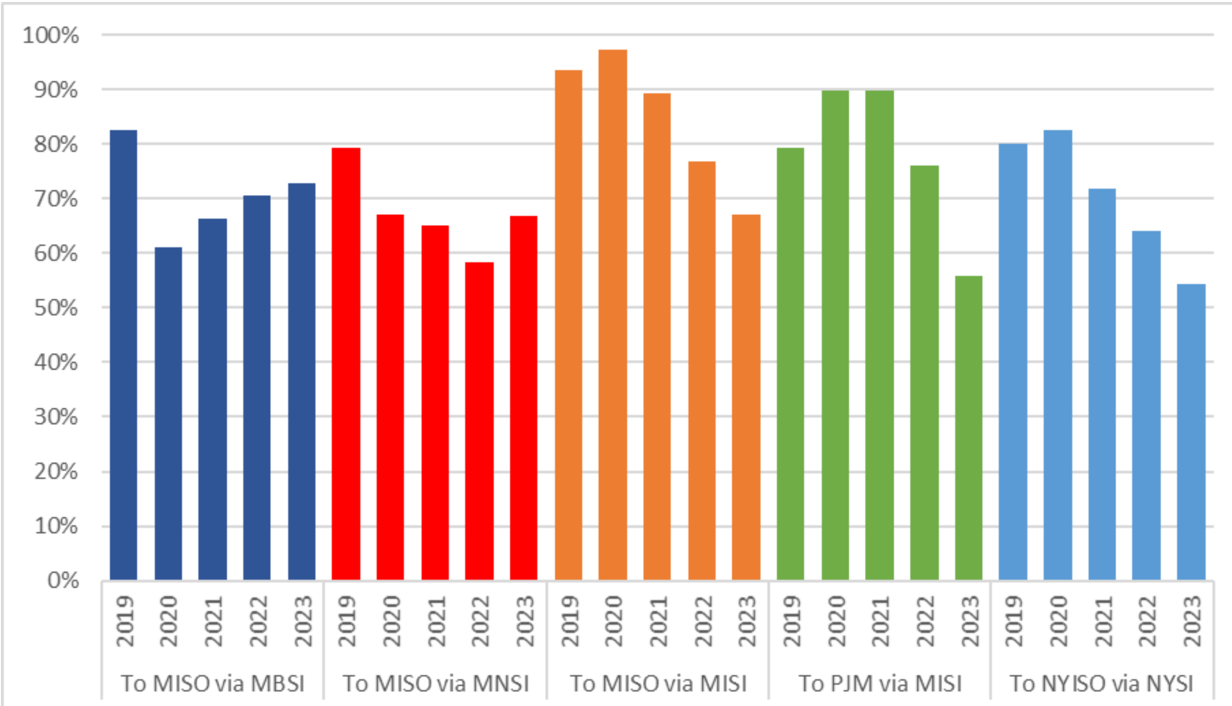
The MCP drop from PD-1 to real-time would present a price risk for importers if import transactions are scheduled in PD-1 but settled based on real-time prices. For example, if a trader's import offer price was lower than the PD-1 intertie zone MCP, it would be scheduled and dispatched in real-time. If the real-time intertie zone MCP were then lower than the import offer price, the trader would be settled at the real-time price and incur a loss relative to its offer price. In principle, the price risk could deter those potentially inefficient import trades where the offer prices were expected to be higher than the real-time intertie zone MCP. However, in the IAM, the price risk of incurring such a loss is eliminated through implementation of the Intertie Offer Guarantee (IOG). The IOG stipulates that import quantities selected in the day-ahead commitment or PD-1 receive the higher of the real-time MCP or the import offer price. Figure 29 shows the total annual IOG payments from 2019 to 2023.

Figure 29 – Annual IOG Payments, 5 Years



On the flip side, the high percentage of ex-post efficient exports is partially due to the price drops from PD-1 to real-time. Figure 30 below presents a hypothetical export efficiency assessment comparing the real-time LMP at the neighboring control areas with the PD-1 IESO nodal shadow prices near the interties. Compared to Figure 25, the efficiency of exports would be consistently lower across the interties and destination areas if the real-time IESO nodal shadow prices were the same as the PD-1 prices.

Figure 30 – Hypothetical Efficiency of Energy Export using PD-1 Nodal Shadow Prices, 5 Years



In conclusion, intertie trading can improve regional efficiency by allowing low-cost supply in one jurisdiction to replace higher cost supply in another. Intertie trading also aids in the maintenance of reliability by helping to provide emergency power, reserves, and capacity.

In the IAM, trades are scheduled an hour ahead of real-time at PD-1. Following the PD-1 schedule, trades are locked-in and no longer respond to changing prices and market conditions. Many of these locked-in trades become sub-optimal according to real-time prices and conditions but occur anyway resulting in productive inefficiencies. Systematic price discrepancy between PD-1 and real-time may also result in consistently inefficient trade levels. While the IOG protects importers from price decreases, this may create unbalanced incentives for traders and drive consistently higher than optimal import levels.

The IESO's Market Renewal Program will introduce new features such as Locational Marginal Pricing, the Day-Ahead Market, and market power mitigation that are intended to improve financial and operational certainty and prevent price manipulation, thereby fostering more competitive and efficient trading on the interties. In relation to this, the Panel notes that IOGs will not be implemented in the DAM but will still remain in the real-time market. The Panel recommends the following review of IOG payments once the MRP deploys:

Recommendation 2024-1-1

The Panel recommends that the IESO review the benefits and costs of continuing the Intertie Offer Guarantee (IOG) in the real-time market after the deployment of the Market Renewal Program, once sufficient data is accumulated, but no later than one year after implementation. The review should consider imports arranged outside of the Day-Ahead Market and quantify the extent to which the IOG:

- ***enhances the reliability or adequacy of the electricity system;***
- ***contributes to inefficient import schedules; and***
- ***dampens real-time market prices thus contributing to other potential real-time scheduling inefficiencies.***

7 TRANSMISSION AND CONGESTION

Ontario's transmission grid facilitates the delivery of energy from generating resources to load centres. To keep up with the increasing demand and rise in emerging technologies, the IESO projects the need for new transmission in the region. In relation to this, the Minister of Energy asked the IESO to continue the work on the development of a transmission selection framework (TSF).[109] The TSF is intended to address the increasing demand for transmission capacity in a transparent and well understood process through a competitive selection of transmitters that will develop and own grid infrastructures.[110] In November 2023, the IESO started its stakeholdering process for the design of the TSF and is due to report back to the Minister of Energy by summer 2024.

In 2023, the Panel noted several major transmission projects at various stages designed to meet expected electricity demand growth and system needs of the province in the coming years.[111] There are three priority transmission projects intended to support economic growth and electrification initiatives throughout northeastern and eastern Ontario.[112] These projects are:

1. A new 230 kV transmission line from the Mississagi Transformer Station (west of Sudbury) to the Third Line Transformer Station (Sault Ste. Marie)
2. A new 500 kV transmission line from the Mississagi Transformer Station (west of Sudbury) to the Hanmer Transformer Station (Greater Sudbury)
3. A new 230 kV transmission line from the Dobbin Transformer Station (Peterborough) to either the Cherrywood Transformer Station (Pickering) or the Clarington Transformer Station (Oshawa)

Located in the northeastern part of the province, the first two projects listed are primarily envisioned to support economic growth and electrification, including the production of steel at Algoma Steel in Sault Ste Marie as it transitions to electric arc furnace operations.[113] According to the IESO's *Northeast Bulk Planning Report* in October 2022, both transmission projects are recommended due to their cost-effectiveness after comparing against a range of options from wires to non-wires alternatives which include new generating resources and energy efficiency mechanisms.[114]

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[109] See Minister of Energy's letter to the IESO dated July 10, 2023.

[110] See the IESO's presentation "Transmitter Selection Framework: Engagement Launch" (November 22, 2023), at slides 6-7.

[111] See Priority transmission projects | Ontario Energy Board (oeb.ca).

[112] See Minister of Energy's directive dated October 19, 2023.

[113] See Minister of Energy's letter to the OEB Chair dated October 23, 2023.

[114] See the IESO's Need for Northeast Bulk System Reinforcement Report, October 2022.

In the coming years, the Panel anticipates that Locational Marginal Pricing post-MRP can inform future transmission investment decisions.[115] Large and frequent differences in nodal prices between and among areas of the grid should be able to create internal congestion rent that signals demand for transmission development. This is consistent with the final report by the Market Design Committee (MDC) in 1999 that envisioned a market setup whereby transmission investments are market driven facilitated by congestion pricing.[116] The Panel notes that in the current market the IESO simply disburses accumulated internal congestion rents back to loads via uplift. This is in contrast to how accrued congestion rents from intertie transactions are presently utilized to support the financial Transmission Rights (TR) market where congestion rents collected, along with auction revenues, offset costs of TR payments owing to TR holders.[117]

7.1 Performance of the Transmission Rights Market

When there is congestion at an intertie, the intertie zone price can be different from the uniform Ontario price, creating a price risk for these transactions. The TR market was established as a financial means to mitigate this risk by compensating the TR holder for the difference between the two prices. Each 1 MW of TR entitles the owner to a payment of 1 MWh times the price difference, for each hour in the period.

TRs are auctioned regularly by the IESO. Those who purchase them are entitled to a revenue flow on a specified intertie, for a specified period of time, should that intertie become congested. TRs do not affect the supply of energy. They are essentially a financial hedging instrument that allows market participants to protect themselves against the financial consequences of transmission congestion. The TR does not grant the holder any physical rights or preferences to transactions at the interties.

When an intertie has a greater amount of economic net import offers (or economic net export bids) than its hour-ahead 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 Pre-Dispatch price 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. As in the last five

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[115] See “Residual network costs and the economic efficiency of regulated cost allocation” by Olmstead, et.al. (2022).

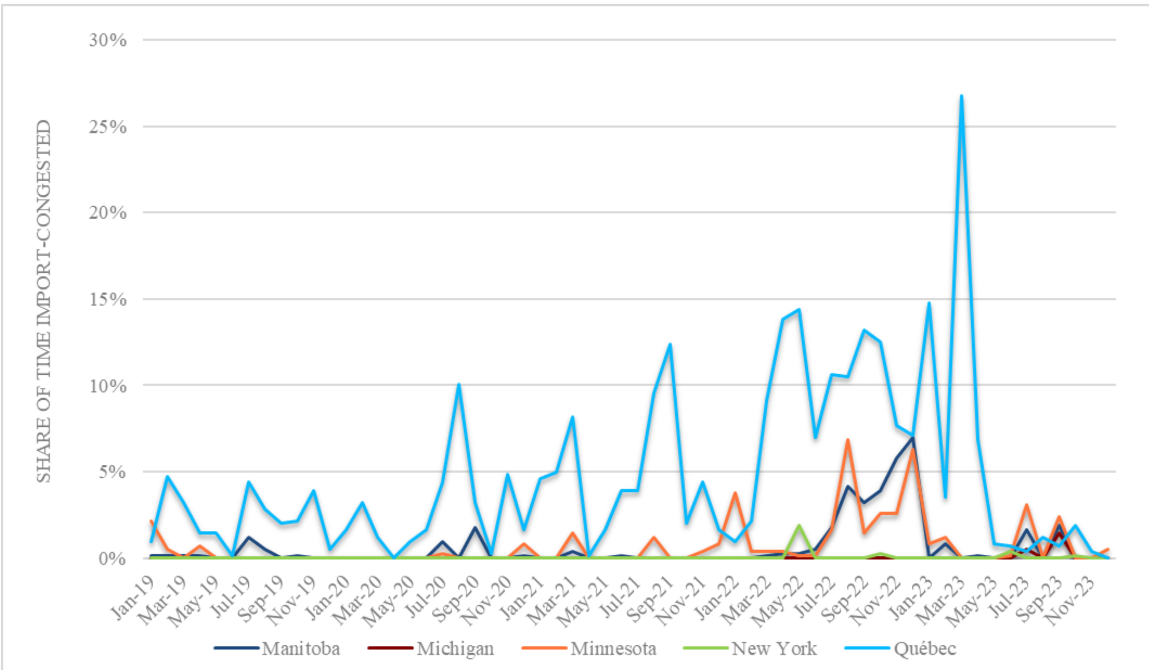
[116] Based on the MDC report, such entrepreneurial approach also requires acceptance of the idea that the beneficiaries of a transmission expansion should pay for it, and have rights with regard to its future use (see also, Section 4.10 of the MDC Final Report, January 29, 1999).

[117] See the IESO Market Rules, Chapter 9, Section 3.6.2.

years, the Ontario market experienced significantly greater amount of export-congestion than import-congestion hours in 2023 on all intertie points.

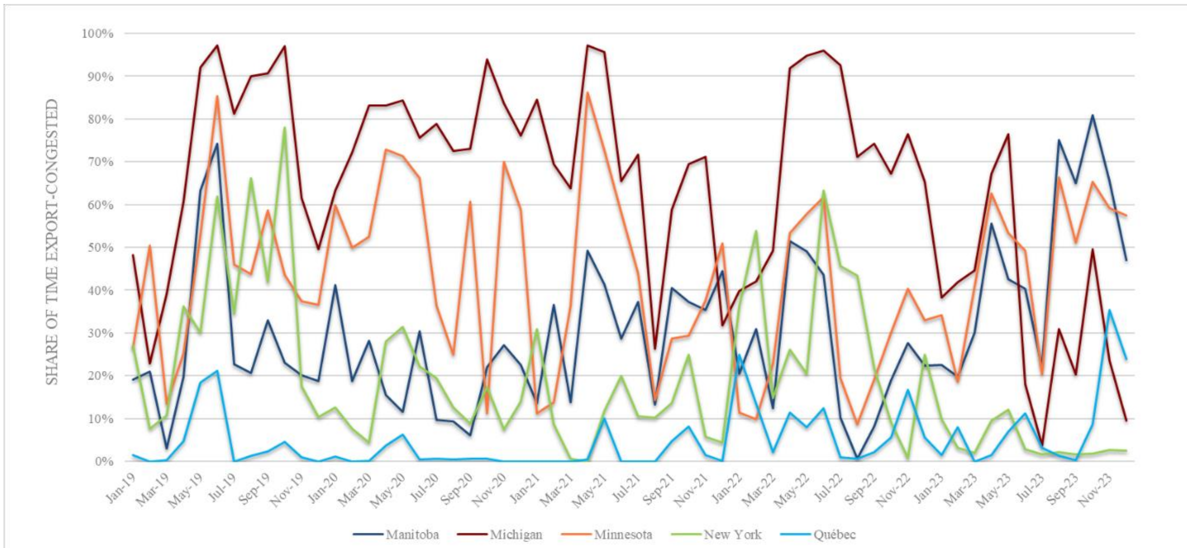
Figure 31 reports the percentage of time of import congestion by intertie per month while Figure 32 reports the same statistics for export congestion. Unless otherwise stated, all references to the Québec intertie refer to the Outaouais intertie.

Figure 31 – Import Congestion by Intertie, 2019-2023



There were 544 hours of import congestion in 2023 which represents a 56% decline from 2022. This is due to the overall decrease in the number of import congestion hours for all interties in 2023, especially at the Québec intertie which comprised almost 80% of the total congestion hours. While the Québec intertie experienced a spike in the number of import-congested hours in March 2023 at 199 hours, it stayed at a low average of 10 hours per month for the remainder of the year. The contributing factor for this spike was the significant increase in imports from Québec during this time. While the Québec interties were limited sporadically throughout the month, these did not impact the import limit for long periods of time. Imports from Québec were at the highest levels in March compared to any other month for 2023.

Figure 32 – Export Congestion by Intertie, 2019-2023



There were 12,618 hours of export congestion that took place in 2023 which represents a 13% reduction from 14,525 hours in 2022. The increase in the number of export-congested hours on Minnesota and Manitoba interties were offset by a larger decrease on Michigan, Québec, and New York interties resulting in the overall net decline this year. The Michigan and New York intertie points experienced the greatest reduction in export-congested hours totaling to 5,443 hours less in 2023 than in 2022.

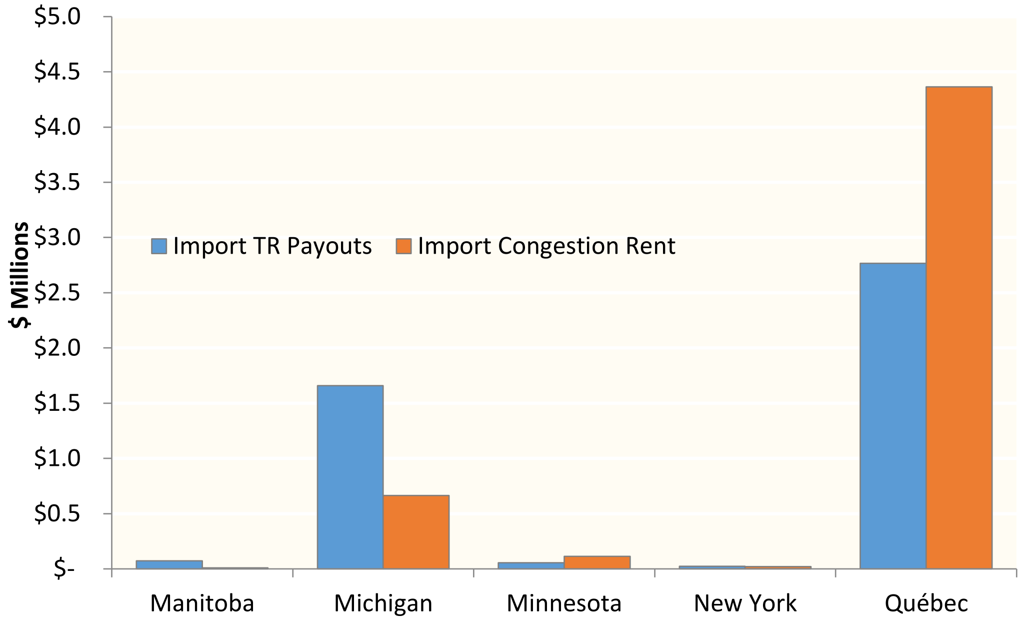
An IZP at a particular intertie is less than the Ontario price when that intertie is import congested. Conversely, an IZP is greater than the Ontario price when that intertie is export congested. The difference between the Ontario price and the IZP in a given intertie zone is the ICP and is equal to the difference (if any) between the hourly pre-dispatch PD-1 MCP and the PD-1 IZP. For example, in cases of an import-congested intertie the importer is paid the lower IZP, while loads in the wholesale market still pay the Ontario price (HOEP or 5-minute Market Clearing Price). In this example, the difference between the amount collected from the load and the amount paid to the importer results in an import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TRCA).

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. TR payouts are funded by congestion rent. Any congestion rent shortfalls, which occur when TR payouts exceed the congestion rent collected, are generally covered primarily by TR auction revenues (i.e. proceeds from selling TRs, a payment into the TRCA).

Figure 33 compares the total import congestion rent collected to total TR payouts by intertie in 2023 and

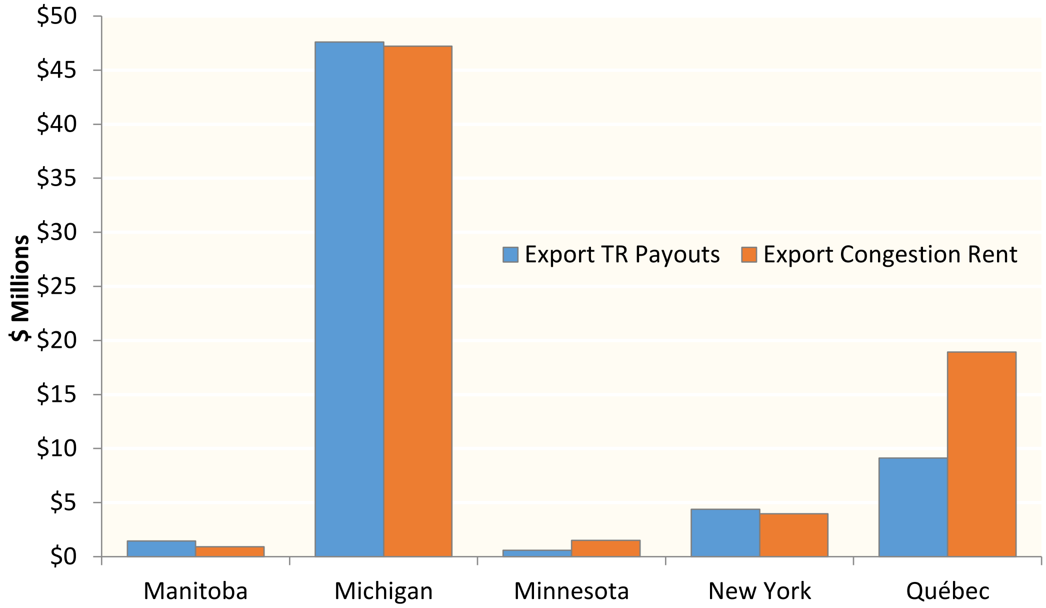
Figure *34* compares the total export congestion rent collected to total TR payouts by intertie for the same period.

Figure 33 – Import Congestion Rent & TR Payouts by Intertie, 2023



Total import TR payouts in 2023 were $4.6 million, while total import congestion rent was $5.2 million, creating a congestion rent surplus of $0.6 million. Much of this surplus was largely emanating from the Québec intertie, partially offset by deficits from the Michigan intertie.

Figure 34 – Export Congestion Rent & TR Payouts by Intertie, 2023



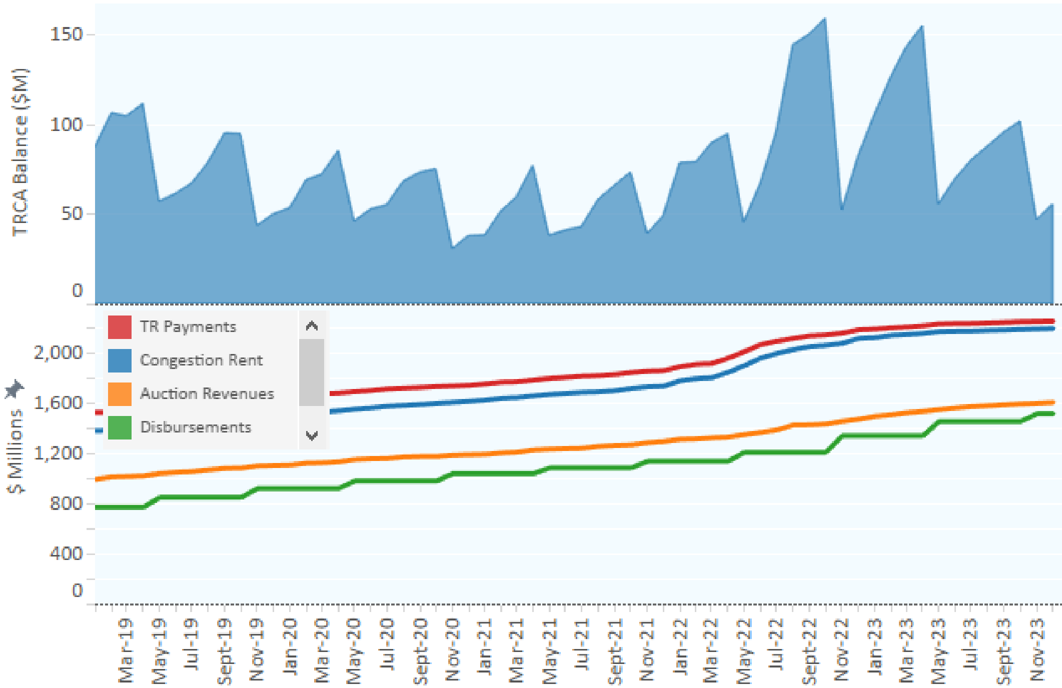
Export TR payouts in 2023 totaled $61.7 million, while export congestion rent totaled $72.5 million to offset it, resulting in congestion rent surplus of $10.8 million, mostly from the Québec intertie. While there was a slight shortfall in congestion rent in the Michigan and New York interties, this was offset by congestion rent surpluses on the Québec and Minnesota interties.

Figure *35* 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 $81.9 million on December 2022 to $57 million on December 2023. The December 2023 balance was $37 million above the reserve threshold of $20 million set by the IESO Board of Directors.[118] This change in balance was composed of:

1. $218.8 million in revenue, specifically:
   - $77.7 million in congestion rent
   - $134.5 million in auction revenues
   - $6.6 million in interest
2. $243.6 million in debits, specifically:
   - $67.8 million in TR payouts
   - $175.8 million in disbursements to Ontario consumers and exporters.

[118] See Chapter 2.2.1 of the IESO's Market Manual 4.4 Transmission Rights Auction.

Figure 35 – Transmission Rights Clearing Account, 2018-2023



Ontario Energy Board

8 OPERATING RESERVE AND ANCILLARY SERVICES

Operating Reserve (OR) is stand-by power or demand reduction which can be called upon with short notice to deal with an unexpected supply shortage. OR is divided into three classes: 10-minute spinning, 10-minute non-spinning, and 30-minute non-spinning reserves. The three types of OR are co-optimally scheduled with energy. Like energy, OR prices are determined every five minutes. Demand for OR is based primarily on reliability standards set by NERC and the Northeast Power Coordinating Council (NPCC).

In previous reports, the Panel has commented on the role of dispatchable loads in the OR market. In its May 2017 report 31, the Panel reported that the IESO scheduled OR from dispatchable loads when they were incapable of providing the stand-by energy reduction required under the market rules. This led to approximately $12 million in inappropriate payments to dispatchable loads for OR services from January 2010 to April 2016.[119]

In 2021, the IESO initiated a process to reconsider long-standing exemptions for several dispatchable loads, citing the Panel's report as a basis for doing so. In July 2022, the Panel submitted a letter to the IESO on their reconsideration of exemptions. In this letter the Panel articulated its view that the existing exemptions appeared to be designed to specifically limit the inappropriate payments to dispatchable loads for OR, but did not address the scheduling of OR by dispatchable loads that they were incapable of providing stand-by energy reductions. The Panel also found that insufficient evidence was provided to support the IESO staff recommendations, including to justify the apparently less stringent exemption conditions being put forth.[120]

Ancillary services are purchased by the IESO to ensure the reliable operation of the bulk grid. Unlike OR, the IESO procures other ancillary services through contracts. The decision to use contracts for these services dates to market open, when the Market Design Committee determined that there would be insufficient competition (too few competitive alternatives to OPG) to operate these as competitive real-time markets like OR.[121] The ancillary services that the IESO contracts for include certified black-start facilities, regulation service, reactive support and voltage control service, and reliability must-run services.[122] Figure 36 illustrates the total payments for OR and ancillary services over the last five years.

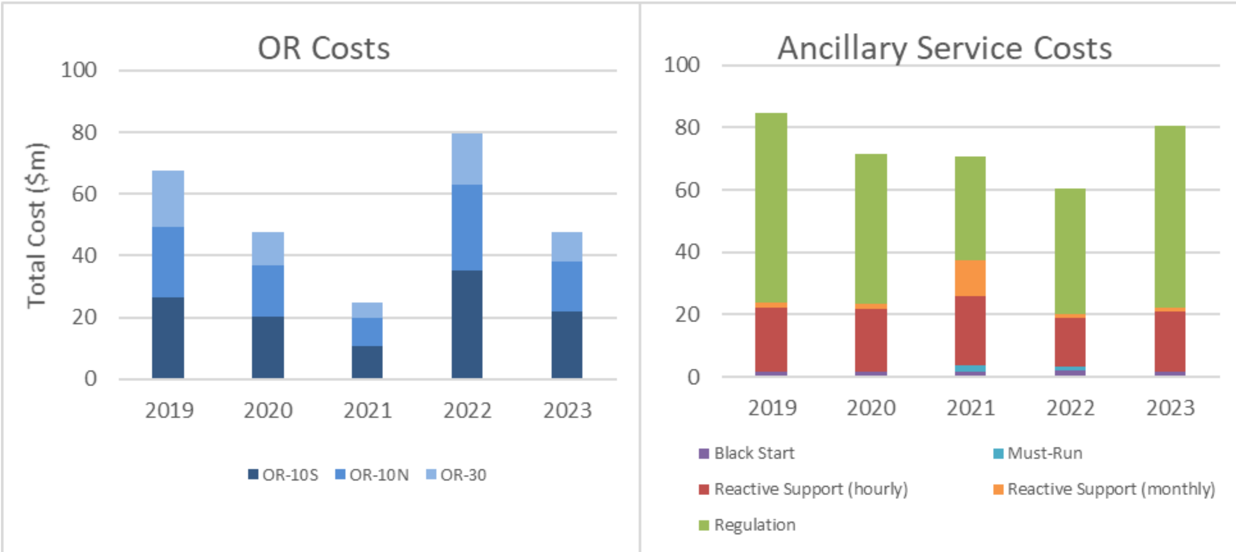
[119] See Section 2.1 of Chapter 3 of the MSP Report 28, 2017.

[120] See MSP letter to the IESO Markets Committee dated July 26, 2022.

[121] See Chapter 2, Exhibit A-Part 6 and Chapter 3 on the portion of Ancillary Services sub-panel, Market Design Committee Final Report (1999).

[122] For more information on each of the ancillary services, see the IESO's website on Ancillary Services.

Figure 36 – OR and Ancillary Service Costs, 2019-2023



In 2023, $47 million was spent on OR and $80 million on ancillary services. These costs represent less than 1% of the total all-in cost of electricity. Like the energy market, the largest player in these markets was OPG who received 26% of the OR payments and 83% of the ancillary services payments.

The Panel anticipates increased competition in these markets through the IESO's recently concluded procurement initiatives, including at least 1,500 MW of new storage resources scheduled to be online through 2027.

9 POLICY, GOVERNMENT, AND COMMUNITY INFLUENCES

As noted in the provincial government's *Powering Ontario's Growth* and the federal government's draft Clean Electricity Regulations, decarbonization and the energy transition have impending deadlines to meet emission reduction targets. Through the work of the Electrification and Energy Transition Panel and the IESO's *Pathways to Decarbonization* report, there is an expectation that the electricity grid will quickly but orderly transition to a low-carbon emissions system while sustaining growth in demand-side electricity and local economic development. There is a delicate balance of meeting these reduction targets – juggling innovative solutions and proven technology, while being cognizant of reliability and affordability. Trying to find this balance is the role of the IESO as the central planner who must navigate through the policies of more than one layer of government.

The Panel recognizes the challenge of trying to find this balance but believes it is essential to consider efficiency and competition in assessing and selecting solutions. Overarching government direction can define the policy objectives, but competitive mechanisms can be used when possible to achieve those objectives.

Over the course of 2023, the IESO received 15 letters and directives from the Minister of Energy. These included directives to engage in competitive long-term procurement activities and directives to implement pilot programs (i.e. small hydro, energy efficiency, interruptible rate pilot). There were also directives for non-competitive bilateral contracts to extend resources (i.e. Brighton Beach Generation Station and Thunder Bay Condensing Turbine Facility) and requests for further assessments on potential projects such as pumped storage (i.e. Meaford and Marmora).

The provincial government released its *Powering Ontario's Growth* report in July 2023. The report outlines the long-term actions to meet increased demand in Ontario – driven from economic growth and electrification. While the report was limited in the analysis to determine those actions, it provided a signal to the market about opportunities for investment in Ontario. The Panel notes that several of the *Powering Ontario's Growth* initiatives, namely nuclear and hydroelectric, will potentially add to OPG's growing portfolio and market share in Ontario. The financing and cost recovery of these comparatively large-scale infrastructure projects raises a number of questions where public capital may be brought to bear on these investments. For example, public financing or publicly-guaranteed financing of such projects offers opportunities to lower interest costs and/or defer recovery of such costs via the Global Adjustment, but may also distort the playing field for future, competitive procurements and add to the total costs ultimately borne by ratepayers if cost recovery is deferred over a very long time horizon.

In addition to activity at the provincial level, the Government of Canada introduced a draft of the new Clean Electricity Regulations which will drastically limit the emissions from natural gas generators across Canada. These proposed regulations have the potential to impact the supply mix in Ontario – the Panel will continue to monitor any new developments and assess its impact on the Ontario market.

By virtue of the IESO's long-term procurement requirements, municipal support is required for projects within their community.[123] This has added an additional layer of complexity to the IESO's recent procurement efforts. Municipal councils essentially have the ability to veto electricity projects in their community. In recognition of this challenge, the Minister of Energy has asked the IESO to make itself available to municipal councils as necessary – to build awareness of the province's electricity system needs. As noted in Chapter 5 – Investments and Long-Term Efficiency, the Panel continues to monitor the procurement efforts to identify opportunities to use competitive drivers, whenever possible, to promote efficiency.

The Panel acknowledges that overarching government strategies can dictate policy objectives but there should be transparent market signals to drive competitive and efficient decisions where practicable.

Table 4 – List of Minister's Directives and Letters to IESO: 2023[124]

1. January 24, 2023	**Minister's Letter on Proposed CIB Financing Approach and Expedited RFP** The Minister of Energy encourages the IESO to work within the Expedited RFP to enable the Canada Infrastructure Bank (CIB)'s proposed approach of offering a standard financing product to submitted stand-alone energy storage proponents, while maintaining the integrity of the procurement process.
2. January 26, 2023 Order in Council 106 / 2023	**Minister Issues Directive on Hydrogen Innovation Fund** The Minister of Energy has directed the IESO to begin developing a Hydrogen Innovation Fund with the goal of investigating, evaluating and demonstrating how low-carbon hydrogen technologies can be integrated into the grid to balance and strengthen Ontario's reliable electricity system.

[123] See the IESO's LT1 RFP document (Section 2.2 (L)).

[124] The information in this table reproduces information from the Ministerial Directives section of the IESO's website.

3. February 2, 2023	**Minister's Letter on Interruptible Rate Pilot** The Minister of Energy has expressed support for the IESO to share with stakeholders the draft pilot rules and contract based on the detailed pilot design proposal that the IESO submitted to the Minister by December 9, 2022. The Minister also supports continued engagement with the hydrogen community to explore options to adapt the Interruptible Rate Pilot and develop a future pilot or program that is tailored for hydrogen producers.
4. February 9, 2023 Order In Council 171 / 2023	**Minister's Directive on the Interruptible Rate Pilot** The Minister of Energy has asked the IESO to design and administer an Interruptible Rate Pilot (IRP) to explore opportunities to enhance demand management on the electricity system with the potential to reduce the cost of electricity for all consumers. The pilot will procure up to 200 megawatts of interruptible demand through a competitive application process. To promote growth in the hydrogen sector, the IESO will report back to the Minister on a plan to design and implement an IRP that is tailored for hydrogen producers in Ontario that employ electrolyzers.
5. February 23, 2023	**Minister Asks IESO to Implement the Clean Energy Credit Registry** The Minister of Energy has asked the IESO to continue to implement the clean energy credit registry following its launch in March 2023, and signaled the province's expectations around program rules, market demand and data-tracking for clean energy credits in Ontario.
6. April 3, 2023	**Updated Summary of Comprehensive Electricity Plan Payments** A summary of monthly payments to come from the Province in the fiscal year 2023/24 (i.e., the fiscal year ending on March 31, 2024) for the government's Comprehensive Electricity Plan has been provided to the IESO by the Minister. The new payments are effective as of April 1, 2023

	and will be reflected in April's electricity market invoice released in May. While subject to change, forecasted amounts were also provided for fiscal year 2024/25 (i.e., the fiscal year ending on March 31, 2025).
7. April 27, 2023 Order in Council 586 / 2023	**Minister Issues Directive on Brighton Beach** The Minister of Energy has directed the IESO to enter into a contract with Atura Power for their Brighton Beach Generating Station. The Direction recognizes the need to re-contract Brighton Beach to ensure reliability in the Windsor-Essex region while transmission infrastructure is developed.
8. July 10, 2023	**Minister's Letter on Pumped Storage** The Minister of Energy has asked the IESO to assess TC Energy and the Saugeen Ojibway Nation's Ontario pumped storage project and Ontario Power Generation and Northland Power's Marmora pumped storage project, to ascertain if any of these two projects would provide positive value to the electricity system. The Minister also asked the IESO to make a recommendation if the unsolicited proposals process is still necessary.
9. July 10, 2023	**Minister's Letter on Powering Ontario's Growth** The Minister of Energy has asked the IESO to lead several initiatives in support of Powering Ontario's Growth; Ontario's Plan for a Clean Energy Future. Activities include beginning the design and consultation of the next competitive procurement for new clean energy resources, developing a contractual approach to a new nuclear build at Bruce Power, and assessing new transmission options that will serve GTA and enable northern development.
10. August 23, 2023 Order in Council 1257 / 2023	**IESO Directed to Move Forward on Long-term Procurement and Small Hydro Program** The Minister of Energy has directed the IESO to continue with the launch this fall of both the Long-Term RFP (LT1 RFP) and the Small Hydro Program to acquire resources to

	meet Ontario's future needs. The LT1 RFP will acquire capacity from new build resources to be online no later than May, 2028, while the Small Hydro Program will provide new contracts for existing hydroelectric facilities with installed capacities of 10 MW and below.
11. October 19, 2023 Order in Council 1529 / 2023	**Minister Issues Directive on Energy Support Programs** The Minister of Energy has issued a directive to the IESO on Indigenous energy support programs effective October 19, 2023. The directive recognizes the IESO's ongoing work in supporting the participation and leadership of First Nation and Métis communities in Ontario's energy sector and increases the budget to $15 million a year.
12. October 19, 2023 Order in Council 1530 / 2023	**IESO directed to enter into a new contract for the Thunder Bay Condensing Turbine Facility** The Minister of Energy directed the IESO to enter into a new contract with Thunder Bay Pulp and Paper Inc. for the Thunder Bay Condensing Turbine Facility, with a contract expiry no later than September 20, 2028.
13. November 14, 2023	**Minister's Letter on Community Engagement** The Minister of Energy has asked the IESO to appear before municipal councils that are considering projects in their communities to provide information on provincial system needs in light of the province's goals for growing a reliable, affordable and clean electricity system.
14. November 27, 2023	**Minister asks IESO to report back on the impacts of the draft Clean Electricity Regulations** The Ministry of Energy has asked the IESO to assess and report back on the impacts of the draft CER on achieving Ontario's goals of ensuring continued access to reliable, affordable and clean electricity.
15. December 7, 2023	**Minister asks IESO for interim Resource Adequacy Update**

	The Minister of Energy has asked the IESO to provide an interim Resource Adequacy Update to provide guidance on upcoming procurements including a forecasted minimum procurement target for new-build non-emitting resources in LT2 RFP and direction for future procurements the IESO expects would have to be undertaken.

10 FUTURE OF ONTARIO MARKET DESIGN

Markets can drive efficiency by creating incentives which align with the market's needs and encourage efficient behavior. Where market design does not align incentives with market needs, inefficient behavior may be induced. In the *State of the Market Report 2022*, the Panel discussed several design elements of the Ontario market which do not promote efficiency. To help address a number of these design inefficiencies, the IESO is presently in the process of completing work on its Market Renewal Program (MRP), with a view to deployment in mid-2025.

10.1 Market Renewal Program

The MRP will bring about key changes to the wholesale market with the objective of improving efficiency, competition, and transparency.[125] These changes are aimed at addressing many of the inefficient elements unique to the Ontario market. Under the program, three key changes to the market will be:

1) Replacement of the Two-Schedule System (2SS) with a single schedule market, reducing the need for out-of-market payments such as Congestion Management Settlement Credits (CMSC).
2) Introduction of the Day-Ahead Market (DAM), which will improve operational certainty for the IESO by reducing financial risk for market participants.
3) Better optimization of scheduling and dispatching resources through the Enhanced Real-Time Unit Commitment (ERUC) program.

These changes are intended to help address two key inefficiencies in the current market design.

First, the single schedule market is aimed at alleviating inefficiencies associated with the uniform price and the 2SS. Ontario currently uses a province-wide uniform price for settlement instead of locational prices. In its first major review of the electricity market shortly after market opening, the Panel highlighted the uniform price as a key market problem.[126]

The 2SS with CMSC payments can distort the incentives for some participants to respond efficiently in the market, at times creating a disconnect between the price that reflects actual system needs and the payment opportunities available to a market participant. The 2SS works by balancing the market two separate times through an unconstrained schedule and a constrained schedule using different parameters. Constrained schedules

[125] The Market Renewal Program's mission statement is: "Market Renewal will deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost" (see also, the IESO's Market Renewal: Mission and Principles).

[126] See MSP Report 1, 2002.

must be formulated in time to issue relevant dispatch instructions for the dispatch interval to which they apply. Unconstrained schedules and prices for a given dispatch interval are presently calculated ex-post, using the most accurate data available for that interval, and initialized with resource-level data determined for the end of the preceding dispatch interval.[127] When physical constraints like transmission limits require some market participants to receive a dispatch instruction in the constrained schedule that is different from the former, that market participant is eligible to receive a CMSC payment. This design opens the door for gaming opportunities and undermines the objective of dispatch efficiency.

In past reports, the Panel has outlined multiple areas where the 2SS with CMSC payments creates misaligned incentives which cause inefficiencies:

- Differences between the uniform price paid by loads and the true (locational) price encourages excess/under consumption depending on the price sensitivity of the load.[128]
- When the uniform price paid by exporters is lower than the true local cost of generation, traders may export power to a lower cost jurisdiction resulting in more demand being served from the higher cost area.[129]
- The uniform price dampens valuable locational signals for long-term investment and retirement. For example, locational prices reward generators with additional profits for building in areas with supply shortages (and high prices). With a uniform price, generators are indifferent to where they build and have no incentive to build according to system locational needs.[130]
- The pay-as-offer nature of CMSC undermines participant's incentive to offer efficiently (at cost), and instead encourages participants to offer above or below

[127] See Section 8.2.1 "Ex-post Prices for Each Dispatch Interval" of Chapter 7 of the Market Rules.

[128] If loads do not respond to the price differences between the uniform and true locational price, then these "allocative efficiency" losses will not arise.

[129] Trading promotes regional efficiency by pulling generation from the lowest cost areas within the region. The uniform price limits the consideration of intra-Ontario locational cost differences, allowing for "productive inefficiency" losses when power from higher cost areas is scheduled instead of lower cost areas.

[130] "Dynamic efficiency" may be eroded as locational signals for investment and retirement are reduced.

costs. This can lead to dispatch inefficiencies and unwarranted payments. The Panel has termed this behavior "nodal price chasing".[131]

The introduction of locational marginal prices is also anticipated to stimulate competition and efficiency by rewarding and incentivizing lower cost generation. Under the current regime with CMSC, there is limited incentive to improve the management of congestion when generators are compensated for lost imputed operating profits as implied by the market schedule. Additionally, the current system does not adequately signal or incentivize the market to respond to locational cost differences across Ontario. In Texas (ERCOT), a move from zonal prices to locational marginal prices was estimated to have reduced prices by 2%.[132] Similarly, the move to nodal prices in California in 2009 was found to improve dispatch of the gas fleet by 2%.[133]

Second, the DAM and ERUC programs are intended to improve the scheduling and commitment of dispatchable generation.[134] These programs will replace the Real-Time Generation Cost Guarantee program which compensates combined-cycle generators for certain start-up and fuel costs, out-of-market, using a non-competitive process.[135] Non-quick start units are then asked to offer and operate ignoring these costs. The intention of the program is to mitigate the risk of market participants not starting their generation units in times when they are uncertain they will be dispatched sufficiently to recover those costs. But this can result in productive inefficiencies in the short-run when demand is not served using the lowest cost resources due to offers not truly being reflective of generation cost. The program also acts to suppress market prices below efficient levels as it removes the incentives for these frequent price-setting generators to reflect fixed start-up costs into their offer prices. The program is designed to favor reliability by ensuring non-quick start resources are brought on-line during times of increased needs, but it suppresses prices at these very times. This weakens price signals and reduces rewards for other market participants to be available at these times.

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[131] "Nodal Price Chasing" refers to the behavior of participants to offer just above or below the nodal price to maximize CMSC payments. If suppliers believe they will get constrained-on, they have incentive to offer as high as possible while still getting dispatched (offering just below the nodal price) to maximize their expected payment. Conversely, if they believe they will get constrained-off, they have incentive to offer as low as possible while still not getting dispatched (offering just above the nodal price). Similar incentives exist on the demand side. The root of the issue is CMSC payments are designed to compensate suppliers according to their offers, rather than a price determined through the competitive market (see also, Chapter 4.2 of MSP Report 7, 2005 and Chapter 3 of MSP Report 37, 2002).

[132] See "Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?" by Zarnikau, et al. (2014).

[133] See "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets" by Wolak, Frank (2011).

[134] See Market Renewal Program: Energy Business Case (October 22, 2019).

[135] The DAM and ERUC programs will also replace the day-ahead commitment program (DACP). The DACP is also designed to compensate for these costs, but uses a more competitive process and three part offers for start-up, speed-no-load and incremental energy costs.

The DAM creates a financially binding Day-Ahead Market which provides more certainty around next-day operations, improving reliability and reducing the need for costlier out-of-market actions. The ERUC program is intended to improve efficiency by optimizing the scheduling of resources over multiple hours. When creating the optimized schedule, ERUC should account for key generator characteristics such as minimum loading points. Under the current design, the optimization algorithm looks at each hour in isolation and does not consider some of these key generator characteristics. This results in the need for out-of-market actions which are costlier and less competitive.

The IESO anticipates that 18 of the previous Panel market design recommendations will be addressed through the Market Renewal Program. To this end, the Panel intends to release an MRP pre-deployment report by early 2025 to set out its plans to:

- Assess market efficiency and competition, consistent with its mandate outlined in OEB By-Law #2, as the wholesale market undergoes its biggest stepwise change since market opening;
- Following deployment, evaluate how MRP has addressed the market inefficiencies raised in at least 18 past MSP recommendations where the MRP program was identified as the remediation measure for the underlying issue; and
- Identify key indicators of MRP's success and adapt the MSP's market monitoring program accordingly, drawing from the practices of other wholesale market monitoring programs in jurisdictions with similar design features.

Appendix A

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 behavior 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:[136]

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.

[136] See Section 4.1.1 of OEB By-law #2.

Appendix B

1. Electricity Cost Data

Figure 37 – All-In Unit Cost, Monthly 2022-2023

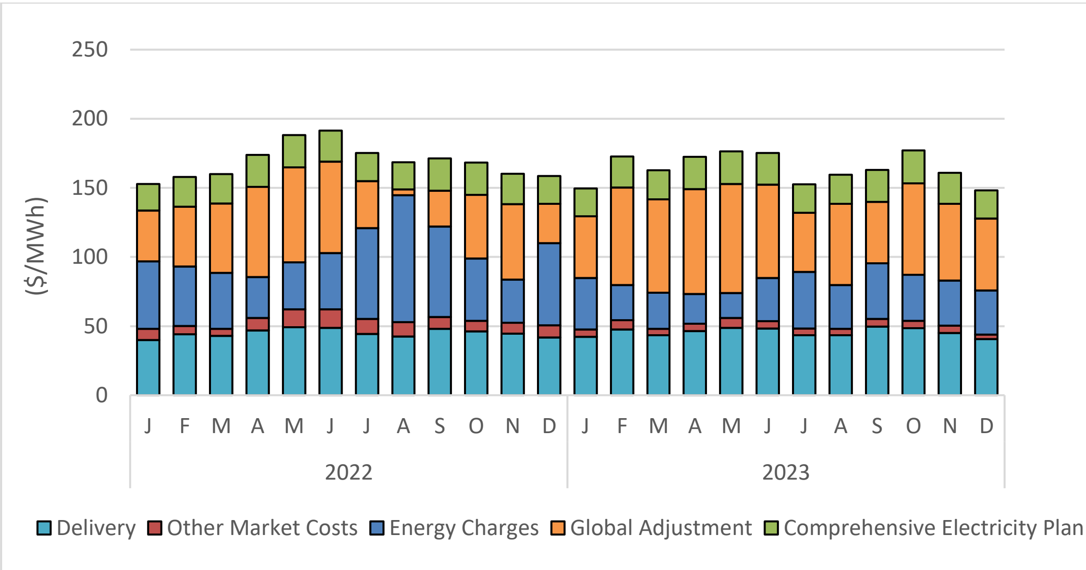


Figure 38 – All-In Costs, Monthly 2022-2023

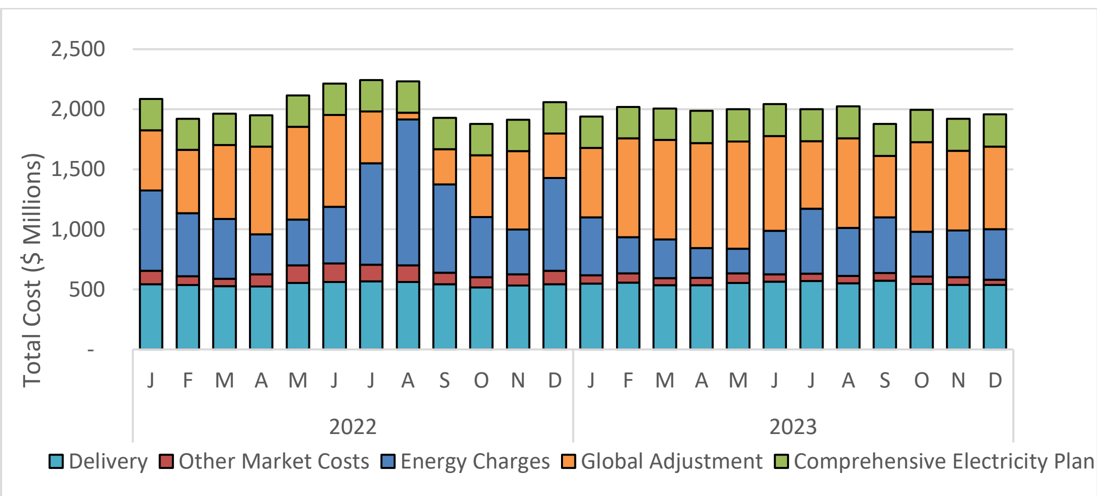


Figure 39 – Generation Unit-Costs, 2014-2023

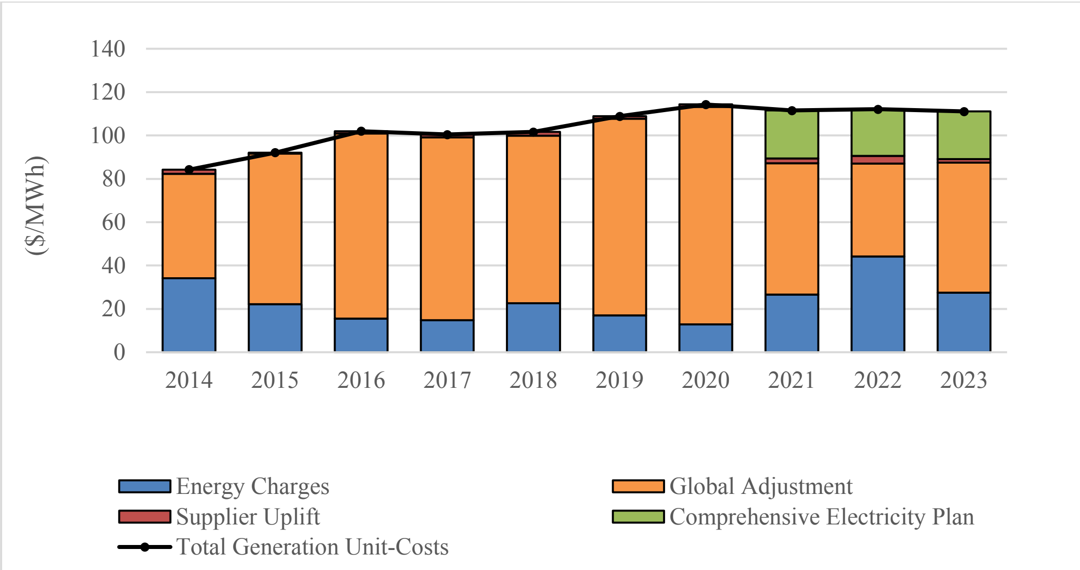


Figure 40 – Generation costs per MWh by fuel type, 2023

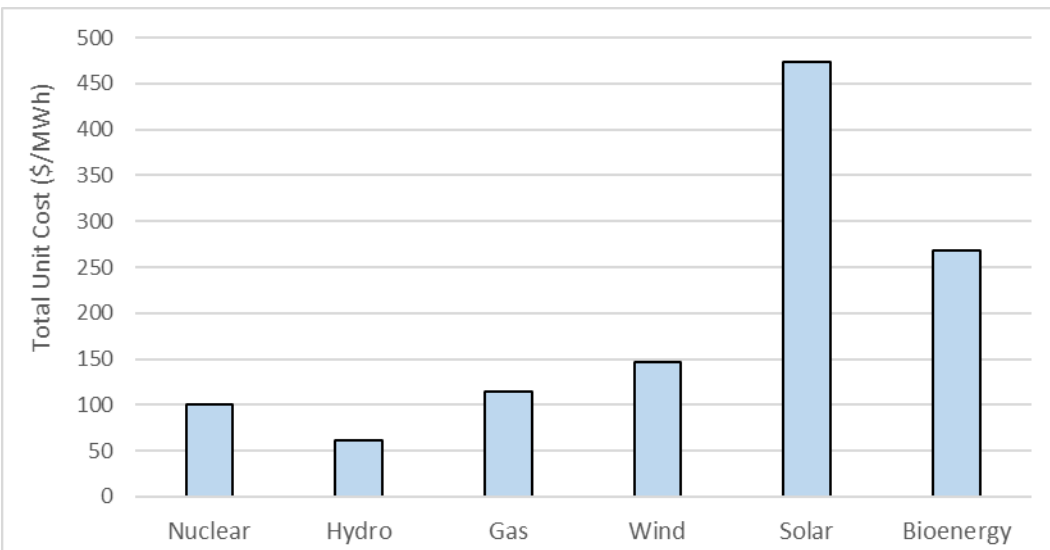


Figure 41 – Annual Global Adjustment by Component, 2014-2023

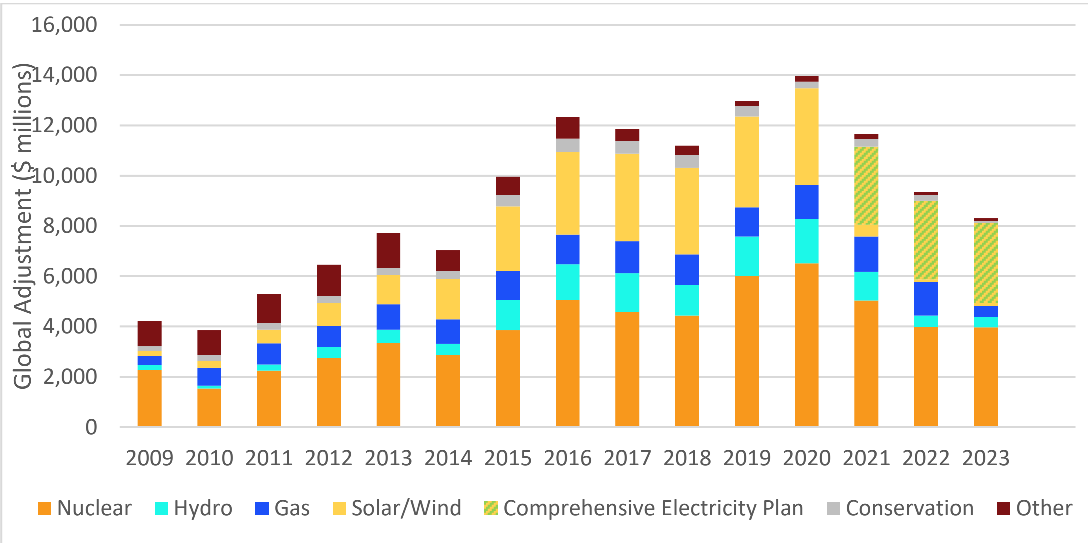


Figure 42 – Government Program Spending and Consumer Cost, 2014-2023

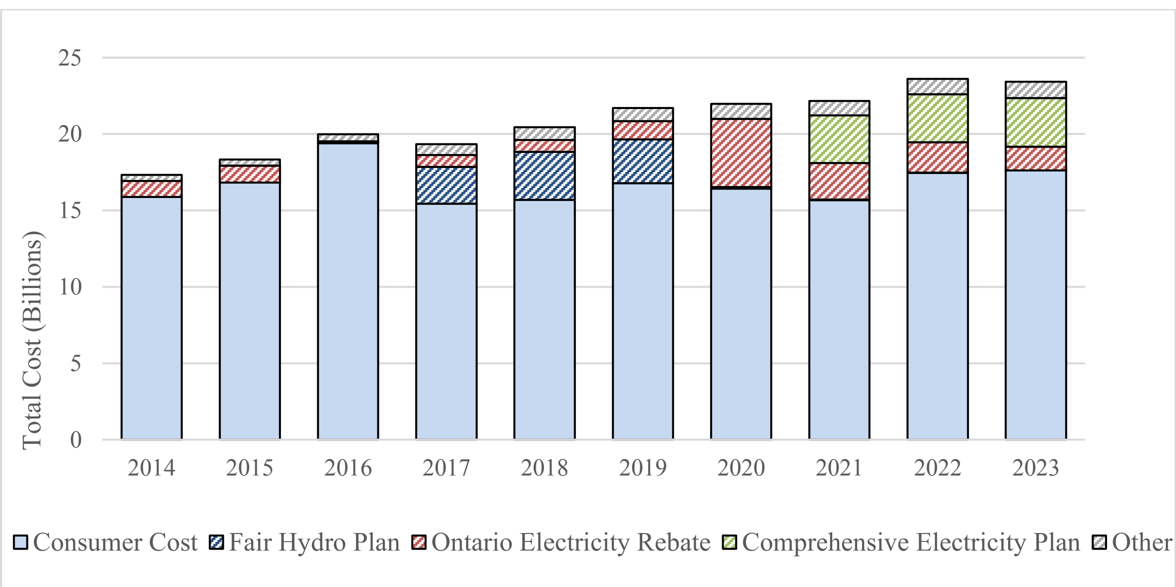
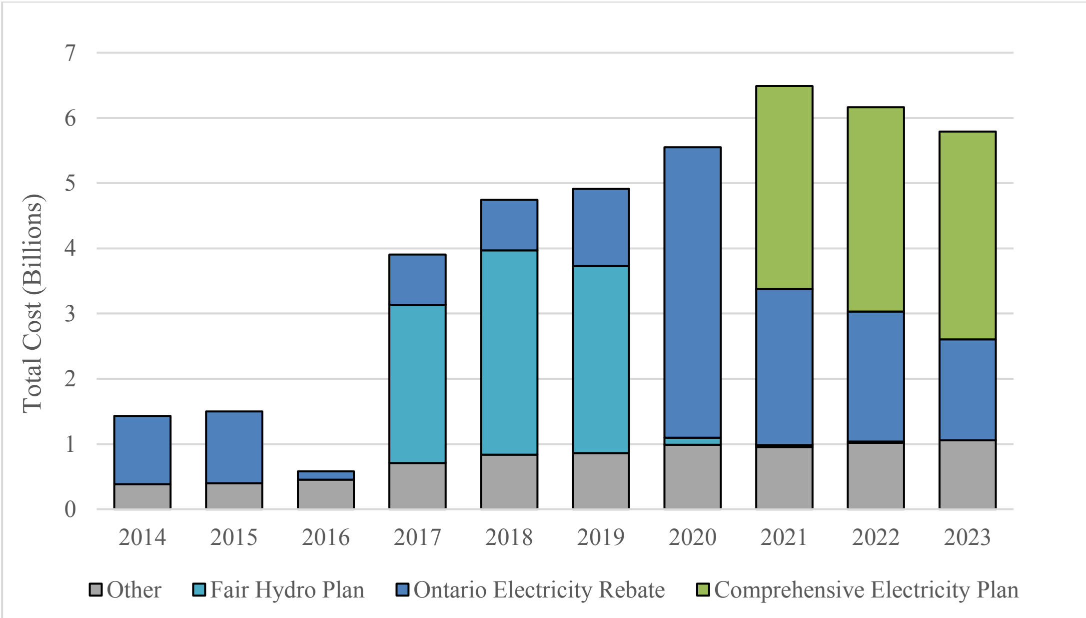


Figure 43 – Government Program Spending, 2014-2023



2. Demand, Supply, Price Outcomes

Figure 44 – Annual Ontario Demand, 1997-2023

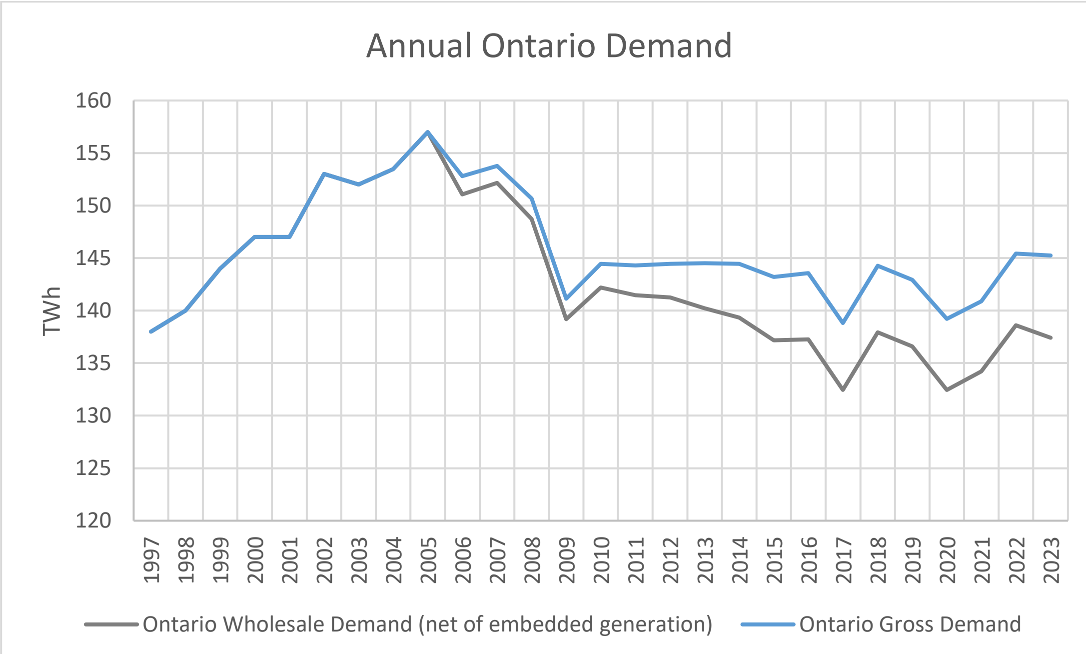


Figure 45 – Average Energy Offer Curve Comparisons, 2022-2023

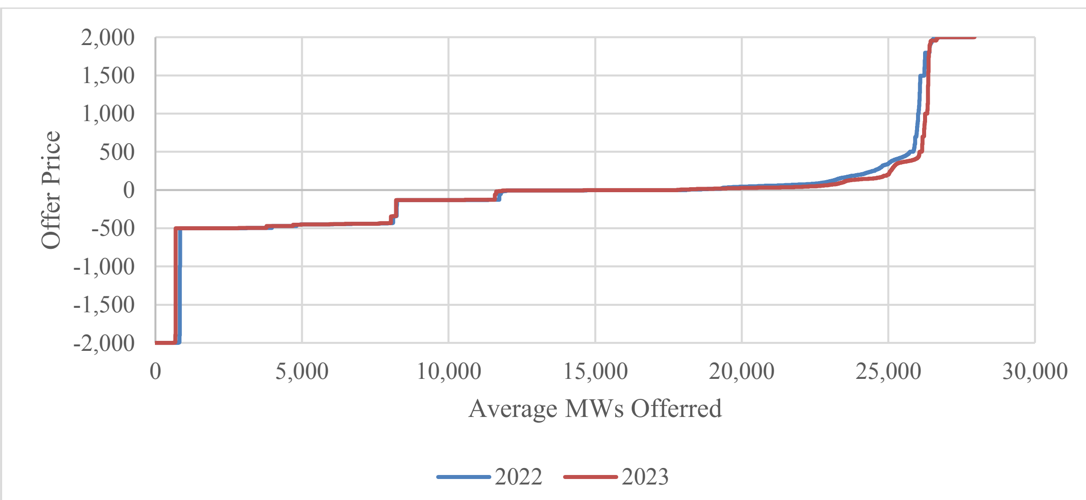
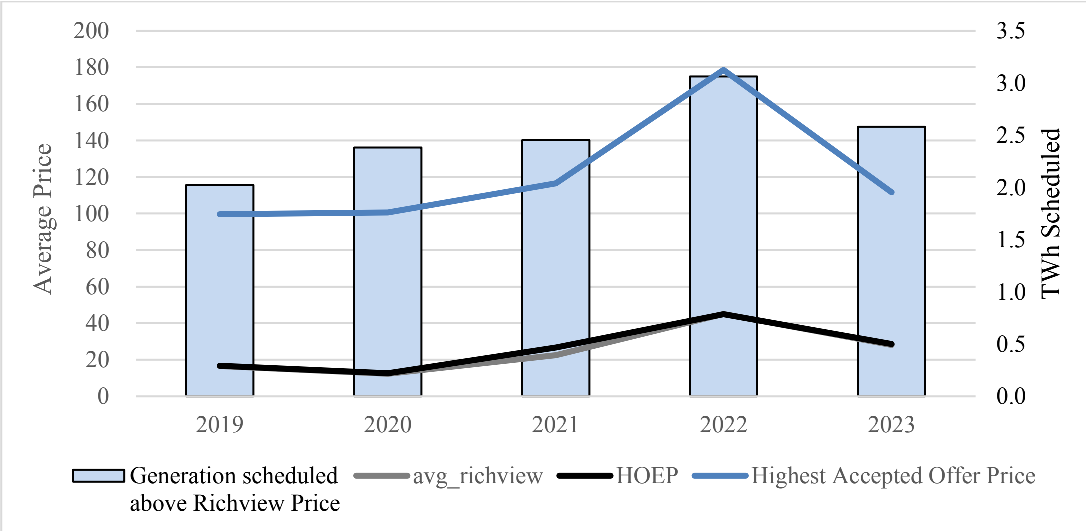


Figure 46 – Highest Accepted Offer Price vs HOEP and Richview Price, 2019-2023



3. Consolidated list of IESO capacity purchases

Table 5 – Historical Capacity Auction Results: Summer Obligation Period

(May 01 – Oct 31)	Target (MW)	Actual (MW)	Capacity Auction Clearing Price ($/MW-day)
2021	700	943.2	197.58
2022	1,000	1,221.3	264.99
2023	1,200	1,393.1	313.79
2024	1400	1,811.5	367.41

Table 6 – Historical Capacity Auction Results: Winter Obligation Period

(Nov 01 – April 30)	Target (MW)	Actual (MW)	Capacity Auction Clearing Price ($/MW-day)
2022/2023	500	806.1	60
2023/2024	750	1,012.7	130.78
2024/2025	850	1,310.8	146.96

Table 7 – E-LT1 Result: Storage Category

Proponent	Nameplate Capacity (MW)	Summer Contract Capacity (MW)	Winter Contract Capacity (MW)	Fixed Capacity Payment ($/MW Business Day)	Fixed Capacity Payment ($/MW-day)[137]
Hagersville Battery Storage Inc	300	285	285	786.25	538.36
Napanee BESS Inc.	265	250	250	896.92	675.97
Tilbury Battery Storage Inc	80	76	76	774.50	530.48
Walker BESS 4 Limited Partnership Walker BESS 4	4.999	4.749	4.749	997.00	682.88
Walker BESS 4 Limited Partnership Walker BESS 5	4.999	4.749	4.749	998.00	683.56
Walker BESS 4 Limited Partnership Walker BESS 6	4.999	4.749	4.749	998.99	683.56
York (Battery) LP	120	114	114	825.50	565.07
1000234763 Ontario Inc SFF 06	4.99	4.74	4.74	1,477	1,011.64
1000234763 Ontario Inc 903	4.99	4.74	4.74	1,477	1,011.64
1000234763 Ontario Inc OZ-1	4.99	4.74	4.74	1,477	1,011.64

[137] Calculated as (Fixed Capacity Payment * 250 business days)/no. of days in a year. Note that some IESO procurement mechanisms do not recognize bank holidays.

Proponent	Nameplate Capacity (MW)	Summer Contract Capacity (MW)	Winter Contract Capacity (MW)	Fixed Capacity Payment ($/MW Business Day)	Fixed Capacity Payment ($/MW-day)[137]
Arlen Energy Storage 1 LP	20	19	19	1,224	838.36
Goreway (Battery) LP1	50	47.5	47.5	1,007	689.73
Vaughan 1E Energy Storage 1 LP	20	19	19	1,186	812.33
Vaughan 3 Energy Storage 1 LP	40	38	38	1,028	704.11
Walker BESS 4 Limited Partnership	4.999	4.749	4.749	969	663.70

Table 8 – E-LT1 Result: Non-Storage Category

Proponent	Nameplate Capacity (MW)	Summer Contract Capacity (MW)	Winter Contract Capacity (MW)	Fixed Capacity Payment ($/MW Business Day)	Fixed Capacity Payment ($/MW-day)
East Windsor (Expansion) L.P	106	81	100	894.75	612.84
Greenfield South Power Inc	212.5	175	195	1,195.00	818.49

Table 9 – Same Technology Upgrade Result

Proponent	Facility	Average Capacity (MW)	Average Upgrade Capacity (MW)	Fixed Capacity Payment ($/MW Business Day)	Fixed Capacity Payment ($/MW-day)
Portlands Energy Centre L.P.	PORTLANDS ENERGY CENTRE	550	50	n/a	n/a
Portlands Energy Centre L.P.	HALTON HILLS GENERATING STATION	641.5	31.5	n/a	n/a
Goreway Station Partnership	GOREWAY POWER STATION	839	40.4	n/a	n/a
Greenfield Energy Centre L.P.	GREENFIELD ENERGY CENTRE	1,005	35	n/a	n/a
Thorold CoGen L.P	THOROLD COGENERATION PROJECT	241.6	23	n/a	n/a
St. Clair Power L.P.	ST. CLAIR ENERGY CENTRE	577	68.5	n/a	n/a
York Energy Centre L.P.	YORK ENERGY CENTRE	393	38	n/a	n/a
	Total	***4247.1***	***286.4***	n/a	n/a
			Weighted average price	***537***	***367.81***

Table 10 – Medium-Term RFP Result

Proponent	Nameplate Capacity (MW)	Contracted Seasonal UCAP (MW) – Summer	Contracted Seasonal UCAP (MW) – Winter	Capacity Price ($/UCAP MW-Business Day	Fixed Capacity Payment ($/MW-day)
Melancthon Wolfe Wind LP	67.5	5.04	12.32	469.95	321.88
Atlantic Power Limited Partnership	20.9	20.506	22.182	250.00	171.23
Cochrane Power Corporation	42.0	25.02	28.73	265.00	181.51
TransAlta (SC) LP	499.0	186.44	239.04	469.95	321.88
Greater Toronto Airports Authority	127.64	71.66	77.69	470.00	321.92
Total	***757.04***	***308.67***	***379.96***		