ONTARIO ENERGY BOARD

Market Surveillance Panel

State of the Market Report 2022

December 2023

Ontario Energy Board

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List of Abbreviations

2SS	Two-Schedule System
AG	Auditor General of Ontario
CSMC	Congestion Management Settlement Credits
DA-PCG	Day-Ahead Production Cost Guarantee
ERA	*Electricity Restructuring Act, 2004*
FIT	Feed-In-Tariff
GA	Global Adjustment
HIM	Hydro Incentive Mechanism
HOEP	Hourly Ontario Energy Price
IAM	IESO-administered Market
ICI	Industrial Conservation Initiative
IOG	Intertie Offer Guarantee
IESO	Independent Electricity System Operator
LMP	Locational Marginal Pricing
MCP	Market Clearing Price
MPMA	Market Power Mitigation Agreement
MRP	Market Renewal Program
MSP	Market Surveillance Panel
OEB	Ontario Energy Board
OER	Ontario Electricity Rebate
OPA	Ontario Power Authority
OPG	Ontario Power Generation Inc.
OR	Operating Reserve
PD	Pre-Dispatch
RFP	Request for Proposals
RT	Real-Time
RT-GCG	Real-Time Generation Cost Guarantee

1 Executive Summary

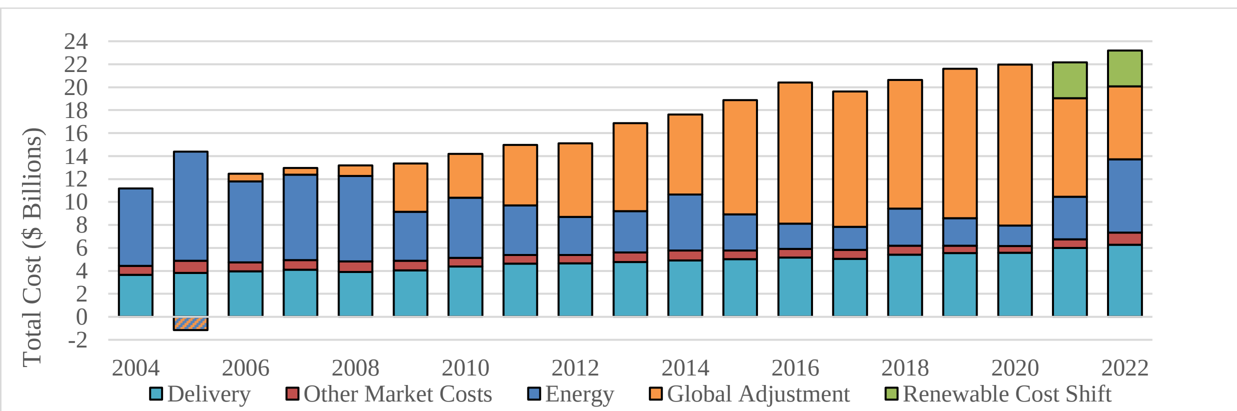
The Market Surveillance Panel (MSP or Panel) serves as the market monitor for the Ontario wholesale electricity markets, which are administered by the Independent Electricity System Operator (IESO). Mandated among other things to monitor, evaluate and report on the efficiency and competitiveness of the wholesale markets, the Panel is an integral part of the oversight framework. The Panel provides independent evaluation and analysis of the 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 2022 State of the Market Report offers an assessment of the performance of the IESO-administered markets, including the Panel's finding that the market is reasonably efficient in the short-term. The year 2022 marks the 20th anniversary of the wholesale market opening in Ontario. In this spirit, the report examines the longer-term market trends to both explain the current status of competition and efficiency in the market and provide insight into how the current state of the market came to be.

All-in Cost of Electricity

The total cost of providing electricity in Ontario has more than doubled since 2004. This total cost, known as the "all-in cost", was $23.1 billion in 2022.[1] The rise in all-in costs can largely be attributed to the procurement of generation in support of government policy objectives. This includes the replacement of coal generation with cleaner but higher total cost sources of generation, including renewables, natural gas and nuclear generation. Procurements through the 2010s contributed to excess capacity conditions, in part due to a decline in Ontario demand. In 2022, the Ontario government spent $6.2 billion in 2022 to help mitigate electricity costs for consumers, with those costs remaining below 2016 levels. The figure below illustrates the all-in cost of electricity by major components annually since 2004.

Figure ES1 – Total All-in Cost, 2004-2022



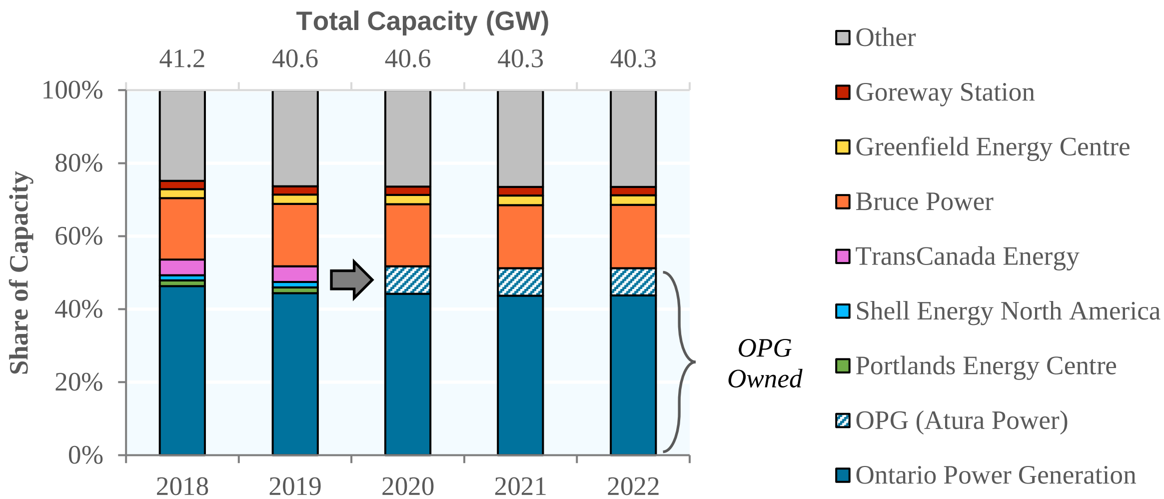
[1] "All-in cost" includes the cost of energy traded at the wholesale market price (Energy), Global Adjustment, the Renewable Cost Shift (a government program also referred to as the Comprehensive Electricity Plan), Delivery (transmission and distribution) and Other Market Costs including payments for reliability and ancillary services, congestion management, IESO administration charges, the Debt Retirement Charge (phased out by 2018) and out-of-market commitment programs.

Competition

Overall, the level of market concentration in the IESO-administered markets (IAM) remained relatively unchanged in 2022. Ontario Power Generation Inc. (OPG) remained the largest supplier in the market, controlling 51% of the province's generating capacity and 68% of the price-sensitive capacity.[2] This level of concentration has been stable since OPG's multi billion-dollar gas plant acquisitions in 2019 and 2020. Since market opening, OPG has been the single largest, dominant supplier in the market. Annual shares of capacity in the IAM from 2018 to 2022 are illustrated in Figure ES2 below.

Despite the high level of concentration, the Panel views the market to be reasonably efficient in the short-term. While market design issues persist, broader concerns around lack of competition in the day-to-day operations are largely mitigated through regulations and contracting.

Figure ES2 – Registered Capacity by Market Participant, 2018-2022



Investment and Future Market Needs

2022 was an important and notable year for investment, procurement, and the long-term efficiency of the market. In 2022, the province's growing capacity needs took center stage and progress was made on several procurement efforts. The Panel continues to closely monitor these efforts and their implications on the long-term efficiency of the market. Similar to the past, contracts signed to secure investments may have significant implications on market costs, efficiency, and competition for years to come.

Unlike much of the last decade, the Panel anticipates broad changes coming to the IESO markets over the coming years. Of particular note, is the deployment of the IESO's Market Renewal Program (MRP) scheduled for mid-2025. The Panel has been a proponent of the objectives of MRP and anticipates that MRP should improve market efficiency in the short-term.

[2] 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.

Electrification and continued decarbonization efforts are also expected to bring sizeable changes to the IAM. The IESO's Pathways to Decarbonization report estimated that the cost of decarbonizing Ontario's electricity system could be $400B over the next 25 years. The development options explored in that report are but one of several options that present themselves to policymakers, the IESO, and market participants over the coming decades. A competitive and efficient market can be a vehicle to effectively guide these large investments, allocate attendant financial risks, and manage the high costs. Efficiency and cost management are of particular importance given the scale of the investments needed.

Large investments also offer an important opportunity to increase competition and improve efficiency in the market. After more than a decade of over-supply, the IESO is currently in the midst of procuring at least 4,000 MW of new-build capacity. Additional opportunities to improve competition and efficiency will arise through the expiration of generator contracts beginning in 2030. The Panel supports the IESO's recent efforts to promote competition through a competitive Request for Proposals (RFP) process. An inherent weakness of the hybrid market has been the increasing cost of capacity procurement, often driven by policies, and with most risks socialized back to the ratepayer or taxpayer. Moving forward with the energy transition, the IESO should employ competitive procurements as much as possible. In the same vein, greater independent regulatory oversight and transparency of the need for investment would help provide more accountability to the procurement process and protect against unnecessary and costly investment errors.

Finally, the assessment of intertie trading shows that there could be a potential for efficiency improvement in the IAM. The Panel anticipates changes to intertie trading as part of MRP, including improved efficiency of import and export scheduling driven by the day-ahead market and the use of locational prices at interties.

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 2022 State of the Market report provides the Panel's annual general assessment of the state of the IAMs, including their efficiency and competitiveness.[3] The Panel publishes its annual general assessment to increase public awareness of the markets' overall performance and to highlight areas of potential improvement. The Panel's previous general assessment was released as part of Monitoring Report 36 in March 2022.[4]

Monitoring the competitiveness and efficiency of a market is an essential part of all restructured 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 a reliable supply of electricity.

The Ontario electricity industry operates as a hybrid market arrangement 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 OPG's generation assets.[5] The Government of Ontario also plays a key role in the hybrid market through ministerial directive powers. At times, government policies may be in tension with 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 remaining chapters of this report provide details on key areas the Panel monitors for competition and efficiency in the IAM:

- 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 highlights key inefficiencies in market design the Panel has commented on extensively in the past and continues to monitor.
- Chapter 7 provides an assessment of intertie trading.
- Chapter 8 offers a brief overview of the Operating Reserve (OR) and Ancillary Services markets.
- Chapter 9 adds forward looking commentary on anticipated developments within the IAM.

[3] See OEB By-law #2, Market Surveillance, Article 7 (Ontario Energy Board 2020a). 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.

[4] See the Panel's Monitoring Report 36 published March 2022, Section 1: (Market Surveillance Panel 2022).

[5] 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.

3 All-In Cost of Electricity

The “all-in cost” of electricity reflects the total cost of serving electricity consumers in Ontario and exporters. In 2022, the all-in cost was $23.1 billion. This chapter provides an overview of the components of the all-in costs, 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 Costs

Figure 1 displays the annual all-in cost, which is the total amount paid into the electricity system by Ontario consumers, exporters, and through government funding for the period 2004 to 2022. Figure 2 presents the annual “all-in unit cost”, which is the all-in cost per MWh of energy consumption for the same period. Table 1 provides a detailed breakdown of the all-in cost and all-in unit cost by components for 2022.

Figure 1 – All-in Costs, 2004-2022

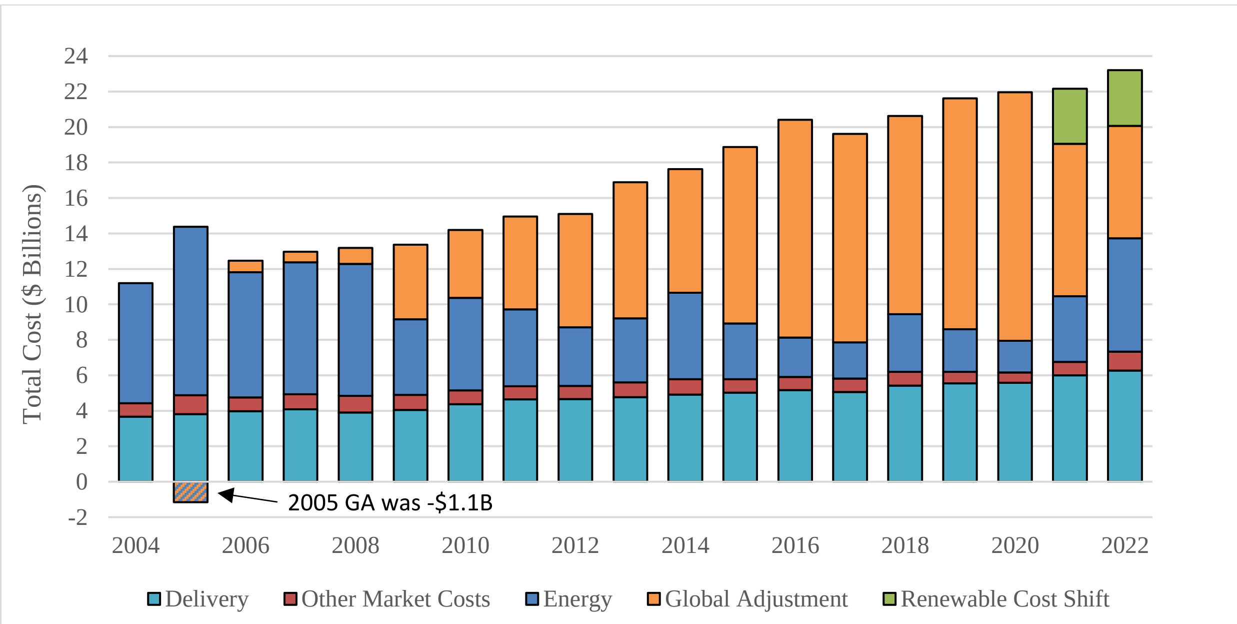


Figure 2 – All-in Unit Cost, 2004-2022

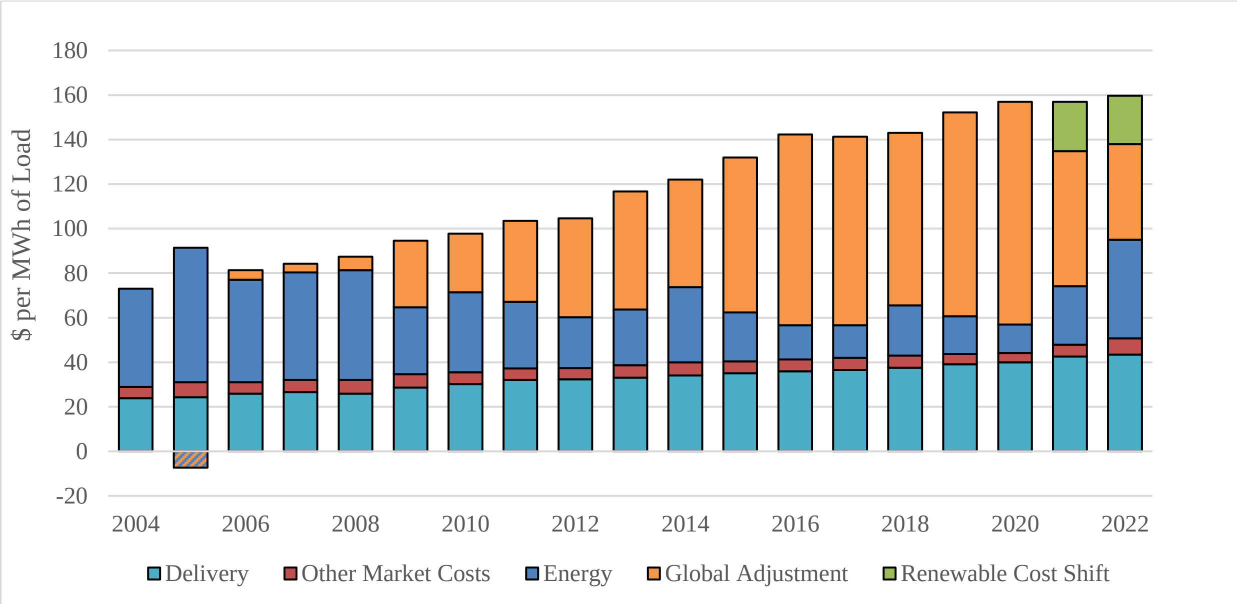


Table 1 – All-in Cost Components, 2022[6]

	All-in Cost ($m)	All-in Unit Cost ($ per MWh)
Energy Traded at the Wholesale Market Price	**6,385**	**44.17**
Global Adjustment	**6,227**	**43.08**
Contracts	2,740	18.95
OPG Regulated Assets	2,146	14.85
FIT/MicroFIT Contracts	1,183	8.18
Conservation	158	1.10
Renewable Cost Shift amount	**3,131**	**21.66**
Other Market Costs	**1,064**	**7.36**
Congestion Management	277	1.92
Uplift	229	1.58
IESO Administration Charge	207	1.43
Operating Reserve	80	0.55
Ancillary Services	60	0.42
Other	211	1.46
Delivery	**6,277**	**43.42**
Distribution	4,091	28.30
Transmission	2,186	15.12
All-in Cost Total	**23,084**	**159.71**
Government Programs	-6,178	-42.74
Renewable Cost Shift	-3,131	-21.66
Ontario Electricity Rebate	-1,998	-13.83
Other	-1,048	-7.25
Consumer Costs (All-in Cost Net of Government Programs)	**16,906**	**116.96**

The nominal all-in unit cost of electricity in Ontario has doubled since 2004. The all-in unit cost in 2004 was $73 per MWh compared to nearly $160 per MWh in 2022. This marks a 119% nominal increase or a 50% increase in real terms (adjusting for inflation).[7]

Energy Traded at the Wholesale Market Price and the Global Adjustment (GA) are the first two components of the all-in cost. These principally represent the amounts paid to generators for electricity production.[8]

[6] Government Program costs are published by the IESO, see (Independent Electricity System Operator 2022f). Delivery costs come from the OEB, see (Ontario Energy Board 2022c). All other costs are compiled from IESO settlements data and may differ slightly from other publications due to adjustments and groupings.

[7] Since 2004, the all-in unit cost grew 4.2% annually, double the 2.1% inflation rate over the same period.

[8] In 2022, less than 3% of the Global Adjustment was spent on conservation and was not paid to generators.

Energy Traded at the Wholesale Market Price

Energy is traded in the IESO-administered markets at the Wholesale Market Price. This wholesale price is determined in the IESO's competitive wholesale energy market by the forces of supply and demand. The wholesale market clearing price (MCP) is determined every 5 minutes. The Hourly Ontario Energy Price (HOEP) is calculated as the average of the twelve 5-minute MCP within the hour. These prices reflect the marginal cost of producing electricity in Ontario.

Global Adjustment

The Global Adjustment (established in 2005) is the mechanism used to (i) reconcile differences between payments made to generators at the competitive wholesale market price and payments made at regulated rates or contracts that differ from the wholesale market price; and (ii) fund the province's conservation and demand management programs.[9] 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 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.[10]

Renewable Cost Shift

Part of the contractual payments owed to generators have been transferred from the GA to the tax base as part of a program called the Renewable Cost Shift. This is described in more detail under section 3.3.

Other Market Costs

The "Other Market Costs" include payments to generators for reliability and ancillary services. They also include payments for congestion management, IESO administration charges, and 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. They also included debt retirement charges which ended in 2018.

Delivery

The all-in cost also includes the costs for "Delivery", which represents the amount paid to the 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. Delivery and other market costs have increased at about 3% annually.

Consumer Costs

Consumer costs are the costs paid by Ontario electricity consumers (including ratepayers) and exporters. Consumer costs is the difference between the all-in cost and the amount of costs covered by Ontario government funding programs.

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[9] See O. Reg. 429/04. In 2005, the GA represented a rebate to consumers of $1.1 Billion.

[10] The price and revenue guarantees also provide consumers with an involuntary hedge against high wholesale market prices.

3.2 Analysis of Costs

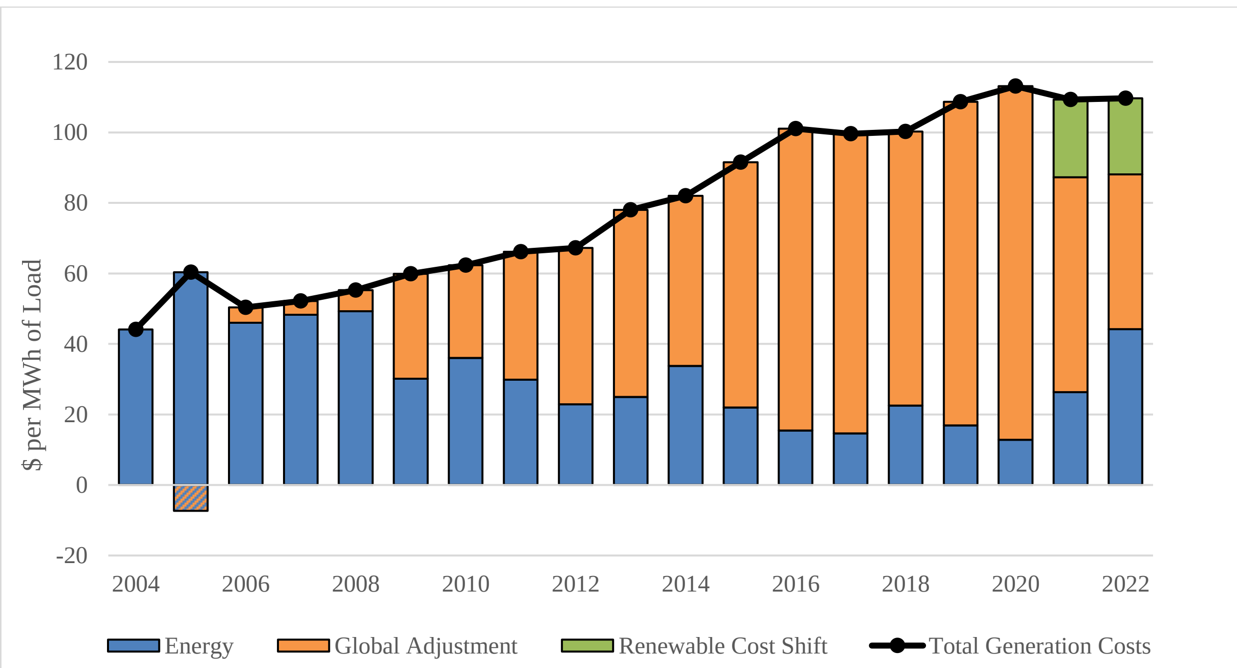
The increase in the all-in cost over the past two decades has been driven by increases in the generation cost components which are (i) the cost of energy traded in the wholesale market (Energy) and (ii) the GA. Together, these costs have increased at an average rate of 5.4% annually and have more than doubled since 2004.[11] This is nearly double the rate of other all-in cost components such as delivery.

As described in section 3.1 above, generators primarily earn revenues by selling their energy in the wholesale electricity market and through GA payments as needed to bring them to their contracted or regulated payments. Since 2008, generators have earned a shrinking share of revenues through the wholesale electricity market, while a growing share of revenues have been earned through GA payments. This has deepened the need for contracts as a key revenue source for generators. This is discussed more in section 4.2.

In 2008, generators earned nearly 80% of their revenues through the electricity market. This fell to only 11% by 2020. In 2022, this share increased to 37% as market prices increased due to rising gas prices and tighter supply conditions.

Figure 3 below illustrates the increase in generation costs since 2004.

Figure 3 – Generation Unit-Costs, 2004-2022



The increase in generation costs in Ontario since market opening can be largely attributed to the province's generation procurements in support of government policy objectives. This includes the replacement of coal generation with higher total cost sources of generation, including renewables,

[11] Spikes in 2005 were largely due to extreme shortage conditions.

natural gas and nuclear generation. Additionally, procurement through the 2010s contributed to excess capacity conditions, further increasing costs.[12]

In support of environmental, social, and economic policy goals, all coal-fired generation in Ontario was decommissioned by May 2014. This has helped reduce electricity sector carbon emissions in 2022 by 28 megatonnes per year compared to 2005 levels, an 84% reduction.[13] The coal generation was largely replaced with gas, refurbished nuclear, wind, and solar. Figure 4 below shows installed capacity levels by fuel type annually since 2010.

Figure 4 – Installed Capacity by Generation Source, 2010-2022

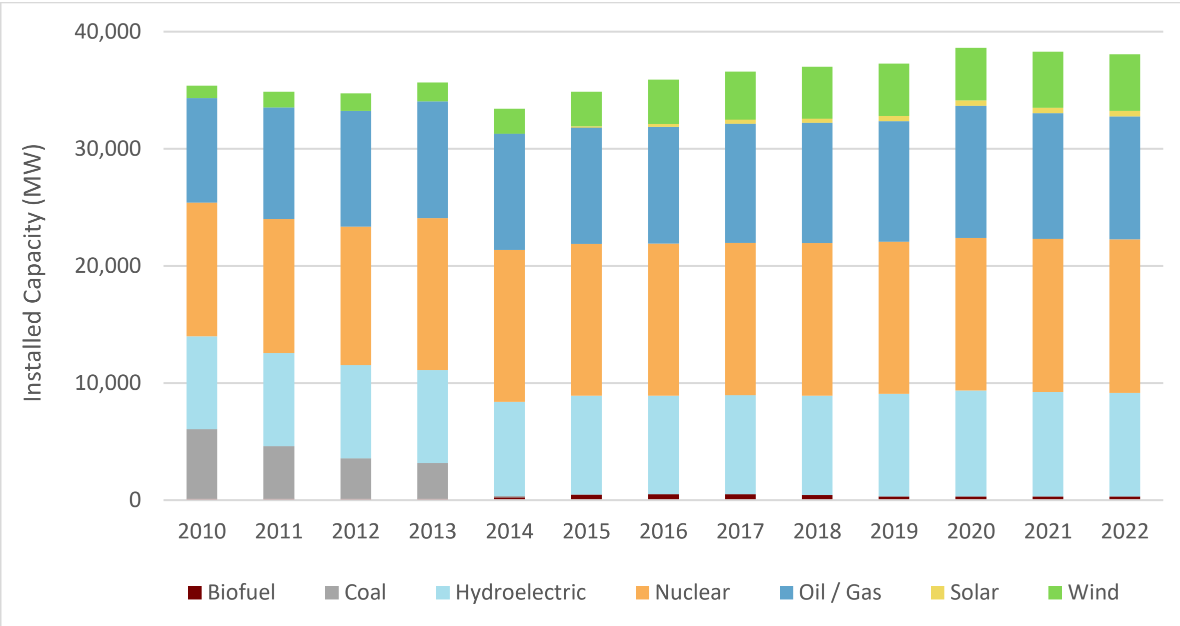


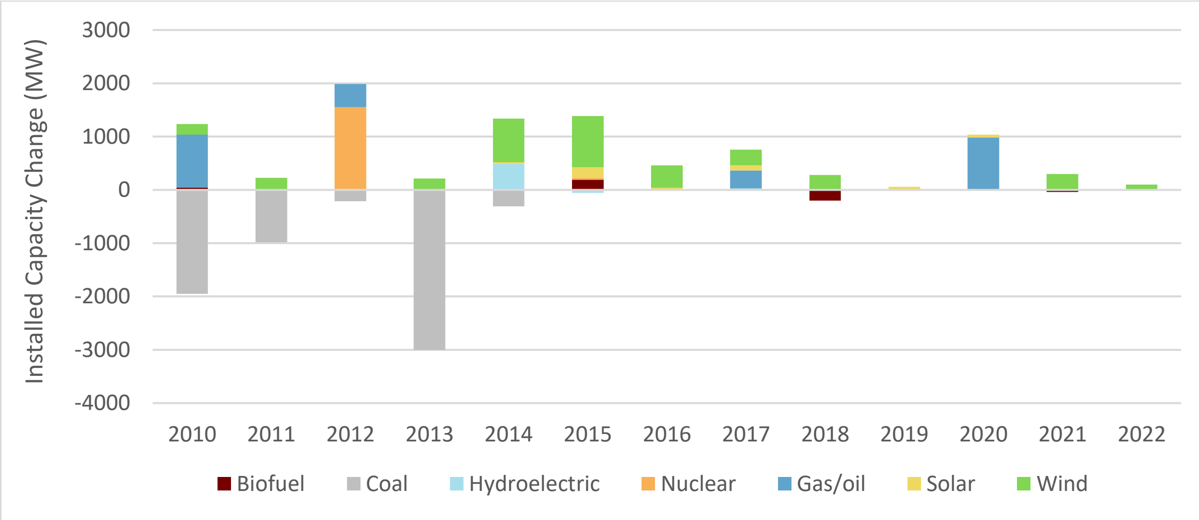
Figure 5 shows new capacity added each year since 2010.[14]

[12] See section 5.1 for a more detailed description on these procurement efforts.

[13] See (Ontario Ministry of Energy 2017).

[14] Bruce Units 1 and 2 are counted as additions to installed capacity in 2012. The units had undergone refurbishments and had not operated since 1997.

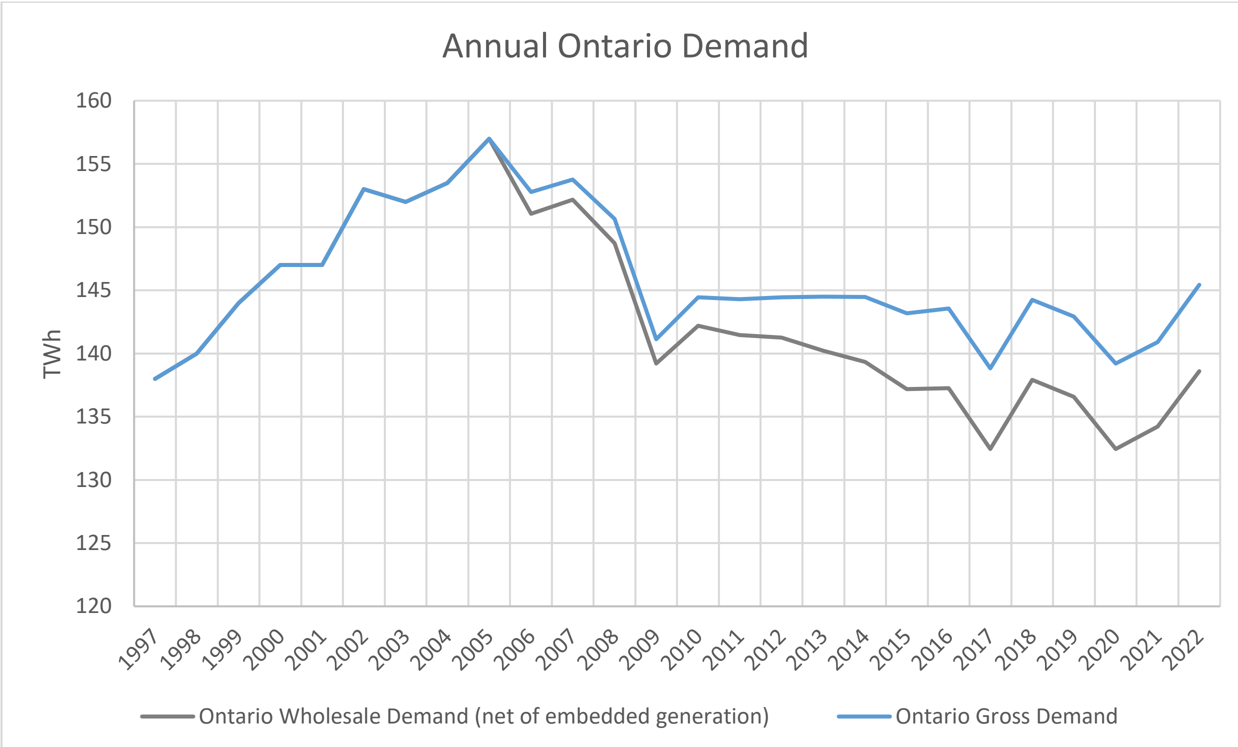
Figure 5 – Changes to Installed Capacity, 2010-2022



These procurements contributed to excess capacity conditions which emerged through the 2010s. These conditions were in part due to Ontario electricity demand declines beginning in the mid-2000s. Demand declines can be attributed to increased energy conservation efforts, significant improvements in energy efficient technologies (i.e. LED light bulbs), shifts in Ontario's economy including the 2009 recession, as well as a general movement towards service-based businesses as opposed to energy-intensive industrial businesses.[15] The supply of embedded generation also increased during this time period, driven by IESO programs like FIT and microFIT, leading to less demand for transmission-connected generation output. Figure 6 displays Ontario's electricity wholesale demand (net of embedded generation) and gross demand since 1997.

[15] See (Canada Energy Regulator 2018).

Figure 6 – Annual Ontario Wholesale Demand (net of embedded generation) and Gross Demand, 1997-2022

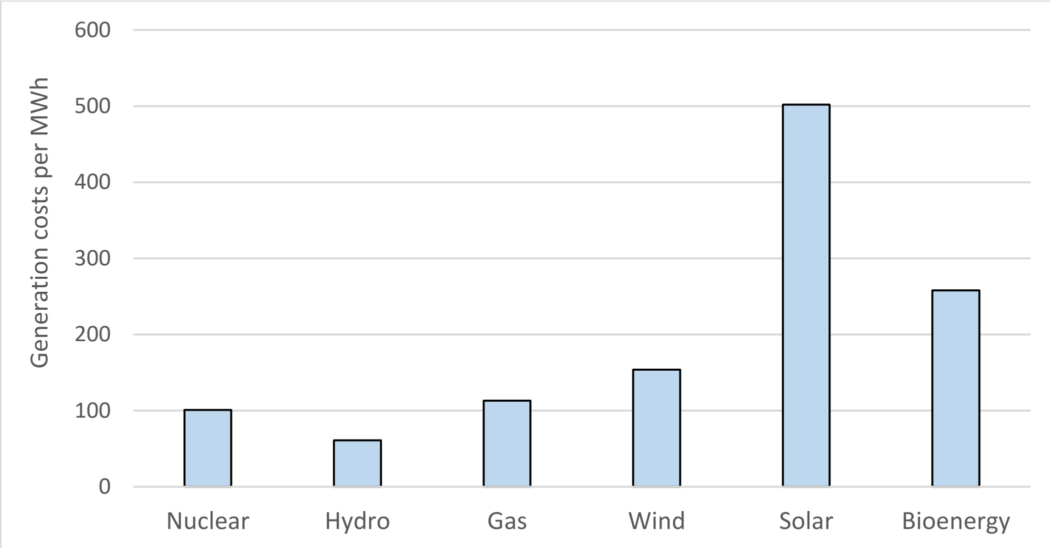


In addition to generation cost increases from over procurement, cost increases were further amplified due to the higher prices paid for much of this capacity. These prices were generally higher than the price of the coal generation they replaced. In 2009, payments to OPG for coal generation were capped at $48/MWh.[16] In some instances, prices were also found to be above the global market rate for the same generation technology.[17] Prices were also locked-in through long-term contracts, such that these procurements continue to influence generation costs in 2022. Figure 7 below shows generation costs per MWh by fuel type in 2022.

[16] See (Ontario Energy Board 2008). After caps were removed in the final years of the coal phase-out, coal revenues remained at about this level.

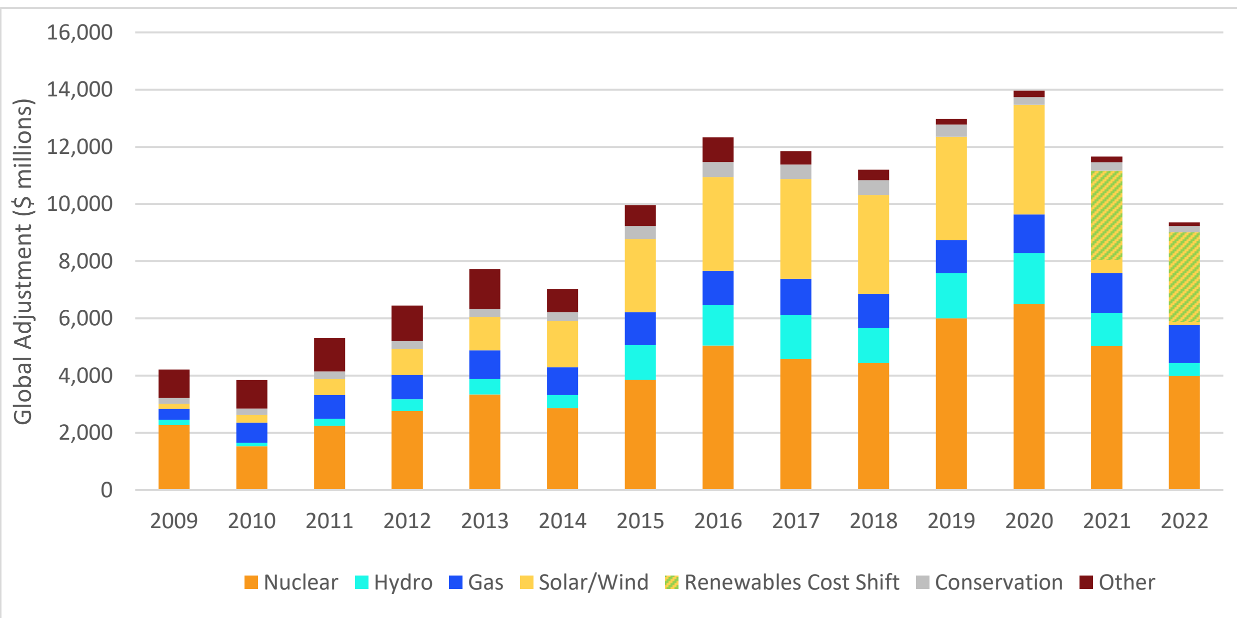
[17] For more discussion on the analysis of prices, see section 5.1.

Figure 7 – Generation costs per MWh by fuel type, 2022[18]



Generators which are contracted at prices above HOEP are paid the difference through GA payments. Figure 8 below illustrates GA payments by component.

Figure 8 – Annual Global Adjustment by Component, 2009-2022[19]



In addition to capacity procurement, another driver of generation costs in Ontario are natural gas fuel prices. The hourly offer (bid) price of natural gas generation, energy-limited hydroelectric generation, and imports (exports) are influenced by the price of natural gas. The variable fuel cost

[18] From OEB's RPP Price Report. See (Ontario Energy Board 2022), Table 2.

[19] Renewable Cost Shift represents cost shifted out of the GA.

of producing electricity among natural gas resources is directly dependent on the price of natural gas. These resources offer into the wholesale electricity market at prices needed to recover their variable fuel costs, causing HOEP to reflect natural gas prices when these units set the price. Furthermore, other resources, such as energy-limited hydroelectric resources and imports (exports) offer (bid) into the market hourly at prices that reflect the resources opportunity cost (i.e., the next best price the resource would receive in an alternative hour or an alternative jurisdiction), which is generally influenced by natural gas prices. Hence, when these resources are the marginal price setting resources, the market prices also reflect the prevailing price of natural gas.

Figure 9 illustrates monthly average HOEP and Henry Hub natural gas spot prices (including the carbon price) over the last 20 years.[20] Table 2 illustrates unforced capacity, energy output, and share of intervals setting pre-dispatch (PD) and real-time (RT) prices by fuel type. Pre-dispatch and real-time prices were set by natural gas generation, energy-limited hydroelectric generation or imports (exports) in 90% or more hours in 2021 and 2022.

[20] Carbon prices are represented in Figure 9 as their contribution to fuel costs have become increasingly significant. In 2022 federal carbon prices were $50 per tonne, or about $2.50 per MMBTu of natural gas. For more information, see (Government of Canada 2018).

Figure 9 – Monthly HOEP and Henry Hub Natural Gas Prices Modified for the Canadian Carbon Price, 2003-2022

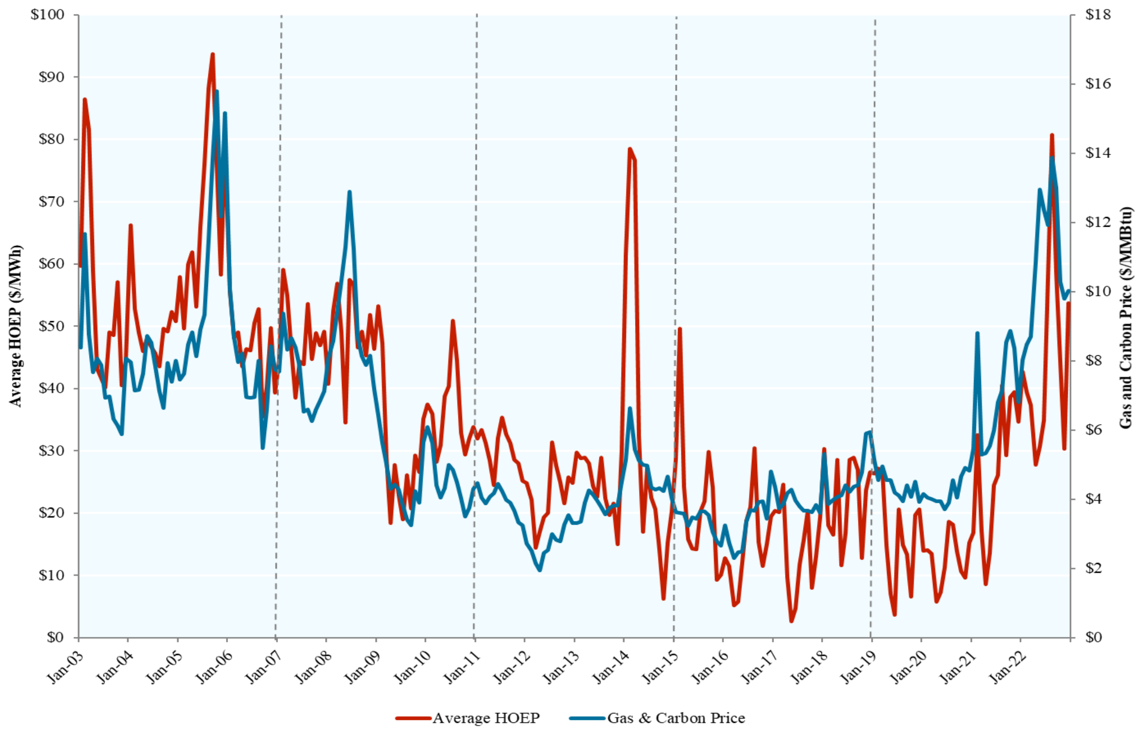


Table 2 – Capacity, Energy Output, and Price Setting by Fuel Type, 2021-2022

Fuel Type	Unforced Capacity[21]				Energy Output				Price Setting			
	Total MW		Share %		Total TWh		Share %		PD MCP Share %		RT MCP Share %	
	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
Hydro	8,918	8,868	23.4%	23.3%	34.2	38.0	25.5%	27.7%	15.2%	14.6%	42.7%	34.9%
Wind	4,783	4,883	12.6%	12.8%	12.0	13.8	9.0%	10.1%	2.1%	1.7%	9.9%	6.2%
Gas	10,515	10,482	27.6%	27.5%	12.2	15.2	9.1%	11.1%	37.7%	37.6%	46.6%	58.1%
Nuclear	13,089	13,089	34.4%	34.4%	83.0	78.8	61.9%	57.4%	0.0%	0.0%	0.0%	0.1%
Solar	478	478	1.3%	1.3%	0.8	0.8	0.6%	0.5%	0.0%	0.0%	0.0%	0.0%
Biofuel	296	296	0.8%	0.8%	0.4	0.3	0.3%	0.2%	0.5%	0.4%	0.7%	0.7%
Import	-	-	-	-	8.7	7.9	6.5%	5.9%	24.6%	18.8%	-	-
Export	-	-	-	-	-17.2	-17.5	-12.8%	-13.1%	19.3%	26.0%	-	-
Total	*38,079*	*38,096*	-	-	*134.1*	*137.3*	-	-	-	-	-	-

From 2005 through 2020, natural gas prices steadily declined due to innovations in the North American gas industry, including large increases in supply driven by the shale gas extraction

[21] Unforced Capacity measures expected capacity contribution after adjusting for outages and de-rates.

revolution. These falling fuel costs helped offset some of the rise in generation costs during this period. More recent shocks to the global gas markets, including the COVID-19 pandemic and the Russian invasion of Ukraine, have driven up gas prices since 2020. These shocks acted to increase all-in costs.

While all-in costs have risen over the last two decades, related factors have driven down wholesale electricity market prices (HOEP) over the same period. These factors include (i) a growing share of zero marginal cost renewable generation, (ii) excess capacity conditions, and (iii) declines in the price of natural gas. Declines in HOEP have reduced the revenues generators earned through the wholesale market and increased the revenues earned through out-of-market GA payments. Since 2020, this trend has reversed slightly due to the tightening capacity conditions and gas price increases. As noted above, the share of generator revenues earned through the market was lowest in 2020 at 11% but in 2022 this climbed back to 37%.

3.3 Government Cost Mitigation

While the all-in costs have been steadily increasing since 2004, government 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, various programs have helped sustain the reduction in average annual consumer costs and continue to hold them below 2016 levels. In 2022, government spending on electricity cost mitigation was roughly $6 billion.

The two largest programs are the "Renewable Cost Shift" and the Ontario Electricity Rebate (OER). The Renewable Cost Shift transfers roughly 85% of the costs of 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 set each year to limit the growth of bills to 2% annually. Together, the two programs represent nearly 80% of the annual support payments made in the 2021-2022 tax year.[22] In 2022, the government programs held total consumer costs to $17B, roughly 27% below the total all-in cost of $23.1B.

Figure 10 below presents the amount of government spending on the different cost mitigation programs and Figure 11 illustrates the effect of this spending on total consumer costs.[23] The height of the bars in Figure 11 are the all-in costs.

[22] See (Financial Accountability Office of Ontario 2022). In 2022, the OER was 17% from January through October. In November, it was adjusted to 11.7%. More precisely, the bill reduction under the OER was set to limit increases for residential electricity bills to 2% from program inception in 2019 through 2022.

[23] Figures 10 and 11 use IESO settlement data. For ease of reference, the reference in these figures 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*. "Other" includes programs such as the Distribution Rate Protection, the Rural or Remote Electricity Rate Protection, the Ontario Electricity Support Program, and Northern Energy Advantage.

Figure 10 – Government Program Spending, 2004-2022

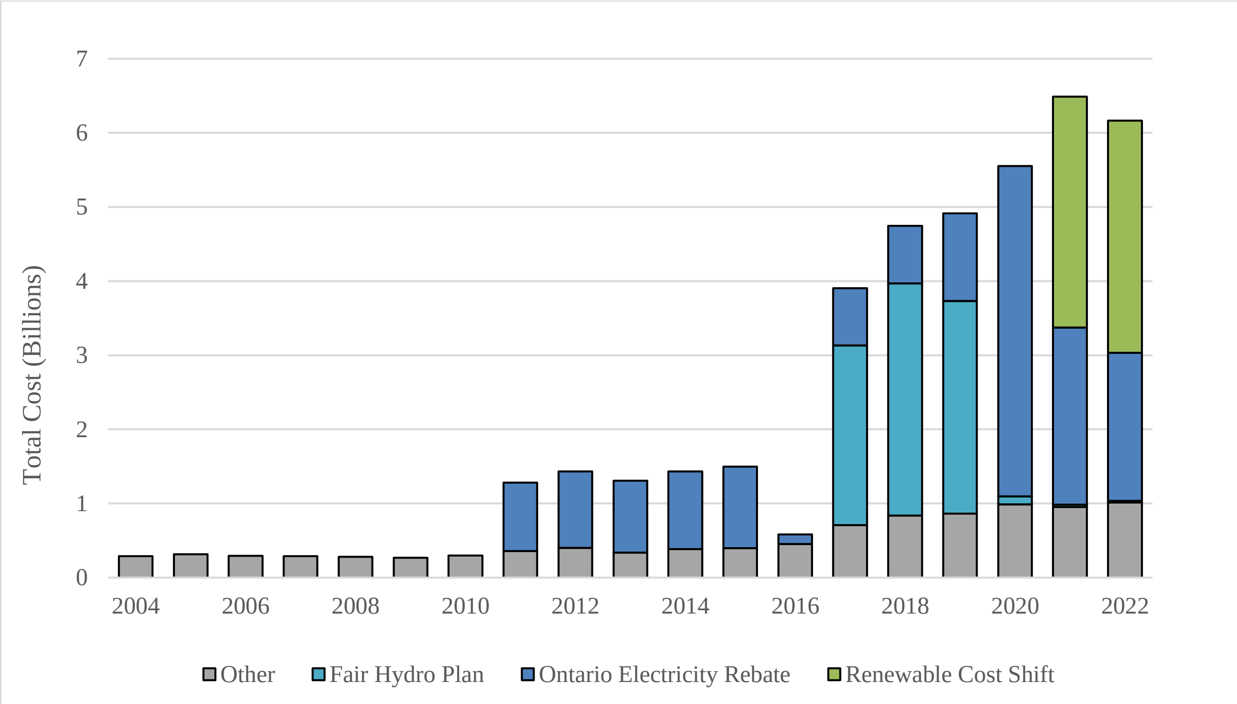
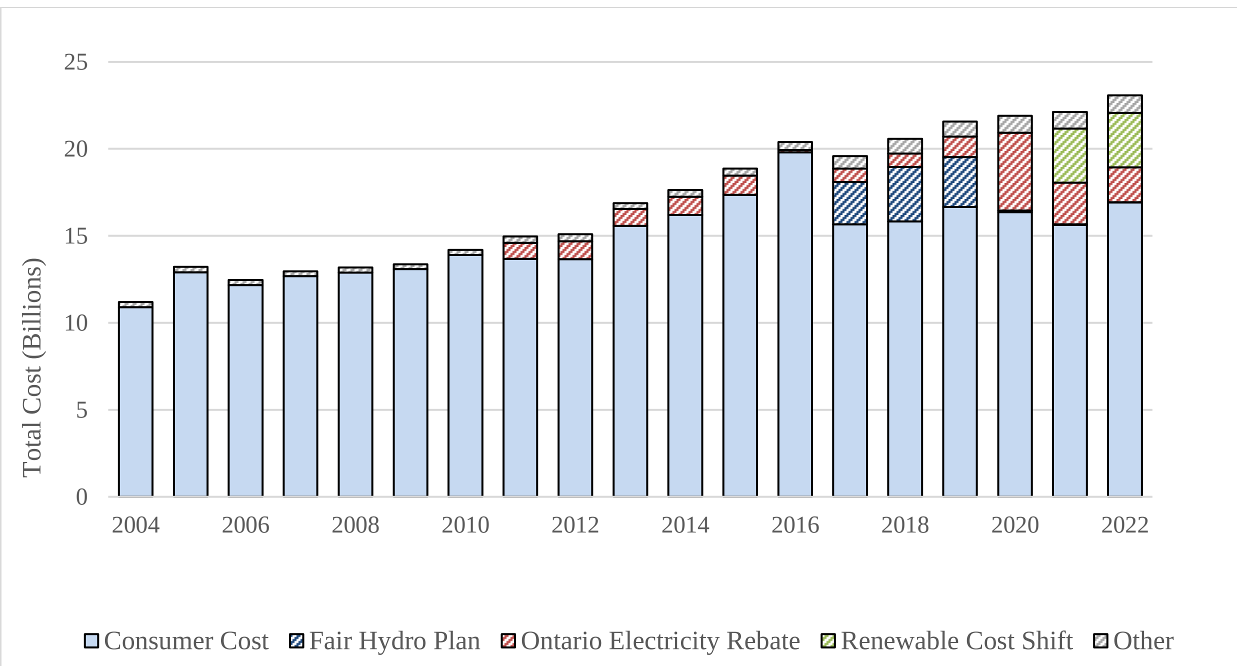


Figure 11 – Government Program Spending and Consumer Cost, 2004-2022



3.4 Conclusions

The all-in electricity cost in Ontario has more than doubled since 2004, driven by increasing generation costs. These cost increases followed from the replacement of coal generation with higher cost generation, and the procurement of excess capacity through the 2010s. The increase in the all-in unit cost has been further affected by the decline in demand since 2004, as the growing fixed costs of generation are allocated over a smaller pool of demand.

At the same time, generators have earned a shrinking share of revenues though the wholesale electricity market, while a growing share of revenues that are guaranteed through contracts and regulation and are paid through the GA. When the GA began in 2005, it was a rebate to consumers. In 2008, GA payments made up 11% of generation costs. By 2020, declines in the wholesale market price and increases in the fixed costs added to the system, resulted in nearly 85% of generation costs being paid through the GA. This trend has receded slightly since 2020 with the rise in wholesale market prices and the increasing utilization of generation assets.

Efficiently and equitably recovering fixed costs is a common problem for electricity market regulators.[24] The Panel has commented extensively on this issue, particularly on the inefficiencies created by the price signals formed under the Industrial Conservation Initiative (ICI) program. The Panel has also commented on the fairness of this fixed cost recovery mechanism, notably how large customers can avoid fixed costs charges (including those associated with baseload generation), ultimately shifting these costs to small customers.[25] This issue is described in more detail in section 6.3.

Over the next two decades, the IESO predicts a significant increase in Ontario's overall electricity demand.[26] The IESO's Pathways to Decarbonization Report explores 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. To meet this increase in overall demand, significant capital investments in new generation and transmission assets will be required. To ensure a cost effective supply of electricity in the future, it is paramount that these investments are made as efficiently as possible. The Panel believes that effective and transparent independent regulatory oversight of the need for investment, would help provide more accountability to the procurement process and protect against unnecessary and costly investment errors. Furthermore, the use of competitive mechanisms, whenever possible, would drive further investment efficiency.

[24] See (Harris 2015).

[25] See (Market Surveillance Panel 2018).

[26] See (Independent Electricity System Operator 2022a).

4 Competitiveness and Contracting

This chapter examines the competitive structure of the Ontario wholesale electricity market. Since market opening, OPG has owned and controlled a large share of the generation assets in Ontario. Within this concentrated structure, the market has relied on regulation and contracting to guide market participant behaviour, mitigate market power, and promote dispatch efficiency.

As part of the initial market design, the Market Power Mitigation Agreement (MPMA) was used to limit OPG's market power. The MPMA capped prices paid to OPG and laid out plans for OPG to reduce, over ten years, its effective control over capacity in the province to 35%.[27] Following these plans, OPG reached agreements to lease its Bruce nuclear operation and divested 490 MW of hydroelectric assets by 2002.

The MPMA was overtaken in 2004 with the enactment of the *Electricity Restructuring Act, 2004* (ERA). 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.[28] In 2014, most of OPG's remaining hydroelectric facilities became rate regulated.

More recently, OPG spent several billion dollars acquiring gas generators, thereby growing its market share. In August 2019, OPG acquired the remaining 50% interest in its Brighton Beach combined cycle gas generator for $200 million.[29] OPG also completed a $2.8 billion acquisition of three combined-cycle natural gas plants from TC Energy in April 2020. When reflecting the 2020 transaction in licences, the OEB 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 these concerns, conditions were added to the facility licences by the OEB. The conditions included provisions which guide OPG offer behaviour and ring-fence operations at the new gas plants.[30]

Today, OPG is the largest capacity, energy, and operating reserve provider in the IAM. The levels of concentration in the IAM, and particularly the size of OPG, would generally raise concerns regarding market power. These concerns are addressed through regulatory measures imposed by the OEB and through IESO agreements.[31] Details on these regulatory measures and other contracts which impact competition in the market are covered in section 4.2.[32]

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[27] More specifically, OPG agreed to reduce its effective control over the output of its fossil and hydroelectric capacity to 35% within 42 months of market opening, and to reduce its effective control over all of its capacity to 35% within 10 years.

[28] See (Government of Ontario 2005)

[29] See (Ontario Power Generation 2019) at page 11.

[30] See (Ontario Energy Board 2020b).

[31] Market power concerns are addressed through the Must-Offer Condition Agreement between OPG and the IESO which was mandated and approved by the OEB in 2020, see (Ontario Energy Board 2020c). They are also addressed through a Memorandum of Agreement between OPG and the government of Ontario, its sole shareholder, see (Ontario Power Generation 2021), and regulated rates for generation assets.

[32] The Panel is also monitoring the development of the Market Power Mitigation (MPM) framework under the market renewal program, including how the mitigating measures in this framework may overlap or interact with similar contract and regulatory provisions.

While regulation and contracts largely drive efficient short-run market outcomes, they do not act as a perfect replacement for competition. Generally, competition authorities view regulation as a poor alternative for true (structural) competition.[33] In electricity markets, economists have found that 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.[34]

The looming procurement needs over the coming years and decades will shape the competitiveness of the Ontario market. While the Panel acknowledges that the abilities and experience of OPG (and other incumbents) make them strong candidates for new investment projects, it also sees potential benefits from new entrants reinvigorating competition within the markets – potential benefits that may be valuable to consider in the selection process.[35] The Panel notes that 28% of the capacity awarded under the new build storage projects and 32% of same technology upgrades announced by the IESO in June 2023 went to OPG.[36]

4.1 Competitiveness

This section contains an analysis of the structural competitiveness in the IAM. 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 interest 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 antitrust 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 2022, OPG controlled 51% of total capacity and 68% of total price-sensitive capacity in Ontario.[37] A market in which a single firm controls more than 50% of the productive assets be is likely to l raise

[33] The Competition Bureau notes that structural remedies are preferred over behavioural 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 behavioural remedies may prevent efficient responses to changing market conditions and restrain pro-competitive behaviour by market participants. See (Competition Bureau Canada 2006).

[34] (Fabrizio 2007) found that plant operating expenses decreased 3-5% in anticipation of increased competition following deregulation, or 6-12% compared to government owned plants. For a broader discussion, see (Schmalensee 2021), Chapter 2.

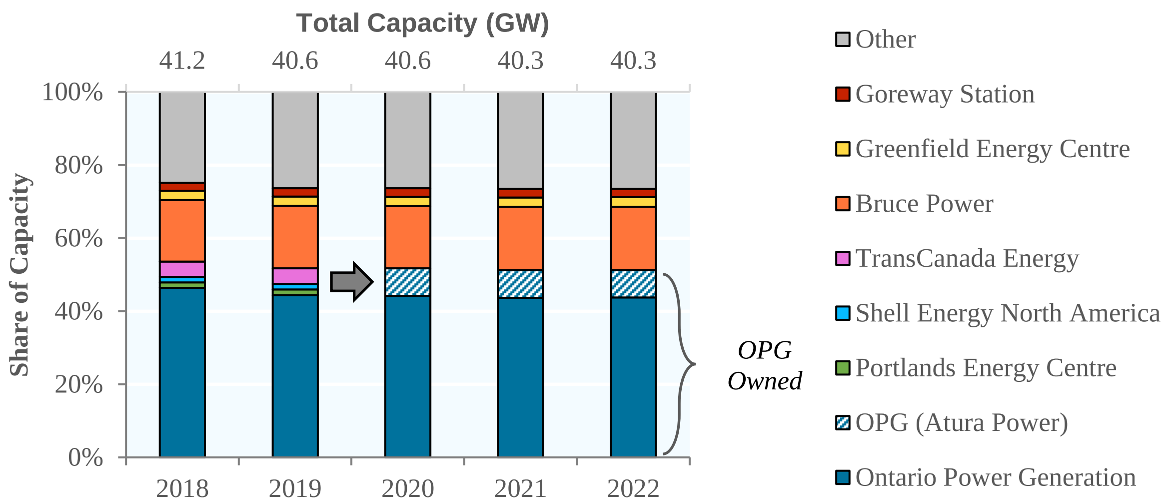
[35] Incumbents may be preferred over new entrants due to risks around project delays or incompletion. A study of US interconnection queues found that only 21% of proposed projects from 2000-2017 had reached commercial operations by 2022. See (Rand, Strauss, et al. 2023).

[36] See (Independent Electricity System Operator 2023c).

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

competitive concerns from competition authorities..[38] Figure 12 below depicts shares of capacity since 2018.

Figure 12 – Registered Capacity by Market Participant, 2018-2022

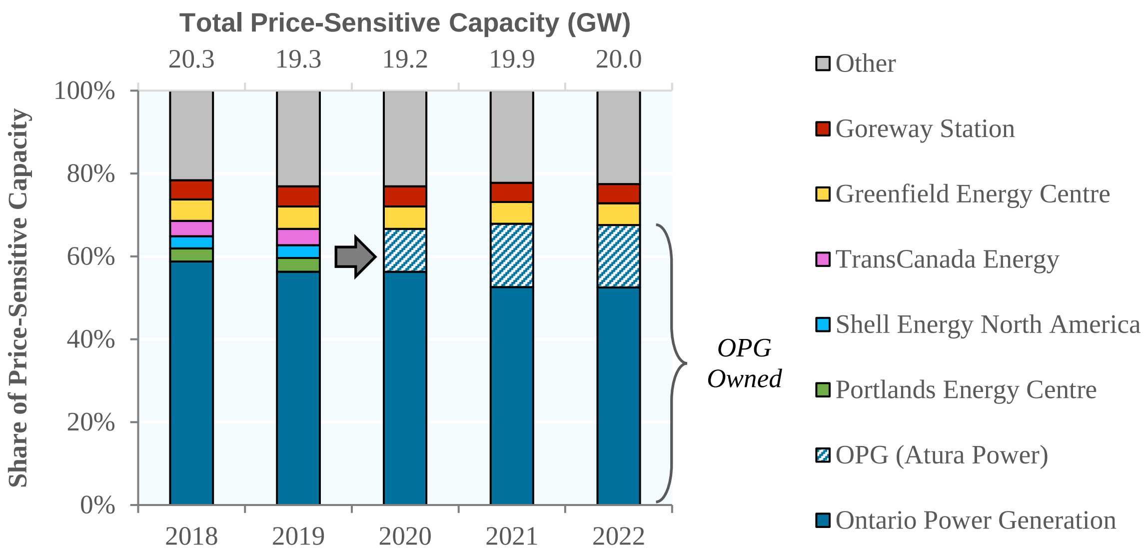


OPG controlled 51% of the capacity in the IAM in 2022. This has remained consistent since OPG acquired the remaining 50% stake at Brighton Beach and its $2.8 Billion acquisition of three more combined-cycle gas plants in 2020. These acquisitions increased OPG's capacity share by about 7%. Without mitigating regulatory mechanisms (and contracts), OPG would have an incentive to exercise its market power by increasing offer prices at its marginal hydroelectric and gas resources (or not offering some of its available capacity), pushing up market prices and the net revenues earned on its baseload and other inframarginal assets.

Figure 13 demonstrates that OPG controls an even larger share of the price-sensitive capacity, which includes gas, some energy-limited hydroelectric, oil, and biofuel. In 2022, OPG controlled 68% of this capacity, an increase from 56% prior to the recent gas plant acquisitions. OPG's dominant share of the price-sensitive resources enhances its potential to exercise market power absent contracts and regulation.

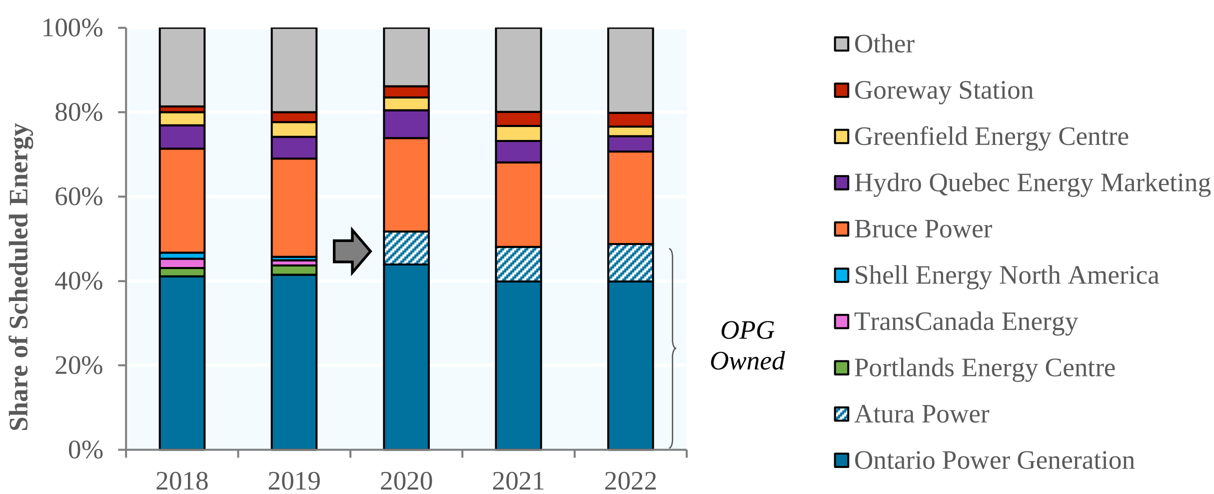
[38] For example, the Canadian Competition Bureau uses market shares as an initial screening mechanism to assess allegations of abuse of dominance. A single firm market share of 50% or more or a combined market share of 65% of a group of firms alleged to be jointly dominant prompts further examination for anti-competitive outcomes. See "Abuse of Dominance Enforcement Guidelines" (Competition Bureau Canada 2022).

Figure 13 – Price-Sensitive Generation Registered Capacity by Market Participant, 2018-2022



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. At these times, generators are more assured their supply will be needed. 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. Figure 14 below presents the share of energy scheduled by market participants during the top 100 demand hours. Again, the large presence of OPG, which owns half of the scheduled generation during these hours in 2022, is displayed.

Figure 14 – Energy Scheduled by Market Participant, Top 100 Market Demand Hours, 2018-2022



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 controls a majority of capacity and price-sensitive generation in the province. Regulatory measures imposed by the OEB, in addition to agreements with the IESO, help alleviate the competitive concerns around OPG's position. They help to prevent the exercise of market power and to encourage OPG to offer its facilities in the market at prices that reflect their marginal production cost. While these agreements 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, in addition to offering in the market at prices reflective of their cost.

4.2 The Role of Contracting

In Ontario, most generators are subject to contracts or rate regulation which influence their participation in the IAM.[39] Well-designed contracts can be an effective way to improve competition and efficiency, particularly 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 behaviours.

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 a generator 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. Trends in the source of generator revenues are discussed in section 3.2.

4.2.1 Overview of Contract Types

The IESO currently manages over 33,000 contracts with a combined 27 GW of capacity. About 425 of these contracts are for larger bulk grid resources including the 6.5 GW Bruce nuclear facility, 9.4 GW of natural gas, 2.4 GW of hydroelectric, and 6.5 GW of wind and solar.[40] The remaining contracts are for small FIT and microFIT solar projects totalling about 1.6 GW. More than half of gas generation contracts will expire by 2030. Most of the wind and solar generation facilities 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 2022, less than 1% of wholesale energy generation came from resources without a contract or rate regulation (not including imports).

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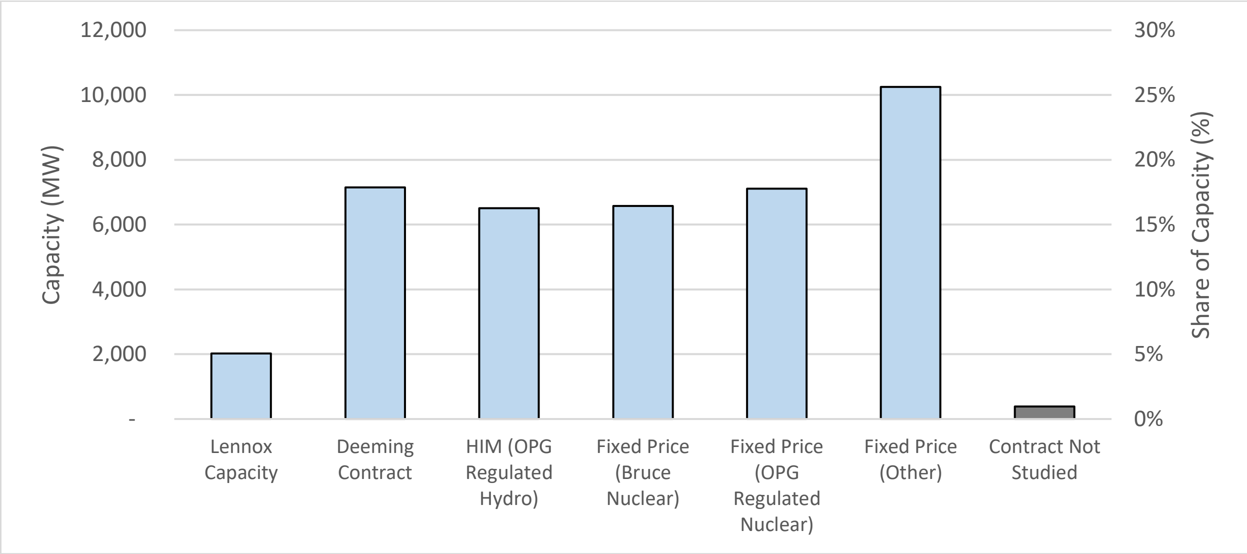
[39] See (Independent Electricity System Operator 2023a). A small number of contracts continue to be held with the Ontario Electricity Financial Corporation, see (Ontario Electricity Financial Corporation 2022).

[40] For a summary of contracts see (Independent Electricity System Operator 2023a).

Figure 15 below illustrates generation capacity under rate regulation and under each type of contract. The IESO contracts have been categorized into 6 groups in addition to a “Contract Not studied” group.[41] Additional details on each group are provided below.

Figure 15 – Regulated and Contracted Capacity by Type, 2022



Lennox Capacity

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. Lennox’s location and operating characteristics help it play a key role in maintaining system reliability. In 2022, the IESO re-contracted 1,657 MW of capacity from the facility through 2029. The “capacity-style” contract is largely defined by a fixed $9 million monthly payment.[42] The contract also includes more minor provisions to compensate for select costs and share net revenues.[43]

Deeming Contracts

Most gas-fired plants in Ontario operate under deeming contracts.[44] 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

[41] Other “Contracts not studied” include the Atikokan Biomass Energy Supply Agreement, Chaudière Falls Contract, Hydroelectric Standard Offer Program, and the Non-Utility Generator Enhanced Dispatch Contract.

[42] Capacity style contracts offer fixed monthly payments, but otherwise contract holders earn revenues according to market prices. These contracts preserve financial incentives to respond to market signals in the short-run and are better suited towards dispatchable resources including gas facilities.

[43] See (Independent Electricity System Operator 2021a).

[44] Over 70% gas capacity in 2022 operated under deeming contracts.

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.[45] 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 desirable short-run incentives may be realized under the deeming contract structure, the same is unlikely true for longer term operational decisions. While the contract does allow gas plants to keep additional net revenues earned through efficiencies achieved with improvements in facility maintenance and small facility upgrades, these savings are not likely to be passed on to consumers. Furthermore, uncertainties around contract renewal and renegotiation may raise generators' cost of capital, costs that are passed on to consumers. Incentives for efficient retirement decisions are also attenuated as contracts continue to provide generators net revenue opportunities, regardless of market trends, and even when some facilities are no longer 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 Expansion" procurement, long-term contracts were needed to motivate gas generators to invest in capacity expansion.

HIM (OPG Regulated Hydro)

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.[46] 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

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

[46] 54 of OPG's 66 hydroelectric stations are rate-regulated and subject to the HIM. In 2022, the total regulated price (base regulated price and deferral and variance account rate riders) for OPG's hydroelectric generation was $44.91/MWh. See (Ontario Power Generation 2023).

revenue security like a fixed-price contract. Approximately 80% of the transmission-connected hydroelectric capacity in Ontario operates under the HIM.[47]

The Panel noted in Monitoring Report 32 that the effectiveness 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. In the same report, the Panel recommended that the OEB consider revisiting the sharing arrangement to ensure that OPG has a clear market incentive to use its hydroelectric assets efficiently.[48]

Fixed Price

Most of the remaining generation in Ontario operates under a fixed-price structure. These contracts guarantee a price per MWh of generation and supplant financial 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 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.

Nuclear generation in Ontario operates under a fixed-price structure. These include fixed-price contracts for Bruce nuclear, and fixed-price rate regulation for OPGs Pickering and Darlington nuclear stations.[49] Nuclear units are largely non-dispatchable and adhere to rigid operating requirements. This lessens the likelihood that fixed-price contracts induce short-run inefficiencies.

Fixed-price contracts are used for grid-connected wind and solar plants, and some hydroelectric stations, and non-utility generators (NUGs) gas plants.[50] 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

[47] 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 6 new hydroelectric units (approximately 438 MW of capacity) on the Lower Mattagami River under a Hydroelectric Energy Supply agreement (HESA) with the IESO.

[48] In 2021, as part of the proceeding to set payment amounts for OPG for 2022 to 2026, the OEB approved a settlement proposal under which it was agreed that OPG would file a future application with the OEB regarding changes to the HIM and other impacts arising from MRP. See (Ontario Energy Board 2021).

[49] Bruce nuclear is contracted under the Amended and Restated Bruce Power Rehabilitation Implementation Agreement (ABPRIA). See (Independent Electricity System Operator 2015).

[50] Wind and solar contract types include FIT, GEIA, LRP, microFIT, RES and RESOP. Hydroelectric fixed-price contracts include HCI and HESA.

negative) marginal costs, specifically available nuclear facilities are not.[51] Prior to 2012, this outcome 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, it also created potential reliability issues as nuclear plants when shutdowns are required to remain out of service for several hours before return 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. These contracts do not offer incentives to respond to market needs.

Finally, these contracts provide limited incentive over the longer-term for efficient investment in capacity upgrades.

4.3 Conclusions

The Panel finds the electricity market to provide reasonably competitive market outcomes in the short-term despite the lack of structural competition envisioned at market open. 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 generators to offer at marginal costs.

The Panel will continue to closely monitor market developments and their implications on dynamic and long-term efficiency of the market. While central planning will continue to play a key role in guiding longer-term decisions around investment and innovation, the Panel supports the IESO’s efforts to leverage competition where possible. Over the longer-term, competition can help keep costs down, drive innovation, and reduce investment risk to ratepayers through mechanisms such as capacity auctions.

[51] An operating nuclear unit faces substantial costs of curtailment, if the curtailment means the unit is not available to produce and earn revenues in future hours. When this is the case, the marginal cost of the unit when facing curtailment is negative as it reflects the potential foregone future revenues.

5 Investment and long-term efficiency

This chapter examines the long-term (or dynamic) efficiency in the IAM as well as its relation to market investment.

Long-term 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.

In the past, the Panel has made many recommendations regarding resource adequacy and long-run efficiency. These recommendations cover topics such as the role of imports and demand response, competitive procurement mechanisms, and transparent cost-benefit analyses.[52]

The Panel acknowledges that the hybrid market structure in Ontario differs from many other restructured electricity markets in North America. In those markets, investment and retirement decisions are largely driven by market prices for electricity and capacity.[53] In contrast, most generation investment in Ontario is determined through centralized planning and government policy directions. Projects are 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.

5.1 Past Investment and Procurement

When the restructured electricity market first opened in May 2002, the intention was to create an "energy-only" market with the wholesale market price driving investment. Initially, unexpected high prices shed light on the relative shortage of supply that had emerged over the preceding decade. High prices can generally act as a signal for new investment. However, delays and uncertainties around market opening including unease around the large role of OPG and government intervention deterred potential investors.[54] Ultimately, key decision makers lost confidence in the market's ability to stimulate the needed investment.

In response to the lack of investment activity, the government enacted the ERA in 2004.[55] The ERA created the Ontario Power Authority (OPA), established prices for a majority of OPG's generating assets and established new rules for the regular setting of electricity prices for certain classes of customers by the OEB. It also saw the abandonment of plans for OPG to transfer effective control over its capacity as a market power mitigation measure.

In 2005, the Panel noted that under the new structure "it is unlikely that any generator would choose to build new supply without contractual guarantees."[56] It pointed out that even the limited number of private sector generators that had recently decided to invest in the province without

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[52] See, for example (Market Surveillance Panel 2020b), and (Market Surveillance Panel 2021b).

[53] Alberta and Texas (ERCOT) use an energy-only market, meaning there is no separate auction for capacity. All other major US 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.

[54] See (Trebilcock and Hrab, Electricity Restructuring in Ontario 2005).

[55] See (Rivard and Yatchew 2016).

[56] See (Market Surveillance Panel 2005).

government assistance modified plans and negotiated contracts with the OPA. The ERA marked the start of the hybrid structure, and since that time, investment decisions have become reliant on central planning and procurement efforts subject to government policy priorities.

The increased confidence of a return on investment provided under government and OPA contracts, combined with the province's decision to phase out coal generators and the IESO's forecast for growing demand, resulted in a rush of new capacity investment. By 2005, the province announced that it had made agreements to procure more than 9,000 MW of new capacity.[57] This included initial efforts to procure renewable generation capacity through the Renewable Energy Supply (RES) program and the Renewable Energy Standard Offer Program (RESOP). Respectively, these programs saw the procurement of 1,570 MW and 916 MW of renewable capacity by 2009.[58] The RES procurements used competitive bidding for a specified type and quantity of power, while the RESOP program used a fixed price. The Panel has previously concluded in Monitoring Report 32 that this centrally planned generation investment was at times more or less competitive.[59]

In 2009, the *Green Energy and Green Economy Act, 2009* (GEA) was passed. The *Act* encouraged the rapid development of more renewable energy projects, largely through the feed-in-tariff (FIT) program. The FIT program offered fixed prices for renewable generation that were much higher than the RESOP program it replaced. Overall, the FIT program helped to secure over 4,000 MW of renewables by 2013, before prices were adjusted.[60] As of 2022, the IESO has contracted over 8,000 MW of solar and wind generation.[61]

Much of the investment in Ontario generation through the 2010s was procured through central planning and Ministerial Directives as to the amount, technology, and contract price rather than on the basis of market needs or price signals. Both the Panel and the Auditor General of Ontario (AG) criticized this approach, finding much of the investment was not needed or excessively costly. Like the AG, the Panel has found these procurements have contributed to capacity surpluses and the procurement processes also lacked competitive drivers. As a result, unnecessarily high costs have been imposed on Ontario consumers. Both the Panel and the AG also found a lack of technical analyses of generation needs.[62]

[57] In contrast, only 2,200 MW of capacity was built between 2000 and 2003. See Power Failure: Addressing the Causes of Underinvestment, Inefficiency and Governance Problems in Ontario's Electricity Sector Michael Wyman, May 2008 and (Ontario Ministry of Energy 2005).

[58] See (Office of the Auditor General of Ontario 2011).

[59] Programs included Renewable Energy Supply (RES) procurements and Feed-in Tariff (FIT) procurements. RES used competitive bidding for a specified type and quantity of power. FIT specified a price for power and accepted all qualified bids. The prices paid under the FIT programs have been criticized as too high and not competitive with US prices. See (Office of the Auditor General of Ontario 2015).

[60] See (Office of the Auditor General of Ontario 2015).

[61] See (Independent Electricity System Operator 2023a).

[62] See MSP report #24 (pg. 162); See the Ontario Auditor General's 2015 Annual Report, Section 3.05 "Electricity Power System Planning": (Office of the Auditor General of Ontario 2015).

The Panel has previously made recommendations encouraging the IESO to provide technical analyses behind capacity and procurement planning processes – all while highlighting the need for greater transparency in the IESO's procurement mechanisms and processes.[63]

5.2 Investment in Other Jurisdictions

After decades of relatively flat electricity demand across North America, broad demand growth is anticipated in the coming years. Many jurisdictions will face growing capacity needs similar to the IESO, and need to attract significant investment in an efficient manner.[64] Studying investment in other jurisdictions can help evaluate the IESO's own efforts to facilitate efficient investment.

In addition to broad demand growth, it is anticipated that the demand for clean energy will also grow. Clean energy production is also being propelled from the supply side, with falling costs and broad encouragement through government policy tools such as carbon pricing and subsidies.[65] In 2022, over 70% of new renewable investments in the US were planned in jurisdictions with open electricity markets.[66] The Inflation Reduction Act (IRA) passed in the United States in August 2022 could see nearly $800 billion in subsidies for clean energy projects such as solar, wind, and battery deployment.[67] Even without the IRA there has been large amounts of private investment in generation projects. Figure 16 below illustrates the large quantities of new build generation projects proposed in key US markets in 2021 (before the IRA).[68] In 2022, Alberta similarly saw 10 new wind facilities (1,349 MW of capacity) and 17 new solar farms (402 MW of capacity) come online.[69] This generation was planned and built by the private sector, generally in response to needs signalled through market prices.[70]

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[63] See (Market Surveillance Panel 2021a), section 1.1.3 and (Market Surveillance Panel 2020b).

[64] 8 of 20 regions under FERC are experiencing an elevated risk of shortfalls between 2023 and 2027. See North American Electric Reliability Corporation 2022.

[65] Both the US and Canada have goals for net-zero electricity grids by 2035. See (United States Department of State 2021) and (Natural Resources Canada 2023).

[66] In 2022 413 GW was added to build queues in open markets with ISOs, 171 GW was added in non-ISO utilities. See (Berkeley Lab 2022).

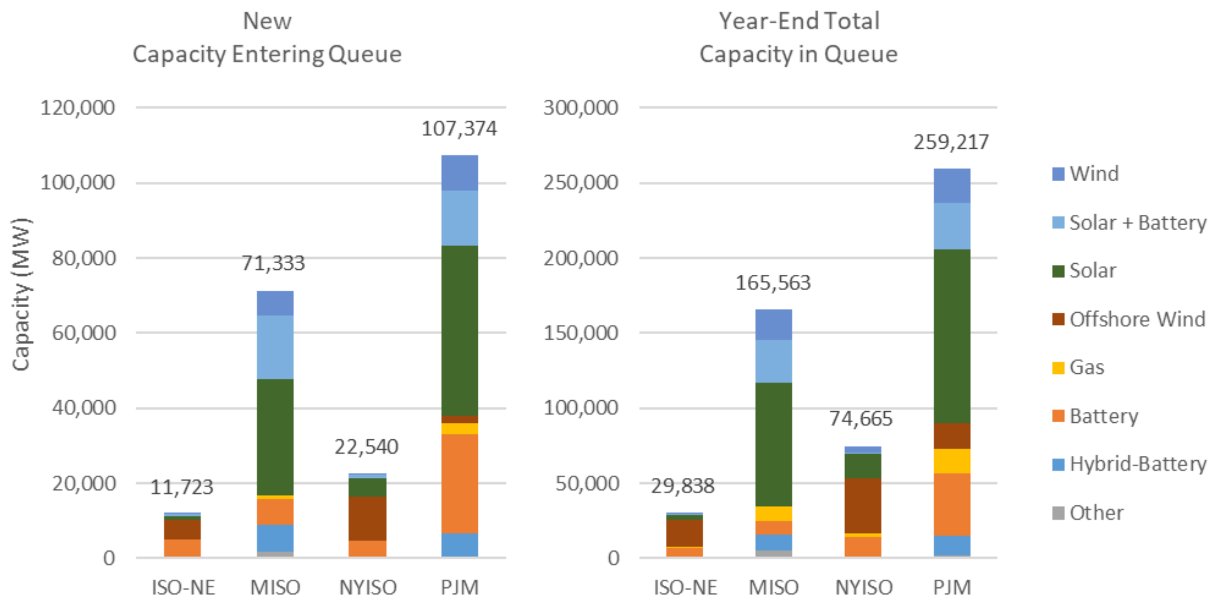
[67] See (Rand, Bolinger, et al. 2021).

[68] Proposed large-scale generation and storage projects in the ISO-NE, MISO, NYISO, and PJM must enter the interconnection queues. While studies show only 21% of recent queue projects reached completion, data on queue length still provides a valuable indicator of trends in investment and developer interest. See (M. B. Joseph Rand 2021).

[69] See (Alberta Electric System Operator 2023).

[70] In 2017 and 2018 the Government of Alberta awarded Power Purchase Agreements (PPA) for renewable generation projects following a competitive RFP process. These projects achieved commercial operation by 2021. Government-issued PPAs were discontinued in 2019, see (Alberta Electric System Operator 2018). Corporate PPAs have been announced at various renewable projects in Alberta, however these do not represent any additional cost to consumers outside the PPA, see (Canada Energy Regulator 2022).

Figure 16 – US Interconnection queues new and total capacity, 2021



Unlike Alberta and the US markets, the IAMs are part of a hybrid structure where market prices alone do not facilitate private investment in generation. To attract investment and address the projected system needs in Ontario, the IESO has launched a variety of procurement efforts which offer additional revenue streams for new build generation outside the IAMs. These procurement efforts mostly involve a competitive RFP process, with targets for capacity needs in MWs. These procurement efforts are summarized in section 5.3.

The IESO also runs an annual capacity auction. In US electricity markets (except Texas), the capacity auction represents a key market mechanism which complements electricity prices and guides efficient investment and retirement decisions. The capacity auction in the IAM is not a key market mechanism in Ontario and holds a limited role guiding investment in generation. The capacity auction is discussed in more detail in section 5.4.

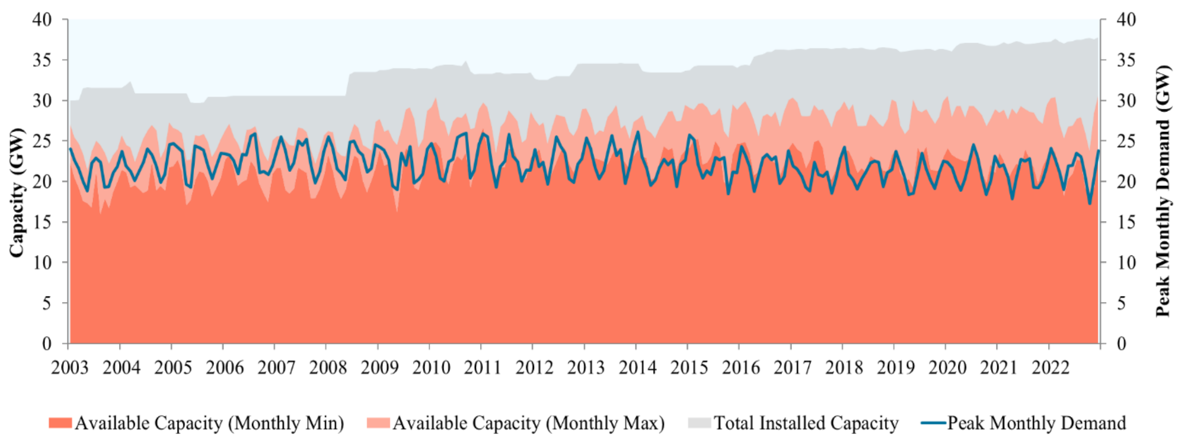
5.3 Current Investment Needs and Efforts

Ontario has experienced excess supply over the last decade. However, supply shortfalls are projected over the coming years without additional generation resources. The shortfalls are driven by increases in anticipated electricity usage and reductions in Ontario's nuclear fleet.[71] Figure 17 below illustrates monthly minimum and maximum available generation capacity, and monthly peak market demand (excluding demand served by imports). In this figure, the supply surplus can be seen to have emerged around 2010 and to have continued through 2022. The growing gap between the installed and available capacities reflects 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.

[71] See (North American Electric Reliability Corporation 2022), at page 52.

Additionally, the figure illustrates the falling peak demand, due in part to conservation efforts, energy efficiency improvements, increased embedded generation deployment and shifts in the Ontario economy. This is covered in greater detail in section 3.2.

Figure 17 – Installed Capacity, Available Capacity, and Peak Demand, 2003-2022



The IESO anticipates capacity shortfalls emerging in the mid-2020s. The IESO's 2022 Annual Planning Outlook (APO) explains these predicted shortfalls are due to anticipated demand growth, impacts from nuclear retirements and refurbishments, and expiring generation contracts. The NERC Long-Term Reliability Assessment forecasts shortfalls of 1,700 MW in 2025 and 2026 (assuming Pickering operates through 2026).[72] The IESO's 2022 Annual Acquisition Report (AAR) lists the immediate needs for new build capacity at 2,500 MW by 2027, and another 1,500 MW by 2030 (4,000 MW total).[73]

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 through three separate processes: 1,500 MW from the Expedited Process, 300 MW from the Same Technology Upgrades, and 2,200 MW from the Long-Term RFP. Across all three procurement efforts, natural gas is targeted for up to 1,500 MW and storage for about 2,500 MW. In June 2023, the IESO announced 1,389 MW of new build capacity contracts were awarded under the Expedited Process and Same Technology Upgrades procurements.[74]

The 2022 AAR also included plans to address medium- and short-term needs due to generators coming off contracts as part of the IESO's Resource Adequacy Framework. The plans include a series of Medium-Term RFPs (MT-RFP) which will provide contracts for existing generation with 3 to 5-year terms. Also included are capacity auctions and bilateral negotiations. The capacity auction is designed to address short-term fluctuations in capacity needs. Bilateral negotiations are included as a way to secure resources where needs cannot be addressed in a practical or timely way through competitive processes.

[72] See (North American Electric Reliability Corporation 2022), at page 9.

[73] See 2022 AAR (Independent Electricity System Operator 2022b), at page 39-40.

[74] See (Independent Electricity System Operator 2023c).

The IESO concluded its first Medium-Term RFP in August 2022. Through this process, new 5-year contracts were awarded to 6 existing resources. Original targets for 750 MW of unforced capacity (UCAP) were not met, instead only about half this target was procured.[75]

5.4 IESO's Capacity Auction

The third annual capacity auction was held in November 2022. The auction is designed to ensure that there is sufficient available capacity of off-contract generators, demand response, energy storage and/or system or generator-backed imports, to meet the IESO's resource adequacy reliability standards for the following calendar year.[76] The auction provides the successful resources with an "availability" payment in exchange for a one-year commitment (two six-month obligation periods, summer and winter) to be available to produce energy.

In the 2022 auction, 1,431 MW of capacity was acquired for the summer 2023 period at a clearing price of $314/MW-day and 1,160 MW was acquired for the winter 2023/2024 period at $131/MW-day.

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 incentive to over-represent the capacity contributions or ignore dispatch instructions.[77] In 2023, the IESO implemented market rule amendments aimed at addressing these incentives.[78]

In Monitoring Report 28, the Panel also concluded there was minimal chance that HDR resources would ever be economically activated.[79] The Panel continues to monitor developments in the capacity auction design.

The initial MRP design documents included plans for an Incremental Capacity Auction (ICA). While the IESO's current capacity auction targets off-contract existing resources, the ICA was intended to drive new build capacity investments with longer commitment periods and higher prices. In the 2017 MRP Benefits Case, this auction accounted for most of the estimated benefits, $2.5B over 10 years.[80] In 2019, the project was stopped as the IESO forecasted "no need for new capacity over the next decade".[81]

Capacity auctions are commonly used in most US markets, as the primary means to achieve resource adequacy. PJM, ISO-NE, and NYISO have relied on capacity markets to economically meet their resource adequacy requirement for more than 15 years, while MISO and CAISO

[75] 750 MW of UCAP was originally targeted. Only 309 MW of summer UCAP, and 380 MW of winter UCAP were procured. See RFP draft document (Independent Electricity System Operator 2021b) and MT 1 RFP 1 Executed Contracts (Independent Electricity System Operator 2022d).

[76] This is capacity availability beyond what has already been committed to the IESO through long-term IESO contracts.

[77] See MSP 35 Recommendation 3.2 (Market Surveillance Panel 2021b), at page 52.

[78] See market rule amendments MR-00476 and MR-00477 (Independent Electricity System Operator 2023f).

[79] See MSP 28 Recommendation 4.2 (Market Surveillance Panel 2017), at pages 97–106.

[80] See (Independent Electricity System Operator 2017).

[81] See IESO engagement email to stakeholders "Market Renewal Update" dated July 16, 2019 (Independent Electricity System Operator 2019b) and (Gregg 2019)

integrated capacity market more recently.[82] Some economists have questioned the net benefits of using capacity auctions to achieve resource adequacy, given the large administrative role in setting targets and enforcing availability requirements and the complexity of the overall design. Some have further questioned the overall efficacy of capacity auctions given the challenges posed by growing levels of renewable penetration and anticipated demand growth due to increased electrification.[83]

5.5 Conclusions

The Panel is of the view that contracts with generators should be designed to encourage dispatch efficiency, but also incentivize efficient investment in facility maintenance, capacity upgrades and expansions. The Panel also believes that the province's implementation of a transparent and independent regulatory review process 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. It would be beneficial to the province to apply transparent and regulatory oversight to decisions which are not subject to the disciplines of effective competition or removed from market-based mechanisms to achieve policy objectives.

The Panel supports the IESO's efforts to provide greater transparency to its needs assessment through the publishing of reports like APO and AAR, and is of the view that continued progress in clearly defining system and reliability needs could bring further benefits. The Panel also supports the IESO's progress in using competitive procurement processes to address these needs whenever possible. Creating an environment where many different resources can compete to fulfill the high-level needs defined by the IESO can result in system efficiencies and cost savings for electricity consumers.

[82] For a review of the experience with the first decade of capacity market operations, see (Spees, Newell and Pfeifenberger 2013).

[83] See (Schmalensee 2021), at page 22-26.

6 Inefficiencies in Ontario Market Design

This chapter examines key sources of inefficiencies in Ontario's market design.

Markets can drive efficiency by creating incentives which align with the market's needs and encourage efficient behaviour. Where market design does not align incentives with market needs, inefficient behaviour may be induced. The Ontario market includes several elements which do not promote efficiency incentives. The sections below provide a recap of a number of these key elements which the Panel has written on significantly in the past. The Panel looks forward to the implementation of the various market design changes contemplated under the IESO's MRP, which are meant to address many of these issues.

6.1 Uniform Pricing, Two-Schedule System, and CMSC

Ontario currently uses a province-wide uniform price for settlement instead of locational prices. Locational prices are standard practice in most electricity markets. The uniform price in Ontario was originally intended as a temporary transitional mechanism towards implementing locational prices. Contrary to those original intentions, the uniform price has endured for more than 20 years.[84] In its first major review of the electricity market shortly after market opening, the Panel highlighted the uniform price as a key market problem.[85] Locational pricing is expected to be implemented with MRP which is discussed in more detail in section 9.

The two-schedule system (2SS) works by balancing the market two separate times, using different parameters. The first (unconstrained) schedule is used to calculate the uniform price and ignores physical realities of the grid such as transmission constraints. The second (constrained) schedule provides actual dispatch instructions and accounts for the physical realities of the grid.

When physical constraints like transmission limits require some market participants to receive a dispatch instruction in the constrained schedule that is different from its unconstrained schedule, that market participant is eligible to receive a Congestion Management Settlement Credits (CMSC) payment. For example, if a generator receives a constrained schedule dispatch that is less than its unconstrained schedule, due to limited transmission, it is "constrained-off". It is eligible to receive a constrained-off CMSC payment equal to the difference between the uniform price (what it would have received if it was able to be dispatched) and its offer price (which is lower than the uniform price) for the amount of constrained-off megawatts. Similarly, if a generator receives a constrained schedule dispatch that is greater than its unconstrained schedule, it is "constrained-on". The generator is eligible to receive a constrained-on CMSC payment equal to the difference between its offer price and the uniform price (which is lower than its offer price) for the quantity of constrained-on megawatts. CMSC payments are designed to incentivize participants to follow their constrained dispatch instruction by providing them with the amount of net-revenues that they would have received had they not been constrained-off, or the level of net-revenues that they need to earn to cover their operating costs as offered when constrained-on.

However, the 2SS with CMSC payments can distort the incentives for some participants to respond efficiently in the market. Fundamentally, prices should reflect the actual needs of the grid and appropriately reward generation which meets those needs at least cost. The 2SS with CMSC can, at times, create a disconnect between the price that reflects actual system needs and the

[84] See the 2019 MRP Business Case (Independent Electricity System Operator 2019).

[85] See (Market Surveillance Panel 2002).

payment opportunities available to a market participant. This design opens the door for gaming opportunities and undermines the objective of dispatch efficiency. It can also create unnecessary and undesirable transfers of wealth among participants and consumers.

In past reports, the Panel has outlined multiple areas where the 2SS and CMSC system 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.[86]
- 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.[87] Section 7 provides more details on trading inefficiencies.
- 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.[88]
- 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 costs. This can lead to dispatch inefficiencies and unwarranted payments. The Panel has termed this behaviour "nodal price chasing".[89]

Figure 18 below illustrates average nodal prices and average HOEP prices. Large differences between nodal prices and the uniform HOEP are common, opening the door for the inefficiencies described above.[90]

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

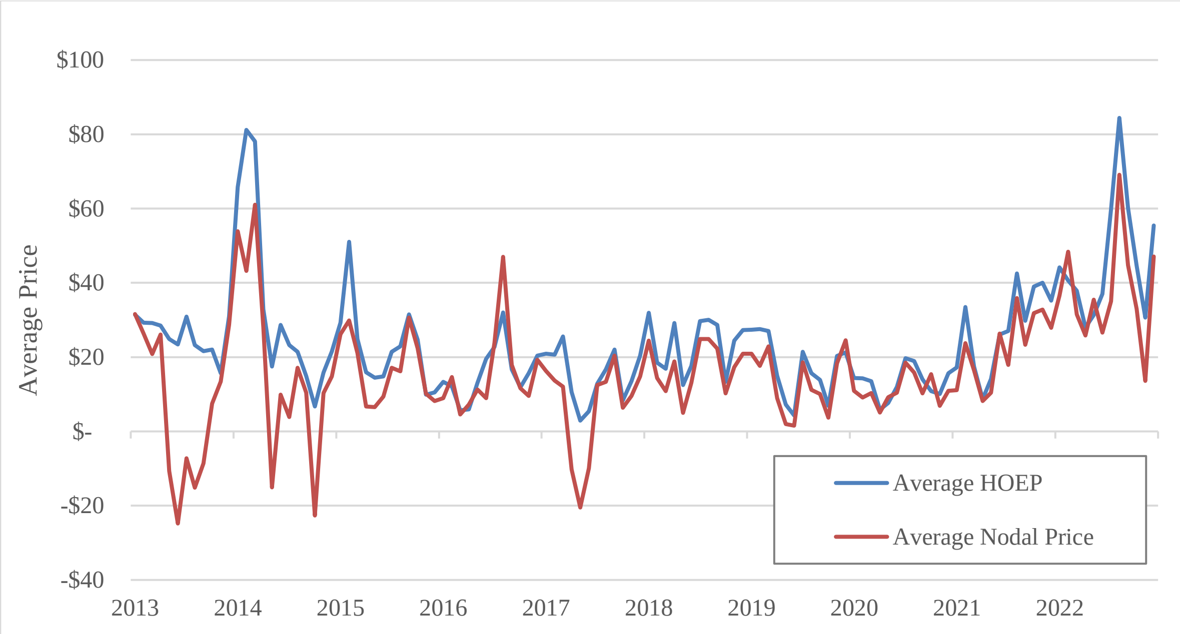
[87] Trading promotes regional efficiency by pulling generation from the lowest cost areas within the region. The uniform price limits the consideration of intra-Ontario locational cost differences, allowing for "productive inefficiency" losses when power from higher cost areas is scheduled instead of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

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

[89] "Nodal Price Chasing" refers to the behaviour 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 (Market Surveillance Panel 2005), in chapter 4.2 and (Market Surveillance Panel 2023), in chapter 3.

[90] Average nodal prices are calculated as weighted average prices across generation nodes after capping raw nodal prices at +/- $2000.

Figure 18 – Monthly Average HOEP and Average Nodal Prices, 2013-2022



The Panel looks forward to the launch of MRP to alleviate many of the inefficiencies of the 2SS. Post MRP, the IAM will use a single schedule market with locational prices. The Panel is also closely monitoring MRP design in this area, including having some load participants pay the uniform Ontario price, rather than locational pricing.[91]

6.2 RT-GCG Program

The Real-Time Generation Cost Guarantee (RT-GCG) program compensates combined-cycle generators for certain start-up and no load (standby) costs, out-of-market, using a non-competitive process.[92] 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.

This program can result in productive inefficiencies in the short-run when demand is not served using the lowest cost resources. This occurs under the RT-GCG program as non-quick start generation units are committed without consideration for fixed start-up and speed no-load costs. The RT-GCG program also does not optimize commitments over the full day or longer.

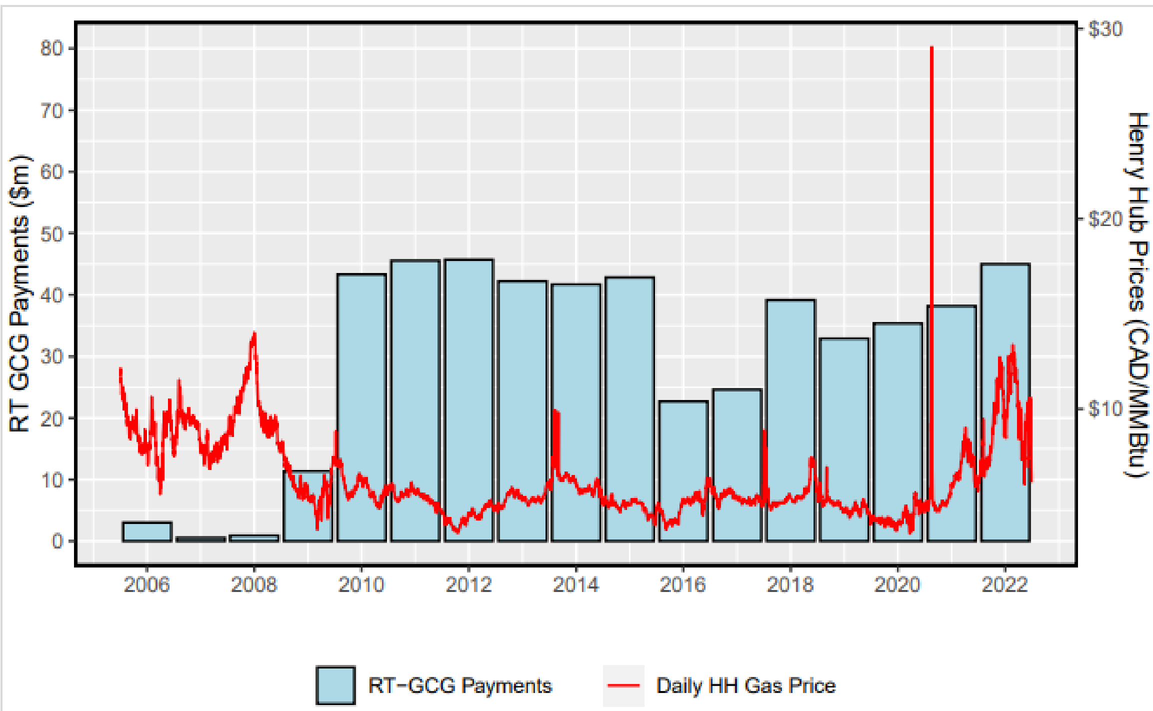
The program also acts to suppress market prices below efficient levels as it removes the incentives for generators to reflect fixed start-up and speed no-load costs in their offer prices. The program is designed to favour reliability by ensuring non-quick start resources are brought on-line during times 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.

[91] Post MRP LMPs will replace the current uniform price for settlement of all dispatchable generation facilities, non-dispatchable generation facilities, dispatchable loads and price responsive loads. Non-dispatchable loads will continue to be charged a uniform Ontario average price. See (Independent Electricity System Operator 2021c).

[92] The DA-PCG program 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 program has also been subject to gaming. The program was initially designed to only compensate for fuel costs. Starting in 2009, Operations and Maintenance costs were added. In 2010, the IESO and the Panel conducted investigations into potential program gaming, finding what it considered to be $89 million in overpayments during a 3-year period to one market participant. In parallel, the IESO's rule enforcement division conducted audits leading to repayment settlements and financial penalties of more than $200 million pursuant to market rule authorities. In 2016, the Panel published a deep analysis of the RT-GCG program, finding that in 2015 it was needed for reliability less than 1% of the time it was used.[93] From 2016 to 2018, the program was updated to use pre-approved cost values to limit room for gaming. Figure 19 below shows the average payments per start-up paid out annually under the program since 2006. Figure 19 also plots daily gas prices at Henry Hub, as generator start-up cost are dependent on the prevailing cost of fuel required to start.

Figure 19 – Total Payments under RT-GCG Program, 2006-2022



The Panel looks forward to the Enhanced Real-Time Unit Commitment (ERUC) program replacing the RT-GCG program with the launch of MRP. The Panel anticipates the program should improve competition and productive efficiency issues associated with RT-GCG. Additional discussion on the ERUC program and MRP is included in chapter 9.

6.3 ICI Program

In 2011, the Government of Ontario introduced a policy known as the Industrial Conservation Initiative (ICI), which changed the way in which Global Adjustment costs are allocated to different groups of consumers. The policy works by billing GA costs to large customers (Class A

[93] See (Market Surveillance Panel 2016), at page 111.

customers) according to their consumption during the 5 highest demand hours throughout the year.[94] If large customers do not consume during these 5 hours, they do not incur GA costs.

The ICI was designed to provide large consumers with an incentive to reduce consumption at critical peak demand times. It also offered large energy-intensive industrial and manufacturing consumers with a means to reduce their electricity costs and to reduce the risk that these consumers would shutdown their Ontario operations and relocate to a jurisdiction with lower energy costs. The anticipated reductions in peak demand were expected to also provide environmental and system benefits by reducing the need to invest in new peaking generation and to use fewer imports from coal-reliant jurisdictions.[95]

The ICI program creates a significant monetary incentive for reduced electricity usage by Class A customers during peak hours. As GA costs have risen from around $5 billion in 2011, to as high as $14 billion in 2020, the incentive has also grown. In some years, the incentive has been close to $100,000/MWh.[96] Not surprisingly, lots of peak shaving behaviour has followed. In 2016, the Panel estimated that participants reduced consumption during critical peak hours by 42% (up from 26% in 2011) above what they would have otherwise consumed. Much of this peak reduction is likely inefficient and comes at a high cost. Companies offer "GA Busting" solutions through installation of behind-the-meter diesel generators or batteries at costs much higher than grid level generation.[97]

The ICI program also shifts GA costs from large consumers to households and small businesses. This raises both fairness and social efficiency concerns. Figure 20 below shows estimated annual and cumulative cost shifting under the program. It is estimated that nearly $11 billion has been shifted from Class A to Class B consumers since 2011. In 2022, nearly $800 million was shifted.[98]

[94] Large customers are known as "Class A" customers. Class A eligibility includes all consumers with an average monthly peak demand of more than 1 MW, as well as consumers in certain manufacturing, industrial and agricultural sectors with an average monthly peak demand of more than 0.5 MW. Class B comprises all other consumers, including residential consumers and small businesses. See: (Market Surveillance Panel 2018) and (Independent Electricity System Operator 2022c).

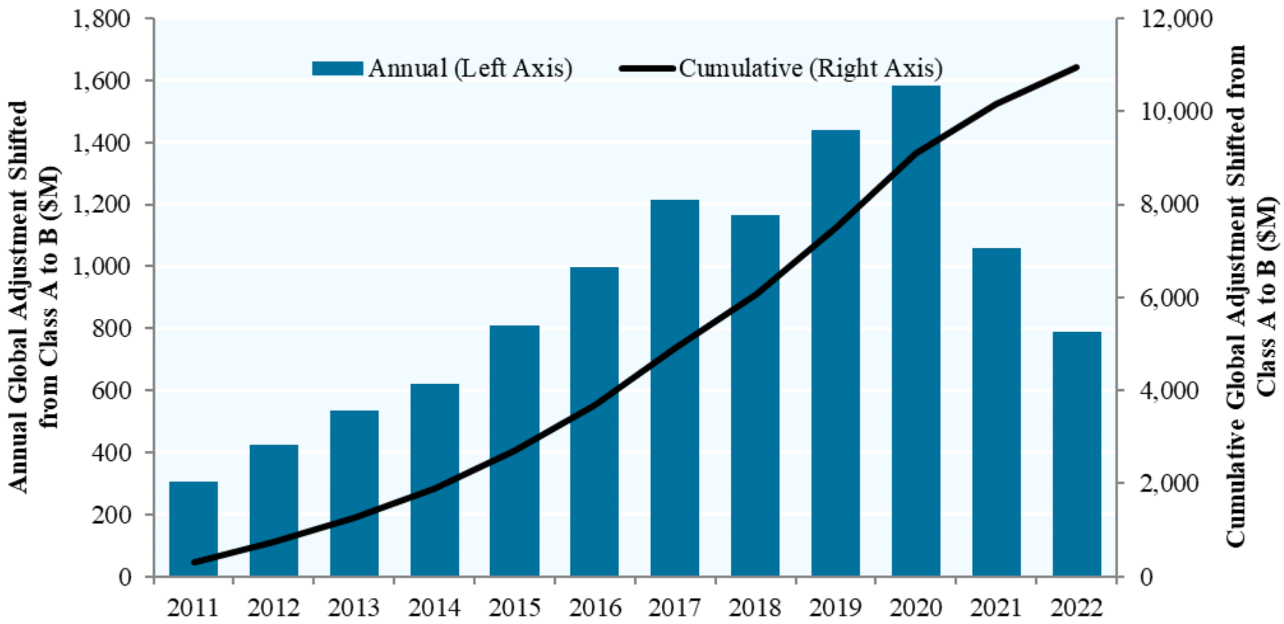
[95] See (Market Surveillance Panel 2018).

[96] For example, from the annual base period ending in April 2019 total consumption during the 5 peak hours was 115 GWh. Using the $13 billion in GA costs from 2019, this works out to a price of $113,043 per MWh during these hours. The Renewable Cost Shift has reduced GA costs and this price starting in 2021. See (Independent Electricity System Operator 2023d).

[97] See (T&T Power Group n.d.).

[98] The shifted costs increased the average Class B customer's bill by 7% in 2022.

Figure 20 – Global Adjustment Costs Shifted from Large to Small Consumers



The Panel's 2018 ICI Report summarized the program as a complicated and non-transparent means of recovering costs, with limited efficiency benefits. It also noted that the policy arguably does not allocate costs fairly in the sense of assigning costs to those who cause them and/or benefit from them being incurred.

The Renewable Cost Shift program was introduced in 2021 to shift about 85% of the non-hydroelectric renewable energy contracting costs from the Global Adjustment to the tax base. This program has served to reduce the size of the GA by about 25%, in turn reducing the magnitude of the inefficiencies arising under the program.

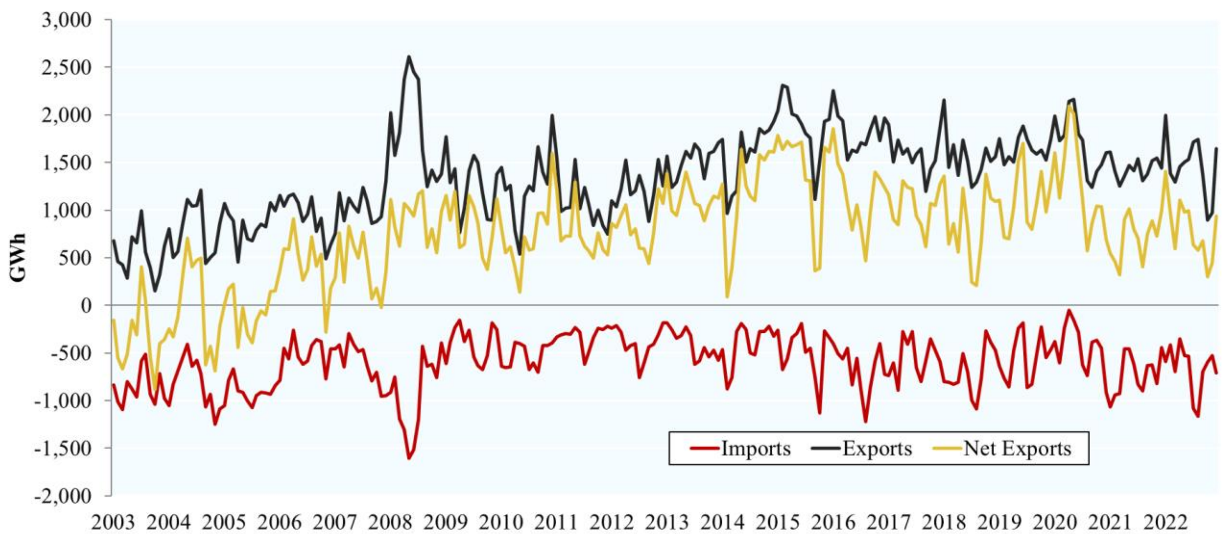
7 External Transactions

The purpose of this chapter is to provide an overview of intertie trading in the IAM. Intertie trading can facilitate the efficient use of the transmission interfaces that connect Ontario and its neighbouring jurisdictions. Intertie trading allows low-cost resources in one jurisdiction to compete to serve consumers in neighbouring 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 at lower costs.

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 (Minnesota and Michigan) and NYISO (New York), and indirect connections to two additional markets, PJM and ISO-NE. It also provides direct connections to Hydro-Québec and Manitoba Hydro's jurisdictions which do not have wholesale electricity markets. Across all five interties, Ontario maintains about 5 GW of import and 4.2 GW of export capacity.[99]

Historically, Ontario has been a net exporter of electricity. Figure 21 below shows monthly imports, exports, and net exports since January 2003. Net exports consistently increased from market open through the mid-2010s. This was a period of increased capacity investment and larger amounts of zero marginal cost resources, both of which drove down HOEP and increased net exports. Since the mid-2010s net exports have levelled off. In 2022, Ontario exported 18 TWh and imported 8 TWh (10 TWh of net exports).

Figure 21 – Monthly Imports, Exports, and Net Exports, 2003-2022[100]



[99] See (Independent Electricity System Operator 2023e).

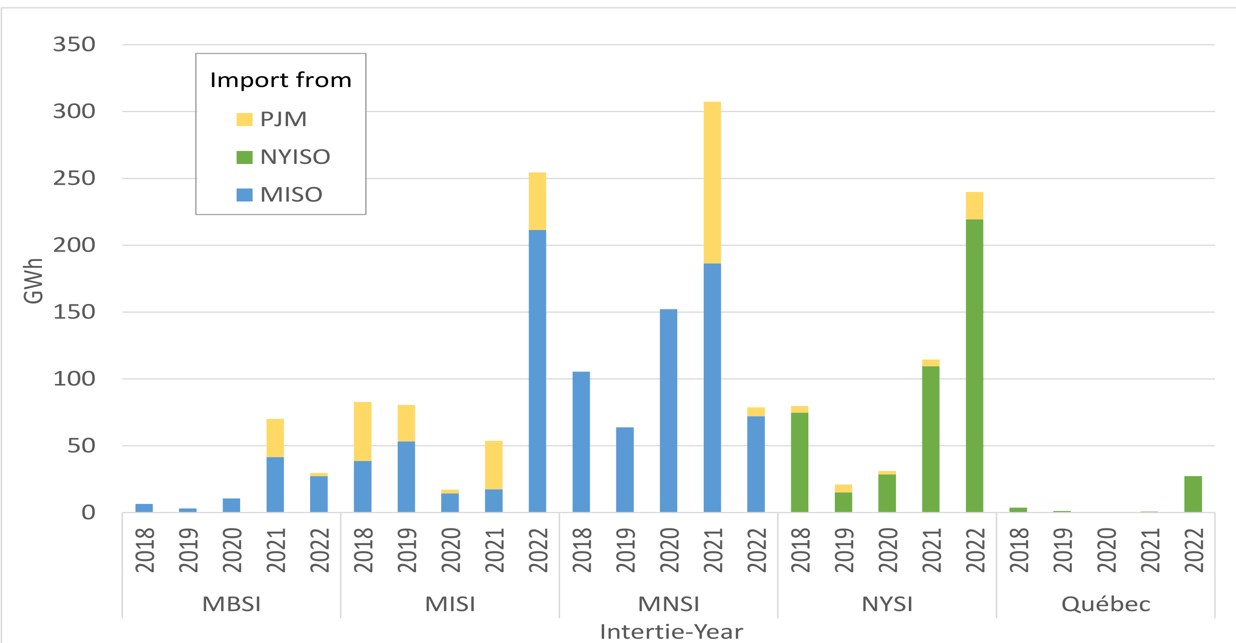
[100] In this figure, import quantities are assigned a negative value, export quantities are assigned a positive value and net exports are calculated as the sum of the two values.

7.1 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 2018 and 2022. Intertie trading efficiency is assessed on an ex-post basis by comparing the hourly average real-time locational marginal price (LMP) at the neighboring control areas with the real-time IESO nodal 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 selected neighboring U.S. control areas where historical price data are readily available, namely MISO, NYISO, and PJM.[102] In 2022, imports from and exports to these three control areas represented 8.2% and 86.7% of the total import and total export of Ontario, respectively.[103] Figure 22 presents a breakdown of imports from the three US control areas from 2018 to 2022.

Figure 22 – Import from the U.S. Control Areas by Intertie, 5 Years



[101] Real-time nodal prices of the intertie zones do not exist, thus real-time nodal prices near the interties are used. Intertie transactions are scheduled by the last pre-dispatch (PD-1) run of the Dispatch Scheduling Optimizer (DSO) before the dispatch hour. In real-time, imports and exports are fixed for the hour and are treated as non-dispatchable resources by the DSO. Thus, no nodal prices are produced for the intertie zones in real-time.

[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.

[103] In 2022, 89% of imports into Ontario originated from Québec.

Among the three 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 three U.S. control areas from 2018 to 2022. Ontario exported the most energy to MISO mainly through MISI, followed by NYISO through NYSI.

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

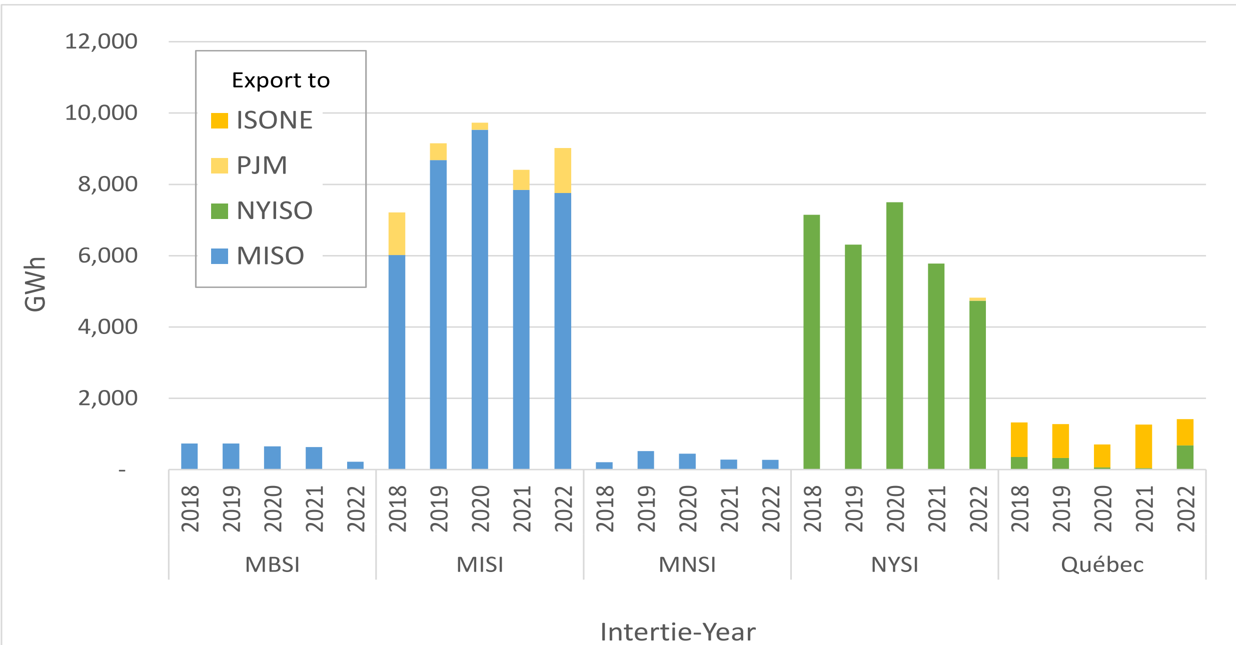


Figure 24 presents the percentage of import energy flows from the three U.S. control areas that were ex-post efficient from 2018 to 2022.[105] An import energy flow is considered efficient ex-post if the real-time LMP at the source control area is lower than the real-time IESO nodal price near the relevant intertie.[106]

[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 (Market Surveillance Panel 2023), chapter 3.

[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, IESO real-time nodal prices for Kenora, Fort Frances, and Beck2 are used for assessing MBSI, MNSI, NYSI intertie transactions, respectively. Average nodal 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

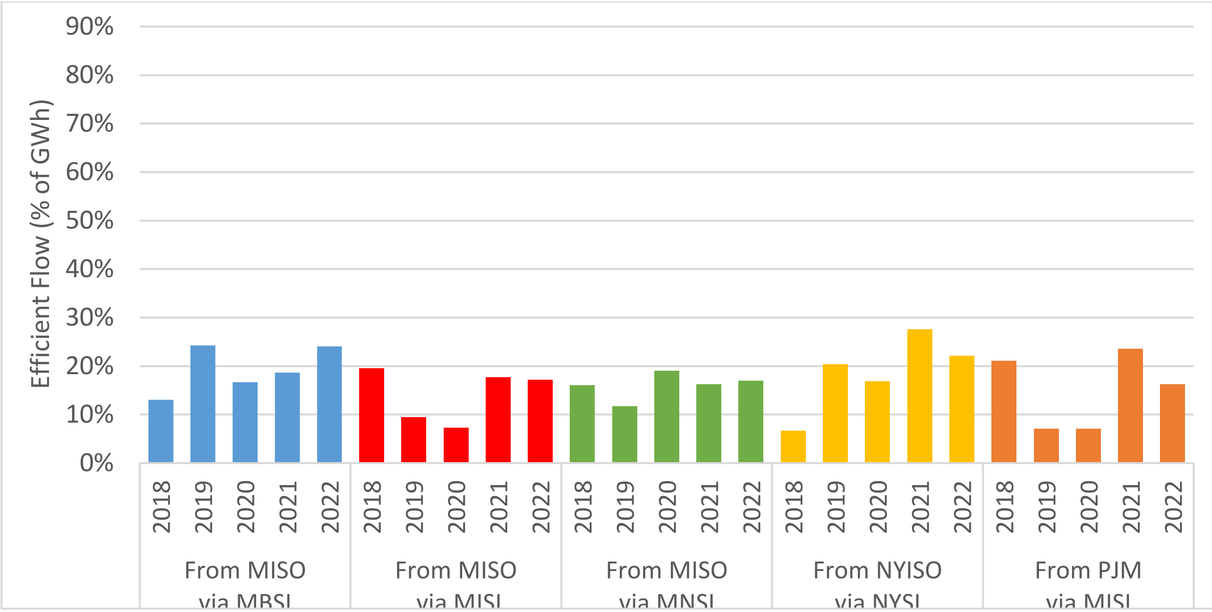
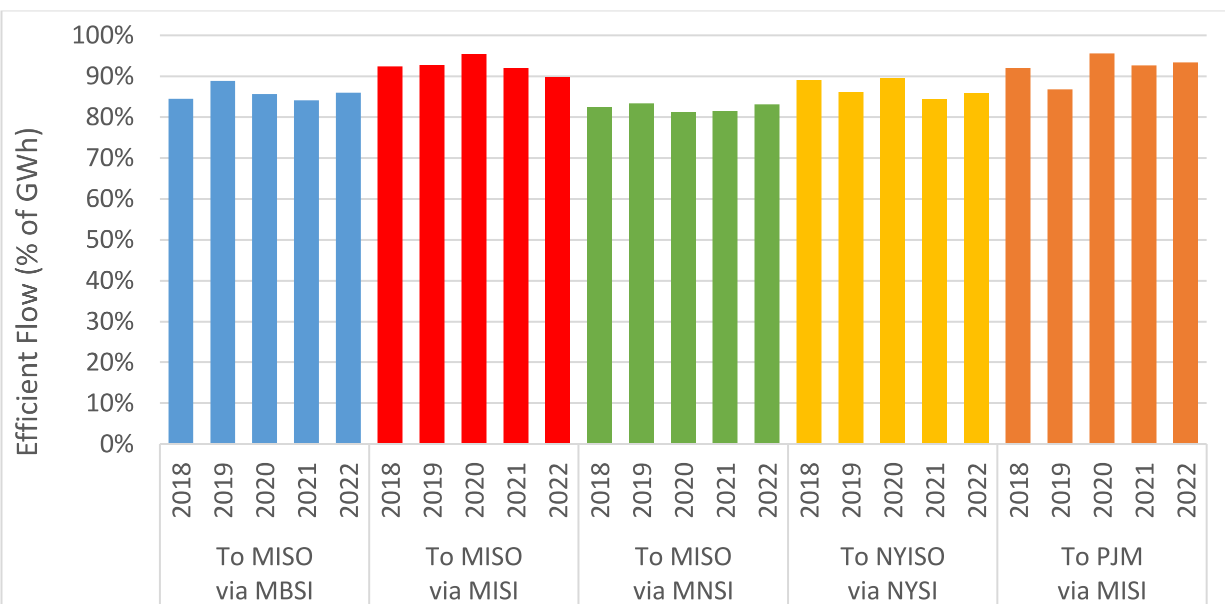


Figure 25 presents the percentage of export energy flows to the three U.S. control areas that were ex-post efficient from 2018 to 2022. An export energy flow is considered efficient ex-post if the real-time LMP at the sink control area is higher than the real-time IESO nodal price near the relevant intertie.

Figure 25 – Efficiency of Energy Exports, 5 Years



During the five years, the percentage of ex-post efficient exports was consistently above 80% across the interties and destinations and was especially high at the Michigan intertie. In contrast, the percentage of ex-post efficient imports was less than 30% 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 projected price in the hour-ahead timeframe (PD-1) tends to be higher than the actual real-time price. 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 prices near the interties. The efficiency of imports would be higher across the interties and source areas if the real-time IESO nodal prices were the same as the PD-1 prices.

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

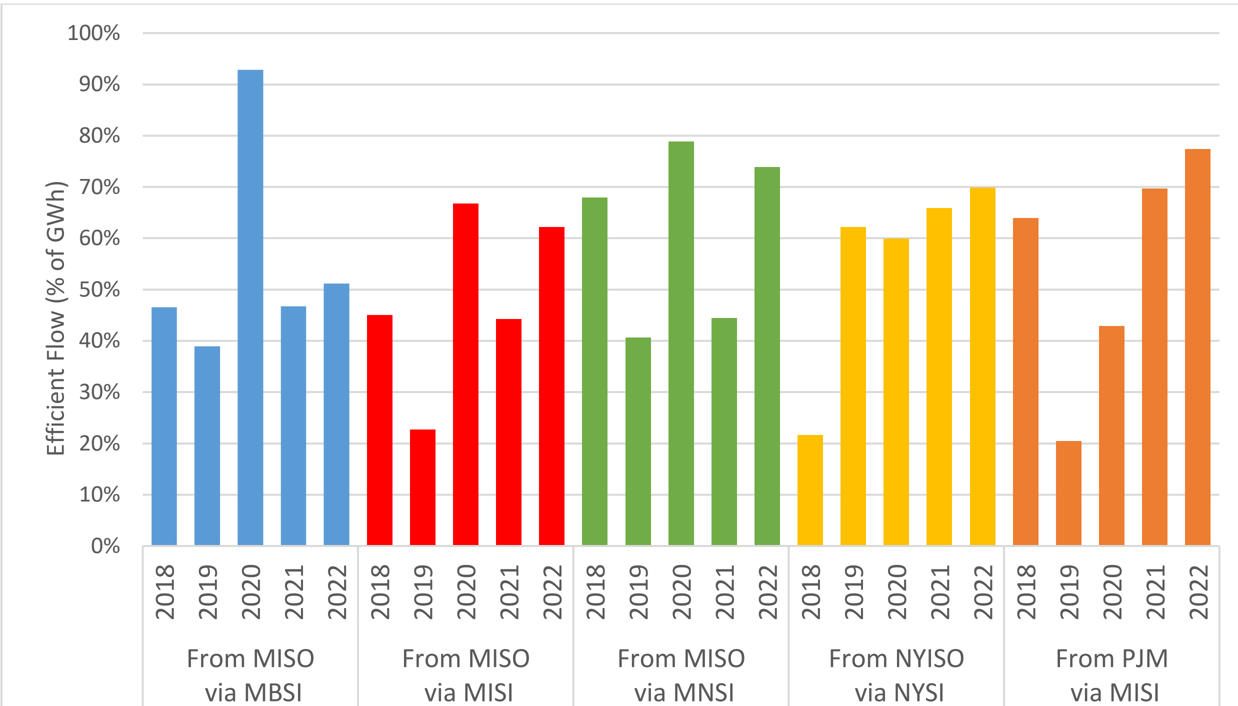
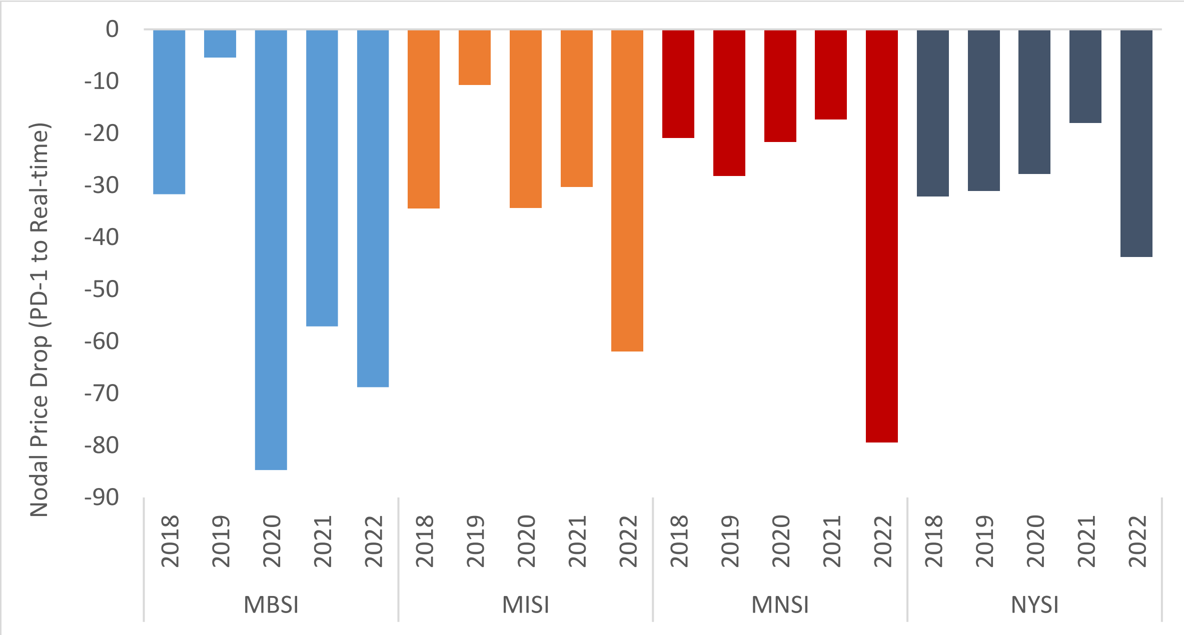


Figure 17 illustrates the average nodal price discrepancy between PD-1 and real-time near the four interties when there were imports scheduled on the interties from the U.S. control areas. Excluding MBSI, which had the least energy import among the four interties,[108] the real-time prices were lower than the PD-1 prices by around $30/MWh between 2018 and 2021, and around $60/MWh in 2022.

[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.

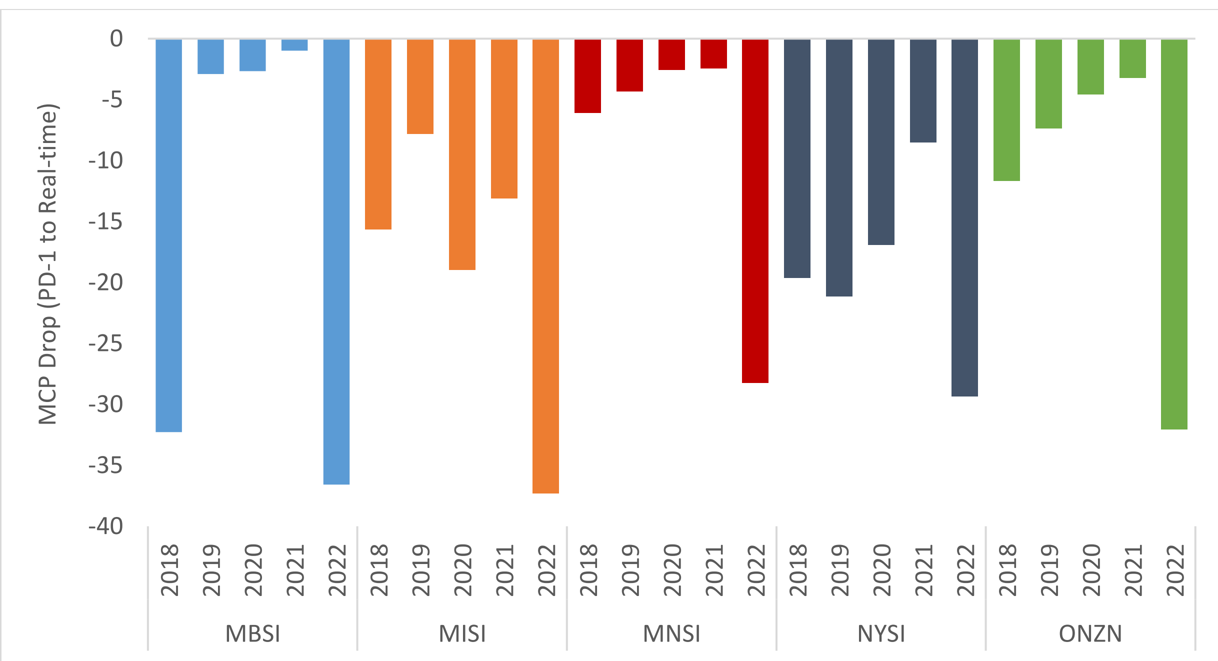
[108] Not counting energy imports from the province of Manitoba.

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



Consistent with what was observed in the nodal prices, intertie zone MCP (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 Drop from PD-1 to Real-Time during Importing Hours, 5 Years



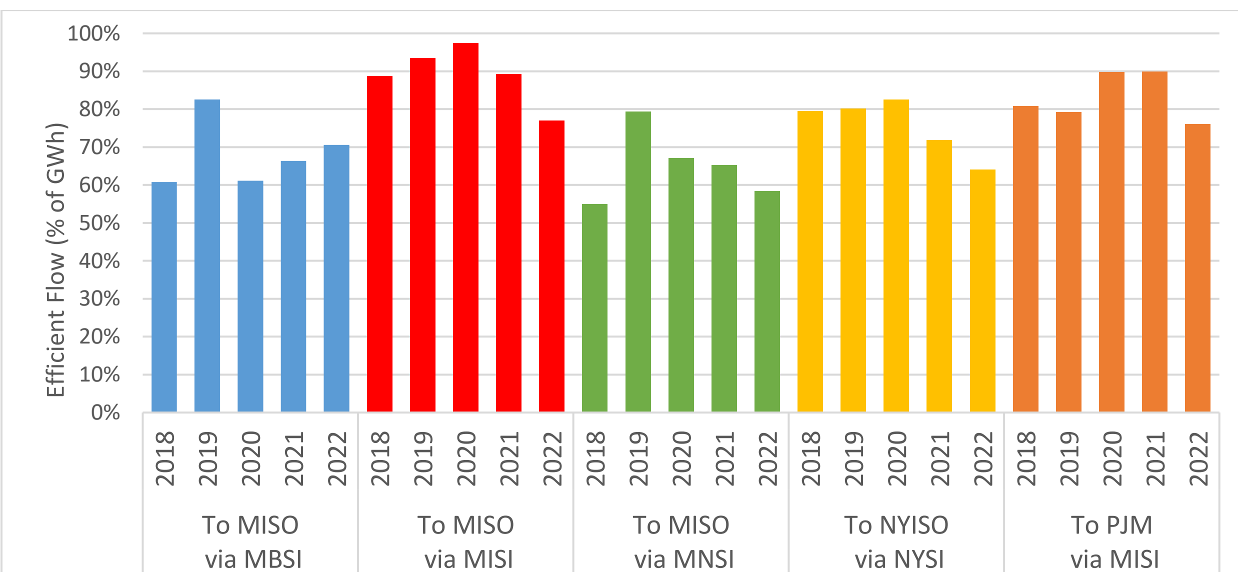
Previous MSP reports have discussed the divergence between the pre-dispatch and the real-time MCP. Demand forecast deviation and wind generation forecast deviation between PD-1 and real-time have been identified as the two main contributing factors.[109] When demand is over-forecasted and wind generation is under-forecasted in the pre-dispatch, PD-1 MCP will be higher than real-time MCP and imports will 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 by the real-time price and incur a loss relative to its offer price. In principle, the price risk associated with real-time settlement, could deter those import trades where the offer prices were expected to be higher than the real-time intertie zone MCP.

In the IAM, the price risk of incurring a loss is eliminated through implementation of the Intertie Offer Guarantee (IOG). The IOG stipulates that import quantities selected in PD-1 receive the higher of the real-time MCP or the import offer price.

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 29 presents a hypothetical export efficiency assessment comparing the real-time LMP at the neighboring control areas with the PD-1 IESO nodal prices near the interties. Compared to Figure 25, the efficiency of export would be consistently lower across the interties and destination areas if the real-time IESO nodal prices were the same as the PD-1 prices.

Figure 29 – Hypothetical Efficiency of Energy Export using PD-1 Nodal Prices, 5 Years



[109] When the marginal (price setting) unit in PD-1 is an import, the price may be lower in real-time as this import offer price is adjusted to -$2,000. All else constant, the price would instead be set by an internal resource at a price equal to or less than the PD-1 price.

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 changes in price from PD-1 to 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 sub-optimal import levels. The Panel anticipates changes to intertie trading as part of MRP, including improved efficiency of import and export scheduling driven by the day-ahead market and the use of locational prices at interties.

8 Operating Reserves and Ancillary Services

This chapter provides a brief overview of the operating reserves and ancillary services markets administered by the IESO.

Operating reserves (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. Similar to energy, OR prices are determined every 5 minutes. Demand for OR is based primarily on reliability standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

In recent reports, the Panel has commented on the role of dispatchable loads in the OR market. In its May 2017 report, 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.[110]

In 2021, IESO staff 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. The Panel also found that that sufficient evidence was not provided to support the IESO staff recommendations, including to justify the apparently less stringent exemption conditions being put forth.[111]

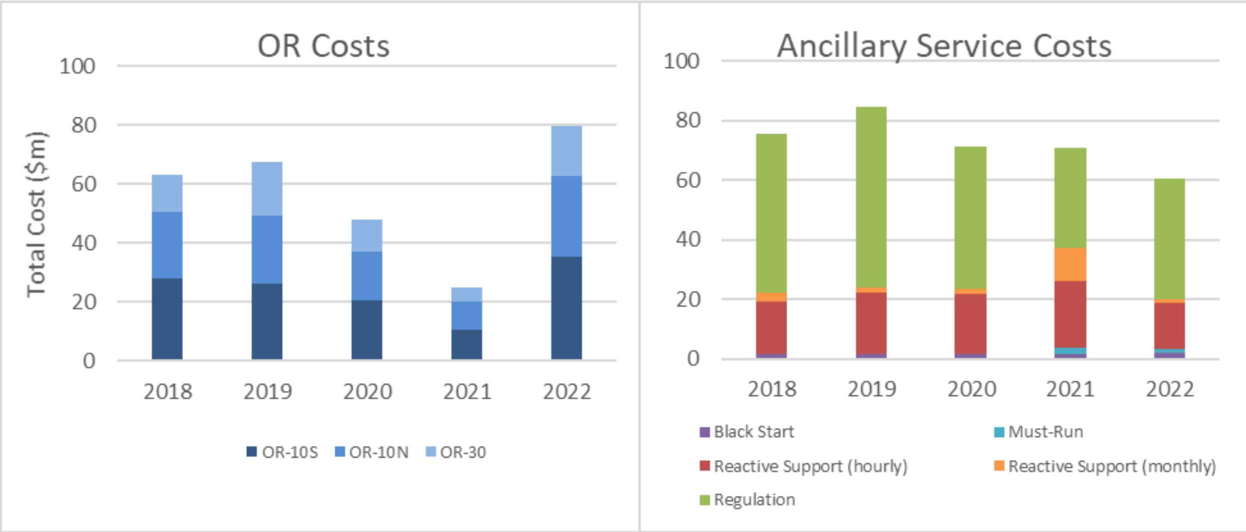
Ancillary services are purchased by the IESO to ensure the reliable operation of the bulk grid. Unlike OR, the IESO procures ancillary services through contracts as it was determined these services cannot feasibly be provided competitively within the day-to-day operation of the real-time market. The ancillary services for which the IESO contracts includes certified black start facilities, regulation service, reactive support and voltage control service, and reliability must-run services.[112] Figure 30 below illustrates the total payments for OR and ancillary services over the last 5 years.

[110] See (Market Surveillance Panel 2017).

[111] See (Market Survelliance Panel 2022).

[112] For more information on each ancillary services see: (Independent Electricity System Operator 2023b).

Figure 30 – OR and Ancillary Service Costs, 2018-2022



In 2022, $80 million was spent on OR and $59 million on ancillary services. These costs represent less than 1% of total all-in costs. Similar to energy, the largest player in these markets was OPG who received 33% of the OR payments and 84% of the ancillary services payments. The Panel anticipates increasing competition in these markets through the IESO's recent procurement initiatives, including at least 1500 MW of new storage resources scheduled to be online through 2027.

9 Market Renewal Program

The Market Renewal Program will bring about key changes to the wholesale market to improve efficiency, competition, and transparency.[113] These changes are expected to address many of the inefficient elements unique to the Ontario market. The new market is scheduled to go live in the second quarter of 2025. Under the program, three key changes to the market will be:

1) Replacement of the two-schedule market with a single schedule market (SSM), reducing the need for out-of-market payments such as 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 will help address two key inefficiencies in current market design as highlighted in Chapter 6.

The single schedule market will help alleviate inefficiencies associated with the uniform price and two-schedule system as described in section 6.1. 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 only compensated for costs. Additionally, the current system does not adequately signal or incentivize the market to respond to locational cost differences across Ontario. In ERCOT, a move from zonal prices to LMPs was estimated to have reduced prices by 2%.[114] Similarly, the move to nodal prices in California in 2009 was found to improve dispatch of the gas fleet by 2%.[115]

The DAM and ERUC programs will improve the scheduling and commitment of dispatchable generation.[116] These programs will replace the RT-GCG program, resolving many of the inefficiencies associated with the program described in section 6.2.[117] 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 will improve efficiency by optimizing the scheduling of resources over multiple hours. When creating the optimized schedule, ERUC will also correctly account for key generator characteristics such a minimum loading points. Under the current design, the DSO 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.

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[113] Market Renewal Programs mission statement, “Market Renewal will deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost.” See (Independent Electricity System Operator n.d.).

[114] See (Zarnikau, Woo and Baldick 2014).

[115] See (Wolak 2011).

[116] See (Independent Electricity System Operator 2019).

[117] The programs will also replace the Day-Ahead Commitment Program (DACP).

The IESO anticipates that 18 previous Panel market design recommendations will be addressed through the MRP. The Panel intends to report on MRP implementation results through its future State of the Market analysis and special reports on single market elements.

10 Appendix A: Role of the Market Surveillance Panel

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

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

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

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

The Panel reports on the results of its monitoring and investigations. The Panel does not have the legislative mandate to impose sanctions or other remedies in response to inappropriate conduct or market defects, but it does make recommendations for remedial action as it considers appropriate.

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